Consumers Energy
Count on Us

A CMS Energy Company

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September 30, 2015

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
P.O. Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-17918 – In the Matter of the Application of CONSUMERS ENERGY COMPANY for Approval of a Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for the Year 2016.

Dear Ms. Kunkle:

Included in this electronic file are Consumers Energy Company's Application, and the Testimony and Exhibits of Consumers Energy Company's witnesses Daniel S. Alfred, Natalie N. Busack, Jim K. Chilson II, David F. Ronk, Jr., Robert C. Schram, Jason M. Shore, and Sara T. Walz.

This is a paperless filing and is therefore being filed only in a PDF format. Also included is a Proof of Service reflecting service on the parties to Case No. U-17678.

Sincerely,

Digitally signed by
Robert W. Beach
Date: 2015.09.30
16:45:07 -04'00'

Robert W. Beach

cc: Parties to Case No. U-17678

fl0915-1-241

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17918
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2016	)	

APPLICATION

Consumers Energy Company ("Consumers Energy" or the "Company") hereby applies for approval of a Power Supply Cost Recovery ("PSCR") Plan and monthly PSCR Factors for the 12-month period January through December 2016. In support of this Application, Consumers Energy states as follows:

1. Consumers Energy is a public utility engaged in, among other things, the generation, purchase, distribution, and sale of electric energy to approximately 1.8 million retail electric customers in the lower peninsula of the State of Michigan.

2. Consumers Energy's retail electric business is subject to the jurisdiction of the Michigan Public Service Commission ("MPSC" or the "Commission") pursuant to certain provisions of 1939 PA 3, as amended by various acts, including 1982 PA 304 and 2000 PA 141, MCL 460.1 *et seq*.; 1909 PA 106, as amended, MCL 460.551 *et seq*.; 1909 PA 300, as amended, MCL 462.2 *et seq*.; and 2008 PA 286, MCL 460.4a *et seq*.

3. This Application is filed pursuant to MCL 460.6j, and Consumers Energy's Rule C8. MCL 460.6j authorizes the Commission to approve a PSCR clause for electric utilities such as Consumers Energy. Company Rule C8 sets forth the Company's PSCR clause.

4. Public Act 304 of 1982 provides that a utility is to be reimbursed for booked costs, including transportation costs, reclamation costs, and disposal and reprocessing costs, of

fuel burned by the utility for electric generation and the booked costs of purchased and net interchanged power transactions by the utility incurred under reasonable and prudent policies and practices. It is in the interests of both customers and the Company for Consumers Energy to recover its power supply costs during the PSCR period in which those costs are incurred. Underrecoveries will send customers inaccurate price signals, impose interest costs on customers at a date after the power supply costs are incurred, and interfere with utility cash flow.

5. Rule C8 of Consumers Energy's electric tariffs requires the Company to file a PSCR Plan, to request approval of specific PSCR Factors for a future 12-month period, and to provide a five-year forecast. Accompanying this Application are the testimony and exhibits of witnesses for Consumers Energy that meet the requirements of Rule C8 with respect to calendar year 2016. The prefiled testimony and exhibits include an evaluation and conclusions as to the reasonableness and prudence of the forecasted costs of fuel and purchased and net interchange power. Also included in these materials is a five-year forecast of the power supply requirements of Consumers Energy's customers, anticipated sources of supply, and projections of power supply costs.

6. As more fully described in the accompanying testimony and exhibits, Consumers Energy seeks approval to apply, for each month in calendar year 2016, a uniform maximum PSCR Factor of $(0.00014) per kWh for all classes of customers.

7. The accompanying testimony and exhibits are an integral part of this Application, and the relief described therein is incorporated by reference in this Application as if fully set forth herein.

8. If power supply costs increase for the PSCR Plan year, due to changes in conditions, the factors that are ultimately requested or approved could be higher than set forth

above. Consumers Energy reserves the right to amend its filing or seek reopening of the power supply cost review for the PSCR Plan year if circumstances warrant.

WHEREFORE, Consumers Energy Company respectfully requests that the Commission grant the following relief:

A. Issue a prompt notice commencing hearings on the relief sought herein;

B. Approve for 2016 a maximum monthly PSCR Factor of not less than $(0.00014) per kWh for all classes of customers as set forth herein and more fully explained in the accompanying testimony;

C. Approve the PSCR Plan for 2016 described in this Application; and

D. Grant Consumers Energy such further and additional relief as may be lawful and appropriate.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Digitally signed by Timothy J. Sparks
Date: 2015.09.30 16:43:49 -04'00'

Date: September 30, 2015

By: ______________________________
Timothy J. Sparks
Vice President of Energy Supply Operations

Digitally signed by Robert W. Beach
Date: 2015.09.30 16:44:36 -04'00'

____
Robert W. Beach (P73112)
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STATE OF MICHIGAN

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In the Matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
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Monthly Power Supply Cost Recovery	)	
Factors for the Year 2016	)	

VERIFICATION

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Timothy J. Sparks, being first duly sworn, deposes and says that he is the Vice President of Energy Supply Operations of Consumers Energy Company; that he has executed the foregoing Application for, and on behalf of, Consumers Energy Company; that he has read the foregoing Application and is familiar with the contents thereof; that the facts contained therein are true, to the best of his knowledge and belief; and that he is duly authorized to execute such Application on behalf of Consumers Energy Company.

Digitally signed by Timothy J. Sparks
Date: 2015.09.30 16:43:18 -04'00'

Timothy J. Sparks,
Vice President of Energy Supply Operations

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17918
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2016	)	

DIRECT TESTIMONY

OF

DANIEL S. ALFRED

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2015

QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Daniel S. Alfred, and my business address is 1945 West Parnall Road, 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 Business Support Consultant II in the Transmission and Regulatory Strategies Department of Energy Supply Operations.

Q. Please describe your educational background.

A. I received a Bachelor of Business Administration in Accounting degree in 1993 from Eastern Michigan University. I received a Master of Business Administration degree with an emphasis in finance from Eastern Michigan University in April of 2003.

Q. Please describe your business experience.

A. In January of 1998, I joined Consumers Energy as a Rate Analyst in the Financial Analysis and Planning Section of the Rates Department and was promoted to General Rate Analyst in October of 1999. During August of 2001, I transferred to a position in the Revenue Requirements Section of the Rates Department. In February of 2004, I was promoted to a Senior Rate Analyst in the Revenue Section of the Rates and Business Support Department. In March of 2013, I assumed my current position as Senior Business Support Consultant II in the Transmission and Regulatory Strategies Section of Energy Supply Operations.

Q. What are your responsibilities within your position in Energy Supply Operations?

A. In this position, I am responsible for monitoring and analyzing the filings by the Midcontinent Independent System Operator, Inc. ("MISO") at the Federal Energy Regulatory Commission ("FERC"). In addition, I support the Company's involvement in stakeholder and transmission planning activities at MISO, the FERC, and the Michigan Public Service Commission ("MPSC" or the "Commission"). I am also responsible for forecasting future transmission and certain energy market related costs expected to impact the Company.

Q. During your tenure with Consumers Energy, have you testified in any utility proceedings before the Commission?

A. Yes. I have testified or submitted testimony in the following proceedings:

Case	Description
1. Case No. U-13730	Gas General Rate Case;
2. Case No. U-14126	Enhanced Security Costs Case;
3. Case No. U-14148	10(d)4 Regulatory Asset Recovery Case;
4. Case No. U-14347	Gas General Rate Case;
5. Case No. U-15245	Gas General Rate Case;
6. Case No. U-15986	Gas General Rate Case;
7. Case No. U-15704	Gas Cost Recovery Plan Case;
8. Case No. U-14126-R	Enhanced Security Costs Reconciliation Case;
9. Case No. U-16564	10d(4) Regulatory Asset Reconciliation Case;
10. Case No. U-16855	Gas General Rate Case;
11. Case No. U-17317	2014 Power Supply Cost Recovery ("PSCR") Plan Case; and
12. Case No. U-17678	2015 PSCR Plan Case.

PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to: 1) identify the transmission and energy market expenses for 2016 for which the Company seeks recovery in this proceeding; 2) identify generation-related credits to PSCR costs relating to Schedule 2 Reactive revenues; and 3) describe the Company's effort to manage its transmission-related costs.

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

A. Yes. I am sponsoring the following exhibit:

Exhibit A-1 (DSA-1)	Transmission and Energy Market Administration Expenses

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

A. Yes.

TRANSMISSION AND ENERGY MARKET EXPENSES

Q. What transmission and energy market expenses does the Company seek recovery for in the Company's 2016 PSCR Plan?

A. The Company seeks to recover all of the charges imposed on the Company under MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff") which is filed with and approved by the FERC.

Q. Has the Commission previously approved the recovery of Transmission, Energy, and Operating Reserve Market ("Market") costs through the PSCR process?

A. Yes. The Commission approved recovery of expenses incurred under MISO's Tariff in the Company's PSCR Factor most recently in the 2012 PSCR Plan, Case No. U-16890.

Q. Are the rates assessed and revenues distributed by MISO subject to FERC review?

A. Yes. All of the charges incurred and revenues received through MISO by the Company are based on the FERC-approved tariff.

Q. Please list each transmission and energy market charge that has been projected for 2016 in the Company's total transmission costs.

A. The transmission and energy market-related charges included in the total transmission costs projected for 2016 (and shown in Exhibit A-1 (DSA-1) page 1 of 5 are incurred as a result of the mandated expenses charged to Consumers Energy by MISO pursuant to MISO Schedules 1, 2, 9, 10, 10-FERC, 16, 17, 24, 26, and 26-A. The charges imposed pursuant to these schedules are discussed more fully below.

Q. Has the Company forecasted other MISO charges?

A. Yes. As discussed by Company witness David F. Ronk, Jr., the impact of other MISO charges is included in the projection of energy costs.

Q. Are your projections based on the demand and sales information provided by Company witness Jason M. Shore?

A. Yes.

Q. Please describe the MISO Schedule 1 rate and the forecasted cost of this expense.

A. MISO Schedule 1 is the Tariff schedule for service required to schedule the movement of power through, out of, within, or into a control area and is provided by the transmission operators within the control area and MISO. The rate for this service is a zonal rate. Applying this rate to the Company's forecasted monthly coincident peak produces the Company's forecasted expense. This forecasted expense for the 2016 PSCR Plan year and the five-year period 2016-2020 is shown on Exhibit A-1 (DSA-1), line 15.

Q. Please describe the MISO Schedule 2 rate and forecasted cost of this expense.

A. MISO Schedule 2 is the Tariff schedule for an ancillary service required to be provided by MISO for Reactive Supply and Voltage Control from Generation Sources. The rate for this service is a pricing zone wide rate. Applying the applicable pricing zone rate to the Company's forecasted monthly coincident peak produces the Company's forecasted expense. This forecasted expense for the 2016 PSCR Plan year and the five-year period 2016-2020 is shown on Exhibit A-1 (DSA-1), line 16.

Q. Please describe the MISO Schedule 9 rate and the forecasted cost of this expense.

A. MISO Schedule 9 is the Tariff schedule for the network transmission service. Schedule 9 includes the rate that applies to the Company's entire retail load within the MISO footprint. MISO utilizes the "license plate" rate approach, which means that the rate applicable to each customer is that of the transmission owner(s) in the pricing zone where the load is located. The Company pays the rate for the Michigan Joint Zone ("MJZ"). The MJZ is made up of multiple transmission owners, including Michigan Electric Transmission Company ("METC"), Wolverine Power Supply Cooperative, and Michigan Public Power Agency, which all reside within the METC footprint. The rate that is assessed to load in the joint zone is an average of the joint zone members' revenue requirements. The MJZ was approved by the FERC in Docket No. ER02-2458.

This rate is calculated per the MISO Tariff Attachment O and is updated biannually. The Company's forecasted expense for the 2016 PSCR Plan year and the five-year period 2016-2020 is shown on Exhibit A-1 (DSA-1), line 17.

Q. Are you forecasting changes for the 2016 PSCR Plan year relative to the MJZ?

A. Yes. Consumers Energy will be a Transmission Owner during the 2016 PSCR Plan year and accordingly will become a new member of the MJZ.

Q. Has Consumers Energy received MPSC and FERC approval to reclassify certain distribution assets?

A. Yes. The MPSC on October 16, 2014 approved a Settlement Agreement in MPSC Case No. U-17598 which allows for certain high-voltage distribution assets of Consumers Energy to be classified as transmission. Subsequently, on April 16, 2015, the FERC issued an Order in FERC Docket No. ER15-910-000 approving Consumers Energy's Application to reclassify the assets approved by the MPSC on October 16, 2014 as transmission assets. The FERC Order also allows Consumers Energy to submit an Attachment O and receive revenues for the transmission assets once Consumers Energy enters into a revenue sharing agreement by joining the MJZ as a Transmission Owner. The above orders provide for Consumers Energy to submit an Attachment O and join the MJZ, which is projected to occur on January 1, 2016.

Q. What implications does Consumers Energy becoming a Transmission Owner have on its 2016 PSCR Plan Case regarding the forecasted calculation of transmission expenses?

A. With Consumers Energy becoming a Transmission Owner and becoming a member of the MJZ, there will be additional transmission revenue requirements within the MJZ to account for Consumers Energy's transmission assets. Utilizing Attachment O of the Tariff, Consumers Energy's transmission revenue requirement is approximately $9 million. I have added the revenue requirement calculated in Consumers Energy's

Attachment O to the other MJZ revenue requirements used to determine the MISO Schedule 9 forecasted rate for the MJZ and subsequent forecasted costs.

Q. Please describe the MISO Schedule 10 rates and forecasted cost of this expense.

A. MISO Schedule 10 is the Tariff schedule for MISO expenses associated with the operation of MISO in the provision of transmission service within the MISO footprint. MISO assesses Schedule 10 with two rates. The first rate is applied to peak load at a 100% load factor. The Company's forecasted expense for the 2016 PSCR Plan year and the five-year period 2016-2020 for this portion of Schedule 10 is shown on Exhibit A-1 (DSA-1) line 18. The second rate is applied to actual volume of MWh of transmission service received. The Company's forecasted expense for the 2016 PSCR Plan year and the five-year period 2016-2020 for this portion of Schedule 10 is shown on Exhibit A-1 (DSA-1), line 19.

Q. Please describe the MISO Schedule 10-FERC rate and the forecasted cost of the expense.

A. MISO Schedule 10-FERC is the Tariff schedule for the FERC Annual Fee that MISO is assessed and then allocated to MISO's wholesale transmission customers. The FERC Annual Fee is designed to reimburse the federal government for all of the costs incurred by the FERC under Parts II and III of the Federal Power Act and related statutes per 18 CFR Part 382. The Company's forecasted expenses for the 2016 PSCR Plan year and the five-year period 2016-2020 are shown on Exhibit A-1 (DSA-1), line 20.

Q. Please describe the MISO Schedule 16 rate and forecasted cost of expense.

A. MISO Schedule 16 is designed to recover MISO administrative service costs associated with MISO Financial Transmission Rights market. In forecasting the Schedule 16 expense, I multiplied the Company's monthly coincident peak load at a 100% load factor against the MISO budgeted Schedule 16 rate to produce the expected expense. The Company's forecasted expenses for the 2016 PSCR Plan year and the five-year period 2016-2020 are shown on Exhibit A-1 (DSA-1) line 21.

Q. Please describe the MISO Schedule 17 rate and forecasted cost of expense.

A. MISO Schedule 17 is designed to recover MISO administrative service costs associated with the Midwest Energy and Operating Reserves Market. The rate is charged to all injections and withdrawals in the market. The Company's forecasted expenses for the 2016 PSCR Plan year and the five-year period 2016-2020 are shown on Exhibit A-1 (DSA-1) on line 22.

Q. Please describe the MISO Schedule 24 rate and forecasted cost of expense.

A. MISO Schedule 24 is the Tariff schedule for the Control Area Operator Cost Recovery charge used to recover Control Area costs incurred with the implementation of the Market. This rate is charged on the same basis as Schedule 17. The Company's forecasted expenses for the 2016 PSCR Plan year and the five-year period 2016-2020 are shown on Exhibit A-1 (DSA-1) on line 23.

Q. Please describe the MISO Schedule 26 rate and forecasted cost of expense.

A. MISO Schedule 26 is the Tariff schedule for the Network Upgrade Charge from MISO's Transmission Expansion Plan ("MTEP"). This schedule is applied on the same basis as Schedule 9. It reflects the sharing of MTEP project costs as allocated according to Attachment FF of the MISO Tariff. The Company's forecasted expenses for the 2016 PSCR Plan year and the five-year period 2016-2020 are shown on Exhibit A-1 (DSA-1) line 24.

Q. Please describe the MISO Schedule 26-A rate and forecasted cost of expenses.

A. MISO Schedule 26-A is the Tariff schedule that includes the Multi-Value Project Usage Rate and is a MISO System-wide rate charged to Monthly Net Actual Energy Withdrawals, certain Export Schedules, and Through Schedules. The rate is calculated using the formula included in Attachment MM of the Tariff. The charges under this Schedule 26-A shall be in addition to any charges under Schedules 7, 8, 9, and 26. Grandfathered Agreements will not be charged this Schedule. The Company's forecasted expenses for the 2016 PSCR Plan year and the five-year period 2016-2020 are shown on Exhibit A-1 (DSA-1) line 25.

Q. What is the total amount of transmission and energy market expenses that you propose to add to the total power costs in each year of the PSCR Plan?

A. Each of the expenses described above, as well as the total expenses for each PSCR Plan year, is identified on Exhibit A-1 (DSA-1). The total cost for 2016 equals $406,718,416 and can be found on line 29, column (o) of page 1 of Exhibit A-1 (DSA-1). It is composed of $400,316,447 of transmission expenses (line 27, column (o)) and $6,401,969 of energy market administration expenses (line 28, column (o)).

