STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of Consumers Energy Company for authority to increase its rates for the distribution of natural gas and for other relief.
_______________________________________/

Case No. U-18424

Volume No. 2

CROSS-EXAMINATION

Proceedings held in the above-entitled matter before Suzanne D. Sonneborn, Administrative Law Judge with MAHS, at the Michigan Public Service Commission, 7109 West Saginaw, Lake Michigan Room, Lansing, Michigan, Wednesday, April 4, 2018, 9:06 a.m.

APPEARANCES:

ANNE M. UITVLUGT, ESQ.
GARY A. GENSCH, JR., ESQ.
ROBERT W. BEACH, ESQ.
THERESA A. G. STALEY, ESQ.
MICHAEL C. RAMPE, ESQ.
Consumers Energy Company
One Energy Plaza, Room EP11-223
Jackson, Michigan 49201

On behalf of Consumers Energy Company

DON L. KESKEY, ESQ.
Public Law Resource Center, PLLC
333 Albert Avenue, Suite 425
East Lansing, Michigan 48823

On behalf of Residential Customer Group

(Continued)

APPEARANCES Continued:

JENNIFER UTTER HESTON, ESQ.
Fraser Trebilcock Davis & Dunlap, P.C.
124 West Allegan, Suite 1000
Lansing, Michigan 48933

On behalf of Retail Energy Supply Association

BRYAN A. BRANDENBURG, ESQ.
CLARK HILL, PLC
212 East Grand River Avenue
Lansing, Michigan 48906

On behalf of Association of Businesses
Advocating Tariff Equity

JOHN JANISZEWSKI,
JOEL BRETSCHE KING,
Assistant Attorneys General
525 W. Ottawa Street, 7th floor
P.O. Box 30755
Lansing, Michigan 48909

On behalf of Attorney General Bill Schuette

LAUREN DONOFRIO,
AMIT T. SINGH,
Assistant Attorneys General
7109 West Saginaw Highway, Floor 3
Lansing, Michigan 48917

On behalf of Michigan Public Service
Commission Staff

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REPORTED BY: Marie T. Schroeder, CSR-2183
Lori Anne Penn, CSR-1315

I N D E X

I N D E X

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A-3	Sch. C-1, C-2, C-3, C-4, C-5, C-6, C-7, C-8, C-9, C-10, C-11, C-12, C-13, C-14, C-15, C-16, C-17, C-18, C-19, C-20, C-21, C-22, C-23 (VOLANSKY)	515	515	516
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A-41	2016 - 12 Months Ended June 30, 2019 Gas Compression Storage and Gas Management Services O&M Expenses (HILL)	440	440	440
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A-86	Adjusted Net Operating Income Pro-forma Interest Adjustment for the Projected 12-Month Period Ending June 30, 2019 (COKER)	171	173	173
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A-103	2016-12 Months Ending June 30, 2019 Gas Compression Storage and Gas Management Services O&M Expenses (HILL)	440	440	440
A-104	OVS Compressor Station - Dehydration System Replacement - Schedule (PMS) - 2/23/18 (HILL)	440	440	440
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NUMBER	DESCRIPTION	MRKD	OFRD	RECD
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Lansing, Michigan
Wednesday, April 4, 2018
At 9:06 a.m.

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(Hearing resumes following adjournment of Tuesday, November 28, 2017.)

JUDGE SONNEBORN: Good morning. This is a continuation of a hearing in Case No. U-18424. Pursuant to the schedule established in this case, this is the time and date set for the evidentiary hearing and cross-examination.

Let's put our appearances on the record, beginning first with Ms. Uitvlugt.

MS. UITVLUGT: Good morning, your Honor. Anne Uitvlugt appearing on behalf of Consumers Energy Company. I'd also like to enter the appearance of Bret Totoraitis, Robert Beach, Gary Gensch, Theresa Staley, and Michael Rampe.

JUDGE SONNEBORN: Thank you. Good morning to each of you.

MR. GENSCH: Good morning.

JUDGE SONNEBORN: And on behalf of Staff, Ms. Donofrio.

MS. DONOFRIO: Yes. Lauren Donofrio and Amit Singh on behalf of Michigan Public Service

Commission Staff.

JUDGE SONNEBORN: Thank you. Good morning to both of you. And Mr. King.

MR. KING: Good morning, your Honor. Joel King and John Janiszewski on behalf of Attorney General Bill Schuette.

JUDGE SONNEBORN: Thank you. Good morning to both of you. And Ms. Heston.

MS. HESTON: Good morning, your Honor. Jennifer Heston of the law firm of Fraser, Trebilcock, Davis & Dunlap appearing on behalf of the Retail Energy Supply Association.

JUDGE SONNEBORN: Thank you. Good morning, Ms. Heston. And Mr. Brandenburg.

MR. BRANDENBURG: Good morning, your Honor. Bryan Brandenburg from Clark Hill, PLC, representing ABATE.

JUDGE SONNEBORN: Thank you. Good morning, Mr. Brandenburg.

MR. BRANDENBURG: Good morning.

JUDGE SONNEBORN: And Mr. Keskey.

MR. KESKEY: Good morning, your Honor. Don Keskey appearing on behalf of the Residential Customer Group. I would also like to enter the appearance of Brian Coyer on behalf of the Residential

Customer Group.

JUDGE SONNEBORN: Thank you. Good morning, Mr. Keskey.

We have had two motions filed before today's hearing, a motion for leave to file surrebuttal testimony has been filed by RESA, and we also have a motion to strike portions of the direct and rebuttal testimony of Mr. Maddipati that has been filed by ABATE. Upon agreement of the parties, that latter motion will be taken up at the outset of Mr. Maddipati's cross-examination on Friday. But we will proceed at this time with RESA's motion for leave to file surrebuttal testimony.

I have read both the motion as well as the Company's response. Would you like to add anything further, Ms. Heston?

MS. HESTON: Yes, your Honor, just a few words. RESA, through its witness, John Mehling, is the proponent of a pooling program for Consumers' gas transportation customers. RESA introduced the pooling program issue when it filed Mr. Mehling's direct testimony in this case on February 28. Consumers filed rebuttal testimony of its witness, Ms. Elizabeth Curtis, and RESA is now seeking an opportunity to file a limited reply in the form of surrebuttal testimony to

Ms. Curtis's rebuttal testimony. And as you know, your Honor, under the Commission's Rules, Rule 792.10427(3), the presiding officer has the authority and discretion to permit surrebuttal, and we ask that you grant RESA's motion. I have just a few words this morning responding to Consumers' response to our surrebuttal motion that I'd like to add.

First, Consumers indicates that surrebuttal is rare in MPSC proceedings. I don't think surrebuttal is as rare as Consumers would like you to believe, your Honor, and I note that Consumers' counsel had to go back nearly 40 years to find authority to support the motion that surrebuttal should be denied. My impression is that surrebuttal has become more common in recent years, and that written testimony provides greater clarity of the issues that are presented by witnesses in these very complex rate case proceedings. If you do a quick search of the Commission's docketing system, there's numerous hits for surrebuttal testimony.

Consumers' counsel also indicated that RESA failed to provide good cause to support the admission of surrebuttal, and that we failed to establish that proper post surrebuttal is essential to providing an adequate record in this proceeding. I will note, your Honor, that it was not possible for RESA to anticipate

Ms. Curtis's concerns in response to Mr. Mehling's testimony, thus, there is good cause to be able to permit Mr. Mehling to provide a limited response to Ms. Curtis's concerns.

Again, I'd note that prefiled written testimony is a much more efficient and clearer way to respond to facts and arguments that are put forth by another party than trying to elicit the same information through cross-examination. So the value in having a clear record I think is paramount to support the Commission's reasoned decision-making in this proceeding.

Consumers also indicates that fundamental notions of procedural fairness dictate that the applicant in any proceeding should ordinarily have the last opportunity to respond to any new legal and factual theories proposed by a party. I'll say with respect to that concern, your Honor, that the error in Consumers' argumentation is that RESA is in fact the proponent in the first instance of the pooling program for gas transportation customers, thus, it's RESA who should be given an opportunity to respond to critiques of its proposal. And in fact, as Consumers' counsel noted, Consumers argues that it never presented a pooling proposal and that it's RESA who has the obligation to support its proposed program, and we agree, and RESA should be given an opportunity to provide a limited response to the critiques of its proposal in this case.

Further, Consumers argues that it's being denied an opportunity to address the further arguments made by RESA in its surrebuttal testimony, and we believe that assertion by Consumers is simply not true. Consumers does have a hearing in this case, and Consumers can cross-examine Mr. Mehling if they so choose, Consumers can respond through briefs, and Consumers could have chosen leave to file sur-surrebuttal if it had wanted to do so. I do note that Consumers has asked for an opportunity to file sur-surrebuttal, and we don't think it would be appropriate in this particular case because, again, the proponent of a proposal should be the one that has the last opportunity to respond to critique to that proposal.

Further, Consumers argues that our surrebuttal is supplemental direct. Again, I would submit to your Honor that that's not the case. The surrebuttal that we've filed in this case is very tightly tailored to Ms. Curtis's rebuttal testimony, it responds directly to Ms. Curtis's concerns without going far afield. The surrebuttal testimony we filed is squarely focused on responding to the concerns that she's made in her rebuttal testimony. There's no way we could have foreseen Ms. Curtis's concerns and addressed them in our direct case. So our surrebuttal testimony is truly in the nature of rebuttal as opposed to supplemental direct.

And then finally I will respond to Consumers' request for sur-surrebuttal. I will just note that Consumers never actually filed sur-surrebuttal, so we can't review what Consumers has in mind for responding to Mr. Mehling's surrebuttal testimony in this proceeding, so I don't know whether I would have an objection to that in general. We haven't seen it, we don't know whether it would be relevant and admissible, and I think it would be inappropriate for your Honor to provide a blanket authorization to permit sur-surrebuttal testimony by Consumers. And again, I will note, your Honor, that as the proponent of the pooling program proposal, it really should be RESA who has the last opportunity to respond to criticisms about its proposal.

So with that, your Honor, we don't think that the arguments and concerns that have been raised by Consumers in its answer to our motion for leave to file surrebuttal testimony has merit, and we ask that you grant our motion for surrebuttal. Thank you.

JUDGE SONNEBORN: Thank you, Ms. Heston.

Ms. Uitvlugt.

MS. UITVLUGT: Yes, just very briefly,

your Honor. In reviewing the testimony put forth by Mr. Mehling, it directly addresses step by step the criticisms offered by Ms. Curtis. Ms. Curtis reviewed the pooling proposal put forward by RESA; Consumers does not support putting forward this pooling proposal, it was nowhere in its direct case, and this proposal would directly impact Consumers Energy. Ms. Curtis indicated that there -- the proposal put forth by RESA's witness was not very specific and had a lot of questions to be addressed, and that was the focus of her rebuttal testimony as to why his proposal should not be implemented at this time.

RESA argues in its motion that no one would be prejudiced by its surrebuttal testimony, but that isn't true. Consumers Energy will be directly prejudiced by the surrebuttal testimony as its opposing the adoption of this pooling proposal that would be a part of Consumers Energy's tariffs.

While RESA indicates that as a proponent it should have the last word in supporting its proposal, if taken to the extreme, then anyone who puts forth a proposal in their direct testimony against the Applicant will be able to further support that proposal, leaving the Applicant in a prejudicial position as to not being able to argue against the application of that proposal to its tariffs if it is not in favor of it, and so in that sense, it is directly prejudicial to the Company.

RESA's counsel argues that Mr. Mehling's testimony is a clean and un -- is a clean way to provide additional clarity to the record in order to further respond to Consumers Energy, and Consumers Energy has the ability through hearing, cross-examine, and briefs to respond to the additional testimony put forth by RESA. I would note that the same is true for RESA's counsel. In this case, Consumers Energy did not support this proposal, RESA's counsel did, and through cross-examination of both Ms. Curtis and Mr. Mehling, any additional information with respect to this proposal could be determined and put forth in the record and be used by both parties in their briefs, keeping -- which would not prejudice either party in this case.

JUDGE SONNEBORN: Would the Company be able to prepare proposed sur-surrebuttal by Ms. Curtis within the next couple of days?

MS. UITVLUGT: We can try, your Honor.

JUDGE SONNEBORN: All right.

MS. UITVLUGT: We can try, your Honor.

JUDGE SONNEBORN: O.K. Ms. Heston, do you have anything further you wish to respond to?

MS. HESTON: No, your Honor.

JUDGE SONNEBORN: All right. Rule 427.3 of the Commission's Rules of Practice and Procedure does provide that some surrebuttal testimony may be permitted at the discretion of the presiding officer or the Commission.

Having reviewed RESA's proposed surrebuttal testimony, I find that while it is indeed responsive to the rebuttal testimony of the Company's witness, Elizabeth Curtis, it is not in fact new information, but information that could have been included in RESA's direct case. RESA's proposed surrebuttal testimony also does not seek to refute or otherwise disagree with Ms. Curtis's rebuttal, but rather to address the concerns raised by Ms. Curtis regarding RESA's pooling proposal concerns that could have been reasonably anticipated and addressed in RESA's direct case.

Having said all this, I nonetheless find that RESA's proposed surrebuttal would add to the adequacy of a more complete record regarding the implementation of a gas transportation customer pooling program. But to avoid any resulting prejudice as articulated by the Company, I will permit RESA's surrebuttal, but also grant the Company's request to file limited sur-surrebuttal, limited in scope to responding to the pooling concerns addressed by RESA. I'd like to review that proposed sur-surrebuttal in advance of allowing for its filing. So in that respect, while I am ruling today, that portion of my ruling is under advisement, subject to receiving and reviewing that limited sur-surrebuttal by Ms. Curtis.

All right. Is there anything further that we need to address before we turn to the Company's case? (No response.)

Ms. Uitvlugt, you may proceed with Ms. DeLacy.

MS. UITVLUGT: Thank you, your Honor.

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(Documents marked for identification by the Court Reporter as Exhibit Nos. A-12, A-20 through A-22, A-91 Confidential, A-92, and A-93.)

MR. GENSCH: Your Honor, the Company's first witness today is Ms. Lisa DeLacy, however, the only party who had expressed interest in crossing Ms. DeLacy was the Attorney General, and we have agreed to the admission of a discovery response in exchange for waiving cross of Ms. DeLacy, so at this point, I am going to move to bind in her testimony and the admission of her exhibits, without cross-examination.

JUDGE SONNEBORN: Thank you.

MR. GENSCH: Ms. DeLacy's direct testimony consisted of a cover page and 51 pages of questions and answers, and Ms. DeLacy sponsored Exhibit A-12 Schedule B-5.1, Exhibit A-20, A-21, and A-22 in connection with her direct testimony. Ms. DeLacy also presented rebuttal testimony, which consisted of a cover page and 16 pages of questions and answers, and sponsored Exhibits A-91, which is a Confidential exhibit, A-92, and A-93.

I'll also note I have a couple very minor revisions to Ms. DeLacy's direct testimony. On page 3 at the bottom, very bottom of the page, the line sort of ends "during 2016 of $5.298 million", that should be $5.268 million" instead of "298".

And then turning to page 18, footnote 15, the end of the footnote says, "surveys in the Muskegon, Flint, and Grand Rapids areas", that should read -- we're adding two more areas to that -- that should read "surveys in the Flint, Kalamazoo, Muskegon, Zeeland, and Grand Rapids areas", so we're adding Flint and Kalamazoo. And the same addition should be on footnote 16, "surveys in the Flint, Kalamazoo, Muskegon, Zeeland, and Grand Rapids area."

And with those changes, I move to bind into the record the direct and rebuttal testimony of Lisa

DeLacy, and to admit Exhibits A-12 Schedule B-5.1, A-20, A-21, A-22, Confidential Exhibit A-91, A-92, and A-93.

JUDGE SONNEBORN: Thank you. Are there any objections to binding in the direct and rebuttal testimony and exhibits as described by Mr. Gensch of Lisa M DeLacy? (No response.)

Hearing no objections, I will bind into the record Ms. DeLacy's direct and rebuttal testimony, as well as the exhibits, A-12 Schedule B-5.1, A-20, A-21, A-22, A-91, noting that it's Confidential, and Exhibits A-92 and 93.

MR. GENSCH: Thank you your Honor.

(Testimony bound in.)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief	)))))	Case No. U-18424

DIRECT TESTIMONY

OF

LISA M. DELACY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2017

LISA M. DELACY
DIRECT TESTIMONY

Q. Please state your name and business address.

A. My name is Lisa M. DeLacy, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Executive Director of the Smart Energy and Gas Automated Meter Reading ("AMR") Program in the Company's Engineering Department.

Q. Please describe your educational background and work experience.

A. I received a Bachelor of Science Degree in Electric Engineering from Michigan Technological University in 1993. For the first five years of my career, I worked at Wisconsin Public Service ("WPS") as a Procurement Engineer at the Kewanee Nuclear Plant, and as a Distribution Engineer in WPS's Green Bay offices. I joined Consumers Energy in 1998 as a High Voltage Distribution Engineer advancing to a supervisory role in that department before accepting a lead supervisory role in the Customer Operations Department on the Business Customer Technical Services Engineering team in 2007. I then advanced to the Director of the Business Customer Technical Services team in 2008. In 2010, I joined the Liaison team in the Company's Regulatory Affairs Department, supporting the Customer Operations area. In 2012, I advanced within this department to the Manager of the Regulatory Affairs Liaison team, with specific responsibility for administration and coordination of the Liaison team, and improving communications with the Michigan Public Service Commission ("MPSC" or the "Commission") Staff with focus on electric and gas rate cases, general Company operations, and the plans for the addition of new generation capacity. In July 2014, I was promoted to the position of

Executive Director for the Smart Energy Program. In 2016, my responsibilities were expanded to include the implementation of the Gas AMR project.

Q. What are your responsibilities as the Executive Director of Smart Energy?

A. My responsibilities generally consist of leading the management of the scope, schedule, and cost of the nearly completed Advanced Metering Infrastructure ("AMI") technology implementation in the Company's electric and gas/electric combination service areas, as well as the ongoing installation of AMR technology in our gas-only service areas. Specific responsibilities have included:

- Leadership of the project management office for both AMI and AMR programs, including the management of program scope, schedule, and budget. This also includes vendor management responsibilities and coordinating closely with the Company's supply chain function;

- Leadership of the Smart Energy Operations Center ("SEOC"); providing day-to-day operational support for the SEOC team lead including measuring key operational indicators and taking corrective action on the achievement of operational goals; ensuring timely root cause analysis and problem solving related to systems, meter, and communication issues; meter vendor support to resolve meter issues; alignment with internal stakeholders regarding work priority; alignment with external stakeholders regarding cellular upgrades and the related necessary firmware upgrades; and general support to the team regarding daily meter and gas communication module issues that are discovered. Due to organizational changes implemented July 1, 2017, the SEOC is now managed within the Electric Operations Department. This organizational transition follows the financial management responsibility for the Operation and Maintenance ("O&M") costs associated with SEOC operations, which had transitioned to operational areas in January of 2017;

- Leadership of AMI and AMR device deployment efforts, including providing support for the deployment team lead in day-to-day operations, measuring and taking corrective actions on deployment targets, ensuring alignment and performance with internal stakeholders responsible for installations performed by Company employees, ensuring alignment and performance with the meter installation vendor, ensuring proper priority is given to any system issues affecting deployment, and responding to customer inquiries and concerns; and

- Since assuming leadership for the AMR Program in mid-year 2016, my responsibilities for AMR include oversight of the necessary information systems upgrades. This includes responsibility for business process blueprinting and system requirements documentation and the design, testing, and implementation of the hardware, software, and infrastructure necessary to support the AMR drive-by meter reading solution. My responsibilities also include leadership and support of the deployment of the gas communication modules, similar to those identified above for the AMI deployment.

As of the end of September 2017, the AMI Program has completed over 1.8 million cumulative electric AMI meter installations and has upgraded over 0.6 million gas meters with AMI communication modules. The AMR Program is beginning the module installation ramp up, and has completed the installation of more than 14,000 AMR gas communication modules. Numerous system enhancements have been planned and executed to support the realization of multiple benefits from these technology upgrades.

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

A. The purpose of my direct testimony is to describe the Company's ongoing installation of meter technology upgrades throughout our service area. AMI technology upgrades in our electric-only utility and electric/gas combination utility service areas will be completed during 2017, and AMR technology upgrades in our gas-only utility service area will be completed in 2019. In this case, the Company is requesting:

- Approval and recognition in customer rates of $0.649 million in projected O&M expenses associated with the installation of gas modules and related activities from July 1, 2018 through June 30, 2019, offset by direct O&M operational savings of $4.556 million;

- Approval and recognition in customer rates of projected capital expenditures for AMI gas module installation and related activities of $16.677 million from January 1, 2017 through December 31, 2017, an increase of $3.342 million compared to 2017 expenditures approved in Case No. U-18124; and

- Approval and recognition in customer rates of projected capital expenditures for AMR gas module installation and related activities of $106.798 million from January 1, 2017 through June 30, 2019, as well as AMR software and system development investments during 2016 of $5.2~~9~~8 million.
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Q. How is the remainder of your direct testimony organized?

A. My testimony includes the following nine major sections: (i) Status of Gas AMI and Gas AMR Cost Recovery; (ii) Smart Grid ("SG")/AMI Program Summary/Update; (iii) Gas AMI Benefits; (iv) Gas AMI Capabilities and Status; (v) Gas AMI Program Costs/Benefits Analysis;[1] (vi) Gas-Only AMR Program Summary/Update; (vii) Gas AMR Benefits; (viii) Gas AMR Capabilities and Status; and (ix) Gas AMR Program Costs/Benefits Analysis.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (LMD-1)	Schedule B-5.1	Summary of Actual and Projected Gas Capital Expenditures for the years 2016 through June 2019 ($000);
Exhibit A-20 (LMD-2)		Summary of Actual and Projected Gas O&M Expenses for the years 2016, 2017, 2018, and the 12-Month period ending June 30, 2019 ($000);
Exhibit A-21 (LMD-3)		Summary of AMI Business Case Costs and Benefits 2007-2032; and
Exhibit A-22 (LMD-4)		Summary of AMR Business Case Costs and Benefits 2014-2037.

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

A. Yes.

[1] With regard to the Company's analysis of costs and benefits related to the implementation of AMI, the terms "cost/benefit analysis" and "business case" are used to generally refer to the Company's analysis of the net present value of net revenue requirements associated with the AMI meter and systems implementation.

I. STATUS OF GAS AMI AND GAS AMR COST RECOVERY

Q. Please summarize the gas AMI costs requested by the Company and approved by the Commission in Case No. U-18124.

A. In Case No. U-18124, the Company requested Commission approval and recognition in customer rates of $2.6 million of O&M expenses for the test year ended December 31, 2017. In addition, the Company requested approval and recognition in customer rates of $90.1 million of actual and projected gas AMI capital investments for 2007 through 2017. The Commission found the Company's forecast of $2.6 million for O&M expense to be reasonable, and approved the recovery of those projected costs for the test year. With regard to the Company's actual and projected capital investments, the Commission agreed that the Company's projections were reasonable and approved recovery of those investments as part of the Company's net utility plant.

Q. Please summarize the Gas AMR investments requested by the Company and approved by the Commission in Case No. U-18124.

A. In Case No. U-18124, the Company requested Commission approval and recognition in customer rates of $26.998 million of actual and projected Gas AMR capital expenditures for 2015 through 2017. The Commission determined $13.635 million to be a reasonable amount to include in net utility plant. Specific disallowances included $1.281 million for 2016 software and systems development, $4.636 million for 2017 software and systems development, $3.490 million for 2017 module purchases, and $3.956 million for contingency included in capital investment projections. The Commission noted that more specific expense information is needed regarding the Company's investments in AMR modules and the associated software and systems supporting the implementation of AMR modules.

Q. Please explain how the findings from Case No. U-18124 are an important consideration in the testimony and exhibits you are presenting in this case.

A. The Company's capital investments in AMI and AMR during 2016 and 2017 exceed the amounts approved for inclusion in net utility plant in the Commission's July 31, 2017 Order in Case No. U-18124. My direct testimony in this case requests approval to include the total amount invested during 2016 and projected for 2017, as well as the projected investment amounts for 2018 and 2019. Both the AMI and AMR projects are expected to be completed prior to the conclusion of the projected test year in this case.

Q. Please discuss the differences in actual and projected AMI capital investments from the amount approved in Case No. U-18124.

A. The Commission approved AMI investments of $28.6 million in 2016 and $13.3 million in 2017. Actual investments during 2016 were $29.9 million and 2017 investments of $16.7 million are projected in this case. In total, the Company is investing approximately $4.7 million more than approved to install AMI gas modules at 42,329 additional customer locations, as discussed later in my testimony, and complete the AMI software and systems development work.

Q. Please discuss the differences in actual and projected AMR capital investments from the amount approved in Case No. U-18124.

A. The Commission approved AMR investments of $2.8 million in 2016 and $10.8 million in 2017. Actual investments during 2016 were $5.9 million, and 2017 investments of $22.1 million are projected in this case. In total, the Company is investing approximately

$14.4 million more than approved for 2016 and 2017, primarily on the development of software and systems that support the ongoing installation and operation of AMR modules. The software and systems development associated with the implementation of AMR is described later in my direct testimony.

II. SG/AMI PROGRAM SUMMARY/UPDATE

Q. Please describe Consumers Energy's SG/AMI Program.

A. The Consumers Energy SG/AMI Program was initiated in 2007 with the objective of investing in metering technology upgrades that will provide multiple benefits to customers. The AMI system includes the following: (i) electric meters and gas meter modules capable of transmitting and receiving data ("smart meter"); (ii) a two-way cellular based point-to-point communications network; (iii) system integration to support the use of the data for billing and operational uses; and (iv) a customer interface/web portal. Additionally, AMI enables and promotes various new beneficial customer programs and billing options for electric and electric/gas combination residential, commercial, and industrial customers who have a smart meter installed.

Q. What is the status of the Company's installation of AMI gas modules?

A. The Company is nearly complete with its investment in AMI gas module technology. Since initiating the installation of gas AMI meter modules in 2015, the Company has installed 656,090[2] gas modules, which represents approximately 99%[3] of full AMI gas module deployment. By the end of 2017, gas AMI module installations will be 100% complete. Gas AMI module installations are performed in conjunction with electric smart meter installations in order to make an efficient transition to this updated

[2] Actual gas module installations as of September 30, 2017.
[3] 656,090/662,218 = 99.07%

technology. In total, the SG/AMI Program will install 662,218 gas AMI modules at combination customer locations on a state-wide basis. The following table summarizes the progress made since 2015 toward completion of the gas AMI module installations:

	Gas Meter Upgrades	**Cumulative Upgrades**	**Cumulative % Complete**
2015 Actual	49,182	49,182	7%
2016 Actual	320,473	369,655	56%
2017 Q1 Actual	98,972	468,627	71%
2017 Q2 Actual	116,612	585,239	88%
2017 Q3 Actual	70,851	656,090	99%
2017 Q4 Plan	6,128	662,218	100%

Q. You have indicated that 662,218 gas AMI modules will be installed. In Case No. U-18124, Company witness Lincoln D. Warriner indicated that 618,000 were estimated to be installed. Can you explain why the number of gas AMI modules has increased in this case compared to Case No. U-18124?

A. Yes. The installation plan for gas AMI modules was specifically increased by 42,329 modules during 2017 to account for the following customer metering scenarios:

- Gas customer accounts that indicate a customer record system premise match with an electric account served by the Company;
- Gas customer accounts that match a Company electric account street address; and
- Gas customer accounts where a gas meter is physically located within 2000 feet of two Company electric AMI meters.

Prior to the identification of customers with the service characteristics outlined above, the Company would have included those customers in its AMR installation plans. The installation of gas AMI modules at these customer locations will allow the Company to enable gas AMI benefits for as many customers as possible. The remaining increase in

AMI modules planned for installation is a result of periodic reevaluations of the customer population within the AMI installation area. This is a normal part of the Company's installation planning process.

Q. Please comment on the performance of the AMI meters and modules in providing actual monthly meter reads for use in billing customers for energy consumption.

A. As of the end of July 2017, 5.656[4] million gas AMI reads have been used to bill customers for monthly energy consumption. Actual meter read rates are exceeding the contractual 98%[5] commitment and the periodic meter read rate[6] is better than expected. Our actual annual experience to date is summarized in the following table:

			AMI Electric Meters			**AMI Gas Modules**	
Year			**Actual Reads**	**Read Rate**		**Actual Reads**	**Read Rate**
2013			284,084	99.55%			
2014			2,433,172	99.53%			
2015			5,937,387	99.51%			
2016			11,493,085	99.11%		1,449,818	99.61%
2017 YTD	Sep		14,119,765	99.77%		4,205,789	99.92%

Q. Please describe the status of the Company's AMI software and systems integration.

A. In addition to the installation of smart meters, systems integration and development is critical to enable smart meter functionality and to achieve the benefits provided by the AMI Program. Successful system implementations to date include:

- Device Lifecycle Management (March 2012) – Enhanced SAP and other systems to support supply chain processes, work management, quality, and audit management. Work order processing between Consumers Energy and our meter installation vendor was also enabled with this release;

[4] 2016: 1,449,818 automated gas meter reads + 2017 through September: 4,205,789 automated gas meter reads.
[5] The 98% or better performance standard is based on Itron's (the Company's AMI meter vendor) contractual commitment for AMI performance.
[6] Beginning in 2017, periodic meter read rate is being used for AMI. This is the meter read rate for devices due to bill in the billing cycle.

- Meter Installation Release (July 2012) – Provided for the implementation of the AMI Head End and Meter Data Management ("MDM") applications just ahead of the initial meter implementation effort that began in August 2012. The Head End application enabled all of the communication with the smart meters, while the MDM application stores all of the meter reading information (registers, interval, and alarms/event data) that is collected from the smart meters. As a result of this system implementation, the Company was able to successfully initiate the planned installation of smart meters in August of 2012;

- Billing Release (April 2013) – Initiated customer billing from the automated meter reads that are provided by the AMI network enabling reductions in manual meter reading workload and improving monthly meter reading success rates. This release also supported the implementation of a pilot customer web portal, which was launched in July 2013. The pilot web portal included the capability to alert customers by e-mail or automated voice message that current month consumption is trending higher than prior months, and also offered customer tips on how to reduce energy consumption. The billing release also enabled basic data analytics for operational reporting;

- Enhanced Operations (July 2014) – Provided initial field operations functionality for remote connection and disconnection of electric AMI meters at locations where the past-due collections process has resulted in insufficient payment for electric services used, provided functionality for on-demand remote meter reads, and the ability to remotely determine the operational state of AMI meters. Additional data analytics for operational reporting were also provided in this release. Systems functionality was also enabled that supports the offering of a customer selected bill due date.[7] This systems release also enabled various remote troubleshooting capabilities including the ability to check the status of the disconnection switch in the meter, the ability to determine if power is flowing to the meter, and the ability to confirm that a meter is transmitting successfully over the AMI network;

- Release 4A (December 2014) – Enabled the installation of electric polyphase AMI meters, provided the ability to track meter firmware history,[8] and prepared the Company for the ability to bill demand rate customers using automated meter reads that are provided by the AMI network;

- Release 4B.1 (July 2015) – Implementation of the final web portal application for electric residential customers. The final web portal application has been integrated with the Company's redesigned website providing easier access to the Interval Web Portal, a tool that customers can use to monitor their energy

[7] The MPSC approved the Company's requests to implement a customer selected bill due date option to customers with AMI meters on October 7, 2015 in Case No. U-17863 and on May 13, 2014 in Case No. U-17597.
[8] Tracking the history of meter firmware upgrades is useful for managing the remote meter upgrade process and responding to customer or manufacturer inquiries regarding the operation of individual meters.

usage to conserve energy and reduce their monthly energy bill. The Company's call center representatives also have the ability to view a customer's web portal display in order to help answer questions customers may have about their bill and energy usage;

- Release 4C.1 (August 2015) – Provided additional field operations functionality for remote connection and disconnection of electric AMI meters for applications beyond the past-due collections process. These situations include move-in/move-out, customer requested turn-off/turn-on, and elimination of the "current occupant" account status for smart meter customers. Current occupant is a temporary account status used at service locations where no billable party is identified until the services are either terminated or a billable party can be identified;

- Release 4C.2 (November 2015) – Enabled initial functionality for remote gas meter reading and register billing as well as implemented functionality for the Direct Load Administration Customer Program (AC Peak Cycling), and the Dynamic Peak Pricing Program (Peak Time of Use), including work order processing with our device installation vendor. Remote gas meter reading enables reductions in manual meter reading workload and improvements in monthly meter reading success rates in combination electric/gas service areas;

- The automation of interval billing and time of use rates using meter reads provided by the AMI network was implemented in May 2016;

- The implementation of the business customer web portal application and the display of daily gas energy consumption within the residential and business web portal applications was implemented in March 2016;

- Technology solutions supporting customer enrollment and participation in the Peak Time of Use Program,[9] and the PrePay Program, called Pay My Way, were implemented in May 2016; and

- The integration of event notifications and post-event customer feedback, supporting the reduction of summer peak demand by customers participating in the Peak Time of Use rate options, with the Company's two-way customer communication application was implemented in May 2016.

Systems integration development and testing is near completion during 2017 for the following items:

- Integration of AMI meter data with the Company's Outage Management System - This improves the Company's ability to more efficiently identify and locate electric service outages for restoration, and support improvements in

[9] Peak Time of Use has two offerings: Critical Peak Time of Use and Peak Rewards Time of Use.

the accuracy of service restoration estimates that are provided to customers. The integration of AMI meter data with the Outage Management System was implemented in May 2017. The costs incurred through May 2017 for the completion of system development and performance/user testing was $579,216. This enhancement specifically supports the Company's electric operations, and the 2017 costs incurred are not reflected in the gas portion of the 2017 projections provided in my exhibits;

- Development of gas design work orders for new construction - This enhancement builds on previously implemented enhancements that provide for the inclusion of a gas communication module in existing gas meter modifications and meter exchange work and adds the ability to include gas communication modules in work orders for new construction. The completion of system development and performance/user testing has cost $248,157 from January through August 2017, and system enhancements were implemented during July 2017; and

- Implementation of smart meter data analytics, including electric energy and gas energy theft identification and verification - Remaining work for this functionality includes completion of systems development for electric and gas analytics and system, and performance and user testing. The expenditures for this remaining work are projected to be approximately $2.0 million, with functionality expected to be phased in during the fourth quarter of 2017. This enhancement supports both the Company's electric and gas operations, and will be allocated between electric and gas plant in service accounts when completed. The Company has been performing manual analysis of AMI theft indicators since September 2014, and the implementation of automated analysis will enhance our theft identification process.

III. GAS AMI BENEFITS

Q. What customer benefits result from the implementation of gas AMI?

A. Similar to other utilities that have already implemented gas AMI, Consumers Energy customers realize benefits related to:

- Reduced meter reading cost;
- Improved billing accuracy as a result of higher actual meter read rates;
- Reductions in energy theft resulting from the analysis of meter tamper alerts and energy consumption patterns; and
- Gas conservation associated with the availability of web portal displays and consumption alerts.

The Company is also projecting savings of $2.166[10] million in test year gas uncollectible accounts as electric service connection/disconnection capabilities of AMI reduce the amount of energy consumption by customers who have a past-due account status.

Q. Please provide more detail regarding the customer and operational benefits that result from the Company's investment in gas AMI technologies?

A. The most immediate benefit realized by customers is that automated meter readings enhance the quality of information used to generate energy consumption billings, which improves customer satisfaction with monthly bills. Daily automated meter reading improves billing accuracy by increasing the number of actual meter reads compared to existing manual meter read processes. Performance results to date for meters read using the AMI system have been higher than expected. AMI automated gas meter read rates have averaged 99.92% during the first nine months of 2017.[11] In comparison, the 2010 to 2014 historical average gas manual read rate was 89%. AMI enhanced billing nearly eliminates estimated reads for our combination gas/electric customers, even when weather conditions would make it impossible to safely read meters manually.

Our customers expect monthly utility service billings to be calculated using actual meter reads. J.D. Power customer satisfaction surveys indicate that residential and business customers are more satisfied with the billing and payment dimension of gas utility service when actual meter readings are used for monthly billing calculations. This conclusion by J.D. Power is consistent with customer satisfaction indicators that the Company has observed in its own customer surveys. The use of automated meter reading

[10] Source: Exhibit A-32 (DLH-3), page 1 of 2.
[11] Year to date as of September 2017.

to increase the frequency of actual gas meter reads and limit estimated billings results in improved levels of customer satisfaction.

Gas/electric combination customers with AMI are able to access and view up to two years of historical annual, monthly, or daily gas usage data through a web portal. The web portal includes a number of features that enable customers to make informed decisions to manage their energy usage behaviors. In addition to high electric bill alerts, the web portal also provides customers with bill projection and bill comparison features. Bill comparisons include historical energy use comparisons and neighborhood average energy use comparisons. Customers are also able to export their detailed electric consumption data, or view daily temperature data overlaid on energy consumption, to further understand the variables that impact their utility bill. Customers with multiple meters served by the Company are able to view all of their meters' energy usage on the web portal. Customer engagement in energy efficiency programs is directly encouraged through the use of energy saving tips provided through the web portal.

The Company's investment in its meter technology upgrade also allows AMI metered customers the flexibility to choose a customized billing due date. As of September 30, 2017, 54,384 customers are currently billed on their selected due date, and another 1,819 have enrolled and are transitioning to their selected due date. In recent studies of utility customer satisfaction, J.D. Power has observed that satisfaction increases when customers are offered billing and payment options, such as the ability to select their monthly payment due date. According to their analysis, satisfaction ratings among residential customers who select their own payment due date is 756 (on a 1,000-point scale), compared with ratings of 714 among those who do not select a due date.[12] Analysis of previous surveys of both residential and business gas customers indicate that overall customer satisfaction increases by approximately 12% when customers can choose the due date of their monthly bill.

Revenue assurance benefits will also be realized by enabling energy theft investigations with automated analysis of meter tampering events and access to daily usage data. Systems development work associated with the analysis of AMI meter data for identification of energy theft cases will be completed during 2017. The systems being implemented will provide flexibility to the Company's Corporate Security/Theft staff for configurable business rules that will be utilized in the automated analysis process for energy theft detection.

IV. GAS AMI CAPABILITIES AND STATUS

Q. Please discuss the status of the Company's investment in updated meter technology for gas combination customers.

A. Advanced metering capabilities are achieved by updating existing gas meters with communications modules (or "ERTs"),[13] integrating gas meters into the AMI network infrastructure that will be completed during 2017 to support electric SG/AMI. Gas utility customer revenue requirements include the direct investment in gas modules and a small allocation of the common program costs as described later in this direct testimony. The gas modules are installed by removing the existing index at the front of the gas meter that measures gas consumption. The installer removes the existing index and inserts the gas module on the back of the index. Once that is complete, the installer ensures that the read

[12] Source: http://www.jdpower.com/sites/default/files/2013100_electric_utility_residential_customer_satisfaction_study_final.pdf

[13] ERT® stands for "encoder receiver transmitter" and is a registered trademark of Itron, the vendor of the AMI meters and gas modules.

on the module matches the read on the index. The integrated module/index is then placed back on the gas meter and the reads from the communication module are used for billing. In most cases the existing gas meter remains in place, thereby avoiding additional meter acquisition costs and utilizing existing AMI systems infrastructure.

Q. Please describe the gas meter modules that have been selected for the Company's gas AMI customers.

A. The Company has selected the Itron 100G DLS Datalogging ERT® module as our gas meter module. A large share of the United States natural gas market is served by Itron gas modules. Itron has shipped more than 18 million of the 100-series radio-frequency gas meter modules to utilities for installation. This module supports the following capabilities, features, and functions:[14]

1. The module stores gas interval usage data, enabling:
   - Move-in/move-out reads to minimize manual off-cycle reading and reduce field trips for customer requested special reads;
   - Daily usage data for customer service and billing dispute resolution; and
   - Monthly gas balancing analysis.
2. The module provides meter tamper detection:
   - Tilt tamper alerts provide notification of physical meter tampering; and
   - Magnetic tamper alerts provide notification of magnetic fields that may disrupt normal gas use measurement.
3. 20-year module and battery life.

The 100G DLS Datalogging ERT® device is also compatible with and able to utilize the communications capability of the electric smart meters that are installed, thereby

[14] Detailed specifications regarding Itron's gas module are documented on Itron's website at the following internet location: https://www1.itron.com/PublishedContent/100G%20DLS%20Spec%20Sheet.pdf

eliminating the need and associated costs of a dedicated gas module communications network.

Q. Please describe how the Company notifies residential customers that AMI metering is scheduled for installation at their location.

A. The customer notification process begins with public outreach and advertisements in planned implementation areas at least six months prior to meters being scheduled for installation. Public outreach efforts include presentations to municipal and community organizations about the Smart Energy Program installation schedule and process. In addition, billboards and digital media provide another source of general awareness to customers. Individual customers are mailed postcard notifications 30 days prior to the scheduled meter upgrade. The Company also mails individual letters to customers 14 days prior to their scheduled meter upgrade, detailing what to expect on the day of the upgrade and what to do if they have questions. Lastly, the Saturday before the week of the scheduled upgrade, an automated call is made to the customer, again notifying them of the scheduled upgrade and providing a toll free phone number for questions or to schedule an appointment, if desired. Exceptions to this process may occur when meter replacements are needed prior to the scheduled meter replacement.

Q. How has this communication process been received by customers?

A. Customer response to the Company’s implementation of the AMI investment has been very positive. The Company surveyed customers in selected implementation areas before and after the meter upgrade. These surveys measured customers’ overall satisfaction with the Company, AMI meters, and the meter upgrade process, including the communications received. The results of these surveys were used to measure the effectiveness of the communication and installation process. In surveyed installation areas, overall results have shown a 75% average lift in Net Promotor Score – which is the likelihood that customers would recommend the Company to their friends and family. Seventy-eight percent[15] of customers remember receiving communication from the Company regarding their smart meter installation. In our surveys, customers who recalled receiving communications from the Company regarding their meter rated the Company higher in areas for installation satisfaction and Company satisfaction.[16] We have also seen an improvement of more than 20 points in our J.D. Power Customer Satisfaction metric for those customers who have identified as smart meter customers.

V. GAS AMI PROGRAM COSTS/BENEFITS ANALYSIS

Q. What is the total capital investment expected in conjunction with the implementation of Consumers Energy's AMI Program?

A. The purchase, testing, processing, and installation of electric smart meters and gas meter modules; the enabling systems, infrastructure, and design; and pilot and implementation of customer programs will result in approximately $716 million[17] in capital investment for the period 2007 through 2017. The estimated direct and indirect capital costs associated with the gas SG/AMI components are projected to be about $95 million[18] of the program total.

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[15] Calculation based on customer survey data from the post-install surveys in the Flint, Kalamazoo, Muskegon, Zeeland, and Grand Rapids areas.

[16] This is based on data from customer post-install surveys in the Flint, Kalamazoo, Muskegon, Zeeland, and Grand Rapids area.

[17] Exhibit A-21 (LMD-3) indicates a cumulative capital cost at the end of 2017 of $712.5 million. That estimate does not include any systems development costs being incurred in 2017, and it also does not include the 42,329 additional gas modules identified earlier in my testimony.

[18] Source: Exhibit A-21 (LMD-3), page 1, line 15, columns c-l + Exhibit A-12 (LMD-1), Schedule B-5.1, page 1, line 7, column f.

Q. How was the allocation of Project Management and other shared expenditures for the SG/AMI Program determined?

A. The allocation of common Program Engineering/Design and Management, and other shared expenditures, is 12% to Gas Operations and 88% to Electric Operations for program years 2007 through 2017. This allocation is based upon gas module/communications costs, electric meter/communications costs, and load control program direct costs. There will be over one million more electric smart meters installed than gas AMI meter modules installed.[19] The bulk of the total Company costs, as well as program benefits, are associated with the installation of the electric smart meters.

Q. Please describe Exhibit A-12 (LMD-1), Schedule B-5.1.

A. Pages 1 and 2 of this exhibit present the capital investments associated with gas activities for the AMI Program.

Field Equipment/Facilities refers to $0.029 million in actual 2016 investments. An additional $0.005 million in actual investment was incurred during March 2017. There are no additional projected investments for this category. These investment amounts are primarily based on direct and allocated costs for gas module field devices, testing equipment, and any required facility modifications.

Modules are the direct investments associated with the AMI gas meter modules. The actual investments during 2016 for AMI gas meter modules were $25.404 million. Projected investments for 2017 to complete the AMI gas meter module installations are $15.578 million. Annual expenses reflect gas module purchases to support the installation of gas modules, as well as the module installation costs.

[19] 1.8 million electric AMI meter installations are planned; of this 1.8 million, 662,218 customers are planned for installation of an AMI gas meter module.

Software & Systems Development includes new systems development, existing systems modifications, and software licensing allocated costs. For this line item, 2016 actual investments were $3.359 million; projected 2017 investments are $0.600 million. There are no projected investments in this category beyond 2017.

Smart Energy Infrastructure includes allocated investments in the computer and network infrastructure to support the installation of gas modules and their associated systems. These investments were $0.441 million in 2016 and are projected to be $0.153 million in 2017.

Program Engineering/Design & Management refers to $0.667 million in actual 2016 investments, and projected investments for 2017 are $0.341 million. These costs are primarily based on allocated costs projected for the design, integration, and management of the gas meter modules, and overall costs to support the program (labor, expenses, and corporate allocations).

Q. Please discuss the $1.2 million of 2016 gas AMI O&M expenses that are summarized on line 1 of Exhibit A-20 (LMD-2).

A. The $1.2 million of 2016 actual O&M expense is further detailed on pages 2 and 4 of Exhibit A-20 (LMD-2). The individual line items are described as follows:

Project Management and Other – Gas AMI refers to the allocation of total program management and other corporate costs allocations, including hardware and software maintenance of AMI components, such as software systems and data storage infrastructure, developed as part of the Smart Energy Program. The actual O&M expenses in 2016 were $0.561 million, of which $0.071 million are labor costs and the remaining $0.490 million are non-labor costs. The organizational responsibility for the hardware and software maintenance costs were transferred to the Information Technology ("IT") area of the Company effective with the 2017 calendar year. In the instant case, the gas share of test year O&M costs related to software and hardware maintenance costs are supported by Company witness Christopher J. Varvatos.

Deployment and Meter – Gas AMI includes the O&M costs associated with the purchase and installation of gas meter modules. The O&M installation costs incurred when a gas meter module is installed are offset by O&M credits resulting from the capitalization of installation costs at the time gas modules are purchased. There are no installation costs projected for the test year in this case because the installations will be completed during 2017. This O&M category also includes the gas share of the operating costs of the two-way AMI communications infrastructure. The total expense incurred during 2016 was $0.468 million, of which $0.172 million are labor costs and the remaining $0.296 million are non-labor costs. The organizational responsibility for the communications infrastructure operating costs and other gas module related O&M were transferred to the Electric and Gas Distribution Operations area of the Company effective with the 2017 calendar year, and are included in the test year projections of Company witness Mary P. Palkovich.

Operations – Gas AMI refers to the gas share of the total SEOC O&M costs. The total expense incurred during 2016 was $0.177 million. Of that total, $0.156 million were labor costs, and $0.021 million were non-labor costs. The SEOC does have ongoing O&M costs, but effective with the 2017 calendar year, the organizational responsibility for those costs has transitioned to the Electric and Gas Distribution

Operations area, and the test year costs are included in the projections of Company witness Palkovich.

Change Management & Regulatory refers to the gas share of project O&M salary and expenses related to customer and employee communications. The total O&M expense incurred during 2016 was $0.007 million, and the Company is not projecting any future O&M costs for this type of activity. Of the total 2016 O&M costs, $0.004 million were labor costs and the remaining $0.002 million were non-labor costs.

Q. Please discuss the overall results of the AMI cost-benefit analysis as summarized in Exhibit A-21 (LMD-3).

A. The Company's business case for AMI includes both costs and benefits for both electric only and electric/gas combination customers to arrive at an estimation of the Net Present Value ("NPV") of revenue requirements associated with the AMI investment. The updated cost/benefit analysis shows a present value of net savings in revenue requirements of $31.4 million. The details of this calculation are provided in Exhibit A-21 (LMD-3) on page 5. A similar calculation of the present value of gas customer net savings in revenue requirements of $11.3 million is provided in Exhibit A-21 (LMD-3) on page 6.

Q. Please discuss the changes in the program's NPV since the Company's gas rate case filing in Case No. U-18124.

A. This update reflects a modest improvement overall from the $29.3 million[20] present value of net savings in revenue requirements provided in the Company's last gas rate case. The cost/benefit analysis changes between those two rate case updates are summarized as follows:

[20] Case No. U-18124, direct testimony of Company witness Warriner.

1. Program capital expenditure requirements, shown on pages 1 and 2 of Exhibit A-21 (LMD-3), are reduced by $31.892 million from the prior cost/benefit analysis to remove forecasted contingency dollars, remove capital requirements for meter inventories from the program scope, and reconcile actual expenditures and update projections. Reducing the capital expenditure requirements for the program increased the NPV of revenue requirement savings by $35.4 million;

2. Benefits associated with savings in peak demand capacity costs, shown on pages 3 and 4 of Exhibit A-21 (LMD-3), lines 36 and 37, are reduced by $128.213 million from the prior cost/benefit analysis to reflect a reduction in the long-range expected market price of avoided capacity and revise the estimated timing for customer enrollments in Load Control and Dynamic Peak Pricing programs. These reductions in the value of benefits account for a reduction in the NPV of revenue requirement savings of $63.5 million;

3. Benefits associated with avoided energy theft, shown on pages 3 and 4 of Exhibit A-21 (LMD-3), lines 38 and 56, are reduced by $38.342 million from the prior cost/benefit analysis to reflect ongoing development of theft analysis enhancements. These reductions in the value of benefits account for a reduction in the NPV of revenue requirement savings of $36.2 million;

4. Program O&M expense requirements, shown on pages 3 and 4 of Exhibit A-21 (LMD-3), lines 79 through 83, are reduced by $26.046 million from the prior cost/benefit analysis to lower estimates of ongoing O&M costs for AMI. Reducing the O&M cost requirements for the program increased the NPV of revenue requirements savings by $14.9 million;

5. Program revenue requirements are reduced as a result of updating the cost/benefit analysis with the weighted average cost of capital approved by the Commission in Case No. U-17990. Updating the cost of capital also reduced the NPV discount factors for future years in the cost/benefit model. Changing the pre-tax weighted average cost of capital from 8.9205% to 8.5809% increased the NPV of revenue requirement savings by $28.8 million; and

6. In order to reflect the difference in timing between rate cases, the NPV calculation was adjusted so that all future net revenue requirements are discounted back to the beginning of 2018. The cost/benefit analysis provided in Case No. U-18124 discounted net revenue requirements back to the beginning of 2017. Making this change increased the calculated NPV of revenue requirement savings by $22.8 million.

In summary, the cost benefit analysis provided in Exhibit A-21 (LMD-3) confirms that the investment in AMI produces benefits for customers.

Q. Please explain the gas meter reading benefits in the Company's Summary of Business Case Costs and Benefits.

A. Automation of meter reading provides many benefits to customers relative to existing manual meter reading processes. These benefits include improved meter read accuracy and reduced estimates of energy consumption for billing purposes. Meter reads are collected on a daily basis instead of a monthly basis, which enables new program offerings to customers. The automation of meter reading also enables the reduction of manual meter reading staff levels. These savings will ramp-up over the meter installation period as customers transition from energy billings based on manual meter reads to billings based on automated meter reads.[21] The direct O&M expense savings have been included as part of this proceeding in Company witness Palkovich's Exhibit A-49 (MPP-1).

Q. Please explain the gas uncollectible expense benefits in the Company's Summary of Business Case Costs and Benefits.

A. The Company administers an energy billing collection process consistent with the MPSC's Billing Practice Rules that attempts to collect past due accounts from customers. After the appropriate period of time from a payment due date and numerous outreach attempts, the Company disconnects utility service until payment is made. Unfortunately, some customers struggle to pay their past due accounts and the Company must charge off these accounts to uncollectible accounts expense. With a manual service disconnection process, the completion of shut-off orders can be delayed from the date a customer is eligible for service shut-off, resulting in additional energy consumption beyond the

[21] The Company initially implemented billing based on AMI automated electric meter reads in April 2013. The capability to generate monthly billings from gas AMI module meter reads was implemented in November 2015.

earliest possible shut-off date, and a larger outstanding balance for the customer to manage. Our Revenue Operations Department has experienced a 14 to 30 day delay on average between the shut-off eligibility date and the actual completion of field work. The AMI remote disconnect and reconnect[22] functionality allows the Company to reduce the average number of days to complete an electric service shut-off order, effectively reducing the amount of past due balances that are charged off to uncollectible expense and making payment more reasonable for customers. The Company is projecting a 25% reduction in the gas portion of combination service uncollectible accounts.[23] These savings will ramp-up over the meter installation period as combination service customers transition from energy billings based on manual meter reads to billings based on automated meter reads.[24] Annual gas uncollectible benefits are shown on pages 3 and 4, line 54, of Exhibit A-21 (LMD-3). The uncollectible accounts expense savings have been included as part of this proceeding in Company witness Daniel L. Harry's Exhibit A-32 (DLH-3).

Q. Please explain the gas other O&M expense benefits in the Company's Summary of Business Case Costs and Benefits.

A. The Company expects that the technological enhancements associated with AMI will generate operating efficiencies in several areas of the Company. For example, the improved meter read accuracy and reduced estimates associated with automated meter reading reduces the need for gas operations workers to make field trips associated with special manual read requests to resolve billing issues and customer concerns about meter

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[22] Remote disconnect/reconnect using AMI began in July 2014.

[23] The Company's business case calculates a 25% reduction on 35.2% of projected gas uncollectible expense, for an effective reduction of 8.8% of total gas uncollectible accounts expense.

[24] A customer's meter must have passed validation for billing based on automated meter reading before a remote service disconnection will be performed at that location.

reading accuracy. The availability of daily meter reads will also allow billing staff to validate energy consumption without requesting special manual reads. The Company is planning for a 90% reduction in special gas reads for combination service customers, which would result in a 27% reduction in all special gas reads.[25] The business case for AMI also reflects cost savings for the following types of shared expenses, which have been allocated within the business case model 74% electric/26% gas:

1. The Company's Customer Billing staff is projected to be reduced by three full-time equivalent employees as increased meter reading accuracy reduces the need to process billing adjustments;

2. The Company's Call Center staff is also projected to reduce staff by five full-time equivalent employees as increased meter reading accuracy results in fewer calls related to delayed or estimated bills; and

3. Additional cost reductions have been estimated in the area of employee safety. As meter reading staff is reduced, the Company expects to incur up to 16 fewer workers compensation claims annually.

The AMI remote disconnect and reconnect functionality of AMI will also allow the Company to reduce the gas share of Revenue Operations staff expense by 6%, as field trips associated with combination electric/gas customers are reduced. Safety will also be significantly improved for the Revenue Operations Department.

Annual gas other O&M expense benefits are shown on pages 3 and 4, line 55, of Exhibit A-21 (LMD-3). The direct O&M expense savings have been included as part of this proceeding in Ms. Palkovich's Exhibit A-49 (MPP-1).

Q. Please explain the gas theft reduction benefits in the Company's Summary of Business Case Costs and Benefits.

[25] The 27% effective reduction is a 90% reduction in 34% of gas special reads, based on combination service customer share of total gas customers.

A. The Company's pre-AMI theft detection process relies upon tips from meter reading or field service employees and contacts received from customers to initiate investigations of suspected energy theft. The most common form of gas energy theft identified using our existing theft tip process is where customers attempt to reconnect gas service after being disconnected for non-payment of past-due energy billings. In our enhanced AMI theft detection process, the Company will receive meter tilt tamper alerts and magnetic tamper alerts from gas modules as part of our daily AMI data collection process. This data will be analyzed for correlation with service work orders, customer notifications, and daily consumption patterns to identify locations where energy theft has been attempted. Because meter alerts will be analyzed on a daily basis, energy theft situations will be identified more quickly than prior to the installation of AMI resulting in improved safety for our customers and the communities in which we serve.

Other theft detection activities are occurring during the AMI installation process. Examples of these activities include visual inspection by smart meter installers and billing/theft reviews of pre-deployment reports that list inactive meters with energy consumptions.

Customers also benefit from the incremental gas sales revenue that results from the improved identification of energy theft. The theft benefit is expected to grow to 1%[26] of residential and commercial gas sales revenue as gas modules and analytical systems for gas module data are implemented. The Company's projections of AMI enabled theft benefits are supported by utility industry research on energy theft and analysis of related data sources. Benefit projections have been reviewed by subject matter experts in our

[26] The projected 1% theft benefit is applied to 35.2% of residential and commercial gas sales revenue, for an effective benefit of 0.352%.

Corporate Security Department to ensure that expected benefits are reasonable and achievable. Annual gas theft reduction benefits are shown on pages 3 and 4, line 56, of Exhibit A-21 (LMD-3). In this proceeding, incremental gas sales attributed to improved identification of energy theft have been factored into the development of the Company's gas sales forecast.

Q. Please explain the gas AMI induced conservation and energy efficiency benefits in the Company's Summary of Business Case Costs and Benefits.

A. Historically, customers would typically receive feedback from the Company regarding their natural gas consumption when they receive their monthly billing statement. Reading gas modules on a daily basis will allow the Company to provide customers with feedback on their natural gas usage more frequently. Customer consumption data is available and updated daily for viewing on a web portal application, and customers also have the option to request consumption alerts to update them on their usage as the billing month progresses. Customer benefits will be realized in avoided gas supply costs as a result of energy conservation that occurs as a result of providing this information to customers. Annual benefit values reflect the following calculation assumptions:

1. Residential Gas Cost Recovery ("GCR") revenue is multiplied by 35.2% to account for the natural gas customers that are located in our combination electric/gas service area. No natural gas consumption benefits are quantified for the commercial and industrial class;

2. Participation is phased-in over a multiple year period so that an end state participation rate of 27% of combination electric/gas residential customers is achieved in 2019;

3. Participating customers are expected to realize a 5% reduction in natural gas consumption; and

4. Overall, a 1.35% reduction (27% participation x 5% conservation) is expected for the portion of the residential customer class that takes both electric and gas utility service from the Company.

Web portal gas conservation benefit estimates were reviewed and validated by subject matter experts in the Company's Energy Efficiency Solutions Department to ensure that projected benefits are reasonable and achievable. Annual gas AMI induced conservation and energy efficiency benefits are shown on pages 3 and 4, line 57, of Exhibit A-21 (LMD-3). In this proceeding, the web portal is integrated into Energy Waste Reduction Program savings estimates that are incorporated into the forecasts of gas sales.

Q. Please explain the Lost and Unaccounted For ("LAUF") gas reduction benefits in the Company's Summary of Business Case Costs and Benefits.

A. LAUF gas is the difference between the volume of natural gas delivered to the distribution system and the volume of natural gas billed to customers. These differences can occur for a variety of reasons, including unidentified gas leaks, customer billing issues, customer theft, meter accuracy, and gas vented for operational, maintenance, and safety purposes. AMI usage data and the corresponding systems being developed will enable improvements in LAUF analysis for geographic areas served by individual gas citygate stations. Daily meter reads will provide enhanced information for analysis as gas volumes at a citygate level for a particular time period can be directly compared to the gas volumes reported from meters served by that citygate. This analysis will identify local areas that require action to reduce LAUF volumes and costs.

LAUF benefit estimates have been reviewed and validated by subject matter experts in the Company's Gas Storage and Measurement Engineering Department to ensure that projected benefits are reasonable and achievable. Annual gas LAUF reduction benefits are shown on pages 3 and 4, line 58, of Exhibit A-21 (LMD-3).

Q. Please explain the terminal value benefits in the Company's Summary of Business Case Costs and Benefits.

A. The calculation of the terminal value starts with the business case calculation of AMI net revenue requirements modeled for the calendar year 2032. In that year, the business case value of AMI customer savings is $166.7 million, and the business case value of AMI customer costs is $57.2 million, resulting in a net revenue requirement savings of $109.5 million. This value is then adjusted each year from 2033 to 2037 based on the percentage of all AMI meters installed that have remaining useful life based on the expected AMI meter useful life of 20 years. The adjusted annual values are then discounted back to their present value in 2032 using two variables: the Company's weighted average cost of capital and the number of years difference between each year and 2032. The annual adjusted and discounted annual values for 2033 to 2039 are then summed together to arrive at the 2032 terminal value of $280.3 million that is shown on page 4, line 77, of Exhibit A-21 (LMD-3). The gas allocation of 12% of the total model terminal value, or $33.6, is shown on page 4, line 59, of Exhibit A-21 (LMD-3).

Q. Does the cost/benefit of the program as summarized in Exhibit A-21 (LMD-3) support the Company's continued gas AMI investment for combination gas/electric customers?

A. Yes. The Company's business case demonstrates that gas customers will realize a wide array of benefits that exceed program costs, resulting in an NPV benefit for customers of $11.3 million. The total (electric and gas) NPV benefit for customers from the Company's AMI Program is $31.4 million. These results are detailed in Exhibit A-21 (LMD-3).

VI. GAS-ONLY AMR PROGRAM SUMMARY/UPDATE

Q. What is the status of the Company's implementation of AMR meter reading technology enhancements?

A. The Gas AMR Program builds on the Gas AMI Infrastructure and extends AMR functionality and customer benefits to the Company's gas only utility customers. The additional necessary systems functionality has been installed through a series of three system upgrade releases that began in December 2016, and concluded with the final system release implemented in July 2017. Customer contact center functionality that enables the Company's customer service representatives to identify a customer served by an installed AMR meter upgrade was the primary focus of the first system enhancement. As a result of the second IT systems release (Phase 2), the Company was able to implement the designed AMR module installation business process in April 2017. With the last IT systems release (Phase 3) in July 2017, the delivery of all remaining functionality for the drive-by meter reading solution was implemented. The ongoing installation of Gas AMR modules will be completed during the first half of 2019.

Q. Please provide additional detail supporting the AMR Program costs.

A. Additional detail supporting AMR Program costs is as follows, categorized in the same manner as in Part III, Attachment 11 of the Commission's Rate Case Filing Requirements:

1. Purpose and Necessity of the Project with Supporting Data: The Company is installing Gas AMR modules in the "gas only" portion of our service area, which includes approximately 1.1 million customers. The Gas AMR project is necessary to deliver customer benefits related to higher monthly meter read rates with reduced meter reading resources. The AMR project leverages the existing smart energy IT architecture, the same gas communications module, the same deployment and project management teams, and the same meter installation vendor. With this approach, the Gas AMR project will be

complete in 2019 with all of the supporting IT systems work completed in 2017. The necessity of the project is supported by the AMR Summary of Business Case Costs and Benefits, which is provided as Exhibit A-22 (LMD-4);

2. Line Design, size, material used: The Company has selected the Itron 100G DLS Datalogging ERT® module as our gas meter module. This is the same gas meter module that is used in our combination gas/electric service areas to provide gas meter data through our AMI, and is described in detail in the "Gas AMI Capabilities and Status" section of my testimony. This module is fully compatible with the drive-by data collection approach that has been developed for use in our gas only service areas;

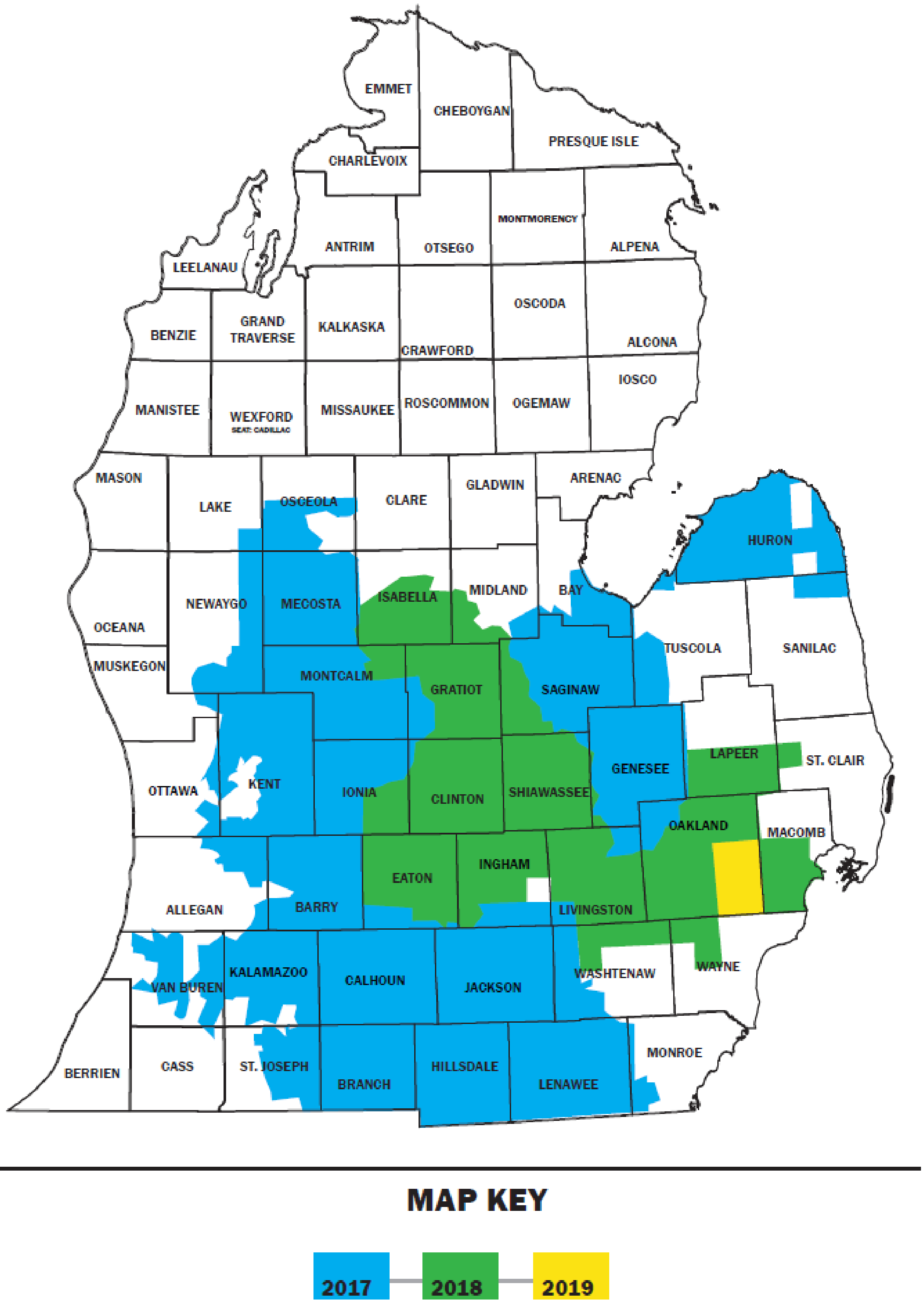
3. Line Length and ROW requirements: Not applicable;

4. Approximate Construction Schedule: The Gas AMR installation plan calls for the installation of approximately 100,000 gas modules in 2017, approximately 900,000 in 2018, and the remaining approximately 120,000 in the first half of 2019. The most recent installation plan is contained in the table and map included in this section of my testimony. The table and map detail the total number of gas meters that are planned to be updated by geographic region and the planned timing of the meter upgrades. The 2018 purchase plan has been finalized and supports the installation plan in the table below. As part of the overall plan, there will be obsolete meter exchanges in 2017 and 2018 that will utilize gas integrated units, which is a gas meter with a gas communication module already installed (gas integrated unit = gas meter + gas communication module);

1 5. Table of AMR Installations;

		Total Meters	Target Start	Target Finish
2017 Plan	**Meter Reading HQs**	**100,220**		
	Jackson (Ramp-up)	255	April	June
	Adrian	1,585	June	July
	Battle Creek/Bronson	2,531	August	August
	Hastings	529	August	August
	Greenville	1,499	August	August
	Grand Rapids	201	Sept	Sept
	Big Rapids	976	Sept	Sept
	Kalamazoo	15,457	Oct	Dec
	Bad Axe	17,906	July	Sept
	Saginaw	12,276	Sept	Oct
	Flint	1,571	Oct	Oct
	Lapeer	23,152	Oct	Dec
	OBS Meters (REX)	22,282	April	Sept
2018 Plan	**Meter Reading HQs**	**899,993**		
	Lansing	65,040	Jan	Feb
	Owosso	59	Jan	Feb
	Alma	1,758	Jan	Feb
	Groveland	91,096	March	April
	Livonia	249,775	May	Sept
	Howell	92,089	Sept	Dec
	Traverse City/Clare	712	Jan	Feb
	Macomb	285,953	Jan	Sept
	Royal Oak	93,480	Oct	Dec
	OBS Meters (REX)	20,031	April	Sept
2019 Plan	**Meter Reading HQs**	**122,089**		
	Royal Oak	122,089	Jan	Feb
	Grand Total	**1,122,302**		

6. <u>Map of AMR Module Installations;</u>



*Installation plans are based on Consumers Energy Service Center Territories
Colors reflect the year installation will begin

In addition, the Gas AMR Program is also utilizing the same customer communications and awareness approach. We plan to utilize the successful direct customer communications approach that was developed in the Smart Energy Program. Specifically, a thirty day postcard will make the customer aware that there will be an upgrade to their gas meter coming in the next few weeks. A two week letter will inform the customer of what to expect the day of the installation process and the associated benefits with the upgrade. The day of the installation, there will be a door hanger left behind. A green door hanger will be left for a successful upgrade. A blue door hanger will be left if the upgrade was not able to be performed. If a customer has questions or wants to learn more, there is a toll free phone number and the AMR website referenced on all of the written communication material;

7. Project effect on cost of operation and reliability of service: The Gas AMR installation will improve meter reading operating costs and increase the reliability of obtaining actual meter reads for use in customer billing. When fully converted to AMR meter reading, the Company plans to utilize 16 driving meter readers in the gas only territory. Once per month a driving meter reader with a mobile collector will receive 40 days' worth of daily reads, the consumption read at the time of the read, and the event counter count at the time of the read. This data is collected securely using enhanced security encryption.

   The Company's selection of AMR technology for gas-only customers is consistent with other industry metering technology applications and practice. Combination electric and gas utilities typically choose AMI technology and gas-only utilities typically choose AMR technology. Revenue assurance benefits will be realized by enabling energy theft investigations with automated analysis of meter tampering events and access to daily usage data when systems development work is complete. The systems being implemented will provide flexibility to the Company's Corporate Security/Theft staff for configurable business rules that will be utilized in the automated analysis process for energy theft detection. Further details on energy theft reduction are provided in the "Gas AMR Program Costs/Benefits Analysis" section of my testimony;

8. A description of the property being replaced and salvage value: The Gas AMR project is not intended to replace existing assets, but represents an upgrade to existing gas meter assets with the addition of the gas communication module. The gas modules will be installed by removing the existing index at the front of the gas meter that measures gas consumption. The installer will remove the existing index and insert the gas module on the back of the index. Once that is complete, the installer will ensure that the read on the module matches the read on the index. The integrated module/index will then be placed back on the gas meter and the reads from the communication module will be used for billing. In most cases, the existing

gas meter will remain in place, thereby avoiding additional meter acquisition costs;

9. <u>Map of site and location of facilities</u>: Gas AMR modules will be installed across the Company's service area where customers receive gas-only utility service. Details on the planned installation by area are provided in the "Approximate Construction Schedule" section of my testimony;

10. <u>Funding from other entities (Michigan Department of Transportation, Customer, Municipalities, Etc.):</u> There are no external funding sources to finance or share in the Company's investment in AMR; and

11. <u>All studies performed by the Company or third party regarding the project</u>: The choice of the Itron AMR drive-by solution is supported by the AMR Program Cost/Benefit analysis, which is described in detail later in my testimony. The Company believes that customer service will be enhanced with the implementation of AMR technology upgrades. Like many gas-only utilities, the Company chose AMR for its gas-only customers based on the operations benefit of reduced meter reading expense.

    While AMI for gas-only customers would provide more frequent and timely data to support conservation or time of use rates, it also requires a fixed network to install (and maintain). AMI would reduce the number of driving meter readers compared with AMR, but it would not eliminate them.

    Due to the safety concerns regarding remote disconnect of gas meters, the Company did not consider remote disconnect a benefit of AMI for gas-only customers. If remote disconnect capability were pursued, there would be additional cost of about $175 per meter for a remote disconnect device that is independent from the meter. A remote disconnect device integrated into the meter will not be available until 2019.

    In the Company's original study, it was determined that AMR was the better value solution for gas-only customers with an NPV of net revenue requirement benefit of $20.0 million versus AMI's NPV of net revenue requirement benefit of $15.8 million. The original estimate of a fixed network scenario to support our gas-only customers included an additional $23 million investment for the upfront installation of approximately 3,500 field network devices (Gas AMR utilizes 16 mobile collectors) with an associated estimated maintenance expense of over $54 million for 20 years and the initial investment of over $5 million for back office systems development and integration.

    While the Company decided to pursue AMR as the best value for our customers, AMI is still an option for the future since the gas communication modules (approximately 76% of the 2014 - 2019 AMR investment) are the same for either solution. Therefore, the Company is positioned for the future and can upgrade to AMI if there are sufficient future benefits for our customers.

Due to the geographic density characteristics of our gas-only customers, it is likely that the investment required to build a gas-only AMI network utilizing mounted data collection devices will not be cost justified for the entire gas-only area and that AMR would still be required to serve those customers that would be located outside of any future gas-only AMI network. Therefore, investing in AMR provides benefits to be realized in reduced operating costs and will continue to provide benefits even if the Company were to pursue investments in a future gas-only AMI network.

The Company also explored meter reading utilizing another utility's network. While this idea seemed mutually beneficial at the beginning of the study, the investment required for each utility to enable this capability and the technical challenges identified outweighed the potential benefit. One of the main technological challenges was the Company's position that enhanced security encryption to protect our customers' meter data was a requirement. In addition, in the case of Consumers Energy, the IT infrastructure and communications contract service levels and pricing were based on the number and type of the Company's devices and would not support the additional devices of another utility. Due to the Company's service territory of our gas-only customers, manual meter reading or Gas AMR would still be required to serve those customers not covered by the fixed communication network.

VII. <u>GAS AMR BENEFITS</u>

Q. What customer benefits result from the implementation of Gas AMR?

A. Similar to AMI, Consumers Energy customers realize benefits related to:

- Reduced meter reading cost;
- Improved billing accuracy as a result of higher actual meter read rates; and
- Reductions in energy theft resulting from the analysis of meter tamper alerts and energy consumption patterns.

VIII. GAS AMR CAPABILITIES AND STATUS

Q. Please discuss the status of the Company's investment in updated meter technology for gas-only customers.

A. To achieve automated meter reading capabilities, the Company is updating existing gas meters with communications modules, installing mobile collectors in meter reading trucks, and implementing an Itron Field Collection System ("FCS"). The project is also leveraging and building on existing operational systems.[27] Together, all of these components provide the infrastructure necessary to provide the benefits of AMR to our customers.

Q. Please describe the gas meter modules that have been selected for the Company's Gas AMR customers.

A. The Company has selected the Itron 100G DLS Datalogging ERT® module as our gas meter module, which is the same gas communication module utilized for gas AMI. While it is the same gas communication module, it will be programmed for Gas AMR's drive-by meter reading solution.

Q. Please describe Itron's FCS.

A. The FCS is a key element of the Gas AMR implementation, as it is the system that is used to collect meter reads and meter event data from a truck-based mobile collector. The FCS includes both hardware and software components. The FCS also manages the scheduling of the meters to be read each day by importing a list of meters to be read from SAP, and assigning daily routes to individual truck drivers. When daily meter read data

[27] Examples of existing operational systems include the Enterprise Service Bus ("ESB"), SAP, Itron Enterprise Edition ("IEE") Meter Data Management, PI MODM, Grid Director, and the Web Portal.

is collected by truck-based mobile collectors, the FCS then updates the operational systems used for billing and other operational processes.

Q. Please describe the status of the AMR systems upgrades.

A. Building on the existing systems work completed as part of the AMI implementation, the following systems upgrades include:

- Phase 1 - Customer Service & Front Office Processes (December 2016) – This systems release updated the customer service and front office processes to include Gas AMR, enabling customer accounts to be identified within the Company's SAP system as having an AMR enabled gas meter;

- Phase 2 (March 2017) – This systems release updated Device Lifecycle Management/Deployment and SEOC Operations to include Gas AMR. This release enhanced SAP and other systems to support supply chain processes, work management, quality, and audit management. Work order processing between the Company and our meter installation vendor was also enabled with this release. This release also included Route Planning & Optimization, specifically the interfaces necessary to perform the data exchange to create the optimized routes for the most efficient deployment of gas communication modules and cutover to meter reading truck routes; and

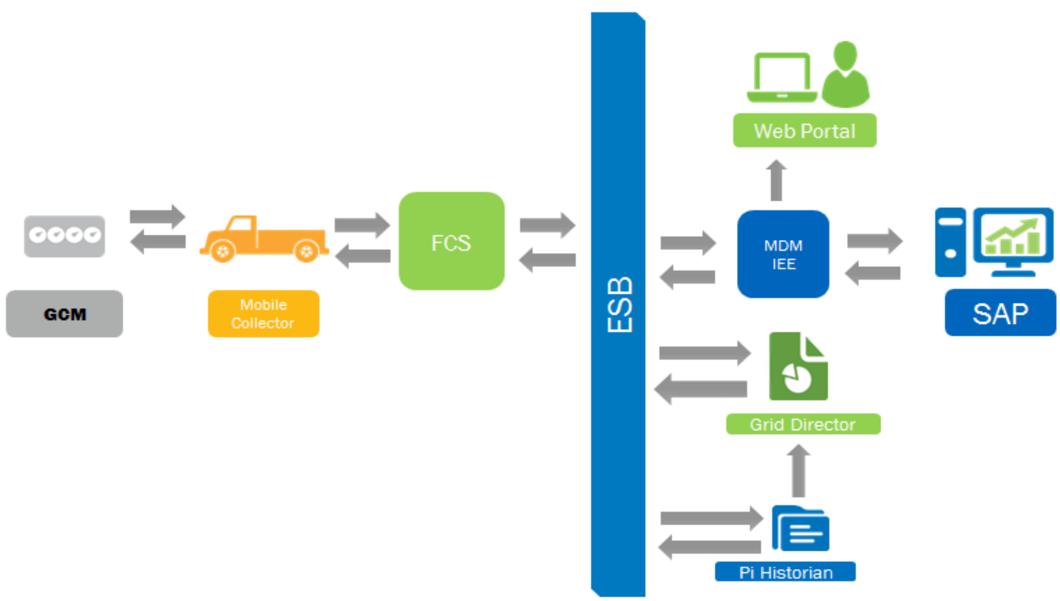
- Phase 3 (July 2017) – This IT systems release delivers all of the remaining functionality necessary for the Gas AMR drive-by solution. It integrates the new equipment and software for the FCS. This release also implemented the Route Planning and Optimization software that will be used by Meter Reading Planning & Scheduling for truck-based meter reading route development and maintenance.

Q. Are the AMR system upgrades necessary?

A. Absolutely. Without the upgrades, the Company could not install gas communication modules, validate the FCS meter read with a manual meter read, cutover the gas communication module to a FCS drive-by route, redistrict manual meter read routes into optimized driving routes, and optimize module installation routes for efficiency and timely realization of operational benefits.

Q. What are the major capital expense categories related to the AMR system upgrades?

A. The major categories are infrastructure hardware which includes mobile field devices and associated antennas, the FCS which is used to collect gas meter data stored in individual gas modules, and design work that includes all of the labor associated with integrating the drive-by solution. This design work includes: blueprinting and requirements identification, code and interface development, testing, and implementation. To integrate Itron's FCS into the Company's IT infrastructure, interfaces or upgrades to the following systems were necessary: Enterprise Service Bus ("ESB"), Itron Enterprise Edition ("IEE") MDM, SAP, PI Historian, the web portal, and Grid Director, as well as interfaces to support the Itron cloud and optimized routes. See the diagram below for the simplified architecture. Note that Gas AMR is leveraging the Smart Energy infrastructure, mainly ESB, IEE, Grid Director, PI Historian, and the web portal.



IX. GAS AMR PROGRAM COSTS/BENEFITS ANALYSIS

Q. What is the total capital investment expected in conjunction with the implementation of Consumers Energy's Gas AMR Program?

A. The AMR Program cost/benefit analysis, Exhibit A-22 (LMD-4), page 1, line 15, rows (c) through (h), indicate that projected investments for the purchase, testing, processing, and installation of gas communication modules, as well as the design, testing, and implementation of systems were originally estimated to require approximately $170 million in capital investment for the period 2014 through 2019. However, my Exhibit A-12 (LMD-1), Schedule B-5.1, pages 5 through 8, updates this projection for the removal of approximately $57 million of projected investment related to two specific business case investment components. Business case program contingency of $33 million has been removed from the projections in this case, and business case program management cost estimates have been reduced by $24 million, resulting in an updated capital expenditure projection of approximately $113 million as the total 2014 through 2019 capital expenditure requirement requested for approval in this case. Out of that total program investment, the Company is specifically requesting approval to include 2016 actual investments of $5.865 million and projected 2017 through June, 2019 investments of $106.798 million in the calculation of net utility plant for this case.

Q. Please explain your decision to exclude the approximately $33 million of capital investment contingency and $24 million of other program management expenditures from your capital expenditure in Exhibit A-12 (LMD-1), Schedule B-5.1.

A. The decision to exclude contingency from the projected capital investments is the direct result of the reduction in overall program investment risk that results from the successful implementation of software and system development components of the AMR implementation. The business case estimates of program management costs have also been determined to exceed the actual requirements necessary to complete the planned meter upgrade scope. These cost estimate reductions are reasonable given the progress made to complete system upgrades and establish contractual agreements with module manufacturers and installation contractors. At the time of this filing, my expectation is that the projections included in Exhibit A-12 (LMD-1), Schedule B-5.1, for the AMR Program will be sufficient to complete the remaining module installation aspects of the program.

Q. Please describe Exhibit A-12 (LMD-1), Schedule B-5.1, pages 5 through 8.

A. This exhibit presents the capital expenditures associated with the Gas AMR Program.

<u>Field Equipment/Facilities</u> refers to $1.636 million in projected equipment investments during 2017 through 2019 to support the AMR Program. These investments include purchases of mobile field devices and associated antennas used in the mobile collection of meter read and meter event data.

<u>Modules</u> are the direct investments associated with the purchase and installation of more than 1.1 million gas meter modules. The overall investment for AMR module purchases and installation is estimated to be $85.628 million through the completion of planned meter upgrades. Projected investments for 2017 are $7.904 million, projected investments for 2018 are $69.907 million, and projected investments for 2019 are $7.817 million. Annual expenses reflect gas module purchase estimates to support the scheduled installation of gas modules, as well as the installation costs. The actual purchase cost of gas modules, including both the vendor price and State of Michigan

sales tax, is the primary cost component included in these projections. Installation costs for purchased modules are also accrued as part of the total module capital investment. Contractual agreements with experienced manufacturers and installers are in place to support the Company's meter upgrade plan.

Software/Systems Development includes new systems development, existing systems modifications, and software licensing costs. For this line item, 2016 actual investments were $5.268 million, and projected 2017 investments are $12.519 million. There are no projected costs in this category beyond 2017. The FCS and other system modifications required to implement a drive-by meter reading approach are described earlier in my testimony.

Smart Energy Infrastructure includes investments in computer and network infrastructure to support the installation of gas modules and their associated systems. Because the Company is utilizing existing corporate data storage capabilities for AMR data, there are no actual or projected investments for this category.

Program Engineering/Design & Management refers to $0.597 million in actual 2016 investments, 2017 projected investments of $1.520 million, 2018 projected investments of $3.975 million, and projected investments in 2019 of $1.520 million. These costs are primarily incurred for the design, integration, and management of the gas meter modules, and overall support of the program (labor and expenses, customer communications, and associated corporate allocations).

Q. Please describe Exhibit A-20 (LMD-2), pages 3 and 5.

A. This exhibit presents the actual and projected O&M expenses for Gas AMR Program activities.

Program Management and Other refers to the program management and other related costs with $0.091 million in actual expenses in 2016, $0.740 million projected expense in 2017, $0.510 million of projected expenses for 2018, and $0.549 million for the test year ended June 30, 2019. These costs primarily include ongoing hardware and software maintenance, and other outside services expense.

Deployment and Meter O&M costs are expenses associated with the purchase and installation of gas meter modules. There were no costs for this line item in 2016, and none are projected for 2017. Projected costs for 2018 and the test year ended June 30, 2019 are $0.100 million respectively. This category of costs includes program staff salaries and expenses related to the O&M of the AMR technology. This category will also include costs related to the installation of gas modules by the Company's installation contractor, which will be offset by first set credits that result from the accrual of first set costs at the time modules are purchased. As a result of the first set credit offsets, I am not including projections of the installation costs on this exhibit.

Gas AMR Operational Savings are also summarized as part of Exhibit A-20 (LMD-2). These direct operational savings include both labor and non-labor cost impacts that will be realized through the automation of meter reading activities. Loadings for employee benefits and payroll taxes that are reflected in business case benefits are excluded from the direct operational savings benefits.

Q. Please discuss the overall results of the cost-benefit analysis as summarized in Exhibit A-22 (LMD-4).

A. The Company's business case for Gas AMR includes both costs and benefits associated with implementing drive-by automated meter reading for gas-only customers. The majority of our customers, including electric-only and electric/gas combination customers are included in the scope of AMI. The NPV calculation in the business case is based on numerous assumptions for both costs and benefits, and the analysis that is presented in Exhibit A-22 (LMD-4) was last updated during 2016. The key areas of variability in annual capital investments and O&M costs are the meter/module installation schedules and the systems modifications and new systems development requirements. The area of focus on the benefits side is the transition of current manual meter reading processes to drive-by automated meter readings and the ancillary impacts of meter read rate and billing accuracy improvements that will result from the use of enhanced gas meter reading technology. Savings to customers are measured by the program NPV of revenue requirements calculation of $24.2 million. The details of this calculation are provided in Exhibit A-22 (LMD-4), page 5.

Q. Please explain the gas meter reading benefits in the Company's Summary of Business Case Costs and Benefits.

A. Automation of meter reading provides several benefits to customers relative to existing manual meter reading processes. These benefits include improved meter read accuracy and reduced estimates of energy consumption for billing purposes. The automation of meter reading also enables the reduction of manual meter reading staff levels. At the time of full AMR implementation, the Company expects to achieve meter reading savings equivalent to approximately 80% of baseline gas-only area manual meter reading expenses. These savings will ramp-up over the meter installation period as customers transition from energy billings based on manual meter reads to billings based on automated meter reads. Annual gas meter reading benefits are shown on pages 3 and 4, line 53, of Exhibit A-22 (LMD-4). The meter reading benefits calculated in the cost/benefit analysis include direct labor and non-labor O&M savings as well as estimated savings in employee benefit costs and payroll taxes. The direct O&M expense savings (excluding benefit costs and payroll taxes) have been included as part of this proceeding in Exhibit A-20 (LMD-2). Of the total $4.556 million of direct operational savings identified in Exhibit A-20 (LMD-2) for the test year ending June 30, 2019, approximately $3.980[28] million is attributed to meter reading benefits.

Q. Please explain the gas other O&M expense benefits in the Company's Summary of Business Case Costs and Benefits.

A. The Company expects that the technological enhancements associated with AMR will generate operating efficiencies in customer service and billing areas of the Company. For example, the improved meter read accuracy and reduced estimates associated with automated meter reading reduces the need for gas operations workers to make field trips associated with special manual read requests to resolve billing issues and customer concerns about meter reading accuracy. Improved meter read rates and higher accuracy levels will also allow billing staff to avoid the need to request special manual reads. The Company is planning for a 70% reduction in special gas reads for gas-only service customers, which would result in a 45.5% reduction in all special gas reads. Of the total

[28] The estimated meter reading savings during the test year is calculated as 86.66% of test year labor direct savings and 90.40% of test year non-labor direct savings.

$4.556 million of direct operational savings identified in Exhibit A-20 (LMD-2) for the test year ending June 30, 2019, approximately $0.576 million is attributed to reductions in special reads, and customer service and billing efficiencies.

Q. Please explain the gas theft reduction benefits in the Company's Summary of Business Case Costs and Benefits.

A. The Company's pre-AMR theft detection process relies upon tips from meter reading or field service employees and contacts received from customers to initiate investigations of suspected energy theft. The most common form of gas energy theft identified using our existing theft tip process are customers who attempt to reconnect gas service after being disconnected for non-payment of past-due energy billings. In our enhanced AMR theft detection process, the Company will receive meter tilt tamper alerts and magnetic tamper alerts from gas modules as part of our drive-by AMR data collection process. This data will be analyzed for correlation with service work orders, customer notifications, and daily consumption patterns to identify locations where energy theft has been attempted.

Other theft detection activities are occurring during the AMR installation process. Examples of these activities include visual inspection by smart meter installers and billing/theft reviews of pre-deployment reports that list inactive meters with energy consumption.

Customers also benefit from the incremental gas sales revenue that results from the improved identification of energy theft. The theft benefit is expected to grow to 0.75% of residential and commercial gas sales revenue as gas modules and analytical systems for gas module data are implemented. Annual gas theft reduction benefits are shown on pages 3 and 4, line 56, of Exhibit A-22 (LMD-4).

Q. Please explain the Gas AMR induced conservation and energy efficiency benefits in the Company's Summary of Business Case Costs and Benefits.

A. Customers typically receive feedback from the Company regarding their natural gas consumption when they receive their monthly billing statement. At the time the Company was planning for the rollout of AMR, it was expected that daily consumption data would be available for viewing within the Company's customer web portal application. Customer benefits were expected to be realized in avoided gas supply costs as a result of energy conservation that would occur as a result of providing this information to customers in conjunction with monthly meter read data collection. More recently, the Company has determined that the estimated energy savings benefits of periodic updates of web portal data views with historical daily gas consumption are too small relative to updated cost estimates to pursue the integration of AMR data. As a result, the web portal will continue to display monthly consumption for customers with AMR meter upgrades, and benefits estimated for gas energy conservation are no longer being pursued as part of the AMR implementation. The following explanation describes the calculations included in the cost/benefit analysis:

1. Residential GCR revenue is multiplied by 65.7% to account for the natural gas customers that are located in our gas-only service area. The percentage of gas meters converted to AMR is also considered in each annual benefit calculation, starting in 2018. No natural gas consumption benefits are quantified for the commercial and industrial class;

2. Participation is expected to be 27% of gas-only residential customers;

3. Participating customers are expected to realize a 1% reduction in natural gas consumption; and

4. Overall, a 0.27% reduction (27% participation x 1% conservation) is expected for the portion of residential customer class that takes gas-only utility service from the Company.

Q. Please explain the LAUF gas reduction benefits in the Company's Summary of Business Case Costs and Benefits.

A. AMR usage data and the corresponding systems[29] being developed will enable improvements in LAUF analysis for geographic areas served by individual gas citygate stations. Daily meter index reads will provide enhanced information for analysis as gas volumes at a citygate level for a particular time period can be directly compared to the gas volumes reported from meters served by that citygate. This analysis will identify local areas that require action to reduce LAUF volumes and costs.

Annual gas LAUF reduction benefits are shown on pages 3 and 4, line 58, of Exhibit A-22 (LMD-4).

Q. Please explain the terminal value benefits in the Company's Summary of Business Case Costs and Benefits.

A. The calculation of the terminal value starts with the business case calculation of AMR net revenue requirements modeled for the calendar year 2037. In that year, the business case value of AMR customer savings is $33.4[30] million, and the business case value of AMR customer costs is $8.3[31] million, resulting in a net revenue requirement savings of $25.1 million. This value is then adjusted each year from 2038 to 2039 based on the percentage of all AMR modules installed that have remaining useful life based on the expected AMR module useful life of 20 years. The adjusted annual values are then discounted back to their present value in 2037 using two variables: the Company's weighted average cost of capital and the number of years difference between each year and 2037. The annual adjusted and discounted annual values for 2038 to 2039 are then

[29] PI MODM is the operational system that will provide data extracts used for LAUF analysis.
[30] Source: AMR Business Case spreadsheet.
[31] Source: AMR Business Case spreadsheet.

summed together to arrive at the 2037 terminal value of $15.4[32] million that is shown on page 4, line 77, of Exhibit A-22 (LMD-4).

Q. Does the cost/benefit of the program as summarized in Exhibit A-22 (LMD-4) support the Company's continued gas AMR investment for gas-only customers?

A. Yes. The Company's business case demonstrates that gas customers will realize benefits that exceed program costs, resulting in an NPV benefit for customers of $24.2 million. These results are detailed in Exhibit A-22 (LMD-4). Given that the supporting systems development work has been completed, the Company is in a position to complete the first 100,000 AMR module installations during the last half of 2017, and will complete all 1.1 million module installations prior to the end of the test year in this case. As mentioned previously in my testimony, the cost/benefit analysis includes capital investment contingency amounts that have been excluded from the Company's request for capital investment, so even without the AMR energy conservation benefits included in the business case, the investment in AMR will still provide positive benefits to customers through reduced overall cost to provide utility service.

X. SUMMARY

Q. On what basis are the gas AMI expenses concluded to be reasonable and appropriate?

A. As described throughout this testimony, the projected benefits which the AMI gas modules will provide to our gas combination customers are significant. Gas AMI automated meter reading has resulted in improved billing accuracy and reductions in estimated bills. Meter tamper notification data and analytical systems will result in gas theft reductions. Detailed energy usage information provided to customers through a web portal enables energy conservation and efficiency. Project completion in the Company's

[32] Source: Exhibit A-22 (LMD-4), page 5.

combination gas and electric service area is in customers' best interest not only because of the direct benefits to gas customers, but also to preserve the ability to realize significant electric savings in those areas. For example, elimination of monthly field visits to collect manual meter reads in combination areas requires that AMI be deployed for both gas and electric service.

Q. On what basis are the Gas AMR expenses concluded to be reasonable and appropriate?

A. As described throughout this testimony, the projected benefits which the AMR gas modules will provide to our gas only customers are considerable. Gas AMR will result in improved billing accuracy and reductions in estimated bills. Meter tamper notification data and analytical systems will result in gas theft reductions.

Q. Does this conclude your direct testimony regarding the AMI Program and the Gas AMR Program gas O&M expenses and capital expenditures?

A. Yes, it does.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
______________________________________	)	

REBUTTAL TESTIMONY

OF

LISA M. DELACY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2018

Q. Please state your name and business address.

A. My name is Lisa M. DeLacy, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. Are you the same Lisa M. DeLacy who previously submitted direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut certain assertions and recommendations made by the following witnesses regarding Consumers Energy Company's ("Consumers Energy" or the "Company") ongoing Smart Energy (including both Advanced Meter Infrastructure ("AMI") and Automated Meter Reading ("AMR")) Program investments and customer benefits discussed in the direct testimony and exhibits I filed as part of Consumers Energy's original Application in this case:

- The Michigan Public Service Commission ("MPSC" or the "Commission") Staff's ("Staff") witness Lauren Fromm; and
- The Attorney General's witness Sebastian Coppola.

Q. Are you sponsoring any exhibits in connection with your rebuttal testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-91 (LMD-5)	**Confidential** - Gas AMR/AMI Assessment Final Report;
Exhibit A-92 (LMD-6)	Integrated Remote Disconnecting Gas Meter memo from Itron; and
Exhibit A-93 (LMD-7)	Case No. U-17882 Direct Testimony Excerpt of Company witness Lincoln D. Warriner and Discovery Response No. 17882-AG-CE-148.

I. **CONSUMERS ENERGY'S ASSESSMENT OF AMR ALTERNATIVES**

Q. On page 5 of her direct testimony, Staff witness Fromm indicates that Staff has concerns that the Company did not properly evaluate other technology options with respect to the Company's selection of AMR metering technology for gas-only customers. Did the Company evaluate other alternative technologies?

A. Yes. Pages 36 and 37 of my direct testimony describe the Company's evaluation of AMR versus AMI alternatives for our gas-only service area. The original assessment, described on page 36, line 27 of my direct testimony, was completed during 2014, and is summarized in **Confidential** Exhibit A-91 (LMD-5). This evaluation included cost/benefit analysis of two AMR alternatives and two AMI alternatives. However, the cost/benefit analysis was only one consideration. The Company's decision also considered other important factors such as the amount of technical effort and resources required to integrate each option into the Company's operational systems, as well as potential business impacts. In summary, the net present value of revenue requirements for drive-by AMR was favorable for customers, minimized the amount of technical effort and resources required for integration, minimized potential business impacts, and enabled the Company to utilize existing project deployment resources and vendors involved in the implementation of electric/combination area AMI technology. The Company made reasonable and prudent decisions with respect to the implementation of drive-by AMR for gas-only service customers.

Since that analysis was completed in 2014, the Company has completed the development of various AMI enabled customer applications that support electric-only and combination gas/electric customers in their efforts to reduce unnecessary energy consumption, manage their monthly energy expense, and improve their overall customer experience when interacting with the Company. The Company recognizes Staff's desire for the delivery of the benefits derived from newly enabled AMI capabilities to all gas customers, and would like to work with Staff on the evaluation of costs and benefits for service enhancements that extend beyond the planned improvements in billing accuracy and operational efficiency that result from the utilization of gas meter modules in drive-by meter reading, including further evaluation of gas-only AMI. Progress can be made with Staff on the analysis of AMI type enhancements for gas-only customers while the Company continues to invest in gas meter modules for the following reasons:

i. In the short term:

- customers can realize the benefits of reduced meter reading expense in 2018 and beyond;
- customers can realize improved billing accuracy as a result of higher actual meter reads in 2018; and

ii. In the longer term:

- the gas communication modules installed can easily be reprogrammed to work with an AMI system as needed.

The Company is willing to commit to the development of a plan with input from Staff on conducting a pilot with integrated remote disconnecting gas meters to test and confirm the customer benefits that could be realized. This pilot, and further detailed study of gas-only AMI, will inform decisions on the future technology enhancement options, as well as evaluate and consider the utilization of AMI for gas-only customers where it is reasonable and prudent to do so.

Because the Company's gas module is compatible with AMR or AMI data collection technologies, options exist to determine the best overall benefit to our customers.

II. STAFF'S SUGGESTED USE OF ELECTRIC AMI METERS AS DATA COLLECTION DEVICES

Q. On page 7 of her direct testimony, Staff witness Fromm suggests that the Company could install electric AMI meters on utility poles in the Company's gas-only service areas to function as data collection and communication devices. Does the Company believe this is an alternative that should be further evaluated for use in the Company's gas-only service areas?

A. At this time, the Company cannot confirm that electric AMI meters installed on utility poles would be a cost effective alternative to drive-by meter reading or a fixed network of data collection devices.

While the Company has utilized AMI programmed modules to transmit gas meter data through nearby electric meters, as discussed on page 8 of my direct testimony, the Company's experience is that the gas module communication capabilities of electric smart meters have operational limits. These limitations would need to be factored in to any plan that involves installing electric AMI meters to function as data collection units for meters in our gas-only service area. Our experience is that one electric AMI meter can reliably collect meter reading data from at most 15 nearby gas meters. A simple estimate using the 15-to-1 module to meter ratio is that 74,820[1] electric AMI meters would be required for this approach; however, the distance from the module to the meter would also need to be considered in estimating the electric AMI meter requirements. At a minimum, the installation of an electric meter would also require the installation of a meter socket and connection to a power source from an electric provider other than the Company. The comparison of the cost of electric AMI meters to fixed network devices,

[1] 1,122,302 gas modules / 15 module per electric AMI meter = 74,820 electric AMI meters

included in Ms. Fromm's direct testimony, needs further assessment of each device's technical capability and supporting costs to install and operate. Specifically, the capability of the electric meter to function beyond simply collecting meter reads needs to be explored and evaluated with the electric meter manufacturer. Today, the electric meter can only collect gas meter reads and events. An AMI network not only collects meter data, but is also capable of issuing commands such as a command to remotely disconnect an integrated gas meter that supports that functionality. If a data collection system utilizing pole mounted electric AMI meters proves to provide additional benefits to customers, then the gas meter modules presently being installed by the Company could be adapted to work with that type of system.

III. AMR TRUCK ROLL OPERATING COSTS

Q. On confidential page 8 of her direct testimony, Staff witness Fromm claims that the Company failed to provide information on the cost of a truck roll to collect AMR meter reads in response to requests for costs associated with AMR modules. Is this claim correct?

A. It is true that the Company's response to Discovery Request No. 18424-AG-CE-134-CONFIDENTIAL, which is provided by Staff as Confidential Exhibit S-17.6, does not provide the cost of a truck roll. The Company has included AMR truck roll costs in its projection of meter reading costs, and reductions in meter reading costs related to AMR are described on page 46 of my direct testimony. Thus, the Company did not interpret the Attorney General's discovery request regarding the installation and operating costs of AMI versus AMR meters to include drive-by meter reading costs. The cost of a truck roll represents a cost reduction from the existing practice of reading meters manually, while also delivering improvements in actual meter read rates and reduced estimated billings.

IV. <u>SUPPORT PROVIDED FOR AMR</u>

Q. On page 8 of her direct testimony, Staff witness Fromm states that the Company did not provide a cost/benefit analysis for AMI gas meters. Does this support Ms. Fromm's recommendation to disallow investments by the Company in AMR?

A. No. In its July 31, 2017 Order in Case No. U-18124, pages 20 and 21, the Commission acknowledged that the Company had "provided some explanation regarding the data and the benefits of the AMR program," but stated that "without specific expense information for modules and software and systems development, the Commission cannot determine whether the Company's projected expenses for these items are reasonable and prudent…" The detail provided in my direct testimony and exhibits in this case provide the level of detail that was identified as missing from the Company's support in Case No. U-18124 for gas-only AMR investments. When the Company decided to invest in AMR, our assessment was that it was the most reasonable and prudent alternative to reading meters manually. The Company has encountered challenges with meter access, weather and other hazardous conditions, and other safety concerns as outlined in Staff's Exhibit S-17.4, which is the Company's report on estimated billing practices from Case No. U-18002. In that report, the Company identified AMR as a reasonable opportunity to address high estimated billing frequencies experienced by some customers. The Company is moving forward with the plan committed to in that proceeding because it provides immediate benefit to our customers through reduced meter reading expense and improved billing accuracy as a result of higher actual read rates.

V. REMOTE DISCONNECTION OF GAS METERS

Q. Also on page 8 of her direct testimony, Ms. Fromm indicates that remote disconnect capability of gas AMI meters will be a significant benefit of AMI relative to AMR in the near future. Does this support the proposed disallowance of the Company's investment in AMR?

A. No. Once available, remote disconnect capability in the integrated gas meter will also be available to AMR systems, as well as AMI, per the manufacturer. Please see Exhibit A-92 (LMD-6). Regardless of remote disconnect capability and the associated value, the gas communication modules that are being installed today can be converted to AMI through over the air programming. The Company agrees that there may be benefits associated with remote disconnect of integrated gas AMI meters. The Company is willing to work with Staff to develop a plan that leads to a common understanding of the costs and benefits associated with implementing the remote disconnect integrated gas meter technology. The proposed remote disconnect pilots at other gas utilities will be useful sources of information regarding potential costs and benefits. When integrated gas meters that support remote disconnection functionality are commercially available, the Company could conduct a pilot in our own service area to fully assess the costs, including any necessary system upgrades, customer and Company benefits, any application restrictions, and proper operating practices. If the pilot proved successful, and with common understanding of the cost and benefits, a very deliberate replacement program could be created that allows integrated gas meters to replace existing meters over time where it is operationally appropriate. The Company envisions a gradual approach much like an update to a meter standard is implemented today. For example, the integrated meters could be placed on new facilities and replace meters as they are taken out of service. This approach would maximize the intended life of existing meters and the associated gas communication modules remaining in the field while creating a cost effective means of meter upgrades. This consideration should not lead to disallowance of AMR investments in this proceeding because, as discussed, AMR provides current benefits to our customers, and remote disconnect integrated gas meter technology should be evaluated from an AMR perspective as well.

VI. ACCELERATED DEPRECIATION REQUESTS BY OTHER UTILITIES

Q. On pages 8 and 9 of her direct testimony, Ms. Fromm indicates that Indiana Michigan Power ("I&M") requested approval in 2011 for recovery of costs to implement electric AMR metering, and is currently requesting accelerated depreciation of AMR meters in order to transition to AMI meters over the next five years. Does this development support Staff's proposed disallowance of the Company's investments in gas AMR?

A. No. While the Company is not familiar with the technological details or the associated customer benefits of I&M's AMR metering solution for its electric customers, Staff's objection to I&M's request is not relevant to the Company's request for recovery of investments in AMR modules for the following reasons:

i. When the Company installed AMI metering in our electric and combination electric/gas service areas, we did not iterate our technology investment. The Company went from a manual meter reading process directly to an AMI system. The Company is not planning to make a short term commitment to AMR for our gas service area. The Company's offer to work with Staff on a cooperative plan to evaluate alternative advanced metering technology for gas only service customers should alleviate this concern. Furthermore, the AMR modules' ability to quickly and efficiently be reprogramed to AMI functionality ensures that the original investment is not lost and ensures maximum flexibility with the investment; and

ii. The Company's AMR installation does not require the replacement of all customer meters. In most cases, the Company's AMR module is compatible with gas meters already in service. If an alternative metering technology is determined by the Company and Staff to provide additional benefits at a reasonable cost, the Company would expect to roll that technology out in a way that makes appropriate use of the remaining service life of existing gas meters.

Q. On pages 9 and 10 of her direct testimony, Ms. Fromm indicates that Staff questions the ability of the Company to deliver benefits as projected in the AMR cost/benefit analysis based on her assessment of AMI cost/benefit analysis benefit projections. How do you respond?

A. On page 10, lines 7 through 9 of her direct testimony, Ms. Fromm contends that the Company projected $2.175 billion in gas and electric O&M benefits from AMI in Case No. U-17735, then revised that value to $1.947 billion in Case No. U-18322. This statement requires clarification. The lines referred to by Ms. Fromm include more than O&M benefits. For example, AMI benefits include avoided capacity costs that result from the implementation of residential demand response programs and energy savings benefits that result from the implementation of web portal displays of customer usage. Even with the changes in benefit estimates provided by the Company between the two cases cited, both cost/benefit calculations support the Company's conclusion that investments in AMI in our electric and combination electric/gas service locations result in a reasonable expectation of net benefits to customers. The comparison of $11.558 million of 2017 meter reading benefits to the business case meter reading benefit of $16.577 million also needs clarification. The business case meter reading benefits include estimates of payroll taxes and employee benefit costs that need to be factored out of the benefit estimate prior to applying the benefit to meter reading projections in operational O&M witness exhibits. The Company has consistently included projected

AMI benefits in its test year forecasts of O&M expense over multiple electric and gas rate cases.

Q. On page 10 of her direct testimony, Ms. Fromm recommends that all AMR costs be disallowed. She further suggests that if the Commission were to allow recovery of AMR costs, that recovery should be netted against the annual average benefits of AMR. Should these recommendations be adopted by the Commission in this case?

A. No. The Company is implementing AMR not only to realize benefits associated with reductions in meter reading staffing requirements and more efficient identification and investigation of energy theft, but also to realize unquantified benefits associated with increasing meter read rates and reducing the frequency of billing estimates for customers. This is evident from Staff's Exhibit S-17.4, which represents the Company's plan to address higher than desired billing estimate frequency. The meter read rate performance improvements (from historical manual reading experience) that will be realized as the Company automates gas meter reading with AMR is an unquantified benefit that is not included in the AMR cost/benefit analysis. The Company's selection of the gas module being installed at gas-only service locations (with the flexibility to easily be reprogrammed for AMI) is reasonable and prudent, and the Company respectfully requests the Commission to determine that those investments are appropriately included in the plant in service projections used to provide utility service for customers.

The Company also respectfully disagrees with Staff's suggestion that the recovery of AMR investments be netted against the annual average benefits of AMR. The Company did not develop the cost/benefit analysis for this purpose, and Staff has not indicated how such an approach would impact the development of the Company's revenue requirement in this case. The Company does not have enough information about Staff's proposal to determine that a netting approach fairly balances the interests of customers and shareholders. Generally, the cost/benefit analysis is predicated on the traditional ratemaking treatment of capital assets and operating costs. The Company notes that Staff witness Brian Welke has included the projected Gas AMR test year direct O&M benefits in Exhibit No. S-3, Schedule C5. Since the test year O&M benefits of AMR have been adopted by Staff in that exhibit, it is only fair and reasonable that AMR investments be treated the same way as other utility asset investments in this proceeding. The projected O&M benefits of AMR can only be realized through the automation of meter reading in gas-only service areas, which is supported by the Company's investments in gas modules that are compatible with both AMI and AMR systems.

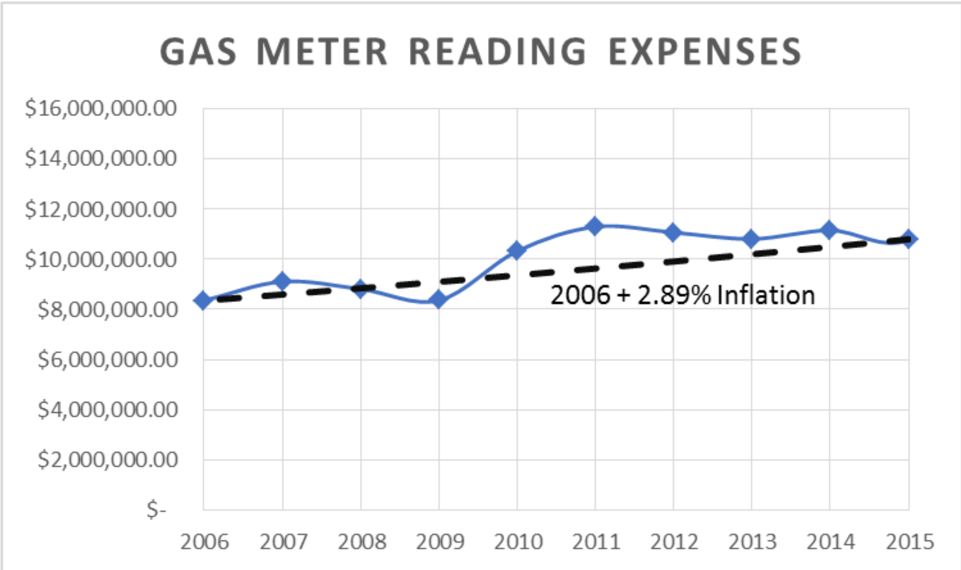
Q. Would the disallowance or deferral of historical AMR capital spending in a Commission order result in an asset impairment assessment and potential write-off of the capital asset?

A. Yes. While I have supported that the historical AMR expenditures are necessary, prudent, and in the best interest of customers, the rebuttal testimony of Company witness Daniel L. Harry indicates that a disallowance of historical spending in a Commission order would require an asset impairment assessment. Please refer to the rebuttal testimony of Company witness Harry for further discussion of the accounting requirements.

VII. METER READING O&M EXPENSE

Q. On page 18 of her direct testimony, Staff witness Fromm indicates that the Company assumes an arbitrary inflation rate of 2% and does not adequately account for the benefit of the Smart Energy Program. Is her analysis correct?

A. No. The 2006 through 2015 data provided in the chart labeled "Gas Meter Reading Expenses" on page 18 of Ms. Fromm's direct testimony actually indicates that the Company is being conservative in its expectation that gas meter reading expenses would increase at an inflation rate of 2% without the benefit of advanced metering technology. The data that Staff witness Fromm used to create the chart, provided on page 18 of her direct testimony, supports an inflation rate of 2.89%. I have updated Staff witness Fromm's chart to include a dashed line that represents annual inflation of 2.89% from 2006:



Staff witness Fromm reached an incorrect conclusion regarding the 2% inflation rate included in the Company's projections, and I recommend that the Commission accept the

Company's projection of meter reading expenses before adjustment for the Smart Energy Program.

Staff witness Fromm also indicates on page 19 of her direct testimony that meter reading expenses should be reduced by 37% to reflect the automation of meter reading for combination gas/electric customers. The rationale that 37% of customers would require 37% of the Company's meter reading effort is an oversimplification of the Company's meter reading operations. The AMI Program, which the Company did complete during 2017, has never claimed that the automation of combination gas/electric customers would result in a 37% decrease in gas meter reading costs. The Company has expected as part of its cost/benefit evaluation of AMI that automating the combination gas/electric customers would reduce the need for gas meter reading labor and non-labor costs by approximately 14%. This 14% reduction to 37% automation relationship exists because prior to the installation of AMI, the Company would, in most cases, be able to read both the gas and electric meter in the same visit for combination gas/electric service customers. The Company has expressed this expectation in testimony and discovery responses in prior gas rate cases.[2] Please see Exhibit A-93 (LMD-7). At page 20 of her direct testimony, Staff witness Fromm also makes an incorrect comparison of the meter reading benefits indicated in Exhibit A-51 (MPP-3) to the meter reading benefits provided in Exhibit A-21 (LMD-3), page 3. These two values should not match as suggested by Staff witness Fromm. The direct labor and non-labor savings included in the exhibits of Company witness Mary P. Palkovich are a subset of the labor, non-labor, employee benefit, and payroll tax savings summarized in Exhibit A-21 (LMD-3). Since

[2] Examples include the direct testimony of Lincoln D. Warriner in Case No. U-17882, page 21, line 26 and discovery response 17882-AG-CE-148.

only the labor and non-labor costs are included in Company witness Palkovich's historical meter reading O&M, it would not be appropriate to adjust those costs for the employee benefit and payroll tax savings that are included in the cost/benefit analysis. As a result, I recommend that the Commission should not adopt Ms. Fromm's proposals to:

- Reduce 2015 actual meter reading by 37% for AMI automation; and
- Support operating department cost adjustments with cost/benefit estimates that also include employee benefit and payroll tax impacts.

Staff witness Fromm's recommendation to further adjust meter reading by the AMR business case estimates of meter reading cost impacts should be rejected for the same reason. In addition, Consumers Energy already reflected AMR meter reading savings in Exhibit A-20 (LMD-2), and any additional reduction to the meter reading expense shown in Exhibit A-51 (MPP-3) would be double counting the benefit. The Company has included the appropriate meter reading cost adjustments for AMI in Exhibit A-51 (MPP-3) and the appropriate meter reading cost adjustments for AMR in Exhibit A-20 (LMD-2).

Q. On page 22 of his direct testimony, Attorney General witness Coppola claims that the Company has overstated the amount of meter reading expense for the projected test year, and recommends an adjustment to Meter Reading O&M of $4.145 million for the projected test year. How do you respond to Mr. Coppola's conclusion and proposed adjustment?

A. Mr. Coppola's conclusion is incorrect, and his proposed adjustment duplicates cost reductions already included in the Company's projections of test year O&M. The analysis described by Mr. Coppola focuses on the Meter Reading O&M expenses and

Smart Energy O&M reductions provided in Exhibit A-49 (MPP-1), but ignores the O&M reductions provided in the Company's Exhibit A-20 (LMD-2). The Company has included Gas AMR operational savings of $4.556 million in Exhibit A-20 (LMD-2). These operational savings for the most part will be realized in reduced Meter Reading O&M costs. Page 46, line 11 of my direct testimony quantifies the test year direct operational savings related to meter reading as $3.980 million. Because Mr. Coppola overlooked the Company's adjustments for AMR in its test year projections, his proposed $4.145 million adjustment duplicates Gas AMR savings that the Company has already accounted for. Therefore, I recommend that the Commission refuse to adopt the $4.145 million O&M adjustment proposed by Mr. Coppola. The Company has provided accurate forecasts of Meter Reading costs considering the implementation of both AMI and AMR. There is no reason to adjust the test year projections provided by the Company.

VIII. <u>CONCLUSION</u>

Q. Please summarize your rebuttal testimony conclusions and recommendations with respect to the proposed disallowances of Company investments in AMR for gas-only customers.

A. In conclusion, while the Company is receptive to further consider AMI and a pilot with remote disconnecting integrated meters, it is reasonable and prudent for the Company to proceed with the installation of gas communication modules for the following reasons: (i) the flexibility of the technology to easily be reprogrammed for AMI; (ii) some areas of the service territory may still need to rely on AMR (vs AMI) for a solution; and (iii) to realize the immediate meter reading and billing benefits discussed in my direct and rebuttal testimony. The installed AMR gas communication module technology is providing benefits to our customers today with the recent cutover to AMR billing gas communication modules and will continue to realize further benefits as more gas communication modules are cutover to AMR billing. As of March 14, 2018, the Company's initial AMR truck read experience has realized 15,759 reads with an actual read rate of 99.9%.[3] By year-end 2018, 542,290 customers are targeted for AMR drive-by reads. The Company will study the benefits of AMI, seek staff input, work to develop a common understanding, and provide those findings in an upcoming gas rate case. That work may include a pilot to further quantify benefits and costs.

Q. Please summarize your rebuttal testimony conclusions and recommendations with respect to proposed adjustments to the Company's projections of test year Meter Reading Program expense.

A. The Company has considered appropriate Smart Energy adjustments to the Meter Reading Program expense, and those estimates should be relied upon by the Commission in determining the Company's revenue requirements associated with Meter Reading O&M.

Q. Does this conclude your rebuttal testimony?

A. Yes.

[3] 15,759 actual reads / 15,767 attempts = 0.9995

MR. GENSCH: At this time the Company calls Herbert Kops to the stand.

JUDGE SONNEBORN: Thank you.

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(Documents marked for identification by the Court Reporter as Exhibit Nos. A-43 through A-45, A-105 through A-107.)

JUDGE SONNEBORN: Good morning.

THE WITNESS: Good morning.

H E R B E R T B. K O P S

was called as a witness on behalf of Consumers Energy Company and, having been duly sworn to testify the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. GENSCH:

Q Mr. Kops, will you please state your full name for the record?

A Herbert B. Kops.

Q And by whom are you employed?

A Consumers Energy Company.

Q And what is your job title with Consumers Energy?

A I'm the Executive Director of Total Rewards and Workforce Relations.

Q And did you prepare a document entitled Direct Testimony of Herbert B. Kops on behalf of Consumers Energy Company,

which consists of a cover page and 41 pages of questions and answers?
A I did, yes.
Q Did you also prepare a document entitled Rebuttal Testimony of Herbert B. Kops, which consists of a cover page and six pages of questions and answers?
A I did, yes.
Q Are there any changes that you wish to make at this time to your direct or rebuttal testimony?
A I have no changes to make.
Q And is that the testimony you are adopting as your own today?
A I am, yes.
Q Did you also prepare a number of exhibits with your testimony and rebuttal testimony?
A Yes, I did.
Q And are those exhibits marked as Exhibits A-43, A-44, A-45, A-105, A-106, and A-107?
A That's correct, yes.
Q Do you have any changes that you wish to make today to those exhibits?
A I do not.

MR. GENSCH: At this time, your Honor, the Company moves to bind in the direct and rebuttal testimony of Herbert Kops, and for the admission at the end of cross-examination of Exhibits A-43, A-44, A-45, A-105, A-106, and A-107. And with that, I tender Mr. Kops for cross-examination.

JUDGE SONNEBORN: Thank you. Are there any objections to binding in the direct and rebuttal testimony of Mr. Kops? (No response.)

Hearing none, I will bind in the direct and rebuttal testimony of Mr. Kops, and I will take up his exhibits at the conclusion of cross-examination.

(Testimony bound in.)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
	)	

DIRECT TESTIMONY

OF

HERBERT B. KOPS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2017

Q. Please state your name and business address.

A. My name is Herbert B. Kops, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By who are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your current position with Consumers Energy?

A. I am currently the Executive Director - Total Rewards and Workforce Relations.

Q. What are your responsibilities as Executive Director - Total Rewards and Workforce Relations?

A. I am responsible for the design, implementation, and administration of the Company's retirement and insurance benefit plans for employees and retirees as well as the compensation programs for employees. I have responsibility for administration of the Company's Self-Insured Workers Compensation Program, Absence Management Program, and the Educational Assistance Program. I also have responsibility for the workforce policy and practice relationship with exempt, non-exempt, and union employees.

In the retirement benefits area, the Company contributes to the cost of the Pension Plan, the Defined Company Contribution Plan ("DCCP"), and the 401(k) Employee Savings Plan ("ESP"). My responsibilities for these benefit plans include the design and implementation of competitive, cost-effective, quality plans that will attract and retain qualified and talented employees to serve customers. These plans are designed to provide a portion of an employee's retirement income along with the employee's social security benefits and personal savings.

In the insurance benefits area, the Company contributes to the cost of these insurance benefit plans - health care (medical/prescription drug/dental including Health Savings Accounts ("HSA") and Health Care Flexible Spending Accounts ("HCFSAs")), life insurance, and Long-Term Disability ("LTD") insurance. Like the retirement plans, my responsibilities for these health care and insurance benefit plans include the design and implementation of competitive, cost-effective, quality plans for employees and retirees of the Company that help attract and retain qualified and talented employees to serve customers. In addition to these plans, I have responsibility for several additional benefit plans offered to employees by the Company at group discounted rates, which require the employee to pay the full cost of the coverage elected. These voluntary plans include 24-hour accident insurance, health care and dependent care flexible spending accounts, vision insurance, dependent term life insurance, and long-term care insurance. These insurance benefit plans also help attract and retain qualified and talented employees to serve customers as these plans help protect employees and their families from significant financial loss in a number of areas.

Q. What is your formal educational experience?

A. I graduated from the University of Michigan in Ann Arbor in 1977 with a Bachelor of Business Administration Degree. In 1987, I graduated from the University of Michigan - Flint, earning a Master of Business Administration Degree with High Distinction. Since joining Consumers Energy's insurance benefits area in 1989, I have successfully completed a number of benefits certification courses through World at Work (formerly American Compensation Association) and obtained a Certificate in Benefits Administration.

Q. Would you please describe your previous work experience?

A. In 1977, I began my career at Consumers Power Company (now known as Consumers Energy) as a Human Resources Advisor in the Grand Rapids Service Center. In 1979, I accepted additional responsibility as the Human Resources Administrator in the Company's Cadillac District. This was a generalist Human Resources role, offering independent work responsibility for 150 employees in the Cadillac, Prudenville, Clare, and Big Rapids energy distribution headquarters.

In 1982, I became the Human Resources Supervisor in the Company's Saginaw office of the Central Region. I supervised the Saginaw office operation staff in this generalist role and provided leadership and support to other Central Region offices as needed. My responsibility in Saginaw covered human resources responsibilities for over 600 employees in the Region.

I became the Insurance Benefits Supervisor for the Company in 1989 and moved to the corporate office in Jackson. In 1994, I became the Director of Insurance Benefits with responsibility for health care, various other insurance programs, and the relocation plan of the Company for active and retired employees. In 2003, I became the Director of Employee Benefits and assumed responsibility for the retirement benefit plans (Pension Plan, DCCP, and ESP) and the Workers Compensation Program. In 2014, I assumed responsibility for the Absence Management Program for non-occupational leaves and absences.

In May 2016, I became the Executive Director - Employee Benefits and Compensation with additional responsibility for the Company's compensation programs. In May 2017, I became the Executive Director - Total Rewards and Workforce Relations, assuming additional responsibilities for the Company's workforce policies and practices for exempt, non-exempt, and union employees.

Q. Are you a member of any professional societies or trade associations?

A. Yes, I am a member of World at Work. World at Work is an international professional association dedicated to knowledge leadership in compensation, benefits, and total rewards. I am also a member of the International Foundation for Employee Benefits.

I am a current member of the Michigan Chamber of Commerce Health and Human Resources Committee, having chaired this committee for a two-year period during my membership. This Committee deals with health and human resources policy and legislation in the State from a business perspective.

I represent the Company as a member of the National Business Group on Health ("NBGH"), an association of over 400, mostly large, employers across the country who provide health coverage to over 50 million individuals. NBGH represents the national voice of large employers dedicated to finding innovative and forward-thinking solutions to the nation's most important health care issues.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide support for the Company's expenses related to the gas business portion of its retirement benefit plans (Pension Plan, DCCP, and the ESP) and its health care/insurance benefits plans (health care, life insurance, and LTD insurance plans) provided to its active employees and retirees. In Part I of my testimony I will address the retirement benefit plans. In Part II of my testimony I will address the health care and insurance benefit plans.

Q. Are you sponsoring any exhibits?

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

Exhibit A-43 (HBK-1)	Summary of Gas Benefits O&M Expenses for the years 2016, 2017, 2018 and 12 Months Ended June 30, 2019;
Exhibit A-44 (HBK-2)	CMS Energy - ASC 715 (Formerly FAS 87) Pension Expense Estimates ($ millions); and
Exhibit A-45 (HBK-3)	CMS Energy - ASC 715 OPEB Expense Estimates ($ millions).

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

A. Yes.

Q. Please describe Exhibit A-43 (HBK-1).

A. Exhibit A-43 (HBK-1) summarizes 2016 through the 12 months ended June 30, 2019 gas Operating and Maintenance ("O&M") expenses for the Company's retirement and health/insurance benefit plans offered to employees and retirees. On this exhibit, column (a) provides a program description of the O&M expense category. Column (b) provides the 2016 actual expense for each program. Column (c) provides the projected expense in 2017 for each program. Column (d) provides the projected expense in 2018 for each program. Column (e) provides the projected expense for the 12 months ended June 30, 2019 for each program. Column (f) provides a source reference for the expense.

Q. Please describe Exhibits A-44 (HBK-2) and A-45 (HBK-3).

A. These exhibits provide the Aon Hewitt actuarial projections for Pension and Other Post-Employment Benefits ("OPEB") expenses for 2017, 2018, and 2019. The projected Pension and OPEB expenses for the 12 months ended June 30, 2019 were calculated by adding 50% of the 2018 projected expense and 50% of the 2019 projected expense. Both the Pension and OPEB projections in these exhibits provided by the Aon Hewitt actuaries are based upon the year-end 2016 measurement of the Pension and OPEB plans and reported in the Company's 2016 Form 10-K filing.

I. RETIREMENT BENEFIT PLANS

Q. Which retirement benefits are you addressing in this section of your testimony?

A. I am addressing the Pension Plan, DCCP, and ESP. These expenses are shown on lines 1 through 3 of Exhibit A-43 (HBK-1). I am addressing active health care/life insurance/LTD and retiree health care and life insurance later in my testimony.

Q. How are the Pension Plan, DCCP, and ESP expenses that are common to gas and electric utilities allocated to the gas portion of the business?

A. Expenses common to both the gas and electric utilities associated with the Pension Plan, DCCP, and ESP are allocated on the basis of the relationship of employee labor dollars charged to the gas utility compared to the labor dollars charged in both gas and electric utilities. These allocations are made by the Accounting Department. The gas portion of the O&M expense for these plans is shown on Exhibit A-43 (HBK-1).

Pension Plan

Q. Would you please explain line 1 of Exhibit A-43 (HBK-1)?

A. Exhibit A-43 (HBK-1) shows the actual 2016 expense and the projected expenses for 2017, 2018, and the 12 Months Ended June 30, 2019 attributable to the gas utility.

Q. How does the Company determine its expense for the Pension Plan?

A. The Pension Plan expense is determined using actuarial analysis that is performed in accordance with Accounting Standards Codification ("ASC") 715, formerly known as

Statement of Financial Accounting Standards ("FAS") 87. Consumers Energy follows Generally Accepted Accounting Principles ("GAAP") for its financial statements. Under the provisions of GAAP, ASC 715 describes the methodology and assumptions required to properly calculate and account for pension expense. The calculations required by the accounting standards are performed annually by Consumers Energy's actuary, Aon Hewitt, using information specific to the Company's Pension Plan. In addition, the actuarial assumptions are reviewed by the Company's auditors to ensure consistency with GAAP.

ASC 715 requires an annual determination of pension expense. Expense is determined based on actuarially reviewed employee census data, the plan provisions, plan assets, and certain other actuarial assumptions. Year-end disclosure information is also produced, based on these accounting standards, to show a reconciliation of plan assets and liabilities at the end of the Company's fiscal year. For this gas rate case, the Pension Plan was measured on December 31, 2016. Pension expense in this case, including 2017, 2018, and the 12 Months ended June 30, 2019, is based upon this year-end 2016 actuarial measurement of the Pension Plan.

Q. What are the components of the annual pension expense under ASC 715?

A. There are four components of the expense: (i) service cost; (ii) interest cost; (iii) expected return on plan assets; and (iv) amortization of gains or losses, prior service cost, and any transitional amounts. The plan's service cost represents the value of the benefits earned during the year. This is determined individually for each participant based on his/her specific employee demographics. The interest cost represents interest on the plan's liabilities due to the passage of time. All future benefits are discounted back to the valuation date using a full-yield curve discount (interest) rate assumption. There is also an assumption made for the expected earnings or return on plan assets. The expected return on plan assets each year reduces the plan's annual expense. The expected return assumption is reviewed periodically by the plan's actuary and the Company and is intended to be a long-term assumption based on the best estimate of the long-term expected investment earnings of the plan assets. The last component of plan expense is amortization of various plan experiences that were not anticipated by the plan's actuarial assumptions. For example, plan experience gains or losses and any plan design changes would be amortized and included as a part of this component of plan expense. The amortization can be either positive or negative.

In order to calculate the plan's total pension benefit obligation and annual ASC 715 expense, the actuary uses a number of assumptions including: (i) discount rate; (ii) mortality table; (iii) salary change; (iv) expected return on plan assets; and (v) expected future contributions needed to avoid at-risk status under the Pension Protection Act. The assumptions used by the actuary are determined by the Company each year and reviewed by the Company's auditors.

Q. Has the Company applied the new FAS Board ("FASB") Presentation of Pension/OPEB Costs Standard in this case?

A. Yes, the Company early adopted this new FASB Presentation of Pension/OPEB Costs Standard as of January 1, 2017 and has applied the new standard in this case for both Pension and OPEB. This new FASB Standard allows only the service cost component of expense to be recorded as an operating expense, and all other benefit cost components are to be recorded outside operating income. The new FASB Standard also allows only service costs to be capitalized, while all other cost components are recorded to net income immediately.

Q. Please describe the development of the Pension Plan expense shown on line 1 of Exhibit A-43 (HBK-1), which begins with $10,963,000 for 2016.

A. Each of the annual pension expense levels shown on line 1 for the gas utility is based upon Aon Hewitt's actuarial determination of the plan's total expense for that year in accordance with ASC 715 and also includes plan administration fees and Pension Benefit Guarantee Corporation ("PBGC") premiums. Each of the annual pension expense levels shown on line 1 reflects 2016 actual expense and projected expenses for 2017, 2018, and the 12 months ended June 30, 2019. The Consumers Energy pension expense determined by Aon Hewitt, plus administration fees and PBGC premiums, are allocated to the gas and electric portions of the utility using the Accounting Department methodology described earlier. This allocation resulted in the actual gas utility O&M expense for pensions of $10,963,000 in 2016. For 2017, 2018, and the 12 Months ended June 30, 2019, Aon Hewitt has projected the Company's ASC 715 pension expense based upon a series of specific assumptions for each year. The gas utility's portion of the ASC 715 O&M pension expense plus projected administration fees and PBGC premiums for 2017, 2018, and the 12 Months ended June 30, 2019 are included on line 1. For 2017, the gas utility's portion of the projected O&M pension expense is $16,753,000. For 2018, the gas utility's portion of the projected O&M pension expense is $23,000,000. For the 12 months ended June 30, 2019, the gas utility's portion of the projected O&M pension expense is $23,966,000.

Q. Did the Company make any cash contributions to the Pension Plan in 2015 or 2016?

A. Yes. The Company contributed $209,500,000 to the Pension Plan in December 2015. The Company also contributed $93,300,000 to the Pension Plan in December 2016.

Q. Will the Company make any cash contributions to the Pension Plan in 2017, 2018, or for the 12 months ended June 30, 2019?

A. No Pension Plan contributions are required in 2017, 2018, or in the 12 months ended June 30, 2019 to avoid benefit restrictions or at-risk status. Any contributions the Company elects to make during these periods of time will depend upon future decisions of the Company regarding funding policy, the future value of plan assets and liabilities, and any potential legislative guidance or changes.

Q. Why does the pension expense increase from 2016 to 2017?

A. The pension expense increases in 2017 due to the use of a lower yield curve discount rate, reflective of market conditions, at the time the 2017 pension expense was projected by the Company's actuary based upon the December 31, 2016 measurement of the plan. In addition, pension expense increases in 2017 due to changes in several other actuarial assumptions including retirement rates, salary increases, and optional forms of pension payment. The increase in pension expense from these assumption changes was somewhat mitigated by the Company's 2016 pension contribution and favorable changes to the withdrawal rate and disabled mortality rate assumptions.

The gas utility O&M pension expense is also higher due to the application of the new FASB Presentation of Pension/OPEB Costs Standard, which only allows capitalization of the pension service cost.

Q. Why does the pension expense increase for 2018 over 2017?

A. Pension expense in 2018 increases primarily because the expected and actual asset returns assumption for 2018 is projected at 7.00%, down from its 7.25% in 2017. This assumption is changed due to the general acceptance in the marketplace that economic growth will not accelerate anytime soon, and long-term expected rates of return have been decreasing and are expected to continue to decrease further moving forward.

The Company anticipates that economic growth will be sluggish, and 10-year treasury interest rates will decline. As interest rates are a key factor in projecting out long-term returns, lower returns can be expected. The Company has anticipated this declining return trend for a number of years and has reduced its expected rate of return by 25 basis points every two years since 2010. These 25 basis point reductions took place in 2010, 2012, 2014, and 2016.

Q. Have any changes recently been made to Pension Plan benefits?

A. On September 1, 2015, a change was made to the survivor benefit for a retirement-eligible employee covered by the plan who passes away prior to retirement. In such case, the surviving spouse/beneficiary will automatically receive the employee’s full monthly retirement annuity (rather than 50% of the annuity), even if the employee had not completed the paper application process for this benefit prior to passing away.

While this modest 2015 change was made to the Pension Plan, no significant benefit changes have been made to the Pension Plan since September 1, 2005 when the Pension Plan was closed to new hires and the DCCP was implemented for new hires. Increases in pension expense created by the assumption changes are moderated by the closure of the Pension Plan to new hires as of September 1, 2005. In addition, pension liabilities and expenses are moderating overall as many participants are retiring or leaving and commencing their benefits, which reduces the liability and associated expense over time. Liability and expense will continue to diminish (presuming no change in the market assumptions) until there are no longer any employees or retirees covered by the defined benefit Pension Plan. The changes in the projected pension expense estimates for 2017 through 2019 are primarily the result of economic market conditions external to the Pension Plan and over which the Company has no control.

DCCP

Q. Does the Company provide an alternative qualified benefit plan to the closed Pension Plan for employees hired on and after September 1, 2005?

A. Yes. In order to remain competitive in the area of a benefits package that attracts and retains qualified and talented employees for the benefit of the customer, the Company replaced the Final Average Pay and Cash Balance versions of the qualified defined benefit Pension Plan with the qualified DCCP for all existing Cash Balance participants and newly hired employees on and after September 1, 2005.

Q. Are there any employees included in the DCCP that were hired before September 1, 2005?

A. Yes. Those employees who were hired between July 1, 2003 and August 31, 2005 and were provided coverage under the Cash Balance version of the defined benefit Pension Plan became participants in the DCCP as of September 1, 2005. As of September 1, 2005, for this specific group of employees, additional pay credits under the Cash Balance version of the defined benefit Pension Plan were discontinued.

Q. Will the Cash Balance version of the defined benefit Pension Plan accept any new employees as participants?

A. No. As with the Final Average Pay defined benefit Pension Plan, the Cash Balance version of the defined benefit Pension Plan now has a finite group of participants that, over time, will diminish until there are no longer any employees or retirees covered under this plan.

Q. Please provide a general description of the DCCP.

A. The DCCP currently provides an employer-funded cash contribution of 5% to 7% of the employee's base pay to the ESP. No employee contribution is required to receive the employer contribution. All existing Cash Balance Plan employee participants and employees hired on and after September 1, 2005 participate in the DCCP as part of their retirement benefit package.

Q. Have any recent changes been made to the DCCP?

A. Effective in January 2016, the DCCP provides a 5% to 7% (previously 6%) employer-funded cash contribution based upon the employee's service with the Company. New hires receive a 5% contribution, which increases to 6% when they have six years of service with the Company. Employees receiving a 6% contribution before January 1, 2016 continue to receive their 6% employer contribution. When employees reach 12 years of service, they receive a 7% employer contribution. This service-based contribution approach for the DCCP serves as a talent attraction and retention mechanism and helps contain the expense of the DCCP for the benefit of the customer as all new hires starting in 2016 began receiving a 5% (previously 6% for new hires) employer contribution.

Q. Would you please explain line 2 of Exhibit A-43 (HBK-1), which begins with $3,940,000 in 2016?

A. Line 2 represents the gas utility O&M expense related to the DCCP. The actual gas utility expense for this plan in 2016 was $3,940,000, as shown in column (b). Column (c) shows the projected gas DCCP expense of $4,287,000 for 2017. Column (d) shows the projected gas DCCP expense of $4,930,000 for 2018. Column (e) shows the projected gas DCCP expense of $5,300,000 for the 12 months ended June 30, 2019. The projected expenses are based upon anticipated salary/wage increases and the Company continuing to hire employees at a higher than usual rate due to larger numbers of expected Pension Plan employee retirements.

Currently, all new hires begin receiving a 5% of base wage Company contribution to the DCCP after 90 days of employment instead of participating in the more costly defined benefit Pension Plan. The DCCP expense will continue to grow annually based upon the expectation that all newly hired employees participate in this DCCP and not the Pension Plan. Offsetting this increase in the DCCP expense is a declining defined benefit Pension Plan expense as the group covered by the Pension Plan is now finite in size and will reduce in numbers with the passage of time.

Q. As a result of the revised eligibility requirements for participation in the Final Average Pay defined benefit Pension Plan or the Cash Balance version of the defined benefit Pension Plan, is it correct to say that all new hire employees starting with September 1, 2005 and after will receive their retirement benefits through plans that are referred to as defined contribution-type plans?

A. Yes. The primary plans that will provide monetary benefits to this group of employees upon retirement are the DCCP and the ESP.

ESP

Q. Please explain briefly how the ESP works.

A. The ESP is a 401(k)-type retirement savings program funded by employee and employer contributions. A portion of employee contributions are matched by Consumers Energy. The Company currently matches 100% of the employee's first 3% in contributions and 50% of the employee's next 2% in contributions to the ESP. Employee contributions beyond 5% are not matched by the Company. Consumers Energy's expense includes the Company matching contributions and the payments made to Fidelity Investments for administration of the program.

Q. Have any recent changes been made to the ESP?

A. Effective in January 2016, the Company match changed to 100% of employee contributions of up to 3% of the employee's salary, and then 50% of employee contributions of up to the next 2% of the employee's salary (previously 60% of employee contributions up to 6% were matched). Employee contributions beyond 5% will not be matched by the Company. This change will help to keep the ESP expense and talent retention competitive in the market to attract and retain qualified and talented employees for the benefit of customers.

Q. Would you please explain line 3 of Exhibit A-43 (HBK-1), which begins with $4,789,000 in 2016?

A. Line 3 represents the Company's gas utility expense related to the ESP. In 2016, the actual gas utility O&M expense for the ESP was $4,789,000. For 2017, the gas utility

O&M expense projected for the ESP is $4,687,000. For 2018, the gas utility O&M expense projected for the ESP is $4,849,000. For the 12 months ended June 30, 2019, the gas utility O&M expense projected for the ESP is $4,933,000.

Q. Is the ESP employer matching program important to attracting and retaining employees?

A. Yes.

Q. Please explain why the ESP employer matching program is important to attract and retain employees.

A. The ESP employer match for Consumers Energy employees serves a number of important purposes. The ESP is a defined contribution plan. The match helps provide a competitive benefits package that enables the Company to attract and retain qualified and talented employees, who directly and indirectly serve and benefit the customer. Defined contribution savings plans with employer matching provisions are offered by the vast majority of Fortune 500 companies located across the country, including Consumers Energy in Michigan. These plans have become a core benefit offering that greatly helps attract and retain qualified and talented employees.

In fact, a Fidelity Investments survey conducted in 2014 on the importance of employer contributions to employee retirement savings indicated employees were more likely to accept a position that had an employer match as part of its overall compensation package. The survey article went on to indicate that only 13% say they would take a job with no company match, even if it came with a higher pay level. Further, a 2015 Deloitte and International Foundation of Employee Benefit Plans survey indicates 89% of defined contribution plans offered matching contributions in 2015. Recent information received from Fidelity's analysis of 22,100 corporate defined contribution plans covering

14.8 million participants in 2017 indicates that 87% of active employee participants received employer contributions. Not offering a savings plan with an employer match feature would be a competitive disadvantage for the Company as it needs to attract a continual flow of qualified new talent to replace retiring workers. The Company also needs to retain current talented and trained workers to avoid expensive turnover costs.

While many current employees are covered by the Company's defined benefit Pension Plan and all new hires since September 1, 2005 are covered by only the DCCP, the Pension Plan, or the DCCP by itself, is not designed to fully meet the employees' retirement income needs. The Pension Plan or the DCCP is only part of an overall competitive employee retirement package that includes the Pension Plan or the DCCP and the contributory ESP with an employer-matching contribution - but only for those employees who contribute to their own future retirement benefit through the ESP. The combination of these plans provide a meaningful incentive for employees to do well in their jobs to the benefit of customers because doing so will benefit them with a more financially secure retirement, supplemented by their own personal savings and social security benefits.

The ESP employer match also reflects a prudent business practice because it incents employees to create savings for their retirement. The employer match encourages employees to save more when their contributions are matched. Matching contributions offer an immediate, tangible return that employees contributing to the plan can see and appreciate. New employees are automatically enrolled in the ESP due to the importance of starting to save early as a secure retirement will depend significantly on how much the employee contributes to their ESP account. Employer-matching contributions and automatic enrollment in the ESP are important features that help create savings. These features are important because most retirement studies show that employees, including Consumers Energy employees, do not save enough and need to save more for their retirement than they currently do as costs in retirement continue to increase. Longer life expectancies are leading to longer retirements which require more savings. Additionally, other costs such as health care are expected to continue to increase for retirees. The employer match encourages employees to plan and save for retirement. The ESP provides an excellent vehicle to help employees achieve a more self-sufficient and independent retirement.

The bottom line is that savings plans with a match are very much available from Michigan employers as well as from other utility company employers that Consumers Energy competes with for employee talent. It is necessary to continue providing this highly visible, competitive benefit to employees of Consumers Energy in order to continue attracting and retaining competent employees needed by the Company, particularly in light of the large number of retirement-eligible employees at the Company. Attracting qualified and talented employees, and retaining this talent, maximizes the efficiency of the Company's labor force and reduces costly turnover. Retaining trained, experienced, and motivated employees works very much to the customers' benefit.

Q. Is the ESP employer match "discretionary"?

A. It is not discretionary for union employees. A provision in the Working Agreement ratified in 2005 with Operating Maintenance and Construction ("OM&C") and Virtual Call Center ("VCC") union employees assured these employees that the match would not be suspended during their five-year contract. This provision was renewed in the 2010 contracts as part of the final union agreements for these union groups, and it is also part of the Steelworker's union contract effective January 1, 2011. This provision was not changed in the most recent five-year contracts negotiated in 2015. This has been an important issue to the union during the last several labor negotiations, all of which were finally resolved through arms-length bargaining.

With respect to non-union employees, there is not a similar contractual prohibition against suspension. However, the ESP employer match is part of an overall competitive benefit package, and employees depend upon its continuation so they can accumulate savings for retirement. The Company's competitors continue to offer a savings plan match, and the Company plans to continue offering the match to compete for new talent and retain current talent for the benefit of the customer. As noted above, it is a benefit that helps the Company attract and retain qualified and talented employees. From a practical standpoint, the Company views the employer match as non-discretionary.

II. HEALTH CARE, LIFE INSURANCE, AND LTD PLANS

Q. Which health care and insurance benefits are you addressing?

A. I am addressing active employee health care (including HSAs and HCFSAs), life insurance, and LTD plans, as well as retiree health care and life insurance plans. These expenses are shown on lines 4 and 5 of Exhibit A-43 (HBK-1).

Q. Are the expenses for active employee health care (including HSAs and HCFSAs), life insurance, and LTD benefits determined in the same way as expenses for retiree health care and life insurance benefits are determined?

A. No. The expenses for active employees are based upon the actual costs for these benefits that have been incurred or are expected to be incurred. The expenses for retirees are determined using actuarial analysis, which is performed by the Company's actuary, in accordance with ASC 715, formerly known as FAS 106.

Q. How were the portions of active employee and retiree health care (including HSAs and HCFSAs), life insurance, and LTD expenses allocated to gas O&M expense determined?

A. The portion of the Company's total program expenses attributable to the gas utility was allocated based upon an annual study by the Accounting Department of the relationship between the number of employees in the gas utility to the total number of employees in both the gas and electric utilities. The amount allocated to the gas utility is then allocated between O&M expense and capital expense based upon the Accounting Department's formula.

Active Health Care (Including HSAs And HCFSAs), Life Insurance, And LTD Insurance

Q. Please describe the development of the active health care (including HSAs and HCFSAs), life insurance, and LTD insurance expense levels that are shown on line 4 of Exhibit A-43 (HBK-1), which begins with $15,941,000 in 2016.

A. Line 4 contains gas utility O&M expenses for the Company-subsidized benefit plans for active employees' health care (including HSAs and HCFSAs), life insurance, and LTD insurance. The primary component of this expense is health care. Life insurance and LTD expense make up a much smaller portion of the expense. In 2016, the Company incurred an actual combined expense of $15,941,000 for health care, life insurance, and LTD for the gas utility. The projected gas utility expense for these benefits in 2017 is $15,490,000. The projected gas utility expense for these benefits in 2018 is $16,016,000. For the 12 months ended June 30, 2019, the projected gas utility expense is $16,289,000.

Q. Why does the projected active health care expense decrease in 2017 from 2016?

A. The 2017 total active health care expense is expected to increase 4.3% over the 2016 expense. However, the O&M portion of this expense actually decreases in 2017 because more of the gas utility portion of the expense is being capitalized in 2017 (51%) than in 2016 (46%).

Q. What factors did you consider in projecting the Company's 2017, 2018, and the 12 months ended June 30, 2019 health care, life insurance, and LTD expenses?

A. In projecting expected 2017, 2018, and the 12 months ended June 30, 2019 health care expenses, a number of factors were considered. Primary factors included: (i) review of 2017 and 2018 national health trends and costs survey information; (ii) the Company's medical and prescription drug carrier's health care cost and claims experience expectations; (iii) the continuing rapid rise in availability and price of specialty prescription drugs; (iv) the ages of the Company's employee workforce and its retirees; (v) the continuation and improvement of the Company's Healthy Living Plan and Wellbeing initiative for employees and retirees; (vi) changes to the 2016 through 2020 OM&C/VCC/ Steelworkers union employee health care benefit contract provisions; (vii) changes to 2017 and 2018 salaried employee health care plans; (viii) the current employee headcount; and (ix) the continuing cost increase impacts of national health care reform. All of these factors are included in the 2017 and 2018 rate studies completed by the Company and Willis Towers Watson ("WTW") actuarial consulting.

Q. Please explain how these factors were used in the WTW rate studies to determine the Company's expected health care expenses in 2017, 2018, and the 12 Months ended June 30, 2019.

A. To help understand projected health care trends and costs in 2017, 2018, and the 12 Months ended June 30, 2019, the Company and WTW reviewed expected health care trends and costs survey information from several large consulting firms. Recent 2017 health care trend and cost surveys included in the review were Aon Hewitt, The Segal Group, WTW, and Mercer. For 2017, medical health care trend (per capita claims cost) is expected to increase from 4% to 8% on just medical expenses. The leading medical trend contributor is prescription drugs, which is expected to trend 11.6% in 2017, while the specialty prescription drug trend is 18.9%. For 2018, a PricewaterhouseCoopers survey projected medical trend at 6.5% - the first uptick in growth in three years according to the survey. A review of these projected trends in medical and prescription expenses serves as a basis of what to expect in future medical expense increases.

The Company and WTW also reviewed the Company's actual health care claims experience for employees and retirees in its health plans - Blue Cross/Blue Shield of Michigan, Express Scripts, Priority Health, and Blue Care Network. The Company's health plans indicate that the Company's workforce is older than the average workforce in their plans and, as a result, has a higher expected utilization rate of services that is associated with an older covered population. Of the Company's current workforce on December 31, 2016, 52% of employees are over age 45; 38% are over age 50; and 23% are over age 55. The Company understands the older age of its workforce is expected to lead to higher health care expense (primarily due to utilization of services). Most of these discussions with the Company's health plans suggest health care expenses are expected to increase from 5% to 8% for 2017 and 2018. Historical claims experience data for Consumers Energy participants was also gathered from these health care companies to be used in the 2017 and 2018 health care expense impact studies completed with WTW to determine the Company's projected expense increases in 2017, 2018, and the 12 months ended June 30, 2019.

Consideration to future health care expenses for payment of the State of Michigan's mandated Health Insurance Claims Assessment was also factored into the WTW rate study analysis.

Also considered in projecting future health care expenses, the Company and WTW considered all the plan changes and programs the Company has already implemented, which are summarized below and detailed later in this testimony. These changes include: (i) sharing expected health care expense increases with employees through plan design changes including increased deductibles, copayments, and out-of-pocket maximums; (ii) increasing employee premium contributions for coverage; (iii) adding telehealth benefits to medical plans to lower expense; (iv) educating employees regarding the prudent and informed use of health care benefits; (v) promoting use of preventive benefit services; (vi) promoting well-being, which includes offering only Healthy Living Plan designs that encourage and reward plan participants for taking steps toward healthier lifestyles; (vii) securing favorable pricing on prescription drugs obtained through a large employer prescription drug collaborative; and (viii) negotiating lower administrative fees with health plans and promoting enrollment into the Consumer

Directed Health Plan ("CDHP"), a high deductible health plan which currently provides a Company contribution to the participant's HSA.

The Company and WTW also considered the specific changes to the union employees' health care plan benefits, as negotiated in its 2016 through 2020 contracts, as well as changes made to the salaried employees' health care benefit plans in 2017 and 2018 described in detail later in this testimony. While there are very tangible savings in future health expenses to the Company and its customers as a result of these changes to employee health care benefit plans, the Company believes a portion of these savings will be offset by increased health expenses incurred under national health care reform requirements (like Patient-Centered Outcomes Research Institute fees, Transitional Reinsurance fees, employer mandate shared responsibility administrative/reporting requirements, and potential penalties) as well as increased prescription expenses due to the availability of new and expensive specialty prescription drugs in the market. In addition, while the Company has taken numerous steps to control the rising expense of health care, many of these changes are one-time events that lower a plan's expense in that year to establish a new baseline moving forward, but future health care expenses then continue to increase from the new baseline expense.

Based upon the analysis of all this information, including health plan demographics and current enrollments, the Company and its independent employee health care actuarial consultant, WTW, projected in their rate studies that the Company is projected to have a 4.3% increase in its health care expense in 2017 (over 2016 actual expense) after consideration of all the factors reviewed above including known 2017 cost sharing plan design and premium contributions changes. For 2018, the WTW rate study indicates the expected health care expense increase for the Company will be 3.5% after all plan design and premium contribution changes are considered for 2018. Although the 2019 plan changes are not yet known, the Company will continue to seek to contain expense, and the Company's health care expense is projected to increase the same 3.5% in 2019 over 2018 expense. The Company used these WTW actuarially based studies to set its projected active health care expenses for 2017, 2018, and 2019. As a result, the Company projects its expected health care expense will increase 3.5% for the 12 months ended June 30, 2019 (half of the projected 2018 increase plus half of the projected 2019 increase from the 2018 WTW rate study).

Q. What are some of the reasons that health care expenses are increasing at a level higher than general inflation?

A. There are a number of factors causing a much higher rate of health care inflation than is reflected in the general Consumer Price Indexes ("CPIs"). Health care expenses are expected to continue rising during the next several years due to: (i) an aging population living longer; (ii) additional utilization of services; (iii) price increases for services; (iv) new medical technology and services; (v) cost shifts from government plans like Medicare and Medicaid; (vi) mandated benefits coverage; (vii) rising provider malpractice premiums; (viii) new taxes on health claims; and (ix) rapidly escalating prescription drug prices including high prices for new, expensive specialty drugs now trending at an increase of about 19% each year. In addition, national health care reform has increased Company health care expense as a result of: (i) eligibility expansions (*e.g.*, adult children to age 26); (ii) mandated benefits; (iii) removal of annual dollar limits; (iv) additional taxes, fees, and penalties; (v) new compliance/reporting requirements; and (vi) more government shifting of costs through Medicare and Medicaid expansion. These factors are all outside the control of Consumers Energy.

Even with all the success the Company has had in containing its health care expenses with annual plan design and premium contribution changes over a number of years, including its move to Healthy Living Plan designs and introduction of the CDHP, health care expense for the Company is still expected to continue increasing annually at a rate at least two times that of general CPI inflation. The assumption that health care expense will only increase at the general rate of inflation, or will not increase at all, has not been the actual experience for many years and is not expected in the foreseeable future.

Q. Are large increases in health care expenses being experienced both locally and nationally?

A. Yes. While increases in health expenses have moderated somewhat, both local and national health care expenses continue to increase at rates much higher than general CPI inflation.