SCHEDULE 2 REACTIVE REVENUE REQUIREMENT CREDIT

Q. What is the basis for proposing to credit reactive revenue requirements revenues against total PSCR costs?

A. Consumers Energy provides generation-related reactive services that are necessary for the transmission of power. The Company receives revenue from MISO for providing this service. Consumers Energy incurs an expense under the MISO Tariff when it receives reactive service within MJZ pricing zone. The Company believes that the revenues received from this service should be credited against total power costs for Consumers Energy's retail customers via the PSCR Factor, since the expense for the service is included in the PSCR.

Q. Have you identified the revenues the Company expects to receive in 2016 from Schedule 2?

A. Yes. The Company expects to receive $19,706,000 in 2016. This amount is composed of the FERC-approved revenue requirements established in FERC Docket Nos. OA96-77 and ER04-1110.

COMPANY ACTIVITIES RELATED TO TRANSMISSION COST MANAGEMENT

Q. Does the Company take actions to mitigate transmission-related costs?

A. Yes. The Company actively participates in the transmission provider's stakeholder process dealing with transmission planning and project approval. It is primarily through this stakeholder process that the Company works to assure new transmission investments are justified and allocated on a cost causation basis. Additionally, the Company actively monitors and intervenes in tariff filings by MISO and transmission owners to assure that the new tariff provisions are in compliance with FERC policy and are based on cost causation principles.

Q. Is the Company involved in other activities to mitigate transmission related costs?

A. Yes. Under the FERC-approved MISO Tariff, transmission owners recover their Operations and Maintenance ("O&M"), Depreciation, and Tax expenses, as well as a Return on Investment through an Attachment O formula rate that utilizes the actual costs incurred and reported on the transmission owners' FERC Form 1 reports. The Company actively reviews the Attachment O rates of the MJZ transmission owners to assure the application of the formula is consistent with the tariff.

Q. Can you identify some of the MISO stakeholder groups the Company actively follows that impact transmission expenses?

A. Yes. The Company has been very active in MISO's transmission-related groups such as the East Sub-regional Planning Meetings, Michigan Technical Study Task Force, Planning Advisory Committee, Planning Subcommittee, Advisory Committee, Regional Expansion Criteria and Benefits Task Force, and the MISO Board of Directors System Planning Committee. The Company's focus is to monitor and assure new transmission projects are justified and costs are allocated according to cost causation principles.

Q. How does participating in these groups impact the Company's transmission expense?

A. By actively participating in the stakeholder process regarding proposed transmission projects, the Company can independently validate the need for the project before the project is approved by the MISO Board of Directors in the MTEP. If the Company does not believe a project is needed, it can raise issues with MISO before the project is approved.

Q. Does that mean that MISO will reject a project Consumers Energy or another customer or interested party does not believe is needed?

A. No. Third party input to MISO and transmission owners is advisory only.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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EXHIBIT

OF

DANIEL S. ALFRED

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2015

Consumers Energy Company

2016 Transmission and Energy Market Administration Expenses

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper DSA-1	5,575	5,193	5,191	4,792	5,476	7,114	7,812	7,334	6,499	5,257	5,269	5,594	**71,108**
2	Hours per Month	Day in Month * 24	744	672	744	720	744	720	744	744	720	744	720	744	**8,760**
3	Delivered MWhs	Workpaper DSA-3	3,246,237	2,782,578	2,964,592	2,722,561	2,833,116	3,100,805	3,423,322	3,289,345	2,909,846	2,866,622	2,854,697	3,147,007	**36,140,727**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	385.0746	385.0746	385.0746	385.0746	385.0746	385.0746	385.0746	385.0746	385.0746	385.0746	385.0746	385.0746	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	3,308.5554	3,308.5554	3,308.5554	3,308.5554	3,308.5554	3,461.4129	3,461.4129	3,461.4129	3,461.4129	3,461.4129	3,461.4129	3,461.4129	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0569	0.0569	0.0569	0.0569	0.0569	0.0569	0.0569	0.0569	0.0569	0.0569	0.0569	0.0569	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0795	0.0795	0.0795	0.0795	0.0795	0.0795	0.0795	0.0795	0.0795	0.0795	0.0795	0.0795	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0720	0.0720	0.0720	0.0720	0.0720	0.0720	0.0720	0.0720	0.0720	0.0720	0.0720	0.0720	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	1,211.5956	1,211.5956	1,211.5956	1,211.5956	1,211.5956	1,211.5956	1,211.5956	1,211.5956	1,211.5956	1,211.5956	1,211.5956	1,211.5956	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 195,575	$ 182,165	$ 182,105	$ 168,104	$ 192,087	$ 249,563	$ 274,047	$ 257,283	$ 227,991	$ 184,398	$ 184,843	$ 196,246	**$ 2,494,407**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,146,896	1,999,695	1,999,027	1,845,332	2,108,611	2,739,540	3,008,312	2,824,284	2,502,734	2,024,204	2,029,084	2,154,264	**27,381,982**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	18,446,099	17,181,349	17,175,615	15,855,069	18,117,158	24,625,565	27,041,543	25,387,322	22,496,931	18,195,454	18,239,320	19,364,552	**242,125,976**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	236,021	198,564	219,765	196,324	231,813	291,459	330,722	310,491	266,265	222,533	215,874	236,831	**2,956,663**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	258,076	221,215	235,685	216,444	225,233	246,514	272,154	261,503	231,333	227,896	226,948	250,187	**2,873,188**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	144,133	123,546	131,628	120,882	125,790	137,676	151,995	146,047	129,197	127,278	126,749	139,727	**1,604,648**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	37,332	31,407	34,761	31,053	36,666	46,101	52,311	49,111	42,116	35,199	34,145	37,460	**467,662**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	467,458	400,691	426,901	392,049	407,969	446,516	492,958	473,666	419,018	412,794	411,076	453,169	**5,204,265**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	65,574	56,208	59,885	54,996	57,229	62,636	69,151	66,445	58,779	57,906	57,665	63,570	**730,043**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	6,754,976	6,291,823	6,289,723	5,806,139	6,634,517	8,619,667	9,465,329	8,886,304	7,874,582	6,368,940	6,384,294	6,778,158	**86,154,454**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	3,116,929	2,671,739	2,846,503	2,614,113	2,720,264	2,977,290	3,286,960	3,158,320	2,793,938	2,752,435	2,740,985	3,021,652	**34,701,129**
26	METC Agency Agreement		2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	**24,000**
27	Total Transmission Expenses	**Lines 15-20 + 24-26**	**$ 31,300,706**	**$ 28,872,097**	**$ 29,082,052**	**$ 26,824,406**	**$ 30,357,474**	**$ 39,889,273**	**$ 43,833,063**	**$ 41,233,553**	**$ 36,524,971**	**$ 30,105,139**	**$ 30,150,097**	**$ 32,143,617**	**$ 400,316,447**
28	Total Energy Market Administration Expenses	**Lines 21-23**	**570,364**	**488,307**	**521,547**	**478,098**	**501,864**	**555,253**	**614,420**	**589,221**	**519,913**	**505,898**	**502,886**	**554,199**	**6,401,969**
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 31,871,070**	**$ 29,360,404**	**$ 29,603,598**	**$ 27,302,503**	**$ 30,859,338**	**$ 40,444,526**	**$ 44,447,483**	**$ 41,822,774**	**$ 37,044,883**	**$ 30,611,037**	**$ 30,652,983**	**$ 32,697,816**	**$ 406,718,416**

Consumers Energy Company

2017 Transmission and Energy Market Administration Expenses

Case No.: U-17918
Exhibit: A-1 (DSA-1)
Witness: DSAlfred
Date: September 2015
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Line	Description (a)	Source / Calculation (b)	Jan (c)	Feb (d)	Mar (e)	Apr (f)	May (g)	Jun (h)	Jul (i)	Aug (j)	Sep (k)	Oct (l)	Nov (m)	Dec (n)	TOTAL (o)
	Billing Determinants														
1	Peak MWs	Workpaper DSA-1	5,420	5,243	5,227	4,775	5,483	7,161	7,780	7,344	6,488	5,238	5,263	5,643	**71,066**
2	Hours per Month	Day in Month * 24	744	672	744	720	744	720	744	744	720	744	720	744	**8,760**
3	Delivered MWhs	Workpaper DSA-3	3,162,163	2,869,958	2,976,120	2,733,481	2,847,366	3,113,709	3,438,811	3,301,183	2,921,604	2,875,845	2,870,162	3,174,596	**36,284,998**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	385.4812	385.4812	385.4812	385.4812	385.4812	385.4812	385.4812	385.4812	385.4812	385.4812	385.4812	385.4812	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	3,520.0781	3,520.0781	3,520.0781	3,520.0781	3,520.0781	3,544.7634	3,544.7634	3,544.7634	3,544.7634	3,544.7634	3,544.7634	3,544.7634	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0578	0.0578	0.0578	0.0578	0.0578	0.0578	0.0578	0.0578	0.0578	0.0578	0.0578	0.0578	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0807	0.0807	0.0807	0.0807	0.0807	0.0807	0.0807	0.0807	0.0807	0.0807	0.0807	0.0807	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0660	0.0660	0.0660	0.0660	0.0660	0.0660	0.0660	0.0660	0.0660	0.0660	0.0660	0.0660	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	1,259.1068	1,259.1068	1,259.1068	1,259.1068	1,259.1068	1,259.1068	1,259.1068	1,259.1068	1,259.1068	1,259.1068	1,259.1068	1,259.1068	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.3841	1.3841	1.3841	1.3841	1.3841	1.3841	1.3841	1.3841	1.3841	1.3841	1.3841	1.3841	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 190,116	$ 183,927	$ 183,356	$ 167,513	$ 192,330	$ 251,215	$ 272,921	$ 257,637	$ 227,583	$ 183,748	$ 184,628	$ 197,947	**$ 2,492,920**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,089,173	2,021,164	2,014,886	1,840,794	2,113,503	2,760,591	2,999,110	2,831,154	2,500,898	2,019,191	2,028,868	2,175,224	**27,394,557**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	19,077,589	18,456,560	18,399,227	16,809,480	19,299,762	25,385,527	27,578,873	26,034,399	22,997,469	18,567,845	18,656,833	20,002,677	**251,266,241**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	233,062	203,655	224,775	198,729	235,776	298,030	334,572	315,836	269,993	225,255	219,034	242,662	**3,001,380**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	255,187	231,606	240,173	220,592	229,782	251,276	277,512	266,405	235,773	232,081	231,622	256,190	**2,928,199**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	140,400	127,426	132,140	121,367	126,423	138,249	152,683	146,573	129,719	127,688	127,435	140,952	**1,611,054**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	32,258	28,188	31,111	27,506	32,633	41,250	46,308	43,714	37,369	31,177	30,316	33,586	**415,416**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	417,406	378,834	392,848	360,820	375,852	411,010	453,923	435,756	385,652	379,611	378,861	419,047	**4,789,620**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	63,876	57,973	60,118	55,216	57,517	62,897	69,464	66,684	59,016	58,092	57,977	64,127	**732,957**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	6,823,917	6,601,780	6,581,272	6,012,631	6,903,387	9,016,988	9,796,069	9,247,468	8,168,745	6,595,334	6,626,943	7,104,989	**89,479,523**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	4,376,890	3,972,435	4,119,378	3,783,532	3,941,165	4,309,821	4,759,810	4,569,313	4,043,922	3,980,583	3,972,718	4,394,098	**50,223,666**
26	METC Agency Agreement		2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	**24,000**
27	Total Transmission Expenses	**Lines 15-20 + 24-26**	**$ 33,188,334**	**$ 31,800,554**	**$ 31,897,206**	**$ 29,156,637**	**$ 33,044,128**	**$ 42,413,697**	**$ 46,173,551**	**$ 43,670,784**	**$ 38,576,103**	**$ 31,933,724**	**$ 32,050,082**	**$ 34,516,740**	**$ 428,421,540**
28	Total Energy Market Administration Expenses	**Lines 21-23**	**513,539**	**464,995**	**484,076**	**443,542**	**466,003**	**515,156**	**569,695**	**546,154**	**482,038**	**468,881**	**467,155**	**516,760**	**5,937,993**
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 33,701,873**	**$ 32,265,549**	**$ 32,381,283**	**$ 29,600,179**	**$ 33,510,131**	**$ 42,928,853**	**$ 46,743,245**	**$ 44,216,939**	**$ 39,058,140**	**$ 32,402,605**	**$ 32,517,236**	**$ 35,033,499**	**$ 434,359,532**

Consumers Energy Company

2018 Transmission and Energy Market Administration Expenses

Case No.: U-17918
Exhibit: A-1 (DSA-1)
Witness: DSAlfred
Date: September 2015
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Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper DSA-1	5,460	5,173	5,245	4,806	5,547	7,190	7,726	7,311	6,513	5,278	5,307	5,645	**71,200**
2	Hours per Month	Day in Month * 24	744	672	744	720	744	720	744	744	720	744	720	744	**8,760**
3	Delivered MWhs	Workpaper DSA-3	3,182,478	2,806,967	2,997,224	2,752,767	2,868,255	3,135,097	3,461,737	3,325,690	2,946,168	2,901,711	2,895,263	3,178,025	**36,451,382**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	384.2360	384.2360	384.2360	384.2360	384.2360	384.2360	384.2360	384.2360	384.2360	384.2360	384.2360	384.2360	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	3,579.8737	3,579.8737	3,579.8737	3,579.8737	3,579.8737	3,601.0120	3,601.0120	3,601.0120	3,601.0120	3,601.0120	3,601.0120	3,601.0120	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0577	0.0577	0.0577	0.0577	0.0577	0.0577	0.0577	0.0577	0.0577	0.0577	0.0577	0.0577	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0807	0.0807	0.0807	0.0807	0.0807	0.0807	0.0807	0.0807	0.0807	0.0807	0.0807	0.0807	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0670	0.0670	0.0670	0.0670	0.0670	0.0670	0.0670	0.0670	0.0670	0.0670	0.0670	0.0670	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	1,227.9499	1,227.9499	1,227.9499	1,227.9499	1,227.9499	1,227.9499	1,227.9499	1,227.9499	1,227.9499	1,227.9499	1,227.9499	1,227.9499	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.6388	1.6388	1.6388	1.6388	1.6388	1.6388	1.6388	1.6388	1.6388	1.6388	1.6388	1.6388	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 191,525	$ 181,473	$ 183,978	$ 168,576	$ 194,574	$ 252,202	$ 271,014	$ 256,473	$ 228,469	$ 185,136	$ 186,164	$ 198,028	**$ 2,497,612**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,097,861	1,987,751	2,015,193	1,846,488	2,131,258	2,762,484	2,968,536	2,809,259	2,502,525	2,027,872	2,039,135	2,169,094	**27,357,457**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	19,545,486	18,519,605	18,775,273	17,203,477	19,856,639	25,889,657	27,820,758	26,328,027	23,453,359	19,004,969	19,110,519	20,328,478	**255,836,247**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	234,384	200,590	225,148	199,644	238,115	298,683	331,660	313,865	270,576	226,564	220,473	242,342	**3,002,044**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	256,826	226,522	241,876	222,148	231,468	253,002	279,362	268,383	237,756	234,168	233,648	256,467	**2,941,627**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	141,302	124,629	133,077	122,223	127,351	139,198	153,701	147,661	130,810	128,836	128,550	141,104	**1,618,441**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	32,497	27,811	31,216	27,680	33,014	41,412	45,984	43,517	37,515	31,413	30,568	33,600	**416,228**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	426,452	376,134	401,628	368,871	384,346	420,103	463,873	445,642	394,786	388,829	387,965	425,855	**4,884,485**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	64,286	56,701	60,544	55,606	57,939	63,329	69,927	67,179	59,513	58,615	58,484	64,196	**736,318**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	6,704,392	6,352,500	6,440,198	5,901,049	6,811,122	8,828,408	9,486,915	8,977,892	7,997,627	6,480,720	6,516,712	6,932,038	**87,429,573**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	5,215,560	4,600,159	4,911,958	4,511,334	4,700,600	5,137,911	5,673,219	5,450,261	4,828,286	4,755,428	4,744,861	5,208,261	**59,737,836**
26	METC Agency Agreement		2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	**24,000**
27	Total Transmission Expenses	**Lines 15-20 + 24-26**	**$ 34,389,337**	**$ 32,195,228**	**$ 32,928,699**	**$ 30,176,940**	**$ 34,293,128**	**$ 43,563,545**	**$ 46,987,165**	**$ 44,553,820**	**$ 39,651,407**	**$ 33,045,692**	**$ 33,182,061**	**$ 35,477,813**	**$ 440,444,835**
28	Total Energy Market Administration Expenses	**Lines 21-23**	**523,235**	**460,646**	**493,388**	**452,157**	**475,299**	**524,844**	**579,784**	**556,338**	**491,814**	**478,856**	**477,018**	**523,652**	**6,037,031**
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 34,912,572**	**$ 32,655,874**	**$ 33,422,087**	**$ 30,629,097**	**$ 34,768,427**	**$ 44,088,389**	**$ 47,566,949**	**$ 45,110,158**	**$ 40,143,221**	**$ 33,524,549**	**$ 33,659,079**	**$ 36,001,464**	**$ 446,481,866**