Q. Are the significant increases in health care expenses limited to active employees?

A. No. Health care expenses are also increasing at a rate higher than the general CPI inflation for retirees for the same reasons cited earlier. In fact, retiree expenses are generally increasing at higher rates because of retirees' older ages and the resulting increases in utilization, particularly in the use of prescription drugs, including higher-priced specialty prescription drugs. The projected increases for active employee health care expense, like projected increases for retiree health care expense, are substantial, reasonably expected to occur, and largely beyond the control of the Company.

Q. Please describe the development of the expense levels for active employee life insurance and LTD expenses included on line 4 of Exhibit A-43 (HBK-1).

A. For 2017, 2018, and the 12 Months ended June 30, 2019, the Company used a 3.5% annual increase in expense for these annual periods. This means 2017 life insurance and LTD expense is expected to be 3.5% higher than 2016, 2018 expense will be 3.5% higher than 2017, and 2019 will increase another 3.5% over the 2018 expense level. These expense estimates are reasonable as both life insurance and LTD premium expenses are based on wage and salary levels and changes to this coverage throughout the year. The 3.5% annual increase reasonably represents the normal, expected merit increase in salaries/wages, increases due to salary adjustments made for job changes and promotions throughout the year, upward movement in Company-paid life insurance coverage in each annual enrollment period, and periodic increases in premium rates due to plan experience.

In addition, the Company renegotiated its life insurance contracts with Aetna Inc. ("Aetna") beginning in 2016, and all coverage will be provided on a prospective basis. These renegotiated contracts provide for some reduction in the Company's expense for life insurance provided to employees. However, much of this 2016 and 2017 expense reduction is offset with an expense increase resulting from OM&C/Zeeland union employees being provided an increased and competitive level of Company-paid life insurance coverage under their new contracts - one-times their base pay, up from the flat $40,000 previously provided by the Company. Given that the improved union employee life insurance coverage expense is offset by lower premium rates in the new Aetna contracts, the annual 3.5% increase in this expense for 2017, 2018, and the 12 Months ended June 30, 2019 is expected to equal the Company's life insurance/LTD expenses during these periods.

Q. What has the Company done to control the increase in active employee and retiree health care, life insurance, and LTD expenses?

A. The Company has aggressively managed these benefit expenses for more than a decade. Significant changes have been made to all health care, life insurance, and LTD plans since the introduction of the Benefit by Choice Program first implemented in 2002, which offered employees and retirees different levels of health, life insurance, and LTD coverage. A summary of various changes made to manage the expense of the Company's health care plans offered to employees and retirees from 2002 through 2015 follows:

- Increased employee/retiree premium contribution levels annually;
- Implemented Preferred Provider Organization ("PPO") plans, providing discounted networks to all participants;
- Reduced PPO Plan benefit coverage levels from 90%, 80%, and 70% to 85% and 70%;
- Reduced Health Maintenance Organization ("HMO") Plan benefit coverage levels from 100% to 90%;
- Increased employee/retiree PPO and HMO Plan design cost sharing provisions including medical/dental deductibles; out-of-pocket limits; office copays; urgent care copays; and emergency room copays on several occasions;
- Switched to Maintenance of Benefits ("MOB") coordination;
- Required covered spouse working full-time to have own employer coverage primary;
- Negotiated administrative fees and insured plan premium rates annually and bid the health plan market to improve pricing;

- Increased employee/retiree prescription drug benefit expense sharing through incentive three-tier plan designs, higher prescription drug copays and coinsurance, and use of an exclusive network for specialty drugs;

- Implemented prescription drug management programs including full-menu; dynamic-based coverage management programs; mandatory use of mail order; safety/efficiency provisions; and regular market bids for pricing through an employer collaborative;

- Implemented health and disease management programs and added case management;

- Implemented a Company-defined dollar contribution plan management approach;

- Eliminated duplicative, higher-cost health plan offerings on several occasions;

- Introduced informed consumerism, cost information, and credible health resources;

- Used enhanced technology for more timely determination of plan eligibility and coverage;

- Implemented access only retiree health care benefits for new hires (no Company subsidy);

- Implemented preventive benefits with no cost sharing, included the mandated changes required under the Affordable Care Act ("ACA");

- Implemented and promoted enrollment in a CDHP with an HSA;

- Implemented Healthy Living Plan designs requiring completion of annual health monitoring and improvement steps to maintain preferred benefit coverage levels or receive an additional Company HSA contribution. Employees/pre-Medicare retirees and their covered spouse that do not participate are moved to a lower standard, higher out-of-pocket cost benefit coverage level or do not receive the second Company HSA contribution;

- Separated employee/retiree medical and dental plans to minimize reporting and compliance costs required by the ACA;

- Changed insured HMO plans to self-insured HMO plans;

- Implemented an ongoing medical/dental/vision plan dependent audit process to ensure only eligible employees, retirees, and their dependents are covered by these plans; and

- Secured improved prescription drug pricing and plan consulting services as part of membership in a large employer prescription drug purchasing collaborative.

Q. What changes were made to the 2016 health care plans?

A. During 2015, new five-year union contracts were negotiated with the Company's three union groups, which cover health care benefits starting in 2016 and running through 2020. In addition, similar health care benefit changes were made to all non-union employee health care and all pre-Medicare retiree health care benefits starting in 2016.

Beginning in 2016, employees and pre-Medicare retirees were offered up to four medical plan options - one fewer than in 2015. Each of the four plans (one PPO, one CDHP PPO and two HMOs) covered medical costs at 80% (down from 85%) after meeting the plan's deductibles. Deductibles, copays for specialty physicians and emergency room visits, prescription drug maximums, and out-of-pocket maximums for the three standard medical plan options (one PPO and two HMOs) were all increased in 2016 to share expected cost increases with employees and pre-Medicare retirees. These three standard medical plan options required successful completion of the Healthy Living Plan steps by employees, pre-Medicare retirees, and their covered spouses to stay in the higher preferred level of benefit coverage. If the Healthy Living Plan steps were not completed, participants were moved to a lower level of benefit coverage (15% to 20% more out-of-pocket cost sharing) beginning May 1 of 2016. Premium contributions for employees and pre-Medicare retirees also increased in 2016 for those who stayed in their current plans as a method to help share in expected health care cost increases in 2016.

Participants continued to be offered a CDHP with an HSA. This plan provides the same PPO providers/benefits as the standard PPO Plan, but does have higher deductibles before paying 80% for covered benefits. Participants in this plan also had an HSA, and the Company will make a larger contribution into their HSA - one early in the year and a second contribution later upon successful completion of the employee, pre-Medicare retiree, and covered spouse Healthy Living Plan steps. This plan offered the lowest premium contribution requirements for employees and pre-Medicare retirees.

All four medical plan options being offered in 2016 also included Telehealth benefits - virtual physician visits using a computer, tablet, or smart phone. This benefit offers 365/24/7 availability, convenience, and lower cost when a plan participant has a minor medical issue that requires a physician's attention.

Q. What changes were made to the 2017 health care plans?

A. In 2017, the same health care benefit changes were made for all union and non-union employees as well as all pre-Medicare retirees. The Healthy Living Plan designs were changed to comply with new Equal Employment Opportunity Commission requirements for wellness plans. This required only the employee and pre-Medicare retiree, not covered spouses, to complete their Healthy Living Plan steps under the wellness plan design. Those employees and pre-Medicare retirees that complete their two Healthy Living Plan steps in 2017 will have less cost sharing in their health plans or receive a second Company contribution to their HSA in 2017.

In addition, the ACA expanded non-discrimination definitions to include gender identity. As a result, the Company added coverage for gender transition benefits to all of its health plans.

Also, as a result of the ACA employer mandate testing process, the Company re-enrolled all waived-out employees into health plan coverage for 2017. This was followed by efforts on the Company's part to have these re-enrolled employees again waive-out of coverage for 2017, certifying they had coverage for themselves and their tax dependents elsewhere. This certification from waived-out employees was necessary to avoid counting waive-out cash payments in the employer mandate testing for affordability and the possibility of being penalized for not offering affordable coverage under the ACA to employees waiving coverage.

Finally, all health plan premium contributions for employees and pre-Medicare retirees were increased to share in expected increased costs in 2017.

Q. What changes will be made to the 2018 health care plans?

A. In 2018, deductibles and out-of-pocket limits will be increased in the majority of plans for all salaried and union employees, as well as early retirees. Several prescription drug coverage management programs will be added to help participants better manage various chronic and expensive medical conditions. The CDHP will have increased out-of-pocket limits as well as a reduction in Company HSA contributions. The prescription drug plans will have increased specialty drug copay. A refreshed wellbeing approach will be introduced to encourage and incent plan participants to improve their health and wellbeing year-round. Premium contributions will also be increased across all health plans to help manage the expected expense increases for the Company.

The active employee health care expense for the Company, after consideration of all of these changes, is expected to increase 3.5% for the 12 months ended June 30, 2019 as documented in the WTW rate study.

Retiree Health Care And Life Insurance

Q. Would you please explain line 5 of Exhibit A-43 (HBK-1), which begins with ($7,816,000) in 2016?

A. Exhibit A-43(HBK-1), line 5, reflects the actual 2016 gas utility retiree health care and life insurance expenses under ASC 715 as well as the projected retiree health care and life insurance expense for 2017, 2018, and the 12 Months ended June 30, 2019.

Each of the annual expense levels shown on line 5 is the total of two separate items which make up the total expense. Each year's expense contains an ASC 715 expense calculation and an actuarial services/administrative expense.

Q. How does the Company determine its ASC 715 expense for retiree health care and life insurance?

A. The expense is determined using actuarial analysis that is performed in accordance with ASC 715. Consumers Energy follows GAAP for its financial statements. Under the provisions of GAAP, ASC 715 describes the methodologies and assumptions required to properly calculate and account for retiree health care and life insurance expense. The calculations required by the accounting standards are performed annually by the plan's actuary, Aon Hewitt. In addition, the actuarial assumptions are reviewed by the Company and the Company's auditors to ensure consistency with GAAP.

ASC 715 requires an annual determination of retiree health care and life insurance expense (OPEB expense). The expense is determined based on actuarially reviewed employee census data, the plan provisions, plan assets, and certain other actuarial assumptions. Year-end disclosure information is also produced, based on these accounting standards, to provide a reconciliation of plan assets and liabilities at the end of the Company's fiscal year. For this gas rate case, OPEB was measured on December 31,

2016. The OPEB expense in this case, including 2017, 2018, and the 12 months ended June 30, 2019, is based upon this year-end 2016 actuarial measurement of OPEB. The 2018 and the 12 months ended June 30, 2019 OPEB expense estimates have been updated in October 2017 to reflect additional OPEB expense savings from a retiree health care change (discussed later in this testimony) the Company expects it will announce before calendar year 2018.

Q. What are the components of the annual ASC 715 retiree health care and life insurance expense?

A. There are four components of the annual ASC 715 expense: (i) service cost; (ii) interest cost; (iii) expected earnings on plan assets; and (iv) amortization of gains and losses, prior service costs, and any transitional amounts. Service cost represents one year's expected benefits earned by active covered employees. Interest cost represents interest on the plan's benefit obligation (its liabilities) due to the passage of time. All future benefits are discounted back to the valuation date using a full-yield curve discount (interest) rate assumption. There is also an assumption made for the expected rate of return on plan assets. This rate of return assumption is intended to be a long-term assumption based upon the best estimate of long-term expected investment earnings of the plan assets. The last component represents amortization of various plan experiences that were not anticipated by the actuarial assumptions.

In order to calculate the plan's total benefit obligation and annual ASC 715 expense, the actuary uses a number of assumptions including: (i) health care inflation trend rates; (ii) mortality table; (iii) the rate of employee retirements from the Company; (iv) the actual retiree health care and life insurance claims of the Company; (v) a discount rate; and (vi) the expected contributions to the plan. The assumptions used by the actuary are determined by the Company each year and reviewed by the Company's auditors.

Q. Are actuarial and administrative services expenses included on line 5 of Exhibit A-43 (HBK-1)?

A. Yes. An annual expense for the actuarial and administrative services provided for the retiree health care and life insurance plans is included on line 5 of the exhibit.

Q. What changes were made to retiree health care coverage from 2011 to 2018?

A. The same plan changes described previously for active union and non-union employees from 2011 to 2018 were made to all of the pre-Medicare retiree plans. These changes included: (i) the Healthy Living Plan requirements; (ii) increased plan deductibles, copays, and out-of-pocket limits; (iii) various plan eliminations; (iv) three-tier incentive prescription drug coinsurance plans; (v) self-insured HMO plans; (vi) a CDHP/HSA Plan option; (vii) increased premium contribution requirements; (viii) additional prescription drug coverage management programs; and (ix) the implementation of MOB coordination. In addition, as described earlier in the ESP section above, all new union hires since September 1, 2010 (non-union hires since January 1, 2007) may become eligible for an access-only retiree health care plan at retirement which requires 100% retiree premium contribution for coverage at retirement, provides for no Company contribution or subsidy, and results in no Company ASC 715 liability or expense.

The Medicare retiree plan was also changed throughout this 2011 to 2018 period with similar changes including increased deductibles and out-of-pocket limits, MOB coordination, a new three-tier incentive prescription drug copay plan, and increased premium contribution requirements. Specifically in 2017, Medicare retirees have an increased deductible and out-of-pocket limit in their Medicare supplemental plan provided by the Company. In addition, premium contributions for most Medicare retirees increased to 7% of plan costs in 2017.

In 2018, Medicare retirees will have increased prescription drug copays and the addition of specialty drug copay in their plan. In addition, premium contributions for most Medicare retirees will increase to 10% of the plan's cost.

Q. Were additional significant changes to retiree medical coverage announced during 2013?

A. Yes. The Company made a change to the financing arrangement for providing its prescription drug coverage to Medicare retirees effective January 1, 2015. The Company moved away from the Retiree Drug Subsidy approach and implemented an Employer Group Waiver Plan ("EGWP") with wrap coverage. The EGWP with wrap coverage allows the prescription drug benefit plan to deliver the same or very similar prescription drug benefit coverage and cost sharing to the Company's Medicare retiree supplemental health plan participants. Due to a couple of national health care reform changes involving increased prescription drug subsidies and manufacturer discounts under an EGWP financing approach, the Company's expense for providing Medicare retirees' prescription drug coverage decreases significantly as drug manufacturers' discounts and Medicare subsidy payments will cover a portion of the Company's prescription drug benefit expense.

In addition, the Company announced the implementation of an increasing schedule of premium contributions for its Medicare retirees covered under the Company's Medicare Supplemental Plan beginning January 1, 2016. The Company indicated it would begin to phase in a schedule of premium contributions for many of its current Medicare retirees and all of its future Medicare retirees eligible for subsidized retiree health care coverage. Medicare retirees on lower fixed incomes, who have been retired for a longer period of time, will not pay premium contributions under this provision. For younger Medicare Supplemental Plan retirees, premium contributions will start at 5% of the plan's cost in 2016 and gradually move to 10% in 2018, while younger Medicare retirees will pay 15% of plan costs by 2020. Premium contributions percentage amounts are dependent upon the retiree's age on December 31, 2013.

Q. Does the Company anticipate making additional significant changes to retiree health care coverage in the near future?

A. Yes, the Company expects that it will make a change to its Medicare retirees' supplemental health care coverage, which will become effective January 1, 2019.

Q. What change does the Company anticipate making to its Medicare retirees' supplemental health care coverage?

A. The Company expects that most of its current Medicare retirees and all future Medicare retirees will begin to choose their Medicare retiree health care benefit plans from the individual Medicare marketplace beginning January 1, 2019 rather than be covered by the Company's one current supplemental Medicare health plan. These retirees will receive assistance in their plan elections and be provided advocacy services by a private Medicare marketplace company selected by the Company. Medicare retirees eligible to receive subsidized retiree coverage from the Company will instead receive a Company-funded Health Reimbursement Account ("HRA") to reimburse them for their premium and out-of-pocket costs for the plan(s) elected in the individual Medicare marketplace.

Q. Why is the Company expecting to make this change in Medicare retiree coverage?

A. This change to the individual Medicare marketplace offers the Company's Medicare retirees a much greater choice of plans and flexibility to select coverage that best meets the Medicare retiree's individual needs. Also, due to the cost efficiency of the individual Medicare marketplace, it will provide more affordable coverage for Medicare retirees now and well into the future.

Q. If the Company makes this change in Medicare retiree health coverage, will there be an impact on the Company's OPEB liability and expense?

A. Yes, the Company's OPEB liability and expense is favorably impacted, and both OPEB liability and expense are expected to significantly decline from current levels. The Company has included the estimated expense impacts from making this change in its OPEB expense projections for 2018 and the 12 months ended June 30, 2019 submitted with this rate case.

The implementation of the Medicare Supplemental Plan's EGWP prescription drug coverage, the gradual phase-in of premium contributions, and the expected change of Medicare retirees electing individual Medicare marketplace coverage all allow the Company to continue controlling its retiree health care expense, provide reasonable and affordable health coverage to its retirees, honor its retiree health care commitments to retirees, and further reduce the Company's retiree health care expense for the benefit of customers.

Q. Do the calculations for the retiree health care and life insurance expense follow the prescribed methodology of ASC 715?

A. Yes. The amounts are projected based on ASC 715 using information specific to the Company's retiree health care and life insurance plans, including the July 1, 2013 remeasurement of ASC 715 expense for retiree health care and life insurance due to the announced Medicare retiree prescription drug coverage and premium contributions changes.

Q. Has the Company applied the new FASB Presentation of Pension/OPEB Costs Standard in this case for OPEB?

A. Yes, the Company early adopted this new FASB Presentation of Pension/OPEB Costs Standard as of January 1, 2017 and has applied the new standard in this case for both Pension and OPEB.

Q. Please describe the development of the retiree health care and life insurance expense levels that are shown on line 5 of Exhibit A-43 (HBK-1), which begins with ($7,816,000) in 2016.

A. Each of the O&M retiree health care and life insurance expense levels shown on line 5 for the gas utility is based upon Aon Hewitt's actuarial determination of the plan's expense for that period in accordance with ASC 715 plus the expense for actuarial and administrative services related to these plans. Due to the retiree medical plan changes described earlier, the actual 2016 O&M retiree health care and life insurance expense for the gas utility was ($7,816,000). The projected O&M retiree health care and life insurance expense is ($10,787,000) in 2017 and ($26,758,000) in 2018. For the 12 months ended June 30, 2019, the projected gas utility O&M expense is ($27,178,000).

To determine the projected 12 months ended June 30, 2019 ASC 715 expense for Consumers Energy retiree health care and life insurance, key actuarial assumptions (discount rate, expected return on assets, mortality table, trust contributions, etc.) were updated at the end of 2016 and used by the actuary to develop the 2017, 2018, and 2019 expense projections. The 2018 and 2019 expense projections were then further updated in October 2017 to reflect the expected change to the individual Medicare marketplace using updated January 1, 2017 census, updated claims cost and health care trend rate projections, and the September 30, 2017 yield curve. Using all of the plan changes noted earlier in this testimony along with the updated actuarial assumptions, the Company's total ASC 715 projected OPEB expense is ($58,000,000) in the 12 months ended June 30, 2019 for Consumers Energy. In addition, the Company's total actuarial and administrative services expense related to maintenance of the plan and preparation of required actuarial reports is projected to be $230,000 for the 12 months ended June 30, 2019. Using the headcount allocation methodology mentioned previously, the projected gas utility O&M expense for retiree health care and life insurance for the 12 months ended June 30, 2019 is ($27,178,000).

Q. Why does the total overall OPEB expense increase from 2016 to 2017?

A. The total overall OPEB expense increases in 2017 due primarily to an increase in retiree claim liability experience and the use of a lower yield curve discount rate, reflective of market conditions, at the time the 2017 OPEB expense was projected by the Company's actuary based upon the December 31, 2016 measurement of the plan.

However, the gas utility O&M OPEB expense is actually lower due to the application of the new FASB Presentation of Pension/OPEB Costs Standard, which only provides for capitalization of the OPEB service cost and not the other components of OPEB expense. The large (credit) OPEB expense components - expected return on assets and amortization of prior service cost - are now fully part of the O&M costs (no capitalization) and help drive down the OPEB expense under the new FASB Standard.

Q. Why is the retiree health care and life insurance expense so low in 2018 and beyond?

A. In addition to significantly improved prescription pricing beginning in 2013 and 2014, the 2013 announcement by the Company of EGWP and Medicare retiree premium implementation, along with the expected change to individual Medicare marketplace coverage for most Medicare retirees in 2019, are the primary drivers for the significantly reduced 2014 through 2019 OPEB expense for retiree health care and life insurance. These retiree coverage changes are significant and have turned the expense from positive to negative, greatly benefiting customers going forward.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
	)	

REBUTTAL TESTIMONY

OF

HERBERT B. KOPS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2018

HERBERT B. KOPS
REBUTTAL TESTIMONY

Q. Please state your name and business address.

A. My name is Herbert B. Kops, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Herbert B. Kops who previously submitted direct testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to certain recommended changes to Pension and Retiree Health Care/Life Insurance or Other Post-Employment Benefits ("OPEB") expenses by Michigan Public Service Commission ("MPSC") Staff ("Staff") witness Robert F. Nichols and Attorney General witness Sebastian Coppola. I will also rebut recommended rate of return expense adjustments to Pension and Retiree Health Care/Life Insurance or OPEB as well as pension plan contribution recommendations in the direct testimony of Mr. Coppola.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-105 (HBK-4)	Summary of Gas Benefits O&M Expenses - 12/31/2017 Pension & OPEB Plan Measurements;
Exhibit A-106 (HBK-5)	Updated EEI Survey; and
Exhibit A-107 (HBK-6)	NEPC Expected Return Memo and Analysis.

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

A. Yes.

Pension and OPEB Expenses – December 31, 2017 Plan Measurements

Q. In Staff witness Nichols' direct testimony, page 9, he discusses the pension and OPEB plan remeasurements, and recommends reducing Operation and Maintenance ("O&M") expense for the test year by $6,665,000 for pension and $14,538,000 for OPEB to reflect the remeasurements. Attorney General witness Coppola makes a similar recommendation at pages 45 and 46 of his direct testimony. Does Consumers Energy Company ("Consumers Energy" or the "Company") agree with this update?

A. Yes. Based upon the December 31, 2017 pension and OPEB plan actuarial measurements, the Company agrees the total benefits test year expense should be reduced by $6,665,000 for pension and $14,538,000 for OPEB, for a total test year expense reduction of $21,203,000. Please see Exhibit A-105 (HBK-4) for the updated expense based upon the December 31, 2017 actuarial measurements.

Rate of Return Assumption

Q. In Attorney General witness Coppola's direct testimony, beginning on page 45, he asserts that Consumers Energy did not support the updated expected rate of return on Plan assets for 2018 and 2019. Does the Company agree with Mr. Coppola's assertion?

A. No. The Company is required to comply with rigorous standards set by Generally Accepted Accounting Principles accounting and Accounting Standards Codification 715 requirements. At least annually, the Company is required to review assumptions used in valuing its Plan assets, which are audited and checked for reasonableness by several professional consultants. The Company has updated its expected return on Plan assets assumption in accordance with those requirements.

Q. Mr. Coppola recommends using the 2017 rate of return on Plan assets assumption of 7.25% instead of the updated and current assumption of 7.00% used for 2018 and 2019 fiscal years. Does the Company agree with this recommendation?

A. No. The Company has updated Plan information that requires it to update its expected return assumption. The Company incorporates future expected capital market assumptions, asset allocation information, and other resources provided by its consultants.

It is important to note that the expected return assumption is based on long-term expectations and not short-term returns. For example, Mr. Coppola contends that the Company should update its expected return based on "the booming stock market in recent years." This contention disregards the market swings that already have taken place in 2018 or potential future market expectations.

Secondly, the Edison Electric Institute Pension Survey for 2017, attached as Exhibit A-106 (HBK-5), demonstrates that the Company's long term assumption decline from 7.25% to 7.00% is consistent with what other utility peers are expecting for 2018. The average expected pension plan fund return for 2018 is 7.05%. Consumers Energy's historical 10-year return for its Pension Plan is 6.3%, which is more in line with the 2018 return assumption of 7.00% versus the 7.25% recommended by Mr. Coppola.

Also, the Company's investment advisory consultant, New England Pension Consultants, prepared a memo which fully supports the 7.00% return on assets assumption rate used to calculate 2018 and 2019 expense for the Company's pension and OPEB plans. The memo is provided as Exhibit A-107 (HBK-6).

In summary, the Company's use of a lower expected return assumption of 7.00% in 2018 and 2019 for its pension and OPEB plans is reasonable and fully supported.

For all of these reasons, the Commission should reject the Attorney General's recommendation for setting the 2018 and 2019 expected return on assets assumption at 7.25% based only upon recent asset performance. Instead, the Commission should continue to support the Company's practice of using the most recent financial analysis and assumptions to establish the most accurate test year pension and OPEB expenses.

Pension Plan Contributions

Q. Beginning at page 48 of his direct testimony, Mr. Coppola contends that the Company should be required to contribute $100 million in annual pension contributions in 2018 and 2019. Does the Company agree with this requirement?

A. No. The Company complies with all regulations set forth by the Employee Retirement Income Security Act ("ERISA") Minimum Funding Standards, as set forth by the Internal Revenue Service and other federal commissions, including the Department of Labor and Pension Benefit Guarantee Corporation ("PBGC"). The Company has contributed in excess of these Minimum Funding Standards, when reasonable, and after consideration of Company-wide priorities to ensure its employees and retirees have a secure pension. Continually contributing in excess of Minimum Funding Requirements would put at risk other Company priorities for the benefit of customers.

The Company prudently manages its Pension Plan assets and liabilities, above and beyond what is required by ERISA regulations. The Company's commitment to prudently managing its Pension Plan assets and liabilities is demonstrated by the recent Pension Plan split, recent Pension Plan contributions in excess of requirements, and closing the Pension Plan to new participants. Additionally, the Company employs a team of subject matter expert consultants to help manage the Pension Plan's risk exposure of assets as well as to design the pension portfolio to best match its liabilities.

Q. Does the Company agree with Mr. Coppola's assertion that Consumers Energy should be required to contribute $100 million in annual pension contributions in 2018 and 2019 in order to avoid the PBGC variable rate premiums?

A. No. As Mr. Coppola confirms, the PBGC premiums are already reduced based on Company management action. The splitting of the Pension Plan has allowed the Company's variable rate premium to be reduced to $1.8 million in both 2018 and 2019 (for the entire Company). The Company is prudently taking action, when available, to reduce PBGC premiums and to contribute in excess of the ERISA Minimum Funding Standards, even though not required to do so.

Q. Does the Company agree with Mr. Coppola's adjustment to Pension Expense for insufficient cash contributions, based upon a requirement for the Company to contribute $100 million to the Pension Plan in 2018 and again in 2019?

A. No. As previously discussed, the Company should not be required to make continuous contributions above what is required under various plan regulations and what is required to ensure participants receive benefits earned. Decisions around excess contributions are made while managing Company obligations in aggregate. Making two $100 million contributions to the Pension Plan would reduce the funding available for other Company priority projects for the benefit of customers. Additionally, if the Company were to make $200 million in contributions as recommended by the Attorney General, the working capital would need to be increased to reflect the $200 million in pension plan contributions. Company witness Jason R. Coker indicates in his rebuttal testimony that this would cause an increase to the projected revenue deficiency.

For all of these reasons, the Commission should reject the Attorney General's recommendation to further reduce pension expense by requiring the Company to contribute $100 million dollars to the Pension Plan in both 2018 and 2019. Instead, the Commission should continue to support the Company's practice of funding the Pension Plan as required under ERISA pension regulations and to ensure Plan participants receive benefits earned under the Plan.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

JUDGE SONNEBORN: And with that, Mr. King, will you be proceeding on behalf of the Attorney General?

MR. KING: I will be.

JUDGE SONNEBORN: Thank you.

MR. KING: Thank you.

CROSS-EXAMINATION

BY MR. KING:

Q Good morning, Mr. Kops.

A Good morning.

Q Joel King on behalf of the Attorney General. Mr. Kops, you are the Director of Employee Benefits for the Company; is that correct?

A Yes, that was my prior title, correct.

Q And sorry, your new title again is?

A It's Executive Director - Total Rewards and Workforce Relations.

Q And you began working at Consumers Energy in 1989 right after finishing college; is that correct?

A 1977.

Q 1977?

A Yes. 1989 was when I moved to Jackson with the Company.

Q O.K. And your work at Consumers has been entirely in the human resources and insurance areas; is that correct?

A It's a little more expansive than that. It's been in the

HR area, but with emphasis, correct, on insurance and retirement plans.

Q Now, Mr. Kops, you have not been involved in the treasury functions of the Company at all; is that correct?

A I have not, no.

Q And you have not had experience in investing and managing stock and bond portfolios for the Company's pension and OPEB plans; is that correct?

A I am part of the benefit administration committee at the Company, which there are seven of us that are on the committee that work with our advisor and work on the investments for our plans, both pension and retiree healthcare and our savings plan.

Q And you have not performed that type of work for any other company; is that correct?

A That's correct.

Q Now, in this case, Mr. Kops, you filed direct and rebuttal testimony supporting the Company's employee benefit costs?

A That's correct, yes.

Q Could you please turn to page 2 of your rebuttal testimony.

A O.K.

Q Now, beginning on line 13 and into page 4, you disagree with the Attorney General's witness, Mr. Sebastian

Coppola, that the Company should keep the assumed rate of return on the assets of the pension and OPEB plans at 7.25 percent, correct?
A I disagreed we should move them to 7.25 and that we should keep them at 7.0, yes. The Company moved the plans to 7.0 percent for the years 2018 and 2019 for expected return on assets from both pension and OPEB plans; they were at 7.25 in '17, so we were -- we proposed to go to 7.0, right, and the Attorney General suggested leaving them at 7.25.
Q Right. Sorry, I think my question got a little long there. You disagreed with Mr. Coppola that it should stay -- Mr. Coppola said it should say --
A Correct.
Q -- at 7.25 --
A You're correct.
Q -- instead of 7.0?
Can you please go to page 3 of your rebuttal.
A Yep.
Q On lines 8 and 9, you state that, "It is important to note that the expected return assumption is based on long-term conditions and not short-term returns." Correct?
A That's correct.

Q Can you tell me what the long-term time period is that the expected rate of return is based on?
A Thirty years.
Q And how do you know that?
A That's expected in the business, and working with our investment consultants, they really provide the reference documentation and the study to support the long-term asset return expectation.
Q And you don't invest or manage the bonds or stock portfolio of the Company's pension OPEB plans, correct?
A I don't personally, but as a member of the benefit administration committee, we do, yes.
Q Now, you said the Company relies on the advice of experts to make a recommendation on the long-term time period; is that correct?
A That's correct.
Q And so how did you know that they used the 30-year time period?
A We have used it for a number of years, and our investment consultant is the New England Pension Consultants group, who has helped and assisted the BAC investment from an investment advisory perspective for a number of years. So we've had discussions in our benefit administration committee about rates of return and NEPC's model and procedure to go about calculating what those are on an

annual basis.
Q And is there anywhere in the exhibits that you filed or in your testimony that that 30-year time period is stated?
A Yes. It's in the rebuttal exhibit, and it would be A-107 (HBK-6). This is the most recent return summary that we've used to set our current 7.0-percent rate of return for the plans.
Q Mr. Kops, is the long-term time period a rolling time period that incorporates recent stock and bond market results?
A Yes, it is rolling, so each year it's updated and it's looking forward 30 years.
Q So then would I be correct that since it is a rolling time period, the stock market gains from 2009 to 2017 that Mr. Coppola discussed, that those would be reflected in the rolling long-term period?
A Yes, that's correct.
Q Can you please go to Exhibit A-106 which you filed with your rebuttal.
A Sure.
Q Now, on page 3 -- I'm sorry. Can I take you back. On page 3 of your rebuttal, lines 13 to 16, you point to the survey results by the Edison Electric Institute to justify the Company's decision to use the 7.0-percent

assumed rate of return, correct?
A Yes, as a supportive exhibit, correct.
Q And that exhibit, then, is the A-106?
A That's A-106, correct.
Q Now, as I understand it, you received the information in A-106 on January 30, 2018?
A Correct.
Q Is that correct?
A That's correct.
Q And you made the decision to use the 7.0 percent for 2018 in December 2016 or sometime early 2017, correct?
A We made the 7.0-percent decision at the end of December 2017, correct, based on the NEPC exhibit, 107. Exhibit 106 is an after-the-fact survey of a benchmark of utility peers to see what they set their rates at. So 106 is really an after-the-fact support, we didn't really have this, we really can't wait until the end of January to set a return-on-investment rate, so we use the NEPC memo; but I included 106, because it's after the fact, it's a survey of what our partners or our benchmark group sets as their rates, so you can see in 106 a whole range of different return assumptions.
Q Do you have your direct testimony in front of you?
A I do, yes.
Q Could you please turn to page 10, and specifically lines

12 to 17.
A O.K.
Q And you state there that the 2017 pension expense in later years was based on the actuarial analysis as of December 31, 2016?
A That's correct.
MR. KING: At this time I'd like to circulate a discovery response, which I will mark.
(Document distributed and marked for identification by the Court Reporter as Exhibit No. AG-55.)
Q (By Mr. King): All right. I've marked this Exhibit AG-55. Are you familiar with this discovery response?
A I am, yes.
Q And did you personally complete this discovery response?
A I did.
MR. KING: At this time, your Honor, I'd like to move to admit this exhibit as AG-55.
JUDGE SONNEBORN: Are there any objections to the admission of AG Exhibit 55? (No response.)
Hearing none, I'll admit that exhibit.
Q (By Mr. King): If we can go to your Exhibit A-106. I see in this exhibit that you picked the average rate of 7.05 percent in the column labeled Expected Return CY+1 (2018) to justify the 7.0-percent return rate; is that

correct?
A No. The 7.05 was recited as the expected '18 return in the survey amongst the benchmark companies. 7.05 is very close to 7.0, so it was supportive in that regard, but it was not used to set our 7.0-percent rate. It's where Exhibit 107 came in, that was used to set our 7.0-percent rate.
Q Sorry, what was that last piece?
A Exhibit 107 is what we used, the NEPC memo, to set our return-on-asset expectation for 2018 and 2019.
Q Can you please go back to page 3 of your rebuttal.
A O.K.
Q On lines 19 to 22, you state that the 7.0 percent is fully supported by the memo submitted by the Company's advisory consultants, New England Pension Consultants, correct?
A That's correct.
Q And then can you please go to Exhibit A-107.
A Uh-huh.
Q And the date on this letter is December 18, 2017, which means that it was not prepared until after the decision to use the 7.0-percent rate and after your testimony in this rate case was filed; is that correct?
A No. December 18 was prior to the Company setting the 7.0 percent, which was December 31, 2017. So again, this

was the source document in helping us establish the return-on-investment or return-on-asset rate at the end of 2017 as we remeasured both plans, I mean the pension and the OPEB plans.

Q On this Exhibit 107 still, when I look at the second paragraph from the bottom on page 1, I see that the consultant stated that capital market assumptions in the letter represent passive market returns and exclude returns from active management of the plan assets, among other items, correct?

A That's correct.

Q Now, if you -- if we go to table, the table on the second page of the letter, the consultant shows the target and expected return rate based on passive and active management of the pension and OPEB VEBA plan assets, correct?

A That's correct.

Q And it appears that by going with the 7.0-percent expected return, you relied on the passive management of the plan assets to support the conclusion that 7.0 percent is appropriate; is that correct?

A Not necessarily. If you look at the memo in more detail, we're looking at the asset allocation across both equity and fixed income, looking forward 30 years, and based on NEPC's model, we're looking at what returns could be expected from those particular funds that make up the investment assets in the plans. So as I take it, just to clarify, there is some discretion on whether or not you wanted to -- if there were something you, some credit you wanted to give to active management of the plans, very conservative there because there is general disagreement on exactly how much that does or does not add to returns, so we tend to stick fairly close to where NEPC comes out as a recommendation based upon their 30-year look forward.

Q And as I understand it, approximately 65 percent of the Company's pension and OPEB assets are actively managed; is that correct?

A That's correct, yes.

Q Can you please go to page 4 of your rebuttal. Now, beginning on line 8 and then all the way into page 6, you disagree with Mr. Coppola's recommendation that the Commission should assume that the Company will make additional cash contributions of $100 million to the pension plan in 2018 and 2019; is that fair?

A Yes, that's correct.

Q And still on page 4, lines 15 to 19, you state that the Company has made contributions in excess of the minimum funding standards, when reasonable, correct?

A Yes. We've always met the minimum funding requirements,

and at times we've exceeded those, correct, yes.
Q And as I understand it, in the two-year period 2015 and 2016, the Company made $219 million in cash contributions to the pension plan above the minimum funding requirements?
A That's correct.
Q Why was it reasonable to make those excess contributions in 2015 and 2016, but it wouldn't be reasonable to do so between 2018 and 2019?
A I would suggest it's management of the business and competing priorities and the best use of the funds at that particular time, that was our decision back at those particular times. So we always have a lot of competing priorities for our customers within the business, so there are certainly a lot of other opportunities to use cash funds as opposed to put them in the pension plan. But in '15 and '16, as we looked at this late in the year, it was prudent to do so.
Q Now, you've also stated that contributing in excess of the minimum funding requirements could put other Company priorities at risk; is that correct?
A Yeah. There's only so much money, and it could put other priorities in place, it could be reliability for our customers, other things that we have opportunities to do, trimming trees, whatever the priority may be; so I think,

yes, it's a competing priority business, and pension contributions are looked at every year in that competition for funds, and occasionally we do make contributions to the pension plan over the minimum.
Q Now, can you please go to page 5 of your rebuttal.
A O.K.
Q Lines 7 to 12, you discuss the PBGC variable premiums that the Company has forecasted it will incur for not making sufficient contributions to the pension plan, correct?
A That's correct.
Q Is it possible that the Company may make additional contributions in 2018 and 2019 to avoid those premiums?
A That's still possible, yes.
Q And still on page 5 of your rebuttal, beginning on line 21, and then ending on line 2 of page 6, you state that the additional $200 million in contributions cited by Mr. Coppola would increase the revenue deficiency, and you reference the testimony of Mr. Coker, correct?
A That's correct, yes.
Q Do you know the amount of increase in revenue deficiency that Mr. Coker calculated?
A I do not.
Q Are you aware that Mr. Coker did not calculate any increase, or calculate the increase in revenue

deficiency?

A I'm not aware that he did; I didn't really ask him to. We just know that if we put contributions in, the end result is that the revenue deficiency goes up. But I didn't try to get a specific number, I didn't ask him for a specific number.

MR. KING: I have no further questions.

JUDGE SONNEBORN: Thank you, Mr. King.

Mr. Gensch, do you have any redirect of Mr. Kops?

MR. GENSCH: No, your Honor.

JUDGE SONNEBORN: All right. Thank you. Mr. Kops, you may be excused.

THE WITNESS: Thank you.

(The witness was excused.)

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JUDGE SONNEBORN: Are there any objections to the admission of Exhibits A-43, A-44, A-45, and Exhibits A-105, 106, and 107? (No response.)

Hearing no objection, those exhibits are admitted into the record.

Mr. Gensch.

MR. GENSCH: Can we go off the record, your Honor?

JUDGE SONNEBORN: We may.

MR. GENSCH: Thank you.

(At 10:50 a.m., a brief pause was had in the proceedings.)

JUDGE SONNEBORN: Good morning, Mr. Beach.

MR. BEACH: Good morning. I think we're ready to start.

JUDGE SONNEBORN: Thank you.

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(Documents marked for identification by the Court Reporter as Exhibit Nos. A-11, A-13, A-76, A-80 through A-87; A-64, A-126; and A-72.)

MR. BEACH: Your Honor, pursuant to the stipulation of the parties, the Company will move to bind in a handful of witnesses before calling Mr. Fultz to the stand, who is the next witness. The witnesses that I'll be moving to bind in, and I will list details about the testimony and exhibits they are presenting, are Company Witness Jason R. Coker, Company Witness Deborah S. Pelmear, and Company Witness Brian J. VanBlarcum, and all those witnesses, the parties have indicated there will be no cross for, so we'll be moving to bind in.

Your Honor, with respect to Company Witness Jason R. Coker, he sponsored direct testimony, which consists of a cover page and 19 pages of questions and answers; and rebuttal testimony, which consists of a cover page and 10 pages of questions and answers. Mr. Coker also had quite a few exhibits, I will run through them quickly just for completeness purposes. He sponsored with his direct testimony A-11 Schedule A-1, A-11 Schedule A-2, A-11 Schedule A-3, A-11 Schedule A-4, A-12 Schedule B-1, A-12 Schedule B-1a, A-12 Schedule B-2, A-12 Schedule B-3, A-12 Schedule B-4, A-12 Schedule B-5, A-13 Schedule C-1, A-13 Schedule C-2, A-13 Schedule C-3, A-13 Schedule C-4, A-13 Schedule C-5, A-13 Schedule C-6, A-13 Schedule C-7, A-13 Schedule C-8, A-13 Schedule C-9, A-13 Schedule C-10, A-13 Schedule C-11, A-13 Schedule C-12, A-13 Schedule C-13, A-13 Schedule C-14, and A-76, which is a two-page exhibit, it does not have a schedule. With his rebuttal testimony, Mr. Coker provided Exhibit A-80, A-81, A-82, A-83, A-84, A-85, A-86, and A-87. And that completes the testimony and exhibits provided by Mr. Coker.

With respect to Company Witness Deborah S. Pelmear, Ms. Pelmear sponsored direct testimony, which consisted of a cover page and three pages of questions and answers; and rebuttal testimony, which consisted of a cover page and two pages of questions and answers. With her direct testimony, Ms. Pelmear sponsored Exhibit A-64, and with her rebuttal testimony, Ms. Pelmear sponsored

Exhibit A-126.

The final witness the Company moves to bind in before the next witness is called up for cross is Company Witness Brian J. VanBlarcum. Mr. VanBlarcum only sponsored direct testimony. His direct testimony consisted of a cover page and five pages of questions and answers; and he sponsored Exhibit A-72.

Pursuant to the stipulation of the parties, the Company would move to bind in that testimony and those exhibits as I listed, your Honor.

JUDGE SONNEBORN: Thank you, Mr. Beach.

Are there any objections to binding in the direct and rebuttal testimony of Mr. Coker and Ms. Pelmear, as well as the direct testimony of Mr. VanBlarcum, as well as their individual exhibits as described by Mr. Beach? (No response.)

Hearing no objections, I will bind into the record the testimony listed, as well as the exhibits described, which will be bound and admitted into the record.

(Testimony bound in.)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
	)	

DIRECT TESTIMONY

OF

JASON R. COKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2017

Q. Please state your name and business address.

A. My name is Jason R. Coker, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Rate Analyst II in the Revenue Requirement and Analysis Section of the Rates and Regulation Department.

Q. Please state your educational background.

A. I graduated from Western Michigan University in 1999 with a Bachelor of Business Administration Degree, majoring in Accounting. I am also a Certified Public Accountant registered in the State of Michigan.

Q. Please describe your business experience.

A. After receiving my accounting degree in 1999, I joined Willis and Jurasek, PC in Jackson, Michigan as a staff auditor working on financial audits and income tax returns. I remained in that position for approximately four years. In 2003, I became the Director of Accounting for Delhi Charter Township in Holt, Michigan. In that role I had overall responsibility for the Township's payroll, accounts payable, accounting, financial reporting, and budgeting. In 2005, I joined Consumers Energy as a General Accounting Analyst II in the Technical Accounting and Accounting Policy Department. My responsibilities included the implementation of new financial accounting standards, research of technical accounting issues, and review of contracts for accounting issues. In 2009, I was promoted to Senior Accounting Analyst and assumed responsibility for restricted stock accounting and some Securities and Exchange Commission reporting disclosures while maintaining my previous duties. In 2012, I assumed responsibility for accounting and reporting of contingencies, including Consumers Energy's manufactured gas plants. In 2016, I accepted the position of Senior Rate Analyst II in the Revenue Requirement Section of the Rates and Regulation Department.

Q. What are your job responsibilities?

A. As a Senior Rate Analyst, I am responsible for forecasting the Gas Cost Recovery factor on a monthly basis. I am also responsible for developing, analyzing, and reviewing the Company's monthly return studies. These include studies pertaining to balance sheet working capital, cost of capital, return on investment, and Return on Equity ("ROE"). In addition, I assist in the development of analyses related to the Company's revenue requirements and the preparation of electric and gas rate case filings at the Michigan Public Service Commission ("MPSC" or the "Commission"). I am also responsible for various ad hoc studies pertaining to cost of capital, ROE, and revenue requirements.

Q. Have you previously testified in any proceedings before the Commission?

A. Yes. I have provided testimony in the following cases:

Case No. U-18166	Saginaw Trail Pipeline Act 9 Filing;
Case No. U-18322	Electric General Rate Case; and
Case No. U-17943-R	Reconciliation of Gas Cost Recovery Costs and Revenues.

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

A. The purpose of my direct testimony is to (i) present Consumers Energy's revenue requirement calculation for the Projected Test Year, and (ii) present the calculation of the Investment Recovery Mechanism ("IRM").

Q. How are the following sections of your direct testimony organized?

A. My direct testimony is divided into two sections. In section I, I present supporting direct testimony and exhibits for the Projected Test Year revenue requirement calculation. In section II, I present direct testimony and exhibits supporting the mechanics of Consumers Energy's proposed IRM, as described in the direct testimony of Company witness Michael A. Torrey.

Q. Please describe the revenue requirements determination.

A. To comply with the Projected Test Year Filing Requirements, my direct testimony presents and explains the development of the revenue requirement for the Projected Test Year. I also reconcile the Historic and Projected Test Years. The Company demonstrates in this instant case that it requires a rate increase to its gas tariffs in order to earn a just and reasonable return.

Q. Are you sponsoring any exhibits?

A. Yes. The Projected Test Year exhibits that I am sponsoring are identified in section I of my direct testimony. The IRM exhibits I am sponsoring are identified in section II of my direct testimony.

I. PROJECTED TEST YEAR

Q. What is the Projected Test Year used in your exhibits and supporting direct testimony?

A. The 12-month period ending June 30, 2019 was chosen for the Projected Test Year.

Q. Please identify the exhibits that you are sponsoring to comply with the Commission's Filing Requirements for the Projected Test Year.

A. The following exhibits are being submitted to support and satisfy the Projected Test Year Filing Requirements:

Exhibit A-11 (JRC-1)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-11 (JRC-2)	Schedule A-2	Financial Metrics – Ratemaking Basis – Gas Results Only;
Exhibit A-11 (JRC-3)	Schedule A-3	Comparison of the Gas Revenue Requirement between the Historical Year and the Test Year;
Exhibit A-11 (JRC-4)	Schedule A-4	Reconciliation of the Gas Revenue Requirement – Historical Year Versus Test Year;
Exhibit A-12 (JRC-5)	Schedule B-1	Projected Rate Base for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-12 (JRC-6)	Schedule B-1a	Development of Projected Rate Base for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-12 (JRC-7)	Schedule B-2	Total Utility Plant for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-12 (JRC-8)	Schedule B-3	Depreciation Reserve and Other Deductions for the Projected 12-Month Period Ending June 30, 2019;

Exhibit A-12 (JRC-9)	Schedule B-4	Gas 13-Month Average Working Capital Balance Sheet for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-12 (JRC-10)	Schedule B-5	Projected Capital Expenditures;
Exhibit A-13 (JRC-11)	Schedule C-1	Adjusted Net Operating Income for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-13 (JRC-12)	Schedule C-2	Projected Revenue Conversion Factor for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-13 (JRC-13)	Schedule C-3	Projected Operating Revenue for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-13 (JRC-14)	Schedule C-4	Projected Cost of Gas Sold for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-13 (JRC-15)	Schedule C-5	Projected Other Operation and Maintenance Expenses for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-13 (JRC-16)	Schedule C-6	Projected Depreciation and Amortization Expenses for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-13 (JRC-17)	Schedule C-7	Projected General Taxes for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-13 (JRC-18)	Schedule C-8	Projected Federal Income Taxes for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-13 (JRC-19)	Schedule C-9	Projected State Income Taxes for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-13 (JRC-20)	Schedule C-10	Projected Other (or Local) Taxes for the Projected 12-Month Period Ending June 30, 2019;

Exhibit A-13 (JRC-21)	Schedule C-11	Projected Allowance for Funds Used During Construction for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-13 (JRC-22)	Schedule C-12	Tax Effect of Pro Forma Interest Adjustment for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-13 (JRC-23)	Schedule C-13	Tax Effect of Interest Synchronization Adjustment for the Projected 12-Month Period Ending June 30, 2019; and
Exhibit A-13 (JRC-24)	Schedule C-14	Development of Net Operating Income for the Projected 12-Month Period Ending June 30, 2019.

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

A. Yes.

Q. Please discuss the organization and format of the Projected Test Year exhibits.

A. The Projected Test Year exhibits are organized and formatted in a similar fashion to the Historical Year exhibits. I am sponsoring schedules that present the development of the revenue requirement (Schedule A), rate base (Schedule B), and adjusted Net Operating Income ("NOI") (Schedule C). Company witness Andrew J. Denato is sponsoring schedules that address rate of return (Schedule D). Company witness Eric J. Keaton is sponsoring sales, load, and customer data (Schedules E) exhibits. Company witness Luis F. Saenz is sponsoring cost-of-service allocation, present and proposed revenue, and proposed tariff sheet (Schedule F) exhibits.

Q. Please summarize the key findings for the Projected Test Year exhibits.

A. The Projected Test Year exhibits demonstrate that for the year ended June 30, 2019:

	(In Thousands)
Rate Base	**$5,468,042**
Adjusted NOI	**225,422**
Overall Rate of Return	**4.12%**
Required Rate of Return	**6.11%**
Income Required	**334,231**
Income Deficiency/ (Sufficiency)	**108,809**
Revenue Multiplier	**1.6377**
Revenue Deficiency/ (Sufficiency)	**$178,194**

The data for the above are presented on Exhibit A-11 (JRC-1), Schedule A-1, Revenue Deficiency (Sufficiency) for the Projected 12-Month Period Ending June 30, 2019.

Q. What inflation factors is the Company using in its presentation?

A. The Company is using an inflation factor of 2.3% for 2017, 1.8% for 2018, and an inflation factor of 2.2% for 2019, as forecast by IHS Global Insight and reported in the April 2016 edition of their publication *U.S. Economic Outlook.* IHS Global Insight is a leader in economic and financial analysis, forecasting, and market intelligence.

Q. How has Consumers Energy addressed the filing requirement to reconcile the Projected Test Year to the most recent calendar year?

A. The following is a list of exhibits that reconcile the Projected Test Year to the Historical Year: Exhibit A-11 (JRC-3), Schedule A-3; Exhibit A-11 (JRC-4), Schedule A-4; Exhibit A-12 (JRC-6), Schedule B-1a; Exhibit A-12 (JRC-9), Schedule B-4; Exhibit A-13 (JRC-15), Schedule C-5; and Exhibit A-13 (JRC-24), Schedule C-14.

Q. Please explain Exhibit A-11 (JRC-2), Schedule A-2.

A. This exhibit provides the financial metrics for the Projected Test Year as required by the Filing Requirements. Column (b) shows the metrics assuming no rate relief is granted. Column (c) shows the metrics assuming full rate relief request is granted.

Q. Please explain Exhibit A-11 (JRC-3), Schedule A-3.

A. This exhibit presents the Projected Test Year revenue deficiency for Consumers Energy of $178,193,739 (line 10, column (f)). Column (d) of the exhibit presents pertinent rate base and rate of return amounts for the Historical Year. Column (e) shows the changes resulting from adjustments as supported by the various Company witnesses that were made in developing the Projected Test Year revenue requirement. Column (f) shows the rate base, income requirement, and revenue requirement for the 12 months ending June 30, 2019.

Q. What are the major differences between Historical Year and Projected Test Year results shown on Exhibit A-11 (JRC-3), Schedule A-3?

A. The comparison of historical and projected results in Exhibit A-11 (JRC-3), Schedule A-3 shows that rate base increases by approximately $1,448 million (line 4) and the rate of return increases from 6.05% to 6.11% (line 5). In addition, adjusted NOI (line 7) decreases by approximately $39 million when moving from the Historical Year to the Projected Test Year.

Q. Please describe Exhibit A-11 (JRC-4), Schedule A-4.

A. This exhibit reconciles the Historical Year and the Projected Test Year revenue requirement from Exhibit A-11 (JRC-3), Schedule A-3. The projected $213 million increase in the revenue requirement from the Historical Year shown on line 11 is primarily the result of $80 million in adjustments to NOI shown on line 10, a projected $128 million increase related to investments in rate base shown on line 9, and a $5 million increase related to changes in the capital structure and cost rates shown on line 5.

Q. Please describe Exhibit A-12 (JRC-5), Schedule B-1.

A. Schedule B-1 is a summary presentation of the Projected Test Year average rate base. The year ended June 30, 2019 average rate base is $5,468,042,000 as shown on line 9.

Q. Please describe Exhibit A-12 (JRC-6), Schedule B-1a.

A. Exhibit A-12 (JRC-6), Schedule B-1a, is a summary presentation of the development of the Projected Test Year average rate base from Exhibit A-12 (JRC-5), Schedule B-1. Line 4 shows the average rate base for the Historical Year. Lines 5 through 13 show the adjustments to the Historical Year rate base necessary to develop the Projected Test Year rate base. The adjustments to historical net plant (line 5) are the result of (i) projected capital expenditures for 2017 through June 30, 2019, as provided by Company witnesses Mary P. Palkovich, Danielle M. Hill, Christopher T. Fultz, Christopher J. Varvatos, Jeffrey J. Shingler, and Lisa M. DeLacy. Manufactured Gas Plant (line 6) is increased to reflect Projected Test Year amounts supplied by Company witness Daniel L. Harry. Working capital is adjusted to reflect May 2017 balances (line7). Pension and Other Post-Employment Benefits ("OPEB") accounts (line 8 and line 9) were adjusted to reflect Projected Test Year amounts based on projections supplied by Company witness Herbert B. Kops. The adjustment shown on line 10 is necessary to reflect differences in Gas Stored Underground. The adjustment on line 11 adjusts working capital for accrued taxes. The Projected Test Year rate base of $5,468,042,000 is shown on line 13.

Q. Please describe how the Projected Test Year average plant and related amounts were developed.

A. Average gas plant and reserve balances for the Projected Test Year were developed by taking the average of the balances at June 30, 2018 and June 30, 2019. Actual calendar year 2016 balances for Construction Work in Progress ("CWIP"), gross plant, and depreciation reserve were used as the starting point. Capital expenditures (including Allowance for Funds Used During Construction ("AFUDC") and plant additions were added for the calendar year 2017, calendar year 2018, and 6 months ended June 30, 2019 then retirements, depreciation, cost of removal, ending balances for CWIP, plant, and depreciation reserve were calculated.

Q. Please describe Exhibit A-12 (JRC-7). Schedule B-2.

A. Exhibit A-12 (JRC-7), Schedule B-2, shows the total utility plant for the Projected Test Year that was developed as described above. The total on line 6 is carried forward to line 1 on Exhibit A-12 (JRC-5), Schedule B-1. The amounts on lines 7 and 8 are carried forward to lines 2 and 3 on Exhibit A-12 (JRC-5), Schedule B-1.

Q. Please describe Exhibit A-12 (JRC-8), Schedule B-3.

A. Exhibit A-12 (JRC-8), Schedule B-3 presents the depreciation reserve for the Projected Test Year by functional group. The total on line 21 is carried forward to line 5 on Exhibit A-12 (JRC-5), Schedule B-1.

Q. Please explain Exhibit A-12 (JRC-9), Schedule B-4.

A. Exhibit A-12 (JRC-9), Schedule B-4, develops the Company's proposed Projected Test Year working capital balance sheet. The starting point for this exhibit is the 2016 historical working capital shown in column (b), which is first adjusted to reflect

May 2017 balances shown in column (d). The May 2017 balances are then adjusted to: (i) reflect changes to gas stored underground as sponsored by Company witness Deborah S. Pelmear; (ii) reflect changes to pension and OPEB balances based on projections sponsored by Company witness Kops; and (iii) reflect an adjustment to accrued taxes. Details for the adjustments made to calculate the Projected Test Year working capital are shown on page 2 of the exhibit.

Q. Why did the Company use the Balance Sheet Method in determining working capital?

A. Use of the Balance Sheet Method was mandated by the Commission in Case No. U-7350. The Filing Requirements also require that this method be used to develop the allowance for working capital.

Q. Please describe Exhibit A-12 (JRC-10), Schedule B-5.

A. This exhibit provides a summary of historical and projected capital expenditures presented in this case as required by the Filing Requirements.

Q. Based on your analyses, what is Consumers Energy's adjusted NOI for the Projected Test Year?

A. Adjusted NOI for the Projected Test Year of $225,422,000 is shown on line 22 of Exhibit A-13 (JRC-11), Schedule C-1. Total operating revenue on line 4 is netted against total operating expense on line 15 to arrive at NOI on line 16. Further adjustments are made on lines 17 through 20, which utilize normal ratemaking practices to arrive at adjusted NOI on line 22.

Q. Please describe Exhibit A-13 (JRC-12), Schedule C-2.

A. Exhibit A-13 (JRC-12), Schedule C-2, shows the development of the revenue multiplier for the Projected Test Year. The revenue multiplier is a factor that converts a utility's after-tax income deficiency (or sufficiency) into the required pre-tax revenue requirement. For Projected Test Year, the Federal Income Tax ("FIT") rate is 35.0%, the Michigan Corporate Income Tax ("MCIT") rate is 5.898%, and the City Income Tax ("CIT") rate is 0.16%, which results in a 1.6377 revenue multiplier.

Q. Please explain Exhibit A-13 (JRC-13), Schedule C-3.

A. This exhibit presents the total operating revenue for the Projected Test Year. Lines 1 and2 of the exhibit present the sales and transportation revenue supported by Company witness Keaton. The total on line 5 is carried forward to line 4 on Exhibit A-13 (JRC-11), Schedule C-1.

Q. Please explain Exhibit A-13 (JRC-14), Schedule C-4.

A. This exhibit presents the cost of gas sold for the Projected Test Year. This total is carried forward to line 5 on Exhibit A-13 (JRC-11), Schedule C-1.

Q. Please explain Exhibit A-13 (JRC-15), Schedule C-5.

A. Exhibit A-13 (JRC-15), Schedule C-5, presents the other Operations and Maintenance ("O&M") expense for the Projected Test Year. The amounts on lines 1 through 24 and 26 were provided by Company witnesses Palkovich, Julio H. Morales, Shingler, Hill, Varvatos, DeLacy, Kops, Harry, and Amy M. Conrad and are supported in their direct testimony and exhibits. Loss and Unaccounted for ("LAUF") on line 28 is carried forward to line 6 on Exhibit A-13 (JRC-11), Schedule C-1. Company Use on line 29 is carried forward to line 7 on Exhibit A-13 (JRC-11), Schedule C-1. The total on line 30 is carried forward to line 8 on Exhibit A-13 (JRC-11), Schedule C-1.

Q. Please explain Exhibit A-13 (JRC-16), Schedule C-6.

A. Exhibit A-13 (JRC-16), Schedule C-6, presents depreciation and amortization expense by functional grouping for the Projected Test Year. The total on line 22 is carried forward to line 9 on Exhibit A-13 (JRC-11), Schedule C-1.

Q. Please explain Exhibit A-13 (JRC-17), Schedule C-7, through Exhibit A-13 (JRC-21), Schedule C-11.

A. These exhibits present the following: (i) projected general taxes; (ii) projected FIT; (iii) projected state income taxes; (iv) projected other (or local) taxes; and (v) projected AFUDC. The total from each schedule is carried forward to Exhibit A-13 (JRC-11), Schedule C-1.

Q. Please describe Exhibit A-13 (JRC-22), Schedule C-12.

A. Exhibit A-13 (JRC-22), Schedule C-12, shows the calculation of pro-forma interest expense for the Projected Test Year and the corresponding change in FIT.

Q. Please describe Exhibit A-13 (JRC-23), Schedule C-13.

A. Exhibit A-13 (JRC-23), Schedule C-13, shows the calculation of the tax effect of the interest synchronization adjustment for the Projected Test Year.

Q. Why are Exhibit A-13 (JRC-22), Schedule C-12, and Exhibit A-13 (JRC-23), Schedule C-13, included in the presentation?

A. The exhibits are part of the Filing Requirements. The purpose of these exhibits is to align the interest expense and the associated tax benefits in the Projected Test Year with the amount of rate base that is financed with debt.

Q. Please explain Exhibit A-13 (JRC-24), Schedule C-14.

A. This exhibit presents the reconciliation of Historical Year NOI to Projected Test Year NOI. The amounts within this schedule are taken from other exhibits in my presentation. The exhibit presents revenue in columns (b) through (e), expense in columns (f) through (m), and the resulting adjusted NOI in column (p). The exhibit begins with the Historical Year on line 1, adjustments to the historical year on lines 2 through 13, and Projected Test Year adjustments on lines 16 through 29. Total NOI for the Projected Test Year is shown on line 31. In general, the revenue and expense adjustments are shown with their accompanying tax impacts to arrive at adjusted NOI. Historic Year NOI of $240 million on line 1 column (p) ties to the Historic NOI on line 18 of Exhibit A-3 (AGV-9), Schedule C-1.

Q. Please explain the adjustments on Exhibit A-13 (JRC-24), Schedule C-14.

A. The adjustments on lines 2 through 13 are made to comply with prior Commission orders and follow traditional ratemaking adjustments to historical results such as removing regulatory disallowances, normalizing for unusual, one-time, or out-of-period items, bringing certain revenues and expenses “above the line,” adjusting historical revenues to reflect “normal” weather, and related adjustments to income taxes. Additional adjustments include certain O&M expense normalizations to better align the Historic Year with expected expense amounts in the Projected Test Year. These adjustments are supported by Exhibit A-3 (AGV-20), Schedule C-12, through Exhibit A-3 (AGV-31), Schedule C-23. Compensation disallowances on line 2 are supported by Exhibit A-3 (AGV-20), Schedule C-12. Dues and donations disallowances on line 3 are supported by Exhibit A-3 (AGV-21), Schedule C-13. Advertising disallowances on line 4 are supported by Exhibit A-3 (AGV-22), Schedule C-14. Corporate giving and communications disallowances on line 5 are supported by Exhibit A-3 (AGV-23), Schedule C-15. Line 6 normalizes expenses related to a voluntary separation agreement and is supported by Exhibit A-3 (AGV-24), Schedule C-16. Weather and miscellaneous revenue normalizations on line 7 are supported by Exhibit A-3 (AGV-25), Schedule C-17. The adjustment for energy optimization surcharge revenue and expense on line 8 are supported by Exhibit A-3 (AGV-26), Schedule C-18. Including jobwork revenue on line 9 in the determination of NOI (*i.e.*, "above the line") is supported by Exhibit A-3 (AGV-27), Schedule C-19. The accompanying jobwork expense on line 10 is supported by Exhibit A-3 (AGV-28), Schedule C-20. Line 11 aligns the interest income on cash equivalents to the determination of NOI as supported on Exhibit A-3 (AGV-29), Schedule C-21. The pro-forma income tax savings and interest synchronization on lines 12 and 13 are longstanding ratemaking conventions that are supported on Exhibit A-3 (AGV-30), Schedule C-22 and Exhibit A-3 (AGV-31), Schedule C-23, respectively. Adjusted Historical Year NOI on line 15 column (p) of Exhibit A-13 (JRC-24), Schedule C-14, of $265 million ties to the adjusted NOI on line 33 of Exhibit A-3 (AGV-9), Schedule C-1.

Q. How were the Projected Test Year adjustments on Exhibit A-13 (JRC-24), Schedule C-14 developed?

A. These adjustments represent the movement from adjusted Historical Year NOI to the Projected Test Year NOI. The adjustments on lines 16 through 29 are developed from my exhibits and supporting workpapers and from the exhibits of Company witnesses Keaton, Palkovich, Shingler, Morales, Hill, Harry, Conrad, Kops, Denato, Varvatos, DeLacy, Pelmear, and Brian J. VanBlarcum. The Projected Test Year NOI on line 31 is the result of netting the Projected Test Year adjustments on line 30 against the adjusted Historical Year NOI on line 15. Projected Test Year NOI of $225 million on line 31 column (p) ties to the adjusted NOI on line 22 of Exhibit A-13 (JRC-11), Schedule C-1.

Q. Please explain the Projected Test Year adjustments on Exhibit A-13 (JRC-24), Schedule C-14.

A. Lines 16 through 19 represent the changes in gross margin from the adjusted Historical Year to the Projected Test Year and are related to the sales forecast supported by Company witness Keaton, the cost of gas sold forecast supported by Company witness Pelmear, and projected other gas revenue supported by Company witness Andrew G. Volansky's workpapers.

Lines 20 and 21 represent the change in LAUF and Company Use, respectively.

Line 22 represents the change in Other O&M expense from the adjusted Historical Year to the Projected Test Year and is supported by Company witnesses Palkovich, Morales, Shingler, Hill, Harry, Kops, Varvatos, and DeLacy.

Line 23 represents the change in the book depreciation expense from the adjusted Historical Year to the Projected Test Year. The Company used the depreciation rates approved in the March 2017 MPSC Case No. U-18127 Gas Depreciation Case Order along with the projected capital expenditures and assumed plant retirements in the determination of this depreciation expense adjustment necessary to arrive at an appropriate level of book depreciation expense. Book depreciation expense was developed by applying the functional composite book depreciation rates to the average Projected Test Year depreciable plant balances. The adjustment on line 23 increases depreciation expense for the Projected Test Year due to significant new investment combined with the higher book rates.

Line 24 represents the change in real and personal property tax from the adjusted Historical Year to the Projected Test Year and is supported by Company witness VanBlarcum.

Line 25 represents the change in payroll and other general taxes from the adjusted Historical Year to the Projected Test Year.

Line 26 represents the change in CIT from the adjusted Historical Year to the Projected Test Year.

Line 27 reflects the impact of MCIT. The Projected Test Year MCIT expense is shown on Exhibit A-13 (JRC-19), Schedule C-9.

Line 28 represents an adjustment to AFUDC from the adjusted Historical Year to the Projected Test Year. AFUDC is an accounting convention that recognizes the costs, both interest and equity, of financing certain construction projects. The recognition is through the transfer of interest and equity cost from the income statement to CWIP on the balance sheet. The interest and equity costs are capitalized in the same manner as construction labor and material costs when the project is closed to plant-in-service. The criteria for applying AFUDC to a construction project require on-site construction activities of more than six months duration and an estimated plant cost (excluding AFUDC) in excess of $50,000. This adjustment reduces AFUDC because AFUDC is expected to be less in the Projected Test Year than in the Historical Year.

Line 29 represents the FIT adjustments which result from the other changes in revenue and expense levels for the Projected Test Year. Line 29 also reflects the differences between the FIT expense calculated at the current federal statutory rate and the actual total income tax expense.

II. IRM

Q. Describe the IRM proposed by the Company.

A. The proposed IRM would authorize the Company to collect additional revenues associated with incremental capital spending beginning July 1, 2019, through June 30, 2020, as discussed in the testimony of Company witness Michael A. Torrey. Company witness Heather L. Rayl is sponsoring the rate design for the IRM surcharge.

Q. Are you sponsoring any exhibits for the proposed IRM?

A. Yes. The following exhibit describes the calculation and reconciliation methodology for the proposed IRM:

Exhibit A-76 (JRC-25)	Investment Recovery Mechanism – Incremental Annual Revenue Requirement June 30, 2020.

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes.

Q. Please explain Exhibit A-76 (JRC-25).

A. This exhibit is a two page exhibit. Lines 1 through 9 on page 1 show the annual capital expenditures of the eight programs by functional grouping. Lines 10 through 18 provide the averaged values of the capital expenditures. Lines 19 through 23 summarize the components of the revenue requirement of the program. The calculations on page 2 show the incremental revenue requirement for the projected capital expenditures for the 12 months ending June 30, 2020. The incremental revenue requirement for incremental capital is the sum of:

A. The incremental return on investment;

B. The incremental depreciation expense;

C. The incremental property tax; and

D. The incremental AFUDC offset amount.

Q. How was the IRM incremental revenue requirement calculated?

A. The incremental revenue requirement was calculated using the projected incremental capital expenditures shown on Exhibit A-76 (JRC-25), page 1, lines 1 through 8. Line 9 shows the calculation of a total incremental capital expenditure level of $301,987,000, and is the basis for which the revenue requirements components are calculated. Lines 19 through 22 show the components of the revenue requirement of $19,581,000, shown on line 23. Lines 24 through 35 show the calculation of return on investment, depreciation expense, property tax expense, and the AFUDC offset components. Lines 36 through 40 show the factors used in making the calculations on lines 24 through 35, above. The pre-tax rate of return, property tax rate, and revenue multiplier are based on the Company's proposal in this instant case. The depreciation rates are based on the composite rates authorized by the Commission in its March 28, 2017 Order in MPSC Case No. U-18127.

Q. Does this complete your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
______________________________________	)	

REBUTTAL TESTIMONY

OF

JASON R. COKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2018

Q. Please state your name and business address.

A. My name is Jason R. Coker. My business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Jason R. Coker who previously prepared and filed direct testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to discuss the revenue requirement positions presented by Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Robert F. Nichols II and Attorney General witness Sebastian Coppola. My testimony will also rebut the impact of Federal Income Tax Reform as calculated by Residential Customer Group ("RCG") witness William A. Peloquin. My rebuttal testimony will also present an adjusted revenue deficiency.

Q. Are you sponsoring any exhibits in connection with your rebuttal testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-80 (JRC-26)	Computation of Adjusted Revenue Requirement – 10.75% ROE for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-81 (JRC-27)	Computation of Adjusted Revenue Requirement – 10.50% ROE for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-82 (JRC-28)	Computation of Adjusted Rate Base for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-83 (JRC-29)	Projected Utility Plant Reconciliation for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-84 (JRC-30)	Computation of Adjusted Projected Net Operating Income for the Projected 12-Month Period Ending June 30, 2019;

Exhibit A-85 (JRC-31)	Projected Net Operating Income Reconciliation for the Projected 12-Month Period Ending June 30, 2019;
Exhibit A-86 (JRC-32)	Adjusted Net Operating Income Pro-forma Interest Adjustment for the Projected 12-Month Period Ending June 30, 2019; and
Exhibit A-87 (JRC-33)	Tax Effect of Interest Synchronization Adjustment for the Projected 12-Month Period Ending June 30, 2019.

<u>REVENUE REQUIREMENT – MPSC STAFF POSITION</u>

Q. Is Staff's revenue requirement sufficiency of $6.6 million, as presented by Staff witness Nichols, the appropriate amount of incremental revenue the Commission should approve in this case?

A. No. The Staff proposed a number of adjustments to rate base, cost of capital, and net operating income. Several Consumers Energy witnesses are providing rebuttal testimony to the Staff's adjustments. For the reasons stated in such rebuttal testimony, the Commission should reject the Staff's revenue sufficiency proposal of $6.6 million and adopt a revenue deficiency consistent with the direct and rebuttal testimony of the Company's witnesses.

Q. Please explain why Staff's rate base adjustments are not correct.

A. Staff proposed several adjustments to rate base which would result in a reduction to the Company's rate base amount by $258,026,000. These include: (i) adjustments to capital expenditures relating to Gas Automated Meter Reading ("AMR"), contingency costs, transmission and distribution programs, storage and compression projects, and IT expenditures which is discussed in the rebuttal testimony of Company witnesses Mary P. Palkovich, Christopher T. Fultz, Danielle M. Hill, and, Christopher J. Varvatos, and (ii) a net increase to working capital for pension and Other Post Employee Benefits ("OPEB") costs, for the Customer Attachment Program ("CAP") , and for customer deposits, which I discuss in my rebuttal testimony below.

Q. Did the Company find an error in Staff witness Jay S. Gerken's derivation of capital expenditure impacts which if corrected would change the Staff filed amounts for projected rate base and revenue sufficiency?

A. Yes. The Company's review of Staff's testimony, exhibits, and workpapers found an inconsistency between Staff witness Gerken's capital expenditure adjustment inputs to derive Figure 1, on page 5 of his direct testimony, and the capital expenditure adjustments filed by Staff witness Cynthia L. Creisher. Staff witness Gerken used an adjustment input of $13,941,000 in the six-month bridge period instead of $4,554,000 for the six-month bridge period and $9,587,000 for the projected test year as supported by Staff witness Creisher on line 13 of her Exhibit S-11.3.

Q. What is the Company recommending regarding this error?

A. The Company recommends that if the ALJ and/or the Commission adopt Staff witness Creisher's adjustments on line 13 of her Exhibit S-11.3 that the appropriate impacts of these adjustments be reflected in determining the Company's rate base and revenue deficiency/sufficiency. The Company's recommendation in this regard should not be construed to mean that the Company adopts the cost reductions proposed by Ms. Creisher.

Q. On Exhibit No. S-2, Schedule B-4, Staff witness Stacy A. Harris proposes adjustments to working capital in the amount of $5,144,000 for pension and OPEB costs, for CAP programs, and for customer deposits. Do you agree with the adjustments to working capital proposed by Staff Witness Harris?

A. Yes, I agree with the adjustments to working capital as proposed by Staff witness Harris.

REBUTTAL OF STAFF WITNESS ROBERT FRAZIER

Q. Do you agree with Mr. Frazier's recommended reduction of 6% of the overall requested IT capital spending?

A. No. IT Capital spending should be approved as supported in the rebuttal testimony of Company witness Varvatos. Company witness Varvatos provides reasoning as to why the 6% adjustment is not appropriate. In addition to that reasoning, I will show that applying the 6% reduction to historical capital spending is inappropriate.

Q. Please explain Mr. Frazier's justification for the 6% IT capital reduction.

A. Mr. Frazier argues that overall requested recovery for IT capital projects should be reduced by 6% because 6% of the approved capital spending in the prior gas rate case was not spent on projects included in the approved capital spending for that case.

Q. Even if it were true that 6% of approved capital spending in the prior case was not spent, would it be accurate to apply the 6% reduction to historical capital spending?

A. No. Amounts included as historical capital spending represent real dollars spent on assets already being used to serve customers. Thus, Staff's proposed reduction of 6% on the basis that spending did not occur would unreasonably result in a 6% reduction to costs which **were actually spent**.

Q. Mr. Frazier indicates that the Company recovered $6,210,506 in capital expenditures for projects that were never implemented. Do you agree with this statement?

A. No. The Company is afforded a return on, and depreciation of, capital assets. Depreciation on capital assets is recovered over a period of time as determined in the Company's depreciation cases. As depreciation is recovered, rate based is decreased by a like amount. The Company earns a return on the value of the capital assets included in rate base, which declines over time as depreciation accumulates. As such, the Company did not recover the full $6,210,506 in rates.

Q. Mr. Frazier states: "And Consumers Energy is not merely asking for the difference between the $8,213,539 spent and the $6,210,506 recovered in rates but not spent. Consumers Energy is currently asking for recovery of $7,995,275 (96.5% of $8,213,539), and not offsetting for previous recovery of the unspent $6,210,506." Please explain why this is not accurate.

Q. The $6,210,506 of projects included in approved IT projects from the prior case that was not spent is not being requested in this case and it has not been recovered in rates. In the prior case, the Company was afforded a return on, and depreciation of, IT capital spending dollars. The Company did not include in rates the full cost of the capital projects approved in the prior case. In addition, as pointed out by Company witness Varvatos, capital dollars not spent on certain approved projects were spent on other IT capital projects. This means that customers were not asked to pay more in rates than was required to support the return on, and depreciation of, actual IT capital spending. It would not be appropriate to offset the IT capital spending request in this case with the unspent project dollars from the last case because the unspent project dollars are not included in historical capital amounts and are not being requested in this case.

<u>REVENUE REQUIREMENT – ATTORNEY GENERAL'S POSITION</u>

Q. Have you reviewed the direct testimony of Attorney General witness Coppola?

A. Yes.

Q. On page 8 of his direct testimony, Mr. Coppola proposed a revenue deficiency of $54.9 million. Do you agree that this $54.9 million revenue deficiency is appropriate for consideration by the Commission in this case?

A. No. The Attorney General proposes a number of adjustments to rate base, cost of capital, and net operating income. Several Consumers Energy witnesses are providing rebuttal testimony addressing Mr. Coppola's adjustments. Consistent with the reasons stated in such rebuttal testimony, the Commission should reject the Attorney General's revenue deficiency proposal of $54.9 million and adopt a revenue deficiency consistent with the direct and rebuttal testimony of the Company's witnesses.

Q. Are there any other issues the Commission should address in regard to the Attorney General's revenue requirement?

A. Yes. On pages 48 through 51 of Mr. Coppola's direct testimony and on the Attorney General's Exhibit AG-16, Summary Calculations of Benefit Plans Reductions and Disallowances – Projected Test Year June 30, 2019, Mr. Coppola makes adjustments to the Company's projected pension expense for hypothetical cash contributions to the pension plans in the amount of $200 million. The Commission should note that if the Company were to make cash contributions in the amount of $200 million, working capital would increase, causing an increase to the projected revenue deficiency.