Consumers Energy Company

2019 Transmission and Energy Market Administration Expenses

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper DSA-1	5,539	5,232	5,302	4,867	5,615	7,264	7,715	7,343	6,579	5,344	5,354	5,711	**71,864**
2	Hours per Month	Day in Month * 24	744	696	744	720	744	720	744	744	720	744	720	744	**8,784**
3	Delivered MWhs	Workpaper DSA-3	3,208,110	2,830,049	3,020,160	2,773,909	2,888,650	3,157,391	3,487,069	3,350,986	2,968,581	2,921,652	2,904,247	3,200,476	**36,711,281**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	380.5473	380.5473	380.5473	380.5473	380.5473	380.5473	380.5473	380.5473	380.5473	380.5473	380.5473	380.5473	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	3,727.3391	3,727.3391	3,727.3391	3,727.3391	3,727.3391	3,754.5712	3,754.5712	3,754.5712	3,754.5712	3,754.5712	3,754.5712	3,754.5712	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0586	0.0586	0.0586	0.0586	0.0586	0.0586	0.0586	0.0586	0.0586	0.0586	0.0586	0.0586	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0818	0.0818	0.0818	0.0818	0.0818	0.0818	0.0818	0.0818	0.0818	0.0818	0.0818	0.0818	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0670	0.0670	0.0670	0.0670	0.0670	0.0670	0.0670	0.0670	0.0670	0.0670	0.0670	0.0670	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	1,204.6921	1,204.6921	1,204.6921	1,204.6921	1,204.6921	1,204.6921	1,204.6921	1,204.6921	1,204.6921	1,204.6921	1,204.6921	1,204.6921	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.8994	1.8994	1.8994	1.8994	1.8994	1.8994	1.8994	1.8994	1.8994	1.8994	1.8994	1.8994	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 194,302	$ 183,527	$ 185,978	$ 170,745	$ 196,969	$ 254,808	$ 270,623	$ 257,568	$ 230,775	$ 187,460	$ 187,801	$ 200,345	**$ 2,520,902**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,107,848	1,990,953	2,017,544	1,852,291	2,136,780	2,764,230	2,935,800	2,794,177	2,503,514	2,033,617	2,037,319	2,173,406	**27,347,481**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	20,645,703	19,500,749	19,761,201	18,142,604	20,929,082	27,272,563	28,965,309	27,568,027	24,700,278	20,064,152	20,100,685	21,443,352	**269,093,703**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	241,491	213,383	231,145	205,367	244,806	306,475	336,348	320,122	277,569	232,987	225,881	249,002	**3,084,577**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	262,423	231,498	247,049	226,906	236,292	258,275	285,242	274,111	242,830	238,991	237,567	261,799	**3,002,983**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	142,440	125,654	134,095	123,162	128,256	140,188	154,826	148,784	131,805	129,721	128,949	142,101	**1,629,981**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	32,968	29,131	31,556	28,036	33,421	41,840	45,918	43,703	37,893	31,807	30,837	33,993	**421,103**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	429,887	379,227	404,701	371,704	387,079	423,090	467,267	449,032	397,790	391,501	389,169	428,864	**4,919,312**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	64,804	57,167	61,007	56,033	58,351	63,779	70,439	67,690	59,965	59,017	58,666	64,650	**741,568**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	6,672,780	6,302,726	6,386,906	5,863,768	6,764,370	8,750,678	9,293,812	8,845,480	7,925,334	6,437,786	6,449,508	6,880,316	**86,573,464**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	6,093,602	5,375,498	5,736,601	5,268,864	5,486,807	5,997,263	6,623,465	6,364,985	5,638,631	5,549,491	5,516,433	6,079,100	**69,730,741**
26	METC Agency Agreement		2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	**24,000**
27	Total Transmission Expenses	**Lines 15-20 + 24-26**	**$ 36,362,591**	**$ 33,925,987**	**$ 34,702,520**	**$ 31,855,707**	**$ 36,125,361**	**$ 45,746,480**	**$ 48,867,425**	**$ 46,575,255**	**$ 41,652,736**	**$ 34,876,204**	**$ 34,886,144**	**$ 37,431,422**	**$ 463,007,832**
28	Total Energy Market Administration Expenses	**Lines 21-23**	**527,659**	**465,524**	**497,264**	**455,773**	**478,850**	**528,709**	**583,624**	**560,425**	**495,649**	**482,326**	**478,672**	**527,507**	**6,081,982**
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 36,890,249**	**$ 34,391,512**	**$ 35,199,784**	**$ 32,311,480**	**$ 36,604,212**	**$ 46,275,189**	**$ 49,451,049**	**$ 47,135,680**	**$ 42,148,385**	**$ 35,358,530**	**$ 35,364,816**	**$ 37,958,929**	**$ 469,089,814**

Consumers Energy Company

2020 Transmission and Energy Market Administration Expenses

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper DSA-1	5,526	5,267	5,332	4,868	5,633	7,298	7,702	7,351	6,599	5,357	5,365	5,719	**72,019**
2	Hours per Month	Day in Month * 24	744	672	744	720	744	720	744	744	720	744	720	744	**8,760**
3	Delivered MWhs	Workpaper DSA-3	3,205,163	2,827,290	3,017,335	2,770,693	2,885,307	3,154,436	3,483,904	3,347,974	2,965,475	2,918,396	2,912,768	3,197,350	**36,686,092**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	$ 35.0790	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	379.3430	379.3430	379.3430	379.3430	379.3430	379.3430	379.3430	379.3430	379.3430	379.3430	379.3430	379.3430	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	3,859.0401	3,859.0401	3,859.0401	3,859.0401	3,859.0401	3,841.1957	3,841.1957	3,841.1957	3,841.1957	3,841.1957	3,841.1957	3,841.1957	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0574	0.0574	0.0574	0.0574	0.0574	0.0574	0.0574	0.0574	0.0574	0.0574	0.0574	0.0574	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0801	0.0801	0.0801	0.0801	0.0801	0.0801	0.0801	0.0801	0.0801	0.0801	0.0801	0.0801	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0660	0.0660	0.0660	0.0660	0.0660	0.0660	0.0660	0.0660	0.0660	0.0660	0.0660	0.0660	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	1,178.1223	1,178.1223	1,178.1223	1,178.1223	1,178.1223	1,178.1223	1,178.1223	1,178.1223	1,178.1223	1,178.1223	1,178.1223	1,178.1223	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.9316	1.9316	1.9316	1.9316	1.9316	1.9316	1.9316	1.9316	1.9316	1.9316	1.9316	1.9316	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 193,851	$ 184,775	$ 187,058	$ 170,766	$ 197,603	$ 256,021	$ 270,188	$ 257,859	$ 231,502	$ 187,910	$ 188,199	$ 200,611	**$ 2,526,345**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,096,298	1,998,150	2,022,839	1,846,657	2,136,874	2,768,603	2,921,803	2,788,482	2,503,459	2,032,056	2,035,172	2,169,405	**27,319,799**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	21,325,550	20,327,094	20,578,254	18,785,960	21,738,328	28,034,646	29,585,935	28,235,932	25,349,810	20,576,427	20,607,981	21,967,214	**277,113,130**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	235,997	203,178	227,727	201,186	240,565	301,629	328,930	313,921	272,742	228,764	221,724	244,227	**3,020,591**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	256,734	226,466	241,689	221,932	231,113	252,670	279,061	268,173	237,535	233,764	233,313	256,108	**2,938,556**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	142,309	125,532	133,970	123,019	128,108	140,057	154,685	148,650	131,667	129,577	129,327	141,962	**1,628,862**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	32,892	28,318	31,739	28,040	33,528	42,039	45,844	43,752	38,013	31,884	30,902	34,039	**420,988**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	423,082	373,202	398,288	365,731	380,861	416,386	459,875	441,933	391,443	385,228	384,485	422,050	**4,842,564**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	64,744	57,111	60,950	55,968	58,283	63,720	70,375	67,629	59,903	58,952	58,838	64,586	**741,059**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	6,510,455	6,205,637	6,282,314	5,735,146	6,636,472	8,598,427	9,074,219	8,660,163	7,774,969	6,310,938	6,320,616	6,737,502	**84,846,859**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	6,191,084	5,461,185	5,828,275	5,351,862	5,573,250	6,093,100	6,729,498	6,466,937	5,728,103	5,637,166	5,626,295	6,175,992	**70,862,749**
26	METC Agency Agreement		2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	**24,000**
27	Total Transmission Expenses	**Lines 15-20 + 24-26**	**$ 36,954,278**	**$ 34,734,018**	**$ 35,504,126**	**$ 32,438,529**	**$ 36,884,312**	**$ 46,447,154**	**$ 49,346,319**	**$ 47,142,117**	**$ 42,231,788**	**$ 35,338,602**	**$ 35,364,626**	**$ 37,895,022**	**$ 470,280,891**
28	Total Energy Market Administration Expenses	**Lines 21-23**	**520,717**	**458,631**	**490,977**	**449,739**	**472,672**	**522,144**	**576,094**	**553,314**	**489,358**	**476,063**	**474,226**	**520,675**	**6,004,611**
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 37,474,995**	**$ 35,192,649**	**$ 35,995,103**	**$ 32,888,268**	**$ 37,356,984**	**$ 46,969,298**	**$ 49,922,413**	**$ 47,695,431**	**$ 42,721,146**	**$ 35,814,666**	**$ 35,838,852**	**$ 38,415,697**	**$ 476,285,502**

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17918
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2016	)	

DIRECT TESTIMONY

OF

NATALIE N. BUSACK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2015

Q. Please state your name and business address.

A. Natalie N. Busack, 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 Requirements Section of the Rates Department.

Q. Please describe your educational background and business experience.

A. I graduated in December 2003 from Michigan State University with a Bachelor of Arts in General Management and a Bachelor of Science in Psychology. In addition, I have attended courses on utility ratemaking.

Q. How long have you been employed by Consumers Energy?

A. I joined Consumers Energy in April 2002.

Q. Since joining Consumers Energy, what positions have you held?

A. I joined Consumers Energy as a part time Customer Service Representative while I completed my degrees at Michigan State University. In December of 2003, I was promoted to a Financial Analyst for the Customer Services Department. In January 2006, I moved to Rate Administration where I was responsible for developing, implementing, and administering Company tariffs in addition to implementing rate orders and performing research on regulatory issues. In April 2012, I moved to my current position in the Revenue Requirements Section of the Rates Department where I am now responsible for forecasting the monthly Power Supply Cost Recovery ("PSCR") Factor and preparation of economic studies relating to the operations of the Company's business units along with preparation of the revenue requirement for rate cases.

Q. Have you previously testified or sponsored testimony in any regulatory proceedings?

A. Yes, I sponsored testimony in the following Michigan Public Service Commission ("MPSC" or the "Commission") cases:

Case No. U-15943	Reconciliation of the 2008 and 2009 Electric Choice Incentive Mechanism Case;
Case No. U-16759	Reconcile Residual Balance Case;
Case No. U-17095	2013 PSCR Plan Case;
Case No. U-16890-R	2012 PSCR Reconciliation Case;
Case No. U-17133	2013-2014 GCR Plan Case;
Case No. U-17317	2014 PSCR Plan Case;
Case No. U-17678	2015 PSCR Plan Case; and
Case No. U-17735	2014 Electric Rate Case.

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

A. The purpose of my testimony is to present the calculation of the 2016 PSCR Factor.

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

A. Yes, I am sponsoring the following exhibit:

Exhibit A-2 (NNB-1) Calculation of 2016 PSCR Factor.

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

A. Yes.

Q. Please summarize Exhibit A-2 (NNB-1).

A. Exhibit A-2 (NNB-1) shows the calculation of the 2016 PSCR Factor including: (i) total power supply costs provided by Company witness Sara T. Walz; (ii) transmission expenses provided by Company witness Daniel S. Alfred; (iii) Schedule 2 Reactive

Revenue provided by Mr. Alfred; and (iv) urea costs and aqueous ammonia costs, lime expense, and activated carbon expense provided by Company witness Robert C. Schram.

Q. Please describe in more detail the calculations in Exhibit A-2 (NNB-1).

A. The 2016 PSCR Factor is calculated by first summing the total system power supply costs on line 1, the net transmission expenses on line 4, the total of urea costs, aqueous ammonia costs, lime expense, and activated carbon expense ("Total Environmental Costs") shown on line 9. That sum, shown on line 10, is divided by total system energy requirements (measured in units of kilowatt hours ("kWh")) on line 11, provided to me by Company witness Jason M. Shore, to determine the average cost per kWh of requirements on line 12. From this quotient is subtracted the Base Recovery Factor (shown on line 13) collected through the standard tariffs as approved by the Commission. This remaining expense per kWh amount $(0.00013) set forth on line 14 is multiplied by the Line and Transformation Loss Factor on line 15 to determine the 2016 per kWh PSCR Factor of $(0.00014) at sales, shown on line 16.

Q. Please explain page 2 of Exhibit A-2 (NNB-1).

A. In December 2014, the Company filed a request for rate relief with the Commission, Case No. U-17735. Included in that filing was a request to modify the Line and Transformation Loss Factor specified in the Company's Tariff Rule C8; PSCR Clause. Case No. U-17735 will be decided by the Commission in late 2015. Page 2 of Exhibit A-2 (NNB-1) includes the Company's proposed Line and Transformation Loss Factor on line 15 of the calculation for the maximum allowable PSCR Factor. Once the final order in Case No. U-17735 has been issued; the Company proposes to utilize the approved Line Loss Factor in the calculation of the 2016 PSCR Factor.

Q. Is there a difference between the PSCR Factor calculated in this proceeding and the actual PSCR Factor charged throughout the year?

A. Yes. The PSCR Factor calculated in this proceeding sets the maximum factor that the Company is authorized to charge throughout the year. The actual PSCR Factor can be at or below this maximum factor. The actual PSCR Factor is determined each month based on the Company's latest forecast of sales and PSCR costs and available actual sales and PSCR cost information. Each month, using this information, the Company attempts to implement future monthly PSCR factors that will result in an annual zero over- or under-recovery.

Q. What is the purpose of this policy?

A. The Company's policy is intended to match costs with the customers who cause the Company to incur those costs. And while it is unlikely that the Company will succeed in exactly matching costs with customers who incurred the costs, the monthly calculations described above attempt to minimize any over- and under-recovery for the PSCR Plan year. Any amounts over collected are subject to refund with interest at the Company's authorized return on equity, which is currently 10.30%.

Q. Does this conclude your testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
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Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2016	)	

EXHIBIT

OF

NATALIE N. BUSACK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2015

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-17918
Exhibit: A-2 (NNB-1)
Witness: NNBusack
Date: September 2015
Page: 1 of 2

Consumers Energy Company

Calculation of 2016 PSCR Factor

Line			
1	System Power Supply Costs[1]		$ 1,611,480,199
	System Transmission Expenses		
2	Total Transmission Expenses[2]	$ 406,718,416	
3	Less: Schedule 2 Reactive Revenue[3]	(19,706,000)	
4	Net Transmission Expenses		$ 387,012,416
	Environmental Costs		
5	Urea Costs[4]	2,741,000	
6	Aqueous Amonia[5]	1,470,000	
7	Lime Expense[6]	11,058,000	
8	Activated Carbon[7]	2,689,000	
9	Total Environmental Costs		$ 17,958,000
10	Total System Power Supply Costs		$ 2,016,450,615
11	Total System Requirements in kWh[8]		36,284,998,002
	Jurisdictional Factor Calculation		
12	Average Cost at Requirements (Line 10 / Line 11)		$ 0.05557
13	Less: Base Recovery Factor[9]		$ 0.05570
14	Remaining Cost per kWh (Line 12 - Line 13)		$ (0.00013)
15	Line & Transformation Loss Factor[10]		1.086
16	2016 PSCR Factor at Sales (Line 14 x Line 15)		$ (0.00014)

Sources:
[1]Exhibit A-22 (STW-1), Page 1, Line 26
[2]Exhibit A-1 (DSA-1), line 29
[3]DSAlfred Testimony, Page 10, Line 6
[4]Exhibit A-13 (RCS-3), Line 3
[5]Exhibit A-14 (RCS-4), Line 4
[6]Exhibit A-15 (RCS-5), Line 4
[7]Exhibit A-16 (RCS-6), Line 4
[8]Exhibit A-19 (JMS-3), Page 2, Line 13
[9]Per Order in Case No. U-17087
[10]Per Rule C-8 of the Company Tariffs

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Calculation of 2016 PSCR Factor

Line				
1	System Power Supply Costs[1]		$	1,611,480,199
	System Transmission Expenses			
2	Total Transmission Expenses[2]	$ 406,718,416		
3	Less: Schedule 2 Reactive Revenue[3]	(19,706,000)		
4	Net Transmission Expenses		$	387,012,416
	Environmental Costs			
5	Urea Costs[4]	2,741,000		
6	Aqueous Amonia[5]	1,470,000		
7	Lime Expense[6]	11,058,000		
8	Activated Carbon[7]	2,689,000		
9	Total Environmental Costs		$	17,958,000
10	Total System Power Supply Costs		$	2,016,450,615
11	Total System Requirements in kWh[8]			36,284,998,002
	Jurisdictional Factor Calculation			
12	Average Cost at Requirements (Line 10 / Line 11)		$	0.05557
13	Less: Base Recovery Factor[9]		$	0.05570
14	Remaining Cost per kWh (Line 12 - Line 13)		$	(0.00013)
15	Line & Transformation Loss Factor[10]			1.079
16	2016 PSCR Factor at Sales (Line 14 x Line 15)		$	(0.00014)

Sources:
[1]Exhibit A-22 (STW-1), Page 1, Line 26
[2]Exhibit A-1 (DSA-1), line 29
[3]DSAlfred Testimony, Page 10, Line 6
[4]Exhibit A-13 (RCS-3), Line 3
[5]Exhibit A-14 (RCS-4), Line 4
[6]Exhibit A-15 (RCS-5), Line 4
[7]Exhibit A-16 (RCS-6), Line 4
[8]Exhibit A-19 (JMS-3), Page 2, Line 13
[9]Per Order in Case No. U-17735
[10]Per Rule C-8 of the Company Tariffs

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17918
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2016	)	

DIRECT TESTIMONY

OF

JIM K. CHILSON II, PE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2015

Q. Would you please state your name and business address?

A. Yes, my name is Jim K. Chilson II, and my business address is 1945 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 Fuels Transportation & Planning Director in the Energy Supply Operations Department.