Mr. Coppola failed to provide the corresponding increase to the projected revenue deficiency.

Q. Do you have any observations regarding Mr. Coppola's calculation of the test year revenue deficiency adjusted for the Tax Cuts and Jobs Act ("TCJA")?

A. Yes. The Commission should note that Mr. Coppola calculated the impact of the TCJA after making all adjustments in the case. My calculation was made before any adjustments to the revenue deficiency with all adjustments calculated at the lower federal income tax rate.

Q. What is your summation of Mr. Coppola's testimony?

A. In summary, the Commission should reject the Attorney General's proposed revenue requirement and adopt the Company's revenue requirement of $82,775,000, which is consistent with the direct and rebuttal testimony of the Company's witnesses.

TCJA IMPACT ON REVENUE REQUIREMENT – RCG'S POSITION

Q. Are there errors in the calculation of the impact on the revenue requirement of the TCJA as calculated by RCG witness Peloquin?

A. Yes. Mr. Peloquin's Exhibit RCG-2 (WAP-2) shows a calculation of the reduction in federal income tax expense resulting from a change from a 35% federal income tax rate to a 21% federal income tax rate. This calculation does not correctly reflect the federal income tax expense reduction. Exhibit S-3, Schedule C-8, sponsored by Staff witness Nichols shows the calculation of the appropriate reduction in federal income tax expense of $21,992,000 caused by the reduction in the federal income tax rate.

Q. Are there other issues with Mr. Peloquin's calculation of the TCJA impact on this case?

A. Yes. It is unclear why Mr. Peloquin is adding estimated TCJA 2017 Revenue Reduction to the revenue deficiency on Exhibit RCG-3 (WAP-3). The Company does not see the need for any add backs related to the TCJA.

Q. What is the impact on the Company's case related to the change in the federal income tax rate from 35% to 21%?

A. The change in federal income tax rate reduces the Company's filed $178 million revenue deficiency by $61 million.

Q. What is the difference between the $22 million reduction in federal income tax expense caused by the reduction in the federal income tax rate and the $61 million reduction to the Company's filed revenue deficiency?

A. The difference of $39 million is the impact from the change in the revenue conversion factor from 1.6377 to 1.3475.

ADJUSTED REVENUE DEFICIENCY

Q. Please describe Exhibits A-80 (JRC-26) through A-87 (JRC-33).

A. Exhibits A-80 (JRC-26) through A-87 (JRC-33) present the computation of the Company's adjusted revenue deficiency for the projected 12-month period ending June 30, 2019. As shown on line 8, column (d), of Exhibit A-80 (JRC-26), the Company has recalculated a test year revenue deficiency of $82,775,000.

Q. Why is the Company proposing an adjusted test year revenue deficiency of $82,775,000?

A. Based on certain facts and circumstances revealed subsequent to filing the case, the Company believes it is appropriate and necessary to make the adjustments.

Q. Please describe the proposed adjustments to the revenue deficiency.

A. The Company has made the following adjustments to its originally filed revenue deficiency:

1. A decrease to the projected revenue deficiency to include the impacts of the TCJA on current tax expense;

2. Increased other gas revenues by $7,678,000 for an incorrect amount of Asset Management Agreement Revenue that was removed in the Company's originally filed revenue deficiency. (Staff WP-KSK-1);

3. The removal of $450,000 in capital spending for the St. Clair Compressor Upgrade that may be recoverable through insurance. Company witness Fultz discusses this in his rebuttal testimony;

4. The net downward adjustment of capital spending in the amount of $9,283,000 related to Transmission Enhancement for Deliverability and Integrity ("TED-I") sponsored by Company witness Fultz;

5. The removal of $617,000 of capital spending related to TED-I sponsored by Company witness Palkovich;

6. The removal of $5,573,000 of capital spending related to MAOP Compliance sponsored by Company witness Palkovich. An adjustment was also made to reduce O&M expense by $5,638,000 for spending on MAOP compliance;

7. The removal of $7,875,000 of capital spending related to New Business sponsored by Company witness Palkovich;

8. The removal of $2,800,000 of capital spending related to Distribution Regulator Stations sponsored by Company witness Palkovich;

9. The removal of $103,460 of capital spending related to IT costs for the electric utility sponsored by Company witness Varvatos;

10. The net downward adjustment of capital spending related to the DCE Website in the amount of $565,570 sponsored by Company witness Varvatos;

11. An increase to working capital of $19,990,000 and a decrease to O&M expense of $21,203,000 for the 2017 actuarial update of Pension and OPEB Plans. Staff Witness Nichols discusses the working capital adjustments in his testimony. Company Witness Herbert B. Kops discusses the O&M expense reductions in his rebuttal testimony;

12. A decrease to working capital in the amount of $6,488,075 to remove Non-Current CAP Installment Receivables. Staff Witness Harris discusses this in her testimony; and

13. Removed customer deposits, security deposits, and Gas Customer Choice supplier deposits from capital structure and included them in working capital with an add back of interest paid to Net Operating Income. Staff witness Gerken discusses this in his direct testimony.

14. A decrease to working capital of $5,408,000 related to deferred unamortized Manufactured Gas Plant expense and a related decrease to O&M expense of $601,000. Company witness Daniel L. Harry discusses these adjustments in his rebuttal testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
	)	

DIRECT TESTIMONY

OF

DEBORAH S. PELMEAR

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2017

DEBORAH S. PELMEAR
DIRECT TESTIMONY

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

A. My name is Deborah S. Pelmear. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company"). My business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. What is your position with Consumers Energy?

A. My position is Principal Financial Analyst.

Q. Would you briefly describe your background?

A. In 1988, I graduated from Michigan State University with a Bachelor of Arts Degree with a major in Accounting. In 1992, I joined CMS Enterprises as the Accountant for CMS Gas Marketing, the unregulated natural gas trading company. In 1993, I transferred to CMS Gas Marketing in the Nominations Department and through 2003 held positions of increasing responsibility. In 2003, I transferred to Consumers Energy as a Senior Risk Analyst in the Risk Department. In 2008, I assumed the position of Principal Financial Analyst in the Gas Supply Department.

Q. What are your responsibilities as Principal Financial Analyst?

A. I am responsible for fulfilling the Company's efforts to obtain reliable and reasonably priced natural gas supply for its customers, and I am also responsible for the negotiation and administration of gas supply and transportation contracts.

Q. Have you previously provided testimony before the Michigan Public Service Commission?

A. Yes. I filed testimony on behalf of Consumers Energy in the 2011 Gas Rate Case No. U-16855, 2013 Gas Rate Case No. U-17197, 2014 Gas Rate Case No. U-17643, 2015 Gas Rate Case No. U-17882, and the 2016 Gas Rate Case No. U-18124.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to provide gas pricing information that will be utilized to establish the 13-month average volume and cost of gas stored underground. I will provide an average cost of gas sold as well.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibit:

Exhibit A-64 (DSP-1) Storage Fields Month End Summary.

Q. Was this exhibit prepared by you or under your supervision?

A. Yes.

<u>GAS STORED UNDERGROUND</u>

Q. Please describe Exhibit A-64 (DSP-1).

A. Exhibit A-64 (DSP-1) is a listing of the Company's June 2016 through June 2019 underground gas storage volumes and dollars.

Q. Would you briefly explain the background for Exhibit A-64 (DSP-1)?

A. Yes. Exhibit A-64 (DSP-1) reflects the end of the month underground gas storage volumes and dollars which result from the Company's natural gas purchases for its Gas Cost Recovery ("GCR") and Gas Customer Choice ("GCC") customers. The costs and volumes reflect the Company's existing supply and transportation contracts for the historical period, as well as those of the GCC suppliers. Projected supply sources and prices are used for the future periods.

Q. What is the Company's projected test year 13-month average volume and cost of gas in storage as set forth on Exhibit A-64 (DSP-1)?

A. Through June 2019, the Company is projecting a 13-month average volume of working gas in storage of 122,300 MMcf and a 13-month average cost of $367,864,128 ($3.008 per Mcf).

Q. What gas prices were assumed for July 2018 - June 2019 in developing your Exhibit A-64 (DSP-1)?

A. The average New York Mercantile Exchange ("NYMEX") settlement prices for July 2018 - June 2019 as of the first five business days of June 2017 were used. These NYMEX natural gas prices averaged $2.934/MMBtu for July 2018 - June 2019. None of the July 2018 - June 2019 GCR requirements (191,948 MMcf) are at a fixed price, therefore 100% of the GCR requirements would be subject to the NYMEX average.

COST OF GAS SOLD

Q. What is the Company's projected average cost of gas sold for July 2018 - June 2019?

A. The Company is projecting an average cost of gas sold for July 2018 - June 2019 of $3.094/Mcf ($695,309/224,699). The Company's cost of gas sold reflects locational pricing differences between NYMEX (Henry Hub) and other supply locations (basis), transportation costs, unused reservation charges, and the GCR accounting treatment of net system uses.

Q. Does that conclude your direct testimony?

A. Yes, it does.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
	)	

REBUTTAL TESTIMONY

OF

DEBORAH S. PELMEAR

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2018

DEBORAH S. PELMEAR
REBUTTAL TESTIMONY

Q. Please state your name and business address.

A. My name is Deborah S. Pelmear, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Financial Analyst.

Q. Are you the same Deborah S. Pelmear who previously filed direct testimony and an exhibit in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut Michigan Public Service Comission Service ("MPSC" or the "Comission") Staff ("Staff") witness David W. Isakson's claims regarding the Company's Other Gas in Kind ("GIK") volume forecast methodology.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibit:

Exhibit A-126 (DSP-2) Calculation of Other Gas in Kind (GIK) Volumes.

Q. Was this exhibit prepared by you or under your supervision?

A. Yes.

Q. Do you agree with Staff witness Isakson's statement on page 7, lines 4 and 5, of his direct testimony, which asserts that the Company's as-filed Other GIK test year projection did not adhere to the methodology approved by the Commission in Case No. U-18124?

A. No. The Company's as-filed Other GIK test year volume forecast of 355,330 Mcf did reflect a five-year historical average in compliance with the approved methodology. The Company subsequently updated this calculation as provided in Staff Audit Response No. 131, provided by the Company as workpaper DSP_5, to reflect a revised June 2017 actual value, resulting in the 353,424 Mcf historical five-year average ultimately used by Staff witness Isakson in Staff's

Exhibit S-19. Both the update and the Company's original as-filed test year projection reflect the historic five-year average methodology as can be seen in Exhibit A-126 (DSP-2).

Q. Please describe Exhibit A-126 (DSP-2).

A. Page one of Exhibit A-126 (DSP-2) reflects the Company's as-filed workpaper DSP_5 supporting the original Other GIK forecast based on five years of historic data. Page two reflects the revised five-year average calculation provided to Staff as part of Staff Audit Response No 131 supporting the updated 353,424 Mcf Other GIK volume and used in Staff Exhibit S-19.

Q. Does this conclude your rebuttal testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief	)))))	Case No. U-18424

DIRECT TESTIMONY

OF

BRIAN J. VANBLARCUM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2017

Q. Please state your name and business address.

A. My name is Brian J. VanBlarcum, and my address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am a Senior Tax Manager in the Company's Corporate Tax Department.

Q. Please briefly describe your education background.

A. I am a graduate of Western Michigan University where I earned a Bachelor of Business Administration in Finance.

Q. Please describe your business experience.

A. I started with the Company in 2004 as a General Accounting Analyst with the Company's property accounting team. In 2015, I was appointed to my current position as Senior Tax Manager with the Company's corporate tax department.

Q. Are you a certified assessor?

A. I am a Michigan Certified Assessing Officer certified by the State of Michigan's State Tax Commission and a member of the Michigan Assessors Association.

Q. What are your responsibilities as Senior Tax Manager?

A. I am responsible for the administration of the Company's real and personal property taxes. This includes: managing the Company's self-declaration of personal property located within the State of Michigan; overseeing property tax matters concerning the Company's land, generating sites, and other real property; and supervising tax payments to approximately 1,500 taxing authorities. I am also responsible for budgeting and forecasting current and future years' property tax payments and expense.

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

A. Yes, I sponsored testimony in the following MPSC Case Nos.:

Gas Rate Case No. U-15506;
Electric Rate Case No. U-15645;
Electric Rate Case No. U-16191;
Gas Rate Case No. U-16418;
Electric Rate Case No. U-17087;
Electric Rate Case No. U-17735;
Gas Rate Case No. U-17882;
Electric Rate Case No. U-17990;
Gas Rate Case No. U-18124; and
Electric Rate Case No. U-18322.

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

A. My testimony identifies the Property Tax Rate for the test year (12 months ended June 30, 2019) and explains how the rate was derived.

Q. Have you prepared any exhibits to accompany your testimony?

A. Yes. I am sponsoring:

Exhibit A-72 (BJV-1) Development of the Property Tax Rate for the Test Year.

Q. Was this exhibit prepared by you or under your supervision?

A. Yes.

Q. What is the Property Tax Rate for the test year?

A. As indicated on page 1, line 16, of Exhibit A-72 (BJV-1), the Property Tax Rate for the test year is 0.012470585.

Q. How did you calculate the Property Tax Rate for the test year?

A. The Property Tax Rate for the gas business was calculated using the Company's prorated Gas Property Tax Expense (page 1, line 10, Exhibit A-72 (BJV-1)) divided by the total of the 2018 year-end plant-in-service (page 1, line 11, Exhibit A-72 (BJV-1)) plus one-half of the estimated Construction Work in Progress (page 1, line 14, Exhibit A-72 (BJV-1)).

Q. What is included in the Gas Property Taxes Paid – 2018 Estimate on page 1 of 4, line 1 of Exhibit A-72 (BJV-1)?

A. The Consumers Energy 2018 taxes paid of $97.0 million on behalf of the gas portion of the business represents estimated property taxes to be paid in 2018.

Q. What is included in the Gas Property Taxes on 2018 Plant Investment on page 1 of 4, line 2 of Exhibit A-72 (BJV-1)?

A. The $17.6 million increase is the estimated property taxes on the 2018 net additions that will be included in the 2019 property tax liability. This is calculated by taking the capital additions, less retirements times the first year, State Tax Commission multiplier table value to recognize a depreciation allowance, which is then multiplied by the statutory reduction of 50% of true cash value to get the assessed value, then multiplied by Consumers Energy's composite millage rate of 47.2226 to obtain the estimated tax amount. This calculation is shown on page 2, line 9 of Exhibit A-72 (BJV-1).

Q. What is included in the Gas Property Taxes on Real Property Taxable Value Increases – Inflation on page 1 of 4, line 3 of Exhibit A-72 (BJV-1)?

A. The $0.1 million increase for the Real Property Taxable Value relates to Article IX, Section 3 of the Michigan Constitution of 1963, allowing local assessors to raise real property taxable values by the lesser of 5% or the Consumer Price Index ("CPI"). For 2019, our property tax model assumes a CPI rate of 2.2%. This calculation is shown on page 3 of Exhibit A-72 (BJV-1).

Q. What is the result of including the Gas Property Taxes on 2018 Plant Investment and the Gas Property Taxes on Real Property Taxable Value Increase on the estimated 2019 property tax amount paid by the gas business?

A. The result of including these additional items is an estimated 2019 property tax amount to be paid for the gas business of $114.7 million as shown on page 1, line 4, of Exhibit A-72 (BJV-1).

Q. How is this paid amount converted to an expense amount?

A. Since the Company expenses property taxes based on the fiscal year of the taxing authorities, 49.4% of the 2018 estimated gas property tax payments for Consumers Energy is added to the 2019 estimated gas payments since that amount will be expensed in 2019, while subtracting 49.4% of the 2019 estimated gas payments that will be expensed in 2020, arriving at a total 2019 property tax expense of $105.9 million as shown on page 1, line 7, of Exhibit A-72 (BJV-1).

Q. What is the next step in calculating the tax rate for the test year?

A. For the test year, property tax expense was prorated for the period July 1, 2018 through June 30, 2019 using a monthly budgeted sales percentage applied to the 2018 and 2019 estimated annual property tax expense amounts. The result of factoring property tax expense monthly for the test year is a prorated Gas Property Tax Expense of $99.1 million. The Prorated Property Tax Expense for the test year is divided by the 2018 estimated year-end plant-in-service plus one-half of Construction Work in Progress to arrive at an average tax rate of 0.012470585.

Q. Does this conclude your direct testimony?

A. Yes.

JUDGE SONNEBORN: Thank you. You may proceed, Mr. Beach.

MR. BEACH: Thank you, your Honor. The Company would call Company Witness Christopher T. Fultz to the stand.

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(Documents marked for identification by the Court Reporter as Exhibit Nos. A-26 through A-29, A-96, and A-97.)

C H R I S T O P H E R T. F U L T Z

was called as a witness on behalf of Consumers Energy Company and, having been duly sworn to testify the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BEACH:

Q Good morning, Mr. Fultz.

A Good morning.

Q Could you please state your full name and business address for the record?

A My name is Christopher Thomas Fultz, and my business address is 1945 West Parnall Road in Jackson, Michigan 49201.

Q Thank you. By whom are you employed?

A Consumers Energy.

Q And in what capacity?

A I am the Director of Project Management for Transmission, Distribution, and Facilities projects.
Q Mr. Fultz, did you cause to be prefiled in this proceeding a document entitled the Direct Testimony of Christopher T. Fultz, which consisted of a cover page and 32 pages of questions and answers?
A I did.
Q Did you prepare that document or was it prepared under your direction?
A Yes, it was.
Q Mr. Fultz, did you also cause to be prefiled in this proceeding a document entitled the Rebuttal Testimony of Christopher T. Fultz, which consisted of a cover page and 16 pages of questions and answers?
A Yes, I did.
Q Did you also prepared that document under your, directly or under your direction?
A It was.
Q Do you have any changes or revisions that you'd like to make to either your direct or rebuttal testimony?
A I have several. To the direct testimony on page 2, line 11, the word "developed", that "d", the "ed" should be dropped, it should read "helped develop entry into new markets."
Q O.K.

A On page 25, line 20, under -- after "Plant 2" the word "unit" should be plural; and on line 21 after "2018", there should being a space after the comma. Those are all the changes for my direct testimony.
Q So just to be clear, on the change on page 25, the sentence should read, "Due to a major failure, the decision was made to retire Plant 2 units 2 and 3 early?"
A That is correct.
Q O.K. And could you proceed with the changes to your rebuttal testimony?
A In my rebuttal testimony, on page 1, line 11, I would like to add the word "the" between "in" and "Mid-Michigan", so it reads, "planned investments in the Mid-Michigan Pipeline."
On page 2, line 21, I would like to insert the word "of" after "cost", so it reads, "available to cover the cost of those risks."
On page 4, on lines 13 and 14, I would like to remove the comma after "expenditures" at the end of line 13 and add the word "and" before "rate recovery" on line 14, so it reads, "a balance between projected expenditures and rate recovery".
On page 5, lines 1 and 2, at the end of line 1, I would like to remove the word "on", and at the beginning of line 2, I would like to remove the word

"amount", so it reads, "Staff witness Frazier includes multiple rate base disallowances". Also on line 5 -- or page 5, line 20, I would like to move the word "plans" to right after "overall project", so it reads "negative impacts to the overall project plans, and customer benefit delivery, significantly outweigh".

On page --

MS. DONOFRIO: I'm sorry, could you repeat that last one, I didn't follow where that was? I couldn't -- what line?

THE WITNESS: Page 5, line 20, where it -- that line begins with "negative impacts to the overall", so the word "plans", which is right before "significantly", I'd like to move that word to right after "overall project".

MS. DONOFRIO: Before the comma?

THE WITNESS: Yes, correct.

MS. DONOFRIO: Thank you.

A On page 14, line 15, into the dollar amount "65,751", after "65", that should be a period, not a comma, so it should read "65.751 million".

On page 15, line 24, the dollar amount "28,980", that should also be a period, not a comma, so it reads "28.980 million".

And the final change --

Q (By Mr. Beach): Hold it. Is there any further change to your testimony?
A Oh.
Q Just testimony.
A No. Just the testimony, thank you.
Q And with those changes, if I were to ask you the same questions today under oath, would your answers remain the same?
A Yes, they would.
Q And is that the testimony you're adopting today in your rebuttal and direct?
A Yes, it is.
Q Mr. Fultz, you're also sponsoring exhibits with your direct and rebuttal testimony; is that correct?
A That is correct.
Q I'll just briefly read through the exhibits, and let me know if anything is stated incorrectly as to the exhibits you're sponsoring. With your direct, you sponsored A-26, A-27, A-28, A-29, and A-12. With your rebuttal -- and that's A-12 Schedule B-5.6. And with your rebuttal, you sponsored A-96, A-97, I believe that is it with your rebuttal. Is that a correct representation of the exhibits you're sponsoring?
A That is correct.
Q Do you have any changes to any of those exhibits?

A Just one. In my rebuttal, schedule A-97, on line 8 in column (p) as in Paul, there is a bold number "46,965", directly below that there is an unbold number "47,415", that "47,415" number should be "46,965", so both numbers should be "46,965".
Q O.K. In the interest of full disclosure, does that change affect any of the overall calculations in this exhibit?
A That has no effect on the overall calculations, the calculations are all based on the bold numbers, that is just a subset number intended to show how the 46,965 was arrived upon.
Q And with those changes, are those the exhibits that you're proposing to enter into the record today?
A Yes, they are.
Q And were those exhibits that you previously discussed prepared by you or under your direction?
A Yes, they were.

MR. BEACH: At this time, the Company would move to bind in the direct and rebuttal testimony, as corrected on the stand today, and moves to bind in the exhibits also sponsored by Mr. Fultz at the end of cross-examination. With that, I tender the witness for cross, your Honor.

JUDGE SONNEBORN: Thank you, Mr. Beach.

Are there any objections to binding in the direct and rebuttal testimony of Christopher Fultz? (No response.)

Hearing no objection, I will bind that testimony into the record, and I will take up Mr. Fultz' exhibits at the conclusion of his cross-examination.

(Testimony bound in.)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
	)	

DIRECT TESTIMONY

OF

CHRISTOPHER T. FULTZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2017

CHRISTOPHER T. FULTZ
DIRECT TESTIMONY

Q. Please state your name and business address.

A. My name is Christopher T. Fultz, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Director of Project Management for Transmission, Distribution, and Facilities projects in the Enterprise Project Management Department, a position I have held since July 2017. Prior to my current position, I was Director of Project Management.

Q. Would you please state your educational background?

A. I graduated from Michigan Technological University in 2001 with a Bachelor of Science degree in Electrical Engineering. In 2007, I received a Master of Science degree in Electrical Engineering from Michigan Technological University.

Q. Please describe your business experience.

A. In 2001, I began employment at Black & Veatch Corporation in Ann Arbor, MI as an Electrical Engineer. My responsibilities included designing upgrades to the high voltage electric grid, specifically electric transmission substations, for utilities throughout the United States. In 2004, I progressed to the position of Project Engineer, in which I oversaw a team of engineers and technicians performing design work for electric transmission system upgrades. My responsibilities included management of project scope, schedule, budget and quality. Also in this role I supported electric utilities with Project Management services on their projects including scope development, permitting support, regulatory filings (outside of Michigan), estimating, schedule management, and risk management. In 2007, I progressed to the position of Power Delivery Section Manager and Chief Engineer. My responsibilities in that position included supervisory and technical leadership for a department of multi-discipline engineers and technicians on electric substation and transmission line projects. In 2012, I accepted a cross training opportunity as a senior engineer on a large Air Quality Control System project at a coal fueled electric generation facility. In this role I was an onsite liaison to the owner and ensured alignment between the consultant's and owner's technical teams.

In 2013, I progressed to the Business Development Manager for Black & Veatch's global renewable energy business. In this role, I developed growth strategies in each target market segment, developed and maintained relationships with strategic clients, led proposal development efforts, and helped develope~~d~~ entry into new markets. In 2014, I joined Consumers Energy as a Project Manager for electric infrastructure projects. Duties included cost, scope, schedule, risk, and quality management for all phases of the projects. In 2015, I was promoted to the manager of the Electric Project Management team. In this role, I led the development of tools and processes, resolved project issues as they were escalated, set performance goals and completed performance reviews, and ensured successful project execution for internal and external customers. In December 2016, I assumed the role of Director of Project Management. In July of 2017, my role was expanded to Director of Transmission, Distribution, and Facilities Project Management in the Enterprise Project Management organization.

Q. What are your duties as Director of Project Management for Transmission, Distribution, and Facilities?

A. I am responsible for the successful delivery of electric and gas transmission and distribution projects, as well as large capital projects in our various facilities throughout Michigan. My department of Project Management professionals lead planning and execution in all project stages, including estimating and forecasting, schedule planning and management, risk management, and communications. They also provide oversight of engineering, permitting, and procurement.

Q. Do you hold any professional certifications and are you a member of any professional societies or trade associations?

A. Yes. I am a licensed Professional Engineer in Michigan and a Project Management Professional as certified by the Project Management Institute ("PMI"). I am also a member of the National Society of Professional Engineers. Further, I am a member of the Michigan Society of Professionals Engineers ("MSPE") and am currently the President of the Jackson, MI Chapter of MSPE.

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

A. The purpose of my direct testimony is to explain the Company's request for rate relief as it relates to the Transmission Enhancement for Deliverability-Integrity ("TED-I") gas transmission pipeline projects on the 2800 and 100A lines, and to the upgrade projects at the St. Clair and Freedom Compressor Stations. Additionally, my testimony supports the Company's position that contingency is a legitimate and forecastable cost of a project, recognized and accepted practice, and real expense which is incurred. I have divided my testimony into three parts: (i) a description of the capital expenditures for the TED-I pipeline projects; (ii) a description of capital expenditures for the upgrade projects to the St. Clair and Freedom Compressor Stations; and (iii) a description of the Company's position on contingency.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit		Description
A-26 (CTF-1)		2016 – June 30, 2019 Capital Expenditures for TED-I Gas Transmission Pipeline, Freedom Upgrade and St. Clair Upgrade;
A-27 (CTF-2)		2017 Monthly Capital Expenditures for TED-I Gas Transmission Pipeline Projects;
A-28 (CTF-3)		2018 Monthly Capital Expenditures for TED-I Gas Transmission Pipeline Projects;
A-29 (CTF-4)		2019 Monthly Capital Expenditures for TED-I Gas Transmission Pipeline Projects; and
A-12 (CTF-5)	Schedule B-5.6	Projected Capital Expenditures TED-I, Compression and Storage Major Projects.

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

A. Yes.

Q. Please explain Exhibit A-12 (CTF-5), Schedule B-5.6.

A. Exhibit A-12 (CTF-5), Schedule B-5.6 provides a summary of actual and projected gas capital expenditures for the major projects including in my testimony for the historical year 12-month period ending December 31, 2016; the 12 months ending December 31, 2017; the 12 months ending December 31, 2018; the six months ending June 30, 2019;

the 30 months ending June 30, 2019; and the projected test year 12-month period ending June 30, 2019.

TED-I Pipeline Projects

Q. Can you describe investments the Company is making in its gas transmission system as part of the TED-I pipeline projects and how they benefit customers?

A. Under the TED-I pipeline projects, higher-relative risk pipe segments will be upgraded taking into consideration the following opportunities: increased transmission capacity to meet the energy needs of Michigan, improved gas pipeline pressure control and isolation capabilities, and improved public safety and customer deliverability.

Q. Please explain the TED-I pipeline projects.

A. The TED-I pipeline projects are focused on maintaining integrity and deliverability. Projects include replacing transmission pipeline segments that contain higher relative risk type pipe to ensure integrity and safe operation. Higher relative risk pipe segments would include segments with low frequency Electric Resistance Welding ("ERW")/ Electric Flash Welding ("EFW") materials and segments that have experienced previous anomalies or stress characteristics and other factors in accordance with the integrity management risk mitigation. An infrastructure enhancement program for transmission piping is advisable and required in order to provide safe, reliable, uninterrupted gas service to our customers. Major projects included in this filing are replacements of segments of Line 2800 and Line 100A. Capacity needs for the future will be factored into line replacements for continued deliverability. The first TED-I pipeline projects include replacing segments of Line 2800 in the Flint-Saginaw area of the State, on which construction started in 2017 ("Saginaw Trail Pipeline"). The overall TED-I Plan will be continually evaluated based on integrity management results, analysis, construction efficiencies, and system modeling. Capital expenditures for the planned TED-I pipeline projects are shown on Exhibit A-26 (CTF-1).

Q. Which TED-I pipeline projects and phases are you supporting in this case?

A. I am sponsoring the capital expenditures intended to complete certain phases of the Saginaw Trail Pipeline and the Line 100A Mid-Michigan Pipeline project ("Mid-Michigan Pipeline") from 2017 through the six Months Ending June 30, 2019.

Q. Are there other projects associated with the TED-I gas transmission pipeline projects?

A. Yes. However, this direct testimony and exhibits only refer to the pipeline replacement projects. There are associated pressure limiting devices, remote closure valves, valve installations, citygate station installations and augmentation projects. These associated projects ensure deliverability, compliance with regulations, and improved pipeline safety. These associated projects are included in the direct testimony of Company witness Mary P. Palkovich.

Q. Please describe Exhibit A-26 (CTF-1).

A. This exhibit presents the capital expenditures for the TED-I pipeline projects from 2016 through June 30, 2019.

Q. Please describe Exhibits A-27 (CTF-2) through A-29 (CTF-4).

A. These exhibits expand on Exhibit A-26 (CTF-1), and provide the monthly capital expenditures for each TED-I pipeline project in the years 2017, 2018, and 2019. The expenditures are broken out by contractor, labor, materials, business expenses, contingency, and other costs.

Q. What level of capital spending does the Company propose the Commission to incorporate into rates in this case?

A. The Company's request for rate relief in this case reflects capital spending on TED-I pipeline projects of $8.5 million for 2016 (Actual), as provided in column (b), lines 1 through 6 of Exhibit A-26 (CTF-1); $115.5 million in 2017 (Projected), as provided in column (c), lines 1 through 6 of Exhibit A-26 (CTF-1); $109.9 million in 2018 (Projected), as provided in column (d), lines 1 through 6 of Exhibit A-26 (CTF-1); and $66.1 million for the six Months Ended June 30, 2019, as provided in column (e), lines 1 through 6 of Exhibit A-26 (CTF-1).

Q. Please identify the capital expenditures that are planned for the Saginaw Trail Pipeline.

A. Lines 1 through 4 of Exhibit A-26 (CTF-1) identify the total capital expenditures for the Saginaw Trail Pipeline project. In 2016, costs were incurred for preparation of the project pipe yard, which is the temporary project headquarters used to locate equipment, materials, and project field support personnel during the project, procurement of long lead materials to ensure materials are available at the time of construction, surveying, engineering and design, and real estate to secure required easement rights. In 2017, 2018, and the six Months Ending June 30, 2019, costs will be incurred for engineering and design, materials, permitting, surveying, real estate, and labor.

Q. Please describe the Saginaw Trail Pipeline project.

A. The Saginaw Trail Pipeline project increases the diameter of approximately 78 miles of Line 2800, between Zilwaukee City Gate in Saginaw County and Clawson Control Station in Oakland County, from 12 inch and 16 inch to 24 inch within the existing pipeline right of way. The project also includes construction of an additional 17 miles of 24 inch pipe to reroute Line 2800 around highly populated areas in Saginaw and Flint.

Q. Why is the Saginaw Trail Pipeline project necessary?

A. The project will: (i) address the high number of corrosion-related anomalies identified on Line 2800 between Zilwaukee and Clawson Control; (ii) reduce the risk of an unplanned outage on Line 2800, and as a result reduce the risks of supply capacity restrictions and cuts, of being unable to fully refill storage at lower summer natural gas prices, and of customer load curtailments; (iii) increase transmission capacity; and (iv) position the Company's natural gas transmission system for future demand growth and required outages.

Q. Has the Company's Board of Directors approved the Saginaw Trail Pipeline project?

A. Yes, the project was approved by the Company's Board of Directors in November, 2016.

Q. Has the Company received Commission approval to construct and operate the Saginaw Trail Pipeline?

A. Yes. On September 2, 2016, the Company filed an Application in Case No. U-18166, with supporting testimony and exhibits, pursuant to the provisions of 1929 PA 9 ("Act 9"), MCL 83.101 *et seq*., requesting a certificate of public convenience and necessity for the Saginaw Trail Pipeline project. The Commission issued an Order on March 28, 2017 approving a Settlement Agreement reached by the parties in that matter which authorizes the Company to construct and operate this pipeline.

Q. Please describe the planned construction sequence for the Saginaw Trail Pipeline included in Exhibit A-26 (CTF-1), and provide the current anticipated spend for each segment.

A. The construction of each segment of the Saginaw Trail Pipeline shown in Exhibit A-26 (CTF-1) is anticipated to follow the sequence shown in the table below. The projected spend for the overall Saginaw Trail Pipeline project is also shown below. These amounts will continue to be evaluated as the project progresses, as engineering is completed, and as major contracts are awarded.

Year	Scope	Length	Projected Spend
2017	- Evon Road Valve Site to Clio City Gate Construction - Engineering, Long-lead Materials Procurement, Real Estate, Environmental, Permitting for Zilwaukee Jct to Evon Road Valve Site (Saginaw Reroute)	18.54 miles	$113.5 million
2018	- Zilwaukee Jct to Evon Road Valve Site (Saginaw Reroute) Construction	18.50 miles	$105.1 million
2019	- Clio GC to Grand Blanc Jct (Flint Reroute) Construction - Cleanup/Restoration for Zilwaukee Jct to Evon Road Valve Site (Saginaw Reroute) Cleanup/Restoration - Engineering, Long-lead Materials Procurement, Real Estate, Environmental, Permitting for Grand Blanc Jct to Clawson Control	29.18 miles	$131.7 million
2020	- Grand Blanc Jct to Clawson Control Construction - Cleanup/Restoration for Clio GC to Grand Blanc Jct (Flint Reroute)	28.23 miles	$190 million - $200 million
2021	- Cleanup/Restoration for Grand Blanc Jct to Clawson Control	n/a	$5 million – $7 million

Q. Have right of way agreements been secured for the construction of the pipeline?

A. Consumers Energy's existing easements provide second line rights in most areas. The term "second line rights" means that the Company has the authority to construct a line parallel to an existing line as outlined in previously executed easement documents. The Company plans to replace in place or exercise second line rights in these areas. Removal and replacement will occur in some locations. The Company plans to abandon two portions of the pipeline and reroute the pipeline around the urban areas west of Saginaw and east of Flint. Negotiations for right of way agreements associated with this rerouting are ongoing.

Q. Please identify the capital expenditures that are planned for the Mid-Michigan Pipeline.

A. Lines 5 and 6 of Exhibit A-26 (CTF-1) identify the total capital expenditures for the Mid-Michigan Pipeline project. In 2016, costs were incurred for preparation of the project pipe yard, which is the temporary project headquarters used to locate equipment, materials, and project field support personnel during the project. In 2017, projected costs will be incurred to complete construction of the pipe yard, engineering, and surveying. In 2018, projected costs will be incurred for engineering and design, environmental assessment, surveying, and real estate. In the six months ending June 30, 2019, projected costs will be incurred for long lead materials procurement, environmental assessment, permitting, engineering, and real estate.

Q. Please describe the Mid-Michigan Pipeline project.

A. The Mid-Michigan Pipeline project is planned to increase the diameter of approximately 55 miles of Line 100A, between Ovid City Gate in Clinton County and Chelsea

Interchange in Washtenaw County, from 20 inch to 36 inch within the existing pipeline right of way, where feasible.

Q. What are the current anticipated timeline and projected spend for the Mid-Michigan Pipeline project, including those phases beyond 2019?

A. The anticipated timeline and projected spend for the overall Mid-Michigan Pipeline project are shown in the table below. These amounts will continue to be evaluated as the project progresses, as engineering is completed, and as major contracts are awarded.

Year	Segment	Length	Anticipated Spend
2017	Conceptual Design / Pipe Yard Preparation	n/a	$2.0 million
2018	Engineering, Environmental, Real Estate, Pipe Yard Preparation	n/a	$4.9 million
2019	Long-lead Materials Procurement, Real Estate, Environmental, Permitting	n/a	$14.6 million
2020	Long-lead Materials Procurement, Real Estate, Environmental, Permitting	n/a	$40 million - $50 million
2021	Chelsea Interchange to Williamston City Gate	29.70 miles	$165 million - $175 million
2022	Williamston City Gate to Ovid Valve Site	25.15 miles	$130 million - $140 million

Q. Why is the Mid-Michigan Pipeline project necessary?

A. The Mid-Michigan Pipeline project is part of the Company's transmission integrity management plan to ensure system safety, integrity, and deliverability. The Line 100A project will replace 1949 vintage pipe which used low frequency ERW and EFW welding. While the low frequency ERW and EFW welding processes were the best available at the time, they are now known to have a higher likelihood of poorly bonded welds than the high frequency welding used in modern piping. Additionally, in May 2015, the line experienced a rupture just north of Chelsea.

Q. What was the cause of the 2015 rupture?

A. Post-event analysis indicated the rupture was caused by near neutral pH Stress Corrosion Cracking ("SCC"). SCC is a form of environmental cracking that requires three conditions to develop. The rupture event did not result in ignition of the natural gas being transported, any injuries, or third-party property damage.

Q. What conditions are required for SCC to develop?

A. The first is a pipeline material that is susceptible to SCC. The second is stresses higher than the threshold stress for SCC such as those supplied by pressurized gas, and the third is environmental conditions that are conducive to cracking such as local soils or ground water.

Q. What events occurred following the 2015 rupture?

A. SCC conditions on Line 100A necessitated a pressure reduction between Freedom Compressor Station and Ovid Valve Site following the rupture and subsequent analysis. Due to the rupture being caused by SCC, a hydro test of the 100A was required prior to returning the line to service. An Electro Magnetic Acoustic Transducer ("EMAT") inspection was performed prior to hydro testing to ensure the pipeline integrity. EMAT is used to detect longitudinal surface-breaking cracks and related crack-like features. Following successful EMAT runs, remediation ensued in parallel to commencing hydro testing in sections. At the same time, a project was undertaken to ensure supply was not placed at risk by replacing a 6.3 mile section of 20 inch pipe from the Freedom Compressor Station to the Chelsea Valve Site in Washtenaw County.

Q. Has the transmission integrity management plan found other areas of concern on Line 100A?

A. Yes. In 2016, 16 locations were identified and remediated based on inline inspection data, which identified areas with characteristics similar to those that failed during the 2015 hydro test procedure.

Q. Will Line 100A require additional hydro testing?

A. Yes. Line 100A requires hydro testing every five years due to the SCC identified on the pipeline per ASME B31.8S-2004. The next hydro test is required by the end of 2020.

Q. What is the significance of Line 100A in the gas transmission system?

A. Line 100A is one of a limited number of paths for gas entering from southern supply points traveling to customers and storage in the eastern and northern parts of the Company's transmission system.

Q. What advantages are realized by increasing the pipe diameter from 20" to 36"?

A. A larger size pipeline provides additional transmission capacity during the summer and winter. Additional summer capacity is needed to accommodate required maintenance outages on other major pipelines, in particular Line 2200. Line 2200 (36" pipeline between Chelsea to Fenton) is currently the primary path for gas moving from White Pigeon Compressor Station and Freedom Compressor Station to storage fields and customers in the east and north. By increasing the Mid-Michigan Pipeline to 36," another primary path from southern supply points to storage will be available in addition to Line 2200. Scheduling outages on Line 2200 to avoid impacting supply capacity is challenging and is limited to small time windows. In the past, the Company has had to adjust and cancel outages on Line 2200 for system integrity and maintenance work as well as emergent work. Depending on system conditions, an unplanned outage on Line 2200 could have a significant impact on supply capacity, which could prevent the Company from fully refilling storage in the summer or providing reliable supply to customers in the winter. The 36" Mid-Michigan Pipeline size would also offset impacts of other outages that can reduce system capacity. In the winter, increasing the diameter of this pipe to 36" will provide additional gas transmission system capacity ahead of potential transmission system load additions. Insufficient winter capacity could be an inhibitor to load growth in Michigan because transmission improvements are typically too costly for a single, or a few new, project developments.

Q. Does the project require Act 9 approval to construct?

A. Yes. An application for Act 9 approval is anticipated to be submitted in 2018 after additional discussions with the MPSC Staff.

Q. Has the Company's Board of Directors approved the Mid-Michigan Pipeline project?

A. Yes, the project was approved by the Company's Board of Directors in January 2017.

Upgrade Projects For St. Clair And Freedom Compressor Stations

Q. Please describe lines 7 and 8 from Exhibit A-26 (CTF-1).

A. Lines 7 and 8 of Exhibit A-26 (CTF-1) identify the total capital expenditures for the St. Clair and Freedom Upgrade Projects.

Q. What level of capital spending does the Company propose for the Commission to incorporate into rates in this case for the upgrade projects to the St. Clair and Freedom Compressor Stations?

A. The Company's request for rate relief in this case reflects capital spending on the upgrade projects to the St. Clair and Freedom Compressor Stations in the amount of $89.4 million for 2016 (Actual); as provided in column (b), lines 7 through 8 of Exhibit A-26 (CTF-1); $76.4 million for 2017 (Projected), as provided in column (c), lines 7 through 8 of Exhibit A-26 (CTF-1); $53.2 million in 2018 (Projected), as provided in column (d), lines 7 through 8 of Exhibit A-26 (CTF-1); and $34.3 million for the first six Months Ending June 30, 2019 (Projected), as provided in column (e), lines 7 through 8 of Exhibit A-26 (CTF-1).

Q. Please summarize the capital expenditures included in Exhibit A-26 (CTF-1), included in this direct testimony for the Freedom Compressor Station upgrade project.

A. Line 7 of Exhibit A-26 (CTF-1) identifies the total capital expenditures for the Freedom Compressor Station upgrade project. Phase 1 of the Freedom Compressor Station upgrade project will be completed in 2017 as well as the engineering for Phase 2. In 2017, 2018, and the six Months Ending June 30, 2019, costs will be incurred for engineering, procurement of new compressor engines, a new transformer, valves, and the balance of equipment, site preparation, construction of new compressor and auxiliary buildings, and construction of the equipment.

Q. What is the projected annual spend for the overall Freedom Compressor Station upgrade project?

A. The projected annual spend for the Freedom Compressor Station upgrade project is currently planned as shown in the table below. These amounts will continue to be evaluated as the project progresses, as engineering is completed, and as major contracts are awarded.

Anticipated Spend (Millions)	
2016	$16.8
2017	$29.1
2018	$53.2
2019	$70.9 - 80.9
2020	$41.0 - 58.0
2021	$9.0 – 22.0
Total	$220.0 - 260.0

Q. Please provide further details regarding the phases of the Freedom Compressor Station upgrade project.

A. The Freedom Compressor Station upgrade project will be completed in two phases. Phase 1 began in 2015 and includes costs for engineering, procurement of two new compressor engines (that will be installed on engine skids and placed in temporary locations to improve plant reliability in the short-term) and the start of construction for a new compressor building.

Phase 2 of the Freedom Compressor Station upgrade project includes costs for continued engineering, procurement of three additional compressor engines, completion of the new facility and demolition of the old compressor building. When Phase 2 is complete, all five new compressor engines (18,750 Brake Horsepower ("BHP") will be permanently installed in the new compressor building and both of the old compressor buildings will be demolished.

Q. What is the timeline of the Freedom Compressor Station upgrade project?

A. Major milestones for the Freedom Compressor Station upgrade project are shown in the table below.

Milestone	Anticipated Completion Date
Phase 1 compressors complete (first two new compressors installed in temporary location)	December 2017
Phase 2 air permit received	December 2017
Phase 2 engineering complete	December 2017
Phase 2 board approval	May 2018
Phase 2 construction start	July 2018
Phase 2 first three compressors complete	May 2020
Phase 2 move Phase 1 compressors to permanent location	May 2021
Demolition of Plant 1 & 2, and site restoration, complete	October 2022

Q. What will be the operating state of the Freedom Compressor Station once the first two new compressors are installed for Phase 1?

A. At the end of Phase 1, the Freedom Compressor Station will have the existing eight compressors in Plants 1 and 2, as well as the two new compressors installed in a temporary location. The two new compressors installed in a temporary location will mitigate potential short-term reliability concerns with the existing units until Phase 2 is complete. Based on an assessment conducted in 2015, the Company forecasted about a 75% probability of consistently meeting design day requirements over the next five years with the original existing engines, compared to a target of 95%. Further decreases in overall reliability would reduce this probability to a level lower than 75%. Phase 1 provides backup horsepower to offset such an occurrence. It also provides capacity to support an increase in supply requirements at the Freedom Compressor Station which is discussed later in this direct testimony. This phased approach will help ensure existing and growing supply requirements are met until the completion of Phase 2. Further, the increase in reliability of the Freedom Compressor Station enables the Company to meet its primary public service obligation to maintain gas service to its customers.

Q. Please explain the primary considerations that cause reliability concerns?

A. The primary considerations include:

(i) The age and condition of the existing equipment at the station. For example, all components of the existing station (engines/compressors, critical systems, gas conditioning, and support infrastructure) were determined to be in fair to poor health. More specifically, the compressor building, engine, and scrubber foundations show signs of cracking and deterioration. The condition of Unit 57 foundation led to placing that unit in mothball status. Station valves have obsolete valve operators. The station piping has higher relative risk due in part to the pipeline characteristics. Engine control panels, gaskets, and seals are old and replacement parts are difficult to source. The largest engine and primary workhorse in the station has operating restrictions in place due to a flow restriction in the cooling system. Oil and glycol tanks are underground and Plant 1 relies on water from Pleasant Lake for engine cooling which is not an optimal configuration for such equipment;

(ii) High actual Random Outage Rates ("ROR") as shown in the table below.

Year	Average Random Outage Rate
2012	15.7%
2013	12.5%
2014	22.8%
2015	11.0%
2016	3.0%
2017 YTD Aug	9.9%

A 4% to 5% ROR is needed to meet a 95% station design reliability target; and

(iii) Increasing supply demands at Freedom. These considerations cause uncertainty related to the Company's ability to consistently meet design supply requirements at the second largest supply location on the system.

Q. Please quantify the increase in supply demand at the Freedom Compressor Station?

A. Since 2005, annual throughput has almost doubled from about 42 Bcf/yr in 2005 to a peak of about 78 Bcf in 2016. The percentage of the Freedom Compressor Station's portion of the supply to the total system supply has also doubled from about 12% to about 24% of total system supply. In addition, the Freedom Compressor Station has experienced an increasing trend in the maximum daily flowrate over that same timeframe. These supply increases have also contributed to the decision to complete Phase 1.

Q. Why is this work necessary?

A. The Freedom Compressor Station is the oldest station on the system. Freedom currently operates eight compressor units with a total capacity of 10,400 BHP. Seven of these units were installed in 1948 and the newest unit was installed in 1955. These units and the remaining station equipment are at the end of their useful operating life and currently fail to meet the required reliability standards for the reasons discussed above. Although the units fail to meet current required reliability standards, it should be noted that the eight existing compressor engines in Plants 1 and 2 were installed prior to August 15, 1967. As a result, they are considered "grandfathered" and were not subject to New Source Review ("NSR") permitting requirements at the time of installation. In addition, each of these engines are classified as "existing" spark-ignition stationary reciprocating internal compressor engines >500 HP located at a major source of hazardous air pollutants. Therefore, pursuant to §63.6590(b)(3)(i), they do not have to meet the requirements of 40 CFR Part 63 Subparts A and ZZZZ.

Q. What alternatives to this project were considered?

A. Seven station configuration options were evaluated. The options included various configurations of rebuilding existing and installing new large and small units. The selected configuration outlined in this direct testimony had the most favorable financial results while delivering the required reliability improvements and capacity increases. Option one consisted of rebuilding existing units and renting interim compression to bridge the gap to installing two new 3750 HP units. Option two consisted of rebuilding the existing units and renting interim compression to bridge the gap to installing three new large units. Option three consisted of installing four new large units and 1 small unit. Option four consisted of installing five new large units and 1 small unit. Option five consisted of building five new large units. Option six consisted of installing 13 smaller new units. Option seven, which is the proposed project, consisted of installing five new large units, two of which are installed early in a temporary location.

Q. What is the priority of Freedom Compressor Station upgrade project compared to other projects?

A. The Freedom Compressor Station is the second largest gas supply location within Consumers Energy's system. If the Company experienced a major unplanned event at the Freedom Compressor Station that eliminated the ability to pump, then Freedom would become the smallest pipeline supply location because it would have the least capacity for incoming pipeline supply on the system. The capacity without pumping would range from 0 to 50 MMcf/d depending on the available pressure at the inlet of the station. As mentioned previously in this direct testimony, the total pipeline supply throughput at the Freedom Compressor Station in 2016 was 78 Bcf, or 24% of the total pipeline system supply. Of the 78 Bcf, the vast majority, or 51 Bcf, occurred during the summer period in part to support storage injection operations. Maintaining summer supply capacity to support summer injection operations is critical to realizing the winter gas pricing benefit provided by the storage fields and to supplying customers during the winter. To give some perspective, storage field supply provides about 80% of the total system supply requirements on very cold winter days. For this reason, refilling storage in the summer is a primary operating objective and the Freedom Compressor Station plays a significant role in meeting this objective. In the futures market, the benefit provided by taking advantage of summer prices over winter prices is on average $0.30/dth out to 2029. In 2016, average summer New York Mercantile Exchange ("NYMEX") natural gas Henry Hub prices were about $0.72/dth less expensive than average winter natural gas prices.

Q. Will the Freedom Compressor Station upgrade project improve reliability?

A. Yes. The Freedom Compressor Station upgrade project will not only replace the existing old compressors, pumping capacity will increase station horsepower from 10,400 BHP to 18,750 BHP and provide for new valves, gas conditioning, separators, and emergency generators will be installed. The current compression reliability is no longer sufficient to meet customer short and long term demands. This improved reliability is critical to ensuring this station can meet system demand for summer injection and winter delivery, thereby providing the winter pricing benefit of the storage fields to our customers. Phase 1 and 2 will improve the probability of consistently meeting design requirements from 75% to over 95%.

Q. Will the project provide additional station capacity beyond its current ability?

A. Yes, the new facilities will provide about 65 MMcf/d of additional design capacity to take gas from the upstream interstate pipelines so that abundant gas supply from northeast shale production sources can be leveraged to benefit the Company's customers. The increased capacity provides additional access to potentially favorable market pricing at that location. These savings would be realized by customers. Based on Consumers Energy's supply portfolio for Gas Cost Recovery customers, the delivered cost of the Freedom Compressor Station pathway at an undiscounted tariff rate is about \$0.10/dth to \$0.65/dth lower than other existing and future supply pathways. Consumers Energy has leveraged this favorable pricing by contracting for interstate capacity to deliver to the Freedom Compressor Station through 2023.

Q. Will the Freedom Compressor Station project reduce emissions?

A. Yes. The Freedom Compressor Station's over 60 year old compressor units will be replaced with new units that are more environmentally friendly and more efficient.

Q. Has the Company's Board of Directors approved the Freedom Compressor Station upgrade project?

A. The Company's Board of Directors has approved funding for Phase 1 of the Freedom Compressor Station upgrade project. The Board approval also included funding for Phase 2 engineering and procurement of long lead materials.

Q. When will the Company's Board of Directors approve Phase 2 of the Freedom Compressor Station upgrade project?

A. Approval for Phase 2 will be requested from the Company's Board of Directors in May 2018.

Q. Please summarize the capital expenditures included in Exhibit A-26 (CTF-1) included in this direct testimony for the St. Clair Compressor Station upgrade project.

A. Line 8 of Exhibit A-26 (CTF-1) identifies the total capital expenditures for the St. Clair Compressor Station upgrade project. Construction on the St Clair Compressor Station upgrade project will be completed in 2017. The St. Clair Compressor Station upgrade project includes four new compressor units that are required to meet storage deliverability requirements. Summer gas purchases are generally lower in price than winter gas purchases, about $0.30/dth on average as traded on the NYMEX in the futures market. Refilling storage and using the gas from storage in the winter allows the Company's customers to enjoy lower prices in the winter overall, thereby saving the customers money. This project will reduce emissions and improve station reliability. The upgrade addresses issues with facility dehydration and replacement of large bore valves, emergency electric generation, and existing pipe supports. Reliable operation of the St. Clair Compressor Station is required to meet customer demands, particularly during periods of high demand.

Q. Why is this investment necessary?

A. Six of the Company's 15 storage fields, or 40% of the storage fields, are connected to the St. Clair Compressor Station. Four of the storage fields (Hessen, Puttygut, Four Corners, and Swan Creek) are used for early winter peaking in November and December. The early winter peaking provides 400 to 700 MMcf/d. These four fields are then transitioned to base load operations for January through March, providing about 23 Bcf of cyclic and rapidly declining daily flowrates. The remaining two fields (Ira and Lenox) are held in reserve and used as peaking fields during January through March. In this capacity, Ira and Lenox can deliver high rates of 520 MMcf/d to 620 MMcf/d for a short period of time and can be fully cycled in about 3 to 4 days. On a design peak day, the St. Clair Compressor Station provides about 18% of the total system supply which is the second largest storage source (behind Ray Field) on the system. The St. Clair Compressor Station provides a total of 25 Bcf of cyclic volume or about 11% of Consumers Energy's total system design winter supply. Also, the St. Clair Compressor Station's current compression reliability is no longer adequate to serve the customer demand. The ROR for the existing St. Clair Compressor Station are shown in the chart below. Based on a 2015 assessment, the overall probability of meeting the design peak day requirements (18% of system supply) without the St. Clair Compressor Station upgrade project was only about 25% to 30% and is below the 95% target by a wide margin. The project will significantly increase reliability and the probability of meeting design day requirements to the 95% target level.

Year	Average Random Outage Rate
2012	24.5%
2013	15.0%
2014	14.6%
2015	23.3%
2016	40.4%
2017 YTD Aug	63.0%

Q. Will the increase in reliability provide additional benefits?

A. Yes. The increase in reliability of the St. Clair Compressor Station will offset the inherent supply risk associated with existing equipment to enable the Company to meet its primary public service obligation to maintain gas service to its customers. Supply risks exist if the Company attempts to use horsepower to withdraw gas out of the St. Clair Compressor Station to meet high demand conditions and is unable to achieve the required flowrates due to reliability issues. A shortfall of supply could result in inadequate pressure to certain portions of the Transmission and Distribution systems and could cause customer curtailments in the areas most impacted. Due to the high supply volume that the St. Clair Compressor Station provides (520 to 620 MMcf/d), the Company is uncertain sufficient gas will be available on the market to purchase in a timely manner to maintain or restore system pressures to sufficient levels to prevent customer curtailments under this circumstance.

Q. Why is Consumers Energy only retiring two units at St. Clair Compressor Station?

A. The Company's plan is to continue to operate some of the existing facility compression in conjunction with the new plant to meet customer loads on the gas transmission system in order to achieve an acceptable level of reliability.

Q. How many compressor units are there at the St. Clair Compressor Station?

A. The St. Clair Compressor Station currently operates five units. The St. Clair Compressor Station upgrade project will install four new units. Once the project is complete in 2017, there will be seven operational units, including the four new Plant 3 units, the two existing Plant 1 units, and one of the existing Plant 2 units. Due to a major failure, the decision was made to retire Plant 2 units 2 and 3 early. One of the remaining Plant 2 units will remain in-service until it is retired in 2018,and the other remaining Plant 2 unit will remain in-service as part of the final configuration.

Q. Did the Company's Board of Directors approve the St. Clair Compressor Station upgrade project?

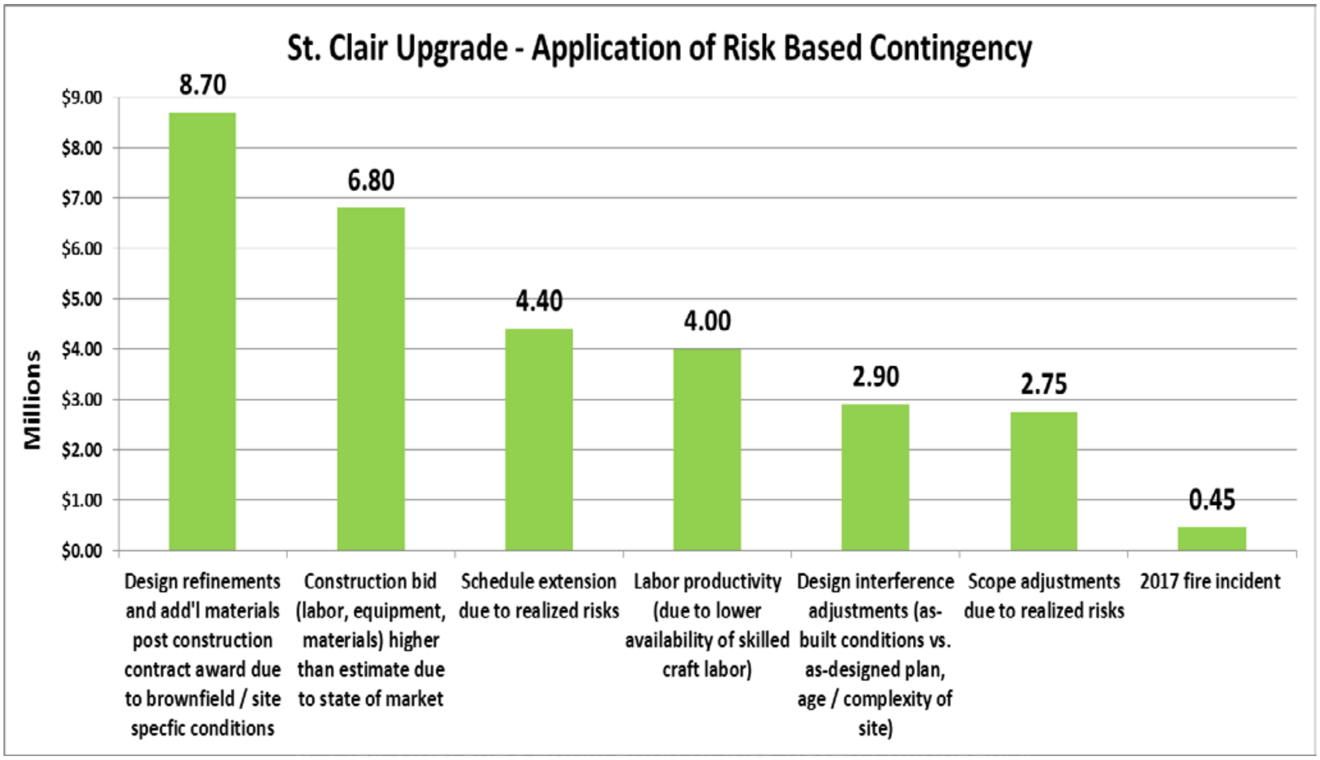
A. Yes. The Company's Board of Directors approved the St. Clair Compressor Station upgrade project.

Q. What amount was approved by the Company's Board of Directors?

A. The Company's Board of Directors approved $165 million in January of 2015. In testimony submitted by Company witness David B. Kehoe in Case No. U-18124, the projected spend was amended to $181 million due to an increase in the 2017 construction packages. The $181 million was within the allowed 10% variance. The projected cost was subsequently amended to $195 million, which was approved by the Company's Board of Directors in May 2017.

Q. Why has the project cost increased from $181 million to $195 million?

A The previous increase from $165 million to $181 million reflected an increase in 2017 construction costs due to market conditions and other realized risks, which used the available contingency and illustrates why contingency is included in the project estimates. The $195 million reflects these actual construction costs and costs that are identified with risk-based contingency, which is standard practice in industry. A summary of the application of risk based contingency is summarized in the graph below, and subsequently described in greater detail.



Q. What factors during construction caused the application of risk based contingency?

A. Multiple factors contributed to the application and use of risk-based contingency. For example, a decision was made to use a cost reimbursable contract structure for the Mechanical/Electrical construction contract. As the St. Clair Compressor Station is a large, complex, and well-established facility, there is inherent risk in finding existing conditions that may not be reflected on existing records due to the age of the plant. Rather than place this risk in the contractor's scope with a lump sum contract (which would include the associated risk premium pricing charged by the contractor), the decision was made to have the Company hold and manage the risk through a cost reimbursable contract. This risk was then managed through the project team and with the project's allocated contingency. The realized risks from the site age and complexity resulted in higher general construction and construction management costs, resulting in a revised forecast of $195 million. The project experienced a substantial increase in material and labor in the as-built condition as compared with original drawings, which resulted from field interferences identified during construction, existing conditions at the site, and final engineering details required for a safe and reliable facility.

Q. Did other factors contribute to the higher construction costs?

A. Yes. Due to the volume of construction activity in the industry during this project, there was a lack of skilled craft labor resources available for the project. As a result, realized risks due to existing site conditions, the previously mentioned skilled craft labor resource availability, and application of contingency to realized risks, the construction schedule was extended into winter conditions. The extended schedule also resulted in an extension of the Company's costs for construction management, quality management, and engineering personnel associated with the project.

Contingency

Q. Do the capital expenditures in Exhibits A-26 (CTF-1) through A-29 to (CTF-4) include contingencies?

A. Yes, they do.

Q. What are contingencies?

A. The Association for the Advancement of Cost Engineering International ("AACE") defines contingency as "[a]n amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs." In simple terms, contingency is an estimate of the uncertainty of the other estimated costs of a project, of similar importance of the other project estimates such as labor and materials. Contingency is generally included in most estimates, and **is expected to be expended**.[1]

Q. How does the Company estimate contingency?

A. The Company uses several methods to calculate contingency, which are consistent with industry practices. The first, which is quantitative, is rigorously applied to more complex projects and is aligned with the definition of "risk-based contingency." These projects are typically longer duration and cadence, and usually involve significant modifications to the operating asset. During the development phase and the construction phases of those projects, time is taken to establish the project risk profiles, estimate the probabilities and impacts of each risk, and determine what the statisticians call an expected monetary value of the risks collectively. The sum of those expected values is the estimate of uncertainty associated with the project, which is called risk-based contingency, for convenience.

The second method is applied to the smaller projects in the portfolio of projects. Here, the projects are much shorter in duration and faster in cadence and involve less modification to the operating asset. For these projects, we typically use the guidelines developed by the PMI and the AACE. Those guidelines simplify the expected value estimated to a percentage of cost, based on the degree of project planning or engineering that has been completed and the level of detail available at the time of estimate. The more planning and contracting that is completed, the lower the percentage that is applied to form the expected monetary value of uncertainty. This type of estimate aligns closely with the definition of "contingency" in the previous question. For example, when limited

[1] "Cost Engineering Terminology," Recommended Practice 10S-90, AACE International, WV, rev. 2007.

engineering and no contracting has occurred, we may apply contingency estimates of 40%. As this project planning moves forward with increasing level of detail and as more information is determined and available, the contingency estimate reduces from 40% to 6% to 10%.

Q. Should the Commission approve contingency expenditures in this, and future, rate case filings?

A. Yes. As explained above, contingency is a very real, reasonable, and forecastable cost of a project. Consumers Energy's methodology for projecting contingency costs reflects established and accepted industry practice, and the consumption of contingency is a reasonable and prudent component of the total costs of its projects. Furthermore, the Company takes an active and thoughtful role in establishing contingency in these projects which encourages active project management, prompting continued focus on identifying and acting on cost avoidance opportunities during the entirety of the project life cycle. Furthermore, there are significant benefits for the inclusion of contingency in project estimates and in the forecasted cash flows. Because contingency covers risk-based estimates and potential exposure due to a level of definition available at the time of estimate, it provides a more realistic business case and predictable cash flow projection for the management of projects. This is why the Project Management industry guidelines have established a prudent basis for estimating and managing contingency, and why it should be included in the requested rate case expenditures.

Q. Please provide additional information regarding estimating and contingency?

A. As previously stated, inclusion of contingency in project cost estimating is a well-established project management methodology. Its purpose is to provide predictability to project outcomes. The Company's risk-based contingency estimate reflects a probabilistic approach tailored to each individual project, which is refined to the risk-specific probability / impact level as the project scope and details are further developed. However, the PMI also recommends that estimates created at the early stages of a project have a larger amount of contingency due to the scope and design not being fully detailed; the PMI recommends up to 75% contingency at the inception of a conceptual business case. As the engineering and procurement progress, and more detail is developed, the amount of contingency is reduced as the certainty of the scope and design replaces the uncertainty of project detail, which was covered in the contingency. The PMI recommends contingency of 50% for preliminary estimates, 25% for budgetary estimates, and 10% for definitive estimates as a guideline. The project team may adjust these amounts based on the level of detail available and the level of risk associated with the project. Definitive estimates include a high level of definition and project detail, and known risks are well documented (however unknown may remain as part of the contingency). Known risks are specific risks with associated response and mitigation plans, each of which is assigned a probability and impact value, which determines the potential cost of the risk. Unknown risks are those that cannot be reasonably predicted or forecasted. Variances within project estimated costs can include such items as material availability, market conditions, labor availability, etc. that can fluctuate from the time of estimating to the time of utilization. In order to track the estimated uncertainty associated with each risk as the project progresses, or to delineate when the contingency associated with a given risk may be removed from the project estimate as the project progresses, the contingency is maintained as a separate line. For example, as we execute contracts and reduce the risk of market condition fluctuations we may be able to reduce the contingency estimate associated with that risk.

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
____	)	

REBUTTAL TESTIMONY

OF

CHRISTOPHER T. FULTZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2018

CHRISTOPHER T. FULTZ
REBUTTAL TESTIMONY

Q. Please state your name and business address.

A. My name is Christopher T. Fultz, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. Are you the same Christopher T. Fultz who previously submitted direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut certain assertions and recommendations made by the following witnesses regarding Consumers Energy Company's ("Consumers Energy" or the "Company") inclusion of $77.654 million of capital expenditure contingency as well as planned investments in the Mid-Michigan Pipeline, Freedom Compressor Upgrade, and St. Clair Compressor Upgrade projects. These specific issues are addressed in the direct testimony and exhibits of the following witnesses in this case:

- The Michigan Public Service Commission ("MPSC" or the "Commission") Staff's ("Staff") witness Lauren Fromm;
- Staff witness Cynthia L. Creisher;
- Staff witness Kevin P. Spence;
- Staff witness Robert Frazier; and
- The Attorney General's witness Sebastian Coppola.

Q. Are you sponsoring any exhibits in connection with your rebuttal testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-96 (CTF-6)	Staff Audit Request #143 - Breakdown of expenditures for actual costs through 2017 and projected expenditures for 2018 and the six months ending June 30, 2019; and
Exhibit A-97 (CTF-7)	Projected Capital Expenditures.

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

A. Yes, they were.

I. CAPITAL EXPENDITURE CONTINGENCY

Q. On page 13, lines 11 through 15 of her direct testimony, Staff witness Fromm indicates that Staff recommends the disallowance of all contingency expenditures included in the Company's capital expenditure projections for this case. Staff witness Fromm indicates that contingency expenditures cannot be judged for reasonableness and prudence. Do you agree with this conclusion?

A. No. As explained in my direct testimony, contingency is a very real, reasonable, expected, and forecastable cost of a project. It is also a widely accepted industry practice.

Q. On page 13, lines 15 through 17 of her direct testimony, Staff witness Fromm suggests that the Company could earn a "return of and on expenditures that were never incurred." Does this reasoning justify the disallowance of projected contingency?

A. No. The risk planning process, in which the contingency amounts are established, determines the expected value of the risks for a given project. Each risk identified is quantified to determine the cost if the risk occurs and the probability of the risk occurring. The expected value of the risk is calculated by multiplying the estimated cost of the risk, times the probability of occurrence. The amount of contingency allocated to a project is thereby determined by the aggregate of those expected values; put simply, it is expected that the risks will occur in the amount of the total expected value, and contingency must be available to cover the cost ^of ~~the~~ those risks. It is important to differentiate the expected value of the risks from the total assessed value of the risks. The total assessed value is the total estimated cost if all risks occurred (the worst case scenario); by assigning a probability to each risk, the costs of the risks are weighted, thereby providing the most likely, and expected, scenario for projected project expenditures.

Q. Why should contingency be included in the rate recovery request, rather than including actual costs in a subsequent rate case?

A. As previously stated, the contingency allocated to a project is directly in line with the expected value of the risks. This is very similar to estimating other expected costs such as materials, equipment, and labor, in that we also quantify the expected value of those costs and allocate funding accordingly. If contingency were not included in the project forecast, it would likely have negative impacts to that, and other, projects when risks occur. As many projects are planned within a given year to deliver safety and reliability benefits to our customers, each project is allocated a portion of the total budget. The budget is finite and the projects are prioritized based on the customer and system benefits they provide. If the expected value of risks were not included in the total project costs, then no funding would be available when those risks occur. Other important projects may need to be delayed or cancelled to fund the costs of the realized risks. If a different project is cancelled to cover these costs, there are customer benefits that will not be delivered; if a different project is delayed to cover these costs; that project may become more expensive as starting and stopping increases the total costs, duration, and efficiency. Since we know the expected cost of risks (and the amount of contingency that should be allocated), it would not be responsible or reasonable to exclude that amount from the total projected expenditures.

Q. Since expected value of risks is based on probability, what if the analysis results in a number that is higher than the actual cost of the risks?

A. As previously explained, the expected value of risk is determined by multiplying the costs of a risk if it occurs by the probability of the risk occurring. Since it is a probability, there are instances where a risk may not occur. While it is fully expected that the expected value of risks is the true value the project will need to fund, it is understood that a balance should exist between projected expenses and rate recovery as it relates to contingency. The aforementioned analysis used to determine the expected value of risks, and the associated amount of contingency, is a widely used and trusted tool to accurately predict total project costs, and therefore optimize the total capital utilization in delivering customer benefits. The contingency included in my exhibits, and the exhibits of other Company witnesses sponsoring capital projects, reflects the expected value of the risks for each of those projects. However, to ensure a balance between projected expenditures and rate recovery, and in the interest of compromise in this proceeding, the Company will agree to modify its requested contingency amounts to 15% or less. Some of the contingency provided in Exhibit A-97 (CTF-7), has been updated to reflect this modification. It should be noted; however, some projects will likely have risks that occur resulting in higher than 15% contingency requirements, and the previously mentioned opportunity costs and negative impacts of delaying or cancelling other projects to fund these realized risks will likely occur. Should the cost of realized risks exceed 15%, they will be included in a capital recovery request in a subsequent rate case.

Q. On page 1 and 2 of his Exhibit S-14.1, Staff witness Frazier includes multiple ~~on (amount)~~ rate base disallowances of contingency included in IT capital expenditures. He does not explain why contingency should not be included in the projected expenditures for IT projects. Are the adjustments proposed by Mr. Frazier reasonable?

A. No. As described above, including contingency in projected expenditures is a widely accepted industry practice to account for the expected value of project risks, which is very similar to how the expected value of project materials, equipment, and labor are included. The variability of whether a risk may or may not occur is addressed by assigning a probability to the risk, which weights the cost. Overall, the total weighted cost reflects the expected cost of all risks. If contingency were not included to cover this weighted cost of risk, it would be similar to intentionally excluding a known expense from a project estimate. This is neither reasonable nor prudent.

Q. On page 53 of his direct testimony, Attorney General witness Coppola recommends a $77.654 million rate base disallowance of contingency included in capital expenditures. He suggests that inclusion of contingency in rate base is neither fair nor reasonable because the amount planned for contingency may not be spent. Does this reasoning justify the disallowance of projected contingency?

A. No. The discussion above illustrates that it is actually fair, reasonable, and prudent to include contingency for the expected value of risks. If there were no contingency, the negative impacts to the overall project, plans and customer benefit delivery, ~~plans~~ significantly outweigh the incorrect perception that contingency reflects dollars that are not intended to be spent. Although the contingency projections directly reflect the anticipated risk for each project, the contingency in this rebuttal is limited to 15% or less to ensure capital is deployed in the most efficient manner, while still remaining sensitive to our customers' rates. Further, while some projects will experience risks that exceed 15% contingency, it is understood those costs can be recovered in future rate cases.

II. MID-MICHIGAN PIPELINE PROJECT

Q. On page 76 of his direct testimony, Attorney General witness Coppola recommends a $14.6 million rate base disallowance for the Mid-Michigan Pipeline Project because the Company has not obtained an Act 9 certificate of necessity for this project. On page 47 of her direct testimony, Staff witness Creisher recommends a $12.5 million rate base disallowance for this project for the same reason; Staff witness Creisher's recommendation is to allow $2.1 million for engineering and design. Is an Act 9 approval for this projected spend required to support the reasonableness and prudence of the Company's projections for this project?

A. No. An Act 9 approval is neither required nor reasonable for the projected expenditures in this recovery request. An exception to this statement is $0.624 million in 2016 and $0.331 million in 2017 that were spent to prepare the construction yard for the project. Also, $0.007 million for materials will be removed from this request and included in a future rate case for recovery. Since these costs are not required to prepare the Act 9 filing, they will be removed from this request and included in a future rate case for recovery.

Q. Are all other costs related to Mid-Michigan Pipeline, besides those associated with the construction yard, prudent and reasonable prior to having an Act 9 approval?

A. Yes. All of these costs are directly attributable to preparing the Act 9 filing. There are several references that outline the MPSC's filing requirements for an Act 9 approval request. In Case No. U-10547, it was indicated the Act 9 filing should demonstrate the necessity and practicability of the lines, whether the lines serve the convenience and necessities of the public, whether the lines will be designed, constructed, and operated in a safe manner and in compliance with the Michigan Gas Safety Code (483.151 et seq), and whether the lines will be routed in an environmentally acceptable manner.

Further, the MPSC has also specified certain filing requirements in Rule 460.868, in which it indicated the requirements in this rule are primarily designed to assist in determining whether the pipeline will serve the public convenience and necessity. This rule requires: (i) the filing of a map of the proposed project showing the dimensions and character of the lines, compressor stations, control valves, and connections; (ii) an estimate of construction costs; (iii) an estimate of proven gas reserves available for transportation through the pipeline; and (iv) an estimate of project's revenues, expenses, and earnings for the first five years of operation. The projected expenditures for Mid-Michigan Pipeline are required in order to prepare these items for the filing. The engineering and design required to develop the filing includes real estate and row/easement costs to determine the routing and depth of the pipeline. Similarly, survey and constructability/construction consulting are critical inputs to the line route, design, and estimated construction costs. There are also services, consultants, and contractors required to perform the permitting and environmental assessments required for an Act 9 filing.

Q. Does the Company's leadership support the Mid-Michigan Pipeline project?

A. Yes. In fact, the Company's Board of Directors approved the project in January 2017, and the projected expenditures are part of the Company's infrastructure planning. In addition to senior leadership and Board of Director support, the Mid-Michigan Pipeline project is a critical component of the Company's Transmission Enhancement for Deliverability and Integrity ("TED-I") strategy as outlined in my direct testimony.

III. FREEDOM COMPRESSOR UPGRADE PROJECT

Q. On page 77 of his direct testimony, Attorney General witness Coppola recommends a $54.3 million rate base disallowance for the Freedom Compressor Upgrade Project because Phase 2 of this investment has not yet been approved by the Company's Board of Directors. Is Board of Directors approval required to support the reasonableness and prudence of the Company's projections for this project?

A. No. The Freedom Compressor Upgrade Project has been approved by the Board of Directors. The criticality of this asset to the Company's natural gas system, as well as the many benefits of this project to our customers, has been thoroughly detailed in my direct testimony. Not only has the Company's Board of Directors already approved Phase 1 of the project, but the total projected expenditures for both phases are included in the Company's infrastructure planning. Board of Directors approval for this project was not approached in two phases to determine whether or not the project would be approved to continue by the time Phase 2 was ready for Board of Directors review. Rather, the approval of Phase 1 by the Board of Directors allowed critical activities to begin that addressed immediate natural gas system reliability, capacity, and safety needs while allowing activities to occur that would significantly increase the accuracy of the projected construction and procurement expenditures by the time Phase 2 Board of Directors approval is requested. The St. Clair Compressor Upgrade Project by comparison necessitated a schedule that required a single Board of Directors approval and a contracting strategy that allowed the Company to manage the risk and the associated risk-based contingency. The circumstances of the Freedom Compressor Upgrade Project allow for a phased approach, and a different contracting strategy, which allows more engineering detail to be prepared prior to construction, higher accuracy estimates for construction, and more of the risk transferred to the contractor.

IV. ST. CLAIR COMPRESSOR UPGRADE PROJECT

Q. On page 8 of his direct testimony, Staff witness Spence recommends a $4.7 million disallowance from rate base for the St. Clair Compressor Upgrade Project, which represents the amount of contingency included in the capital investment projections for this project. Does the Company agree that contingency should not be included in the approved capital expenditures in this case?

A. No. The St. Clair Compressor Upgrade Project is nearing completion, and projections for final project costs have been updated since the time of filing. As shown on the *St. Clair Upgrade – Application of Risk Based Contingency* graph included on page 27 of my direct testimony, the full projected $195 million will be spent to deliver this important project and the associated reliability and safety benefits to customers. In fact, this projection illustrates the importance, prudency, and reasonableness to forecast and include risk based contingency in projected expenditures. The graph on page 27 of my direct testimony reflected the anticipated spending for remaining project costs at the time of filing, and this remains reflective of the actual project costs since the time of filing. At that time, the costs had not yet occurred, but the risks were known, documented, and quantified, and the associated contingency had been allocated accordingly. In this case, the $4.7 million of contingency represented the expected value of the remaining risks. As explained earlier in my rebuttal testimony, the expected value of the risks are project costs that are expected to occur just like other known costs. These risks did occur and the \$4.7 million of contingency was spent to cover these expected, and ultimately actual, costs. Had this contingency not been included, other projects may have been cancelled or delayed to cover these costs, which may have impacted our ability to deliver planned customer benefits. This demonstrates the criticality of analyzing and including the expected value of risks in the overall project costs.

Q. On page 8 of his direct testimony, Staff witness Spence recommends a \$0.450 million disallowance from rate base related to the St. Clair Compressor fire incident. Does the Company agree that the costs related to this incident should be excluded from the approved capital expenditures in this case?

A. In response to Staff Audit, and as shown on the *St. Clair Upgrade – Application of Risk Based Contingency* graph included on page 27 of my direct testimony, at the time of filing the costs associated with the August 24, 2017 fire incident were estimated at \$0.45 million. These costs were included in the recovery request in this rate case. However, the Company is currently in the process of finalizing the total costs such as expert analysis/consulting, and additional design and equipment purchased, to avoid a recurrence of this type of incident in the future. The Company is also determining what portions of the cost may be recoverable from other sources. As such, the Company agrees to exclude the \$0.45 million estimated cost related to the St. Clair fire incident in this recovery request. Any costs not recoverable from other sources will be included in a subsequent rate case for recovery.

V. <u>OTHER CAPITAL EXPENDITURE CHANGES</u>

Q. Is the Company proposing any other changes to the capital expenditures originally proposed in your direct testimony?

A. Yes. In audit, Staff requested a breakdown of expenditures for actual costs through 2017, and projected expenditures for 2018 and the six months ending June 30, 2019. The cost breakdown provided in response to Staff's audit request is being provided with my rebuttal testimony as Exhibit A-96 (CTF-6), Staff Audit Request #143. This audit request was used by Staff witness Creisher to adjust costs for Mid-Michigan Pipeline. Staff's proposed adjustments removed all costs except for Engineering and Design costs included in Staff Audit Request #143. In the interest of using the most up-to-date costs in this case, the Company recommends changes to its originally filed capital expenditures to align with the updated TED-I Pipeline, Freedom Compressor Station Upgrade, and St. Clair Compressor Station Upgrade projected capital expenditures provided in Exhibit A-96 (CTF-6); the updates to the originally filed capital expenditures are reflected in Exhibit A-97 (CTF-7). This Exhibit provides overall decreases in the costs presented for Line 100A, Line 2800, the St. Clair Compressor Upgrade Project, and the Freedom Compressor Upgrade Project.

Q. Please explain the specific cost adjustments that the Company is proposing for Mid-Michigan Pipeline, Line 100A capital expenditures.

A. The Company is proposing updates to the cost requested for Line 100A to account for pre-Act 9 activities. These activities are addressed in more detail above. The following provides the specific adjustments that the Company is proposing:

- In historic year 2016, the recovery request for GL-01629 FDM - Line 100A - Ovid Valve Site to Williamston City Gate - 25.15 Miles of 36" Pipe

Installation was reduced from $1.322 million to $0.698 million. This reduction includes $0.624 million, which was spent preparing the project construction yard. This amount was not required to prepare the Act 9 filing and will be requested in a future rate case following Act 9 approval. All other expenditures related to preparing documents, information, and filing requirements for the Act 9 and are included in this request;

- In the bridge period January 1, 2017 through December 31, 2017, the recovery request for GL-01629 FDM - Line 100A - Ovid Valve Site to Williamston City Gate - 25.15 Miles of 36" Pipe Installation was reduced from $2.043 million to $1.226 million to reflect actual project costs for this period, as shown in Exhibit A-97 (CTF-7). This reduction includes $0.331 million, which was spent preparing the project construction yard, and was not required to prepare the Act 9 filing; this amount will be requested in a future rate case following Act 9 approval, as will $0.005 million spent on materials. All other expenditures related to preparing documents, information, and filing requirements for the Act 9 and are included in this request;

- In the bridge period January 1, 2017 through December 31, 201, the recovery request for GL-02629 FDM - Line 100A - Williamston City Gate to Chelsea Interchange - 29.7 Miles of 36" Pipe Installation was increased from zero to $0.518 million to reflect actual project costs for this period as shown in Exhibit A-97 (CTF-7). Removed from the actual costs are $0.002 million spent on materials, which were not required for the Act 9 filing. This will be requested in a future rate case following Act 9 approval. All other expenditures related to preparing documents, information, and filing requirements for the Act 9 and are included in this request;

- GL-01629 FDM - Line 100A - Ovid Valve Site to Williamston City Gate - 25.15 Miles of 36" Pipe Installation had adjustments to reflect updated projected expenditures as shown in Exhibit A-97 (CTF-7). These adjustments are attributable to updated cost estimates for spending on activities related to the preparation of an Act 9 approval request, such as the planned work to prepare documents, information, and filing requirements. The specific adjustments are as follows:

    - Projected expenditures increased from zero to $0.312 million for the bridge period January 1, 2018 through June 30, 2018. This is an updated estimate of the amount to be spent on activities preparing for the Act 9 filing in this period; and

    - Projected expenditures reduced from $6.472 million to $1.170 million for the test year July 1, 2018 through June 30, 2019. This is an updated estimate of the amount to be spent on activities preparing for the Act 9 filing in this period; and

- GL- 02629 FDM - Line 100A - Williamston City Gate to Chelsea Interchange - 29.7 Miles of 36" Pipe Installation had the following adjustments to reflect updated projected expenditures as shown in Exhibit A-97 (CTF-7). These adjustments are also attributable to updated cost estimates for spending on activities related to the preparation of an Act 9 approval request.

    - Projected expenditures reduced from $2.157 million to $0.312 million for the bridge period January 1, 2018 through June 30, 2018. This is an updated estimate of the amount to be spent on activities preparing for the Act 9 filing in this period; and

    - Projected expenditures reduced from $2.693 million to $1.170 million for the test year July 1, 2018 through June 30, 2019. This is an updated estimate of the amount to be spent on activities preparing for the Act 9 filing in this period.

Q. Please explain the cost adjustments that the Company is proposing for Saginaw Trail Pipeline, Line 2800 capital expenditures.

A. The Company is proposing cost adjustments to Line 2800 capital expenditures to address the contingency cost adjustment, described in more detail above, and to also address actual costs incurred in 2017 and cost projections for 2018 which were updated after the conclusion of 2017. The specific cost adjustments that the Company is proposing are provided as follows:

- In the bridge period January 1, 2017 through December 31, 2017, the recovery requests for GL-01506 SAG - Line 2800 - Evon to Clio 18.5 Miles of 24" Pipe Installation, GL-02506 SAG - Line 2800 - Zilwaukee Junction to Evon Road Valve Site - 18.5 Miles of 24" Pipe Installation were adjusted to reduce the contingency to zero. As shown in Exhibit A-97 (CTF-7), the actual 2017 expenditures for these projects were equal to or higher than the total original request for this period. The costs previously associated with contingency were applied to actual projects costs as the 2017 work was completed;

- In the bridge period January 1, 2017 through December 31, 2017, the recovery request for GL-03506 SAG - Line 2800 - Clio City Gate to Grand Blanc Junction - 29.18 Miles of 24" Pipe Installation was reduced from $8.761 million to $7.952 million to reflect actual costs for this period as shown in Exhibit A-97 (CTF-7).

- In the bridge period January 1, 2018 through June 30, 2018, the recovery request for GL-01506SAG - Line 2800 - Evon to Clio 18.5 Miles of 24” Pipe Installation was increased from $1.476 million to $3.395 million to reflect updated projected expenditures for this period as shown in Exhibit A-97 (CTF-7). This additional cost in the bridge period reflects a shift of cost for Alternating Current mitigation and final restoration from 2017 into 2018;

- GL-02506 SAG - Line 2800 - Zilwaukee Junction to Evon Road Valve Site - 18.5 Miles of 24” Pipe Installation had the following adjustments to reflect updated projected expenditures as shown in Exhibit A-97 (CTF-7):

  - Projected expenditures reduced from $39.085 million to $30.329 million for the bridge period January 1, 2018 through June 30, 2018. This is reflective of more current project estimates and plans since the time of filing in October 2017. These costs have shifted to later in 2018 to better align with construction plans; and

  - Projected expenditures increased from $51.998 million to $~~65,751~~ 65.751 million for the test year July 1, 2018 through June 30, 2019. As described above, engineering and construction planning have progressed since the time of filing and the shift of projected expenditures from the bridge period to the test year reflects those updated plans;

- GL-03506 SAG - Line 2800 - Clio City Gate to Grand Blanc Junction - 29.18 Miles of 24” Pipe Installation had the following adjustments to reflect updated projected expenditures as shown in Exhibit A-97 (CTF-7):

  - Projected expenditures reduced from $67.041 million to $61.137 million for the test year July 1, 2018 through June 30, 2019. Contingency was also reduced to align with the 15% amount described earlier in my rebuttal testimony. The reduction in projected expenditures for the test year reflects engineering and construction planning that have progressed since the time of filing; and

- In the test year July 1, 2018 through June 30, 2019, the recovery request for GL-04506 SAG- Line 2800 - Grand Blanc Junction to Wardlow Valve Site - 20.03 Miles of 24” Pipe Installation was adjusted from $1.032 million to $0.919 million to reflect updated projected expenditures for this period as shown in Exhibit A-97 (CTF-7). Again, this reduction is reflective of updated project plans since the time of filing.

Q. Please describe the cost adjustments for the St. Clair Compressor Upgrade Project capital expenditures.

A. The Company is updating the capital expenditures for the St. Clair Compressor Upgrade Project to reflect actual costs in 2017, dollars previously associated with risk based contingency being applied to actual and known project costs, and the shift of costs from 2017 to the first six months of 2018. Specifically, the Company is proposing the following costs:

- In the bridge period January 1, 2017 through December 31, 2017, the recovery request for the St. Clair Compressor Upgrade Project was reduced from $47.415 million to $44.446 million and contingency was reduced to zero. This reflects the actual costs for this period and a shift of $2.499 million to complete the project in the first six months of 2018. Dollars previously associated with contingency were spent on actual project costs in 2017, and all remaining project costs are known for 2018. Actual 2017 expenditures of $44.916 million were also shown in Exhibit A-97 (CTF-7). Also, the $0.450 million associated with the fire incident is being removed from this request as previously explained.

Q. Please describe the cost adjustments for the Freedom Compressor Upgrade Project capital expenditures.

A. The Company is proposing adjustments to the Freedom Compressor Upgrade Project to reflect actual costs for the bridge period from January 1, 2017 through December 31, 2017. As shown in Exhibit A-97 (CTF-7), actual 2017 costs exceeded the requested amount, and the $0.058 million of contingency was spent on actual project costs for this period. The total $~~28,980~~ 28.980 million is being requested for this period and contingency has been reduced to zero.

VI. SUMMARY

Q. Please summarize the changes you are recommending to the Company's originally filed capital expenditures.

A. The changes described above result in a decrease of actual 2016 costs of $0.624 million, a decrease of $9.569 million in the bridge period of January 1, 2017 through June 30, 2018, and an increase of $0.910 million in the test year. Overall, this results in a decrease in the recovery request of $9.283 million.

Q. Does this conclude your rebuttal testimony?

A. Yes.

JUDGE SONNEBORN: Mr. King.

CROSS-EXAMINATION

BY MR. KING:

Q Good morning, Mr. Fultz.

A Good morning.

Q Joel King on behalf of the Attorney General. Mr. Fultz, your title is Director of Project Management for Transmission, Distribution, and Facilities, correct?

A Correct.

Q And you've been in that, your current position since July of 2017; is that correct?

A Yes, that is correct.

Q And in your current role, you are responsible for developing cost estimates, scope, schedules, risk assessments, and the quality management of large capital projects; is that correct?

A There are a number of responsibilities involved, but that is part of the core of the role, yes.

Q Do you have the -- do you have line or field management responsibilities for construction of the projects?

A My team of project managers have overall accountability for the construction, for the scope, schedule, cost, and quality of the projects.

Q And in addition to filing direct testimony in this case, you also filed rebuttal, correct?

A Correct.
Q And did you prepare the direct and rebuttal testimony yourself?
A I prepared it with the support of others from the Company.
Q And what about the exhibits you filed, was that you yourself or with the support of others?
A Likewise, with the support of others.
Q Now, in your rebuttal testimony, you disagree with the AG and Staff's positions on the disallowance of contingency capital expenditures, correct?
A That is correct.
Q And you also disagree with various other capital expenditure disallowances that were proposed by the AG and Staff, correct?
A Correct.
Q Did you read the AG and Staff testimony on the capital disallowances that you addressed in your rebuttal?
A I did, yes.
Q And did you review the related exhibits?
A I did, yes.
Q So it's fair to say that you're familiar with the specific issues raised by the AG and Staff to which you filed rebuttal?
A Yes, that is fair to say.

Q Can you please turn to page 6 of your rebuttal.

MR. KING: I think I lost the mic.

JUDGE SONNEBORN: O.K. Lori, we could use a battery for the mic.

(Brief pause to change microphone batteries.)

JUDGE SONNEBORN: Back on the record.

MR. KING: Thank you.

Q (By Mr. King): So sorry, we were on page 6 of your rebuttal?

A Yes.

Q Beginning on line 5, you discuss Mr. Coppola's proposed disallowance of 14.6 million in capital expenditures for the Mid-Michigan Pipeline project. Do you see that?

A I do.

Q And you disagree with Mr. Coppola's argument that inclusion of these expenditures in the projected rate base is premature because the Commission has not yet approved the Company's Act 9 application; is that correct?

A That is correct, I disagree with that.

Q And your argument is that it does not matter whether or not the Act 9 approval has been received, correct?

A No, not exactly. My argument is not that it doesn't matter, that's just that it's not required, and that my request is reasonable and prudent.

Q And can you explain why the Act 9 approval is not required?
A The Company believes that this project is -- it's a multidimensional project that delivers multiple customer benefits. It's a prudent project, we have a reasonable anticipation that an Act 9 would be approved, we've reduced our request to include only those expenditures related to the Act 9 filing preparation, which we believe is a reasonable amount, and we believe that because it's reasonably -- reasonable to anticipate Act 9 approval will be granted, therefore, we think it's prudent to ask for recovery on the expenditures that we will put forth in preparing that filing.
Q And what if the Act 9 approval is not granted?
A I really can't speculate on whether it will not be. Again, we feel that this is a very prudent project, we feel it's in our customers' best interest to deliver this project, we have a reasonable anticipation to support or to indicate that the Act 9 would be approved, we have no evidence to indicate that it would not and, therefore, we feel, again, this is a critical project, it's in our customers' best interest, and we think that the Act 9 will be approved, so I can't speculate on a situation where it might not.
Q Can you tell me why the Company has this reasonable

anticipation that the Act 9 will be approved?

A It really is -- it's for the same reasons that are stated in my direct testimony, going back to the multiple benefits delivered by the project from an integrity and deliverability standpoint, the additional capacity it provides, which provides load growth and opportunities for economic development and growth in the state for additional gas customers, as also for operational flexibility on our system.

Q Has the Company made an Act 9 filing yet to build this pipeline?

A Not yet, no.

Q And the Company plans to make -- or pardon. The Company doesn't plan to make an Act 9 filing until the third quarter of 2018; is that correct?

A Third or fourth quarter, but yes, targeting later in 2018.

Q So as of yet, the Commission and other interested parties have not had the opportunity to review whether or not the proposed pipeline is necessary and in the public interest, correct?

A We've had discussions with the MPSC about the project; we have not come to a conclusion or filed the Act 9 yet to formally reach that agreement. But again, falling back to the reasons in my direct testimony, we do feel that

this is a very prudent, very critical project to our customers.
Q Can you please turn to page 8 of your rebuttal. Now, beginning on line 5, you disagree with Mr. Coppola's removal of 54.3 million of capital expenditures for the second phase of the Freedom Compressor Upgrade, correct?
A That is correct.
Q And you disagree with Mr. Coppola's rationale that those capital expenditures have not yet been approved by the Company's board of directors and, therefore, they have not been authorized, correct?
A That is correct, I disagree with that assertion.
Q Is it fair to say that your view is that it does not matter that the capital expenditures have not been authorized, that they should still be included in the rate base?
A No, that is not a fair statement. What is a fair statement is that the prudency of the overall scope of the entire project has been presented to the board of directors, along with an anticipated cost for the project. That project was approved to move forward with a significant investment to begin engineering, to begin procurement of long-lead materials, and to begin construction that achieves interim reliability improvements before the ultimate reliability and capacity

improvements are made at the finality of the project. Also, this is really something that the Company has elected to do in a phased approach, where we in the second ask are really validating the costs. So at this point, I can confirm that the costs are still valid, the capacity and reliability needs are still as critical now as they were at the time of the first request, and there's no evidence to indicate that there would be any disapproval at the second board of approval request, which is really, again, just a validation of the projected cost to move forward.

Q But at this point, the Company's not yet authorized to make those capital expenditures under Phase 2, correct?

A The board has not authorized the Phase 2 expenditures yet. Again, they've -- there's agreement on the prudency of the project, on the financials of the overall project, but yes, the second request will provide formal approval for the Phase 2 expenditures.

Q So what would happen if the expenditures were not approved or approval was delayed?

A We really have no reason to speculate on the situation where the approval would be denied. The prudency of the project has already been approved, I can validate that -- or can confirm that the financials of the project are still valid, and that the customer benefits are still as critical to our gas system now as they have been since the beginning of project.

Q Would you agree that if approval from the board was not obtained, then customer rates would reflect costs for rate base additions that did not happen in the projected test year?

A I really can't speculate on that situation where it wouldn't be approved. These are very necessary improvements to our capacity and reliability of our compression system, so I really can't speculate on the situation where the project would not be approved to move forward with the expenditures for Phase 2.

Q But hypothetically, if that was to happen, then, you know, if the board -- you don't get approval from the board, then the customer rates would reflect rate, costs for rate base additions that did not happen in the projected test year?

A Really we have approval and agreement from our senior team and the board to move forward with the project, this is really just a validation of the cost, so there is really not a reason for me to speculate on what would happen to the rates if it wasn't approved because I have no reason to believe that it won't be approved.

MR. KING: No further questions.

JUDGE SONNEBORN: Thank you, Mr. King.

Mr. Beach, do you have any redirect?

MR. BEACH: Just one minute off the record; I don't think we even need to leave the room.

(At 10:17 a.m., there was a brief pause in the proceedings.)

MR. BEACH: No further questions, your Honor. No redirect, sorry, from the Company.

JUDGE SONNEBORN: Thank you, Mr. Beach.

Mr. Fultz, you may be excused.

THE WITNESS: Thank you.

(The witness was excused.)

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JUDGE SONNEBORN: And are there any objections to the admission of Mr. Fultz' Exhibits A-26 through A-29, Exhibit A-12 Schedule B-5.6, and Exhibits A-96 and A-97? (No response.)

Hearing no objection, those exhibits are admitted into the record.

Mr. Beach.

MR. BEACH: Your Honor, again, I think we're going to have to ask for just a few minutes off the record so we can change attorneys here.

JUDGE SONNEBORN: Certainly, yes. Take your time.

MS. DONOFRIO: Judge, could we please

have a five-minute break?

JUDGE SONNEBORN: Sure. Let's take a five-minute break.

(At 10:18 a.m., there was a five-minute recess.)

JUDGE SONNEBORN: Back on the record. Good morning, Ms. Staley.

MS. STALEY: Good morning, your Honor. I would like to begin by binding in the testimony of Heather L. Rayl, who I think by agreement of the parties is not subject to cross-examination.

JUDGE SONNEBORN: Thank you.

(Documents were marked for identification by the Court Reporter as Correct Exhibit A-16 Schedules F-2, F-2.1, F2.2, F-3, F-4, Corrected Exhibits A-67, Exhibit A-68, and Exhibit A-77.)

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MS. STALEY: All right. Thank you. So at this time, your Honor, the Company moves to bind in the prefiled corrected direct testimony of Heather L. Rayl filed in January of this year, consisting of a cover sheet and 18 pages of questions and answers, and the prefiled rebuttal testimony of Heather L. Rayl, consisting of a cover sheet and six pages of questions and answers.

Further, the Company moves for the

admission of Exhibit A-16 Schedule F-2, Exhibit A-16 Schedule F.2.1, Exhibit A-16 Schedule F-2.2, Exhibit A-16 Schedule F-3, Exhibit A-16 Schedule F-4, and Exhibit A-67. Again, all of those exhibits were corrected exhibits that were filed in January of this year. And we also move for the admission of Exhibits A-68 and A-77.

JUDGE SONNEBORN: Thank you. Are there any objections to binding into the record the direct and rebuttal testimony of Heather L. Rayl, as well as her exhibits as described by Ms. Staley? All right. Hearing no objection, I will bind into the record her direct and rebuttal testimony, and admit into evidence her exhibits. Thank you.

MS. STALEY: Thank you, your Honor.

(Testimony bound in.)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
	)	

DIRECT TESTIMONY

OF

HEATHER L. RAYL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

(CORRECTED)

~~October 2017~~ January 2018

Q. Please state your name and business address.

A. My name is Heather L. Rayl, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Rate Analyst II in the Rates and Regulation Department.

Q. Would you please state your educational background?

A. In August 1993, I graduated from Michigan State University's Program in Professional Accounting and received both a Bachelor of Arts degree in Accounting, and a Master's degree in Business Administration.

Q. Please describe your business experience.

A. From September 1993 to February 1995, I was employed as a Staff/Senior Auditor at Ernst & Young, LLP – Detroit. My responsibilities included the planning, execution, and completion of financial statements and compliance audits for a variety of health care and financial services clients. In February 1995, I joined M-CARE, a non-profit Health Maintenance Organization and a wholly-owned subsidiary of the University of Michigan, as a Senior Financial Analyst in the Finance Department. My responsibilities included financial statement preparation and analysis, general ledger analysis, special projects, and preparation of M-CARE's incurred but not recorded claim liability.

In April 2004, I joined Consumers Energy as a Senior Accounting Analyst in Accounting Research and External Financial Reporting. My responsibilities included the research and documentation of numerous technical accounting topics for departmental clients, including United States Generally Accepted Accounting Principles ("GAAP") issues, United States Securities and Exchange Commission ("SEC") issues, and utility/regulatory issues. In October 2005, I joined FinCor Holdings, Inc. ("FinCor"), a medical malpractice insurance company, as a Senior Financial Analyst. My primary responsibilities included the management and coordination of the monthly close process and the preparation of GAAP and statutory financial statements and disclosures, including Regulation S-X compliant financials and Management's Discussion and Analysis of Financial Condition and Results of Operations. In September 2007, I was promoted to External Financial Reporting Manager where my primary responsibility was the preparation of FinCor's Form S-1.

In October 2009, I rejoined Consumers Energy as a Senior Accounting Analyst in Accounting Policy and External Financial Reporting. My responsibilities included the preparation and documentation of numerous disclosures in the Company's Forms 10-K and 10-Q, with a primary focus in regulatory matters and business outlook. I was also responsible for the research and documentation of technical accounting topics for departmental clients, including United States GAAP, SEC, and regulatory issues. In March 2013, I was promoted to the position of Senior Rate Analyst II in the Revenue Requirements and Analysis section of the Rates and Regulation Department. In December of 2016, I joined the Pricing and Rate Design Section of the Rates and Regulation Department as a Senior Rate Analyst II.

Q. What are your duties as a Senior Rate Analyst II?

A. My current responsibilities include electric and gas rate designs, reconciliation filings, analyses for Senior Management, and customer specific rate analyses.

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

A. Yes. I have filed testimony in Gas Rate Case No. U-18124; Gas Cost Recovery ("GCR") Plan Case Nos. U-17334, U-17693, U-17943, and U-18151; GCR Reconciliation Case Nos. U-16924-R, U-17133-R, U-17334-R, and U-17693-R; and Gas Revenue Decoupling Case No. U-18367.

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

A. The purpose of my direct testimony is to present the Company's proposed rate design. The Company's proposed rate design collects the proposed revenue requirement from customers in an equitable manner reflecting the cost of providing service and taking into consideration rate impacts. In addition, I am sponsoring a proposal for a Revenue Decoupling Mechanism ("RDM"), and rate design for an Investment Recovery Mechanism ("IRM") surcharge.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit	Schedule	Description
Corrected A-16 (HLR-1)	Schedule F-2	Summary of Present and Proposed Revenue by Rate Schedule;
Corrected A-16 (HLR-2)	Schedule F-2.1	Summary of Present and Proposed Rates by Rate Schedule;
Corrected A-16 (HLR-3)	Schedule F-2.2	Calculation of Rate Design Targets;
Corrected A-16 (HLR-4)	Schedule F-3	Present and Proposed Revenue Detail;
Corrected A-16 (HLR-5)	Schedule F-4	Comparison of Present and Proposed Monthly Bills;

Corrected A-67 (HLR-6)	Development of Rates for Transportation ATL Services;
A-68 (HLR-7)	Calculation of Test Year Discount and Carrying Cost Rates for the Customer Attachment Program; and
A-77 (HLR-8)	Calculation of Proposed Investment Recovery Mechanism Surcharge.

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

A. Yes.

SUMMARY OF PROPOSED RATE DESIGN CHANGES

Q. Please describe Corrected Exhibit A-16 (HLR-1), Schedule F-2.

A. Corrected Exhibit A-16 (HLR-1), Schedule F-2, Summary of Present and Proposed Revenue by Rate Schedule, provides a summary of the proposed changes in revenue by rate schedule. The proposed change is derived from the calculated difference between test year present revenue and proposed revenue that incorporate the Company's revenue deficiency. The present and proposed revenues shown in the exhibit are calculated using the test year billing determinants provided by Company witness Eric J. Keaton.

Q. What rates were used to calculate present revenue?

A. The Company applied the final rates approved by the Commission in Case No. U-18124 to the test year sales to calculate present revenue in Corrected Exhibit A-16 (HLR-1), Schedule F-2.

Q. Please describe the Company's approach to rate design in this case.

A. Generally, the Company has designed rates so that the revenue recovered from each customer class reflects the adjusted costs for that class in the Company's test year Cost-of-Service Study ("COSS") as provided by Company witness Luis F. Saenz. Adjustments were necessary to mitigate potential rate impacts of certain customers, in order to prevent rate shock. The proposed gas delivery revenue and associated rate increases for each rate class are shown on Corrected Exhibit A-16 (HLR-1), Schedule F-2, page 2.

Residential Rates

The Company is proposing to maintain its existing residential rate structure for rate schedules A and A-1. Proposed delivery revenue for Rates A and A-1, has been designed to result in an increase of $~~133.6~~ 132.0 million, or 19%, as shown on Corrected Exhibit A-16 (HLR-1), Schedule F-2, page 2. The proposed increase for the residential class is 11% when including the cost of the gas commodity, as shown on Corrected Exhibit A-16 (HLR-1), Schedule F-2, page 1.

General Service Rates

The Company is proposing to maintain its existing rate structure for rate schedules, GS-1, GS-2, and GS-3. Proposed delivery revenue for Rates GS-1, GS-2, and GS-3 has been designed to result in an increase of $~~29.5~~ 30.7 million, or 18%, as shown on Corrected Exhibit A-16 (HLR-1), Schedule F-2, page 2. The proposed increase for the general service class is ~~8~~ 9% when including the gas commodity, as shown on Corrected Exhibit A-16 (HLR-1), Schedule F-2, page 1. The proposed rates maintain the current economic breakeven points for the general service rate classes.

Transportation Rates

The Company is proposing to maintain its existing transportation rate structure for rate schedules, ST, LT, and XLT, and is proposing a pilot Extra Extremely Large Transportation Service Rate Schedule ("XXLT Rate"). Proposed revenue for Rates ST, LT, and XLT has been designed to result in an increase of $~~14.6~~ 14.9 million, or 21%, as shown on Corrected Exhibit A-16 (HLR-1), Schedule F-2, page 1. The proposed rates maintain the current economic breakeven points for the existing transportation rate classes.

General Lighting

Rate Schedule GL is a rate dedicated to customers with gas lighting. It is currently closed to new business and has only a few customers being served. Consumers Energy proposes a 20% decrease to the proposed revenue for Rate GL. Based on the Company's projected cost of gas of $3.0940 per Mcf, which is supported by Company witness Deborah S. Pelmear on page 4 of her direct testimony, the monthly rate for the single fixtures is proposed to be $6.00 per month, which reflects a monthly decrease of $1.00. The monthly rate proposed for the multiple fixtures is calculated to be $11.00 per month, which reflects a monthly reduction of $4.00 per month. The cost of gas is included with other distribution costs in the fixed monthly rate for single and multiple gas fixtures.

ALLOCATION OF THE PROPOSED REVENUE DEFICIENCY

Q. Please describe Corrected Exhibit A-16 (HLR-3), Schedule F-2.2.

A. Corrected Exhibit A-16 (HLR-3), Schedule F-2.2, Test Year Calculation of Rate Design Targets, shows the calculation of the revenue targets used for designing rates, including proposed adjustments, to the test year revenue requirement by rate schedule. The exhibit illustrates test year revenues based on the Company's test year COSS, as provided by Company witness Saenz. This is followed by the Company's proposed adjustments to the COSS, which results in the revenue target used for designing the Company's proposed rates.

Q. How did the Company develop the test year revenue targets for each class shown on Corrected Exhibit A-16 (HLR-3), Schedule F-2.2?

A. As shown on Corrected Exhibit A-16 (HLR-3), Schedule F-2.2, page 1, line 1, the Company started with the test year gas COSS. The COSS was adjusted for the Residential Income Assistance ("RIA") provision and the Low Income Assistance Credit ("LIAC") Pilot to assign cost responsibility to all rate schedules, as shown on page 1, line 2, of Corrected Exhibit A-16 (HLR-2), Schedule F-2.1. The COSS was also adjusted to limit the impact of rate increases to prevent rate shock and to maintain breakeven points. The adjusted cost of service was compared to the test year present revenue to determine the revenue deficiency by class. This deficiency was then adjusted for incremental late payments to determine the adjusted deficiency. The adjusted deficiency was added to the test year present revenue, resulting in the rate design targets by rate schedule as shown on Corrected Exhibit A-16 (HLR-3), Schedule F-2.2, page 1, line 9.

Q. How did the Company allocate the low income credits associated with the RIA and LIAC?

A. The allocation of the RIA credit and LIAC is shown on Corrected Exhibit A-16 (HLR-3), Schedule F-2.2, page 2. The credits are allocated to each rate class based on that class's pro rata share of the total revenue requirement.

Q. What is the basis for allocating the RIA credit and LIAC among all rate schedules?

A. The Company is maintaining the allocation ordered by the Commission in its June 3, 2010 Order in Case No. U-15985 (Michigan Consolidated Gas Company's gas general rate case) ("U-15985 Order"). The Order states:

> "The ALJ found that the revenue shortfall should be recovered from all rate classes, on the basis of Allocation Factor No. 20 rather than on the basis of throughput." U-15985 Order, page 91.

> "The Commission adopts the findings and recommendations of the ALJ. For the electric utilities, this shortfall is spread to all customer classes and the Commission is not persuaded that gas should be treated differently. See, MCL 460.11 (3). The Commission further finds that spreading it on the basis of cost of service plus the cost of gas is fair and reasonable." U-15985 Order, page 92.

Q. Please describe Corrected Exhibit A-16 (HLR-4), Schedule F-3.

A. Corrected Exhibit A-16 (HLR-4), Schedule F-3, Present and Proposed Revenue Detail calculates the test year proposed gas rates required to collect the revenue requirement derived from the test year calculation of rate design targets shown in Corrected Exhibit A-16 (HLR-3), Schedule F-2.2, for each rate schedule, based on the billing determinants provided by Company witness Keaton. Both the present and proposed gas prices are applied to the billing determinants to calculate the test year revenue on Corrected Exhibit A-16 (HLR-1), Schedule F-2. The rates from this exhibit are the source of the proposed rates that appear in the redlined tariffs filed by Company witness Karen J. Miles in this case.

Q. How does the Company propose to design rates to recover the residential revenue requirement?

A. Consumers Energy proposes to increase the monthly customer charge for residential customers billed under Rate Schedules A and A-1 to $15.90 per month, based on the residential customer COSS in Exhibit A-16 (LFS-2), Schedule F-1a, page 6, line 14, column (d). The COSS supports a monthly customer charge of $15.90 based on the total revenue requirement proposed by the Company. The Company is recommending the current customer charge be increased to $15 to better reflect the COSS.

Q. Is the Company recommending a rate change to the Excess Peak Demand Charge for residential Rate A-1 customers?

A. Yes. The Excess Peak Demand Charge is customer-related. As a result, the Company proposes to increase this charge by the same percent increase as the residential customer charge, which represents an increase to $0.0913 per Mcf. The proposed Excess Peak Demand charge is shown on Corrected Exhibit A-16 (HLR-2), Schedule F-2.1, line 6, column (d).

Q. How does the Company propose to set rates to recover the revenue requirement for the General Service Rate Schedules, GS-1, GS-2, and GS-3?

A. Consumers Energy proposes to increase the current GS-1 master customer charge to $16.00 per month, increase the contiguous customer charge to $16.00 per month, and collect the remainder of the increase in the distribution charge. The Company proposes to increase the current GS-2 master customer charge to $86.00 per month, increase the contiguous customer charge to $45.00 per month, and collect the remainder of the increase in the distribution charge. The Company proposes to ~~increase~~ decrease the GS-3 master customer charge to $~~520.50~~ 546.00 per month, increase the contiguous customer charge to $70.00 per month, and collect the remainder of the increase in the distribution charge. These rate changes maintain the economic breakeven points between Rate Schedules GS-1 and Rate GS-2 at 1,001 Mcf annually, and between Rate GS-2 and Rate GS-3 at 10,001 Mcf annually, as well as provide for the recovery of the annual revenue requirement for the general service rate class. These rate changes are shown in Corrected Exhibit A-16 (HLR-2), Schedule F-2.1.

Q. Is the Company proposing to reset the economic breakeven points in the general service rate classes?

A. No. The economic breakeven points for the General Service rate class were reset in Case No. U-18124. The Company's proposed rates in this case maintain those breakeven points.

Q. Please explain economic breakeven points.

A. The economic breakeven point is the point at which the total cost to serve a rate class and the total revenue collected from a rate class is equal.

Q. Why does the Company strive to maintain economic breakeven points as part of the rate design?

A. Maintaining these breakeven points allows for greater precision in revenue prediction and, therefore, greater accuracy in setting rates and minimizes confusion for customers. When economic breakeven points change, customers have an economic incentive to switch from their existing rate to a more economical rate and can result in significant numbers of customers shifting rates. Frequent shifts from rate to rate on a large scale can create volatility in revenues received by the Company. This makes it difficult to accurately predict future revenues for ratemaking and financial purposes. Maintaining economic breakeven points minimizes volatility by eliminating any economic incentive to change rates when the customer use has not changed, while simultaneously establishing cost-based rates for the general service class. However, in certain circumstances it is necessary to realign the breakeven points if the individual rate classes continue to move further from its cost-basis and maintaining the current breakeven points are no longer economical.

Q. How does the Company propose to set rates to recover the transportation class's revenue requirement?

A. The Company is proposing an increase of ~~20~~ 21% for Rate ST and 25% for Rates LT and XLT. The Company proposes to decrease the Rate ST master customer charge to $~~520.50~~ 546.00 per month, increase the Rate LT master customer charge to $~~2,416.50~~ 2,630.00 per month, and increase the Rate XLT master customer charge to $~~11,348.00~~ 11,120.00 per month. The Company proposes to increase the contiguous customer charge to $70.00 for all ST, LT, and XLT contiguous accounts. The proposed contiguous customer charge is based on an average monthly per customer cost for the transportation rate class as shown in Exhibit A-16 (LFS-2), Schedule F-1a, page 6, line 14. This maintains the economic breakeven points between Rate ST and Rate LT at 100,000 Mcf annually, and the breakeven points between Rate LT and Rate XLT at 500,000 Mcf annually, as well as provide for recovery of the transportation class annual revenue requirement.

Q. How was the pilot XXLT Rate developed?

A. The Company determined that costs to serve customers with annual usage of at least 4 Bcf, who require a lower Authorized Tolerance Levels ("ATL"), are lower than other transportation customers and, thus, should be in a separate rate category. The cost to serve these customers was determined by Company witness Saenz.

Customers who use at least 4 Bcf annually will qualify for the proposed pilot XXLT tariff. Similar to the other transportation rate schedules, the proposed pilot XXLT tariff features a customer charge and a volumetric distribution charge. Customers whose annual use falls below 4 Bcf would continue to take service under the XLT tariff. The new tariff is not available for contiguous accounts associated with a master account. At the end of the pilot period, Consumers will review the XXLT pilot to ensure the rate delivers the most cost effective results for all qualifying customers.

Q. Why is this new tariff justified?

A. There are two fundamental reasons for the new pilot XXLT tariff. First, the per-unit cost of serving the largest customers within the XLT class is less than the cost of serving the other, smaller customers in the class. In fact, the COSS sponsored by Company witness Saenz indicates that cost per Mcf of serving customers in the proposed pilot XXLT class is lower than the per-Mcf cost of serving XLT customers, which demonstrates that lower per-unit costs should be reflected in the rates of the largest customers. Second, the customers who currently qualify for this rate are gas-fired electric generating units, whose operating characteristics and economics are significantly different than typical gas industrial load.

Q. Why is the Company proposing a rate increase for the transportation class that is higher than the rate increase for the other rate schedules?

A. The Company is proposing to move the transportation class closer to its total cost to serve. As shown in the Corrected Exhibit A-16 (HLR-3), Schedule F-2.2, page 1, the transportation rate classes would require rate increases of ~~17.0~~ 18.3% to ~~61.6~~ 63.7% to fully reflect their cost to serve. As long as the transportation rates remain below their cost of service, the remaining classes will continue to subsidize the transportation class's under-contribution, based on the current Commission-approved allocation of costs. The Company believes that it is appropriate to move these rate schedules closer to their costs to serve, which reduces the current subsidies other customers are paying that allow transportation rates to be under their cost to serve. Reducing the revenue target for the transportation class allows the Company to minimize rate shock for these customers while moving the transportation class closer to its actual cost of service. Corrected Exhibit A-16 (HLR-3), Schedule F-2.2, page 1, lines 11 through 15, shows how revenue was adjusted in order to mitigate the rate impacts to the transportation class.

Q. Please explain ATLs.

A. An ATL is a percentage of a transportation customer's annual contract quantity. A transportation customer's annual contract quantity is the greatest contracted quantity of gas that can be delivered for transportation on the customer's behalf for any given year as specified in the customer's transportation contract with the Company.

Q. Is the Company proposing changes to the transportation charge adjustment associated with the ATLs?

A. Yes. The Company proposes to use the same methodology utilized in Case No. U-14547, which allows customers to select a greater or reduced level of load balancing from the 8.5% default level. The derivation of these proposed decreases or increases is shown on Corrected Exhibit A-67 (HLR-6). The Company is also proposing a new ATL of 4% for the pilot XXLT rate as these customers are expected to manage their gas supply within lower tolerance levels and, thus, they require less utilization of the Company's storage.

TYPICAL BILLS

Q. Please describe Corrected Exhibit A-16 (HLR-5), Schedule F-4.

A. Corrected Exhibit A-16 (HLR-5), Schedule F-4, Comparison of Present and Proposed Monthly Bills provides the impacts resulting from the proposed gas rates and rate design changes for customers on each rate schedule at various usage levels. This exhibit is used to gauge the distribution of the rate impacts across the population of customers taking gas service under the various rate schedules.

CUSTOMER ATTACHMENT PROGRAM DISCOUNT AND CARRYING COST

Q. Please explain Exhibit A-68 (HLR-7).

A. Exhibit A-68 (HLR-7), Calculation of Test Year Discount and Carrying Cost Rates for the Customer Attachment Program ("CAP"), provides the calculation of the test year discount and carrying costs for the CAP and is used to support the changes to the CAP tariff sheet sponsored by Company witness Miles.

RDM

Q. What is a RDM?

A. Energy efficiency reduces the sale of natural gas, which reduced the Company's ability to collect its distribution revenues. Some form of adjustment mechanism is required to counter this disincentive for utilities to support energy efficiency. Decoupling is one mechanism used to remove this disincentive, by separating the amount of revenue a utility receives from the amount of natural gas it sells. This provides a benefit to both the utility and its customers by enabling the Company to encourage energy efficiency.

Q. Does Consumers Energy currently have an approved RDM in place?

A. Yes. The April 21, 2016 Settlement Agreement approved by the Commission in Case No. U-17882 included a RDM that will be effective at the end of the Case No. U-18124 test year, or January 1, 2018, and continues until the Company implements new rates (including rates for self-implemented rate increases).

Q. Is the Company proposing a RDM in this case?

A. Yes. The Company is proposing a RDM using the same methodology that was included in the July 31, 2017 Order in Case No. U-18124.

Q. Please describe the RDM approved by the Commission in the July 31, 2017 Order in Case No. U-18124.

A. The calculation of the RDM approved by the Commission compares the weather-normalized actual revenue realized by the Company to the approved qualifying rate case revenue by rate schedule and subject to the following conditions: (i) for full service customers, revenues reflected in the calculation will be equal to total rate schedule revenue less monthly customer charges and Excess Peak revenues, GCR revenue, and other surcharge revenue; (ii) for gas choice customers, revenues reflected in the calculation will be equal to total rate schedule distribution revenue less monthly customer charge revenue and other surcharge revenue; (iii) all months associated with the projected test year will be excluded from true-up; thus, (iv) the first annual reconciliation period commences with the first month following the end of the general rate case projected test year (*i.e.* commencing July 1, 2019); (v) operation of the mechanism will terminate upon utility implementation of new rates and must be re-approved in the next general rate case order; (vi) allocation of the qualifying revenue shortfall will be by rate schedule, consistent with the calculation; (vii) the actual revenue used in the calculation will be weather-normalized in a manner consistent with the weather-normalization method proposed by Consumers Energy in this case; and (viii) rate schedule GS-3 and all Transportation rate schedules (ST, LT, XLT, and XXLT pilot) will be exempt from the calculation. The Company proposes no changes to the RDM methodology in this case.

Q. When would the RDM reconciliation be filed?

A. The RDM reconciliation would be filed three months after the end of the 12-month period following the projected test year, or three months after new rates are implemented, whichever comes first. The Company would file subsequent RDM reconciliations at the end of each 12-month period, if new rates have not been implemented. With respect to the first annual reconciliation period, the qualifying revenue shortfall, by rate schedule, is capped at 1.125% of the rate case qualifying revenue; with respect to the second and succeeding reconciliation periods, the qualifying revenue shortfall, by rate schedule, is capped at 2.25% of the rate case qualifying revenue.

IRM

Q. Describe the IRM proposed by the Company.

A. The proposed IRM would authorize the Company to collect additional revenues associated with incremental capital spending beginning July 1, 2019, through June 30, 2020, as discussed in the testimony of Company witness Michael A. Torrey. The calculation of the revenue requirement related to the IRM is provided by Company witness Jason R. Coker.

Q. Please describe Exhibit A-77 (HLR-8).

A. Exhibit A-77 (HLR-8) is an Illustrative Calculation of Proposed IRM Surcharge. Exhibit A-77 (HLR-8) shows how the Company proposes to collect the revenue requirements associated with the IRM. As shown on the exhibit, the revenue requirements associated with the IRM are based on a per customer surcharge for each of the sales rate schedules. The revenue requirements for each class are based on the cost allocation of the revenue requirements in Exhibit A-78 (LFS-5). The surcharge is based on test year customers. These rates would be in effect beginning with the July 2019 bill month as shown in the Exhibit A-78 (LFS-5) and would continue until the incremental revenue requirements are included in the implementation of new rates in the Company's next gas case.

Q. How does the Company propose to reconcile the IRM?

A. The Company proposes to reconcile the capital spend on an annual basis. The reconciliation would compare the Company's total actual incremental investment associated with the IRM and associated revenue requirements for that fiscal year against the incremental investment and associated revenue requirements being collected for that year through the surcharge for the annual period being reconciled. If the total incremental investment fell short of the Commission-approved target spend for that period, the amount of the investment shortfall, reduced by the revenue requirement necessary for that investment amount would be refunded to customers.

Q. Would the Company be allowed to increase the surcharges over the amount the Commission approved in a final order in this case?

A. No. The Company would only be authorized to implement the surcharges approved by the Commission in this proceeding. However, the Company would implement reductions as ordered by the Commission to modify the surcharge if the amount of the investment was less than the total incremental investment proposed spend amount.

Q. How would the RDM work with the IRM also being proposed in this case?

A. If approved, the proposed IRM would authorize the Company to collect additional revenues associated with incremental capital spending beginning in the July 2019 bill month, as discussed in the testimony of Company witness Torrey. The IRM is designed to recover incremental, post-test year investment-related costs. The RDM allows for the reconciliation of certain actual billed revenues to the level of revenues approved by the Commission in this case for the test year. The Company proposes that the RDM exclude the surcharge revenue associated with the IRM. The RDM would not affect the reconciliation of the Company's IRM. The reconciliation of the IRM would be handled in a separate contested proceeding to reconcile the Company's actual investment (capital spending) with the amount of incremental investment authorized.

Q. Does this complete your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
	)	

REBUTTAL TESTIMONY

OF

HEATHER L. RAYL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2018

HEATHER L. RAYL
REBUTTAL TESTIMONY

Q. Please state your name and business address.

A. My name is Heather L. Rayl, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Heather L. Rayl who previously presented direct testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony in this proceeding is to address certain conclusions and proposals made by witnesses Daniel J. Gottschalk and Cynthia L. Creisher on behalf of the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff"); Sebastian Coppola, on behalf of the Attorney General ("AG"); Jeffry Pollock, on behalf of the Association of Businesses Advocating Tariff Equity ("ABATE"); and John Mehling, on behalf of Retail Energy Supply Association ("RESA").

Q. Are you sponsoring any exhibits?

A. No.

Rebuttal of Staff Witnesses Gottschalk and Creisher

Q. Do you agree with the rate design recommendations made by Mr. Gottschalk on page 6, lines 21 through 23, page 7, lines 1 through 23, and page 8, line 1?

A. Yes. Staff's rate design is consistent with the rate design methodology proposed by the Company. Staff's proposed rates, however, differ from that of the Company because they collect Staff's proposed revenue and are based on Staff's cost allocations. The final rates approved by the Commission should be designed so that the revenue recovered from each customer class reflects the final Commission-approved revenue requirements allocated to each rate class based on test year Cost-of-Service Study ("COSS") authorized by the Commission. For the Commission-approved rate design, revenue by rate class may need to be adjusted to minimize any rate shock that might be experienced by any single rate class. In addition, the rates should maintain the crossing points for the General Service and Transportation rate classes as closely as possible.

Q. Do you agree with Staff's position regarding the proposed XXLT rate set forth in Staff witness Gottschalk's testimony on page 9, lines 14 through 21, and page 10, lines 2 through 8?

A. Staff is ambivalent to the creation of a new XXLT rate class, because the rates that the projected XXLT customer would pay under the XLT rate are already below the cost-based rate that is justified by the COSS. As noted in the rebuttal testimony of Company witness Luis F. Saenz, the COSS does demonstrates a lower cost for the XXLT class of 2.6% as compared to the XLT class, even at an Authorized Tolerance Level ("ATL") of 8.5%. However, the Company acknowledges that the projected XXLT customer class was held at a zero percent increase in order to maintain a reasonable economic breakeven point that allows the Company's largest customers to qualify for the rate. Even after accounting for a proposed ATL of 4%, the XXLT COSS does not support a zero percent rate increase for XXLT customers. The Company acknowledges that both the proposed XLT and XXLT rates are below their cost to serve.

Q. What would result if the cost differential supported by the COSS was used to determine the XXLT rate rather than holding the economic breakeven point of 4 Bcf?

A. The breakeven point would be significantly higher than 4 Bcf and the Company would not have any customers that would qualify for the XXLT rate. Under that circumstance, the XXLT customers would be better served on the Staff's proposal to add the 4% ATL option for all Transportation rate classes. Therefore, the Company supports Staff proposal to add the 4% ATL option to the Transportation class, which would provide all Transportation customers who select the 4% option the opportunity to reduce their gas delivery costs.

Q. Do you agree with Staff's definition of economic breakeven points on page 14, lines 23 and 24, and page 15, lines 1 through 3, and Staff's description of the effect of altering economic breakeven points between rate schedules?

A. Yes. The Company agrees that an economic breakeven point is the point of volumetric usage where revenue collected from one rate would equal revenue collected on a different rate. The Company also agrees that if the economic breakeven points between rate schedules were significantly altered, customers may be enticed to switch to a different rate schedule than they were assumed to be on in the projected test year determinants. This would impact the Company's ability to collect its approved revenue requirement.

Q. Do you agree with Staff's recommendation that the residential customer charge remain at the present charge of $11.75 per month?

A. As mentioned in the rebuttal testimony of Company witness Saenz, the Company agrees that Appliance Service Plan expenses should not be included in the residential customer charge calculation; however, Staff's proposed residential customer charge differs from that of the Company because it is based on Staff's revenue requirement. If the final Commission-approved revenue requirement supports a residential customer charge greater than $11.75, then the residential customer charge should be designed to reflect that higher cost.

Q. Do you agree with the Investment Recovery Mechanism ("IRM") reconciliation statement made by Staff witness Creisher on page 56, lines 13 through 15?

A. No. My description of the reconciliation process in my direct testimony was not intended to present a modification of the process ordered by the Commission on August 31, 2017 in Case No. U-18124. Instead, I intended to convey that the reconciliation would compare the Company's total actual IRM incremental investment against the incremental investment previously approved by the Commission for the annual period being reconciled. If the actual incremental investment was less than 3.2% of the incremental investment approved, the excess revenue collected would be refunded to customers. This is consistent with the Commission's August 31, 2017 Order in Case No. U-18124.

Rebuttal of Attorney General witness Coppola

Q. Do you agree with the Attorney General's recommendation on page 140, lines 15 through 16, that the residential customer charge increase by no more than $1 to $12.75 and preferably keeping it at the present charge of $11.75 per month?

A. No. The Attorney General's recommendation regarding the residential customer charge is not based on any cost study. If the final Commission-approved COSS supports a residential customer charge greater than $11.75, then the customer charge should be designed to reflect that higher cost.

Rebuttal of ABATE witness Pollock

Q. Do you agree with ABATE witness Pollock's derivation of the rate design in Exhibit AB-5?

A. No. ABATE's proposed rates differ from that of the Company because they collect ABATE's proposed rate design revenue and are based on ABATE's cost allocations. The final rates approved by the Commission should be designed so that the revenue recovered from each customer class reflects the final Commission-approved revenue requirements allocated to each rate class based on test year COSS authorized by the Commission. For the Commission-approved rate design, revenue by rate class may need to be adjusted to minimize any rate shock that might be experienced by any single rate class. In addition, the rates should maintain the crossing points for the General Service and Transportation rate classes as closely as possible.

Q. Do you agree with ABATE witness Pollock's position on page 30, lines 1 through 18, that the 4% ATL option should apply to all Transportation customers?

A. Yes. The Company agrees with ABATE witness Pollock's position that the 4% ATL option should apply to all Transportation customers. The Company also agrees that a lower ATL would reward Transportation customers that more closely manage their supply imbalances. Customers who can effectively manage their gas supply imbalances use less storage and should pay a lower average rate than customers who are less able to manage their supply imbalances.

Rebuttal of RESA witness Mehling

Q. Do you agree with RESA witness Mehling's position on page 18, lines 1 through 12, that the 4% ATL be rejected?

A. No. As discussed above, the Company agrees with Staff's and ABATE's proposal to offer the 4% ATL level, which rewards customers who can more closely manage their monthly gas supply. The Company does not believe that this proposal is harmful and provides customers with a potential option that can assist them in lowering their energy costs. Furthermore, the Company did not change its ATL assumptions in the COSS to offer the 4% ATL discount. The Company's COSS filed in this case assumes all Transportation customers use an ATL of 8.5%.

Q. Does this complete your rebuttal testimony?

A. Yes.

MS. STALEY: So the Company would call its next witness, Eric J. Keaton.

(Documents were marked for identification by the Court Reporter as Exhibit A-5 Schedules E-1, E-1a, E-2, E-3, Exhibit A-15, Schedules E-1, E-2, E-3, E-4, E-5, E-6, E-7, E-8. E-9, and E-10.)

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E R I C J. K E A T O N

was called as a witness on behalf of Consumers Energy Company and, having been duly sworn to testify the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. STALEY:

Q Good morning, Mr. Keaton.

A Good morning.

Q Would you please state your full name and business address for the record?

A Eric J. Keaton, One Energy Plaza, Jackson, Michigan.

Q And for whom are you appearing in this case?

A Consumers Energy.

Q And what is your position at Consumers Energy?

A I am a Principle Rate Analyst on the Financial Business Planning Team.

Q Did you cause to be prepared a document entitled Direct Testimony of Eric J. Keaton on behalf of Consumers Energy

Company, which consists of a cover sheet and seven pages the questions and answers?
A Yes.
Q And did you cause to be prepared a document entitled Rebuttal Testimony of Eric J. Keaton on behalf of Consumers Energy Company, which consists of a cover sheet and six pages of questions and answers?
A Yes.
Q Are there any changes that you wish to make at this time to either your direct or rebuttal testimony?
A No.
Q If I were to ask you these same questions today would your answers remain the same?
A Yes.
Q Is this the testimony that you are adopting as your own today?
A Yes.
Q Are you also sponsoring any exhibits associated with your direct testimony today?
A Yes.
Q And are those the exhibits that have been previously marked by the Court Reporter as Exhibit A-5 Schedule E-1, Exhibit A-5 Schedule E-1a, Exhibit A-5 Schedule E-2, Exhibit A-5 Schedule E-3, Exhibit A-15 Schedule E-4, Exhibit A-15 Schedule E-2, Exhibit A-15 Schedule E-3,

Exhibit A-15 Schedule E-4, Exhibit A-15 Schedule E-5, Exhibit A-15 Schedule E-6, Exhibit A-15 Schedule E-7, Exhibit A-15 Schedule E-8, Exhibit A-15 Schedule E-9, and Exhibit A-15 Schedule E-10?

A Yes.

Q Are you also sponsoring any exhibits associated with your rebuttal testimony?

A No.

Q Are there any changes that you wish to make your exhibits today?

A No.

Q All right. And were the exhibits prepared by you or at your direction?

A Yes.

MS. STALEY: At this time, your Honor, the Company moves to bind in the direct and rebuttal testimony of Eric J. Keaton, and for the admission at the end of cross-examination of Exhibit A-5 Schedule E-1, E-1a, E-2, and E-3, Exhibit A-15 Schedules E-1 through E-10.

With that, I tender the witness for cross-examination.

JUDGE SONNEBORN: Thank you. Are there any objections to binding into the record the direct and rebuttal of Eric J. Keaton? Hearing no objection, I will bind his testimony into the record, and I will address his exhibits at the conclusion of Mr. Keaton's cross-examination.

MS. STALEY: Thank you, your Honor.

(Testimony bound in.)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
	)	

DIRECT TESTIMONY

OF

ERIC J. KEATON

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2017

Q. Please state your name and business address.

A. My name is Eric J. Keaton, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am a Principal Rate Analyst in the Planning, Budget & Analysis Department.

Q. Please state your educational background.

A. I graduated from Auburn University at Montgomery, Alabama, in November 1999, with a Bachelor of Science in Business Administration degree. In addition, I have attended a number of courses on utility ratemaking, load research, and forecasting.

Q. What is your regulatory experience?

A. Prior to joining the Company, from January 1996 through February 2004, I worked in a variety of positions in technical support, systems analysis and design, database management, programming, and business analysis. I joined Consumers Energy in March 2004 as a Rate Analyst in the Rates and Business Support Department. Since joining Consumers Energy, I have been responsible for completing cost-of-service and revenue requirements studies. I was promoted to Principal Rate Analyst in July 2015, and now perform sales forecasting duties.

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

A. Yes, I provided testimony and exhibits in these recent Consumers Energy cases: MPSC Case Nos. U-15645, U-16191, U-16794, U-17087, U-17643, U-17943, and U-18124.

Q. Please explain the purpose of your direct testimony in this proceeding.

A. I am presenting the Company's forecasted gas delivery and customer count levels used to design test year rates in this case. I will discuss the observed historic gas deliveries, customer counts, and operating revenues. My testimony will address the development of the forecasts used in this case.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am providing the following exhibits:

Exhibit A-5 (EJK-1)	Schedule E-1	Annual Service Area Sales by Major Customer Classes and System Output 5-Year Historical;
Exhibit A-5 (EJK-2)	Schedule E-1a	Summary of 2016 Historical Year Revenues;
Exhibit A-5 (EJK-3)	Schedule E-2	2016 Historical Year Consumption and Customer Counts;
Exhibit A-5 (EJK-4)	Schedule E-3	2016 Historical Year Operating Revenues;
Exhibit A-15 (EJK-5)	Schedule E-1	Market Outlook: 5-Year Annual Calendar Gas Forecast by Class;
Exhibit A-15 (EJK-6)	Schedule E-2	Test-Year Calendar Gas Deliveries Forecast by Class;
Exhibit A-15 (EJK-7)	Schedule E-3	Test-Year Calendar Gas Deliveries by Rate Schedule;
Exhibit A-15 (EJK-8)	Schedule E-4	Test-Year Authorized Tolerance Levels by Rate Schedule;

Exhibit A-15 (EJK-9)	Schedule E-5	Market Outlook: 5-Year Average Customer Forecast by Class;
Exhibit A-15 (EJK-10)	Schedule E-6	Test-Year Customer Count Forecast by Class;
Exhibit A-15 (EJK-11)	Schedule E-7	Test-Year Total Customer Count Forecast by Rate Schedule;
Exhibit A-15 (EJK-12)	Schedule E-8	Calculation of Test-Year Projected Income Assistance Enrollments;
Exhibit A-15 (EJK-13)	Schedule E-9	Calculation of Test-Year Excess Peak Consumption; and
Exhibit A-15 (EJK-14)	Schedule E-10	Transition from 2016 Historical Actuals to 12 Months Ended June 2019 Test-Year Revenues, Deliveries, and Customers.

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

A. Yes.

Q. Please explain the current weather normalization process?

A. The Company contracted with Itron to develop a set of economic models to quantify the weather affects. The models developed by Itron take into consideration the various weather responses by rate class (residential, commercial, and industrial), customer counts, weather trends, billing days, and responses at various temperature levels (55 degrees Fahrenheit versus 65 degrees Fahrenheit).

Q. How well do the econometric models explain the observed variations in gas deliveries?

A. Six main econometric models are used to explain the variation in gas delivery by class (residential, commercial, and industrial) and service type (sales and transportation). For instance, the total variation in residential gas deliveries due to temperature is explained using a residential sales model and residential transportation model. Similar models are used for commercial and industrial gas deliveries. The model is robust and performs well in explaining the variation in gas deliveries.

Q. How accurate was this weather normalization process in 2016?

A. Our weather adjusted deliveries for 2016 totaled approximately 304.0 Bcf, compared to our budgeted deliveries of approximately 303.2 Bcf, or within 0.3% of our anticipated deliveries.

Q. Please explain Exhibit A-5 (EJK-1), Schedule E-1.

A. Exhibit A-5 (EJK-1), Schedule E-1, is a summary of the five-year Historical Annual Service Area Sales by Major Customer Classes and System Output. This exhibit is filed in accordance with the Commission's directive in Case No. U-18238.

Q. Please provide a summary of the 2016 operating revenue based on the actual customer and gas delivery levels for the historical year.

A. The 2016 historical operating revenue is presented in Exhibit A-5 (EJK-2), Schedule E-1a, by rate schedule. A detailed summary of customer counts and deliveries is provided in Exhibit A-5 (EJK-3), Schedule E-2, by rate schedule and type of service (sales, customer choice, transportation, and aggregation). The components of the 2016 historical operating revenues are shown in Exhibit A-5 (EJK-4), Schedule E-3. These exhibits are also filed in accordance with the Commission's directive in Case No. U-18238.

Q. Please summarize Consumers Energy's gas forecasting process.

A. In general, the gas forecasts are based on regression analysis, a mathematical and statistical technique that correlates the relationship between dependent variables (deliveries and customer counts) and independent variables (economics and/or weather).

Applying these relationships to expected independent variables allows one to project the corresponding movements in dependent variables. The four major classes of gas deliveries (sales plus transportation) that are forecast are residential, commercial, industrial, and interdepartmental. For each of these classes, monthly forecasts are developed on a cycle billed (billing month) basis and then adjusted to calendar month amounts using the methodology described later in my testimony. Moreover, the impact of exogenous factors – *e.g.*, incremental energy efficiency – is applied ex post.

Q. Please describe the different models used to develop the gas deliveries and customer count forecasts.

A. Regression analysis is used to develop forecast models that estimate numerical coefficients applied to weather and economic indicators to estimate future gas consumption. The regression models were evaluated against various measures to ensure that reasonable forecasts were generated. For instance, each model was reviewed to validate that the drivers were theoretically sound, model coefficients were statistically significant, and model variables explained historical and current market conditions.

Q. Please briefly describe the economic data used in the forecast process.

A. Historical and projected service sector employment and manufacturing employment are included as independent variables in the forecasting process. These indicators are from the forecasts of Michigan economic activity obtained from IHS Markit.

Q. Please briefly describe the weather data used in the forecast process.

A. The gas delivery forecasts assume normal weather based on the 15-year mean. Under this method, the daily temperature is used to calculate monthly heating degree days. The

15-year mean of the monthly heating degree days is then used to represent future expected weather impacts.

Q. What is the forecast of natural gas deliveries for the test year and five-year outlook?

A. Total calendar deliveries are projected to remain near historic weather normal levels of 303 Bcf in 2016 into 2017, based on the continued level of customer attachments. Over the next five years, total deliveries are projected to increase by 0.04% per annum to 306 Bcf by 2021. However, the growth or loss in gas deliveries is not symmetric across all classes. The total and class level gas delivery annual forecasts for 2017 – 2021 are provided in Exhibit A-15 (EJK-5), Schedule E-1. Exhibit A-15 (EJK-6), Schedule E-2 provides the 12 months ended June 2019 test year 15-year calendar weather normalized deliveries on a monthly basis, by class, in accordance with Commission filing requirements.

Q. Please explain the process used to separate the test year deliveries by rate schedule.

A. The test year forecast is allocated to the various rate schedules based on the 2016 historical deliveries. The results of the allocation process is provided in Exhibit A-15 (EJK-7), Schedule E-3 and Exhibit A-15 (EJK-8), Schedule E-4.

Q. Please describe the forecast of customer count levels in the test year and five-year outlook.

A. Total customer counts are projected to increase 1.6% from 1,749,644 in 2016 to 1,777,539 in the 12 months ended June 2019 test year. Over the next five years, the customer level is expected to increase 0.5% per annum with most of this growth occurring within the residential class. The total and class level forecasts are provided in Exhibit A-15 (EJK-9), Schedule E-5 and Exhibit A-15 (EJK-10), Schedule E-6.

Q. Please describe the process used to separate the customer forecasts by rate schedule.

A. The test year customer forecast is allocated to the various rate schedules based on the 2016 historical customer count levels. The results of the allocation process is provided in Exhibit A-15 (EJK-11), Schedule E-7.

Q. Please discuss the process used to forecast the level of consumption and customers enrolled in the Company's income assistance program.

A. The number of expected enrollments is 69,000 customers per month based on the the 12-month average of the most recent history. The average residential usage for the test year is applied to this level of customers to develop the consumption set forth in Exhibit A-15 (EJK-12), Schedule E-8.

Q. Please describe the process used to forecast the level of excess peak demand.

A. The 2017 excess peak demand consumption associated with residential multi-dwelling service, is based on the peak month consumption and customer levels in accordance with the Company's natural gas tariffs and is provided in Exhibit A-15 (EJK-13), Schedule E-9.

Q. Please provide a summary of the change in revenues, customers, and gas deliveries from the 2016 historical year to the test year.

A. Exhibit A-15 (EJK-14), Schedule E-10, provides a summary of the change in revenue, customer levels, and gas deliveries from the 2016 historical year to the 12 months ended June 2019 test year.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief	)))))	Case No. U-18424

REBUTTAL TESTIMONY

OF

ERIC J. KEATON

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2018

Q. Please state your name and business address.

A. My name is Eric J. Keaton, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Analyst in the Planning, Budget and Analysis Department.

Q. Are you the same Eric J. Keaton who filed written direct testimony in this proceeding?

A. Yes.

PART I – PURPOSE OF REBUTTAL TESTIMONY

Q. Please explain the purpose of your rebuttal testimony in this proceeding.

A. I am rebutting the portion of direct testimony filed by Sebastian Coppola on behalf of the Attorney General regarding his recommendation to increase the Company's forecasted deliveries by 2% (2.9 Bcf) for Residential and 4% (3.3 Bcf) for Commercial customers.

Q. Are you sponsoring any exhibits supporting your rebuttal testimony in this case?

A. No.

PART II – REBUTTAL OF ATTORNEY GENERAL WITNESS COPPOLA

Q. What portions of Mr. Coppola's direct testimony are you- addressing in your rebuttal?

A. I am addressing Mr. Coppola's direct testimony concerning (i) his proposal to exclude future impacts of energy efficiency savings from the forecast, and (ii) his 12 months ended June 2019 gas deliveries forecast.

Q. Do you agree with Mr. Coppola's rejection of the Company's use of energy efficiency savings in its test year forecast?

A. No. The annual incremental energy efficiency savings target was prescribed under Public Act 295 of 2008 and approved by the Michigan Public Service Commission ("MPSC" or the "Commission") in the Company's energy efficiency plans and reconciliations. Moreover, since 2010 the Company has filed annual energy efficiency reconciliation cases demonstrating its ability to exceed the prescribed target.

Q. Based on the foregoing, what is your recommendation?

A. I recommend that the Commission reject Mr. Coppola's proposal to exclude the energy efficiency savings adjustment from the forecasted gas deliveries.

Q. Please briefly describe Mr. Coppola's total gas deliveries forecast.

A. According to Exhibits AG-2 and AG-3, Mr. Coppola is proposing to increase the Company's forecasted 12 months ended June 2019 total gas deliveries by 6.2 Bcf. This increases the test year forecast to 308.4 Bcf.

Q. Do you agree with Mr. Coppola's test year total gas deliveries forecast?

A. No. The sales forecast recommended by Mr. Coppola is simply an historical look at sales trends, which is not the most accurate basis for a sales forecast.

Q. What is the most appropriate method for establishing an accurate sales forecast?

A. Forecasted sales should be based on the regression model results that have been accepted and approved by the Commission in previous rate proceedings. These results incorporate forecasted economic conditions and energy efficiency savings and are more than just a historical trend.

Q. Is this the methodology you utilized to forecast sales in this case?

A. Yes. I followed the methodology approved by the Commission in Case Nos. U-18124, U-17882, and U-17643.

Q. What factors has Mr. Coppola excluded or otherwise failed to take into account in his forecast?

A. As discussed above, Mr. Coppola excluded incremental energy efficiency savings from his forecast even though the Commission approved the target savings levels in prior cases.

Q. What other flaws do you see in the Attorney General's analysis?

A. Mr. Coppola ignores leap days entirely. The extra day in the calendar during 2016 added 1.7 Bcf to the Company's deliveries. Adjusting for that would change the results of his analysis. Additionally, the detail supplied in the Attorney General's forecast is inadequate for designing rates. An annual average rate completely ignores the volatility of customer counts by month and the fact that the average use-per-customer changes drastically by month.

Q. By utilizing historical data only in his sales forecasts, Mr. Coppola appears to be promoting the use of a new, more simplistic, methodology than that used in other cases and approved by the Commission. Do you agree with this change?

A. No. The Commission should continue to approve regression analysis as the foundation of the forecasting process.

Q. Why is the regression model approach superior to simply looking at historic trends?

A. Regression analysis is a statistical process used to predict an outcome based on the relationship between a dependent variable (deliveries, average usage, or customers) and independent variable(s) (weather and economy). For instance, a regression model is used to predict average residential monthly usage based primarily on future expectations of normal weather occurring during the test year. Each model is evaluated for reasonableness – i.e., is it theoretically logical – and statistical significance as part of the forecasting process. Regression analysis is used to develop gas delivery and customer count forecast models based on weather and economic variables. Each model is selected based on its ability to properly explain variations in historical data – i.e., how well it fits the data – along with the statistical significance of the model coefficients. Particularly, I evaluate regression model performance based on the adjusted coefficient of multiple determination (R_a^2) and Mean Absolute Percent Error ("MAPE"). In addition, I also examine the t-statistics and p-values associated with the model coefficients.

Q. Please explain the use of R_a^2 and MAPE.

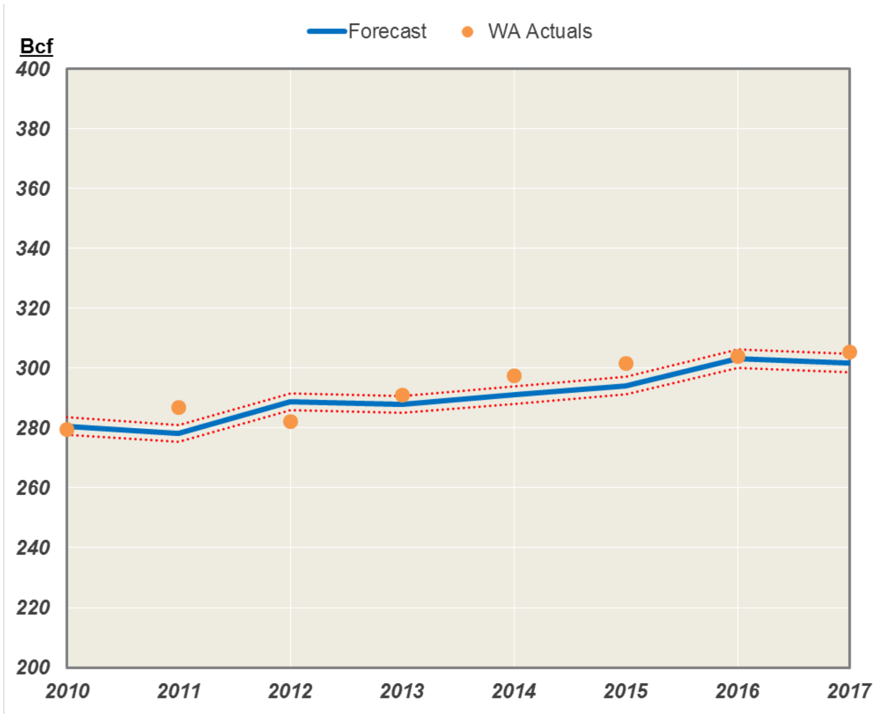
A. Both of these statistical tests are used to evaluate how well the models fit the historical data, and also provide a good indication of how well the models will perform in the forecast period. The R_a^2 measures the ability of the models to explain variations in the historical data. An R_a^2 of unity suggests that a model explains all of the variations in the data whereas an R_a^2 of zero suggests it explains none of the variations. For example, if regression models have R_a^2 values above 0.9, this suggests that at least 90% of the variation in the data is explained by the models. In most cases, the models used in the Company's forecasting process have values in excess of 0.95. In addition, I consider the MAPE values to gauge overall model performance. Essentially, the MAPE is used to measure the model errors in which smaller values suggest better model performance. MAPE values between 5% and 10% are generally considered ideal, although higher values may also be deemed acceptable based on other considerations, such as the R_a^2. The regression models used in the Company's forecasting process generally have MAPE values below 10%.

Q. Please explain the criteria used when considering the t-statistics and p-values associated with the model coefficients.

A. Regression analysis is used to develop models that minimize the variance between the actual data and estimates from the models based on the relationship between dependent and independent variables. A numerical coefficient (β) is estimated for each independent variable in the model and represents the best linear unbiased estimate for that variable's contribution toward explaining the dependent variable. The t-statistics and p-values are used to gauge the relevance of each independent variable in the model. The t-statistics and p-values measure the statistical significance of including a particular independent variable based on a probability distribution. A t-statistic above 2 and p-value below 5% for a particular β suggests the independent variable is statistically significant and is appropriate to include in the regression model. Independent variables with t-statistics below 2 and p-values above 5% suggest the variable should be excluded from the model since it does little to explain the dependent variable. In addition, I also consider the direction (positive or negative coefficient sign) and magnitude of each coefficient when determining to include or exclude variables from the models.

Q. You claim the regression model approach produces superior results. How accurate has the Company's forecast been historically?

A. The Company's forecast accuracy can be seen in the graph below. The standard deviation from 2010 through 2017 is 6 Bcf and the MAPE is only 1.6%.



Q. Do you agree with Mr. Coppola's utilization of different methodologies for forecasting residential and commercial sales versus forecasting sales for industrial customers?

A. No.

Q. What is the effect of Mr. Coppola utilizing different methodologies to forecast sales for residential and commercial customers versus industrial customers?

A. This amounts to cherry picking approaches simply to suit a predetermined outcome.

Q. Does this conclude your rebuttal testimony in this case?

A. Yes.

JUDGE SONNEBORN: Thank you, Ms. Staley.
Mr. King, you may proceed.

CROSS-EXAMINATION

BY MR. KING:
Q Good morning, Mr. Keaton.
A Good morning.
Q Joel King with the Attorney General's office.
Mr. Keaton, you prepared the Company's gas deliveries forecast included in this rate case filing, correct?
A Yes.
Q And you have been with Consumers Energy since 2004; is that correct?
A Yes.
Q And you have been involved with preparing the Company's sales forecasts since July of 2015; is that correct?
A Yes.
Q So someone else prepared the Company's sales forecasts prior to July 2015?
A Yes, correct.
Q Is your sales forecasting methodology exactly the same as the methodology used by your predecessor?
A I can't remember when the methodology was originally approved by the Commission, but the regression modeling methodology has been consistent for many years.

Q Mr. Keaton, would I be correct in assuming that in preparing your rebuttal testimony you thoroughly reviewed AG's expert witness Sebastian Coppola's direct testimony on his proposed revenue adjustment?
A On his sales adjustment?
Q Correct.
A Yes.
Q And you also reviewed and understood Exhibits AG-1 through AG-4 that support that testimony?
A Yes.
Q Can you please go to page 2 of your rebuttal testimony. Lines 1 through 10 you disagree with Mr. Coppola's exclusion of your forecasted gas sales reductions from energy efficiency programs; is that correct?
A Correct.
Q And your view is that the loss of gas sales due to energy efficiencies is based on the goals prescribed under Act 295; is that correct?
A Yes.
Q And the goal has been to achieve gas sales reductions of .75 percent annually, which has now been increased to .9 percent of sales. Is that correct?
A I'm not sure what the exact goals are. The energy waste reduction targets are set and approved in the Company's EWR filings, and I'm not part of those cases.

Q As I understand it, under Act 295 the Company is required to undertake energy efficiency programs to meet those specific energy reduction goals, correct?
A That's my understanding.
Q And as the Company completes the energy efficiency programs each year, it calculates the amount of energy reductions that would result if customers fully complied with energy efficiency programs, correct?
A I don't know how their calculation is done.
Q You're not sure how the Company's calculation is done?
A I don't know what goes into the EWR filings as I'm not part of those cases.
Q Is it correct to say that achievement of the energy efficiency goals, that you have forecasted, assumes that customers will do everything that the Company has estimated they will do in order to achieve the targeted energy reductions?

MS. STALEY: Your Honor, I have to object. He has stated a couple of times that he's not a party to the EWR cases, and to have him continue on a line of questioning to ask him about that is going to get the same response.

JUDGE SONNEBORN: Mr. King, can you respond to that objection?

MR. KING: I'll try to adjust the

question.

JUDGE SONNEBORN: Thank you.

Q (By Mr. King): Mr. Keaton, if energy efficiency reductions had materialized to levels that had been forecasted in the past, we should see those reductions in weather normalized sales per customer consistently over time. Is that your understanding?

A No. There are many factors that impact a customer's usage, especially when you're looking at a simple average use per customer over a 12-month span.

Q Could you discuss some of those impacts?

A The economy is a large factor. The number of customers in any given month. There's fluctuation through the year. More customers in a heating month would increase the average use per customer for the year, whereas more customers in a summer month would reduce the average use per customer for a year.

Q Can you please go to Exhibit AG-1. You stated previously that you're familiar with this exhibit; is that correct?

A Yes.

Q On lines 2 and 4 Mr. Coppola shows the average sales per customer from 2011 to 2019 based on information provided by the Company. Do you see that?