QUALIFICATIONS

Q. Would you please describe your educational background and business experience?

A. I graduated in 1991 with a Bachelor of Science in Engineering from Oakland University and in 1993 with a Master of Science in Electrical Engineering from Michigan State University. I have been employed by Consumers Energy since 1993. I have held a variety of engineering, operating, and supervisory positions. In 2011, I joined the Fossil Fuel Supply Division as the Fuels Transportation & Planning Director in the Energy Supply Operations Department.

Q. What are your duties as the Fuels Transportation & Planning Director?

A. My duties include:

- the preparation of short- and long-term projections specifying purchase volumes and pricing for coal, oil, and natural gas as fuel for generation;
- the optimization of the distribution of coal to the generating plants to minimize the delivered cost of coal;
- managing plant fuel inventories and the daily logistics for the delivery of fuel to the generating plants;
- supervising the management and maintenance of the leased railcars for coal delivery;

- managing the projection of volumes and prices of No. 6 fuel oil for Karn 3 & 4; natural gas for Zeeland, Jackson and Karn 3 & 4 plants; and No. 2 fuel oil and natural gas for the combustion turbines; and

- the preparation of testimony and filings for presentation before the Michigan Public Service Commission ("MPSC" or the "Commission").

Q. Have you testified in other MPSC cases?

A. Yes. I provided direct and rebuttal testimony in:

- Case No. U-17095 (direct and rebuttal), the Company's 2013 Power Supply Cost Recovery ("PSCR") Plan, regarding costs of coal, oil, and natural gas used for electric generation for 2013;

- Case No. U-17317 (direct, revised direct, and rebuttal), the Company's 2014 PSCR Plan, regarding costs of coal, oil, and natural gas used for electric generation for 2014; and

- Case No. U-17678 (direct and rebuttal), the Company's 2015 PSCR Plan, regarding costs of coal, oil, and natural gas used for electric generation for 2015.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I am sponsoring testimony with respect to the Company's projected costs of coal, oil, and natural gas used for electric generation for calendar years 2016 through 2020.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits that were prepared by me or under my supervision:

Exhibit A-3 (JKC-1) – Coal Contract & Annual Purchase Data

Exhibit A-4 (JKC-2) – Estimated As-Burned Coal Costs – 2016

Exhibit A-5 (JKC-3) – Estimated As-Burned Oil & Gas Costs – 2016

Exhibit A-6 (JKC-4) – Estimated As-Burned Coal Costs (2017-2020)

Exhibit A-7 (JKC-5) – Estimated As-Burned Oil & Gas Costs (2017-2020)

COAL PURCHASE STRATEGY

Q. What actions has the Company taken to minimize its cost of coal and ensure adequate supply to meet customer demand?

A. The Fuel Supply Department endeavors to secure coal supplies in quantity and quality sufficient to meet the needs of the Company's coal-fired generating units in an economical manner. Coals from different regions are evaluated and purchased based on total delivered cost. Long-term contracts are made with coal suppliers and transportation providers to ensure a secure supply of fuel at the most economical value offered. Long-term contracts are competitively bid and, to the extent possible, structured to allow volume flexibility in response to changes in market conditions. Short-term and annual coal contracts are also competitively bid. Railcars are leased to lower freight costs and audits are periodically performed on coal supply and freight invoices to ensure correctness. These are some of the actions taken by the Company to minimize the cost of coal.

Q. Can you elaborate on the Company's coal purchasing strategy?

A. Yes. The Company layers its coal purchases in such a way that each year it has a portfolio of coal purchase contracts. The portfolio for a given year will consist of contracts of various qualities, with various volumes, term lengths, and prices. Although these purchases are competitively bid, the pricing of these contracts is reflective of the market at the time the purchase was made. Some contracts within the portfolio may be above or below the market at the time of delivery depending on how the market has changed relative to the time the purchase was made. Maintaining such a portfolio minimizes price risk to customers and protects them from price volatility in the market.

In addition to providing stability in pricing, procuring coal supplies in such a portfolio also mitigates supply risk to our customers in the event coal supplies become constrained. Quantities of coal are secured over time that typically positions the Company to have approximately 70% to 90% of its anticipated total volume secured by the fall of each year for the following calendar year, approximately 40% to 50% secured for the next calendar year, and approximately 20% to 25% secured for the third calendar year.

Q. Have there been any changes to your coal purchase strategy for 2016 compared to the coal purchase strategy from 2015?

A. No. The Company is continuing to layer coal purchases in order to maintain a diverse portfolio of contracts.

<u>LONG-TERM FUEL OUTLOOK</u>

Q. At this time, does the Company expect to incur any fuel shortages in 2016-2020?

A. No.

<u>ENVIRONMENTAL CONSIDERATIONS</u>

Q. Would you briefly explain the air pollution considerations that have an impact on the Company's coal supply purchasing program?

A. In September 2014, the Company reached an agreement with the Environmental Proction Agency ("EPA") and the U.S. Department of Justice regarding emission limits for nitrogen oxides ("NO_x"), sulfer dioxides ("SO_2"), and particulate matter ("PM") at each of our coal-fired units. These restrictions dictate the quality of coal purchased to meet system requirements. In order to comply with this agreement the Company plans to purchase only western coal and low-sulfur eastern coal.

COAL PURCHASE CONTRACTS

Q. Please describe Exhibit A-3 (JKC-1).

A. Exhibit A-3 (JKC-1) shows the annual and multiyear coal contracts for delivery in 2016. The contracts provide western coal supply to our coal plants (the JHCampbell complex, the BCCobb plant, the DEKarn 1-2 plant, the JCWeadock plant, and the JRWhiting plant). Column “a” lists the suppliers, which for the purpose of this exhibit are represented by contract number. Column “b” identifies the coal type, that is, whether it is eastern coal (originating typically in the Central Appalachian regions of Kentucky and West Virginia) or western coal (originating typically in the Powder River Basin region in Wyoming and Montana). Columns “c” and “d” identify the starting and ending dates for the contract, respectively. Column “e” identifies the contract commitment volumes or the volume the Company presently expects to nominate for 2016.

Q. Could you briefly explain “nominate”?

A. Some of our coal contracts offer the Company the ability to specify, or “nominate,” a purchase volume on a six-month or annual basis, within a contract specified minimum and maximum tonnage. This ability to “nominate” tonnage provides the Company with some flexibility to respond to demand and market conditions by taking more or less tonnage from a given contract depending upon the anticipated coal requirements and depending on the contract’s price compared to the projected price of coal that may be available for purchase during the nomination period.

Q. Do you anticipate entering into any additional multiyear or annual coal supply contracts from which tonnage would be received in 2016?

A. Yes. We anticipate soliciting for additional coal before the end of 2015 for delivery in 2016.

COAL PRICE DETERMINATION

Q. Please describe how coal prices were projected for 2016.

A. The Company based the projected coal prices on the present coal contracts with fixed pricing and the present coal contracts tied to an index using the projected index price. The remaining open position was estimated based on the market projection for that period.

COAL TRANSPORTATION CONTRACTS

Q. What arrangements does the Company have for the transportation of coal that is purchased?

A. Coal is transported by rail from the mines either directly to generating plants or to lake terminal facilities, where the coal is transferred to lake vessels for delivery to the generating plants. During 2016, the Company expects to have in effect three contracts that will provide for the shipment of coal on railroads and one or more contracts that will provide vessel services and terminal services for shipments. The Company will not, however, have a bilateral contract with CSX Transportation, Inc. ("CSXT") in place for rail transportation east of Chicago to the Campbell plant. Instead, the Company plans to use common carrier (i.e. tariff) rates for rail transportation for western coal from Chicago to the Campbell plant and for transportation of eastern coal to both the Campbell and Karn plants.

Q. Please discuss why the Company does not have a bilateral contract with CSXT for the Campbell plant.

A. In mid-2013, the Company began efforts to replace its bilateral contract with CSXT for rail transportation that was set to expire on December 31, 2014. In evaluating its transportation contract, it was determined that CSXT's coal transportation costs to the Campbell plant were disproportionately higher than the Company's other coal transportation contracts, and the Company believes that the costs contained in its contract were higher than some other utilities in the mid-west. Complicating maters further is the fact that the Campbell plant is "captive" to CSXT. This means that there are no other coal transportation alternatives to the Campbell plant, and that CSXT is the sole provider of rail transportation to the site. While it is not uncommon for captive rail customers to pay more for transportation services than those that have direct access to competitive alternatives, the Company determined that CSXT's coal transportation rates to the Campbell plant were disproportionately high compared to other plants.

After several proposals and counterproposals between the Company and CSXT, the rates offered by CSXT for transportation services between Chicago and the Campbell plant were no lower than the rates in effect at the end of 2014, and still at levels the Company believed were above what CSXT could justify. Late in 2014, the Company realized an impasse existed and that a bilateral contract with reasonable rates, terms, and conditions for rail transportation to the Campbell plant could not be reached. With no alternatives available, and with a need for new rates, terms, and conditions to transport coal to the Campbell plant, on November 24, 2014 Consumers Energy requested CSXT to provide rate and service terms for the transport of coal. On December 26, 2014, CSXT provided Consumers Energy with Tariff CSXT 13952.

Q. Did the Company utilize any additional efforts to lower the rail transportation rates to the Campbell plant?

A. Yes. On January 13, 2015, Consumers Energy filed a complaint with the Surface Transportation Board ("STB") against CSXT, in STB Docket No. NOR 42142, which requested the STB to: 1) find the challenged rates to be unreasonable and unlawful, 2) prescribe lawful rates, 3) award damages to Consumers Energy, and 4) grant Consumers Energy any further relief as the STB may seem proper. The potential for savings in transportation expense attributable to these efforts is estimated at over $15 million annually. The Company has included in the Plan its portion of the estimated litigation expense that it anticipates will be spent in 2016, which is $2,188,247. This amount is less the Campbell 3 Joint Owners' contribution to the litigation.

Q. Who will benefit if this litigation effort at the STB is successful?

A. The Company's PSCR customers. Since coal transportation expense is a direct pass through to PSCR customers, any reduction in coal transportation expense that results from a positive outcome in the CSXT litigation effort will entirely and directly benefit the Company's PSCR customers. Additionally, any damages that are awarded to the Company from CSXT as a result of a positive outcome in the litigation effort will be passed through in their entirety to the Company's PSCR customers. The Company receives no benefit to undertaking this effort, other than to ensure it is taking prudent actions to minimize the cost of fuel to its customers.

COAL TRANSPORTATION RATE DETERMINATION

Q. What process was used to determine freight rates?

A. Freight rates were determined either by the common carrier rate or contract pricing. Additionally, fuel surcharges were included as defined in each of the transportation contracts or in the railroad published tariffs.

COAL TONNAGE DETERMINATION

Q. How were the coal tonnages determined for 2016?

A. As described in witness Sara T. Walz's testimony, a computer model is used to determine production estimates (*i.e.*, MWh production and hence MMBtu coal burn requirements to support that production) for each generating unit. Besides fuel price, the model uses a variety of inputs, but those most closely related to fuel volume determination include fuel mix, coal quality, and generating unit efficiency. Using the MMBtu coal burn requirements determined from the model, along with inventory considerations, the monthly purchase volumes of coal are determined for each plant. A comparison of these purchase requirements with the amount of coal available under contract determines the need for spot coal purchases.

Q. How many tons has the Company purchased under contract for delivery in 2016 and do you expect to purchase more?

A. The Company presently has approximately 3.65 million tons of coal committed for 2016 from the multi-year or annual purchases shown in Exhibit A-3 (JKC-1). At this time, the Company anticipates it will purchase additional coal in 2015 for 2016 delivery. However, the volume of coal for this purchase is yet to be determined.

SPOT COAL PURCHASES

Q. How much coal do you expect to purchase on a spot basis during 2016?

A. Approximately 600 thousand to 1.9 million tons of coal is expected to be purchased on a spot basis.

Q. What was considered when estimating spot prices for 2016?

A. Spot market prices for coal are generally consistent with current market conditions and fluctuate with supply and demand, economic conditions, environmental compliance requirements, coal mining industry capacity, alternative fuel prices, strikes, and other factors.

TYPES OF COAL

Q. What types of coal does Consumers Energy expect to utilize in 2016?

A. The Company burns a variety of coals in varying combinations at its generating plants in an effort to minimize its production costs and meet regulatory requirements. A blend of low-sulfur eastern and low-sulfur western coal is included in the fuel mix.

Q. How much western coal is expected to be burned in 2016?

A. On a system-wide basis, the Company expects to burn approximately 6.8 million tons of western coal or approximately 99.6% by weight of the Company's total coal burn requirements in 2016.

Q. How much eastern coal is expected to be purchased in 2016?

A. The Company does not have any eastern coal contracts in effect for 2016. Eastern coal is only projected to be used during periods of high electrical demand when eastern coal is necessary to achieve full capability from the coal generation fleet. The Company plans to purchase eastern coal from the spot market as needed to meet these periods of high demand.

AS-BURNED COAL COSTS

Q. Please explain Exhibit A-4 (JKC-2).

A. Exhibit A-4 (JKC-2) summarizes the projected as-burned costs and tonnage at each of the Company's coal-fired generating plants for the year 2016. The total cost includes primary fuel, auxiliary fuel, freeze protection and dust inhibiting treatments, and the projected state air emission fees.

Q. How were the as-burned coal cost developed?

A. The as-burned cost of coal is determined based on the cost of coal in inventory multiplied by the amount of coal projected to be burned during a particular period. Specifically, for each month and each plant inventory location, the delivered cost of coal is added to the cost in inventory at the end of the previous month and divided by the sum of the delivered coal volume for the present month and the volume in inventory at the end of the previous month. This average cost of fuel in inventory is then multiplied by the given burn volume for this inventory location to arrive at the as-burned cost. The month ending inventory is then calculated by subtracting the burn cost and volume, respectively, from the starting inventory values. It is important to note that although the coal costs for this case are developed based on as-burned, the generation units are dispatched based on the replacement cost of fuel. The reason is that once coal is purchased, it becomes a fixed expense for PSCR and economic dispatch purposes. In economic dispatch, only the variable expense relating to coal is included, and is represented by spot coal that will be purchased at the next opportunity. Coal units are dispatched at this spot coal price so their production at this price can be compared to the market for power. This methodology enables the market to help determine whether or not additional purchases are made throughout the year.

Q. What is included in the total monthly delivered cost of coal?

A. The total monthly delivered cost of coal to each generating plant is determined based on the cost of contract and spot coal purchases allocated to the plant; the application of any necessary or required freeze protection treatments to ensure all lading can be removed from the railcars during winter months and to ensure compliance with railroad operating rules and tariffs; the application of any necessary or required dust inhibitors to ensure compliance with railroad operating rules and tariffs; applicable harbor maintenance fees; as well as the cost of transporting the coal to the plant.

<u>2017-2020 PROJECTED COAL COSTS</u>

Q. Please explain Exhibit A-6 (JKC-4).

A. Exhibit A-6 (JKC-4) summarizes the projected as-burned costs and tonnage at each of the Company's coal-fired generating plants for the years 2017-2020. The total cost includes primary fuel, auxiliary fuel, freeze protection and dust inhibiting treatments, and the projected state air emission fees.

Q. How were the coal prices determined to obtain the coal cost projections for the years 2017-2020?

A. In a manner similar to 2016, existing supply and transportation contracts were adjusted based on the expected performance of the indices to which the contracts are tied. Those contracts that have fixed prices had the fixed prices input with no escalation. Forecasted coal prices and transportation costs were utilized for open position (unsecured) tonnage.

Q. Are any new contracts anticipated for the 2017-2020 time period?

A. Yes. It is anticipated that the Company will be entering into new supply and transportation contracts to replace those contracts which will expire during 2017-2020. The pricing for any new coal supply is modeled as previously described. The pricing for any future transportation contracts is modeled as similar to existing contracts.

<u>OIL- AND NATURAL GAS-COST PROJECTIONS</u>

Q. To which generating plants do your oil and natural gas projections apply?

A. I am supplying the oil- and gas-fuel cost projections for the Company's oil- and gas-fired generating units, those being the Zeeland plant, the Karn 3 & 4 plant, the BCCobb plant, the Jackson plant, and all of the combustion turbine units.

Q. What types of fuel do these units burn?

A. The Zeeland and Jackson plants burn natural gas. The Company's BCCobb plant burns natural gas for start-up and over-firing. Karn 3 & 4 can burn natural gas and No. 6 fuel oil. The combustion turbines burn either natural gas or No. 2 fuel oil.

Q. Holding the discussion for the Zeeland and Jackson plants until later, what sources were assumed for each of these fuels?

A. The No. 6 oil burned at Karn 3 & 4 will be purchased on a spot basis. A portion of the gas for Karn 3 & 4 will be purchased on a spot basis, and the remainder under third party contract, but with spot pricing terms. Gas for the Cobb plant will be purchased on a spot basis. Any No. 2 fuel oil for the combustion turbines will also be purchased on a spot basis. Any gas used for any of the remaining combustion turbines will come from the Consumers Energy natural gas utility or DTE Gas Company ("DTE Gas," formally

MichCon) pursuant to the MPSC approved tariff rates (Consumers Energy Rate GS-3 and DTE Gas Rate GS-2).

Q. Please explain why much of the oil and natural gas that is purchased for consumption in the generating units is purchased on a spot basis, rather than under contract like it is for coal.

A. Much of the reason for doing so lies with the difficulty in accurately predicting the demand for these generally higher-cost units. Unlike the coal units, which are typically lower in cost, earlier units to dispatch, and whose production is generally more predictable; the oil and gas peaking units typically have more expensive variable costs, and are among the last units to be dispatched. The utilization of these units depends on a number of difficult-to-predict factors, including but not limited to unit availability, competing market power price and availability, weather and its effects on system electric load, electric transmission constraints, and the more volatile nature of the oil and gas markets. In addition to the unpredictable nature of their use, there is also an issue with the limited amount of storage available for either oil or gas, and the situation that may arise should volumes be contracted for, required to be taken, and not consumed. For these reasons, the Company believes it prudent not to purchase significant volumes of oil or gas ahead of time under long-term contract for these units.