A Yes.

Q And you don't dispute the accuracy of these numbers in

your rebuttal testimony; is that correct?
A That is correct.
Q And on lines 3 and 5 Mr. Coppola calculates the percent change in average usage per customer from year to year, correct?
A Yes.
Q And this percent change would include any reduction in sales due to energy efficiency; is that accurate?
A Yes.
Q In 2015 and 2016 average residential sales per customer actually went up, correct?
A Yes.
Q And the same is true for commercial customers? Sorry, let me rephrase that.
In four of the six years from 2011 to 2017, for commercial customers the average usage per customer increased, correct?
A Yes.
Q Now if we look at your forecasted sales per customer for 2018, 2019, and the 12 months ended June 2019, I see percent declines that are higher than in recent years. Is that fair?
A Yes.
Q Can you please to turn page 3 of your rebuttal testimony. On lines 9 through 12 you state that Mr. Coppola's

analysis is flawed because he failed to consider leap years, correct?
A Yes.
Q Could you please turn to Exhibit AG-2. Now in this exhibit Mr. Coppola calculates a revenue impact of his proposed sales volume adjustment, correct?
A Correct.
Q And on line 1 he starts with the average gas usage during the 12 months ended 2017, and that time period does not include a leap year. Correct?
A Correct.
Q But the 2016 full calendar year, that did include a leap year, correct?
A Yes.
Q And on Exhibit AG-2, line 3, Mr. Coppola calculated that the six-year average decline rate in residential usage per customer was a .2 percent decline, correct?
A Yes.
Q Did you calculate how much that rate would change if the leap day was removed from 2016?
A I did not.
Q Can you please go to Exhibit AG-3. Now based on your review of this exhibit, Mr. Coppola followed this same approach to arrive at the revenue adjustment for commercial customers as he did for residential, correct?

A Yes.
Q And can you please go back to page 3 of your rebuttal testimony? On lines 21 to 23 you state that the regression model approach is superior to simply looking at historic trends, correct?
A Yes.
Q Now as I understand it, you made additional adjustments outside of the regression model to arrive at your forecast, correct?
A Yes.
Q Can you please go to Exhibit AG-4. The volumes that you identified in this response to the AG discovery request were mostly adjustments that you made outside of the regression model results; is that correct?
A Correct.
Q Can you please turn to page 5 of your rebuttal testimony. On lines 22 and 23 you state that the Company's forecast has a standard deviation of 6 Bcf, correct?
A Yes.
Q And can you please turn to page 1 of your rebuttal? On line 13 you identified the adjustment in gas deliveries that Mr. Coppola identified. And if I add the 2.9 Bcf and 3.3 Bcf I get 6.2. Do you agree?
A Yes.
Q Sorry to make you do math here at this point. Can you

please turn to page 4 of your direct testimony? On lines 3 to 6 you measure the accuracy of the 2016 weather adjusted actual gas deliveries of 304 Bcf against a budget forecast, correct?

A Correct.

Q And do you know how the 304 Bcf compares to the Company forecast for 2016 in rate Case U-17882?

A I don't have that number on me right now.

Q Do you have your discovery response to -- Well, can I refresh your recollection?

MR. KING: May I approach?

JUDGE SONNEBORN: You may.

(Document shown to counsel and handed to the witness.)

Q (By Mr. King): Do you recognize this?

A Yes.

Q You prepared this response?

A Yes.

Q And do you see at the top where it mentions that the Company forecasted gas deliveries for 2016 of 301.3 Bcf?

A Yes.

Q So when you compare that to the 304 Bcf, that was the weather adjusted actual gas deliveries in 2016, the forecast for the projected test year was about three billion cubic feet below the actual weather adjusted

volume. Is that accurate?
A Yes.
Q Another question. Based on your understanding of your own forecasts, do you know if the energy efficiency goals that you forecasted for the test year assumed that customers will do everything that the Company has estimated they would do to achieve the targeted energy reductions?
A I'm not in the EWR filing, so I don't know how those numbers are derived.

MR. KING: I have no further questions.

JUDGE SONNEBORN: Thank you, Mr. King. Ms. Staley, do you have any redirect?

MS. STALEY: May I take a moment?

JUDGE SONNEBORN: Yes, you may.

(Brief in-place recess.)

MS. STALEY: Your Honor, I have no additional direct for this witness.

JUDGE SONNEBORN: All right. Thank you, Ms. Staley. Mr. Keaton, you may be excused.

THE WITNESS: Thank you.

(The witness was excused.)

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JUDGE SONNEBORN: Are there any objections to the admission of Mr. Keaton's exhibits, A-5 with the schedules as described at the outset by Ms. Staley, as well as Exhibits A-15 with the schedules as described by Ms. Staley? Hearing no objection, those exhibits are admitted.

MS. STALEY: Thank you, your Honor.

JUDGE SONNEBORN: You're welcome. That does conclude the cross-examination schedule set for today. Does the Company wish to bind in the testimony of its other witnesses?

MS. UITVLUGT: Yes, your Honor, if I may.

JUDGE SONNEBORN: You may.

MS. UITVLUGT: Do you prefer if I go witness by witness and --

JUDGE SONNEBORN: It gets a little dicey for me when --

MS. UITVLUGT: I'll go one at a time, your Honor.

JUDGE SONNEBORN: Thank you.

MR. KESKEY: Your Honor, I wish to be excused as I don't believe I have to be here to hear the binding in of testimony of which witnesses I have waived and other parties have waived.

JUDGE SONNEBORN: Certainly. Thank you very much, Mr. Keskey. You may be excused. And I believe I have all of the witnesses you intend to cross-examine tomorrow. If your plans change, please let me know by e-mail.

MR. KESKEY: Yes, I will, your Honor.

JUDGE SONNEBORN: Thank you.

MR. KESKEY: Thank you.

MS. UITVLUGT: Thank you, your Honor. By agreement of the parties, at this time Consumers Energy would bind in the direct testimony of Michael A. Torrey, which consists of a cover page and 32 pages of questions and answers. Additionally I would ask that we could bind in the rebuttal testimony of Mr. Torrey, which consists of a cover page and eleven pages of questions and answers. Mar Torrey did not sponsor any exhibits.

JUDGE SONNEBORN: Thank you. Are there any objections to binding in the direct and rebuttal testimony of Michael A. Torrey? Hearing no objection, that testimony will be bound into the record.

MS. UITVLUGT: Thank you, your Honor.

(Testimony bound in.)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
	)	

DIRECT TESTIMONY

OF

MICHAEL A. TORREY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2017

MICHAEL A. TORREY
DIRECT TESTIMONY

Q. Please state your name and business address.

A. My name is Michael A. Torrey, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as its Vice President, Rates and Regulation.

Q. Please describe your educational background.

A. I graduated from the University of Michigan-Flint in 1982 with a Bachelor of Business Administration in Accounting degree and in 1992 earned a Master of Business Administration degree from Western Michigan University, majoring in Finance. I have also completed several courses and seminars in utility accounting, economics, finance, and ratemaking.

Q. Please describe your professional experience.

A. In May 1983, I joined Consumers Energy's Nuclear Operations Department as a Graduate Accountant assigned to the Controllers Department at the Palisades Plant. I progressed through several levels of increasing responsibility during my Palisades Plant assignment, achieving the position of Senior Accounting Analyst in April 1993. In July 1998, I was appointed Director of Revenue Requirements, Cost Analysis and Planning in the Company's Rates Department. In December 2006, I was promoted to Executive Director-Rates. In March 2015, my responsibilities were expanded to include Regulatory Affairs. In July 2016, I was promoted to Vice President, Rates and Regulation.

Q. What are your responsibilities as Vice President, Rates and Regulation for Consumers Energy?

A. I am responsible for ratemaking and regulatory activities at Consumers Energy which include revenue requirements, cost allocation, rate design, tariff administration, and regulatory affairs.

Q. Are you a member of any professional organizations?

A. Yes. I am a member of the Institute of Management Accountants, a worldwide association of accountants and financial professionals, and Beta Gamma Sigma, the honor society of the Association to Advance Collegiate Schools of Business, a business school accreditation organization.

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

A. Yes. I have sponsored testimony in the following Consumers Energy cases:

U-12891	Electric Restructuring Implementation Costs;
U-13000	Gas General Rate Case;
U-13380	Stranded Cost;
U-13720	Stranded Cost;
U-13715	Securitization;
U-14098	Stranded Cost;
U-14274	Power Supply Cost Recovery ("PSCR") Plan;
U-14347	Electric General Rate Case;
U-14992	Palisades Sale;
U-14981	Midland Cogeneration Venture Limited Partnership Sale;

U-15290	Balanced Energy Initiative;
U-15415	PSCR Plan;
U-15611	Big Rock Decommissioning Reconciliation;
U-16191	Electric General Rate Case;
U-16861	Department of Energy Litigation Settlement Proceeds;
U-17473	Power Plant Securitization;
U-17990	Electric General Rate Case;
U-18124	Gas General Rate Case; and
U-18322	Electric General Rate Case.

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

A. The purpose of my direct testimony is to provide an overview of the Company's gas general rate filing, including a summary of the key drivers, and a brief discussion of our recent performance and the current business environment. I will summarize the customer value and benefits related to our proposals presented in this proceeding including safety, reliability, value, and sustainability. Finally, I will address, from a policy perspective, certain issues detailed in the direct testimony and exhibits of several other Company witnesses.

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

A. No, I am not.

Q. How is your testimony organized?

A. My testimony is organized as follows:

I. Customer Value
II. Key Drivers
III. Customer Impacts

IV. Adjustment Mechanisms
V. Summary

I. CUSTOMER VALUE

Q. How does customer value impact the Company's decisions?

A. Our day-to-day focus is to enhance and improve service to our customers and to care for the communities where we live and work. That means ensuring the safety of both the public and our employees and supplying reliable, affordable energy to power businesses and warm homes. It also means acting as a solid corporate citizen and committing not only our financial resources, but also the time and talents of our employees, to enhance the quality of life for those we serve. Our core commitment to serving customers, communities, and Michigan has guided our decisions for the past 130 years.

Q. What are some of the customer benefits that will be enhanced by the proposals in this proceeding?

A. Customer benefits may be considered in four categories:

1. Safety – First and foremost, customers expect gas to be delivered safely to their homes and businesses. Inspection and replacement of pipe ensures that the natural gas infrastructure will continue to deliver gas safely to our customers for years to come. Customers also expect to be informed about what is being done to ensure system safety and how they can be best prepared to handle any safety related issue;

2. Reliability – Customers expect gas to be available for their use whenever they need it regardless of weather conditions. They expect the Company to make the investments in pipelines, compressor stations, storage fields, and other infrastructure necessary to ensure reliable delivery. Customers also expect the Company to keep them informed about work to improve all aspects of gas delivery;

3. Value – Customers consider both the price they pay and the service received when assessing value. The focus is to keep bills affordable, and prices stable while service is maintained or improved, where necessary. Investments that help reduce Operation and Maintenance ("O&M") costs and/or improve the Company's ability to access and store gas supply help maintain affordability and price stability. In regards to service, the Company leverages customer

data from J.D. Power and other sources to ensure our proposals provide value for our customers. This includes investments in technology, metering, customer service, reliability, safety, and communications; and

4. Corporate Citizenship – Customers expect the Company to do business in a socially responsible manner. This means taking actions to care for Michigan's environment, encouraging economic opportunities, and enhancing the quality of life in the communities we serve. Consumers Energy is committed to operating sustainably and working to leave our Company, our State, and the world better than we found them. Since the 1990s, we have been working to protect Michigan's environment by cleaning up sites of 23 former manufactured gas plants throughout the state. Our pipe replacement programs work to mitigate gas loss across our system and reduce greenhouse gas emissions. We have goals to reduce water use, encourage recycling to reduce landfill space, and promote sustainable business practices among the companies with which we work. We are working with companies to help expand their operations and attract new employers to the State. Finally, more than 4,000 employees volunteered across Michigan in 2016 to support education, community, civic, and cultural development as well as social services and the environment.

Q. How does the Company gather customer feedback?

A. We have a number of methods for listening to our customers. Informal methods include feedback from customer service representatives and business customer account managers who interact with customers on a daily basis. We also analyze customer data from informal and formal complaints, and feedback from customers who participate in various Company product and service offerings. Additionally, we conduct primary customer research through methods such as focus groups and quantitative survey research.

Q. Does the Company use any external benchmarks of customer satisfaction?

A. Yes. The primary external benchmark we use is J.D. Power. We set an aggressive breakthrough goal to achieve first quartile rankings in all four J.D. Power Utility Customer Satisfaction Studies by 2017.

Q. What is J.D. Power?

A. J.D. Power is a global market research company. J.D. Power analyzes the many aspects of customer experiences in a variety of industries to identify the multiple drivers of customer experience and to measure and understand the impact of those drivers. It conducts research used by companies worldwide to improve quality and customer satisfaction.

Q. Why does Consumers Energy use J.D. Power rankings as a benchmark of customer satisfaction?

A. J.D. Power is a well-respected, independent firm that provides broad and deep data sets on the utility customer experience.

Q. What kinds of data are in these surveys?

A. The gas customer surveys measure approximately 35 service attributes across six categories or "drivers" of customer satisfaction: safety and reliability, pricing, billing and payment, communications, corporate citizenship, and customer service, which include phone, online, and in-person interactions. This data provides a comprehensive understanding of the relative contribution each attribute and driver has on overall customer satisfaction, Consumers Energy's performance on each attribute and driver, and how our performance compares to that of other utilities for benchmarking purposes. Utilization of J.D. Power survey results provides a data-driven, analytical basis for making investment decisions and process improvements to increase value for customers.

Q. How does the Company approach the analysis of all this data?

A. We use the J.D. Power customer feedback as a guide for improvement. We identify the relative importance of each attribute and driver and compare our performance to that of our benchmark companies. These benchmark companies are those utilities within our region that are ranked in the top quartile, or ranked above Consumers Energy if we, ourselves, are top quartile in our region. This allows us to prioritize activities based on their relative importance to overall satisfaction and our comparative level of performance. We use the feedback from other sources to generate and assess ideas for how performance can be improved.

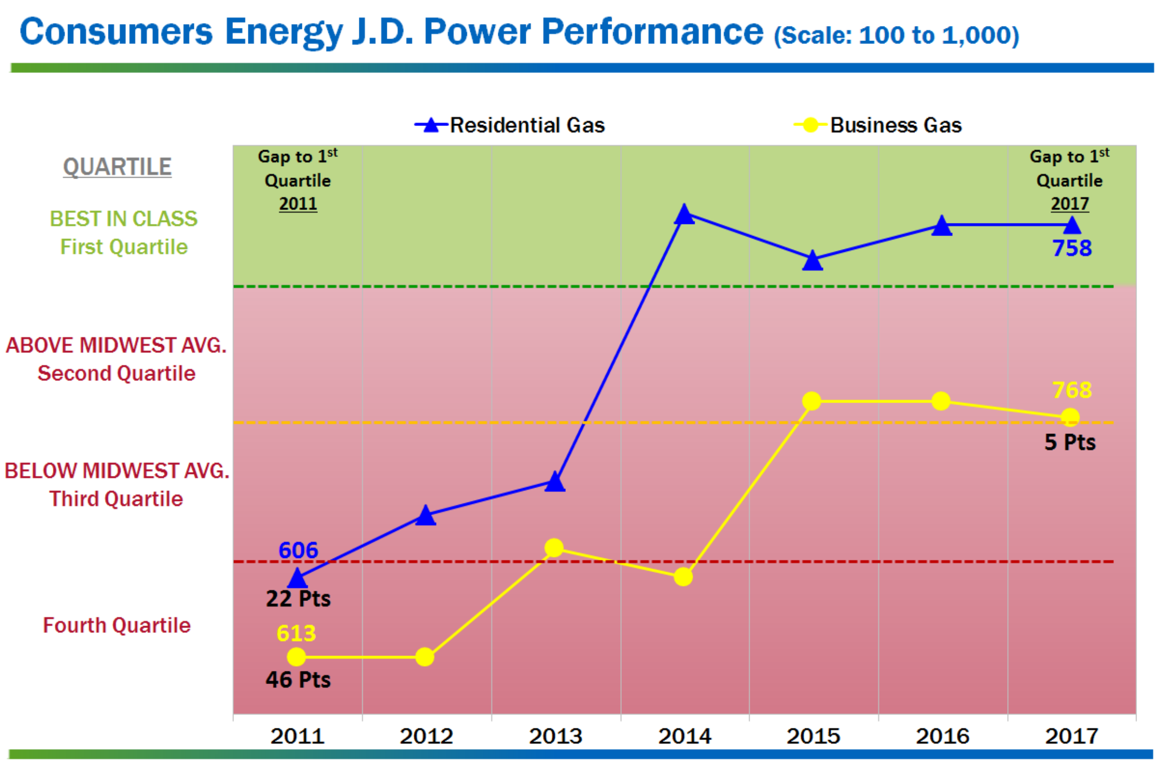
Q. After the Company has identified customer experience improvement opportunities, what does the Company do with this information?

A. Employee teams are charged with developing and implementing measures designed to improve our performance and meet customer expectations. Such measures include implementing communication strategies, instituting policy changes, altering processes to improve service, and enhancing technology to provide new programs and services. With the rich data set that J.D. Power provides, there is no longer the need to speculate about what truly drives customer satisfaction. This independent assessment provides a data-driven, analytical basis for making investment decisions and process improvements that positively impact customer satisfaction. Thus, decisions on where to invest Company resources are driven by what provides the greatest value to our customers, based not upon our opinions or hypotheses, but rather through direct customer feedback.

Q. Is the Company seeing positive movement in the J.D. Power surveys from this approach?

A. Yes. In the residential gas customer survey, the Company achieved a 1st quartile ranking in 2014, maintained 1st quartile performance in 2015 and 2016. In the 2017 survey, the Company remains in the 1st quartile by being ranked 3rd of 18 for overall customer satisfaction in the Midwest large utilities region. In the business gas customer survey, the

Company achieved a 2nd quartile ranking in 2015 and maintained that ranking on all subsequent surveys. Even though the Company has not achieved 1st quartile performance on the business gas survey, our performance has significantly improved compared to where we were in 2011 when we began utilizing J.D. Power data. In 2011, the Company's gap to the 1st quartile was 46 points. By 2014, that gap was reduced by more than 50% to 21 points. Since 2014, that gap has continued to decline. Even though we ranked in the 2nd quartile on the most recent survey, our gap to the 1st quartile has been reduced to just five points.



Q. Has the Company been recognized through any other customer feedback channels?

A. In June 2017, the Company was named as a "Most Trusted Brand," in an independent national survey and was ranked 4th in the nation among providers of electricity and natural gas among residential customers. The results were released by Cogent Reports and are based on residential customer surveys. Forty-four energy utilities nationally were named as "Most Trusted Brands" and the Company is proud to be recognized as a part of this group.

II. Key Drivers

Q. Please summarize the key drivers of the rate relief requested.

A. The key drivers are summarized in Table 1 below:

Table 1

($ Millions)

Infrastructure Investment and Related Costs	$158
Cost of Capital	10
Operating Expenses	(2)
Sales/Revenue	8
MGP/Working Capital	4
Total Request	$178

Q. Please provide a general description of the key financial and operational items that comprise the amount of rate relief requested in this filing.

A. The $178 million in rate relief requested in this filing is driven by the need to serve our customers and reflects the Company's continued investment in Michigan. Consumers Energy is committed to customer value and continues to make significant investments in the infrastructure necessary to provide safe and reliable service to our customers and comply with federal and state requirements. Approximately $158 million, or 89% of this request, is comprised of investment-related costs. This ongoing investment is part of Consumers Energy's capital investment plan over the next five years to maintain and improve utility infrastructure and ensure that our customers receive the service and value that they expect from the Company.

Q. How does the rate relief requested in this case compare to the rate relief approved in Case No. U-18124 on July 31, 2017?

A. The Company's request and the rate relief approved in Case No. U-18124 was primarily driven by new infrastructure investment. Case No. U-18124 utilized a 12 months ended December 2017 test year. The projected capital spending utilized by the Commission to establish rates was $577 million after adjustments. The $577 million was then appropriately included in rate base at an average of $289 million. In this proceeding, the proposed capital spending in the bridge year 2017 is $774 million. The difference between the Company's proposed spending in 2017 in this proceeding and the amount in current rates is $486 million. The revenue requirement related to the $486 million is approximately $65 million, more than 1/3 of the Company's request.

Q. Why is Consumers Energy making significant gas investments?

A. These investments in our gas system allow the Company to maintain and enhance its access to diverse natural gas supply basins, and to maximize the Company's utilization of its vast underground storage fields to purchase natural gas when prices have traditionally been lower and help protect customers against pricing volatility. Consumers Energy operates approximately 29,700 miles of distribution and transmission pipelines to serve our 1.8 million natural gas customers. The Company also operates seven compressor stations and has 15 storage fields. System investments are planned to ensure that continuous and reliable service is provided to our customers as their peak demands continue to change or grow.

Q. Please describe the more significant gas investments included in the Company's rate case filing.

A. Significant natural gas investments include the Enhanced Infrastructure Replacement Program ("EIRP"), New Business Program, Compression and Transmission Replacement Programs, Pipeline Integrity Program, Asset Relocation Program, and Technology Programs. The investments in natural gas infrastructure can be grouped into three main categories: system reliability, compliance, and enhanced technology.

System Reliability

The ongoing EIRP is focused significantly on replacement of distribution pipe such as cast iron, bare steel, and threaded and coupled mains. Replacement of this aging infrastructure will improve safety and increase reliability of gas delivery to our customers. This program was spurred in part by growing industry and regulatory concerns with vintage gas distribution and transmission piping systems. In addition to improving safety and reliability, the elimination of virtually all of the existing cast iron main will enable portions of the system to operate at higher pressures while lowering gas losses and reducing greenhouse emissions. Reduced line losses translates to lower operating expenses which will directly benefit our customers as these significant infrastructure improvements are completed and placed in service. By replacing aging materials that have the potential for increased leak rates, the Company is reducing the future methane emissions into the atmosphere. Consumers Energy recently joined nearly 40 natural gas providers from across the country in the United States Environmental Protection Agency's Natural Gas STAR Methane Challenge Program. The collective goal is simple: to reduce methane, or greenhouse gas, emissions. The Company's involvement in this national program reflects the work being done to make our natural gas system safer and better for the environment. Through December 31, 2016, the EIRP has resulted in replacement of 347 miles of high risk pipe including 120 miles of cast iron and over 33,000 services replaced and retired.

The Commission's July 31, 2017 Order in Case No. U-18124 included a discussion regarding the inclusion of Vintage Service Replacements ("VSR") in the EIRP. The Company believes vintage services were approved for inclusion in EIRP, however, the necessary funding for the program was not included within the EIRP scope. The Company's filing in this case includes a proposal to commence a VSR Program that will mirror the EIRP and accompany the Company's annual EIRP reports. The VSR Program began in 2017, with the goal to programmatically replace all copper and bare steel service types not replaced under other programs. Historically, the Company replaces approximately 3,500 vintage services per year, and under the VSR will replace 6,300 vintage services in 2017. Beginning in 2018, the Company will replace 10,500 vintage services and 12,500 in 2019. These planned replacements are in addition to the replacement of 3,500 historically completed within other programs.

The EIRP and VSR, along with the other replacement programs described in this direct testimony, are an integral part of achieving that goal. In responding to legislative and regulatory changes that are expected to mandate an industry-wide approach to vintage piping replacement, the Company has hired approximately 500 seasonal skilled and trained employees to work primarily on the EIRP thereby contributing to Michigan's overall economic recovery. Additionally, the Company has placed an emphasis on providing jobs for military veterans through outreach efforts.

The New Business Program consists of the capital cost of adding new residential, commercial, and industrial customers. The program costs include the cost of installing mains and services and the cost of meters to service new customers. These costs are partially offset by customer contributions. The Company's test year projection includes a large agri-business customer in 2018, which will require a main extension and citygate installation to serve the customer load, and a main extension to serve a new natural gas fueled power plant. The Company expects to install service to approximately 8,700 customers in 2018 and another 9,100 customers in 2019.

The Compression and Transmission Replacement Programs include compressor rebuilds and other reliability-related projects, such as the St. Clair and Freedom compressor station upgrades, to ensure reliability of gas delivery to our customers and to take advantage of market opportunities to purchase low-cost shale gas at various system receipt points. The replacement and rebuild of compression units have been proven as a successful means to ensure delivery of gas to our customers in some of the coldest of winters. The Transmission Replacement Program includes expenditures for the Transmission Enhancements for Deliverability-Integrity ("TED-I"). TED-I projects are focused on maintaining deliverability and integrity, and improving the ability to control gas flows. Projects include replacing transmission pipeline segments that contain higher-risk type pipe to ensure the integrity and safe operation of the natural gas system. This will provide important enhancements to the system so the Company can continue to ensure customer and public safety. Additionally, it will allow for increased natural gas capacity within Michigan for economic growth and access to lower-cost natural gas. Major projects included in this filing are activities related to replacements for segments of Line 2800 (“Saginaw Trail”) and Line 100A (“Mid-Michigan”). Also included are activities leading to the retirement of Line 3100, which is now part of the South Oakland Macomb Network Project. In addition to the retirement of Line 3100, this project will rebuild and enhance citygate facilities and pipe installations in Oakland and Macomb counties. These enhancements will be more economical than replacement of Line 3100 and will improve reliability to customers in the greater Metro Detroit area in the case of an unplanned outage during peak day conditions. The citygate stations will also include filtration for improved gas quality and emergency shutoff valves and remote monitoring systems for improved public safety. Also included is the installation of remote closure valves and pressure-limiting devices to control pressure and flows.

The Company has included additional details to provide justification surrounding these projects in the testimony of Company witnesses Mary P. Palkovich and Christopher T. Fultz.

Q. With the Company’s focus on system reliability, programs such as the EIRP, VSR, and TED-I are of significant importance. Is the Company proposing any ratemaking treatment for EIRP, VSR, and TED-I spending during the projected test year?

A. Yes. As discussed by Company witness Palkovich, the Company proposes that the EIRP, VSR, and TED-I spending presented in her direct testimony be afforded the same ratemaking treatment approved for the EIRP for the past several years. Program plans and expenditures would be subject to periodic reviews with the MPSC Staff, with periodic reporting, and reconciliation of test year spending. The costs related to any underspend compared to amounts approved for recovery in customer rates during the test year would be subject to refund.

Compliance

The Pipeline Integrity Program includes projects that are required to comply with federal and state pipeline safety regulations and mandates. The program expenditures change from year to year because of work scope variations, which are driven by risk assessments and threat evaluation. A priority-based inspection schedule and the expected remediation costs resulting from the findings of these inspections are included in this program, which complies with the federal Pipeline Hazardous Materials and Safety Administration requirements. Through the use of inline inspection tools, Consumers Energy is able to identify and remediate various anomalies related to corrosion, seam defects, and other defects in the pipelines reducing risk on the transmission system. This program ensures safe and reliable delivery of gas to our customers.

The Asset Relocation Program includes gas transmission and distribution infrastructure replacement projects which are required due to civic improvement activities initiated by federal, state, or local governmental units. Some relocations are from individual customers' requests and some are due to relocation of facilities that our Company has initiated. Civic improvement includes projects to replace or improve aging public infrastructure such as roadways, bridges, sewer lines, water lines, and drainage ditches. If our system is in the public right-of-way, and we have to move it to eliminate interference, it is done at our expense in accordance with the law. The Company works with the governmental units involved to coordinate work and negotiate design criteria wherever possible to minimize our expense. Due to the economic activity the state is experiencing, and the aging municipal infrastructure, civic project expenditures have been increasing dramatically. From 2011 to 2016, the Company has seen an increase of

109% in footage of main replaced. There has also been an increase of 151% in the number of services replaced under the Asset Relocation Program over the same timeframe.

Enhanced Technology

The Company plans to complete installation of 662,000 gas Advanced Metering Infrastructure ("AMI") modules during 2017. Similar to other utilities that have already implemented gas AMI, Consumers Energy customers will realize benefits related to reduced meter reading cost, improved billing accuracy as a result of higher actual meter read rates, reductions in energy theft resulting from the analysis of meter tamper alerts, and energy consumption patterns and gas conservation associated with the availability of web portal displays and consumption alerts. These benefits add convenience, improve gas service, and increase customer satisfaction for Consumers Energy customers.

Furthermore, the Company is currently investing in the gas-only service territory Automated Meter Reading ("AMR") Program for our approximately 1.1 million gas-only customers that are not part of Consumers Energy's AMI Program. Similar to other utilities that have already implemented gas AMR, Consumers Energy customers will realize multiple benefits. These include reduced meter reading expense, improvements in billing accuracy as a result of higher actual meter read rates, and a reduced number of rereads and rebills due to the improved read rates. Other benefits include reductions in energy theft resulting from the analysis of meter tamper alerts. It will also reduce employee safety incidents from dog bites, slips, trips, and falls. This program will improve operational efficiencies and enhance customer value for all gas customers. Plans for the gas-only service territory AMR Program were accelerated in 2015, which will significantly reduce the number of estimated meter reads and associated billing issues. Project completion is expected in 2019.

Additional investments in technology are being made to further enhance the Company's interaction with customers and improve customer satisfaction. As an example, the Digital Customer Website Replacement release 2 was implemented in 2017 and provides significant new capabilities for payment transactions. The new payment interface introduces many more payment options, including: payment by any method, paying a higher amount than is due, allowing customers to see their balance change immediately upon making a payment, making a payment on another customer's account, making a payment without logging into the Company's website, and allowing phone agents to take payments. The Company is also implementing the SAP Platform Modernization Project. The infrastructure that supports the Company's SAP applications (including Customer Relationship Management, the primary application used by the Company's Customer Service Representatives), which has been operating beyond its useful life. To sustain the level of service our customers expect, and overall business operations, the Company is building a new SAP hardware platform. The project is expected to increase SAP application availability and performance for customer service representatives and all SAP users.

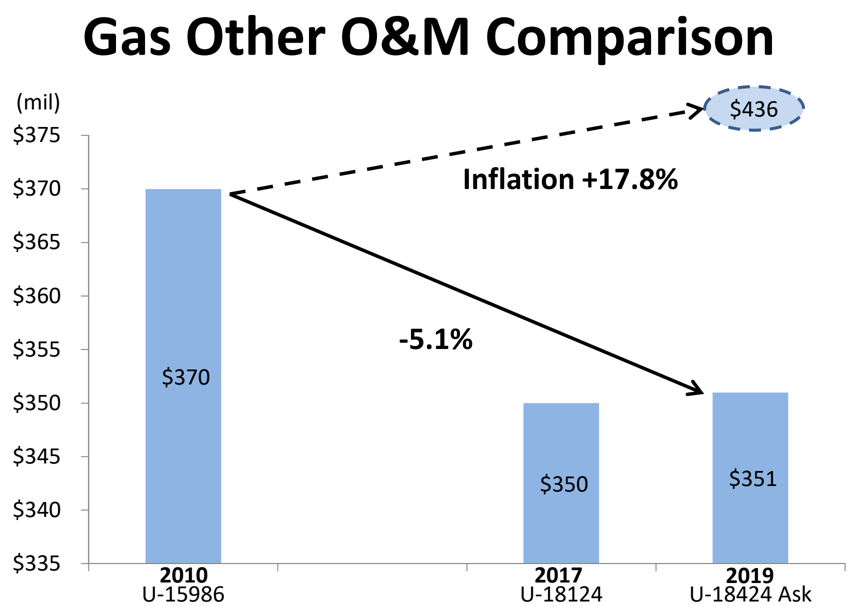
The investments from these programs and additional programs are more fully described in the testimony of Company witnesses Palkovich, Fultz, Danielle M. Hill, Christopher J. Varvatos, and Lisa M. DeLacy.

Q. Are there operational successes you would like to highlight at this time?

A. Yes, there are. In recent colder-than-normal winters (2013-2014 and 2014-2015), the Company surpassed previous all-time records for gas delivery during peak periods. Gas withdrawals for the winter of 2014-2015 were nearly 114 Bcf, one of the largest withdrawals experienced in the past decade. The Company's expanded storage system, the largest in the nation among regulated natural gas utilities, has the capacity to meet up to 80% of customer needs during colder-than-normal peak weather events. In fact, on February 20, 2015 three gas send out records were broken: Peak Hour Total System Throughput at 159,517 Mcf; Peak 24-Hour Sendout to Distribution Citygates at 2,906 MMcf; and Peak Hour Sendout to Distribution Citygates at 146,767 Mcf. System investments in pipelines and regulation facilities ensured continuous reliable service to our customers in these extreme demand weather conditions. This performance underscores that our long-term infrastructure investment strategy to expand and strengthen our gas distribution, transmission, compression, and storage system is providing direct benefit for our customers.

Q. How have operating expenses changed from prior rate levels?

A. Total operating expenses, consisting of Other O&M, Lost and Unaccounted For and Company Use gas expense are projected to decrease in the 12 months ending June 30, 2019 by $2 million from the level used by the Commission to establish customer rates for 2017 in Case No. U-18124. As shown in the chart below, the $351 million in Other O&M proposed in the 2019 test year is in line with the $350 million in Other O&M included in current rates for 2017 and more than 5% below the level used to establish customer rates in 2010. More significant is that if Other O&M increased at the rate of consumer price inflation it would have increased by over 17% to $436 million, or $85 million more than is proposed in this proceeding.



Q. What actions reflected in this proceeding are expected to reduce operating expenses and help to mitigate costs that are expected to increase?

A. Significant decreases in operating expenses are expected in several areas: Company witness Herbert B. Kops discusses the many actions the Company continues to take to control health care costs including sharing expected cost increases with employees through higher premiums, plan changes, increased deductibles and copayments, increases to out-of-pocket maximums, and increased focus on wellness. The Company also plans a change to Medicare retirees' supplemental coverage effective in January 2019. Company witness DeLacy identifies the benefits of meter technology from AMI and AMR programs that reduce meter reading expense, improve billing accuracy, reduce customer contacts, and reduce theft. Company witness Julio H. Morales describes the enhancements to the Company's website reducing the cost of customer contacts when compared to telephone interactions. Mr. Morales also discusses the Appliance Service Plan ("ASP") Program and indicates that revenues from the ASP continue to offset significantly more than the costs of the ASP Program. Company witness R. Michael Stuart discusses the Company's employee safety performance where incidents have decreased and the resulting reduction in lost work days and medical expenses accrue to the benefit of customers.

Q. What other actions is the Company taking to reduce operating costs and keep customer bills affordable?

A. The Company has adopted a lean operating system, the CE Way. The CE Way is focused on completing work safely and correctly the first time, and minimizing rework and eliminating waste, while delivering services on time. Initial efforts have been focused on educating employees in four basic lean techniques referred to as the basic plays: problem solving, standard work, operating reviews, and visual management.

Q. What initial results has the CE Way delivered?

A. The CE Way has results in many early "wins":

(i) Fueling Pilot – Better utilization of highly skilled employees by fueling trucks during off-peak hours with lesser skilled employees. This impacts 450 crews with multiple workers per crew and has the statewide potential to save 100,000 hours and $3 million per year;

(ii) Software Licensing – Software licenses that are unused for 90 days are released for use by others. This avoids new license purchases year over year and is projected to yield $500,000 savings in 2017; and

(iii) Gas Leak Response – Building in logic to the questions we ask customers allows the Company to send the right resources for the situation with potential savings of $200,000 in 2017.

Q. Does the Company's request exclude increased costs associated with estimated meter reads, as directed by the Commission in its June 9, 2016 Order in Case No. U-18002?

A. Yes. The Company has appropriately reflected these impacts. Test year O&M expenses have been reduced by $1,616 to reflect costs that the Company estimates it incurred for good faith credits and amends payments issued to customers due to billing issues related to consecutive estimated meter reads. This adjustment is explained by Company witness Palkovich.

Consumers Energy recognizes that our meter reading performance and resulting estimated bills have not reflected the standards of service that our customers expect and deserve. The Company is committed to ensuring that all customers receive accurate bills based on actual meter reads on a consistent basis. Meter read rates have consistently been in the mid to upper 90% range since March 2016.

Q. Does the Company evaluate major capital projects and O&M expenses on an ongoing basis?

A. Yes. The Company continually evaluates and adjusts its planning for a variety of factors that include: sales and revenue expectations and results; infrastructure investments and the cost of capital; O&M expense expectations and results; and the impact of a variety of items that occur throughout time (changes in environmental laws and requirements, Commission orders, weather, customer demands, commodity prices, financing costs, changes in economic expectations, etc.). In any one period of time the Company's capital investments and its O&M expenses may vary from what was expected in a prior period. While the Company understands and plans for this ever-changing environment, Company witnesses have provided highly-detailed and thorough support for both capital expenditures and O&M expenses.

The individual witnesses addressing capital and O&M expenditures in this case explain the reasons for these expenditures, and these expenditure levels undergo rigorous management review before they are submitted. While the Company must retain the flexibility to react to changing conditions, the proposed expenditure levels included in this case reflect the Company's commitment to meet its legal responsibilities and improve service reliability and quality for customers. Further evidence of the Company's commitment to make the infrastructure investments necessary to improve service result in the improvements in the customer service metrics noted throughout the testimony filed in this case.

In response to the Commission's July 31, 2017 Order in Case No. U-18124, Company witnesses have provided detailed analysis with evidentiary support regarding the reasonable level of cost recovery in this proceeding. More specifically, Company witnesses Palkovich, Fultz, Hill, and Varvatos provide detailed analysis and extensive explanation for transmission, storage, distribution, and technology capital expenditures, and O&M expense; and Company witness DeLacy provides a substantial amount of analysis and support in her testimony for Consumers Energy's AMI and AMR Programs. Additionally, where applicable, these witnesses have included exhibits which provide a breakdown of expenditures by project into greater detail, including: Contractor, Labor, Materials, Business Expenses, Contingency, and Other.

Q. Did the Company include contingency costs in this filing?

A. Yes, Company witnesses who expect to incur contingency costs for projects appropriately disclosed the amount of contingency costs on a separate line on their corresponding exhibits so it is easy for all parties to identify the amount of contingency costs included in this case. Contingency is a legitimate and forecastable cost of a project, a recognized and accepted practice, and a real expense which is incurred. Company witness Fultz provides a comprehensive explanation of the Company's project-management approach, including the active and thoughtful role in establishing risk-based contingency in projects and an ongoing focus on identifying and acting on cost avoidance opportunities during the entirety of the project life cycle.

Q. Does the Company anticipate the need to flex spending between programs in the test year?

A. Yes, the Company has provided their best estimate at this time as to the total cost expected to be spent on each program. However, when the actual dollars are spent in the test year, the Company needs the flexibility to be able to adjust the spending between programs due to unforeseen circumstances arising. For example, a significant storm may arise in a given year requiring the Company to spend additional funds on storm restoration efforts to ensure the customers' power is restored quickly. Due to this circumstance, the Company would then need to adjust spending in another program to compensate for this additional spending. It is not possible for the Company to anticipate every event or circumstance which will arise multiple years from now. Therefore, the need to have flexible spending between programs is prudent and in the best interest of the customer.

Q. What other key drivers make up the approximately $178 million in rate relief request?

A. We are expecting an increase of $10 million related to our projected financing costs, which reflects a higher return on equity net of reduced debt costs as proposed by Company witness Srikanth Maddipati. We also expect a decrease in revenues of $8 million. While rate revenues are relatively flat, this reduction is primarily related to a reduction in miscellaneous revenues from programs and services.

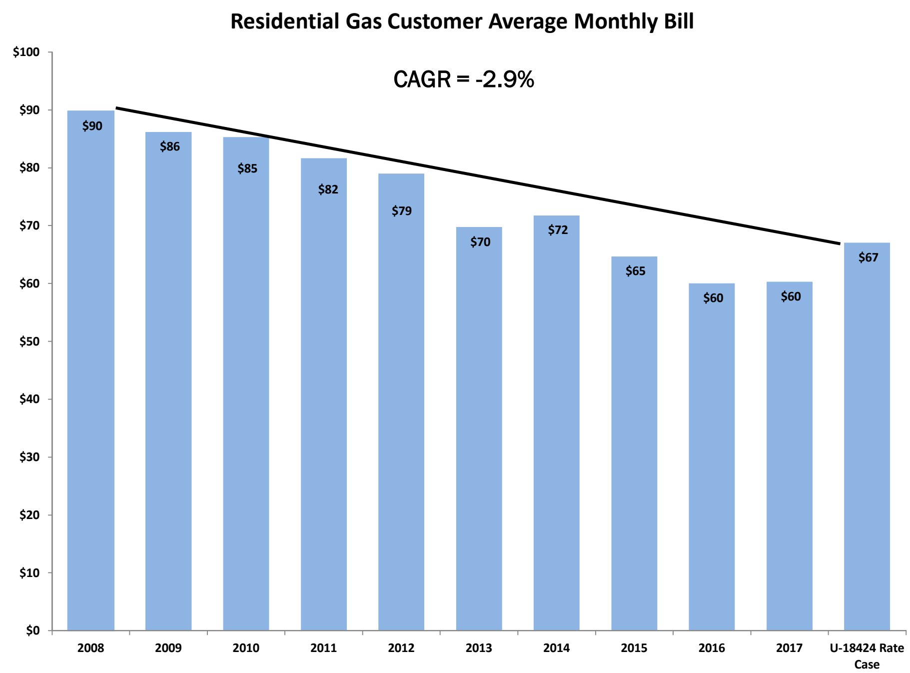
Q In its July 31, 2017 Order in Case No. U-18238, the Commission established new standard rate case filing forms and instructions. Please describe how the Company's filing in this case complies with these requirements.

A. The new filing requirements addressed the 10-month timeframe for general rate cases under the 2016 energy law, a 21-day spacing between certain filings, and updates to the rate case standard filing requirements. Part I filing instructions were updated to reflect new pre-filing requirements which the Company has complied with. This includes the Company-filed "Filing Announcement" 30 calendar days prior to this rate case filing. Also, a "Rate Case Summary" was filed 3 days prior to the official rate case filing, providing the summary level information required by the Commission. Part II filing requirements were unchanged. Part III filing requirements had the largest modifications. A one-year period was given for compliance with most of the Part III filing requirements. However, in an effort to be responsive, the Company has included in this case the information available related to these requirements.

III. Customer Impacts

Q. What is the expected impact of the rate relief requested in this proceeding on a typical residential customer's bill?

A. The chart below illustrates the weather-normalized residential monthly bill from 2010 through 2016, reflecting the rates customers paid during those years, and provides a forecast for the 2017 calendar year as well as the 12 months ending June 30, 2019 test year. As shown in the chart, the Company anticipates that the average monthly residential bill for the 12 months ending June 30, 2019 test year, which includes the total proposed increase requested in this filing, represents an 11% increase over the forecasted 2017 residential monthly bill. However, even with this increase, the compounded annual decrease in the monthly bill is expected to be about 3% when compared to 2008. It is our expectation that the June 30, 2019 test year average monthly residential bill, for customers who use Consumers Energy's gas, will cost approximately $2.20 a day for the average residential customer. When comparing to current average residential customers rates, the increase is approximately $0.22 more per day for a typical residential customer as the average bill increases to $67/month.



Q. Please quantify the average overall rate increase if the Commission authorizes the rate relief requested by the Company.

A. The average overall rate increase would be approximately 11%, or $0.22 per day for the 12 months ending June 30, 2019 test year. As previously mentioned, with the proposed increase, the average residential customer will pay about $2.20 per day for the natural gas service that provides heat, hot water, and fuel for cooking and laundry appliances; a tremendous value for our customers. The Company is aware that this increase will challenge some customers more than others. The Company offers assistance to customers who may continue to be more impacted as the economy recovers. Examples of this assistance include the Consumers Affordable Resource for Energy Program, the Residential Income Assistance Provision, and the Low Income Assistance Credit. These programs are designed to assist customers with the management of their energy use and bills. In addition to these provisions and programs, the Company and its employees are generous contributors to community-based groups including the United Way, the Salvation Army, The Heat and Warmth Fund, and many local community service organizations. The Company strives to keep its requested increase to the lowest level it believes is reasonable while balancing the need for improved reliability and customer service.

IV. <u>Adjustment Mechanisms</u>

Q. Has the Company proposed any adjustment mechanisms in this case?

A. Yes, the Company is proposing two adjustment mechanisms: a Gas Revenue Decoupling Mechanism and an Investment Recovery Mechanism ("IRM") supported by Company witnesses Jason R. Coker, Luis F. Saenz, and Heather L. Rayl.

Q. Why should the Gas Revenue Decoupling Mechanism proposed by the Company be adopted by the Commission?

A. As proposed, the Gas Revenue Decoupling Mechanism allows the Company to recover the level of revenue (excluding Gas Cost Recovery and customer charges) authorized and necessary to cover what are, for the most part, the fixed costs related to investment and expenses approved by the Commission. The mechanism proposed by the Company in this case is the same mechanism currently in place which was approved by the Commission in Case No. U-18124, the Company's last gas rate case. The details of the Company's proposal are described in the direct testimony of Company witness Rayl.

Q. Why might actual revenues differ from Commission approved rate levels, and what are the impacts of significant differences?

A. There are a variety of reasons that revenues might differ from Commission approved rate levels. These reasons include impacts of weather, the economy, energy efficiency programs, customer migration between rate schedules, and other variances in actual sales versus forecast assumptions. It is extremely difficult for the Company to properly balance customer service efforts when revenues are subject to unexpected change (increases or decreases) for the items noted above. Gas Decoupling will provide for increased certainty that the Company will have stability around its revenue assumptions and can therefore better implement O&M and customer service plans that maximize customer value.

Q. Did the Commission approve an IRM in the Company's last gas general rate case, Case No. U-18124?

A. Yes. The Commission approved an IRM, which allowed for the recovery of incremental 2018 and 2019 capital investment of five transmission and distribution programs: EIRP-Distribution, EIRP-Transmission, Pipeline Integrity-Transmission, Pipeline Integrity-Transmission Operated by Distribution, and the Asset Relocation-Decision Analysis Mains and Services Program.

Q. How will the Company recover the incremental capital expenditures approved as part of the IRM in Case No. U-18124?

A. The Company will implement the approved IRM surcharge in January of 2018. This surcharge will remain in place until rates are changed in this case.

Q. Is the Company proposing an IRM in this case?

A. Yes, the Company is proposing a revised IRM in this case. The proposed IRM mechanics are identical to the IRM approved by the Commission in Case No. U-18124.

Q. What portion of the Company's incremental capital expenditures in 2020 does Consumers Energy include for recovery in its proposed IRM?

A. The Company has identified eight specific transmission and distribution programs which are critical in order to continue to provide safe and reliable service to our customers through 2020. These programs are: TED-I-Distribution, TED-I-Transmission, EIRP-Distribution, EIRP-Transmission, VSR, Pipeline Integrity-Transmission, Pipeline Integrity Transmission Operated by Distribution, and Asset Relocation – Decision Analysis Mains and Services.

The Company's proposed IRM would cap the post-test year incremental 2020 expenditures included in the IRM to the June 2019 test year amounts ultimately approved by the Commission in this proceeding.

Q. How would the IRM operate?

A. The IRM would operate through an annual surcharge effective from July 1, 2019 until rates are changed in a subsequent rate case. After the year ending June 30, 2020 is complete, the Company will submit a reconciliation filing. This filing will also include the Company's capital expenditures for the year ended June 30, 2021 for the included programs and will re-calculate the surcharge to include these capital expenditures as well as provide customers a credit for any actual underspending for the year ended June 30, 2020. After the year ended June 30, 2021 is complete, the Company will submit a reconciliation filing to determine if the actual incremental capital spend is more or less than the approved amounts reflected in the surcharge. The annual reconciliation filings will be subject to fully-contested administrative case proceedings including audit and discovery, intervenor filings, rebuttal, cross examination, appeals, etc. The calculation of the revenue requirement related to the IRM is provided by Company witness Coker. Company witness Rayl is sponsoring the rate design for the IRM surcharge.

Q. The Commission's July 31, 2017 Order in Case No. U-18124 provided that future IRM requests should use a 13-month average in calculating the IRM revenue requirement. Is the IRM revenue requirement in this case calculated using a 13-month average?

A. Yes. As shown on Exhibit A-76 (JRC-25), the IRM revenue requirement is based on average capital spending as requested by the Commission.

Q. What was the basis of the Commission's directive to use a 13-month average in revenue requirement calculations in future IRM requests?

A. The Commission adopted the MPSC Staff's recommendation to use the 13-month average, which is based on the belief that a 13-month average would ensure that the timing of the recovery of the expenditures matches the timing of the expenditures.

Q. Do you agree that using an average in the calculation of the IRM revenue requirement provides the appropriate revenue requirement to be collected through the IRM?

A. No. Using an average in the IRM revenue requirement calculation ignores the fact that base rates are set based on a test year that includes an averaged amount of capital spending for the programs that are included in the IRM. In order to have the IRM recovery match the true revenue requirement of the IRM programs, the IRM revenue requirement should be calculated such that it includes an average of the capital spending during the year applicable to the IRM plus an adjustment to acknowledge that the test year capital spending, as included in base rates, should no longer be averaged as the test year is now a bridge year.

Q. How could the IRM revenue requirement included in this case be adjusted to provide for the true revenue requirement of the IRM projects?

A. Given that the IRM revenue requirement is based on the test year capital spending for the IRM programs, the IRM revenue requirement should be adjusted by removing the averaging from the calculation. This would provide for an average of the IRM period capital spending and include the full revenue requirement for the test year which is now a bridge year.

Q. What is the true revenue requirement of the IRM programs during the IRM period?

A. The true incremental revenue requirement of the IRM programs during the IRM period is $39,161,000.

Q. Has the $39,161,000 IRM revenue requirement been reflected in the presentation of this case?

A. No. As directed by the Commission, the Company has included the averaging in the calculation of the IRM revenue requirement as presented by Company witness Coker. However, in order to provide for the true incremental revenue requirement of the IRM programs during the IRM period, the $39,161,000 revenue requirement should be approved for recovery through the IRM surcharge effective July 1, 2019.

Q. What must be true about the IRM to extend the period between gas general rate cases or skip a general rate case?

A. The IRM must result in recovery of substantially all the costs related to the Company's investment plan. The proposed IRM will deliver only a small portion of the revenue necessary to cover the entirety of the Company's ongoing infrastructure investment plan. For illustrative purposes, the current IRM authorized in Case No. U-18124 will provide for $18 million of annual incremental revenues beginning January 1, 2018, which is approximately $1.5 million per month until rates are changed in this proceeding sometime in August 2019. However, the investment-related revenue requirement in this proceeding is $158 million.

V. **Summary**

Q. Please summarize your direct testimony.

A. Consumers Energy respectfully submits this request for approximately $178 million in rate relief because of the significant natural gas infrastructure investments we are making and will continue to make on behalf of our customers. Consistent with our deeply-held commitment to provide exceptional value and service to every customer and caring for the communities where we live and work, we are requesting revenue recovery for customer-driven infrastructure investments that will provide safety and reliability benefits for our customers. The Company continues to minimize the increase in O&M expense through improved safety performance, productivity improvements, and first time quality. Consumers Energy is committed to customer value and service and believes that this filing is a true representation of that commitment.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
	)	

REBUTTAL TESTIMONY

OF

MICHAEL A. TORREY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2018

MICHAEL A. TORREY
REBUTTAL TESTIMONY

Q. Please state your name and business address.

A. My name is Michael A. Torrey. My business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Michael A. Torrey who previously submitted testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal addresses the direct testimony of several Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witnesses. Specifically, I am rebutting Staff witness Cynthia L. Creisher with regards to the Investment Recovery Mechanism ("IRM"), and Staff witness Nathan Miller regarding the capitalization of certain investments. I will also rebut proposed disallowances of cost recovery for certain investments by Mr. Miller for Pipeline Integrity, Staff witness Robert Frazier for Information Technology, and Staff witness Lauren Fromm for Automated Meter Reading ("AMR"). I am also providing rebuttal to the direct testimony of Attorney General witness Sebastian Coppola regarding the appropriateness and affordability of the level of investments Consumers Energy Company ("Consumers Energy" or the "Company") is making and the IRM.

Q. Are you sponsoring any rebuttal exhibits?

A. No.

Q. Staff witness Creisher presents, on pages 55 through 59 of her direct testimony, the Staff's recommendation on the Company's IRM proposal. Does the Company agree with Ms. Creisher's recommendations?

A. Yes, to minimize the differences with Staff, the Company accepts Staff's adjustments to the Company's IRM proposal, which would exclude the Transmission Enhancements for Deliverability-Integrity ("TED-I") projects, include a spending flexibility cap of 3.2% as provided for in Case No. U-18124, and maintain Enhanced Infrastructure Replacement Program ("EIRP") spending of at least $75 million.

Q. On page 58, lines 12 through 19, Ms. Creisher suggested that if the IRM is approved, the IRM expenditures should be adjusted to be in line with Staff's recommendations for the projected test year expenditure levels. Do you agree?

A. The IRM should reflect the test year spending levels in the amounts approved by the Commission for the EIRP-Distribution, EIRP-Transmission, Pipeline Integrity-Transmission, Pipeline Integrity-Transmission Operated by Distribution, Asset Relocation-Decision Analysis Mains and Services, and Vintage Service Replacement programs. If Staff's proposed test year spending amounts are adopted by the Commission, then those amounts should be used in the IRM.

Q. Mr. Coppola offers comments and recommendations on the IRM on behalf of the Attorney General on pages 83 through 85 of his direct testimony. Do you agree with his views?

A. No. On page 84, lines 10 and 16, Mr. Coppola characterizes the IRM as an "automatic" recovery of costs, which fails to recognize that any costs included in the IRM are reviewed in this proceeding and again in a reconciliation proceeding. Furthermore, costs not incurred are subject to refund. Nothing is automatic. On page 84, line 17, Mr. Coppola also suggests that the IRM "includes 100% of what the Company deems reasonable." This statement ignores the fact that the IRM will initially include what the Commission deems reasonable after careful consideration of the recommendations in this case and in a reconciliation proceeding. On page 85, lines 3 through 6, Mr. Coppola states: "The rate case review of proposed costs offers all parties to the proceeding the opportunity to weigh in on the reasonableness of projected costs before significant capital expenditures are incurred. This is one of the benefits of a rate case proceeding that includes projected costs." This statement appears to support the upfront review of costs included in the IRM in this proceeding before they occur. On page 85, line 10, Mr. Coppola later criticizes the IRM's reconciliation process as occurring "years later after summary program amounts have been spent." However, complete details of IRM project spending can only be made available after the work occurs. Furthermore, if the spending did not occur, or is determined to be imprudent, it is subject to refund.

Q. At page 52 of his direct testimony, lines 7 through 12, Mr. Coppola states that: "it is clear that the Company is continuing a major ramp up of capital expenditures in a variety of areas. In this rate case filing $158 million, or 89%, of the requested rate increase of $178 million is for higher rate base related to capital expenditures. The compounding effect of large additions to rate base will continue to increase customer rates to unaffordable levels for many customers, particularly those in lower income brackets." Do you agree that the increase in capital expenditures has increased customer rates to unaffordable levels for many customers?

A. No. The Company recognizes that customers want to keep their bills affordable. Investments that help reduce O&M costs and/or improve the Company's ability to access and store gas supply help maintain affordability and price stability. Based on the Company's rebuttal position, the average overall rate increase is approximately 5.1%, or $0.13 cents per day for the 12 months ending June 30, 2019 test year. With the proposed increase, the average residential customer will pay about $2.09 per day for the natural gas service. The Company is aware that this increase will challenge some customers more than others. In addition to the assistance programs described in my direct testimony, it should be noted that the Company contributed $10 million to community-based groups income assistance programs at year-end 2017. The Company strives to keep its requested increase to the lowest level it believes is reasonable, while balancing the need for improved reliability and customer service.

Q. Do customers benefit from the investments undertaken by Consumers Energy?

A. Yes. Consumers Energy's recent and proposed capital investments are necessary to provide safe, reliable utility service, and comply with environmental requirements, gas safety standards, and pipeline safety regulations. The Company is making significant investments in its natural gas infrastructure to better serve our customers. These investments, among other things, improve the Company's transmission and compression system that is regulated by the MPSC to help ensure the reliability of our gas delivery to our customs, and to maximize the Company's utilization of its vast underground storage fields to purchase natural gas when prices have traditionally been lower and help protect against volatility. In addition, these investments will provide added safety and reliability benefits for customers. The Company's investment plans are driven by the need to serve our customers. Customers expect us to provide the infrastructure necessary to deliver safe and reliable natural gas service to their homes and businesses. And, an additional benefit of these investments is that they support economic growth in Michigan.

Q. At pages 85 through 87 of his direct testimony, Mr. Coppola criticizes Consumers Energy for its level of capital investments noting that the Company spent "$774.4 million in 2017 or $197 million more than the amount authorized in rates." Because of the Company's investment levels, Mr. Coppola requested that the Commission "direct the Company to be more disciplined in its actual spending in future years and stay closer to the amounts approved in the rate case unless there is good reason to move from those levels." Do you agree with this criticism?

A. No. Contrary to Mr. Coppola's assertions, the Company is not bound to its rate case projections. As the Company's case is based on a projected test year, it is natural that there would be variations in spending based on the amounts approved in rates. While the Company fully plans on expending the costs requested in a rate case, there is no guarantee that the Company will spend the exact amount projected. The Company's rate proceedings are premised on the goal of determining a reasonable level of expenses for a future period. The use of a future test year better reflects business conditions during the period where rates are expected to be in effect. The Attorney General's request that the Company be limited in its spending fails to recognize that the Company needs to operate the business.

Q. Is Consumers Energy limited to spending only what is projected in its rate case filings?

A. No. While rate case projections are necessary for the development of rates, these projections cannot control the overall actions of the utility. Consumers Energy needs to be able to spend money to run its business, to provide service, and to invest in its plants. As a result of their prospective nature, rates are designed to be representative of the price necessary to recover all reasonable and prudent costs that the utility is likely to incur during the future period of time that rates will be in effect plus a reasonable rate of return. The Company's spending plans are not controlled by its rate case projections. In the course of providing service to its customers, Consumers Energy's management team makes decisions on a daily basis that are not subject to advance regulatory approval. Consumers Energy manages the business discretion to decide whether or not to expend monies on a particular investment. The Commission's role is responsive in nature – if the utility decides to invest in a particular area, then the Commission must determine if cost recovery is reasonable.

Q. At page 86, lines 13 through 15, of his direct testimony, Mr. Coppola contends that any overspending or underspending from the amount approved in a rate case shows a lack of financial discipline and budget control. Is this accurate?

A. No. Consumers Energy has a robust planning and budgeting process that reviews actual expenditures against expectations. Leadership is appraised of historical variances and updated projections on a monthly basis. This process ensures that limited resources are directed to customer-focused and regulatory compliance priorities.

Q. Why might differences exist between financial plans and spending reflected in rates?

A. Differences between financial plans and amounts included in rates may exist due to the passage of time. It typically takes 4 to 6 months to prepare a general rate case and a general rate case now takes 10 months to process. Spending happens every day and financial plans are updated on a continuous cadence to reflect the best available information. Another reason for differences is contingency amounts for major projects that vary as projects move forward through time. It has been this Commission's practice to not include contingency in customer rates. Our forward looking financial plans and regulatory proceedings assume normal weather. Extreme weather may impact project schedules. Extreme weather, storms for example, may require limited resources to be redirected to emergent work that was not planned for, or included in, customer rates. Sometimes, unplanned significant work also happens requiring immediate attention and the reprioritization of resources. In summary, it is the Consumers Energy leadership team's responsibility to provide safe, reliable, and affordable service to 1.8 million natural gas customers in Michigan. That requires daily decision-making. That's our job.

Q. On page 12, line 17, through page 13, line 2 of his revised direct testimony, Staff witness Miller opines that the Company benefits when capitalizing the remediation of minor pipe anomalies as opposed to considering it a maintenance expense. Mr. Miller suggests that: "when a company records expenses as a capital investment, it allows the company to receive a return on those investment costs as well as a return of those costs through depreciation expenses. The more capital that is invested, the more a company can potentially collect through rates. However, when costs are recorded as maintenance expenses, the cost of performing such work is a direct impact on a company's earnings for the period in which the work is performed. A company, therefore, can be incentivized to maximize capital expenses and minimize maintenance expenses." What is your response to Mr. Miller's point of view?

A. Mr. Miller fails to mention the customer at all in his discussion. For a given amount of work and cost, capitalization will result in a small fraction of the immediate impact on customer rates. Capital project costs such as financing costs, depreciation, and property taxes included in customer rates typically add up to approximately 12% of the spending versus 100% of the spend for maintenance work. Mr. Miller's support for recovery of 38% of the cost of certain projects through O&M expense is more than the 12% of the cost of capitalized spending. Capital projects provide customer benefits over many years, and should be recovered in customer rates over the life of the asset, rather than paid for in maintenance expense. In addition to safety and reliability, Consumers Energy considers the customer rate impacts in the development of its investment plan. Consumers Energy has no need to upsize any particular capital project to collect more of anything through customer rates. Other capital projects are available to be performed should the funding become available. Furthermore, capital projects that reduce O&M expense are attractive from a customer perspective as they provide benefits with an offset to a portion of the costs.

Q. In his revised testimony, based on his contention that the Company inappropriately capitalized remediation dig costs under the Company's Pipeline Integrity Program, Mr. Miller proposed that the Commission "deny capitalization of all of the remediation dig costs that Staff has identified in Confidential Exhibit S-12.24 for 2016 and Confidential Exhibit S-12.30 for 2017 that should have been maintenance expenses." What impact will this recommendation have on the Company?

A. This would cause the Company to write off reasonably incurred expenditures. Nothing in Mr. Miller recommendation recognized that the Company reasonably incurred costs that were undertaken to comply with federal Pipeline and Hazardous Materials Safety Administration requirements, as testified to by Company witness Mary P. Palkovich.

Nor did Mr. Miller argue that the Company should not have undertaken remediation activities on these pipeline segments. Ultimately, Mr. Miller's proposal requires the Company make changes on a historic basis that Consumers Energy could not have reasonably known that it would be required to make.

Q. Did other witnesses in this proceeding recommend disallowances to past investments?

A. Yes. Staff witness Frazier supported the application of a 6% reduction to the investments made for IT projects and a specific reduction for the Field Service Solution project. Staff witness Fromm argued for the disallowance or deferral of historical AMR costs. Additionally, Attorney General witness Coppola concluded that a disallowance of historical capital spending for the Well Rehabilitation Program was warranted.

Q. What is the impact of these recommendations?

A. The disallowance of historical capital spending and the associated write off will lower net income in the year of disallowance by an equal amount and will prevent the Company from recovery of dollars actually invested for assets being used to serve the customer. The impact of this will discourage the Company from making real time business decisions and investments to benefit the customer for fear of future disallowance of assets already invested in.

Q. Were these investments made to the benefit of customers?

A. Yes. Inspection and replacement of pipe ensures that the natural gas infrastructure will continue to deliver gas safely to our customers. The Pipeline Integrity Program includes projects that are required to comply with federal and state pipeline safety regulations and mandates. These are projects that the Company has reasonably undertaken, to the benefit of its customers and have been supported by Company witness Palkovich. Similarly, the

Well Rehabilitation Program will significantly reduce risk across our gas storage system and increase deliverability by rebuilding the gas wells at the Company's gas storage fields back to a like-new condition. The program also provides baseline well integrity conditions during implementation. The well remediation activities undertaken as part of this program are required by the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016, which set federal minimum safety standards for underground natural gas storage facilities. This 10 year plan has been supported by Company witness Danielle M. Hill.

The Company's investment in the gas-only service territory AMR Program provides multiple benefits to customer. These include reduced meter reading expense, improvements in billing accuracy (as a result of higher actual meter read rates), and a reduced number of rereads and rebills due to the improved read rates. Other benefits include reductions in energy theft resulting from the analysis of meter tamper alerts. It will also reduce employee safety incidents from dog bites, slips, trips, and falls. This program will improve operational efficiencies and enhance customer value for all gas customers. Moreover, the gas communication modules installed can be reprogrammed to work with an AMI system as needed. Company witness Lisa M. DeLacy supported the reasonableness of the Company's AMR Program.

The Company's investment in IT projects enables it to securely and effectively enable customers to complete electronic transactions with the Company; respond to customer requirements; schedule and track work performed on behalf of customers; conduct gas supply and distribution functions; and conduct customer billing, procurement, financial, human resources and other business operations essential to providing outstanding customer service. The Field Service Solution project allowed the Company to replace its outdated order management and routing system with updated mobile applications, automated scheduling and routing, and optimization of work schedules to improve the Company's ability to make and meet work commitments for its customers. These projects provide clear benefits to customers, and Company witness Varvatos supported the reasonableness of the Company's IT investments.

Q. Does this conclude your rebuttal testimony in this proceeding?

A. Yes.

(Documents were marked by the Court Reporter as Exhibits A-17, A-18, and A-19.)

MS. UITVLUGT: By agreement of the parties Consumers Energy wishes to bind in the direct testimony of Company witness Amy M. Conrad. Ms. Conrad's direct testimony consists of a cover page and 38 pages of questions and answers. Additionally, Ms. Conrad sponsors rebuttal testimony which consists of a cover page and 12 pages of questions and answers.

I would also move for the admission of Ms. Conrad's exhibits. She sponsored Exhibits A-17, A-18, and A-19.

JUDGE SONNEBORN: Thank you. Are there any objections to binding in the direct and rebuttal testimony of Amy M. Conrad, as well as her exhibits as described by Ms. Uitvlugt? Hearing no objection, the direct and rebuttal testimony of Ms. Conrad is bound into the record and her exhibits are admitted into evidence.

MS. UITVLUGT: Thank you, your Honor.

(Testimony bound in.)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
	)	

DIRECT TESTIMONY

OF

AMY M. CONRAD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2017

AMY M. CONRAD
DIRECT TESTIMONY

Q. Please state your name and business address.

A. My name is Amy M. Conrad, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. In what capacity are you employed?

A. I am employed as Director of Compensation for Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your educational background?

A. I graduated from Central Michigan University in 1999 with a Bachelor of Science degree in Business Administration with a major in Accounting. In addition, I am designated as a Certified Compensation Professional and Certified Executive Compensation Professional by World at Work and a Certified Public Accountant by the Michigan Association of Certified Public Accountants. World at Work is an international professional organization focused on human resources issues, including compensation, benefits, work life, and integrated total rewards to attract, motivate, and retain a talented workforce.

Q. What have your job responsibilities entailed with Consumers Energy?

A. In February 2002, I joined Consumers Energy as a Financial Reporting and Technical Accounting Analyst. My duties included accounting and reporting of equity-based compensation, technical accounting standard research, and preparation of quarterly and annual Securities and Exchange Commission ("SEC") filings. After eight years of progressing responsibilities in this role, I transferred to the position of Principal Human Resources Consultant. In 2013, I was promoted to my current position as Director of Compensation. I currently have responsibility for administering Consumers Energy's compensation function and partnering with Labor Relations on union compensation matters. This includes developing compensation programs designed to attract and retain a qualified workforce for the Company. My duties include gathering of comparable wage and salary data in order to determine how Consumers Energy's pay level compares to the labor market and developing compensation programs that are competitive and deliver pay to employees that is fair and equitable and that motivates employees to perform at their full potential.

My responsibilities also consist of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion and Analysis section of the annual proxy statement for the named executive officers.

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

A. Yes, I have testified in MPSC Case Nos. U-17087, U-17197, U-17643, U-17735, U-17882, U-17990, U-18124, and U-18322.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide support for Consumers Energy's request for rate recovery for costs of its annual Employee Incentive Compensation Plan ("EICP") at target levels. The EICP is a form of short-term incentives. Short-term incentive pay is designed to focus and reward performance over periods of approximately one year or less.

First, I will discuss Consumers Energy's overall compensation philosophy. In this section of my testimony, I will discuss the importance of paying employees a competitive level of compensation and the reasonableness of the overall compensation levels that the Company is requesting in this case. In addition, I will discuss: (i) the fact that EICP compensation is part of an employee's overall market-based compensation and not in addition to it, and (ii) why Consumers Energy has included EICP at target levels as part of overall market-based compensation.

Second, I will discuss the EICP incentives and provide support for the Company's request for rate recovery in this case related to Consumers Energy's non-officer and officer EICP. In my testimony, I will discuss the design of the EICP. As I will discuss later, the Company's incentive compensation plans are based on the target metrics of continuous improvement, safety, quality, cost, delivery, morale, and financial performance.

Third, I will discuss customer-related benefits that result from use of the incentive plans and how customers are best served when Consumers Energy can attract, retain, and motivate a talented workforce with compensation packages that are competitive and fair. Elimination of the EICP would result in Consumers Energy's employee compensation being below market, and would hinder the Company's ability to attract and retain a qualified workforce.

Q. Please summarize your conclusions.

A. My conclusions include the following: (i) use of incentive compensation by utility companies is an accepted, common, and reasonable practice; (ii) Consumers Energy's decision to make a portion of compensation at-risk and subject to incentives is reasonable; (iii) the amount of overall compensation included by Consumers Energy in this case is reasonable and is reasonably necessary to attracting and retaining a talented workforce; (iv) incentive compensation is part of the reasonable level of compensation and not in addition to it; (v) recovering costs of Consumers Energy's EICP employee incentive plans will not result in excess rates; (vi) Consumers Energy's EICP performance goals and thresholds provide customer-related benefits; and (vii) the EICP goals provide customer-related benefits at no incremental cost to customers above those included in market-based compensation.

Q. How is the remainder of your testimony organized?

A. The remainder of my testimony is organized as follows:

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-17 (AMC-1)	EICP Performance Measures;
Exhibit A-18 (AMC-2)	Summary of Requested Expenses; and
Exhibit A-19 (AMC-3)	Target Pay Level Market Analysis.

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

A. Yes.

I. OVERVIEW

Q. How does Consumers Energy structure non-officer compensation for its salaried employees?

A. Consumers Energy first determines what a competitive level of pay is for salaried non-officer employees. It does so using various market surveys. Consumers Energy then structures the compensation by allocating this market-based wage between base salary and incentive compensation. The incentive compensation is part of the overall market-based competitive level. It is not in addition to it. Total compensation is targeted at approximately the market median (50^{th} percentile).

Q. How does Consumers Energy structure officer compensation?

A. Officer compensation levels are determined by the Compensation Committees of the Boards of Directors of Consumers Energy and CMS Energy. The Company creates a compensation package for officers that deliver base salary, annual incentive compensation, and long-term incentive compensation targeted at the median or 50^{th} percentile of the competitive market. In determining individual officer compensation levels, the Compensation Committees are advised by an independent third-party consultant and take into consideration market research, experience levels, and individual contributions.

Q. Is Consumers Energy requesting recovery of long-term incentive pay in this rate case proceeding?

A. No. The Company in this case is not seeking recovery for the costs of long-term incentive compensation (sometimes referred to as restricted stock plans) in its rate recovery request.

Q. In this proceeding, is the Company requesting recovery in rates of all Operating and Maintenance ("O&M") gas expenses related to short-term incentive compensation plans?

A. No. While the Company believes that both officer and non-officer short-term incentive compensation expenses are reasonable, the Company in this case is excluding the costs of short-term incentive compensation for the proxy officers as identified by the most recent SEC proxy filing from its rate recovery request.

Q. Why is the Company requesting recovery in rates of short-term incentive compensation expenses?

A. Consumers Energy uses market data to determine an overall competitive level of compensation. The overall compensation levels, including the officer and non-officer short-term incentive compensation, are reasonable compared to the market. Compensation levels without these incentive payments would be below market competitive levels. Paying non-competitive levels of compensation would result in a lower qualified workforce. In order to hire and retain qualified personnel, it is necessary to either pay a competitive incentive or increase base salaries. The EICP incentive compensation costs are reasonable costs of doing business and, therefore, should be recovered in rates.

Use of annual incentive mechanisms is a recognized management technique for companies, including utility companies. As I discuss later in my testimony, incentive pay is the number one design used to influence short- to mid-term performance results. Incentive mechanisms help communicate priorities, engage the employees in operating and financial success, reward valued skills and behaviors, and create business understanding for employees. Consumers Energy's incentive programs are structured in a way that is designed to help keep non-officers and officers focused on such areas as continuous improvement, safety, quality, cost, delivery, and morale. The incentive compensation program encourages employees to deliver their best performance for the Company's customers.

Q. Who is eligible for the EICP incentives?

A. All non-union employees are eligible for EICP incentives, with the exception of employees rated as "under-contributing" or "moderate" on their annual performance appraisal. These under-performing employees are ineligible to receive an EICP incentive. Both non-officers and officers participate in an annual EICP.

Q. How are the EICP incentives structured?

A. The EICP incentive structure incorporates metrics which measure the following categories of Company performance: (i) continuous improvement; (ii) safety; (iii) quality; (iv) cost; (v) delivery; (vi) morale; and (vii) financial. The Company believes that performance in these areas is critical for the Company's success in its electric and gas public utility business.

The non-officer EICP equally weights the operational measures of continuous improvement, safety, quality, cost, delivery, and morale with the financial measures:

- Half (50%) of employees' incentive will be based on achievement of operational performance measures in areas of continuous improvement, safety, quality, cost, delivery, and morale. (For 2017 there are 12 operational measures.); and

- Half (50%) of employees' incentive will be based on the achievement of two financial measures, Earnings Per Share ("EPS") and operating cash flow. Consumers Energy is a vital part of the Michigan economy and it is important that the utility remain financially strong so that it can provide the utility service that customers expect and deserve. Financial health also leads to reduced costs of capital and greater access to liquidity.

The goals are the same for the officer EICP, but the weightings are different. For the officer plan, the continuous improvement, safety, quality, cost delivery, and morale operational goals are a plus or minus modifier to the financial goals. I will discuss this difference in weightings later in my testimony.

II. EMPLOYEE COMPENSATION PHILOSOPHY

Q. What is Consumer Energy's philosophy about the overall level of compensation?

A. The Company's management believes Consumers Energy should pay a fair and reasonable salary, comparable to the market, that is equitable to employees, consistent with Company values and strategies, and that supports the highest level of customer service at a reasonable cost.

Q. What are the components of Consumers Energy's compensation for non-officer employees?

A. There are two parts of overall compensation for non-officer employees of Consumers Energy. The first part is base pay. The second part for salaried employees is annual employee incentive compensation.

Q. What are the components of Consumers Energy's compensation for officers?

A. There are three parts of overall compensation for officers of Consumers Energy. The first two parts are cash compensation through base pay and annual incentive compensation. The third part is equity-based long-term incentive. As I mentioned earlier in my testimony, the Company in this case is not seeking recovery for the costs of long-term incentive compensation in its rate recovery request.

Q. Why does the Company make a portion of compensation subject to incentives?

A. A wide body of research supports the view that variable pay works. One researcher states, "theory and research show that incentive pay can substantially increase individual and organizational performance, and can represent a powerful tool for establishing a competitive advantage within an industry," (Dow Scott, "Incentive Pay: Creating a Competitive Advantage" – World-at-Work Press, 2007). I agree with this assessment. When properly selected and implemented, incentives motivate employees, focus employees on a company's goals, and increase both individual work performance and team performance. When goals are challenging yet achievable, employees are motivated to increase productivity. In addition, incentives increase a company's ability to attract, hire, and retain qualified and motivated individuals. A study by the International Society of Performance Improvement showed that incentive pay programs increase performance by an average of 22%. (International Society of Performance Improvement, "Incentives Motivation and Workplace Performance Research and Best Practices," Spring 2002). As stated by the Society of Human Resource Management:

> "Research has demonstrated that some human resource programs and initiatives produce a significant impact on performance in organizations (as measured by factors such as quality, productivity, speed, customer satisfaction and unwanted turnover). The two initiatives that consistently showed statistically significant positive results were linking pay to performance and using variable pay. Research has established the potential of variable pay to produce the desired business results." Robert Greene, Variable Pay: How to Manage it Effectively, Society of Human Resource Management, April 2003.

As I discuss in my testimony, Consumers Energy has adopted incentives that are designed to emphasize operational performance criteria in areas that are critical to the

Company's utility business. Focusing employees on these goals provides both qualitative and quantitative benefits for Consumers Energy's utility customers.

Q. Are the overall compensation levels for employees subject to the non-officer EICP reasonable?

A. Yes. Overall compensation levels for employees, subject to the non-officer EICP and management's decision of how to allocate the overall compensation between base salary and EICP, are reasonable.

Q. How does Consumers Energy determine what level of overall compensation for non-officers is reasonable?

A. First, Consumers Energy's management targets overall compensation to the market median. Second, Consumers Energy's management actively reviews compensation levels so that employees are neither overpaid nor underpaid relative to market. Third, the Company uses a rigorous survey process which uses valid and reliable data from multiple sources to determine median levels of compensation. The fact that a portion of the compensation is in the form of an incentive payment does not mean that employees are paid in excess of market rates when they receive their incentive payment. To the contrary, removing the incentive from employees' total compensation package would render their compensation below-market.