Q. In the absence of long-term contracts, what does Consumers Energy do to mitigate some of the price volatility of its oil and natural gas purchases for electric generation?

A. The ability of the Karn Units 3 & 4 to burn either oil or gas or a blend of the two offers us the ability to operationally hedge the price of either fuel against the other. Unlike gas, which because of storage limitations is generally purchased on a spot basis near the time it is consumed; spot purchases of oil are made over time as needed to maintain inventory. Oil can be purchased in varying qualities and prices and stored in tanks at the plant to provide gas and oil blending flexibility. Additionally, the units may also burn 100% gas, though not at full capacity.

Q. What steps has the Company taken to minimize its natural gas related costs, including storage, for its generating units?

A. The Company utilizes the provisions contained in its gas transportation agreements to minimize its natural gas related costs. This includes monitoring gas usage and market prices during the month and competitively bidding purchases to minimize cost and to ensure that month end gas balances are within the specified contract tolerances. It also includes utilizing its available storage (in the form of the contract Authorized Tolerance Level) with the Consumers Energy gas utility and DTE Gas to purchase lower cost gas during periods of lower gas demand and store such gas ahead of the anticipated usage.

Q. To what extent is the gas storage available on the Consumers Energy gas utility system utilized for the electric utility?

A. As described in the response to the previous question, the available storage provided for in the gas transportation agreement with the gas utility is utilized to store gas purchased when prices are lower. The Company does not believe it would be prudent to purchase additional storage, over and above that amount provided for in the gas transportation agreement for several reasons. These reasons include but are not limited to: (1) the difficulty in accurately predicting the production on these units and the concern that additional storage be purchased and not used; (2) recognition of the potential impacts to Consumers Energy's gas customers if storage were used by the electric utility to benefit its electric customers, from both a supply and cost standpoint; and (3) any gas storage purchased by the electric utility from the gas utility would be provided pursuant to tariffs and would only be available to the Karn 3 & 4 plant for a portion of its needs on a seasonal basis.

ZEELAND AND JACKSON PLANTS' NATURAL GAS

Q. What is the source of fuel for the Zeeland plant?

A. The Zeeland plant is a natural gas-fired facility that is connected to the ANR pipeline system through a lateral pipeline owned and operated by SEMCO Energy Gas Company ("SEMCO").

Q. What has the Company done to assure a reliable and economic supply of fuel for the Zeeland facility?

A. The Company plans to use a third party to act as a gas management service agent ("Agent") on behalf of the Company with regard to the gas supply for Zeeland. The Agent's obligations under the contract include purchasing the gas, transporting the gas from its purchase origin to the point of delivery, *i.e.*, the SEMCO interconnection, and storing gas when necessary. Entering into an agreement such as this allows the Company to take advantage of the Agent's diversity of gas purchasing/transportation contracts, gas purchasing experience, as well as the portfolio of arrangements the Agent has with ANR and other pipelines in North America. This experience and expertise enables the Agent to provide transportation and balancing services to the Company more economically than if the Company were required to obtain firm transportation and storage directly from ANR and other pipeline companies. In addition to the transportation provided for under this service contract, the Company also has a contract with SEMCO that was assigned to the Company at the time of the Zeeland plant purchase, which provides gas transportation from SEMCO's point of interconnection with the ANR pipeline system to the Zeeland plant.

Q. How does the gas management services contract work?

A. In addition to procuring the gas commodity and transportation service, the Agent is responsible for providing gas pricing information to the Company which is relied upon by the Company to bid energy from the Zeeland plant into the Midcontinent Independent System Operator, Inc. ("MISO") energy market. The Agent is then responsible for purchasing gas as directed by the Company in the Day-ahead gas market. The Agent also purchases gas as directed by the Company in the Intraday and Real-time gas markets as MISO accepts offers from Zeeland in MISO's energy market. The Agent also provides services to balance gas nomination against dispatch requests from MISO. The pricing of the gas management services contract is based on published indices. If necessary, balancing service above a specified tolerance amount is available at an additional cost.

Q. Does the Company pay the Agent a separate amount to transport the gas from the point of origin to the ANR-SEMCO interconnection point?

A. No. The amount paid to the Agent is an all-inclusive commodity price which includes the price the Agent pays for the physical gas and all costs the Agent may incur to deliver the gas to the ANR-SEMCO interconnection.

Q. Does the Company pay SEMCO for the use of the lateral pipeline SEMCO owns that connects the Zeeland plant to the ANR-SEMCO interconnection point?

A. Yes. The Company pays a fixed annual demand charge as provided for in the December 17, 1999 Transportation Services Contract assumed by the Company from the previous owner of the Zeeland plant at the time the Zeeland plant was acquired by the Company, for transportation of up to 186,000 Mcf of gas per day.

Q. What is the source of fuel for the Jackson plant?

A. The Jackson plant is a natural gas-fired facility that is connected to the Vector pipeline system through a lateral pipeline owned by Consumers Energy.

Q. When will the Company begin to provide fuel to the Jackson plant?

A. The Company expects to begin managing fuel for the Jackson plant in January 2016.

Q. How does the Company expect to manage gas purchasing and transportation for the Jackson plant?

A. Similar to the Zeeland gas management services agreement, the Company will enter into a competitively bid contract with a third party agent to manage the gas supply for the Jackson plant.

Q. Has an agreement been executed?

A. No. The Company has completed the bid evaluations for this service and is in the process of negotiating contract terms for the gas management services agreement for the Jackson plant.

Q. Please explain Exhibit A-5 (JKC-3).

A. Exhibit A-5 (JKC-3) shows the fuel cost projections for the Company's oil-fired and natural gas-fired generating units for the year 2016.

Q. On what were these fuel cost estimates based?

A. These fuel cost estimates are based on price information assembled by the Corporate Risk Management Department within the Company and are indicative of the future market prices for oil and gas at the time the price deck was prepared.

Q. What were your underlying assumptions for your cost projections for 2016?

A. The underlying assumptions for the price of No. 6 oil and No. 2 oil are based on crude oil projections provided by the Corporate Risk Management Department and our approximation of the relationship between crude oil and No. 6 oil and No. 2 oil; while the price of gas for Karn 3 & 4 is based on the market gas prices (New York Mercantile Exchange ("NYMEX") Henry Hub), provided by the Corporate Risk Management Department, added to the cost of firm transport provided through the DCP Midstream Partners Bay Area Pipeline, or with interruptible transport provided through the Consumers Energy gas distribution system. The assumption for the price of gas for the Zeeland plant is based on gas market prices (monthly NYMEX Henry Hub) provided by the Corporate Risk Management Department, adjusted to the MichCon citygate gas index, and then in accordance with the Company's gas management services contract. Also, added into the burn cost projection for Zeeland is the demand charge associated with the use of the SEMCO lateral pipeline. The price of gas for the Cobb plant is based on the market gas projections provided by the Risk Management Department as well, but with seasonally firm transportation provided through the DTE Gas system. Gas prices for the combustion turbines are based on the applicable standard tariff charges for the type of service involved. Gas for the Straits and Gaylord combustion turbines is provided pursuant to DTE Gas' Rate No. GS-2 and gas service for Thetford units is provided pursuant to Consumers Energy's Gas Rate GS-3.

Q. What were the underlying assumptions for the cost projections for the Jackson plant?

A. It is expected that pricing and terms for gas management services for Jackson plant will be similar to the third party Agent services used for the Zeeland plant. Added to the burn cost is the cost of firm transport provided through the lateral owned by Consumers Energy. Consumers Energy gas utility charges the Jackson plant a pipeline demand charge for use of the lateral connecting the Jackson plant to the Vector pipeline.

Q. Have there been any changes to the gas transportation service to the Karn 3 & 4 plant?

A. Yes. Gas transportation service has been restored from the DCP Midstream Partners Bay Area Pipeline to the plants.

Q. Why does the Company use the NYMEX Henry Hub price as the basis for its gas price projections?

A. The NYMEX Henry Hub is the pricing point for natural gas futures contracts traded on the NYMEX and is generally accepted to be the primary gas price for the North American natural gas market. There are no similar pricing points projected for the MichCon citygate.

Q. How does the Company determine its projection for the MichCon citygate?

A. The Company has determined historical relationships between the MichCon citygate and the NYMEX Henry Hub based on actual trades. This relationship is then used to adjust the projected NYMEX Henry Hub price to arrive at an unbiased projection for the MichCon citygate price.

Q. What actions has the Company taken to minimize the cost of oil and gas identified in your exhibit?

A. The Zeeland and Jackson plant gas management services agreements were competitively bid. Regarding the other oil- and gas-burning units, spot purchases of gas and oil are made through a competitive bidding process, selecting the lowest bidder. Specific to No. 6 oil, the Company optimizes its purchases considering supply availability, price, and inventory considerations. More fundamentally, the Company's generating units are dispatched on an economic basis, thereby minimizing the use of the generally higher priced oil- and gas-fired peaking generation.

Q. Have you developed oil- and natural gas-cost projections for the years 2017 through 2020?

A. Yes, the annual costs are shown in Exhibit A-7 (JKC-5).

Q. How were your oil and natural gas projections determined for the years 2017 through 2020?

A. The methods used to determine these costs are the same as used to determine the costs for 2016.

Q. Does this complete your prepared direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17918
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2016	)	

EXHIBITS

OF

JIM K. CHILSON II, PE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2015

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No.: U-17918
Exhibit: A-3 (JKC-1)
Witness: JKChilson
Date: September 2015

Coal Contract & Annual Purchase Data

Line	(a) Supplier Contract No	(b) Coal Type	(c) Contract Start Date	(d) Contract End Date	(e) 2016 Volume (Tons)
1	160	Western	1/1/2015	12/31/2016	936,000
2	165	Western	1/1/2015	12/31/2016	889,200
3	173	Western	1/1/2016	12/31/2017	889,200
4	183	Western	1/1/2016	12/31/2016	936,000
5				**Total**	**3,650,400**

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No.: U-17918
Exhibit: A-4 (JKC-2)
Witness: JKChilson
Date: September 2015
Page: 1 of 1

Estimated As-Burned Coal Costs - 2016

Line	(a) Plant	(b)	(c) Burn Volume (Tons)	(d) Burn Dollars
1	JHCampbell 1-2		1,997,207	$ 87,789,557
2	JHCampbell 3 (CE Owned)		2,156,590	$ 94,492,360
3	BCCobb 4-5		307,601	$ 12,116,991
4	DEKarn 1-2		1,577,236	$ 61,305,798
5	JCWeadock 7-8		301,658	$ 11,523,070
6	JRWhiting 1-3		357,976	$ 15,127,695
			6,698,267	$ 282,355,470
7		Total Primary Fuel		$ 282,355,470
8		Total Auxilliary Fuel		$ 7,510,993
9		Total Freeze/Dust Treatment		$ 1,448,054
10		State Air Emission Fees		$ 974,181
11		STB Rate Challenge		$ 2,188,247
12		Total Coal Cost		$ 294,476,946

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No.: U-17918
Exhibit: A-5 (JKC-3)
Witness: JKChilson
Date: September 2015
Page: 1 of 1

Estimated As-Burned Oil & Gas Costs - 2016

Line	(a) Plant	(b)	(c) Burn Volume (BBLS/MCF)	(d) Burn Dollars
1	Zeeland Generating Station		34,766,714	$ 119,902,487
2	Jackson Plant		16,129,031	$ 59,350,482
3	DEKarn 3-4 - Oil		68,800	$ 2,295,195
4	DEKarn 3-4 - Gas		2,228,695	$ 13,627,555
5	Combustion Turbines - Oil		-	$ -
6	Combustion Turbines - Gas		-	$ 1,017,480
				$ 196,193,199
7		Total Primary Fuel		$ 196,193,199
8		Total Auxilliary Fuel		$ 5,877,944
9		State Air Emission Fees		$ 99,567
10		Total Oil & Gas Cost		$ 202,170,710

Estimated As-Burned Coal Costs
2017 - 2020

Line	(a)	(b)	(c)	(d)	(e)	(f)
	Burn Volume (Tons)					
	Plant		2017	2018	2019	2020
1	JHCampbell 1-2		2,035,115	1,866,362	1,943,915	1,891,592
2	JHCampbell 3 (CE Owned)		3,133,766	2,925,835	2,874,982	3,222,176
3	BCCobb 4-5		-	-	-	-
4	DEKarn 1-2		1,549,465	1,737,820	1,614,394	1,545,073
5	JCWeadock 7-8		-	-	-	-
6	JRWhiting 1-3		-	-	-	-
7		Total Burn Tonnage	6,718,345	6,530,017	6,433,291	6,658,841
	Burn Dollars					
	Plant		2017	2018	2019	2020
8	JHCampbell 1-2		$ 91,390,107	$ 85,440,454	$ 93,248,913	$ 93,932,105
9	JHCampbell 3 (CE Owned)		$ 140,432,667	$ 133,457,670	$ 137,469,396	$ 159,871,578
10	BCCobb 4-5		$ -	$ -	$ -	$ -
11	DEKarn 1-2		$ 62,327,688	$ 72,619,202	$ 70,453,498	$ 70,038,578
12	JCWeadock 7-8		$ -	$ -	$ -	$ -
13	JRWhiting 1-3		$ -	$ -	$ -	$ -
14		Total Primary Fuel	$ 294,150,462	$ 291,517,326	$ 301,171,807	$ 323,842,261
15		Total Primary Fuel	$ 294,150,462	$ 291,517,326	$ 301,171,807	$ 323,842,261
16		Total Auxilliary Fuel	$ 6,509,175	$ 6,604,184	$ 6,688,877	$ 6,783,657
17		Total Freeze/Dust Treatment	$ 1,062,620	$ 1,033,756	$ 1,018,573	$ 1,054,315
18		State Air Emission Fees	$ 451,116	$ 451,116	$ 451,116	$ 451,116
19		STB Rate Challenge	$ -	$ -	$ -	$ -
20		Total Coal Burn Cost	$ 302,173,372	$ 299,606,382	$ 309,330,373	$ 332,131,349

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Estimated As-Burned Oil & Gas Costs
2017 - 2020

Line	(a)	(b)	(c)	(d)	(e)	(f)
	Burn Volume (BBLS/MCF)					
	Plant		2017	2018	2019	2020
1	Zeeland Generating Station		31,869,168	30,693,241	30,433,790	30,722,334
2	Jackson Plant		11,949,083	12,227,099	12,768,731	11,940,334
3	DEKarn 3-4 - Oil		56,095	46,461	57,275	37,512
4	DEKarn 3-4 - Gas		1,568,109	1,631,618	2,150,846	1,774,973
5	Combustion Turbines - Oil		-	-	-	-
6	Combustion Turbines - Gas		-	-	-	-
	Burn Dollars					
	Plant		2017	2018	2019	2020
7	Zeeland Generating Station		$ 116,727,266	$ 113,677,091	$ 112,578,230	$ 116,429,674
8	Jackson Plant		$ 47,011,813	$ 48,880,495	$ 50,284,110	$ 48,753,550
9	DEKarn 3-4 - Oil		$ 2,044,653	$ 1,796,485	$ 2,299,954	$ 1,545,769
10	DEKarn 3-4 - Gas		$ 11,569,280	$ 11,913,875	$ 13,917,515	$ 12,701,849
11	Combustion Turbines - Oil		$ -	$ -	$ -	$ -
12	Combustion Turbines - Gas		$ 1,017,480	$ 426,470	$ 4,320	$ 4,320
13		Total Primary Fuel	$ 178,370,492	$ 176,694,416	$ 179,084,129	$ 179,435,162
14		Total Primary Fuel	$ 178,370,492	$ 176,694,416	$ 179,084,129	$ 179,435,162
15		Total Auxilliary Fuel	$ 5,220,036	$ 5,207,207	$ 5,588,607	$ 5,405,106
16		State Air Emission Fees	$ 99,579	$ 99,591	$ 94,364	$ 94,949
17		Total Oil & Gas Burn Cost	$ 183,690,107	$ 182,001,214	$ 184,767,100	$ 184,935,217

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17918
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2016	)	

DIRECT TESTIMONY

OF

DAVID F. RONK, JR.

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2015

Q. Please state your name and business address.

A. My name is David F. Ronk, Jr. and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director for Electric Transactions and Wholesale Settlements.

QUALIFICATIONS

Q. Please describe your educational background and business experience.

A. I received the degree of Bachelor of Science in Engineering with a specialty in Civil Engineering from the University of Michigan in 1975. Since 1980, I have been a Registered Professional Engineer in the state of Michigan. I have practiced engineering while employed by Consumers Energy since January 1976, with assignments associated with: (i) the construction of Campbell Unit No. 3; (ii) construction of a wood-fired generating station proposed to be constructed in the early 1980s near Hersey, Michigan; (iii) construction of the Midland Nuclear Plant; (iv) assistance to attorneys defending the Company in litigation with the Dow Chemical Company; (v) development of what ultimately became known as the Midland Cogeneration Venture Limited Partnership ("MCV"); (vi) design and procurement of utility motor vehicles; (vii) operation of a fleet of rail cars used to haul coal; and (viii) development of the Company's Acid Rain Program compliance strategy and program. Since August 1997, I have been responsible for the development of strategies to manage the Company's exposure to financial risks associated with the operation of its generating units and the purchase of capacity and energy from others to serve the demand for electricity from Consumers Energy customers. Between 2007 and 2012, I was responsible for the Company's resource planning activities. Beginning in 2012, I was responsible for the Company's electric wholesale settlements activities.

Q. Have you testified in other cases?

A. Yes. Exhibit A-8 (DFR-1) identifies the occasions in which I presented testimony before the Michigan Public Service Commission ("MPSC" or the "Commission").