Q. Would it be reasonable for Consumers Energy to pay employees below market level on an ongoing basis?

A. No.

Q. Why would it be unreasonable for Consumers Energy to pay below market level?

A. Consumers Energy has a responsibility to customers to employ a competent workforce that is ready, willing, and able to provide service for our customers. Paying competitive wages and salaries is necessary in order to fulfill that commitment. It would not be reasonable or fair to the Company, customers, or employees for the MPSC to set rates at a level that did not include reasonable levels of overall compensation.

The level of service our customers deserve requires a qualified, experienced, and motivated workforce. The Company is able to attract, retain, and motivate talented employees when its overall compensation is competitive with market levels. A decision to compensate employees below market levels would detract from the Company's ability to assemble the committed workforce our customers deserve. Over time, this would be detrimental to customers, as well as being unfair to our diligent, hardworking employees. Compensating employees below market levels will eventually result in them leaving for jobs that are paying at market levels. Over time, the workforce would tend to be less qualified, less experienced, or less capable (as the most capable would, in general, tend to go to employers paying at competitive levels). This, in turn, could lead to less efficiency and could result in a need to hire more employees to produce the same service to customers, thus increasing costs to our customers.

Q. How does the Company determine the level of overall compensation for salaried non-officer employees?

A. For salaried non-officer employees, the Company uses salary survey data from utility and energy companies. Using this survey data, a benchmarking analysis of total compensation (base pay and incentive pay) is made between the Company's jobs and comparable survey jobs. Benchmarking analysis is a comparison of jobs commonly found in the labor marketplace and/or a job that is highly relevant/populated within a company. This comparison indicates where the Company's pay stands relative to the market. The Company's goal is to target overall pay levels within plus or minus 5% of the market median for non-officers. While pay for individuals inevitably varies from the survey market levels due to differences in experience levels, education, job performance, longevity, position responsibilities, etc., the survey data indicate that the Company's overall non-officer compensation levels, assuming the EICP payment is at the target level, are on average within target pay level of plus or minus 5% of market median. Exhibit A-19 (AMC-3) provides a summary of average exempt and non-exempt pay for Company benchmark jobs, compared to market, using 2016 data for 2017 pay structure purposes.

Paying compensation that approximates the market median is particularly important given that Consumers Energy will have a need over the next few years to hire engineers and other personnel to staff various projects as Consumers Energy and the State move forward, as well as due to significant attrition. In competing for engineering, as well as other personnel, it will be important to have a reputation for paying a competitive level of overall compensation. Excluding the incentive target amounts would result in the Company's pay levels being approximately 5% to 10% below market level.

Q. How do you know the market data that the Company is using are appropriate and are not inflating salary levels?

A. The Company uses a number of survey sources to compare to the non-officer salaried workforce. The Company participates in, and uses an, industry survey performed by

Willis Towers Watson, a well-respected independent third party compensation expert. This survey is conducted by surveying companies which report data on an anonymous basis. The data from Willis Towers Watson is our primary source of compensation information. The Company also participates and uses EAP Data Information Solutions, LLC, an independent survey firm serving the energy industry, for non-officer hourly workforce market data. To supplement this data, the Company uses a reputable national on-line survey resource, CompAnalyst, which has survey data from a wide variety of independent sources. In every instance when using the survey data, the Company looks at the median total compensation (base pay and incentive) reported for highly populated jobs for which there is a comparable match. In this way, the Company is matching the relevant market, not trying to lead the market, and thus not inflating our overall compensation above prevailing market levels. The Company also looks at data from companies who are in the utility and energy industry, not data from high paying technology companies or pharmaceutical companies. By using three independent survey sources we can determine if any one source is varying significantly from another.

Q. Can you give an example of the relationship between the Company's pay levels and the market's pay levels?

A. Yes. For the Company's Administrative Assistant III (85 employees) job, the Company's average salary plus incentive target (overall compensation target) is 7.2% below the market. For Administrative Specialist II (127 employees) the Company's level is 1.2% above the market. For Technical Specialist II (74 employees) the Company's level is 1.8% above the market. For Senior Technician (125 employees) the Company's level is 1.1% below the market. For Senior Engineer II (143 employees) the Company's level is

1.4% below the market. For Gas Field Leader (72 employees) the Company's level is 2.3% below the market. For IT Technical Senior Analyst II (65 employees) the Company's level is 3.8% above the market. For Senior Business Support II (74 employees) the Company's level is 4.6% above the market. For Senior Engineering Technical Analyst II (64 employees) the Company's level is 1.2% above the market. These nine jobs are among the most highly populated of our salaried workforce.

Q. Are incentive plans common in the utility industry?

A. Yes, incentive plans are quite common. Annual incentive programs are a critical and highly integral part of competitive compensation packages for many organizations. Research from Willis Towers Watson's 2012 Survey Report indicates that approximately 80% of companies offer annual incentive (variable pay) programs. That number is slightly higher at 81.2% for those companies within the utility industry sector. The survey data supports the conclusions that including incentive pay as part of a competitive pay package is a standard industry practice and is required to attract and retain good employees.

Research from Mercer's 2014/2015 US Compensation Planning Survey Report indicates that approximately 83% of companies offer annual incentive (variable pay) programs. For companies within the utility industry sector, the survey indicated that 98% of executives, 99% of management, 94% of non-sales professionals, and 86% of clerical and technicians were eligible for an annual incentive.

A 2012 Mercer study of more than 1,200 organizations reveals that actual company spending on variable pay for salaried exempt employees, as a percentage of pay, is 12% and salaried/hourly non-exempt employees, as a percentage of pay, is 6% to

7% for energy companies. A 2009 Hewitt Associates study, of more than 1,100 organizations, further reports that companies were budgeting variable pay for salaried exempt employees at 11.8%, and 5.5% to 6.1% for salaried/hourly non-exempt employees, for 2010. Ken Abosch, leader of Hewitt's North American Broad-Based Compensation Consulting business, added:

> "Over the past decade, we've seen companies steadily shift from a fixed pay model to one that emphasizes true performance based awards, and we expect this trend will continue."

Consumers Energy's practice of making a portion of overall employee compensation subject to incentives is consistent with best practices for compensation.

Q. What has been the trend in variable or incentive pay?

A. A 2016 study by Aon Hewitt indicated a 72% growth in variable pay spend over the past 20 years. Variable pay grew from 4.1% of base salaries in 1996 to 12.9% of base salaries in 2015. Business incentive plans are the most prevalent with 77% of companies using this type of variable pay award in 2015 up from 55% in 1996. Business incentive plans refer to plans that are based on Company financial and/or operational goals.

Q. Why is the use of incentive pay such a widespread practice?

A. Incentive pay is the number one design used to influence short- to mid-term business or performance results. Coupled with clear strategy, solid leadership, and good, safe working conditions, variable pay incentive designs:

- Increase employees' understanding of what is important to the Company;
- Increase employees' identification with the Company's success and the factors by which it is measured;
- Reward valued skills and behaviors; and

- Enhance employee engagement by educating them on how and why their contributions will benefit them, the Company, and our customers.

Dividing overall compensation between base salary and incentive compensation is an approach that is common and effective in business today.

Q. How many employees does the Company have that will be eligible for the non-officer EICP payout?

A. Consumers Energy has approximately 4,400 employees (total utility) that are eligible to receive an incentive if and when the requirements for a payout are met. The risk of no payout is the same for all of these eligible employees. Either every eligible employee receives a payout, or no one receives any incentive compensation.

Q. How did the Company determine the level of compensation that would be provided as incentive compensation for these eligible employees?

A. The EICP target level for each pay grade was established by measuring the difference between the Company's base salary target and the market's overall compensation level. The EICP compensation is part of the overall competitive level of compensation, not in addition to it.

Q. Explain if the Company reduced base pay when it started to pay incentive awards in order to obtain market-based pay based on the combination of the two components of pay.

A. The Company has always had a broad-based incentive compensation plan in place for salary grades 19 and above. In 2003, an EICP for employees in salary grades 19 and below was initiated. Base pay levels were not reduced for these employees at the time the plan was implemented. This was due to the fact that at the time the plan was implemented, total compensation which is base salary and annual incentive was slightly below the 50th percentile (median) point of survey results. The Company targets pay levels of plus or minus 5% of market median. The Company's level, including the additional incentive, continues to be within this range.

Q. Is there an alternative to providing incentive pay for salaried employees?

A. The alternative would be to increase the base compensation to a level that approximates the overall competitive market level of compensation. Absent the higher base pay, Consumers Energy's compensation offering would not be competitive with the labor market. For example, if our base target was $50,000 for a hypothetical job and market base average pay was $50,000 plus a $2,000 incentive award, then the Company would need to offer $52,000 to match the market's current pay. So the alternative to having an incentive component of overall compensation would be to raise base pay to the market's overall compensation. Eliminating incentive pay would result in the same costs, but the loss of incentives that help focus employees on continuous improvement, safety, quality, cost, delivery, and morale goals.

The Company's overall compensation needs to be comparable to the market for salaried employees, regardless of whether it is composed of only base pay or composed of base pay plus the target incentive award amount. The Company has maintained overall compensation at competitive levels through the incentive plan. But for the incentive plan, the Company's non-officer base salaries would be less than overall competitive compensation levels.

Q. Would elimination of incentive pay be in the best interests of customers?

A. No. With incentive compensation, the employees and the Company as a whole must re-earn the at-risk compensation each year. If high levels of performance are not met each year, incentive pay can be reduced or eliminated. The elimination of variable "at-risk" pay would create a situation where all compensation is guaranteed and would remove an important incentive to improve service. This result would be counter to customer interests.

Q. How does the Company determine the level of overall compensation for officers?

A. A utility must maintain a competitive total compensation package in order to attract and retain executive talent. As discussed in the Overview section of my testimony, Consumers Energy creates a compensation package for officers that deliver base salary, annual incentives, and long-term incentives (excluded from the Company's request in this rate case) targeted at the 50th percentile of the market, as defined by a Compensation Peer Group approved by the Compensation Committees of the Boards of Directors. The Compensation Peer Group consists of energy companies comparable in business focus and size to CMS Energy with which the Company might compete for executive talent. The Compensation Peer Group currently includes 22 companies.

Q. How do you know the market data that you are using for officer compensation are appropriate and are not inflating salary levels?

A. Annually, the Compensation Committees engage an independent third party consultant to provide advice and information regarding compensation practices of the Compensation Peer Group, as well as additional information from published surveys of compensation in the public utility sector and general industry. During the Compensation Committees' review of officers' compensation levels, the Compensation Committees consider the advice and information received from the Compensation Committees' independent compensation consultant; however, the Compensation Committees are ultimately responsible for determining the form and amount of the compensation programs.

Where available by position, Compensation Peer Group data serves as the primary reference point for pay comparisons of utility specific roles, and broader survey data and published proxy data are also provided by the compensation consultant as a point of reference for utility specific roles and comparisons of general industry roles. Where available by position, Pay Governance gathers compensation data from Willis Towers Watson's Energy Services Executive Database (over 60 investor-owned utilities) and Willis Towers Watson's General Industry Executive Database (approximately 450 participating companies), which it regresses based on CMS Energy's revenues to provide additional market context to the Compensation Peer Group. In selecting members of the Compensation Peer Group, financial and operational characteristics are considered. The criteria for selection of the Compensation Peer Group included comparable revenue, approximately $2.4 billion to $13.4 billion (ranging from approximately 34% to 187% that of CMS Energy); relevant utility industry group; similar business mix (revenue mix between regulated and non-regulated operations); and availability of compensation and financial performance data.

The survey data indicate that the Company's overall officer compensation levels, assuming the EICP and restricted stock payment at the target market-based level, are reasonable.

In addition, annually proxy advisor services Glass Lewis & Co. and Institutional Shareholders Services assist institutional investors in their advisory vote on the reasonableness of compensation pay and practices of the proxy named executive officers by providing a vote recommendation. The incentive pay practices for the proxy named executive officers are the same as for the remaining officer group. In 2017, both proxy advisory service firms recommended a vote "for" the proxy named executive officer compensation pay and practices.

Q. Does the independent consultant provide other services for CMS Energy or Consumers Energy that could result in a conflict of interest?

A. No. The independent consultant is required to obtain approval of the Compensation Committees of the Boards of Directors before undertaking any activity on behalf of the management of CMS Energy or Consumers Energy. During the time the consultant has been engaged as the compensation consultant for the Boards of Directors, it has not performed any services on behalf of the management of CMS Energy or Consumers Energy. The independent consultant is hired by and serves the Compensation Committees; it is not hired by or providing services to CMS Energy or Consumers Energy.

Q. Are surveys the only determining measure used in setting officer compensation levels?

A. No. Additionally, the Compensation Committees consider experience levels and individual contributions of the respective officers.

Q. Are incentive plans for officers common in the utility industry or in other industries?

A. Yes, incentive plans are prevalent. Research from Mercer LLC, US Compensation Planning 2014/2015 survey indicates that approximately 96% of companies, and 98% of energy companies, offer annual incentive (variable pay) programs for officers. The survey data support the conclusions that including incentive pay as part of a competitive pay package is a standard practice, and is required to attract and retain qualified officers.

III. INCENTIVE COMPENSATION PLANS

A. Description Of Incentive Plans

Q. Please describe the EICP that is in place for 2017.

A. The EICP for 2017 is based on achieving performance goals related to critical areas of the Company's operations: (i) continuous improvement; (ii) safety; (iii) quality; (iv) cost; (v) delivery; (vi) morale; and (vii) being financially healthy.

The EICP goals seek to encourage employees to provide reliable energy, customer value, and responsive service to our customers, and to do so safely. Each year, the Company establishes utility specific performance criteria which focus on continuous improvement goals and breakthrough goals. For 2017, 12 specific operational performance measures and two measures related to being financially healthy were established. The EICP Performance Measures are summarized on Exhibit A-17 (AMC-1).

Q. Please describe Exhibit A-17 (AMC-1).

A. Exhibit A-17 (AMC-1) identifies the operational performance and financial performance areas that the EICP focuses on and identifies the specific measures that have been adopted for each of these areas. In the last column the year-end target is identified. As I indicated earlier, 50% of the non-officer incentive compensation is based on operational performance in continuous improvement, safety, quality, cost, delivery, and morale, and the remaining 50% is based on the financial performance.

Q. Will the structure of the EICP goals for 2018 be similar to 2017?

A. The specific performance measures and targets for 2018 have not been finalized yet. However, as in prior years, the performance measures will be a combination of measures related to operational performance and measures related to being financially healthy. I anticipate that, as for 2017, for non-officers the operational performance and financial health goals will be weighted equally. I anticipate that for officers the attainment of the financial measures will again be a threshold component with the operational goals as a modifier.

Q. Will the performance measures continue to incorporate measures that provide benefits to Consumers Energy's customers?

A. Yes. Performance measures will continue the focus on world class performance delivering hometown service and will continue to have as their foundation continuous improvement and breakthrough measures. While the number and precise phrasing of operational performance measures may vary from 2017, areas of focus will continue to include employee safety, public safety, reliability, quality, productivity, and customer care and financial measures.

Q. Please discuss the strategy and process for developing the EICP goals.

A. Company witness R. Michael Stuart provides a discussion of the strategy and process for developing the EICP goals.

Q. Why has the Company's management chosen to design the EICP with broad goals and objectives on a Company-wide basis rather than individual goals and objectives for individual employees?

A. It is necessary and appropriate for a large organization, such as Consumers Energy, to establish broad goals and objectives that are communicated to all employees as matters that are important to the success of the organization. Some employees will be in a better position to influence whether particular goals and objectives are met, but having every employee linked to a set of common customer-focused objectives is an effective method for emphasizing the importance of customer value and service. Having common goals and objectives: (i) provides clear communication of Company goals; (ii) encourages employees to support each other and work together for common goals; and (iii) provides a scorecard with a focus on corporate-wide goals that benefit customers.

Consumers Energy incorporates individual goals through the annual performance feedback process, which includes the creation and review of individual goals and objectives for each salaried employee and the opportunity to recognize and reward individual performance. The existence of a common set of customer objectives enables supervisors and employees to establish individual goals and objectives which are supportive of, and in alignment with, the corporate goals reflected in the EICP.

Q. How are the payout levels set that are shown on Exhibit A-17 (AMC-1)?

A. When setting payout levels, threshold is set at a level of achievement that can typically be reached eight or nine times out of every ten years. Maximum payout is for exceptional performance (one to two times out of every ten years). These levels are to engage the employees in meeting the goals. Employees, as a whole, must re-earn the incentive at-risk portion of compensation each year. If the threshold to achieve a payout was set at a level viewed as not achievable, it would be difficult to maintain employee motivation and would result in less customer benefits. Overall compensation levels, including the EICP at target (100%) level, that Consumers Energy seeks are not excessive. It is reasonable for Consumers Energy to pay its employees competitive levels of compensation.

Q. Should a refund mechanism be used for goals that are not achieved?

A. No. The goals are a collective package and the results should not be looked at in isolation. In fact, it would be wholly inappropriate to do so. The approach of looking at the goals as a complete package encourages improved performance and greater efficiencies from employees from which customers benefit. Further, the Company is only requesting that target level performance be included in rates.

Q. Why are you including both gas and electric performance measures in this plan as this is a gas rate case?

A. For purposes of efficiency and improved service, the Company has combined operations as one organization. For that reason, the plan contains both gas and electric measures.

Q. Are the two financial performance goals that are included in the EICP measures consistent with the Company's responsibilities to its customers?

A. Yes. Consistent financial performance is the result of total company performance including achieving operational success. Company witness Stuart quantifies this customer benefit for operating metrics in his testimony in this case. Also, an analysis of the cost of capital is discussed by Consumers Energy's witness Srikanth Maddipati in his testimony and Exhibit A-14 (SM-1), Schedule D-5 in this case. Having a financially healthy utility is important to delivering the energy our customers need when they need it, and to the State of Michigan as the Company is a vital part of the economy. It is in the customers' interests to have a financially healthy utility. This allows the utility to better meet customer needs at the best price. The two financial goals are balanced with operational performance criteria. Financial goals help focus employees on achieving superior results in a cost-effective manner. By focusing employees' attention on goals that encourage improved performance and greater efficiencies, customers are benefited. The incentive compensation goals are designed to help motivate employees to perform at their full potential and exercise discretionary effort to help move the Company forward.

Q. How are the targets for the annual officer EICP incentives measures determined?

A. As mentioned earlier, the goals are the same for the officer and non-officer EICPs, but the weightings are different.

Q. Why is the weighting different for the officer plan?

A. Officer annual incentive awards are based on the achievement of EPS and operating cash flow goals. These two metrics are good indicators of strategy execution. The officer annual incentive award is reduced if there is no award earned under the operational performance measures portion of the EICP and the award is increased (but in no event shall the award exceed the maximum of the target annual incentive) if the maximum award payout is achieved under the operational performance measures portion of the EICP. This potential adjustment provides linkage of executive compensation with the goals related to continuous improvement, safety, quality, cost, delivery, and morale.

Q. How are the EPS and operating cash flow components determined?

A. EPS is determined in accordance with: (i) generally accepted accounting practices; (ii) excluding asset sales; (iii) changes in accounting principles from those used in the budget; (iv) large restructuring and severance expenses greater than $5 million; (v) legal and settlement costs or gains related to previously sold assets; and (vi) regulatory recovery for prior year changes. Cash flow means: (i) generally accepted accounting principles operating cash flow with adjustments to include changes in power supply cost recovery from budget (disallowances excluded); (ii) changes in pension contribution;

(iii) changes in accounting principles from those used in the budget; and (iv) gas-price changes (favorable or unfavorable) related to gas cost recovery in January and February of the following performance year. The Compensation Committees review management's preliminary recommendations and establish final goals.

Q. How are the target amounts for the annual officer incentives determined?

A. The Compensation Committees determine the target amounts of the annual officer incentives. In determining the amount of target incentives, the Compensation Committees consider the following factors:

- The target incentive level, and actual incentives paid, in recent years;
- The relative importance, in any given year, of each performance goal established; and
- The advice of the Compensation Committees' compensation consultant as to compensation practices at other companies in the Compensation Peer Group and the utility industry.

B. <u>Assessment Of Customer Benefits Of The Incentive Compensation Plans</u>

Q. What level of expenses for Consumers Energy's incentive plans has been included in the "test year" revenue requirement?

A. The Company is requesting recovery of gas O&M expenses related to EICP incentive compensation plans at target (100%) levels. The level of expense is $1.8 million as illustrated in Exhibit A-18 (AMC-2). Incentive compensation for the proxy officers is not included in these amounts.

Q. How are the gas expenses of $1.8 million related to annual incentive compensation calculated?

A. The $1.8 million for EICP incentive compensation is based on the following:

- For officers: The rate case expense amount is based on 2017 salaries (excluding the proxy officers) multiplied by the approved target incentive percentage of salary from the 2017 Compensation & Human Resources Committee of the Board of Directors. Factors that impact the incentive expense year-over-year are retirements of officers and successors being at lower incentive amounts (decrease expense) and forecasted salary increases (increase expense), as indicated below; and

- For non-officers: The rate case expense amount is based on an estimate of the number of employees in each salary grade multiplied by the plan prescribed incentive target amount. Progression to higher salary grades as employees gain additional work experience will increase the amount of incentive expense year-over-year and headcount reductions will decrease the amount of incentive expense year-over-year.

Q. How was the gas portion of the incentive compensation expense determined?

A. The allocation percentages were supplied by the Accounting Department.

Q. Is a portion of the gas incentive compensation expense allocated between O&M and capital?

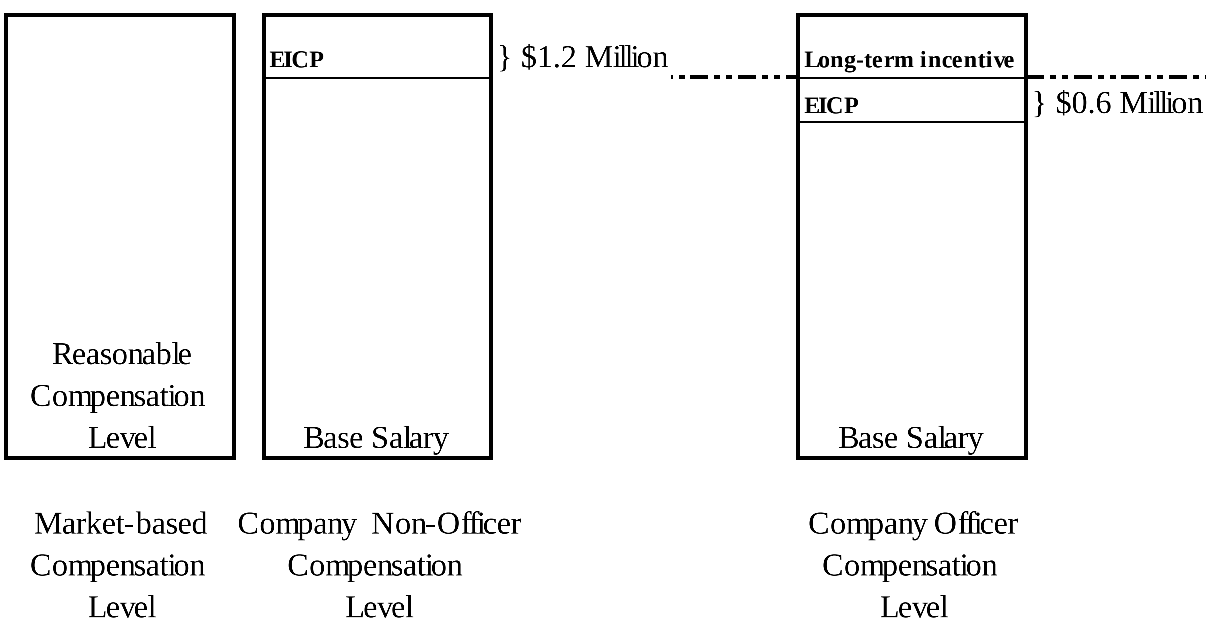
A. Yes. In the Company's Electric Rate Case No. U-17735, the Commission granted an Order approving the recovery of annual incentive (EICP) in rates for non-officers and non-proxy officers. As a result, in the first quarter of 2016 the Company began classifying annual incentive expense for the approved employee groups as a labor cost. The labor costs charge between O&M and capital based on labor studies performed by each business unit.

Q. Do Consumers Energy's gas customers benefit from making a portion of employee compensation subject to incentives?

A. Yes. Paying a competitive level of compensation is an essential prerequisite to being able to attract, retain, and motivate qualified employees. Consumers Energy has determined a reasonable level of compensation and then made a portion of that compensation at-risk. Structuring employee compensation so that it includes both base pay and incentive compensation provides motivation for an employee to strive for the total compensation for his or her position by contributing to the achievement of performance measures. Customers receive both qualitative and quantitative benefits at no additional cost above market-based compensation.

Q. Why do you say there is no additional cost above market-based compensation?

A. The officer and non-officer incentive plans are designed so that the total base salary plus incentive payments will be equivalent to the market-based compensation level. The EICP is part of the overall reasonable level of compensation. It is not in addition to it. This is illustrated in the following diagram:



Q. What is the appropriate standard from a business perspective in evaluating the reasonableness of the EICP costs?

A. Making a portion of compensation subject to incentives is a recognized, well-established, common practice in the utility industry and is reasonable and appropriate. The appropriate standard from a business perspective in evaluating whether the level of compensation is reasonable, is whether the *overall* level of compensation, including both base salary and incentive compensation, is reasonable. Using this standard would also be appropriate for ratemaking purposes. Looking at whether the overall level of compensation is reasonable will provide a better indication of whether the incentive plan results in excess rates rather than attempting to examine the cost allocable to the incentive compensation compared to benefits to customers. The overall level of compensation that Consumers Energy has included in its request in this case is reasonable.

Q. Are you aware of what criteria the Commission identified for review of employee incentive plan costs in its December 22, 2005 Order in Consumers Energy's Electric Rate Case No. U-14347?

A. Yes. In its Order in that case, the Commission stated:

> "In Case Nos. U-10149 and U-10150, the Commission determined that executive bonus and employee incentive plans require a showing that the plan will not result in excess rates and that the benefits to ratepayers from the bonus and incentive plans will, at a minimum, be commensurate with the programs' costs."

Q. Do you believe that Consumers Energy's EICP compensation meets these criteria?

A. Yes. Evidence which I present and which Mr. Stuart presents support finding that the including the EICP costs at the 100% payout level will not result in excessive rates and that the costs of the EICP will, at a minimum, be commensurate with the programs' costs.

Q. Are you aware of what criteria the Indiana Utility Regulatory Commission ("IURC") identified in a 2011 Order involving Southern Indiana Gas and Electric Company in reviewing whether incentive compensation is recoverable in rates?

A. Yes. In a 2011 Order issued by the IURC regarding Southern Indiana Gas and Electric Company (doing business as Vectren Energy), the IURC stated:

> "The Commission recognizes the value of incentive compensation plans as part of an overall compensation package to attract and retain qualified personnel. The criteria for the recovery of incentive compensation plan costs are well established. We will allow recovery in rates when: (1) the incentive compensation plan is not a pure profit-sharing plan, but rather incorporates operational as well as financial performance goals; (2) the incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce; and (3) shareholders are allocated part of the cost of the incentive compensation programs." IURC Case No. 43839, April 27, 2011, page 50.

In that case, the IURC allowed recovery of incentive compensation costs by the utility.

Q. How do these IURC criteria differ from criteria applied by the MPSC in Consumers Energy's Case No. U-14347?

A. The IURC recognized the value of incentive compensation plans as part of an overall compensation package to attract and retain qualified personnel. Instead of requiring a quantification of customer benefits specifically related to the metrics, which can be extremely difficult for measures that support undeniably desirable achievements (*e.g.*, improved customer satisfaction and safety), the Indiana criteria require there be a combination of operating and financial metrics and a demonstration that there is no resultant excess compensation. These requirements, as applied by the IURC in its 2011 Order, provide a reasonable approach to evaluate whether an incentive plan benefits customers and whether it results in excessive rates.

Q. Would the EICP plans in place at Consumers Energy meet these requirements?

A. Yes. Consumers Energy's EICP is part of an overall compensation package to attract and retain qualified personnel which meets these requirements, as applied by the IURC in its 2011 decision.

Q. Please discuss the first standard under the IURC criteria.

A. The first standard requires that the incentive compensation plan “incorporates operational as well as financial performance goals.” At page 50 of its April 27, 2011 Order, the IURC stated that the annual incentive compensation plan under review incorporated non-financial measures such as safety, customer satisfaction, and unit availability in addition to financial performance measures. It appropriately rejected the argument that incentive plan costs should be disallowed to the extent they relate to financial measures. As discussed above, the Consumers Energy EICP includes non-financial operational performance goals in addition to financial goals. The Company’s EICP meets the first standard of the criteria. It provides a balanced approach to controlling costs and efficiently serving customers which will both benefit customers in the short- and long-run and improve the Company’s utility’s financial health. These goals are not mutually exclusive.

Q. Please discuss the second standard under the IURC criteria.

A. The second standard involves whether the incentive compensation results in “pay levels beyond what is reasonably necessary to attract a talented workforce.” In applying this standard, the IURC stated that the evidence showed the utility’s Human Resources Department evaluated the competitiveness of its compensation package, and a compensation package was developed that was market competitive. This is also true for Consumers Energy’s compensation. As was true in the Indiana case, base pay plus annual incentives are within the market competitive range as established by peer companies and a broader national sample. The second standard of the IURC criteria provides confirmation that Consumers Energy has used a reasonable methodology and its

EICP incentive compensation plan does not result in excessive pay beyond what is reasonable to attract and retain a talented workforce.

Q. Please discuss the third standard under the IURC criteria.

A. In applying the third standard, the IURC noted that the utility was only seeking funding for its incentive compensation plan up to the approved target level. It stated that the evidence showed that the shareholders would bear the expense of incentive compensation in excess of the target level. The IURC found that shareholders were, therefore, allocated part of the utility's compensation costs. Consumers Energy's incentive plans meet this standard, as applied by the IURC.

Q. How does the Company's proposal for recovery of incentive compensation costs result in a sharing of costs with the Company's shareholders?

A. Non-officer EICP payments made in 2015, 2016, and 2017 averaged at 127% of the target level. The Company's proposal to include incentive compensation costs at target levels will result in the Company absorbing the incentive compensation costs in those years when the actual payouts are greater than target level. In the 2016 historical test year this equated to $0.4 million of the actual $1.8 million of non-officer O&M expense based on the 133% payout. Also, this equated to shareholders absorbing $0.1 million of the actual $0.6 million of non-proxy officer O&M expense based on the 141% payout. Thus, shareholders will absorb any resulting increase in costs arising from above target performance. If actual payouts in future years are less than target levels due to inadequate financial performance, then the Company's shareholders will absorb the consequence of inadequate financial results.

In addition, the Company is allocating to shareholders 100% of the costs of incentive compensation for the proxy officers as identified by the SEC proxy rules.

Q. Is the payment of incentive compensation reasonable given the economic conditions facing the Company's customers?

A. Yes. The incentive compensation costs are reasonable costs of doing business. The market median of survey data reflects current economic conditions and current pay practices. The Company maintains an annual practice of surveying the external market. Any trends in compensation – increases/decreases – would be reflected in the market survey results. Paying a reasonable level of compensation is reasonable and is in the interests of the Company's customers. Incentive compensation does not result in excessive compensation and is reasonably necessary to attract, retain, and motivate a talented workforce. Further, gaps between the skills that employers require and those available in the labor market are growing. Paying a reasonable level of compensation, which includes incentive compensation, is necessary to attract, retain, and motivate a talented workforce.

Q. Is the EICP a bonus or profit sharing plan?

A. No. The EICP is not a bonus or profit sharing plan. A bonus is a discretionary payment given without predetermined goals or objectives and a profit sharing plan entitles employees to a share of the profits of the company. Consumers Energy offers incentive compensation, which is based on predetermined goals, objectives, and award levels. Incentive compensation is part of an employee's overall compensation and not in addition to it, like a bonus or profit sharing plan. The fact that a portion of compensation is in the form of an incentive payment does not mean that employees are paid in excess of market rates when they receive their incentive payment. Employee compensation is a reasonable cost of doing business. If overall compensation levels are reasonable, then those costs should be recoverable through utility rates.

Q. What are some of the ways the EICP incentives benefit customers?

A. Customers derive benefits by having a portion of compensation shifted to the EICP Program since the goals of the program are in the interests of customers. Customer benefits are achieved without any additional cost to customers since this program has been structured as a "carve out" of the employee's base salary. If the EICP costs had not been allocated to incentive compensation, those costs would need to be recovered as base compensation in order for Consumers Energy to have a reasonable competitive level of compensation.

Also, customers are best served when Consumers Energy can attract, retain, and motivate talented salaried employees and executives with compensation packages that are competitive and fair. Performance-based incentives (like Consumers Energy's) permit the Company to provide an incentive to accomplish specific annual goals that represent performance priorities for Consumers Energy and its customers. With variable pay, the employee and the Company as a whole must re-earn the incentive award every year. If performance goals are not achieved, cash compensation is reduced or eliminated. Variable pay creates a performance culture rather than an entitlement culture.

In addition, an incentive program structured to focus employee attention on operational performance measures in areas of continuous improvement, safety, quality, cost, delivery, and morale results in both qualitative and quantitative customer benefits.

Among other things, customers benefit from increased productivity and quality and the focus on employee and public safety.

A quantitative analysis of the benefits received by the customer as a result of the EICP is discussed by Consumers Energy witness Stuart in his testimony in this case.

Further, customers are best served when Consumers Energy can raise capital at the best available rates. The use of earnings and cash flow measures in the EICP and officer annual incentive recognizes that Consumers Energy's financial health is important. Financial health provides appreciable benefits to customers by allowing Consumers Energy to maintain an attractive cost of capital and broader access to liquidity, in addition to any benefits provided to investors. An analysis of the cost of capital is discussed by Consumers Energy witness Maddipati in his testimony in this case.

Q. How do customers benefit from the focus on employee safety?

A. Customers directly benefit from having a qualified, talented, and motivated workforce that is focused on areas such as safety. The incentive compensation program encourages employees to deliver their best performance for customers. This is illustrated in the area of safety. The number of safety incidents in 2006 was at 495. In 2007, the number of incidents increased to 558. For six of the last eight years, incidents have decreased: 355 in 2008, 258 in 2009, 207 in 2010, 149 in 2011, 119 in 2012, 137 in 2013, 150 in 2014, 106 in 2015, and 73 in 2016. This decrease from 2006 to 2016, of approximately 85%, can be directly attributed to the significant emphasis Consumers Energy has placed on safety during this period. The decrease in safety incidents helps reduce lost days and helps reduce medical costs from levels that would otherwise occur. The safety components of the EICP performance measures have been an important part of keeping all employees focused on safety. This is an example of how all employees can be motivated and engaged in achieving a common Company goal through use of the EICP.

Q. Has Consumers Energy assessed whether benefits to customers of this program equal or exceed costs?

A. Yes. The performance measures provide appreciable benefits to customers. The benefits to customers of the Company's EICP Program outweigh the costs of the program. The costs of the EICP are projected at $1.8 million for the test year. Since this amount is part of the overall level of reasonable compensation, rather than being in addition to it, all benefits to customers are achieved at zero additional cost to customers. Achievement of the Company's EICP goals and objectives result in pay that is competitive with the labor market, not above the market. The EICP costs are not in addition to the reasonable level of compensation, they are part of the reasonable level of compensation. If these amounts are not paid, then overall compensation would be at a level which is below the market level. There is no valid basis to eliminate incentive costs from the cost of service recovered in rates because they are a part of an incentive plan rather than including these costs as part of base pay. As stated before, overall levels of compensation are at levels that are not excessive. Rate recovery of 100% should be allowed.

IV. <u>CONCLUSION</u>

Q. Is the Company's overall compensation program, including the customer-focused incentive, reasonable?

A. Yes. The approach used by the Company is a reasonable approach, is consistent with industry standards, and represents well-established best practices for creating customer focus through compensation design, and it does so without any additional customer cost above the market. The overall compensation levels are reasonable relative to the market, are determined in a reasonable manner, and are a reasonable cost of doing business. Compensation is structured in a manner that rewards improved operational and financial performance that benefits customers. The incentive compensation costs should, therefore, be included in the cost of service recovered from customers. These are legitimate and reasonable costs of doing business. Rates established in this rate case should include $1.8 million for incentive compensation expense.

Q. Please summarize reasons why full recovery of incentive compensation costs should be allowed in this case.

A. Reasons that full recovery of compensation costs should be allowed include the following:

- Employee compensation is a reasonable cost of doing business, has been set at a reasonable level, and has been determined using a reasonable methodology;
- The amount of compensation that is subject to incentive measurements is part of the market-based compensation level, not in addition to it;
- The incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce;
- Making a portion of compensation subject to incentives is a recognized, well-established, and common industry practice and is neither irrational nor unreasonable;
- The decision of Consumers Energy to allocate a portion of overall compensation that would otherwise have been in base pay so that it is subject to incentives does not provide a valid basis to disallow these expenses;
- The plan incorporates operational as well as financial performance goals;
- Benefits of having a portion of compensation subject to incentives occur at no additional cost above market-based compensation to customers given the compensation structure adopted;

- Investors, including shareholders, bear the expense of incentive compensation in excess of the target levels and for incentive compensation provided to proxy officers; and

- The focus should be on whether the overall level of compensation is reasonable, not on the precise structure of the compensation program.

It is reasonable for Consumers Energy to pay its employees competitive levels of compensation. Paying employees at competitive market levels is reasonable and prudent. Those costs are reasonable costs of doing business and are recoverable from customers. Since the total level of compensation – including both base pay and incentive pay – is reasonable, that justifies the expense. Customers do not pay more than the reasonable level of compensation.

Q. Does this conclude your testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-18424
distribution of	)	
natural gas and for other relief.	)	
____	)	

REBUTTAL TESTIMONY

OF

AMY M. CONRAD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2018

AMY M. CONRAD
REBUTTAL TESTIMONY

Q. Please state your name and business address.

A. My name is Amy M. Conrad, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Amy M. Conrad who previously submitted direct testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut to the direct testimony and exhibits presented by witnesses for the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") and the Attorney General regarding Consumers Energy Company's ("Consumers Energy" or the "Company") incentive compensation plan and the recommendations to exclude incentive compensation costs from the revenue requirement in this case. For the reasons discussed in my direct testimony, and in this rebuttal testimony, the Commission should find that the incentive compensation costs that Consumers Energy is seeking to recover in this case are reasonable costs of doing business and should be included in rates. Consumers Energy has acted reasonably in paying its employees at market levels, and it would be unreasonable to not allow the Company to have that reasonable and appropriate business expense recovered in rates.

Q. How is your rebuttal testimony organized?

A. In Section I of my rebuttal testimony, I address the direct testimony and exhibits presented by Staff witness Brian Welke. In Section II of my rebuttal testimony, I address the direct testimony and exhibits presented by Attorney General witness Sebastian Coppola.

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

A. No.

I. <u>REBUTTAL TO STAFF WITNESS WELKE</u>

Q. Mr. Welke discusses Employee Incentive Compensation Plan ("EICP") expenses at page 2 through page 5 of his direct testimony. What portions of this direct testimony are you rebutting?

A. I agree with Mr. Welke's recommendation for full recovery in rates of the portion of the EICP expense that is tied to operational measures. However, I disagree with Mr. Welke's recommendation to exclude the half of the non-officer EICP expense tied to financial measures. I also disagree with Mr. Welke's recommendation to exclude the non-proxy officer EICP expense.

Q. Mr. Welke, in his direct testimony and on Exhibit S-3, Schedule C5, has recommended that an EICP expense amount of $590,000 be included in rates, and has made an adjustment to remove $1,162,550 of incentive compensation expense. Do you agree with this adjustment?

A. No. For the reasons stated in my direct testimony, and in this rebuttal testimony, the full amount of the non-officer EICP expense of $1,180,000 and the full amount of the non-proxy officer EICP expense of $572,550 should be included in rates. These amounts are shown on Exhibit A-18 (AMC-2). The difference of $590,000 reflects the inclusion of the $590,000 excluded by Mr. Welke from the non-officer EICP, and the $572,550 excluded by Mr. Welke from the non-proxy officer EICP. Making this adjustment results in a projected test year EICP expense, assuming payout at 100%, of $1,752,550. This is the EICP amount that should be included in rates in this case.

Q. Mr. Welke indicates in his direct testimony that he excluded $1.163 million of EICP costs from his recommendation because they relate to financial measures. Do you agree with his conclusion that these costs should be excluded?

A. No. The Commission should not adopt Mr. Welke's recommendation to exclude EICP incentive plan costs that relate to financial measures from the revenue requirement. Reasons that the Commission should reject Mr. Welke's recommendation to exclude EICP costs that relate to financial measures include:

i. Mr. Welke has concluded that Consumers Energy has sufficiently satisfied the criterion that the benefits to customers from operational measures outweigh the costs. In his direct testimony, Company witness Daniel G. Shirkey[1] quantified an annual benefit to gas customers of $61.5 million. This far exceeds the $1.753 million annual expense to customers which results from the inclusion of the $1.163 million that relate to financial measures in addition to the $0.59 million that relate to operational measures. Since the quantified benefits to customers from operational measures exceeds total expense for the EICP of $1.753 million, adding financial incentives as part of the EICP measures in addition to the operational measures, does not harm customers. The operational benefits alone support the inclusion in rates of $1.753 million of EICP expense which the Company is seeking;

ii. Mr. Welke's conclusion that financial measures do not benefit customers is incorrect. The financial measures provide appreciable benefits to customers by allowing Consumers Energy to maintain an attractive cost of capital, among other benefits, in addition to any benefits provided to shareholders. The two are not mutually exclusive. As discussed in my direct testimony, in this rebuttal testimony, and in the testimony of Company witness Srikanth Maddipati, customers benefit from having a financially healthy utility; and

iii. Consumers Energy has presented evidence that the overall employee compensation levels are developed using market surveys with average compensation for jobs targeted at market medians. These overall levels of compensation are reasonable and are developed in a reasonable manner. A portion of these reasonable amounts does not become unreasonable because Consumers Energy has made a management decision to make a portion of this overall compensation, subject to meeting certain performance criteria. Yet, that is the effect of Mr. Welke's recommendation to exclude a portion of the EICP expense from the revenue requirement.

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[1] Company witness Shirkey is adopting the pre-filed direct testimony of Company witness R. Michael Stuart.

For all of these reasons, individually and in combination, Mr. Welke's recommendation to exclude $1.163 million of EICP expense from the revenue requirement should be rejected, and the full projected test year annual EICP total of $1.753 million shown on Exhibit A-18 (AMC-2) should be included in the revenue requirement calculation.

Q. On page 4 of his direct testimony, Mr. Welke states: "the Commission found that incentive compensation plans that were tied to Company earnings and cash flow were financial considerations that largely benefit shareholders and should not be paid by ratepayers." Do you agree with this statement?

A. No, I disagree with the recommendation to exclude incentive plan costs that relate to financial measures because these measures benefit customers.

Q. Please explain why you concluded that the financial measures benefit customers.

A. It is important that the utility remain financially strong so that it can provide the utility service that customers expect and deserve. It is in the customers' interests to have a financially healthy utility. This allows the utility to better meet customer needs at the best price. The two financial performance goals are balanced with the operational performance criteria. Having a financially healthy utility is important to customers and to the State of Michigan. Financial goals help focus employees on achieving superior results in a cost-effective manner. By focusing employees' attention on goals that encourage improved performance and greater efficiencies, customers are benefited. The incentive compensation goals are designed to help motivate employees to perform at their full potential and exercise discretionary effort to help move the Company forward.

The Company must ensure that its financial performance supports these investments. The incentive compensation plans described in my direct testimony help the

Company achieve that objective. Good financial health leads to lower costs of capital for Consumers Energy and broader access to liquidity to the benefit of customers. For evidence of this, one observes utility bond spreads, or the difference in yields (rate of return), between high investment-grade and low-investment grade companies. The differences in bond spread, or yield, are an indication that a financially healthy company with higher credit ratings will generally have lower credit spreads and a lower overall cost of capital, which clearly benefits customers. This is why, for instance, an A-rated company has a lower cost of capital than a B-rated company. An analysis of the cost of capital is discussed by Consumers Energy witness Maddipati in Exhibit A-14 (SM-1), Schedule D-5, page 12, in his direct testimony and in his rebuttal testimony in this case.

Q. Do you agree with Mr. Welke's statement that financial measures "largely benefit shareholders"?

A. No. While financial measures may provide benefits to shareholders, this does not mean that they do not provide meaningful benefits to customers. As discussed in Company witness Maddipati's direct testimony, the two are not mutually exclusive. Further, if overall compensation levels are reasonable, then the allocation of such costs between base salary, annual incentive, and long-term incentive should be disregarded and overall compensation levels should be recoverable through utility rates.

Q. Under the Company's proposal, do shareholders bear a portion of the EICP costs?

A. Yes. The Company's incentive compensation proposal in this case results in shareholders bearing a portion of these costs. The Company's proposal to include incentive compensation costs at target levels will result in the Company absorbing the incentive compensation costs in those years when the actual payouts are greater than target level. Thus, shareholders will absorb any resulting increase in costs arising from above target performance. If actual payouts in future years are less than target levels due to inadequate financial performance, then the Company's shareholders will absorb the consequence of inadequate performance results, along with customers. In addition, the proposal in this case excludes the expenses related to the named officers in the proxy statement. The Company is allocating to shareholders 100% of the costs of incentive compensation for the proxy officers as identified by the Securities and Exchange Commission proxy rules.

Q. If the Commission concludes that customers should not pay 100% of the portion of the EICP costs that relate to financial measures due to shareholder benefits, would Mr. Welke's recommendation to exclude 100% of incentive plan costs that relate to financial measures from the revenue requirement be warranted?

A. No. While I believe that 100% recovery from customers of the portion of the EICP costs that relate to financial measures is appropriate for the reasons discussed in my direct and rebuttal testimony, if the Commission disagrees, then a 50/50 sharing of the portion of the EICP costs that relate to financial measures should be adopted rather than a complete disallowance of those costs. One half of Staff's recommended EICP disallowance of \$1.163 million is \$0.581 million. Adopting a 50/50 sharing would increase the \$0.59 million EICP expense recommended by Staff to \$1.171 million. If the Commission concludes that customers should not pay 100% of the portion of the EICP costs that relate to financial measures due to shareholder benefits, then it should, at a minimum, include EICP expense of \$1.171 million in the revenue requirement calculation.

Q. Mr. Welke states that the Company has been unwilling to share the benefits of the achievement of financial measures with ratepayers on a projected basis. As an example, he points to Case No. U-18322 where Staff requested a reconciliation of the expense projections made in that case with projected 2% Operating and Maintenance ("O&M") savings made to investors. Do you agree with this reason for excluding incentive compensation related to financial metrics?

A. No, because overall levels of compensation for Consumers Energy are reasonable and are developed in a reasonable manner. Specific information regarding the 2% O&M savings is addressed in Company witness Andrew J. Denato's rebuttal testimony.

Q. Do you agree with Mr. Welke's statement that the fact that financial measures were undefined should result in disallowance of recovery?

A. No. Information regarding Earnings Per Share ("EPS") and operating cash flow guidance is publically available on the Company's website. For 2017, the EPS target was $2.14 (6% growth from prior year actuals) and the Operating Cash Flow goals was $1.650 million ($100 million increase from prior year). CMS Energy does not provide forecasted stock price information prospectively outside of our annual earnings guidance. To do so in this rate proceeding would violate Securities and Exchange Commission regulations.

II. REBUTTAL TO ATTORNEY GENERAL WITNESS COPPOLA

Q. In his direct testimony, Mr. Coppola refers to the $1.8 million of short-term incentive compensation that Consumers Energy is seeking in this case as a "bonus." Is this a correct description of Consumers Energy's incentive compensation?

A. No. As I testify at page 33 of my direct testimony, the EICP is not a bonus or a bonus plan. A bonus is a discretionary payment given without predetermined goals or objectives, and is not part of total cash compensation market levels. Consumers Energy offers incentive compensation, which is based on predetermined goals and objectives and award levels. Incentive compensation is part of an employee's overall compensation and not in addition to it, like a bonus. The fact that a portion of compensation is in the form of an incentive payment does not mean that employees are paid in excess of market rates when they receive their incentive payment. Consumers Energy uses market data to determine an overall competitive level of compensation. Mr. Coppola's characterization of the EICP as a bonus, at page 31 of his direct testimony and elsewhere, is incorrect.

Q. At page 33, lines 10 and 11 of his direct testimony, Mr. Coppola states: "Generally, the Company's short-term incentive plans are too heavily weighted toward financial measures that mostly benefit shareholders and not customers." Do you agree?

A. No. As stated in my rebuttal response to Mr. Welke, it is important that the utility remains financially strong so that it can provide the utility service that customers expect and deserve. This allows the utility to better meet customer needs at the best price. As discussed in my direct testimony, and above in rebuttal to Mr. Welke, including both operational measures and financial measures benefits customers.

Further, as I discuss above, the Company's proposal to include incentive compensation costs at target levels will result in shareholders absorbing the incentive compensation costs in those years when the actual payouts are greater than target level and for the proxy officers.

Q. At page 34, lines 3 through 7 of his direct testimony, Mr. Coppola disagrees that customers benefit from the financial incentives in the EICP. Is his conclusion correct?

A. No. As I discuss above, there are customer benefits. It is a basic tenant of financing that investors have a limited amount of funding and that companies with better credit ratings, all other things being equal, can obtain capital at a lower cost of capital, and greater access to liquidity. In addition, Mr. Coppola is incorrect in his belief that Consumers Energy has not offered proof in support of its argument. Benefits to customers are discussed by Company witness Maddipati at page 54 of his direct testimony, and illustrated on his Exhibit A-14 (SM-1), Schedule D-5, page 12.

Q. At page 35 of his direct testimony, Mr. Coppola states: "Another concern is the low threshold to achieve a payout under the EICP." Is Mr. Coppola's belief that the Company's EICP operating measures have a low payout threshold correct?

A. No. Employees, as a whole, must re-earn the incentive at/risk portion of compensation each year. If the threshold to achieve a payout was set at a level viewed as not achievable, it would be difficult to maintain employee motivation and would result in less customer benefits. Overall compensation levels including the EICP are established at a target (100%) level that is not excessive. The incentive compensation portion of the Company's total compensation ensures that employees are provided a reasonable incentive to achieve exceptional performance levels. The Company's proposal to include incentive compensation costs at target levels will result in the Company absorbing the incentive compensation costs in those years when the actual payouts are greater than target level. Thus, shareholders will absorb any resulting increase in costs arising from above target performance.

Q. At page 35 of his direct testimony, Mr. Coppola states: "[T]he fact that the performance measures use CMS Energy financial information and comingle electric and gas business measures is a concern." Do you agree?

A. No. The incentive structure incorporates continuous improvement, safety, quality, cost, delivery, morale, and financial performance measures. Performance in these areas is critical for the Company's success in its gas public utility business. For purposes of efficiency and improved service, the Company has combined operations as one organization. For that reason, the plan contains both gas and electric measures. The related incentive expense is then allocated between electric and gas businesses based on multiple factors determined by the Accounting Department based on the type of activities the departments or business units perform. These factors include but are not limited to: (i) percentage of time; (ii) property, plant, and investments; (iii) operating revenue; (iv) headcount; and (v) labor. Only the gas portion of the EICP expense is being requested in this case.

Q. At page 35 of his direct testimony, Mr. Coppola states: "The Company has stated that it continues to pay salary increases each year of approximately 3% and has included such an increase also in the test year O&M expenses for all employee labor costs." He states that salary increases have historically been higher than this percentage. Mr. Coppola goes on to state at page 36: "Such significant increases in compensation are difficult to justify when one considers that in Michigan the Median Household Income has declined from $55,812 in 2005 to $52,492 in 2016." Do you agree?

A. No. Consumers Energy's salary structures and trends are reviewed annually. The Company uses salary survey data from utility and energy companies in the Midwest/Central region. I present evidence in my direct testimony that the overall compensation levels are reasonable relative to the market, are determined in a reasonable manner, and are a reasonable cost of doing business. The Company's merit increases have aligned with market data. Two independent third party surveys, 2016 Mercer survey and 2016 Conference Board survey, both showed that pay increases are expected to be 3.0%. This increase correlates to historic and projected merit budgets. Customers are best served when Consumers Energy can attract, retain, and motivate a talented work force with compensation packages that are competitive and fair.

Q. At pages 33 through 36 of his direct testimony, Mr. Coppola discusses various reasons that he disagrees with the Company's request to recover incentive compensation costs in rates. Do the concerns and issues identified in his direct testimony provide a valid basis to not allow any recovery of incentive compensation costs in rates?

A. No. I disagree with his analysis and his conclusions. Mr. Coppola's conclusion that Consumers Energy's incentive compensation plans do not benefit customers is not correct. A wide body of research supports the view that, when properly selected and implemented, as has been done with the Consumers Energy plans, incentives motivate employees, focus employees on a company's goals, and increase both individual work performance and team performance. The overall compensation levels are reasonable. The incentive compensation is part of the overall reasonable compensation level, not an addition to it.

Q. Does this conclude your rebuttal testimony?

A. Yes.

(Documents were marked for identification by the Court Reporter as Exhibit A-41, Exhibit A-42, and Exhibits A-99 through A-104.)

MS. UITVLUGT: The Company requests at this time that the direct testimony of Danielle M. Hill be bound into the record. The direct testimony of Ms. Hill consists of a cover page and 22 pages of questions and answers. Additionally, Ms. Hill sponsored rebuttal testimony which consists of a cover page and 14 pages of questions and answers.

I would also move for the admission of Ms. Hill's exhibits. Ms. Hill sponsored Exhibit A-41, Exhibit A-12 Schedule B5.2, Exhibit A-42, Exhibit A-99, Exhibit A-100, Exhibit A-101, Exhibit A-102, Exhibit A-103, and Exhibit A-104.

JUDGE SONNEBORN: Thank you. Are there any objections to binding into the record the direct and the rebuttal testimony of Danielle M. Hill, as well as the admission into evidence of her exhibits as described by Ms. Uitvlugt?

Hearing no objection, Ms. Hill's testimony is bound into the record and her exhibits are admitted into evidence.

MS. UITVLUGT: Thank you, your Honor.

(Testimony bound in.)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
	)	

DIRECT TESTIMONY

OF

DANIELLE M. HILL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2017

DANIELLE M. HILL
DIRECT TESTIMONY

Q. Please state your name and business address.

A. My name is Danielle M. Hill, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Director of Portfolio and Performance Management for Generation Engineering and Services – Energy Resources, Portfolio and Performance Management.

Q. Please describe your educational background.

A. In 2006, I received a Bachelor of Arts in Accounting from Michigan State University. In 2010, I received a Master of Business Administration from Central Michigan University.

Q. Please describe your business experience.

A. My professional working career began in 2007 as a Staff Accountant for Centex Homes. In this position, I managed the monthly reconciliation process, miscellaneous journal entries, and month-end close. In 2009, I joined Anesthesia Business Consultants. In this position, my responsibilities included payroll, general ledger analysis, preparation of financial statements, month-end close, monthly budgets, accounts payable, and cash management. In 2010, I accepted a position as an Engineering Capital Accountant with Campbell Soup Company. In this position, my responsibilities included management and oversight of capital spending, development of the long-term strategic plan, and monthly budget forecasting and adherence. In 2011, I was promoted to Senior Plant Analyst where I assumed responsibility as the finance lead for the SAP advanced planning system. My responsibilities also included production and packaging, labor and overhead variance reporting, month-end close preparation, and oversight of the annual operating plan development.

In 2014, I joined Consumers Energy as a Financial Analyst within Energy Resources Business Service. In this position, my responsibilities included support of the Long-Term Financial Plan ("LTFP"), business plan, and key performance indicator reporting for Energy Resources. In 2016, I was promoted to Senior Financial Analyst – Lead and subsequently to my current position as Director of Portfolio and Performance Management. In this position, I am responsible for the development of the LTFP, as well as leading a team of Financial Analysts which support the LTFP, financial, performance, and business reporting. In addition, I am a licensed Certified Management Accountant.

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

A. Yes. I sponsored testimony in MPSC Case No. U-18322 (2017 Electric Rate case).

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to explain the Company's request for rate relief as it relates to the Company's Gas Compression, Storage ("GCS") and Gas Management Services ("GMS"). I have divided my direct testimony into four parts: (i) a description of the Company's GCS assets; (ii) a description of Operation And Maintenance ("O&M") expenses for the years 2016 through the projected test year (July 1, 2018 through June 30, 2019); (iii) a description of functions within Gas Compression and Gas Storage, and GMS; and (iv) a description of capital expenditures for the years 2016 through the projected test year (July 1, 2018 through June 30, 2019) for inclusion in the Company's rate base.

Q. Are you sponsoring exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-41 (DMH-1)		2016 – 12 Months Ended June 30, 2019 Gas Compression Storage and Gas Management Services O&M Expenses;
Exhibit A-12 (DMH-2)	Schedule B-5.2	2016 – 12 Months Ended June 30, 2019 Gas Compression Storage Capital Expenditures; and
Exhibit A-42 (DMH-3)		Storage Well Rehabilitation Detail.

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

A. Yes.

GCS ASSETS

Q. Please provide an overview of the Company's GCS assets.

A. The Company operates and maintains eight compressor stations, 15 storage fields, and approximately 1,000 wells throughout Michigan's Lower Peninsula. The compression fleet is comprised of 51 natural gas-fired engines which generate 166,475 Brake Horse Power ("BHP"), providing the pressure necessary to move gas in and out of the storage fields and to citygate stations. The Company's compression fleet (and the respective BHP) will change in the near future as two units are retired and four new compressor units are added at the St. Clair Compression Station ("St. Clair"). The St. Clair and Freedom Projects are discussed in more detail in Company witness Christopher T. Fultz's direct testimony.

The Company's storage fields are naturally occurring porous rock formations which are located deep underground. These rock formations hold natural gas, much like sponges hold water, and have a total working gas volume of 150,940 Million Cubic Feet

("MMCF"). Consumers Energy purchases 100% of the natural gas it provides to customers. Natural gas, which is placed in storage, flows through one or more of our numerous wells. The Company's GCS fleet is comprised of the following:

Compressor Stations:

Freedom	17,900 BHP	Manchester, MI
Muskegon River	34,272 BHP	Marion, MI
Northville	10,800 BHP	Northville, MI
Overisel	10,800 BHP	Hamilton, MI
Ray	36,751 BHP	Armada, MI
St. Clair	19,942 BHP	Ira, MI
White Pigeon	34,975 BHP	White Pigeon, MI
Huron	1,035 BHP	Sebewaing, MI

Gas Storage Fields:

Marion/Muskegon River		Marion, MI
Winterfield	25,300 MMCF	
Cranberry	11,000 MMCF	
Riverside	1,500 MMCF	
Northville		Northville, MI
Northville Reef	500 MMCF	
Lyon 29	1,230 MMCF	
Lyon 34	700 MMCF	
Overisel	23,000 MMCF	Hamilton, MI
Salem	11,600 MMCF	

St Clair		Ira, MI
Ray	48,100 MMCF	
Ira	2,000 MMCF	
Lenox	1,200 MMCF	
Puttygut	9,500 MMCF	
Swan Creek	420 MMCF	
Four Corners	2,390 MMCF	
Hessen	12,500 MMCF	

Q. What value do customers receive from the Company's GCS and GMS?

A. GCS and GMS is an important foundation to the Company's ability to ensure adequate supplies of natural gas are available for customers during long, cold winters. It is also an important foundation to maintaining affordable prices, as it allows the Company to take advantage of market conditions, while procuring adequate supplies to meet customers' needs. Finally, storage fields hold approximately 45 percent of the gas supply needed for customers through a typical winter.

<u>GCS AND GMS O&M EXPENSES</u>

Q. Please describe Exhibit A-41 (DMH-1).

A. Exhibit A-41 (DMH-1) identifies the 2016 – 12 Months Ended June 30, 2019 GCS and GMS O&M Expenses. Specifically:

- Column (a) identifies each O&M expense category;
- Column (b) identifies the Actual 2016 GCS and GMS O&M expense as $30,338,332;
- Column (c) identifies the Projected 2017 GCS and GMS O&M expense as $27,305,776;

- Column (d) identifies the Projected 2018 GCS and GMS O&M expense as $27,349,330;
- Column (e) identifies the Projected test year GCS and GMS O&M expense as $27,145,000;
- Line 1 identifies Base O&M expenses for 2016 through the test year of July 1, 2018 through June 30, 2019;
- Line 2 identifies Adjusted O&M expenses, which are expenses that are projected to change from past years' or have been requested to be called out separately;
- Line 3 identifies O&M expenses for Well Logging and are projected to decline from past years' due to the Well Rehabilitation Capital project. The remaining O&M expenses are to cover those costs that cannot be capitalized as part of the Well Rehabilitation Program discussed later in my direct testimony. An example of one of these expenses are for example employee training;
- Line 4 identifies Outside Services and are projected to decrease slightly from past years due to performing more maintenance with internal labor;
- Line 5 identifies Purchased Power which is projected to increase from past years; and
- Line 6 identifies Total O&M expenses for 2016 though the test year of July 1, 2018 through June 30, 2019.

Q. Please explain how the 2016 Actual O&M expenses were calculated.

A. The 2016 Actual O&M expenses were taken from Consumers Energy's internal accounting records.

Q. Please explain how the 2017, 2018, and Projected Test Year O&M expenses were calculated.

A. Consumers Energy tracks the history and future maintenance needs of each station and field. Once costs to operate and comply with regulations are prioritized, Energy Resources Business Services, with the support and input from Asset Strategy and Asset Management, evaluates the maintenance plans required to maintain and improve the condition of the plant. Using this information, a preliminary plan is prepared, reviewed (to ensure high-priority issues are addressed and adequate resources and funding are available), and approved by management. The overall objective is the safe, reliable, and cost-effective operation of the GCS operations.

Q. Please discuss Base O&M costs.

A. Base O&M costs projected in Exhibit A-41 (DMH-1) were developed by evaluating a unit's operating history and are broken into two categories – "labor" and "non-labor." Labor is the primary component and has a predictable increase. Because the Company has been in the natural gas business for over 60 years, the Company has an excellent basis to make accurate forecasts. Non-labor expenses are also predictable and include items required to operate. These items include, but are not limited to: (i) fuel (diesel and gasoline) for equipment and vehicles; (ii) material; (iii) tools; (iv) cleaning supplies; (v) facilities; (vi) security; and (vii) road and grounds maintenance.

Q. Please explain why the Projected Test Year O&M expenses proposed in Exhibit A-41 (DMH-1) are reasonable.

A. Base O&M costs are determined by operating history, and because these costs are relatively stable from year to year, accurate forecasting is achievable. This level of O&M expense allows the Company to provide reliable service by operating and maintaining equipment to meet customers' needs.

Q. Exhibit A-41 (DMH-1) includes labor and non-labor expenses for three areas within Consumers Energy: gas compression, gas storage, and GMS. Would you please provide further insight into each of these three areas?

A. Yes.

Gas Compression

Q. Please describe the primary functions of gas compression.

A. Gas compression has responsibility for the safe operation, maintenance, and performance of the Company's 51 natural gas-fired engines. These engines provide the pressure necessary to move gas in and out of the storage fields and to citygate stations.

Q. Do maintenance costs vary by individual compression engine(s)?

A. Yes, maintenance costs vary by individual compression engine(s). The Company's compression engines vary in age, size, type, and design.

Q. Is it common to have different size, type, and design differences?

A. Yes. Consumers Energy is not unique in that its fleet contains units of different size, type, and design.

Q. Please describe the work completed in a natural gas compressor engine maintenance inspection.

A. Compressor engine inspections consist of disassembling, inspecting, and cleaning the different components of the engine. During the inspection, worn or damaged parts are repaired or replaced to specific tolerances.

Q. How does Consumers Energy measure the success of its gas compressor engine maintenance program?

A. The Company measures Random Outage Rate ("ROR").

Q. What is the Company's current ROR, and how does it compare to previous years?

A. Through June 2017, ROR is 15.8%. In 2016, ROR was 10.7%, and in 2015, ROR was 7.8%. Consumers Energy's 2015 ROR was the lowest (best) ROR the Company has achieved in the history of utilizing this metric.

Q. Why is ROR increasing?

A. ROR is increasing, primarily, due to the St. Clair project. Consumers Energy has undertaken limited maintenance at St. Clair during the current project because the Company plans on retiring the old St. Clair units. As a result, ROR has increased. The Company anticipates the 2018 ROR will improve compared to 2017 when the old St. Clair units are retired and the new units are put into operation.

Q. Has the Company calculated the June year to date ROR without St. Clair?

A. Yes, without St. Clair, the Company's June year to date ROR would be 8.6%.

Q. What is the 2017 ROR goal?

A. The 2017 ROR goal is 8.5%.

Q. Do you expect that the Company will be able to maintain its target performance?

A. Yes. As explained by Company witness Fultz, Consumers Energy continues to move forward with plans to replace and upgrade compression units at both its St. Clair and Freedom locations. This work will not only improve reliability, but will help the Company to achieve high relative performance.

<u>Gas Storage</u>

Q. Please describe the primary functions of gas storage.

A. Gas storage has responsibility for the safe operation, maintenance, and performance of the Company's 15 storage fields and 1,000 wells.

Q. Please provide further insight into well maintenance.

A. Well maintenance is comprised of many different programs and has been the topic of media attention. Well logging is one of the primary components of well maintenance.

Well logging is an industry term which describes a method used to help assess storage well integrity.

Q. Please provide more detail on well logging.

A. Well logging includes the use of gamma ray logs for identification of gas accumulation behind casings, corrosion logs for internal and external casing corrosion, and cement bond logs to assess integrity of cement between the casing, surrounding rock, or additional casings. Additionally, well maintenance work is performed in conjunction with the well logging to mitigate the formation of skin damage. Skin damage is a term used to describe the reduction in the ability of the reservoir rock to store and deliver gas. Remediation removes solids, scale buildup, and compressor oils in the well accumulated during the normal process of injecting and withdrawing gas from storage.

Q. Do storage well integrity regulations currently exist?

A. Yes. On June 22, 2016, the Protecting our Infrastructure of Pipelines and Enhancing Safety ("PIPES") Act of 2016 was enacted. This new law was in response to the Aliso Canyon incident and required the Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") to set federal minimum safety standards for underground natural gas storage facilities and allows states to go above those standards for intrastate facilities. The PIPES Act of 2016 also improves protection of coastal areas, marine coastal waters, and the Great Lakes by explicitly designating them as unusually environmentally sensitive to pipeline failures.

Q. Did PHMSA set federal minimum safety standards?

A. Yes. PHMSA adopted two American Petroleum Institute ("API") Recommended Practices ("RP"): 1170 and 1171.

Q. Is Consumers Energy compliant with the standards set forth in API RP 1170 and 1171?

A. Not at this time. However, both API RP 1170 and 1171 allow 10 years for compliance. Also, API RP 1170 does not apply to Consumers Energy. API RP 1170 is specific to underground solution-mined salt cavern natural gas storage facilities. The Company owns and operates depleted hydrocarbon reservoirs – which are covered under API RP 1171.

Q. Is the Company projecting O&M expenses related to well logging in this case?

A. Yes. There are certain costs and situations that will result in O&M well logging expenses that cannot be capitalized as part of the Well Rehabilitation Program. These include observance of high annulus pressures, potential gas migration, potential leaks in casing, and abnormal well head pressure readings; these may require logging and mitigation that may not meet the requirements needed for capitalization. On wells that do not have tubing and packer, the Company may observe an increase in annular pressure often due to a leakage of the primary and secondary wellhead seals. In order to confirm the issue and rule out any other possible issues, logging may be required.

On wells with a packer that exhibits high annular pressure, the Company will log the well. If the logging data indicates that the well does not need a packer reinstalled, then the cost of logging would be considered an O&M expense.

Finally, throughout the course of the 10-year Well Rehabilitation Program, if the Company returns to any "rehabbed" well and needs to re-log the well, depending on configuration and the issues found, the costs associated with that logging may not be capitalized.

Q. Does gas storage have additional responsibilities?

A. Yes, gas storage is also responsible for the gas storage field inventory verification.

Q. Please describe the gas storage field inventory verification process.

A. As a prudent operating practice, Consumers Energy performs storage field pressure surveys at the conclusion of each injection cycle (usually September through November) and each withdrawal cycle (usually March through May). Storage well pressures are collected, the average field pressure is determined, and the results are plotted against the metered volumes. Plotting storage field pressure and inventory data provides a means of monitoring and trending storage field performance over time. It was through this process that the inventory balances at the above-mentioned storage fields were identified for adjustment.

Q. Why is the performance of storage field inventory verification a prudent practice?

A. Verification of storage field inventory after each injection and withdrawal cycle provides important data used to monitor the current condition of the storage field. In addition, storage field inventory verification provides a means of determining flow meter measurement accuracy and whether losses between the transmission and storage systems may be occurring as a result of valve leakage.

Q. What are the recent results from the gas storage inventory verification process?

A. The storage fields previously mentioned experienced deviations from the accounting booked figures. The Company typically adjusts gas storage inventory based on a deviation occurring for three consecutive years (considered long-term). Routine changes in operating parameters during a given injection or withdrawal season may cause short-term storage field pressure variations. These short-term pressure variations may cause the natural gas to migrate deeper into the reservoir rock formation, temporarily impacting the inventory survey results. Company personnel have investigated the integrity of these fields and believe most of the inventory adjustment is attributed to metering accuracy limitations or valves not sealing properly. The storage field inventory adjustment is addressed by Company witness Mary P. Palkovich.

Q. Why does the storage inventory deviation occur?

A. A common cause of the deviations and subsequent storage field inventory adjustments is valves not sealing properly. To remediate this cause, new valves were installed with the installation of ultrasonic meters over the last few years at storage sites. As part of the pressure survey work each spring and fall, the sealing capability of the valves used to isolate the storage field are inspected. The primary cause of valve leakage, as with the field meter, is debris affecting the sealing mechanisms in the valves. In addition, the electrical or hydraulic mechanical operators used to open and close the valves can go out of adjustment, not allowing the valve to fully close. When storage field isolation valves are found to be not sealing, the valve is repaired.

GMS

Q. Please describe the primary functions of GMS.

A. GMS has responsibility for four major functions:

- Gas Control;
- Gas Strategic Planning;
- Gas Supply; and
- Gas Transportation and Customer Choice Programs.

The Gas Control section is responsible for ensuring that adequate transmission and storage volumes and gas pipeline pressures are safely maintained on an instantaneous, daily, and seasonal basis for deliveries made to approximately 150 citygates. These citygates supply the Company's natural gas distribution system, which enables continuous reliable gas delivery to our customers, even during peak demand days in severe winters such as those experienced in Michigan in recent years. This section has responsibility for the centralized Gas Control Room operation, which monitors and controls the gas transmission system and key points on the distribution system on a 24/7 basis.

Gas Strategic Planning is responsible for studying and projecting changes in transmission and storage system requirements and proposing system improvement recommendations as well as the daily, monthly, and seasonal scheduling and planning of the transmission and storage systems. This section also has responsibility for the long- and short-term planning of gas supply requirements and the preparation of related financial forecasts.

The Gas Supply section is responsible for procurement of all gas supply and transportation arrangements and development of long- and short-term gas supply strategies.

The Gas Transportation and Customer Choice section manages gas nomination activity for all supplies entering the transmission and storage system. It also manages the Gas Customer Choice Program and all third-party gas storage and transportation functions.

GCS CAPITAL EXPENDITURES

Q. What are the major drivers in determining capital expenditures for GCS?

A. Over the last five years, the Company has invested significantly in upgrades for improved system reliability, deliverability, system integrity, safety, and customer service. These investments include the Ray Compressor Station upgrade which allowed the Company to fully utilize its compression and storage facilities to provide adequate supply during peak periods. In 2014, the Company set new Peak Hour Total System throughput, Peak Hour Sendout to citygates, and Peak 24-Hour Storage withdrawal records. In 2015, the Company established new records for Peak Hour Total System throughput, Peak Hour Sendout to citygates, and Peak 24-Hour Sendout to citygates. These system investments ensured continuous reliable service to customers during these extreme demand weather conditions. In this filing, the Company seeks recovery of capital expenditures intended to complete the St. Clair Compressor Station upgrade, to move forward with the design and engineering necessary for the Freedom Compressor Station upgrade, and to comply with new regulations resulting from the PIPES Act of 2016.

Q. Please describe Exhibit A-12 (DMH-2), Schedule B-5.2.

A. This exhibit presents the capital expenditures for GCS from the year 2016 through the projected Test Year. The expenditures are grouped by: Compression Sites, Storage Fields, Storage New Wells (line 13), and Well Rehabilitation (line 14).

Q. What is the Company's projected level of capital spending?

A. The Company's rate relief request in this case reflects capital spending on projects for its gas compression and storage sites of $31.7 million for 2016 (Actual), $15.9 million for the six months ending June 30, 2017 (Projected), $85.5 million for the 12 months ending

June 30, 2018 (Projected), $75.1 million for the 12 months ending June 30, 2019 (Projected), and $176.5 million for the 30 months ending June 30, 2019 (Projected).

Q. Please summarize the significant capital expenditures in 2016, 2017, 2018, and 2019 included on page 3 of Exhibit A-12 (DMH-2), Schedule B-5.2.

A. Line 1 of Exhibit A-12 (DMH-2), Schedule B-5.2, identifies the total capital expenditures for the Freedom Compression Station. The expenditures identified on line 1 are separate from the Freedom Upgrade Project. Company witness Fultz provides details of the Freedom Upgrade Project in his direct testimony. In 2016, costs were incurred for system monitoring equipment. In 2017 through 2019, for example, costs will be incurred for assessing system integrity.

Q. Please identify the capital expenditures projected for the Muskegon River Compression Station.

A. Line 2 of Exhibit A-12 (DMH-2), Schedule B-5.2, identifies the total capital expenditures for the Muskegon River Compression Station. In 2016, costs were incurred for unit monitoring and the relocation of Plant 3's relief stack. In 2017 through 2019, examples of projected costs include: unit overhaul, rebuilds, and unit monitoring.

Q. Please identify the capital expenditures projected for the Northville Compression Station.

A. Line 3 of Exhibit A-12 (DMH-2), Schedule B-5.2, identifies the total capital expenditures for the Northville Compression Station. In 2016, costs were incurred for engine control upgrades and installation of a compressor discharge check valve. In 2017 through 2019, examples of projected costs include: replacement of the uninterrupted power supply system, electrical system upgrades, replacement of the back-up generator, engine control upgrades, and a Safety Valve Replacement Program.

Q. Please identify the capital expenditures projected for the Overisel Compression Station.

A. Line 4 of Exhibit A-12 (DMH-2), Schedule B-5.2, identifies the total capital expenditures for the Overisel Compression Station. In 2016, costs were incurred for the installation of compressor discharge check valves and blowdown vent silencers. In 2017 through 2019, examples of projected costs include: valve replacements, engine control upgrades, silencers, replacement of the dehydration system, unit monitoring, and new office space.

Q. Please identify the capital expenditures projected for the Ray Compression Station.

A. Line 5 of Exhibit A-12 (DMH-2), Schedule B-5.2, identifies the total capital expenditures for the Ray Compression Station. In 2016, costs were incurred for noise reduction and building modifications. In 2017 through 2019, examples of projected costs include: a field scrubber, unit monitoring, valve replacements, tank containment liners, and an electrical upgrade.

Q. Please identify the capital expenditures projected for the St. Clair Compression Station.

A. Line 6 of Exhibit A-12 (DMH-2), Schedule B-5.2, identifies the total capital expenditures for the St. Clair Compression Station. These expenditures are separate from the St. Clair Upgrade Project. Company witness Fultz provides details of the St. Clair Upgrade Project in his direct testimony. In 2016, costs were incurred for valve replacements and unit monitoring. In 2017 through 2019, examples of projected costs include: a Valve Replacement Program and engine control upgrades.

Q. Please identity the capital expenditures projected for the White Pigeon Compression Station.

A. Line 7 of Exhibit A-12 (DMH-2), Schedule B-5.2, identifies the total capital expenditures for the White Pigeon Compression Station. In 2016, costs were incurred for engine compressor rebuilds. In 2017 through 2019, examples of projected costs include: unit monitoring, fire block valve replacements, engine control upgrades, and rebuilds.

Q. Please identify the capital expenditures projected for the Marion Storage Fields.

A. Line 8 of Exhibit A-12 (DMH-2), Schedule B-5.2, identifies the total capital expenditures for the Marion Storage Fields. In 2017 through 2019, examples of projected costs include: packer removal and drilling new wells.

Q. Please identify the capital expenditures projected for the Northville Storage Fields.

A. Line 9 of Exhibit A-12 (DMH-2), Schedule B-5.2, identifies the total capital expenditures for the Northville Storage Fields. In 2017 through 2019, an example of the work to be undertaken is the replacement of the Lyon 29-34 separator.