<u>PURPOSE OF TESTIMONY</u>

Q. What is the purpose of your testimony?

A. My testimony will address: (i) the selection of an appropriate capacity planning reserve margin target for 2016 through 2020; (ii) the resources required to satisfy the capacity planning reserve margin target; (iii) the resources previously approved by the Commission; (iv) the resources included in this Power Supply Cost Recovery ("PSCR") Plan that have not been previously approved by the Commission; (v) the resources already purchased for the planning period; and (vi) the resources remaining to be purchased for the planning period.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring:

Exhibit A-8 (DFR-1)	Previously Sponsored Testimony Before the Michigan Public Service Commission;
Exhibit A-9 (DFR-2)	Projected Zonal Resource Credits, Demand, and Margins; and
Exhibit A-10 (DFR-3)	Midcontinent Independent System Operator (MISO) Energy Market Settlement Charge Line Items.

CAPACITY PLANNING RESERVE MARGIN TARGET

Q. What is a capacity planning reserve margin target?

A. The capacity planning reserve margin target is the amount of capacity that a Load Serving Entity ("LSE") (such as Consumers Energy) maintains to assure that sufficient capacity exists to provide adequate electric supply in each Planning Year ("PY") period. Generally, the capacity planning reserve margin target is designed to include consideration of demand forecast variances, generator forced outages and derates,[1] and transmission import limitations.

Q. How does the Company determine the capacity planning reserve margin target?

A. The Company relies on Midcontinent Independent System Operator, Inc. ("MISO") to determine the appropriate capacity planning reserve margin that Consumers Energy should maintain. For the 12-month periods beginning on June 1, 2015 and June 1, 2016, the MISO Loss of Load Expectation ("LOLE") Working Group performed a LOLE study which considered the probability that various amounts of generation resources would be inadequate to serve firm demand in the MISO footprint. Upon determining the amount of generation resources that would be necessary to achieve a LOLE of less than one occasion every ten years, a reserve margin (expressed as a percentage of peak firm demand) is calculated and assigned to all LSEs.

Q. What capacity planning reserve margin target is appropriate for the planning period?

A. For the 12-month period beginning June 1, 2015, the MISO LOLE Working Group determined that, using capacity discounted for forced outages, a capacity planning

[1] MISO addresses generator forced outages and derates by discounting the generator capacity value used in achieving the capacity planning reserve margin target and, thus, excludes forced outages and derates from the actual target.

reserve margin target (or "unforced" capacity planning reserve margin target) for MISO of at least 7.1% of the Company's demand at the time of MISO's coincident peak demand was sufficient to satisfy ReliabilityFirst Corporation's ("RF") capacity planning criteria of expecting to interrupt firm load no more frequently than one occasion in ten years. For the 12-month period beginning June 1, 2016, MISO Staff with consultation by the LOLE Working Group determined that, using capacity discounted for forced outages, a capacity planning reserve margin target for MISO of at least 7.6% of each LSE's demand at time of MISO's coincident peak demand was sufficient to satisfy RF's capacity planning criteria. RF is the regional reliability organization that represents the North American Electric Reliability Corporation ("NERC") in portions of the MISO footprint and portions of the area served by other regional transmission organizations. NERC is the electric reliability organization appointed by the Federal Energy Regulatory Commission to establish, monitor, and enforce reliability standards in the United States. Projected planning reserve margin targets of 7.6% were assumed for the years 2016-2020 that are included in this PSCR Plan, as shown on line 3 of Exhibit A-9 (DFR-2).

Q. How is Consumers Energy planning to meet the 7.1% reserve target for the first five months of 2016 and 7.6% for the last seven months of 2016?

A. To facilitate compliance with the planning reserve margin target, MISO has established Zonal Resource Credits ("ZRCs") for each 12-month period or PY, which are a measure of each resource's available capacity after discounting for the resource's effective forced outage rate. One ZRC of capacity is expected to be sufficient to serve one MW of forecasted demand, providing an appropriate discount for generator forced outages. Within MISO's footprint, Consumers Energy, as an LSE, is required to comply with the appropriate unforced capacity reserve margin requirement by having ZRCs equal to annual firm peak demand at the time of MISO's coincident peak demand times 1.071 for the five months ending May 31, 2016 and annual firm peak demand at the time of MISO's coincident peak demand times 1.076 for the seven months beginning June 1, 2016. This amount of capacity provides an adequate reserve to cover load forecast error, weather variability, and transmission contingencies while considering the benefits that result from demand diversity over the MISO footprint. ZRCs eliminate the potential for double counting MISO market participants' resources within the MISO market footprint through tariff requirements on market participants to use the Module E Capacity Tracking tool.

Q. How do you determine the amount of ZRCs needed for the peak demand season and the corresponding MISO PY?

A. To determine the amount of ZRCs represented by the capacity planning reserve margin target, the Company utilizes the demand forecast discussed in the direct testimony of Company witness Jason M. Shore. Mr. Shore's forecast of 8,382 MW of demand shown on Exhibit A-19 (JMS-3), page 1, line 7 occurs in July 2016 and includes jurisdictional and non-jurisdictional demand from the Company's distribution and wholesale customers adjusted for the demand expected to be offset by energy efficiency, direct load administration, dynamic peak pricing, web portal, and pay-as-you-go programs at the time of the Company's peak demand. Mr. Shore also prepares an estimate of the amount of demand expected to be offset by Retail Open Access suppliers of 602 MW at the time of the Company's peak demand, as shown on Exhibit A-19 (JMS-3), page 3, line 7.

Based on these assumptions, the resulting demand expected to be served with ZRCs of 7,780 MW is shown on Exhibit A-19 (JMS-3), page 2, line 7 and Exhibit A-9 (DFR-2), line 35. Since the ZRCs provided by direct load administration that are expected to offset the Company's peak demand are available as capacity resources, the Company's final ZRC requirement is increased by 22 ZRCs, as shown on line 27, column (a) of Exhibit A-9 (DFR-2). However, because the Company's peak demand traditionally occurs at a period different than MISO's peak demand, capacity requirements are reduced based on the Company's demand coincident with MISO's peak demand. Historical data of the Company's demand at the time of MISO's peak demand indicates that this diversity in peak demand periods reduces the Company's ZRC requirements by 263 ZRCs. The resulting capacity requirement of 7,539 ZRCs is shown on line 36, column (a) of Exhibit A-9 (DFR-2). Of course this applies to the 2016 PY because the peak period occurred in July 2016. The resources applicable for the 2015 PY were presented in MPSC Case No. U-17678 and updated in MPSC Case No. U-17751.

<u>RESOURCES PLANNED TO SATISFY RESERVE MARGIN REQUIREMENT</u>

Q. What resources are required to meet the 7.1% and 7.6% zonal reserve margin target for 2016?

A. The resources required to meet the 7.1% reserve margin target for the first five months of 2016 were presented in MPSC Case No. U-17678. Lines 4 through 30 of Exhibit A-9 (DFR-2) provide a description of the resources currently available to the Company and the resources that are expected to be acquired by Consumers Energy to achieve the 7.6% capacity planning reserve margin under peak load conditions. In 2016, the Company expects to have 5,330 ZRCs from owned units during the peak load period

(Consumers Energy is a summer-peaking system), as shown on line 8, column (a) of Exhibit A-9 (DFR-2). In September 2015, the Company acquired 150 ZRCs through a reverse auction, as shown on line 10 of Exhibit A-9 (DFR-2). The Company anticipates purchasing another 100 ZRCs between now and April 2016 to provide sufficient capacity for the 2016 PY. The Company also has long-term contracts with several Non-Utility Generators ("NUGs") for 2,444 ZRCs, as shown on line 24 column (a) of Exhibit A-9 (DFR-2). The Company is also able to provide ZRCs in the form of load modifying resources, including direct load administration programs, and the Company's interruptible service provision (Provision GI). MISO regards these load modifying resources as resources not requiring a reserve margin to be maintained and, therefore, the 86 MW of resources shown on line 28 of Exhibit A-9 (DFR-2) will be awarded ZRCs equal to the equivalent generating capacity[2] times one plus the reserve margin requirement or, in this case, 92 ZRCs. The compilation of all resources for 2016 totaling 8,116 ZRCs, when compared to the forecast of peak demand expected to be served with 7,539 ZRCs, as shown on line 36, column (a) of Exhibit A-9 (DFR-2), provides a reserve margin of 7.65%, as shown on line 38, column (a) of Exhibit A-9 (DFR-2).

<u>RESOURCES PREVIOUSLY APPROVED BY THE COMMISSION</u>

Q. To what extent have the owned resources providing 5,330 ZRCs and NUG resources providing 2,444 ZRCs been included in previous PSCR plans?

A. Owned resources providing 5,330 ZRCs and NUG resources providing 2,444 ZRCs have been included in previous PSCR plans, most recently in MPSC Case No. U-17678. While the Commission has yet to conclude its consideration of PSCR plans presented in

[2] Both interruptible and direct load administration capacity have been restated at generation levels by multiplying customer demand by the sum of one plus transmission losses.

MPSC Case Nos. U-17317 and U-17678, the resources included in this PSCR Plan were included in the last PSCR Plans. Those resources have previously been approved by the Commission with the exception of the Jackson Plant, certain ZRC purchases, and certain renewable resources which are discussed in more detail below.

RESOURCES NOT PREVIOUSLY APPROVED BY THE COMMISSION

Q. Are there any resources included in this PSCR Plan that have not been previously approved by the Commission?

A. Yes.

- The Company expects to finalize the purchase of the Jackson Plant from DPC Juniper in January 2016. The Jackson Plant consists of an existing 542 MW nameplate, combined cycle and natural gas-fueled, electric generating plant located in Jackson, Michigan. The Company requested the Commission's approval to include the Jackson Plant in rate base in MPSC Case No. U-17735.

- In August 2015, the Company purchased 124.7 ZRCs for the balance of the 2015 PY at a cost of $1.072 million (approximately $600,000 to be booked as 2016 PSCR expense) to cover an outage of Ludington Unit 5. Absent the purchase of ZRCs, the Company's customers would have been exposed to capacity costs in future years of several million dollars. The Company requests the Commission's approval of this purchase.

- Transfer price schedules associated with phases solicited after 2014 of the Company's Experimental Advanced Renewable Program, Solar Photovoltaic Expansion Program, and the Company's Solar Garden Program have yet to be approved by the Commission.

RESOURCES REMAINING TO BE PURCHASED FOR 2016

Q. Does Consumers Energy need to acquire additional capacity for 2016?

A. Yes. The retirement of Cobb Units 4 and 5; Weadock Units 7 and 8; and Whiting Units 1, 2, and 3 had potentially exposed the Company and its customers to the cost of purchasing replacement capacity for the six-week period between April 16, 2016 and May 31, 2016, however, the Company secured a waiver from certain requirements contained in MISO's tariff and is not required to purchase replacement capacity for that period. For PY 2016, the Company's projections indicate that it is short of its planning reserve margin target by approximately 100 ZRCs. It anticipates purchasing capacity through various demand response initiatives currently being tested and in MISO's Planning Resource Auction ("PRA"or "auction") to be conducted in March 2016.[3]

MISO CAPACITY MARKET

Q. What are the Company's options for meeting its planning resource requirements?

A. The Company can meet its planning resource requirements by: (i) participating in the PRA; (ii) self-scheduling resources into the auction; or (iii) opting out of the auction by submitting a Fixed Resource Adequacy Plan ("FRAP").

Q. Please explain the self-scheduling option.

A. The self-scheduling option will allow the Company to offer its capacity resources into the auction at a price of zero or more and then bid to purchase the amount of resources necessary to meet its capacity obligation. In other words, if the Company selects the self-schedule option, and all of its offered capacity clears, it would be left financially indifferent because it would be buying and selling the same net amount of capacity through the auction at the same capacity price as other alternatives.

Q. Please explain the opt-out option.

A. The Company can opt-out of the auction by submitting a FRAP. A FRAP will identify the resources to which the Company has ownership or contractual rights that will be relied upon to meet the Company's planning reserve margin requirement. The

[3] On September 15, 2015, the Company executed an Agreement to purchase the output from a 100 MW wind-powered facility proposed to be developed by Geronimo Energy LLC in Huron County, Michigan. The Contract has not yet been presented to the Commission for approval and is not included in this PSCR Plan.

Company's owned resources or contractual commitments for resources that are in excess of its FRAP resources may be offered into the auction. Conversely, if the Company's FRAP does not cover all of its resource requirements it will be required to make up any shortfall through the auction.

Q. When will the PY begin?

A. The PY will be the 12-month period beginning June 1, 2016.

Q. When will MISO conduct its PRA?

A. The PRA offer window will be open the last three business days of the month of March 2016. MISO will then post the results the tenth business day of the following month (April).

Q. How will MISO provide ZRCs for new capacity resources to be offered in the PRA?

A. Whether or not a resource is eligible for ZRCs to be available in the annual PRA depends upon the ability of the resource to demonstrate the capacity of the new or upgraded resource early enough to be included in the PRA. Normally, the Generator Verification Test Capacity real power test to determine the resource's available capacity (subject to discounting for the resource's effective forced outage rate) is performed prior to August 31 of the year before the PRA is conducted. In the case in which a new or upgraded capacity resource is not available until after August 31 of the year before the PRA, MISO allows for ZRCs associated with the new capacity or upgraded resource to be included in the PRA if testing is completed by March 1 prior to the PRA. For new or upgraded resources that cannot test before March 1 prior to the PRA but can complete a test prior to the last business day prior to June 1 of the upcoming PY, a LSE can provide notice to MISO on or before February 15 prior to the PRA. That notice provides the

LSE's intentions to: (i) complete the test prior to the last business day prior to June 1 of the upcoming PY; (ii) to post cash collateral beginning March 1 prior to the PRA; and (iii) to be subject to a non-performance payment in the event the unit clears in the PRA and fails to complete the test at the offered capacity rating on or before the last business day prior to June 1 of the upcoming PY.

Q. How will the costs and revenue associated with the PRA be treated in the PSCR cases?

A. Capacity costs and revenues associated with the PRA are invoiced by MISO on a daily basis over the course of the PY.

BLACK START SERVICE

Q. Please explain what the term "Black Start" means.

A. Normally, electric generating units rely on external power supply to initiate operations. In the event of an upset condition where frequency or voltage disruption causes generators over a broad area to interrupt service resulting in loss of transmission service, the absence of external power to re-start generators could result in a lengthy system restoration process. As part of each Transmission Owner's System Restoration Plan, Transmission Owners have identified those generators that have the capability to start without external power supply. As part of their System Restoration Plan, Transmission Owners can isolate the appropriate portions of their system, have the generators capable of starting without external power start, and feed that power to generators that require external power to start, thus restoring the transmission system to normal condition. Black Start service refers to the process of restoring a generation resource without relying on the external electric power transmission network.

Q. Will the Company have any generation resources designated for Black Start service in 2016?

A. Yes. On July 1, 2013, the Company entered into an Agreement with Michigan Electric Transmission Company, LLC ("METC") to maintain Ludington Units 2, 3, and 5 and Thetford Units 1, 2, 3, and 4 to be available for Black Start service. Subsequently, METC and the Company agreed to remove Thetford Unit 1 from the Agreement.

TEMPORARY REMOVAL OF SMALL COMBUSTION TURBINES FROM SERVICE

Q. What is the Company's future strategy for temporarily removing certain combustion turbine generating units from service?

A. The Company has recently restored Campbell Unit A to available status but has purchased ZRCs to avoid the expense of maintaining the unit in a must offer condition. The Company anticipates returning Straits Unit 1B and Gaylord Units 1, 2, and 3 to available status on February 16, 2016. Thetford Unit 1, Whiting Unit A, Weadock Unit A, and Cobb Units 1, 2, and 3 are retired.

TERMINATION OF CONTRACTS

Q. Does the Company have any power purchase agreements that have terminated or will terminate in 2016?

A. Yes.

- In MPSC Case No. U-17678, I advised that the Company's Contract with Hillman Power Company was eligible to terminate effective December 31, 2015. On December 18, 2014 the Company provided the appropriate notice to Hillman electing to terminate the Agreement. At this point in time, the Company and Hillman have not reached a new agreement.

- The Company's Contract with Thornapple Association ("Thornapple") is eligible to terminate on December 31, 2016. In 2014, the Company paid about $64/MWh for the output from that facility during a period when the capacity and energy had a value of about $35/MWh. While Consumers Energy expects the value to be greater in the future, the Company does not anticipate the value reaching the $64 level for several years and, as a result, it is anticipated that the Company will provide notice to terminate the 600 kW Contract.

- The Company's Contract with White's Bridge Hydro ("White's Bridge") is eligible to terminate on December 31, 2016, as well. In 2014, the Company paid approximately $73/MWh for the output from that facility for capacity and energy that had a value of about $35/MWh. The Company anticipates that it will provide notice to terminate this 300 kW Contract.

- The Company anticipates offering both Thornapple and White's Bridge new five-year contracts for the energy and capacity of the respective facilities. The new contract offers will be based on the actual market price of energy (Locational Marginal Price), as well as a forecasted capacity expense, based on the Company's recent purchase of capacity for the next five years.

- The Company's Public Act 295 Contract with Zeeland Farms Services Plant No. 2 ("Zeeland") expires on October 12, 2016. In 2014, the Company paid approximately $109/MWh (approximately $88/MWh charged to PSCR) for the output from this facility. The Zeeland Plant will be available to bid into future solicitations.

MISO ENERGY MARKETS

Q. With regard to serving Consumers Energy's bundled load, will all of the charges incurred and revenues received by Consumers Energy under the MISO's Transmission, Energy, and Operating Reserve Markets Tariff be included in net PSCR costs to be recovered from Consumers Energy's PSCR customers in 2016 and later years?

A. Yes. All of the expenses incurred with MISO and all of the revenues received from MISO, to the extent the revenues received were from the output of jurisdictional facilities sold to MISO, are expected to be included in PSCR costs reconciled in the Company's 2016 PSCR reconciliation case. As noted in prior testimony, to the extent that the revenue is provided to offset PSCR costs incurred, the Company plans to credit that revenue against PSCR expense.