Q. Please identify the capital expenditures that are planned for the Overisel Storage Fields.

A. Line 10 of Exhibit A-12 (DMH-2), Schedule B-5.2 identifies the total capital expenditures for the Overisel Storage Fields. In 2016, costs were incurred for well plugging and abandonment. In 2017 through 2019, examples of projected costs include: packer removal, installation of stairs and walkway, replacement of the secondary containment system, and lateral 8-L.

Q. Please identify the capital expenditures projected for the Ray Storage Fields.

A. Line 11 of Exhibit A-12 (DMH-2), Schedule B-5.2, identifies the total capital expenditures for the Ray Storage Fields. In 2016, costs were incurred for observation wells. In 2017 through 2019, examples of projected costs include: converting plugged wells to observation wells and well hookups.

Q. Please identify the capital expenditures projected for the St. Clair Storage Fields.

A. Line 12 of Exhibit A-12 (DMH-2), Schedule B-5.2, identifies the total capital expenditures for the St. Clair Storage Fields. In 2016, costs were incurred for observation wells. In 2017 through 2019, examples of projected costs include: converting plugged wells to observation wells and well hookups and observation.

Q. Please identify the capital expenditures that are planned for Storage New Wells.

A. Line 13 of Exhibit A-12 (DMH-2), Schedule B-5.2, identifies the total capital projected expenditures that are not tied to a specific site. In 2017 through 2019, this includes funding for capital tools, adding new wells, and small valves and instrumentation. These costs are budgeted for all storage fields in one common project based on historical trends and known future needs. Actual expenditures for 2016 will not be identified as "Storage New Wells" but instead will be represented within the site that ultimately adds the new well, replaces valves, or purchases capital tools.

Q. Please identify the capital expenditures that are planned for Well Rehabilitation.

A. Line 14 of Exhibit A-12 (DMH-2), Schedule B-5.2, identifies the total capital projected expenditures for the Company's Storage Well Rebuild Capital Program. Exhibit A-42 (DMH-3), Storage Well Rebuild Capital Program to Combine Rebuild with Logging, provides additional detail for this multi-year program that is in response to the federal minimum safety standards that are identified in API RP 1171, and which resulted from the PIPES Act of 2016.

Q. Please provide more detail on the Well Rehabilitation Program.

A. The Well Rehabilitation Program will significantly reduce risk across our gas storage system and increase deliverability by rebuilding the gas wells at the Company's gas storage fields back to a like-new condition. The program also provides baseline well integrity conditions during implementation.

This program will use mechanical methods, solvents, and other chemicals to remove obstructions, restoring the original flow properties of the wells. This thorough Well Rehabilitation Program will remove the debris and slow the rate of corrosion potential in the wells, thus increasing the useful life of the facilities. This method is preferred over plugging and abandoning wells or drilling new wells. Abandoning and drilling new wells presents increased risk which is unnecessary for storage operations and customers. Depending on the condition of the well, additional replacement of well components may be necessary. Components include, but are not limited to, piping, valves, or packers. To verify continual success of the Well Rehabilitation Program, flow statistics will be taken both before and after the rehabilitation. Absolute Open Flow ("AOF") values will be measured and compared to historical AOF's taken on the wells when originally put into service. Wells will be "logged" or inspected after treatment to assess the condition of the well casing and the success of the restoration. The program will bring the Company up to a 10-year Well Logging cycle and in compliance with the API RP 1171.

Completing the rehabilitation and well logging work simultaneously is prudent, efficient, and directly benefits our customers. If done separately, services such as well service rigs, well hardware, and other ancillary services would be duplicated which is not cost effective for the customer. This program is designed to restore, and in most cases, increase well deliverability while base lining well integrity to an industry average of approximately 10 years. Once baseline well integrity information is determined, a risk based, site specific approach to future well integrity well logging will be implemented as detailed in the API Recommended Practice 1171: Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs (API 1171). At the completion of the well rehabilitation capital project, the well logging O&M will be required to maintain the desired 10-year cycle.

Q. Why is the Well Rehabilitation Program a capital program?

A. Federal Energy Regulatory Commission ("FERC") Docket Nos. AC09-27-000 and AI05-1-000 illustrate FERC's allowance of testing costs that are incurred to extend the useful life of the system in the context of a one-time rehabilitation program to be capitalized. Under the requirement of FERC's Uniform System of Accounts, cost incurred to inspect, test, and report on the condition of existing plant to determine the need for repairs or replacements and testing the adequacy of repairs made are recognized as maintenance expense. However, FERC has permitted natural gas and electric companies to capitalize assessments costs when the work was done in connection with major rehabilitation projects involving significant replacements and modifications of facilities.

FERC has established the following requirements that a project must meet to be able to capitalize assessment type costs. The project must: (i) be completed in connection with a one-time program that involves significant replacements and modifications of facilities; (ii) extend the overall system's useful life and serviceability; and (iii) have in place internal controls to distinguish between costs incurred related to ongoing assessment activities and those that are part of the rehabilitation project.

Q. Are the Company's capital expenditures in GCS reasonable and prudent?

A. Yes. The capital expenditures in GCS will improve system reliability, deliverability, integrity, safety, and customer service. These capital expenditures will allow the Company to take advantage of market conditions and procure adequate supplies of natural gas to meet the needs of our customers. Furthermore, many of these capital expenditures are related to compliance with environmental, federal, and/or state regulations and thus not discretionary.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief	)))))	Case No. U-18424

REBUTTAL TESTIMONY

OF

DANIELLE M. HILL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2018

Q. Please state your name and business address.

A. My name is Danielle M. Hill, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. Are you the same Danielle M. Hill who submitted direct testimony in this case?

A. Yes.

Q. Are you sponsoring exhibits with your rebuttal testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-99 (DMH-4)	Original Staff Audit Request #087(i);
Exhibit A-100 (DMH-5)	Staff Audit Request #087(i) 2017 Actuals;
Exhibit A-101 (DMH-6)	Staff Audit Request #087(j) 2017 Actuals;
Exhibit A-102 (DMH-7)	Staff Audit Request #087(k) 2017 Actuals;
Exhibit A-103 (DMH-8)	2016-12 Months Ending June 30, 2019 Gas Compression Storage and Gas Management Services O&M Expenses; and
Exhibit A-104 (DMH-9)	OVS Compressor Station – Dehydration System Replacement – Schedule (PMS) – 2/23/18.

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

A. Yes, they were.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut the direct testimony of Cynthia L. Creisher on behalf of the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") and explain why her recommendation to adjust Base Operations and Maintenance ("O&M") expenses should not be adopted. My testimony will also rebut the direct testimony of Lauren Fromm on behalf of the MPSC Staff and explain why her recommendation to disallow contingency expenditures should not be adopted. Finally, my testimony will rebut the direct testimony of Sebastian Coppola on behalf of the Attorney General and explain why his recommendation to reduce Gas Compression and Storage capital expenditures should be rejected.

<u>REBUTTAL OF STAFF WITNESS CREISHER</u>

<u>O&M Expenses</u>

Q. At page 30, starting on line 7 of her direct testimony, Ms. Creisher states regarding Gas Compression, Storage, and Gas Management Services, that "[t]he projected test year Base O&M expense levels should be adjusted based on 2017 actual Base O&M expense levels that were not available at the time of the Company's preparation for filing of this application, testimony, and projected test year calculations in this current case." At line 21, Ms. Creisher recommends a "[b]ase O&M expense level for the test year ending June 30, 2019 of $22,457,000..." How does Ms. Creisher's recommendation compare with Consumers Energy Company's ("Consumers Energy" or the "Company") Projected Test Year Base O&M?

A. Consumers Energy projected Test Year Base Gas Compression, Storage, and Gas Management Services O&M to be $23,095,000 (see Exhibit A-41 (DMH-1), page 2, line 6, column (e)), or approximately $638,000 more than Staff's recommendation.

Q. Does Ms. Creisher identify the basis for her recommendation?

A. Yes. At page 29, starting on line 23 of her direct testimony, Ms. Creisher states, "Staff finds that the Company's forecast of the 2017 Base O&M expenses varied substantially from the actual expenses through November 2017 and the forecasted expenses for December 2017, and represented a larger decrease in expenses from 2016 to 2017 than what the Company projected at the time of this rate case filing."

Q. Does Ms. Creisher provide details of this variance?

A. Yes. Beginning on page 29, line 3, Ms. Creisher discusses Staff's review of Exhibit A-41 (DMH-1) and Staff Audit Request #087(i).

Q. Have you identified any issue with this direct testimony?

A. Yes. Specifically on page 29, line 17, Staff incorrectly identifies the 2017 December Forecasted Material expenses as $4,133,000 – the correct number is $4,311,000 and is found in Exhibit S-11.8, page 32, and Exhibit A-99 (DMH-4), line 3, column (d). Secondly, two lines below (on line 19), she incorrectly identifies 2017 projected Other expenses as $1,706,000 – the correct number is $1,284,000 and is found in Exhibit A-41 (DMH-1), page 2, line 5, column (c). The bottom line is that Staff's comparison/analysis incorrectly identifies two of the three components that comprise Total Base O&M.

Q. At page 30, beginning on line 1, Ms. Creisher identifies the basis of Staff's recommendation as "…2017 Base O&M expenses varied substantially from the actual expenses through November 2017…" Does Staff identify the total variance between Exhibit A-41 (DMH-1) and Staff Audit Request #087(i)?

A. No.

Q. What is the total variance between Exhibit A-41 (DMH-1) and Staff Audit Request #087(i)?

A. Exhibit A-41 (DMH-1) identifies 2017 Projected Test Year Total Base O&M to be $22,895,000 – see page 2, line 6, column (c). The Company's response to Staff Audit Request #087(i) identifies 2017 Total Base O&M to be $21,770,000 – see Exhibit A-99 (DMH-4), line 6, column (d). Therefore, the total variance is $1,125,000 – or approximately 5%.

Q. What is the total variance if 2017 Actuals are used?

A. Once available, Consumers Energy updated its response to Staff Audit Request #087(i) with 2017 Actuals to create Exhibit A-100 (DMH-5). Exhibit A-100 (DMH-5) identifies 2017 Actual Total Base O&M to be $22,096,000 – see page 2, line 6, column (c). Therefore, the total variance is $799,000 – or approximately 3%.

Q. Is a 3% (or $799,000 difference in a $22 plus million budget) variance "substantial"?

A. No.

Q. Other than the above variance discussion, does Staff identify other issues or concerns with the Company's Base O&M amounts?

A. No.

Q. On page 30, beginning on line 19 of her direct testimony, Ms. Creisher recommends "[a]pplying an inflation factor of 2.01% for 2018 and a prorated inflation factor of 1.13% for the 6 months ending June 30, 2019, Staff calculated a Base O&M expense level for the test year ending June 30, 2019 of $22,457,000…." Does Consumers Energy agree with Staff's use of inflation factors?

A. No. The Company's Base O&M expense level was projected based on the needs of the business, while Staff's inflation factors are not. Furthermore, Staff's calculations were based on January through November Actuals (and December projections), not January through December Actuals. Therefore, Consumers Energy created Exhibit A-103 (DMH-8), which applies Staff's inflation factor using 2017 Actuals. Applying Staff's inflation factor of 2.01% for 2018 and a prorated inflation factor of 1.13% for the 6 months ending June 30, 2019 to the full year 2017 Base O&M Actuals of $22,096,000 (see Exhibit A-103 (DMH-8), line 2, column (i)) results in a Base O&M expense level for the test year ending June 30, 2019 of $22,795,000 – see line 2, column (k). That is $300,000, or 1%, less than the requested $23,095,000 filed in Exhibit A-41 (DMH-1) – see page 1, line 1, column (e).

Q. Does Staff support the use of their inflation factors?

A. No. At page 30, line 15, of her direct testimony, Ms. Creisher states, "Staff's proposed test year Base O&M expense level is derived by applying Staff's forecasted inflation factors, which are supported by Staff Witness Kirk Megginson…"

Q. Does Staff witness Kirk D. Megginson's direct testimony address why the Company's Projected Base O&M expense level is not acceptable and/or why Staff's forecast inflation factors are more appropriate?

A. No. Mr. Megginson's direct testimony does not address why the Company's Projected Base O&M expense level is not acceptable. Mr. Megginson's direct testimony simply states, on page 14, lines 6 through 8, "Staff recommended an average inflation rate of 2.01% for 2018 and 2.25% for 2019 using December 2017 estimates from Value Line, Global insight and the Energy Information Administration."

Q. Should the Commission approve Staff's recommendation to decrease Test Year Total Base O&M to $22,457,000 (see Ms. Creisher's direct testimony, page 30, line 21)?

A. No, as stated above, Ms. Creisher's direct testimony regarding her review of Exhibit A-41 (DMH-1) and the Company's response to Staff Audit Request #087(i) contains multiple errors and does not identify any other issues with Base O&M expenses. Also, Staff's recommended calculation of test year ending June 20, 2019 Base O&M would result in a $300,000 reduction, from $23,095,000 to $22,795,000, a 1% change to Projected test year Base O&M, which is not a substantial variance, nor is it sufficiently supported. Finally, although Consumers Energy does not agree with Staff's practice of reconciling general rate case filings (which are intended to focus on forward-looking test years), Gas Compression, Storage, and Gas Management Services 2017 Projected Base O&M expenses of $22.895 million (found in Exhibit A-41 (DMH-1), page 2, line 6, column (c)) are within 3% (or $799,000) of the 2017 Actual Base O&M expenses of $22.096 million (found in Exhibit A-100 (DMH-5) line 6, column (c)).

REBUTTAL OF STAFF WITNESS FROMM

Contingency Expenditures

Q. At page 13 of her direct testimony, beginning on line 11, Ms. Fromm recommends "[t]he Commission disallow recovery of all contingency expenditures." Does Ms. Fromm identify the amount of contingency in this case?

A. Yes. Ms. Fromm identifies $34.802 million in the 18-month bridge period and $42.849 million in the test year – see Ms. Fromm's direct testimony, page 13, lines 7 through 8.

Q. Does Consumers Energy agree with Ms. Fromm's recommendation?

A. No. Company witness Christopher T. Fultz addresses Ms. Fromm's recommendation and why the Company does not agree with Staff's position regarding Contingency expenditures.

REBUTTAL OF ATTORNEY GENERAL WITNESS COPPOLA

Capital Expenditures

Q. At page 68, starting on line 16 of his direct testimony, Mr. Coppola discusses the Muskegon River capital expenditures and recommends the Commission "[r]emove $2.7 million of capital expenditures from the amount forecasted in 2017 and also $1.9 million from the 2018 projections." Does Mr. Coppola identify why he makes this recommendation?

A. Yes. At page 68, starting on line 6, Mr. Coppola states:

> "In response to discovery request AG-CE-359, the Company disclosed that the Muskegon River Compression project ended the year 2017 with actual capital expenditures of approximately $3.3 million. This amount is about 45% lower than what the Company forecasted in Exhibit A-12, Schedule B-5.2. The difference is approximately $2.7 million. This amount was not spent and should be removed from the capital expenditures proposed by the Company."

Q. Does discovery Response No. 18424-AG-CE-359 support Mr. Coppola's claim for disallowance?

A. No. Exhibit A-12 (DMH-2), Schedule B-5.2, page 3, line 2, column (c), to which Mr. Coppola refers, includes the total capital expenditures projected for the 12 months ended December 31, 2017 for all capital projects at the Muskegon River Compression site, and totals $5,984,000. Discovery Response No. 18424-AG-CE-359, subpart (a), which is Mr. Coppola's Exhibit AG-29, requests detail for only one capital project at Muskegon River – the Muskegon River Compression MRC-Clark Unit H-11 Unit Rebuild. There are seven capital projects included in the $5,984,000 identified on Exhibit A-12 (DMH-2), Schedule B-5.2. Mr. Coppola has made an invalid assumption that the Muskegon River Compression MRC-Clark Unit H-11 Unit Rebuild was the only capital project planned for 2017 at Muskegon River.

Q. What did the Company forecast for 2018 for the MRC H-11 Unit Rebuild?

A. The Company forecasted $4,116,000 in 2017 and $175,000 in 2018. The Company actually incurred $3,336,122 in 2017, and forecasts $955,000 to be incurred in 2018.

Q. What caused the delay in capital expenditures?

A. Materials originally projected to be received in 2017 are now forecasted to be received in 2018.

Q. At page 68 of his direct testimony, starting on line 12, Mr. Coppola continues:

> "The significant variance in spending in 2017 indicates that project costs for 2018 may be similarly overstated. As such, I propose that the forecasted capital expenditures for 2018 of $4.3 million also be reduced by 45%, or $1.9 million."

Do you agree with Mr. Coppola's recommendation?

A. No. As explained above, Mr. Coppola has made an incorrect assumption, rendering his analysis of 2017 actual costs irrelevant and unrelated. Additionally, Mr. Coppola's recommendation incorrectly assumes the 2018 expenditures are causally related and, therefore, will be incurred in the same proportion as the 2017 expenditures.

Q. Other than his flawed causal relationship argument, does Mr. Coppola's direct testimony provide proof that only 45% of 2018 capital expenditures will be incurred?

A. No. Mr. Coppola's only argument for the 2018 proposed capital expenditures at Muskegon River are based on his incorrect assumption of 2017 actual expenditures.

Q. Should the Commission adopt Mr. Coppola's recommendation to remove $2.7 million of the Muskegon River Compression capital expenditures in 2017 and also $1.9 million from the 2018 projections?

A. No. For the above-stated reasons, the Commission should reject Mr. Coppola's recommendation.

Q. At page 69, starting on line 17 of his direct testimony, Mr. Coppola again refers to the Company's response to discovery Request No. 18424-AG-CE-359, and the Exhibit A-12 (DMH-2), Schedule B-5.2; he recommends, with respect to the Overisel Compression project, that "the Commission remove the entire $5.5 million in capital expenditures forecasted for 2018 and the $5.1 million projected for the 6 months ending June 2019, and instead include $3.2 million of the 2018 capital expenditures that were planned to be incurred in the first half of that year into the first half of 2019." What is the basis for Mr. Coppola's recommendation?

A. At page 69, starting on line 4 of his direct testimony, Mr. Coppola opines:

> "The Company has projected $0.7 million of capital expenditures for this project in 2017, $5.5 million in 2018, and $5.1 million for the first 6 months in 2019. In response to discovery request AG-CE-359, the Company disclosed that the implementation plan for the Overisel Compression OVC Dehydration System Replacement project is still under development.[32] In the discovery response, the Company provided only a one sentence explanation stating a general objective of completing the engineering work on the project sometime in 2018 and perhaps some procurement of components. Construction is targeted for 2019-2020."

Does the Company's discovery Response No. 18424-AG-CE-359 (Exhibit AG-29) support Mr. Coppola's claim for disallowance?

A. No. Exhibit A-12 (DMH-2), Schedule B-5.2, page 3, line 4, columns (c) and (d), that Mr. Coppola refers to, include the total capital expenditures projected for the 12 months ended December 31, 2017 for all capital projects at the Overisel Compression site, and totaled $730,000 in 2017 and $5,516,000 for 2018. The discovery Response No. 18424-AG-CE-359, subpart (c), requests detail for one capital project at the Overisel Compression site – the Overisel Dehydration System Replacement. There are approximately 15 capital projects included in the 2017 and 2018 expenditures identified on Exhibit A-12 (DMH-2), Schedule B-5.2. Mr. Coppola has again made an invalid assumption that the Dehydration System Replacement is the only capital project planned for 2017 or 2018 at the Overisel Compression site.

Q. Mr. Coppola's recommendation to disallow capital expenditures is based on the implementation plan disclosed in response to discovery Request No. 18424-AG-CE-359 for the Overisel Compression Dehydration System Replacement. What is the timeline for that project?

A. As explained in response to discovery Request No. 18424-AG-CE-359, the high-level project plan is to begin engineering and incurring capital expenditures in 2018. Mr. Coppola has incorrectly used this project to justify a recommended disallowance when in fact there were no expenditures planned for the Overisle Dehydration System Replacement in 2017. The current project implementation plan supports the project request of $600,000 in 2018 and $3,000,000 in the first six months of 2019. Please see Exhibit A-104 (DMH-9) for the most up-to-date implementation schedule for the Overisle Compressor Station Dehydration System Replacement project.

Q. Should the Commission adopt Mr. Coppola's recommendation to remove $5.5 million of the capital expenditures forecasted for 2018 and also $5.1 million projected for the 6 months ending June 30, 2019 and instead include $3.2 million of the 2018 capital expenditures in 2019?

A. No. As explained above, Mr. Coppola has made an incorrect assumption, rendering his analysis of 2017 actual costs irrelevant and unrelated. Actual costs for 2017 have been provided in Exhibit A-101 (DMH-6). Additionally, Mr. Coppola's recommendation incorrectly assumes that the remaining projects, of which there are approximately 15, will incur zero capital expenditures through 2019, an assumption that is not grounded in fact. For the above-stated reasons, the Commission should reject Mr. Coppola's recommendation.

Q. At page 73, starting on line 10 of his direct testimony, Mr. Coppola recommends "[t]he Commission should disallow $41.2 million of capital expenditures proposed by the Company in this rate case for Well Rehabilitation." What is the basis for Mr. Coppola's recommendation?

A. At page 73, line 6, Mr. Coppola opines, "[g]iven the lack of evidence and supporting justification for this program, it is not possible to accept the capital expenditures that the Company has proposed for 2017 and future periods in this rate case."

Q. Has there been a lack of evidence and supporting justification for the Company's Well Rehabilitation Program?

A. No. In Case No. U-18124, and in the instant case, the Company has: (i) identified new laws that require regulatory compliance by 2026; (ii) submitted a detailed plan and related expenditures to achieve regulatory compliance; and (iii) provided updates which show schedule and budget adherence.

Q. At page 70, starting on line 10 of his direct testimony, Mr. Coppola states, “[t]he Company justifies undertaking this multi-year program primarily in response to safety standards under the PIPES Act of 2016 and the American Petroleum Institute standard – API RP 1117.” Is Mr. Coppola correct?

A. Only partially. Mr. Coppola incorrectly identifies the American Petroleum Institute (“API”) Recommended Practice (“RP”) standard as API RP 1117 – the correct standard is API RP 1171. Furthermore, Mr. Coppola fails to recognize the PIPES Act of 2016 and API RP 1171 set forth regulatory standards that require compliance.

Q. Is Consumers Energy compliant with the standards set forth in API RP 1171?

A. As stated in my direct testimony (see page 11, line 2), “[n]ot at this time. However, both API RP 1170 and 1171 allow 10 years for compliance.”

Q. At page 70, line 18 of his direct testimony, Mr. Coppola asserts, “[t]here is no evidence provided in her testimony of any safety risks posed by the current storage wells…” Can API RP 1171 be ignored as Mr. Coppola seems to suggest?

A. No, it would be imprudent to ignore the PIPES Act of 2016 and subsequent regulations set forth in API RP 1171.

Q. At page 72, staring on line 8 of his direct testimony, Mr. Coppola states, “[t]he Company has designed a program to prevent a problem or incident similar to the Aliso Canyon of which it has no detailed knowledge.” Does the Company’s Well Rehabilitation Program require a detailed knowledge of the Aliso Canyon incident?

A. No. The Company’s Well Rehabilitation Program requires a detailed knowledge of the requirements set forth in API RP 1171 and a plan to achieve compliance within the 10-year requirement.

Q. At page 72, starting on line 12 of his direct testimony, Mr. Coppola suggests, “[g]iven the size of this large capital program, which exceeds $180 million, it would seem reasonable to expect that the Company would perform some financial analysis to show that the increased deliverability will provide some significant financial benefits. No such analysis was performed.” Does Consumers Energy routinely perform analyses for its projects?

A. Yes. The Company performs financial analyses for economic projects. Projects required for regulatory compliance (such as the Well Rehabilitation Program), are not subject to financial benefit or economic reviews.

Q. Should the Commission adopt Mr. Coppola’s recommendation on page 73, lines 11 through 12 of his direct testimony, to “[d]isallow $41.2 million of capital expenditures proposed by the Company in this rate case for Well Rehabilitation”?

A. No. As stated above, Consumers Energy’s underground gas storage fields are currently not compliant with the regulatory requirements set forth in API RP 1171. As identified in Exhibit A-42 (DMH-3) (Storage Well Rehabilitation Detail), the Company is on track to achieve compliance with API RP 1171 by 2026 – or within the required 10-year period. Finally, the Commission approved recovery of the Company’s Well Rehabilitation

Program in Case No. U-18142 and, based on the detail provided in the present case, there is no basis for the Commission to disallow continued funding.

Q. Would the disallowance or deferral of historical capital spending in a Commission order result in an asset impairment assessment and potential write-off of the capital asset?

A. Yes, while I have supported that the historical spend is necessary, prudent, and in the best interest of customers, a disallowance of historical spending in a Commission order would require an asset impairment assessment. Please refer to the rebuttal testimony of Company witness Daniel L. Harry for further discussion of the accounting requirements. Exhibit A-102 (DMH-7) provides the Company's actual year-to-date expenditures for the Well Rehabilitation.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

(Documents were marked for identification by the Court Reporter as Exhibit A-70.)

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MS. UITVLUGT: Thank you, your Honor. At this time Consumers Energy requests that the direct testimony of Jeffrey J. Shingler be bound into the record. Mr. Shingler's testimony consists of a cover page and eight pages of questions and answers.

I would also move for the admission of Mr. Shingler's exhibits. Mr. Shingler sponsored Exhibit A-70 and Exhibit A-12 Schedule B-5.4.

JUDGE SONNEBORN: Are there any objections to the binding into the record of the direct testimony of Jeffrey J. Shingler, as well as the admission into evidence of his exhibits as described by Ms. Uitvlugt?

Hearing no objection, I will bind into the record Mr. Shingler's direct testimony and admit into evidence his exhibits.

(Testimony bound in.)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
	)	

DIRECT TESTIMONY

OF

JEFFREY J. SHINGLER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2017

JEFFREY J. SHINGLER
DIRECT TESTIMONY

Q. Please state your name and business address.

A. My name is Jeffrey J. Shingler, and my business address is 11801 Farmington Rd, Livonia, MI 48150.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director, Electric Operations LVD.

Q. What are your responsibilities as Executive Director, Electric Operation LVD?

A. I am responsible for all Operations and Maintenance ("O&M") on the low voltage electric system across our eastern territory, which equates to 960,000 customers. In my previous role as Executive Director of Business Services, I was responsible for Fleet Operations, Facilities Management and Projects, Real Estate, and Administrative Operations.

Q. What is your formal educational experience?

A. I graduated from Eastern Michigan University in 1997 with a Bachelor of Science in Construction Management. I have also completed numerous management courses and am a Certified Utility Safety Professional through the Utility Safety and Ops Leadership Network.

Q. Would you please describe your previous work experience?

A. After graduating college, , I worked for Frito-Lay as a Supervisor in the Service and Distribution Department running warehouse, facility, and traffic operations in both the Plymouth Distribution Center and the former Allen Park Plant. In 1999, I started working for Penske Logistics, managing the implementation of a new supply chain network from all Tier I suppliers to their final assembly plants. I also was responsible for all inbound logistics for the Wixom Assembly Plant. In 2001, I started my career at Consumers Energy as the Fleet Field Leader for the Jackson, Adrian, and South Monroe locations. In that role, I was responsible for all daily fleet operations. In 2003, I accepted the role of Fleet Acquisition and Disposition Manager, responsible for all fleet capital purchases, fleet vehicle design, licensing, rentals, asset sales and data management.

In 2006, I was asked to lead the fleet conversion into SAP. My responsibilities included blueprinting and configuring the SAP Work Management System to fit the needs of our Fleet Department, as well as all data conversion activities. These included financial, supply chain, and human resources integration. Before launching, I was responsible for providing all training to fleet employees and overseeing the super user team.

Upon the launch of the SAP System in July of 2008, I became the Senior Fleet Field Leader responsible for all fleet maintenance operations for half of the state locations. This span of control consisted of 55 mechanics, 6 field leaders and 6 non-exempt employees.

In 2011, I was named the Director of Fleet Services, responsible for all fleet activities for the company which include maintenance, acquisition, and disposition and the Department of Transportation regulatory responsibilities. During my tenure as Director, I also took on the responsibility to lead the Company’s Safety Culture Team that was responsible for training activities that surround our Safety Culture Program. In March of 2015, I became the Executive Manager of Business Services, responsible for the support services of Fleet, Facilities, Real Estate, Corporate Security, and

Administrative Operations, which include janitorial management, flight management, copy services and travel.

As of August 2017, I have been in the role of Executive Director, Electric Operations responsible for all operations and maintenance on the low voltage electric system across our eastern territory, which equates to 960,000 customers.

Q. Are you a member of any professional societies or trade associations?

A. Yes. I am a member of the Electric Utility Fleet Managers Council and I am also a Certified Safety Utility Professional through the Utility Safety and Ops Leadership Network.

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

A. The purpose of my direct testimony is to support the Company's costs related to the gas business portion of business services capital projects.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-70 (JJS-1)		Summary of Gas Business Services O&M Expenses for the years 2016, 2017, 2018 and 12 months ended June 30, 2019; and
Exhibit A-12 (JJS-2)	Schedule B-5.4	Summary of Projected Gas & Common Capital Expenditures for the years 2016, 2017, 2018 and 12 months ended June 30, 2019.

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

A. Yes.

Q. Please describe the exhibits you are sponsoring.

A. Exhibit A-70 (JJS-1) details the O&M costs related to Gas Business Services. Exhibit A-12 (JJS-2), Schedule B-5.4, details the capital costs related to business services. Capital spending is divided into three programs and multiple cost categories. The three capital spending programs are: Asset Preservation, Transportation Equipment, and Computer and Other Equipment. The Company's total projected investment is $30.0 million in 2018 and $30.5 million 12 months ended June 30, 2019.

Q. Please explain the Gas Business Services function.

A. Gas Business Services consists of the following support organizations: Fleet Services, Facility Operations, Real Estate, Corporate Security, and Administrative Operations. Gas Business Services provides support by acquiring, constructing, and maintaining assets required to operate the functional areas of the business. For example, Fleet Services manages a fleet of 6,318 units through their useful life for use in daily operational work. Facilities manages and operates 61 buildings comprising 3.5 million square feet of building space across the state of Michigan that allows our workforce to continuously improve, serve local customers, and respond timely to needs of the operating units.

Q. What support services are included in Exhibit A-70 (JJS-1)?

A. Gas Business Services operations include O&M for all Company gas-related facilities work. Items such as maintenance and repair on heating, air conditioning, and ventilation systems, miscellaneous building repairs, yard maintenance and snow removal, and daily cleaning or other major scheduled cleaning projects such as windows and carpeting. Real estate services includes the lease costs associated with corporate facilities, records management and land inventory systems, property rights research and investigation, costs for land transactions, and the cost of land management and maintenance activities required to closely monitor encroachments and uses of Company property and easement rights to ensure system integrity and safeguard the public. Mail services includes all activities relating to receiving, sorting, processing, and delivering all mail for general office buildings, which also includes all postage not related to gas billing.

Q. Please explain the calculated O&M expense for Gas Business Services as displayed on Exhibit A-70 (JJS-1), line 1.

A. The test year 12 months ended June 30, 2019 O&M expense for Gas Business Services is projected to be $ 9,874,000 and is shown on Exhibit A-70 (JSS-1), column (e). The test year expense was derived by using six months of the 2018 and 2019 long-term financial plan from the Company's planning format. The long-term financial plan starts with amounts from the previous budget cycle and incorporates changes for the forecasted period based on known and measurable changes, where available, and conservative assumptions of expected available resources. In general, Business Services' strategy is to keep costs flat in support of operations, hence the reason for a projected 2018 amount of $9,874,000 compared to the same amount 12 months ended June 2019. The budget that is the baseline for the long term financial plan is a detailed planning exercise by cost center supported by company directives. The budget for Facilities, in particular, is based on costs per building at the cost center and cost category level supported by operational knowledge, including contractual price fluctuations for facility services and snow removal budgeted at a five-year historical average, to identify a few examples. Each program area within Business Services is involved in development of their individual budget/plan based on requirements to support operations. Costs fluctuate based on increasing numbers of buildings, vehicles, and operational support requirements.

Q. Please describe the capital expenditures related to Gas Business Services as shown on Exhibit A-12 (JJS-2), Schedule B-5.4, line 15.

A. There are a number of areas that are contained within Gas Business Services. These primarily include Asset Preservation/Facilities Investments and Transportation Equipment/Fleet Investments. Gas Business Services also includes a small amount of capital spending for Computer & Other Equipment.

Q. What type of expenditures are included in Asset Preservation/Facilities Investment?

A. Asset Preservation/Facilities Investments include: (i) infrastructure investments; (ii) upgrades and maintenance; and (iii) purchases, new construction, and renovations. Infrastructure investments include removing conditions that contribute to potential health and safety hazards, proactively repairing emergency backup systems, and repairing failed capital components of buildings which are comprised of yards, grounds, building envelope, and operating systems. These minimal facilities infrastructure investments mitigate the effects of building depreciation to avoid imminent near-term failures and upgrades for health and wellness. Upgrades and maintenance capital expenditures include parking lots, roofs, and elevators at various building and plant sites. The final component of the Facilities Investment plan is the purchase, new construction, and/or renovation of service centers to support operations across the state of Michigan. An example of this is the ongoing renovations at the Parnall Road Complex.

Q. What type of expenditures are included in Transportation Equipment/Fleet Investment?

A. Transportation Equipment/Fleet Investment includes the purchase of vehicles, equipment, and trailers as part of the Company's Fleet Lifecycle Replacement Program that supports operations.

Q. What type of expenditures are included in Computer & Other Equipment?

A. Computer & Other Equipment includes the purchase of miscellaneous printers, mechanical equipment, print production equipment, and wellness equipment.

Q. How much is the Company projecting for total Gas Business Services capital expenditures in this case?

A. The Company is projecting total Gas Business Services capital expenditures to be $6,933,000 for the 6 months ending June 30, 2017; $30,009,000 for the 12 months ending June 30, 2018; and $30,534,000 for the 12 months ending June 30, 2019 as set forth in Exhibit A-12 (JJS-2), Schedule B-5.4, line 30, column (b); line 30, column (c); and line 15, column (g), respectively. For the 30-month period ending June 30, 2019, the Company's total capital expenditures for Gas Business Services is projected to be $67,476,000 as set forth in Exhibit A-12 (JJS-2), Schedule B-5.4, line 15, column (f).

Q. Please explain the Asset Preservation and Transportation Equipment projected costs.

A. Asset Preservation includes new construction, remodeling of existing facilities, emergent work, lifecyle replacement of infrastructure equipment and system failures. Transportation Equipment includes vehicles, trucks, trailers, backhoes, etc. The estimated Asset Preservation and Transportation costs are based on long-term planning to support operational workforce strategies and customer reliability. The Company's strategy focuses on customer reliability, employee safety, and limiting overall maintenance costs. Asset Preservation supports the Company's facilities infrastructure plan; location, replacement of inefficient facilities, and overall health conditions determine the replacement plan for Asset Preservation. The estimated costs are based on current construction estimating and planning with the known requirements. These estimates can vary as changes to either the scope, initial design, materials, or possible unseen issues are realized.

Transportation equipment is supported by a comprehensive lifecycle replacement plan. All units purchased have an optimal replacement date to maintain an efficient and cost effective fleet. The projected replacement cost is based on the specific vehicle/unit being replaced during that specific period of time.

Q. Are there any contingency costs included in the Company's projected Gas Business Services capital expenditures?

A. No. As stated above, the Transportation Equipment and Computer & Other Equipment categories pertain to the purchase of physical assets and vehicles/equipment. Therefore, there are no contingency costs included in the Company's projections. With respect to Asset Preservation, the Company does not include contingency in its Asset Preservation projects. Accurate projected costs are established based on standard designs, construction estimates, and historical spend.

Q. Does this conclude your direct testimony?

A. Yes.

(Document was marked for identification by the Court Reporter as Exhibit A-71.)

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MS. UITVLUGT: Thank you, your Honor. At this time I would ask that the rebuttal testimony of Company witness Daniel G. Shirkey be bound into the record. I would also ask that the direct testimony of Company witness R. Michael Stuart, which has been adopted by Daniel G. Shirkey, be bound into the record. The direct testimony consists of a cover page and eleven pages of questions and answers. The rebuttal testimony of Mr. Shirkey consists of a cover page and eleven pages of questions and answers. And the exhibit being sponsored, I would move for the admission of Exhibit A-71.

JUDGE SONNEBORN: Thank you. Are there any objections to binding into the record the rebuttal testimony of Daniel G. Shirkey, as well as the direct testimony of R. Michael Stuart, and the admission into evidence of R. Michael Stuart's Exhibit A-71, adopted by Mr. Shirkey?

MS. UITVLUGT: And I would note for the record that the direct testimony will now indicate it has been adopted by Company witness Shirkey.

JUDGE SONNEBORN: Thank you. With that

clarification, and hearing no objection, the testimony of Mr. Shirkey and Mr. Stuart are bound into the record, as well as Exhibit A-71 is admitted into evidence.

(Testimony bound in.)

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-18424
distribution of natural gas and for other relief	)	
	)	

DIRECT TESTIMONY

OF

~~R. MICHAEL STUART~~
adopted by **DANIEL G. SHIRKEY**
ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2017

adopted by **Daniel G. Shirkey**
~~R. MICHAEL STUART~~
DIRECT TESTIMONY

Q. Please state your name and business address.

A. My name is R. Michael Stuart, and my business address is One Energy Plaza, Jackson, Michigan, 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Strategy Alignment Director in the Strategy Mobilization and Integration Department.

Q. Please review your educational and business experience.

A. I was graduated from Michigan State University in December of 1985 with a Bachelor of Arts Degree in Business Administration. Since joining Consumers Energy in June of 2000, I have held various positions in the Supply Chain, Electric Meter Operations, Business Technology Support, and Strategic Development, Communications, and Integrations Departments.

Q. What are your responsibilities as Strategy Alignment Director?

A. I was named Strategy Alignment Director effective May 1, 2017. In addition to added responsibilities for executive communications, I maintained my role with Utility Metrics and I will be transitioning the Utility Metrics responsibilities to my successor through the end of the 2017 Employee Incentive Compensation Plan ("EICP"). In the Utility Metrics role I am responsible for the development and administration of the Company's Breakthrough Goal program which includes the operational metrics incorporated in the Company's EICP.

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

A. Yes, I testified in Case Nos. U-17643, U-17735, U-17882, U-17990, U-18124, and U-18322.

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

A. The purpose of my testimony is to provide support for Consumers Energy's request for rate recovery for costs of annual EICP incentives. I will discuss Consumers Energy's EICP operational performance goals and thresholds and how the EICP goals provide customer-related benefits.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring:

Exhibit A-71 (RMS-1) EICP Performance Measures.

Q. Was this exhibit prepared by you or under your supervision?

A. Yes.

Q. How is your direct testimony organized?

A. In the first portion of my direct testimony, I provide support for Consumers Energy's request for rate recovery for costs of annual EICP incentives. In the concluding portion of my direct testimony, I address changes to the 2017 EICP goals approved in December 2016.

Q. How has the MPSC historically addressed the inclusion of incentive compensation in customers' rates?

A. Based on my research, the issue of recovery in rates of incentive compensation expenses was first raised in Michigan Consolidated Gas Company's rate case, Case No. U-10150, in which the utility requested recovery of 100% of incentive compensation paid to company executives. The Commission's Order in this case stated that:

> "Executive bonuses have often been viewed as an appropriate cost of operating a utility. This is particularly true when the bonus plan is structured in a way that produces significant benefits for the utility's ratepayers."

The Commission adopted the MPSC Staff's position of a 50/50 sharing between ratepayers and shareholders of these costs, noting that in future filings, Michigan Consolidated Gas Company's recovery of incentive compensation would require a showing by the utility that customer benefits are commensurate with the costs.

The Commission subsequently further modified the ratemaking that it had been following with respect to incentive compensation plans. In a December 22, 2005 Order in a subsequent Consumers Energy general rate case, Case U-14347, at page 34, the Commission stated:

> "In Case Nos. U-10149 and U-10150, the Commission determined that executive bonus and employee incentive plans require a showing that the plan will not result in excess rates and that the benefits to ratepayers from the bonus and incentive plans, at a minimum, will be commensurate with the programs' costs."

In Case No. U-17735, a Consumers Energy rate case, the Commission approved Consumers Energy's request for cost recovery associated with the EICP, finding that the Company had provided convincing evidence that "the short-term EICP provides appreciable benefits to customers and meets the standard set forth in the December 22 order." Case No. U-17735, November 19, 2015 Order, pages 77-78.

In its July 31, 2017 Order in Case No. U-18124, Consumers Energy's most recent gas rate case, the Commission concluded that Consumers Energy had provided convincing evidence that the non-financial measures of the short-term EICP provide appreciable benefits to customers, and that the Company quantified those benefits with the metrics of safety, reliability, and customer value. Case No. U-18124, July 31, 2017 Order, page 87.

Q. Is the conclusion that the short-term EICP provides appreciable benefits to customers true in the current rate case?

A. Yes.

Q. Is there a direct tie between the design of the current incentive plan and desirable benefits for customers?

A. Yes. There is a direct tie between the current design of the incentive plans and desirable benefits for customers. The Commission should permit recovery of these costs in the current case.

Q. Do you believe that benefits to customers from the incentive plans will, at a minimum, be commensurate with the programs' costs?

A. Yes. I believe that the Company fully satisfies the Case No. U-14347 standard in this case and recovery of incentive compensation expenses should be allowed. Company witness Amy M. Conrad discusses various benefits to customers from the design of the Company's incentive compensation plan. In addition, there are quantitative benefits. The design of the EICP clearly leads to lower costs and improved service which benefits our customers.

Q. Has the Company quantified customer benefits that are tied to its incentive compensation program?

A. Yes. Although specific quantification of the costs of the program and the benefits is not easy to perform for every metric included in the program, the Company has looked at five metrics of the program and has quantified benefits associated with these metrics. The benefits associated with these metrics confirm the Company's conclusion that there is substantial benefit that accrues to the customer.

The first of those metrics is employee safety. Employee safety incidents decreased by 85% from 2006 through 2016. The resulting reduction in lost work days and medical expenses approximates $3.708 million of annual savings that accrue to the benefit of the customer.

A second metric that can be translated to cost avoidance for our customers is in the area of distribution reliability. Using cost per outage minute estimates from Berkeley Labs, the 6.2 minute annual average reduction in outage minutes from 2006 to 2016 results in annual economic benefits to our customers in excess of $18.256 million.

The third quantified metric is generation reliability. Our improvement in this area from an annual forced outage rate of 9% to an annual rate of 1.9% from 2006 through 2016 has reduced fuel expenses by more than $1.844 million per year.

A fourth metric that the Company quantified customer benefits for is first time quality improvement. The initial year for this metric was 2013, and calculated average annual savings that benefited the customer were $2.048 million.

The fifth metric that the Company quantified customer benefits was in productivity improvement. The productivity improvement of approximately 66% from 2006 through 2016 is a key reason that the Company's level of Operation and Maintenance ("O&M") expenses is near the top of the second quartile versus our utility peers. To quantify the benefit to customers we can look at the Company's actual O&M costs versus what they would have been had they instead grown at the United States

Consumer Price Index ("CPI") inflation rate. During this period, the Company's O&M costs decreased by an average of .04% per year, while the United States CPI inflation rate grew by an average of 1.7% per year. This represents an average annual savings of $160.400 million, which benefits customers.

Q. What does first time quality improvement measure?

A. First time quality is an equally-weighted index of process improvement measures across seven operating areas. These measures were established to quantify the Company's continuous process improvement efforts. The Company endeavors to reduce, rework, and eliminate waste. Annual improvement targets are established for each metric and for the index total. In the first four years (2013 through 2016), the Company achieved an average annual improvement of 31%.

Q. Please explain how you define productivity improvement and how you calculated that there has been a productivity improvement of approximately 66% from 2006 through 2016.

A. Consumers Energy's productivity metric is based upon the percent improvement across 10 weighted department-level productivity metrics. These 10 areas are weighted based upon their O&M expense from the base year of 2006. A productivity target is established annually for the Company, and each of the 10 areas contributes towards that goal. The annual achievements are then summed to determine the improvement level over the period.

Q. Why have you included both electric and gas benefits in your quantification?

A. Consumers Energy's utility operations are combined in one organization. Establishing operational goals in the critical areas of safety, quality, cost, delivery, morale, and continuous improvement helps keep employees focused on the importance of world class performance delivering hometown service for both the electric and gas operations. The quantified benefits show that benefits to gas customers clearly exceed the gas incentive compensation amounts that Consumers Energy has requested to be included in rates in this case. The EICP metrics are based on annual targets that support the achievement of Consumers Energy's Breakthrough Goals and Continuous Improvement goals. This establishes a culture of continuous improvement that benefits the customers.

Q. What portion of the benefits that you have quantified above do you conclude benefit gas customers?

A. Of the metrics that I have quantified above, a portion of the quantified benefits in the areas of employee safety, quality, and productivity benefit gas customers. Utilizing an allocation of 37% for gas customers this equates to annual savings for gas customers of more than $61.478 million, significantly more than the annual costs of the EICP allocated to gas customers.

Q. Why did you use a 37% allocation to evaluate benefits to gas customers?

A. The 37% allocation is based on the total number of gas employees as a percentage of total number of Consumers Energy employees. Using the percentage of total employees is a reasonable allocation methodology to use to allocate the employee safety benefits, first time quality, and improved productivity benefits that I have identified above.

Q. Are not these benefits things that the Company should be pursuing independent of the incentive compensation plan?

A. Yes. The incentive plan takes this into consideration. As discussed by Ms. Conrad, incentive mechanisms help communicate priorities, engage employees in business success, reward valued skills and behaviors, and create business understanding for employees. The incentive plan is structured in a way that helps to highlight certain important elements of utility service and to emphasize to employees that they should pay particular attention to achieving these targets. Making it clear to employees that a portion of their total compensation depends upon their collective ability to meet these targets communicates clearly to employees the importance of serving customers and encourages them to deliver their best performance. Because the incentive compensation plan has been designed so that the incentive payments simply bring employee compensation to a competitive market-rate level, I think a better way to describe this program is that employees are penalized if the targets are not achieved.

Q. Do you believe that the incentive plan is the reason that the above benefits have been realized?

A. I believe that the design of the incentive plan is intended to, and does, make it significantly more likely that these customer benefits will be achieved. As mentioned above, it is not easy to quantify exact savings directly attributable to every incentive compensation plan metric. However, even if one were to take an extremely conservative approach to that quantification and apply it only to the five metrics discussed above, then it would remain evident that customers receive significant benefits from improvement in the performance areas included in the Company's incentive compensation plan. The benefit to gas customers far exceeds the incentive compensation expense for its gas business that the Company has included in this filing.

Q. Do you believe that any of the metrics included in the EICP are duplicative?

A. No. The metrics have been selected and designed to create a designed balance that results in a safe, productive, and customer-centric work environment for the Company's employees. Focusing too much in one area could have a detrimental impact on other measures.

Q. How are the operational metrics structured for the 2017 EICP?

A. The operational metrics have been developed under two general categories, Continuous Improvement and Breakthrough. A list of these metrics is provided in Exhibit-71 (RMS-1). Continuous Improvement metrics are key operational areas that require employee focus to enhance our customers' experience, and deliver value through a process of continuously evaluating and improving work and delivery processes resulting in more efficient processes. These are areas of performance that provide balance, as they must be achieved while the Company pursues aggressive improvement in key strategic operational areas referred to as Breakthrough. Breakthrough metrics, or goals, are strategically directional goals that will position the Company to continue to be competitive in the future, through our purpose to provide world class performance delivering hometown service. The breakthrough goal categories are safety, quality, cost, delivery, and morale. One of the Safety performance measures for 2017 is "Public Safety: Gas Infrastructure," which has targets for gas service lines replaced and record accuracy.

Q Do the changes in the 2017 EICP metrics affect the quantification of the operational benefits which were obtained prior to 2017?

A. No. The quantification of the operational benefits obtained prior to 2017 illustrates how customers benefit from the EICP. The same conclusion applies to the 2017 EICP - customers will benefit as employees are incentivized to improve service by achieving the metrics which form the basis for the EICP. The performance measures are linked to utility operating performance metrics meant to benefit customer service.

Q. How will the operational metrics be structured for 2018?

A. A new portfolio of Breakthrough and Continuous Improvement goals are under development. These metrics will be designed to focus employees' efforts on enhancing our customers experience through improvement in areas of safety, quality, cost, delivery, and morale, while providing strategic direction to ensure that the Company is positioned for future success. The EICP will be developed to incent a balanced improvement approach that provides value and economic benefit to the customer.

Q Will quantifiable benefits from the operational measures of the incentive plan continue to exceed EICP Program costs?

A. Yes. The measures and targets will continue to include, among other things, measures related to employee and customer safety, quality and productivity improvement, and reliability. The quantifiable benefits from these measures will continue to benefit customers and exceed EICP Program costs. In addition, the Company anticipates adding a cyber safety measure to reinforce the importance of protecting against malware and ransomware. The recent ransomware attack on Lansing Board of Water and Light ("LBWL") crippled that utility's ability to communicate internally and with its customers. LBWL incurred around $2.4 million in direct costs as a result. Impacts of a successful cyber-attack on Consumers Energy could exceed this amount.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief	)))))	Case No. U-18424

REBUTTAL TESTIMONY

OF

DANIEL G. SHIRKEY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2018

DANIEL G. SHIRKEY
REBUTTAL TESTIMONY

Q. Please state your name and business address.

A. My name is Daniel Shirkey, and my business address is One Energy Plaza, Jackson, Michigan, 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Utility Metrics Director in the Quality Lean Office Department.

Q. Please review your educational and business experience.

A. I graduated from Grand Valley State University in July of 2004 with a Bachelor of Science Degree in Engineering. In December of 2009, I graduated from the University of Michigan with a Masters of Business Administration. Since joining Consumers Energy in December of 2009, I have held various positions in the Risk, Project Management, Work Management, and Quality Lean Office departments.

Q. What are your responsibilities as the Utility Metrics Director?

A. In the Utility Metrics role I am responsible for the development and administration of the Company's World Class Performance Measures (formerly Breakthrough Goals) Program which includes the operational metrics incorporated in the Company's Employee Incentive Compensation Plan ("EICP").

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

A. No.

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

A. The purpose of my rebuttal testimony is to rebut the direct testimony presented by Attorney General witness Sebastian Coppola regarding the Company's EICP. In addition to filing this rebuttal testimony, I am also adopting the direct testimony and exhibit of Company witness R. Michael Stuart.

Q. Are you sponsoring any rebuttal exhibits?

A. No.

Q. Please provide an overview of your rebuttal testimony.

A. Mr. Coppola argues that $1.8 million of EICP costs included in the test year should be disallowed, claiming that the annual plan does not provide real customer benefits. This is incorrect. My rebuttal testimony provides support demonstrating that the customer benefits from the annual incentive compensation exceed the cost to customers of the EICP Program. Mr. Coppola's recommendation to disallow these EICP costs should be rejected. The EICP provides appreciable benefits to customers.

Q. Mr. Coppola is critical of a number of the measures and quantifications of customer benefits. If the Commission were to agree with some of his criticisms, would this require disallowance of the $1.8 million cost of the annual incentive that he seeks to disallow?

A. Definitely not. As an initial matter, it should be emphasized that the costs for the EICP are not over and above the reasonable level of compensation. Company witness Amy M. Conrad has explained that the incentive compensation amount is not a "bonus" or pay in excess of the reasonable compensation level. Rather, the Company has chosen to make a certain portion of its reasonable compensation level at risk. This provides motivation for employees to strive for the total level of compensation by providing world class performance and seeking to contribute to achievement of operational and financial performance measures. Additionally, the EICP provides both qualitative and quantitative benefits to customers. Specific quantification of benefits is not easy to perform for every metric included in the program. However, even if the critiques of the benefits that were not quantified were to be accepted, which I do not believe would be appropriate, this would not reduce the overall quantified customer benefits. Third, the annual benefits to gas customers were quantified in the amount of $61.478 million. Even if some of these quantified benefit amounts were reduced, the benefits to customers would still exceed the $1.8 million amount for the annual incentive that Mr. Coppola seeks to disallow.

Q. At page 32 of his direct testimony, Mr. Coppola states: "With regard to the Meter Read rate, the company has set a goal to achieve at least a 96% read rate each month. With the implementation of the AMI meters nearly complete and the AMR gas meters following shortly thereafter, achieving this measure should be a no-brainer." Do you agree with Mr. Coppola's criticism of including the meter read rate as an EICP performance measure?

A. No. This is an area that is an appropriate focus. This measure is designed to place emphasis on the need to maintain a very high level of monthly meter reads. There are many instances throughout the year where extreme weather can make it difficult to deploy meter readers into the field. Maintaining this high meter read rate requires employee dedication, focus on service, ability to manage changing conditions, and the transition of areas to automated capability. While Mr. Coppola is correct that implementation of Advanced Metering Infrastructure ("AMI") and Automated Meter Reading ("AMR") meters will help improve meter read rates, this does not mean the performance measure should not be included. In addition, Mr. Coppola's implication at page 32 of his direct testimony that customers are paying twice is not correct. The costs for implementation of the AMI and AMR meters are for the program. The incentive amount is part of the overall reasonable level of compensation. In addition, while this measure provides benefits to the customer and was not included in the quantitative economic benefit analysis, quantifying the savings would further increase the amount by which the benefit of the EICP to customers exceeds the cost to customers.

Q. At page 32 of his direct testimony, Mr. Coppola states: "Billing Accuracy, as defined by the Company, is primarily the reversal of estimated bills and is a function of estimated meter reads. Again with the implementation of the new automated meter reading functions and the use of actual reads to bill customers each month and for turn-on and turn-offs, invoice or billing reversals will diminish greatly. The AMI capability should make this measure also easily achievable." Do you agree with Mr. Coppola's conclusion?

A. No. First, estimated meter reads are only one component of the issues that result in customer invoices being reversed. Billing accuracy, as measured by invoice reversals, is an appropriate area of focus for the EICP measures. While this measure provides benefits to the customer, it was not included in the quantitative economic benefit analysis. Quantifying the savings would further increase the amount by which the benefit of the EICP to customers exceeds the cost to customers.

Q. At page 32 of his direct testimony, Mr. Coppola states: "With regard to the Regulatory environment measure, this is a measure that is published by Barclays Bank and ranks regulatory commissions in the United States based on a set of factors to indicate how favorable or unfavorable commission orders are to the utility. The Company does not or more importantly should not have control over this measure. To have control over this measure would imply that the Company has some indirect influence over the Commission's decisions. This would be a troubling outcome. Therefore, the necessity and propriety of this measure is suspect." Do you agree with Mr. Coppola's conclusions?

A. No. Barclays North America ("Barclays") looks at a number of factors, and there are many facets of the Regulatory Environment that are evaluated. The Company in no way strives to achieve any inappropriate influence over the Commission's decisions as implied in Mr. Coppola's direct testimony. A positive Regulatory Environment is beneficial to customers in many ways, including favorable access to investment dollars, and fair, timely actions by the Commission on behalf of customers. Barclays states that when it cross-referenced its regulatory rankings with JD Powers' residential customer satisfaction levels, states with higher state regulator rankings had higher average customer satisfaction scores. This is an important measure to focus employee efforts. While this measure has a positive qualitative customer component, it was not included in the quantitative economic benefit analysis.

Q. At page 33 of his direct testimony, Mr. Coppola discusses the Competitive Price goal and states: "With regard to the Competitive Price measure, this is not a price comparison but a bill comparison between the Company's average annual residential bill and the national average bill with all the differences in sales volumes and local taxes. Such a comparison is not a true measure of price or rate competitiveness." Do you agree?

A. No. There are two components to the Competitive Price measure that Mr. Coppola is discussing, Residential Bill and Industrial Rate. The measure is designed to provide an affordability index that balances Residential Bills and Industrial Rate. Providing employee focus on these important measures provides a qualitative benefit to customers; however, it is not included in the quantitative analysis.

Q. At page 33 of his direct testimony, Mr. Coppola claims that the Company's "new measures" are not likely to drive higher operating performance or any visible and critical improvements for customers. Do you agree?

A. No, the "new measures" are a positive addition to the portfolio of metrics. These metrics, along with the other metrics, help to focus employee effort on priorities and emphasizing the need to balance multiple considerations in providing world class service to customers. They provide benefits to customers.

Q. At page 34 of his direct testimony, Mr. Coppola states: "I see considerable duplication in many of the measures. For example, in the customer service area, the Company has three measures: Digital Customer Experience Index, Customer Care and Customer Satisfaction Surveys. Performance in one measure is likely to affect the other two. So if the Company does a good job answering customer calls quickly, this performance will likely result in high scores in customer satisfaction surveys since most customers only have contact with the Company by telephone. A similar point can be made with regard to the Digital Customer Experience and the customer satisfaction survey results." Do you agree that there is duplication in the incentive compensation metrics?

A. No. The portfolio of incentive compensation measures was carefully constructed to provide a balance between Customer Value, Reliability, and Safety. It is important for employees to understand the balance of these measures as they focus on achieving the annual targets for the individual metrics. Mr. Coppola's example that the Company is duplicative, using the example of call center response and customer satisfaction, is incorrect. Customer satisfaction is derived through good performance in a number of key driver areas and is only marginally impacted by the call center response. Call center response is an important measure, independent of customer satisfaction, which measures the Company's ability to respond to customers in a timely manner. Additionally, Digital Customer Experience measures a customer's specific interaction with the Company's website applications and is important to measure as the Company continues to improve digital offerings which are less expensive to customers. While these measures complement each other, they are not the same.

Q. At page 35 of his direct testimony, Mr. Coppola states: "Another concern is the low threshold to achieve a payout under the EICP." Do you agree that the number of measures required to be achieved is low?

A. No. The EICP is a part of the reasonable level of compensation and not in addition to it. The EICP is a component of reasonable, market-based compensation which is placed at risk unless the targets are achieved. Aggressive targets for the measures are set annually, with the expectation that with good performance the Company should be able to achieve six of 12 targets and therefore pay 100% of the portion of an employee's base pay that has been put at risk in this program.

Q. At page 37 of his direct testimony, when addressing the cost savings related to certain operating performance measures, Mr. Coppola states: "[I]t becomes obvious that the claimed financial benefits are highly inflated and often stale." Do you agree with his conclusion?

A. No. Mr. Coppola seeks to support this incorrect conclusion by referring to the calculation that the reduction in lost work days and medical expenses from the 85% decrease in safety incidents from 2006 through 2016 approximates $3.7 million in annual savings that accrues to the benefit of customers. Mr. Coppola's assertions that "the $3.7 million of annual savings put forth by the Company mainly relate to what was achieved more than 5 years ago," "that most of the reported safety incidents are for minor muscle strains, sprains and insect bites," and that "information is also contradictory, with safety incidents sometimes declining and lost work days increasing, and vice versa" are incorrect and do not support his conclusions.

Q. Please explain.

A. All calculations are based upon industry norms or studies. Safety incidents are based on recordable incidents. In the specific case of employee safety, the value of the elimination of days lost is not the only component of the calculation, medical expense savings and the reduction of exposure to paid compensation is also calculated, compared to the previous year. Mr. Coppola states that in 2013 the Company did not have an improvement, which is true. The resulting increase in expenses brought the average savings per year down. Additionally, in 2015 and 2016, the Company had back to back years with the fewest employee safety incidents in our history, an 85% improvement over 2006, and a 51% improvement over 2014. The performance and the value to the customer is most certainly not contradictory, and in fact, the steady improvement in the culture of employee safety at the Company has led to significant reductions in the severity of injuries thereby reducing the overall cost per incident.

Q. At page 38 of his direct testimony, Mr. Coppola states that: "The reduction in the SAIDI index cannot be used directly to calculate the benefits of lower outage time." Do you agree?

A. No. In the Berkeley National Laboratory study, "Estimated Value of Service Reliability for Electric Utility Customers in the United States" from June of 2009, the System Average Interruption Duration Index ("SAIDI") is very effectively used to model the economic and societal benefits related to customer reliability. These benefits are based on independent, expert research of the Berkeley National Laboratory.

Q. At page 38 of his direct testimony, Mr. Coppola claims that the Company's presented savings for residential customers of $51,000 for each one-minute reduction in outage time and approximately $1.7 million for commercial and industrial customers for each one-minute reduction in outages "is rather preposterous even if based on a study by the Berkeley National Laboratory." Do you agree?

A. No. The savings referenced by Mr. Coppola are not, as he contends, calculated as cost savings. Rather, these benefits are the economic societal benefit related to reductions in outage time. The Company's calculations of benefits are the result of independent, third-party research and analysis. It is not preposterous to consider that each minute of SAIDI improvement results in a $51,000 benefit to more than 1.5 million residential customers, a $1.7 million benefit to 248,000 small commercial and industrial customers, and a $1.7 million benefit to 8,500 large commercial and industrial customers.

Q. At page 39 of his direct testimony, Mr. Coppola claims that the Company's presented savings of $1.8 million per year from improvements in the generation forced outage rate were "highly dependent on the Locational Marginal Prices experienced in the power market in any year, which are outside the Company's control. So any savings or costs are masked by market price variations that can swing wildly from year to year." Do you agree?

A. No. The Company works aggressively to reduce the forced outage rate of our coal baseload generation units to provide our customers the lowest cost of power possible. Calculated savings are based on what it would have cost to purchase power at market to replace the power generation capacity lost to forced outages of historical outage rates. By improving the reliability of our baseload generation units, the Company is reducing the risk of market fluctuations in price for our customers.

Q At page 39 of his direct testimony, Mr. Coppola claims "Mr. Stuart also presents potential annual savings of $160 million since 2006 for supposedly keeping O&M expenses below the rate of inflation. These are not real savings but simply a 'what-if' exercise." Do you agree?

A. No. The comparison of actual expenses to the Consumer Price Index data is a reasonable comparison to what costs would have been, if cost saving measures were not developed through the emphasis on productivity.

Q. At page 46 of his direct testimony, Mr. Coppola claims that "cost savings … related to productivity and quality improvements are mostly based on internal and subjective measures which cannot be objectively validated and relied upon." Do you agree with this criticism?

A. No. The Company's productivity measures have been demonstrated over the years to measure improvement that drives improved overall productivity and creates accountability at the department level. Quality measures are focused on removing rework and in process improvements that reduce costs. The productivity and quality measures are results based.

Q. At page 46 of his direct testimony, Mr. Coppola claims that "the purported cost savings to customers are questionable at best, not sufficiently supported or objectively determined." Do you agree?

A. No. The calculated savings are conservative and represent quantification for only a portion of the metrics for the EICP. The metrics whose value has not been quantified also provide significant value to the customer. However, the economic value to the customer is difficult to calculate and support and have therefore been excluded from the calculations. The calculations used to determine economic value to the customer are based on industry norms and studies, and are reasonable.

Q. Does this conclude your rebuttal testimony?

A. Yes.

(Documents were marked for identification by the Court Reporter as Exhibit A-1 Schedules A-1 and A-2, Exhibit A-2 Schedules B-1, B-2, B-3, B-4, B-5, B-6, Exhibit A-3 Schedules C-1, C-2, C-3, C-4, C-5, C-6, C-7, C-8, C-9, C-10, C-11, C-12, C-13, C-14, C-15, C-16, C-17, C-18, C-19, C-20, C-21, C-22 and C-23, Exhibit A-4 Schedules D-1, D-2, D-3, D-4, and D-5.)

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MS. UITVLUGT: Thank you, your Honor. The Company would ask that the direct testimony of Company witness Andrew G. Volansky be bound into the record. Mr. Volansky's direct testimony consists of a cover page and eight pages of questions and answers.

I would also move for the admission of Mr. Volansky's exhibits. Mr. Volansky is sponsoring Exhibit A-1 Schedule A-1, Exhibit A-1 Schedule A-2, Exhibit A-2 Schedule B-1, Exhibit A-2 Schedule B-2, Exhibit A-2 Schedule B-3, Exhibit A-2 Schedule B-4, Exhibit A-2 Schedule B-5, Exhibit A-2 Schedule B-6, Exhibit A-3 Schedule C-1, Exhibit A-3 Schedule C-2, Exhibit A-3 Schedule C-3, Exhibit A-3 Schedule C-4, Exhibit A-3 Schedule C-5, Exhibit A-3 Schedule C-6, Exhibit A-3 Schedule C-7, Exhibit A-3 Schedule C-8, Exhibit A-3 Schedule C-9, Exhibit A-3 Schedule C-10, Exhibit A-3 Schedule C-11, Exhibit A-3 Schedule C-12,

Exhibit A-3 Schedule C-13, Exhibit A-3 Schedule C-14, Exhibit A-3 Schedule C-15, Exhibit A-3 Schedule C-16, Exhibit A-3 Schedule C-17, Exhibit A-3 Schedule C-18, Exhibit A-3 Schedule C-19, Exhibit A-3 Schedule C-20, Exhibit A-3 Schedule C 21, Exhibit A-3 Schedule C-22, Exhibit A-3 Schedule C-23, Exhibit A-4 Schedule D-1, Exhibit A-4 Schedule D-2, Exhibit A-4 Schedule D-3, Exhibit A-4 Schedule D-4, and Exhibit A-4 Schedule D-5.

JUDGE SONNEBORN: Thank you. Are there any objections to binding into the record Andrew G. Volansky's direct testimony, as well as his exhibits as described by Ms. Uitvlugt?

Hearing no objection, his testimony is bound into the record and his exhibits are admitted into evidence.

(Testimony bound in.)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief	)))))	Case No. U-18424

DIRECT TESTIMONY

OF

ANDREW G. VOLANSKY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2017

ANDREW G. VOLANSKY
DIRECT TESTIMONY

Q. Please state your name and business address.

A. My name is Andrew G. Volansky, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Rate Analyst II in the Revenue Requirement and Analysis section of the Rates and Regulation Department.

Q. Please state your educational background.

A. I graduated from Wayne State University in 1992 with a Bachelor of Science Degree, majoring in Psychology and in 2001 with a Bachelor of Business Administration Degree, majoring in Accounting. I am also a Certified Public Accountant registered in the State of Michigan.

Q. Please describe your business experience.

A. After receiving my accounting degree in 2001, I worked as a staff auditor at Arthur Andersen LLP (2001 to 2002) and George Johnson and Company (2002 to 2003) working on financial audits, compliance audits, and Income tax returns. In 2004, I joined Consumers Energy as an Accounting Analyst in the Technical Accounting and External Financial Reporting Department and was promoted throughout the years to a Senior Accounting Analyst. In 2016, I accepted the position of Senior Rate Analyst II in the Revenue Requirement Section of the Rates and Regulation Department.

Q. What are your responsibilities as a Senior Rate Analyst II?

A. I am responsible for developing, analyzing, and reviewing the Company's monthly return studies. These include studies pertaining to balance sheet working capital, cost of capital, return on investment, and Return On Equity ("ROE"). Additionally, I assist in the development of analyses related to the Company's revenue requirements and the preparation of electric and gas rate case filings at the Michigan Public Service Commission ("MPSC" or the "Commission"). I am also responsible for forecasting the Power Supply Cost Recovery ("PSCR") Factor on a monthly basis.

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

A. The purpose of my testimony is to present Consumers Energy's revenue requirement calculation for the Historical Test Year.

Q. What is the Historical Test Year used in your exhibits and supporting testimony?

A. Calendar year 2016 was chosen for the Historical Test Year.

Q. Are you sponsoring any exhibits?

A. Yes. The following exhibits are being submitted to satisfy the Historical Test Year Filing Requirements:

Exhibit A-1 (AGV-1)	Schedule A-1	Computation of the Gas Revenue Requirement for the Historical Year Ended December 31, 2016;
Exhibit A-1 (AGV-2)	Schedule A-2	Financial Metrics - Gas Results Only;
Exhibit A-2 (AGV-3)	Schedule B-1	Total Rate Base for the Historical Year Ended December 31, 2016;
Exhibit A-2 (AGV-4)	Schedule B-2	Total Utility Plant for the Historical Year Ended December 31, 2016;
Exhibit A-2 (AGV-5)	Schedule B-3	Depreciation Reserve and Other Deductions for the Historical Year Ended December 31, 2016;
Exhibit A-2 (AGV-6)	Schedule B-4	Gas 13-Month Average Working Capital Balance Sheet for the Historical Year Ended December 31, 2016;

Exhibit A-2 (AGV-7)	Schedule B-5	13-Month Average Working Capital Balance Sheet Summary for the Historical Year Ended December 31, 2016;
Exhibit A-2 (AGV-8)	Schedule B-6	Working Capital Balance Sheet Summary for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-9)	Schedule C-1	Adjusted Net Operating Income for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-10)	Schedule C-2	Computation of the Revenue Multiplier for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-11)	Schedule C-3	Total Operating Revenue for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-12)	Schedule C-4	Total Cost of Gas Sold for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-13)	Schedule C-5	Other Operation and Maintenance Expense for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-14)	Schedule C-6	Depreciation and Amortization Expense for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-15)	Schedule C-7	General Taxes for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-16)	Schedule C-8	Federal Income Tax for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-17)	Schedule C-9	State Income Taxes for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-18)	Schedule C-10	Other (or Local) Taxes for the Historical Year Ended December 31, 2016;

Exhibit A-3 (AGV-19)	Schedule C-11	Allowance for Funds Used During Construction for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-20)	Schedule C-12	Compensation Disallowances Impact on Net Operating Income for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-21)	Schedule C-13	Dues and Donations Disallowances Impact on Net Operating Income for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-22)	Schedule C-14	Advertising Classification and Disallowance for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-23)	Schedule C-15	Corporate Giving and Communications Disallowances Impact on Net Operating Income for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-24)	Schedule C-16	Voluntary Separation Agreement Impact on Net Operating Income for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-25)	Schedule C-17	Weather and Other Gas Revenue Normalizing Adjustments Impact on Net Operating Income for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-26)	Schedule C-18	EO Surcharge Revenue and Expense Impact on Net Operating Income for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-27)	Schedule C-19	Jobwork Revenue Impact on Net Operating Income for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-28)	Schedule C-20	Jobwork Expense Impact on Net Operating Income for the Historical Year Ended December 31, 2016;

Exhibit A-3 (AGV-29)	Schedule C-21	Sales and Use Tax Settlement Adjustment Impact on Net Operating Income for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-30)	Schedule C-22	Tax Effect of Pro-Forma Interest Adjustment for the Historical Year Ended December 31, 2016;
Exhibit A-3 (AGV-31)	Schedule C-23	Tax Effect of Interest Synchronization Adjustment for the Historical Year Ended December 31, 2016;
Exhibit A-4 (AGV-32)	Schedule D-1	Overall Rate of Return Summary for the Historical Year Ended December 31, 2016;
Exhibit A-4 (AGV-33)	Schedule D-2	Cost of Long-Term Debt for the Historical Year Ended December 31, 2016;
Exhibit A-4 (AGV-34)	Schedule D-3	Cost of Short Term Debt for the Historical Year Ended December 31, 2016;
Exhibit A-4 (AGV-35)	Schedule D-4	Cost of Preferred Stock for the Historical Year Ended December 31, 2016; and
Exhibit A-4 (AGV-36)	Schedule D-5	Cost of Common Equity for the Historical Year Ended December 31, 2016.

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

A. Yes.

Q. How are these exhibits organized?

A. The exhibits I am sponsoring are organized into schedules that present the development of the revenue requirement (Schedule A), rate base (Schedule B), adjusted Net Operating Income ("NOI") (Schedule C), and rate of return (Schedule D).

Q. Who is sponsoring Historical Test Year Schedule E and Schedule F exhibits?

A. Historical Test Year Schedule E exhibits are sponsored by Company witness Eric J. Keaton. Historical Test Year Schedule F exhibits are sponsored by Company witness Luis F. Saenz.

Q. Please describe the Schedule A exhibits for the Historical Test Year.

A. Exhibit A-1 (AGV-1), Schedule A-1, presents the computation of the gas revenue requirement for the year ended December 31, 2016. Schedule A-1 is developed from financial data presented in Schedules B, C, and D described below.

Exhibit A-1 (AGV-2), Schedule A-2, is a multiple page exhibit that provides financial metrics on a financial basis (pages 1-3) and on a ratemaking basis (pages 4-6) for the years 2012 through 2016. Pages 1 and 4 calculate a gas ROE for each of these years.

Q. Please describe the Schedule B exhibits for the Historical Test Year.

A. Exhibit A-2 (AGV-3), Schedule B-1 presents the calculation of the average rate base for the year ended December 31, 2016 in the amount of $4,020,092,000 as shown on line 6, which is carried forward to Exhibit A-1 (AGV-1), Schedule A-1, line 1. Exhibit A-2 (AGV-4), Schedule B-2, through Exhibit A-2 (AGV-8), Schedule B-6, support the development of the various components of average rate base including net utility plant and working capital.

Q. Please describe the Schedule C exhibits for the Historical Test Year.

A. Exhibit A-3 (AGV-9), Schedule C-1 presents the calculation of adjusted NOI for the year ended December 31, 2016 in the amount of $264,714,000 shown on line 33, which is carried forward to Exhibit A-1 (AGV-1), Schedule A-1, line 2. Exhibit A-3 (AGV-10), Schedule C-2 through Exhibit A-3 (AGV-31), Schedule C-23 support the development of the various components of adjusted NOI. Schedule C data for the Historical Test Year are generally sourced to the Company's 2016 Form P-522 Annual Report to the MPSC.

Q. Please describe the Schedule D exhibits for the Historical Test Year.

A. Exhibit A-4 (AGV-32), Schedule D-1 presents the overall rate of return summary for the year ended December 31, 2016. The weighted cost of capital is shown on line 13, column (h), and is carried forward to Exhibit A-1 (AGV-1), Schedule A-1, line 4. Exhibit A-4 (AGV-33), Schedule D-2 through Exhibit A-4 (AGV-36), Schedule D-5 support the development of various components of the overall rate of return for the Historical Test Year including debt, preferred stock, common equity, and other sources of financing.

Q. Based on your review of the Historical Test Year exhibits, was there a revenue deficiency in the Historical Test Year?

A. No, I have calculated a Historical Test Year gas revenue sufficiency of $35,282,774 for the year ended December 31, 2016.

Q. Please summarize the key findings for the Historical Test Year exhibits.

A. The Historical Test Year exhibits demonstrate that for the year ended December 31, 2016:

	(In Thousands)
Rate Base	**$4,020,092**
Adjusted NOI	$**264,714**
Overall Rate of Return	**6.58%**
Required Rate of Return	**6.05%**
Income Required	**243,170**
Income Deficiency/ (Sufficiency)	**(21,544)**
Revenue Multiplier	**1.6377**
Revenue Deficiency/ (Sufficiency)	**$(35,283)**

The above information is presented on Exhibit A-1 (AGV-1), Schedule A-1.

Q. Do the above results include typical ratemaking adjustments such as weather, unusual, one-time, out-of-period items, and regulatory disallowances?

A. Yes. Ratemaking adjustments and normalizations are recognized, where appropriate, as summarized on Exhibit A-3 (AGV-9), Schedule C-1.

Q. Does this complete your testimony?

A. Yes.

MS. UITVLUGT: Thank you, your Honor. I believe that all remaining Company witnesses are subject for cross-examination.

JUDGE SONNEBORN: All right. Thank you very much. Is there anything further before we close for the day?

I would ask that counsel e-mail me their cross-examination plans. I do have the Company's cross-examination plans of Staff witnesses, who they intend to cross, and I do have Mr. Keskey's plans that he has shared with me. I don't know which witnesses the Attorney General is crossing. I don't know which witnesses ABATE is crossing other than the two that we have discussed for Friday, Mr. Brandenburg. So that would be helpful for me to know that for planning purposes. Thank you. And Ms. Heston, I don't who is being cross-examined by RESA. So thank you very much. O.K. We'll see you in the morning.

(At 11:00 a.m., the hearing was adjourned to Thursday, April 5, 2018.)

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C E R T I F I C A T E

We, Marie T. Schroeder and Lori Anne Penn, do hereby certify that we reported in stenotype the proceedings had in the within-entitled matter, that being Case No. U-18424, before Suzanne D. Sonneborn, Administrative Law Judge with MAHS, at the Michigan Public Service Commission, Lansing, Michigan, on Wednesday, April 4, 2018; and do further certify that the foregoing transcript, consisting of Volume 2, is a true and correct transcript of our stenotype notes.

Marie T Schroeder

Digitally signed by Marie T Schroeder
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Date: 2018.04.04 19:34:55 -04'00'

Marie T. Schroeder, CSR-2183

Lori Anne Penn

Digitally signed by Lori Anne Penn
DN: cn=Lori Anne Penn, o=Metro Court Reporters, ou=Metro, email=metrostate@sbcglobal.net, c=US
Date: 2018.04.04 19:35:44 -04'00'

Lori Anne Penn, CSR-1315
33231 Grand River Avenue
Farmington, Michigan 48336
metrostate@sbcglobal.net

Dated: April 5, 2018