Q. Please enumerate these costs and revenues seen on a normal settlement statement.

A. Exhibit A-10 (DFR-3) is a listing of the line items of settlement on a normal day.

Q. What are some of the key charges that Consumers Energy sees on the settlement statement?

A. Based on the experience with the Market to date, Consumers Energy is seeing the largest level of costs in the Day Ahead Asset Energy Amount (line 5 of Exhibit A-10 (DFR-3)) and Non-Excessive Energy Amount (line 32 of Exhibit A-10 (DFR-3)). Consumers Energy is seeing the largest revenues in with the Day Ahead Non-Asset Energy Amount (line 13 of Exhibit A-10 (DFR-3)) and Real Time Asset Energy Amount (line 33 of Exhibit A-10 (DFR-3)). Consumers Energy also sees sizable costs and revenues in charges associated with Financial Transmission Rights ("FTRs") and Auction Revenue Rights.

Q. Has the amount of settlement been forecasted for any of these charges?

A. Yes. Company witness Daniel S. Alfred, in his direct testimony, discusses his forecast of expenditures for: (i) Day-Ahead Market Administration Amount; (ii) FTR Market Administration Amount; and (iii) Real-Time Market Administration Amount. Mr. Alfred is able to make such forecasts because MISO has projected a settlement rate for each of these charges.

Q. Have the other Market charges been forecasted?

A. Yes. Consumers Energy estimates the gross marginal energy price expected to be paid or charged by MISO using methods the Company has previously used to estimate the prices experienced in bilateral markets. Consumers Energy will include all settled charges incurred and revenues received during the year in the 2016 PSCR reconciliation case.

Q. If MISO makes a change to settlement charges after the 2016 PSCR reconciliation case is resolved, how will Consumers Energy account for the change?

A. The expense or revenue associated with any settlement, net of any reserves established for such settlement, will be booked in the year that the settlement occurs. As a result, those charges will be included in the then-current PSCR reconciliation case.

Q. Is the Company forecasting or expecting a major settlement?

A. No.

RENEWABLE RESOURCE PROGRAM ("RRP")

Q. Are you familiar with the RRP?

A. Yes. The RRP was approved by the Commission in January 2005 in MPSC Case No. U-13843. Under this RRP, the Company contracts to purchase energy generated by renewable technologies and then allocates the cost of that energy between power supply costs recoverable from PSCR customers and renewable energy costs to be recovered from either voluntary contributions from customers or the Renewable Resource Fund. The Renewable Resource Fund is funded in part by a contribution from MCV in accordance with a Settlement Agreement filed and approved by the Commission in MPSC Case No. U-15320.

Q. How are RRP costs treated in this PSCR Plan?

A. In accordance with the Commission's orders in MPSC Case No. U-13843, Consumers Energy has adjusted the cost of energy delivered from the RRP generators to the average PSCR cost calculated before considering the energy delivered by the RRP suppliers themselves. This cost will be recovered from the Company's PSCR customers. The remainder of the cost contracted to be paid to RRP suppliers that remains unrecovered after such adjustment will be recovered from contributions paid by customers who voluntarily participate in the RRP (if any) and then from the Renewable Resource Fund created in MPSC Case No. U-13843, *supra*. In this way, the inclusion of the costs associated with these Contracts will have no effect on the PSCR Factor in accordance with the Commission's May 18, 2004 Order in that case.

RENEWABLE ENERGY PLAN ("RE Plan")

Q. Are you familiar with the Company's RE Plan?

A. Yes. The Company's RE Plan was approved by the Commission in its May 26, 2009 Order in MPSC Case No. U-15805. The RE Plan addresses the measures necessary to comply with MCL 460.1001 et seq. The RE Plan was amended with the Commission's orders in MPSC Case Nos. U-16543, U-16581, U-17301, and U-17752. An amendment to the RE Plan is being considered in MPSC Case No. U-17792.

Q. To what extent have the cost of resources used to satisfy the requirements of MCL 460.1001 et seq. been included in the Company's PSCR Plan?

A. In accordance with MCL 460.1001 et seq. and the Company's approved RE Plan, the Company's PSCR Plan includes (i) all of the cost of renewable energy resources for which recovery in rates was approved as of October 6, 2008 and (ii) that portion of the cost of renewable energy resources for which recovery in rates was not approved as of October 6, 2008 ("new resources") that represents the value of the energy, capacity, and ancillary services that those resources are expected to deliver to the Company. All additional costs are expected to be recovered as Incremental Cost of Compliance through the Renewable Energy Surcharge.

Q. On what basis was the value of energy from new resources determined?

A. Prior to the Commission's Order in MPSC Case No. U-16655, the Company's estimate of the value of energy delivered through power purchase agreements is based on the lower of (i) the monthly schedule of average on-peak and off-peak locational marginal prices included with the application for approval of the related agreement and (ii) the actual forecast expense associated with the resource. Similarly, prior to the Order in MPSC Case No. U-16655, for all solar photovoltaic agreements, the estimate is based on the lower of (i) the monthly schedule of average on-peak locational marginal prices included with the application for approval of the related agreement and (ii) the actual forecast expense associated with the resource. Agreements approved by the Commission on or before May 10, 2011 utilize the monthly schedule of average on-peak and off-peak locational marginal prices shown on pages 15 and 16 of Exhibit A-14 (DFR-7) in MPSC Case No. U-15805. No new contracts were approved by the Commission between May 10, 2011 and May 1, 2012. Contracts approved between May 1, 2012 and June 27, 2013 utilize the monthly schedule of average on-peak and off-peak locational marginal prices shown on lines 14 through 39 of page 2 of Exhibit A-32 (JSR-5) in MPSC Case No. U-16581. Subsequent to the Commission's Order in MPSC Case No. U-16655, all transfer price schedules which had not yet been "locked in" are based on transfer prices provided by the MPSC which correspond to the time at which the projects were approved, or if the project has not yet been approved, the transfer price schedule which corresponds to the time when they will likely be approved. The Cross Winds Energy Park was approved on June 28, 2013 and uses the annual Transfer Price shown in column J of Exhibit S-1 (JJH-1) in MPSC Case No. U-16655 as the basis for energy and capacity expense. The Company's Experimental Advanced Renewable Program (Anaerobic Digester) uses the annual Transfer Price shown in column J of Exhibit S-1 (JJH-1) in MPSC Case No. U-17321 as the basis for energy and capacity expense. The Company's Solar Gardens Program uses the annual Transfer Price shown in column J of Exhibit S-1 (JJH-1) in MPSC Case No. U-17631. The expansion phase of the Experimental Advanced Renewable Program (Solar Photovoltaic) uses a number of different transfer price schedules, including the Company's projection of transfer prices stated in MPSC Case No. U-16581, as well as the MPSC Staff's transfer price schedules as stated in MPSC Case Nos. U-16655, U-17321, and U-17631. The Company's estimate of the value of energy delivered by new Company-owned facilities is determined using the same monthly schedules of on-peak and off-peak locational marginal prices, but is not limited to the actual forecast expense associated with the facility. In most cases, the volume of energy delivered from the various new resources is based on the expected annual or monthly capacity factors appropriate for the various technologies.

Q. On what basis was the value of capacity from new resources determined?

A. For resources approved by the Commission on or before May 10, 2011, the value of capacity for new resources is based on the schedule of capacity costs included as pages 59 and 60 in Exhibit A-14 (DFR-7) in MPSC Case No. U-15805. No new resources were approved by the Commission between May 10, 2011 and May 1, 2012. For resources approved by the Commission between May 1, 2012 and June 27, 2013, the value of capacity for new resources is based on the schedule of capacity costs included on page 3 in Exhibit A-32 (JSR-5) in MPSC Case No. U-16581. Subsequent to the Commission's Order in MPSC Case No. U-16655, the value of capacity is included as a portion of the transfer price schedule forecasts as provided by the Commission Staff, depending on the approval date of the facility. The amount of capacity to be delivered by each new resource is expected to be the amount of unforced capacity expected to be approved by MISO.

Q. On what basis was the value of ancillary services from new resources determined?

A. No value for ancillary services for new resources were included in the RE Plan or this PSCR Plan because of the minimal amount of ancillary services expected to be provided by these resources at the time the RE Plan was prepared.

ENERGY EFFICIENCY AND DEMAND MANAGEMENT PROGRAM

Q. Are you familiar with the Company's plan to implement an Energy Optimization Program?

A. Yes. In MPSC Case No. U-15805, the Company proposed to implement an Energy Optimization Program expected to reduce the need to acquire capacity and generate electricity. The Energy Optimization Program was subsequently revised in MPSC Case Nos. U-16412, U-16670, U-17138, and U-17351.

Q. Has the PSCR Plan been adjusted to address the Energy Optimization Program?

A. Yes. As discussed in Mr. Shore's direct testimony, the Company has estimated the reduction of energy consumption and demand during peak load conditions for energy efficiency programs and included those reductions in the demand forecast included in the 2016 PSCR Plan.

Q. What additional adjustments have been forecasted?

A. Mr. Shore has also made adjustments to demand during peak load conditions for direct load administration, dynamic peak pricing, web portal, and pay-as-you-go programs, which are forecasted on Exhibit A-9 (DFR-2) on lines 27, 33, and 34. Line 33 is labeled as energy efficiency at the time of peak load conditions, but also includes web portal and pay-as-you-go program forecasts.

<u>SUMMARY</u>

Q. Please summarize your testimony.

A. My testimony explains the need to maintain a capacity planning reserve margin target and advises the Commission that, for purposes of this PSCR Plan, the Company has used a capacity planning reserve margin target of 7.1% for the first five months of 2016 and 7.6% for the last seven months of 2016. I have demonstrated that the Company will have adequate resources in 2016 to meet demand and capacity planning reserve margin requirements. I have advised the Commission of the types of charges expected to be incurred with the MISO Energy Market and their inclusion in the PSCR Plan. I have advised the Commission that the PSCR Plan includes the costs incurred under the RRP only to the extent allowed by the Commission's orders. I have advised the Commission that the PSCR Plan includes certain costs incurred under the RE Plan only to the extent that those costs are less than or equal to the amount paid and the Company's estimate, as approved by the Commission, of the energy and capacity value provided by the resource. I have advised the Commission that adjustments for Energy Optimization, direct load administration, dynamic peak pricing, web portal, and pay-as-you-go programs have been incorporated into the PSCR Plan consistent with the Company's prior applications.

Q. Does this complete your testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17918
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2016	)	

EXHIBITS

OF

DAVID F. RONK, JR.

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2015

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

PREVIOUSLY SPONSORED TESTIMONY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

1. MPSC Case No. U-10710-R (direct and rebuttal), the Company's 1995 Power Supply Cost Recovery ("PSCR") Reconciliation case, regarding the treatment of sulfur dioxide emission allowances;

2. MPSC Case No. U-10973-R (direct), the Company's 1996 PSCR Reconciliation case;

3. MPSC Case No. U-11180 (rebuttal), the Company's 1997 PSCR Plan case, regarding the treatment of sulfur dioxide emission allowances and certain permit conditions;

4. MPSC Case No. U-12488 (direct and rebuttal), regarding certain terms and conditions of service for retail open access customers;

5. MPSC Case No. U-13917 (direct, supplemental, and rebuttal), the Company's 2004 PSCR Plan case, regarding electric capacity requirements; the appropriate calculation of energy payment rates under certain qualified facility contracts, and the appropriate treatment of third party sales revenues in calculating PSCR costs;

6. MPSC Case No. U-14031 (direct, rebuttal, and supplemental rebuttal), regarding the calculation of the hold harmless amount associated with the proposed resource conservation plan;

7. MPSC Case No. U-14274 (direct and rebuttal), the Company's 2005 PSCR Plan case, regarding electric capacity requirements and costs for 2005;

8. MPSC Case No. U-14347 (direct), regarding operating and maintenance expense and capital cost associated with electric and fuel supply for 2006 test year and power supply cost for the five year period 2005 through 2009;

9. MPSC Case No. U-13917-R (direct), the Company's 2004 PSCR Reconciliation case, regarding power supply costs incurred in 2004;

10. MPSC Case No. U-14701 (direct, supplemental and rebuttal), the Company's 2006 PSCR Plan case, regarding electric capacity requirements and costs for 2006;

11. MPSC Case No. U-14274-R (direct and supplemental), the Company's 2005 PSCR Reconciliation case, regarding power supply costs incurred in 2005;

12. MPSC Case No. U-15001 (direct), the Company's 2007 PSCR Plan case, regarding electric capacity requirements and costs for 2007;

13. MPSC Case No. U-15245 (direct and supplemental), regarding operating and maintenance expense and capital cost associated with electric and fuel supply for 2008 test year and power supply cost for the five year period 2007 through 2011;

14. MPSC Case No. U-14701-R (direct and supplemental), the Company's 2006 PSCR Reconciliation case, regarding power supply costs incurred in 2006;

15. MPSC Case No. U-15290 (direct and supplemental), regarding the Company's balanced energy initiative;

16. MPSC Case No. U-15415 (direct), the Company's 2008 PSCR Plan case, regarding electric capacity requirements and costs for 2008;

17. MPSC Case No. U-15001-R (direct and supplemental), the Company's 2007 PSCR Reconciliation case, regarding power supply costs incurred in 2007;

18. MPSC Case No. U-15645 (direct and rebuttal), regarding operating and maintenance expense and capital cost associated with electric and fuel supply for 2009 test year and power supply cost for the seven year period 2007 through 2013;

19. MPSC Case No. U-15675 (direct), regarding the Company's 2009 PSCR Plan, regarding electric capacity requirements and costs for 2009;

20. MPSC Case No. U-15805/U-15889 (direct and rebuttal), regarding the 2009 renewable energy plan and energy optimization plan;

21. MPSC Case No. U-15415R (direct and rebuttal), the Company's 2008 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2008;

22. MPSC Case No. U-16045 (direct and rebuttal), the Company's 2010 PSCR Plan, regarding electric capacity requirements and costs for 2010;

23. MPSC Case No. U-16191 (direct and rebuttal), regarding Operating and Maintenance expense and Capital cost associated with Electric and Fuel Supply for the test year ended June 30, 2011 and Power Supply cost for the 12-month period ended June 30, 2011;

24. MPSC Case No. U-15675R (direct, rebuttal, supplemental rebuttal, and second supplemental rebuttal), the Company's 2009 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2009;

25. MPSC Case No. U-16300 (direct and rebuttal), the Company's 2009 Renewable Cost Reconciliation Case, regarding renewable energy costs incurred in 2009;

26. MPSC Case No. U-16432 (direct and second rebuttal), the Company's 2011 PSCR Plan, regarding electric capacity requirements and costs for 2011;

27. MPSC Case No. U-16543 (direct and rebuttal), the Company's application for approval of a Renewable Energy Plan amendment;

28. MPSC Case No. U-16794 (direct), regarding Operating and Maintenance expense and Capital costs associated with Energy Supply Operations for the test year ended September 30, 2012;

29. MPSC Case No. U-16045R (direct and rebuttal), the Company's 2010 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2010;

30. MPSC Case No. U-16301 (direct), the Company's 2010 Renewable Cost Reconciliation Case, regarding renewable energy costs incurred in 2010;

31. MPSC Case No. U-16890 (direct and supplemental), the Company's 2012 PSCR Plan, regarding electric capacity requirements and costs for 2012;

32. MPSC Case No. U-16581 (direct), the Company's application for biennial review of its Renewable Energy Plan;

33. MPSC Case No. U-16432R (direct), the Company's 2011 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2011;

34. MPSC Case No. U-16655 (direct), the Company's 2011 Renewable Cost Reconciliation Case, regarding renewable energy costs incurred in 2011;

35. MPSC Case No. U-17087 (direct and rebuttal) regarding capacity planning matters associated with the test year beginning January 1, 2013;

36. MPSC Case No. U-17095 (direct and rebuttal) regarding the Company's 2013 PSCR Plan, specifically addressing electric capacity requirements and costs for 2013;

37. MPSC Case No. U-16890R (direct), the Company's 2012 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2012;

38. MPSC Case No. U-17301 (direct and supplemental), the Company's 2013 Application for biennial review of the Renewable Energy Plan, regarding various changes to the Renewable Energy Plan;

39. MPSC Case No. U-17321 (direct), the Company's 2012 Renewable Cost Reconciliation Case, regarding renewable energy costs incurred in 2012;

40. MPSC Case No. U-17429 (direct), the Company's application for a certificate of necessity associated with the construction of a natural gas-fueled combined cycle electric generating unit located in Thetford Township, Genesee County, Michigan;

41. MPSC Case No. U-17317 (direct, supplemental, and rebuttal) regarding the Company's 2014 PSCR Plan, specifically addressing electric capacity requirements and costs for 2014;

42. MPSC Case No. U-17496 (direct and rebuttal) regarding long-term power purchase auction procedures;

43. MPSC Case No. U-17631 (direct and rebuttal), the Company's 2013 Renewable Cost Reconciliation Case, regarding renewable energy costs incurred in 2013;

44. MPSC Case No. U-17678 (direct and rebuttal) regarding the Company's 2015 PSCR Plan, specifically addressing electric capacity requirements and costs for 2015;

45. MPSC Case No. U-17725 (direct and rebuttal) regarding the acquisition of long term capacity contracts for MISO Planning years 2015 through 2020;

46. MPSC Case No. U-17735 (direct and rebuttal) regarding the expenses associated with power supply issues for the test year beginning June 1, 2015; and

47. MPSC Case No. U-17792 (direct) regarding the Company's 2015 Application for biennial review of the Renewable Energy Plan, regarding various changes to the Renewable Energy Plan.

CONSUMERS ENERGY COMPANY
PROJECTED ZONAL RESOURCE CREDITS, DEMAND, AND MARGINS

Line	Description	(a) 2016	(b) 2017	(c) 2018	(d) 2019	(e) 2020
1	MISO Diversity Factor	-3.37%				
2	Transmission Losses	4.20%				
3	Reserve Margin Requirement	7.60%	7.60%	7.60%	7.60%	7.60%
4	ZRCs for Owned Capacity					
5	Net Demonstrated Capability less EFORd	5,400	5,330	5,444	5,429	5,454
6	ZRCs for Projected Unit Upgrades/Re-ratings/Additions	793	115	28	25	25
7	ZRCs for Projected Retirements/remove/return from/to service	-863	0	-43	0	0
8	Subtotal ZRCs for Owned Capacity	5,330	5,444	5,429	5,454	5,479
9	ZRCs for Transactions (Annual Contracted Amounts)					
10	ZRCs Acquired in Reverse Capacity Auction	150	20	20	20	20
11	ZRCs for Projected Capacity Purchases	100	75	75	75	50
12	ZRCs for Projected Self Generation/Load Shift	0	0	0	0	0
13	Subtotal ZRCs for Purchases	250	95	95	95	70
14	ZRCs for Non-Utility Generation Projects (NUGs)					
15	ZRCs for MCV Contract Capacity	1,228	1,228	1,228	1,228	1,228
16	ZRCs for Palisades PPA	744	744	744	744	744
17	ZRCs for Other NUGs	401	400	398	357	357
18	ZRCs for PA 295 Wind NUGs	53	53	53	53	53
19	ZRCs for PA 295 Landfill Gas NUGs	17	15	15	15	15
20	ZRCs for PA 295 Anaerobic Digestion NUGs	2	3	3	3	3
21	ZRCs for PA 295 Existing Solar NUGs	0	1	1	1	1
22	ZRCs for PA 295 New EARP Solar NUGs	0	2	2	2	2
23	ZRCs for PA 295 Hydro NUGs	0	0	0	0	0
24	Subtotal ZRCs for NUGs	2,444	2,446	2,444	2,403	2,403
25	ZRCs for Load Modifying Resources					
26	Demand from Interruptible Customers	64	64	64	64	64
27	Smart Grid- Direct Load Administration (AC Cycling)	22	49	84	113	122
28	Subtotal ZRCs for Demand Response Resources	86	113	148	177	186
29	Subtotal ZRCs (Owned Generation, Purchases, NUGs)	8,024	7,985	7,968	7,953	7,952
30	Total ZRCs (Including Interruptibles and DLM)	8,116	8,107	8,128	8,143	8,152
31	System Peak Load	8,767	8,865	8,973	9,055	9,136
32	Demand expected to be served by Retail Open Access Suppliers	602	613	617	624	666
33	Demand expected to be reduced by Energy Efficiency	342	400	424	466	500
34	Demand expected to be reduced by Smart Grid- Dynamic Peak Pricing	21	77	133	150	143
35	Non-Coincident Peak Load	7,780	7,726	7,715	7,702	7,705
36	Coincident to MISO Peak Load	7,539	7,513	7,536	7,552	7,563
37	Margin -- MW	577	594	592	591	589
38	Margin Reserve -- %	7.65%	7.91%	7.85%	7.83%	7.79%

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR (MISO)
ENERGY MARKET SETTLEMENT CHARGE LINE ITEMS

Line	Charge Line Item Description
1	Auction Revenue Rights Infeasible Uplift Amount
2	Auction Revenue Rights Stage 2 Distribution Amount
3	Auction Revenue Rights Transaction Amount
4	Contingency Reserve Deployment Failure Charge Amount
5	Day Ahead Asset Energy Amount
6	Day Ahead Congestion Rebate on Carve-Out Grandfathered Agreements
7	Day Ahead Congestion Rebate on Option B Grandfathered Agreements
8	Day Ahead Financial Bilateral Transaction Congestion Amount
9	Day Ahead Financial Bilateral Transaction Loss Amount
10	Day Ahead Losses Rebate on Carve-Out Grandfathered Agreements
11	Day Ahead Losses Rebate on Option B Grandfathered Agreements
12	Day Ahead Market Administration Amount
13	Day Ahead Non-Asset Energy Amount
14	Day Ahead Regulation Amount
15	Day Ahead Revenue Sufficiency Guarantee Distribution Amount
16	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount
17	Day Ahead Schedule 24 Allocation Amount
18	Day Ahead Spinning Reserve Amount
19	Day Ahead Supplemental Reserve Amount
20	Day Ahead Virtual Energy Amount
21	Excessive Energy Amount
22	Financial Transmission Rights Annual Transaction Amount
23	Financial Transmission Rights Full Funding Guarantee Amount
24	Financial Transmission Rights Guarantee Uplift Amount
25	Financial Transmission Rights Hourly Allocation Amount
26	Financial Transmission Rights Market Administration Amount
27	Financial Transmission Rights Monthly Allocation Amount
28	Financial Transmission Rights Monthly Transaction Amount
29	Financial Transmission Rights Transaction Amount
30	Financial Transmission Rights Yearly Allocation Amount
31	Net Regulation Adjustment Amount
32	Non-Excessive Energy Amount
33	Real Time Asset Energy Amount
34	Real Time Congestion Rebate on Carve-Out Grandfathered Agreements
35	Real Time Distribution of Losses Amount
36	Real Time Excessive Deficient Energy Deployment Charge Amount
37	Real Time Financial Bilateral Transaction Congestion Amount
38	Real Time Financial Bilateral Transaction Loss Amount
39	Real Time Losses Rebate on Carve-Out Grandfathered Agreements
40	Real Time Market Administration Amount
41	Real Time Miscellaneous Amount
42	Real Time Net Inadvertent Distribution Amount
43	Real Time Non-Asset Energy Amount
44	Real Time Price Volatility Make Whole Payment Amount
45	Real Time Regulation Amount
46	Real Time Revenue Neutrality Uplift Amount
47	Real Time Revenue Sufficiency Guarantee First Pass Distribution Amount
48	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amount
49	Real Time Schedule 24 Allocation Amount
50	Real Time Schedule 24 Distribution Amount
51	Real Time Spinning Reserve Amount
52	Real Time Supplemental Reserve Amount
53	Real Time Uninstructed Deviation Amount
54	Real Time Virtual Energy Amount
55	Regulation Cost Distribution Amount
56	Spinning Reserve Cost Distribution Amount
57	Supplement Reserve Cost Distribution Amount
58	Real Time Demand Response Allocation Uplift Charge
59	Real Time Resource Adequacy Auction Amount
60	Real Time MVP Distribution Amount

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17918
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2016	)	

DIRECT TESTIMONY

OF

ROBERT C. SCHRAM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2015

Q. Please state your name and business address.

A. My name is Robert C. Schram and my business address is 2400 Weiss Street, Saginaw, Michigan 48602.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Director of Compliance & Quality Systems, Energy Resources Business Services ("ERBS").

Q. Please describe your educational background.

A. I received a Bachelor of Science (Electrical Engineering) degree from Saginaw Valley State University in 1988. I also received a Master's degree (Manufacturing Management) from GMI Engineering and Management Institute (now Kettering University) in 1995.

Q. Please describe your business experience.

A. Prior to joining Consumers Energy, I held operational, quality, and leadership positions of progressing responsibility with Dow Chemical Company of Midland, MI.

In 2004, I joined Consumers Energy as the Economic Based Reliability ("EBR") Lead for the JC Weadock ("Weadock") generating facility. In 2007, I became the Maintenance Manager for the DE Karn ("Karn") and Weadock generating facilities. In 2009, I became the EBR Lead for the Karn and Weadock generating facilities. From 2011 through 2014, I assumed lead responsibilities in the Company's Performance Excellence area. In 2015, I was promoted to Director of Quality. In September 2015, I was named as Director of Compliance & Quality Systems, ERBS.

Q. What are your responsibilities as Director of Compliance & Quality Systems, ERBS?

A. As Director of Compliance & Quality Systems, ERBS, I am responsible for regulatory compliance, procedure writing, safety audits, and rate case filings for ERBS of Consumers Energy.

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

A. The purpose of my testimony is to: 1) identify and explain the major fossil and Ludington outages that are planned for this period; 2) identify and support Consumers Energy's periodic outage plans and Random Outage Rate ("ROR") projections for the 2016 Power Supply Cost Recovery ("PSCR") Plan year; 3) compare the projected ROR for fossil, hydro, Ludington, and peaker units with actual ROR experienced in the five-year period 2010 through 2014; 4) address availability of generating units for the five-year forecast period; 5) identify forecasted urea expenses for the 2016 PSCR Plan year, as well as the period 2017 through 2020; 6) identify forecasted aqueous ammonia expenses for the 2016 PSCR Plan year, as well as the period 2017 through 2020, and request this expense be included in all future PSCR Plan cases; 7) identify forecasted lime expenses for the 2016 PSCR Plan year, as well as the period 2017 through 2020, and request this expense be included in all future PSCR Plan cases; and 8) identify forecasted activated carbon expenses for the 2016 PSCR Plan year, as well as the period 2017 through 2020, and request this expense be included in all future PSCR Plan cases.

Q. Are you sponsoring exhibits with your testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-11 (RCS-1)	Major Outages in the 2016 PSCR Plan
Exhibit A-12 (RCS-2)	2016 PSCR Random Outage Rate Projections

Exhibit A-13 (RCS-3)	2016-2020 Urea Expense
Exhibit A-14 (RCS-4)	2016-2020 Aqueous Ammonia Expense
Exhibit A-15 (RCS-5)	2016-2020 Lime Expense
Exhibit A-16 (RCS-6)	2016-2020 Activated Carbon Expense

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

A. Yes.

Major Generating Plant Outages for 2016

Q. Please define major generating plant outages.

A. Major generating plant outages are defined as outages that last 28 days or more. These outages generally deal with major pieces of equipment that require disassembly and repair and/or replacement.

Q. Please describe the major outages that have been reflected by Company witness Sara T. Walz in the dispatch of the Company's generating plants in this case.

A. Exhibit A-11 (RCS-1) describes those major outages.

Q. Please describe the planned start dates, durations, and significant activities for each of the major outages listed on Exhibit A-11 (RCS-1).

A. I describe the individual outages in the following testimony.

Ludington Unit 4

The outage at Ludington Unit 4 began March 17, 2015 and was projected to last 330 days – concluding February 10, 2016. The outage is now projected to conclude March 5, 2016. This is the second unit outage of Ludington's multiyear $800 million overhaul and upgrade. The outage is necessary to replace and upgrade most all major components including the water turbine (a.k.a. – runner), wicket gates, generator/pump, and stator.

Karn Unit 1

The outage at Karn Unit 1 is scheduled to begin October 31, 2015 and is projected to last for 74 days in 2016 – concluding March 15, 2016. The outage is to overhaul the turbine, turbine valves, perform boiler work, and a chemical cleaning.

JH Campbell ("Campbell") Unit 1

The outage at Campbell Unit 1 is scheduled to begin January 9, 2016 and is projected to last for 35 days – concluding February 13, 2016. The outage is necessary to tie-in the Air Quality Control Systems ("AQCS") required to achieve compliance with the United States Environmental Protection Agency's ("EPA") Mercury and Air Toxics Standards ("MATS") rule.

Ludington Unit 3

The outage at Ludington Unit 3 is scheduled to begin January 11, 2016 and is projected to last for 35 days – concluding February 15, 2016. The outage is for cavitation repairs, penstock inspection and testing, and shaft packing.

Ludington Unit 5

The outage at Ludington Unit 5 is scheduled to begin January 31, 2016 and is projected to last 330 days – concluding December 26, 2016. This is the third unit outage of Ludington's multiyear $800 million overhaul and upgrade. The outage is necessary to replace and upgrade most all major components including the water turbine (a.k.a. – runner), wicket gates, generator/pump, and stator.

Campbell Unit 3

The outage at Campbell Unit 3 is scheduled to begin March 5, 2016 and is projected to last for 84 days – concluding May 28, 2016. The outage is necessary to tie-in the AQCS required to achieve MATS compliance. Also during this outage, the Company will perform a turbine inspection/overhaul, and replace the low pressure rotor and valves.

Ludington Unit 1

The outage at Ludington Unit 1 is scheduled to begin September 11, 2016 and is projected to last 330 days – concluding August 7, 2017. This is the fourth unit outage of Ludington's multiyear $800 million overhaul and upgrade. The outage is necessary to replace and upgrade most all major components including the water turbine (a.k.a. – runner), wicket gates, generator/pump, and stator.

Miscellaneous Outages

Q. Are there other outages projected for 2016?

A. Yes. There are other planned outages scheduled for various generating plants that are shorter than 28 days. These outages are scheduled to remove screens from valves after turbine inspections, to remove zebra mussels from raw water piping, to chemically clean boiler tube internals, or to perform work on precipitators or other equipment that will not operate for extended periods without attention. All of these planned outages have been scheduled for periods that avoid high replacement power expenses.

Mothballed Generating Units

Q. Please define what is meant by mothballed generating units.

A. Mothballed refers to removing the generating unit from operations for the present, but maintaining the unit in a physical state such that it can become operational at a future date when market conditions are more conducive to its operation. Company witness David F. Ronk, Jr. refers to mothballed generating units in his testimony as units that have been placed in extended reserve shutdown.

Q. Please provide an update on the generating units that Consumers Energy currently has mothballed.

A. Consumers Energy currently has four combustion turbines mothballed – Gaylord 1-3 and Straits 1.

Q. When does the current mothball period for these units expire?

A. The current mothball period for these units expires on February 15, 2016.

Q. What is Consumers Energy's plan for these units?

A. The units will be returned to service and made available for dispatch.

ROR Projections

Q. How are the ROR projections for the fossil, hydro, and peaker units in this case developed?

A. The ROR projections in this case are developed using a five-year average (2010-2014) and are modified to reflect current operating conditions. This is shown in my Exhibit A-12 (RCS-2). Significant exceptions to the five-year average are described below.

Campbell Unit 2

The 2015 ROR for Campbell Unit 2 is projected to be 4.44% higher than the five-year average. The increase in ROR is due to the Urea Based Ammonia System ("UBAS").

Karn Unit 2

The 2015 ROR for Karn Unit 2 is projected to be 4.08% lower than the five-year average. The decrease in ROR is the result of turbine and boiler work completed in 2014.

Cobb Units 4 & 5

The 2015 ROR for Cobb Units 4 & 5 is projected to be 9.18% and 9.37% (respectively) higher than the five-year average. These units will be retired in 2016 due to increasingly stringent emissions standards. The increase in ROR is the result of decreased major maintenance as these units approach the end of their useful life.

Availability

Q. Do you provide projections for availability of the generating units?

A. Yes. The 2016 projected availability for each of the generating units is also shown in column (b) of Exhibit A-12 (RCS-2).

Q. Do you have an availability projection for the five-year, 2016-2020 forecast period?

A. Yes. The Company is projecting the overall availability of all the generating units will average about 85% over the five-year forecast period.

Nitrogen Oxides ("NO_x") Allowances

Q. Does Consumers Energy expect to incur expenses or revenues in 2016 related to the NO_x allowance program?

A. No.

Q. Please explain why Consumers Energy does not expect to incur expenses or revenues in 2016 related to the NO_x allowance program.

A. The Company has installed Selective Catalytic Reduction units ("SCRs") which have significantly reduced NO_x emissions and the need to purchase allowances. These SCRs were installed to comply with the Clean Air Interstate Rule ("CAIR").

Q. Please provide background on the status of CAIR.

A. CAIR was finalized in March 2005 and governs the emission of sulfur dioxide ("SO_2") and NO_x from fossil-fueled electric generating units through the use of an allowance based "cap and trade" program. In this program, one NO_x allowance permits the emission of one ton of NO_x, with the emissions cap and number of allocated allowances decreasing over time. The program regulates NO_x for both the ozone season (May through September) and on an annual basis. Phase I reductions began in 2009 for NO_x and in 2010 for SO_2. Phase II reductions are scheduled to begin in 2015 for both NO_x and SO_2.

In July 2008, CAIR was vacated by the United States Circuit Court for the District of Columbia ("DC Circuit Court"), but in a second ruling in December 2008 the DC Circuit Court reinstated the regulation and remanded it back to the EPA to be revised. In August 2011, the EPA finalized the CAIR replacement rule, known as the Cross-State Air Pollution Rule ("CSAPR"). Phase I of CSAPR was scheduled to take effect on January 1, 2012, and Phase II on January 1, 2014. However, on December 30, 2011, the United States Court of Appeals for the District of Columbia ("DC Court of Appeals") stayed the rule pending judicial review. As a result of that judicial review, CSAPR was ultimately vacated by the DC Court of Appeals on August 21, 2012. The case then went to the United States Supreme Court ("Supreme Court"). The Supreme Court granted an EPA petition for a rehearing in June 2013. On April 29, 2014, the Supreme Court reversed the DC Circuit Court's Opinion, and remanded the case back to the DC Circuit Court for additional litigation proceedings. On October 23, 2014, the DC Circuit Court ordered that the stay of CSAPR be lifted and that Phase I should be in effect as of January 1, 2015. CSAPR compliance levels for 2015-2016 were set at the 2012-2013 budget levels as finalized in the original rule.

Q. Can you please describe CSAPR?

A. Yes. CSAPR is a cap and trade rule, much like CAIR, except that it restricts interstate trading for relatively small changes in year-to-year emissions variability. Phase I took effect on January 1, 2015, and Phase II will take effect on January 1, 2017.

Q. Is Consumers Energy's fossil generating fleet subject to the requirements of CAIR and CSAPR?

A. Yes. Consumers Energy's fossil generating fleet must comply with the requirements of CAIR and CSAPR.

SO_2 Allowances

Q. Does Consumers Energy expect to incur expenses or revenues in 2016 related to the SO_2 allowance program?

A. No.

Q. Please explain why Consumers Energy does not expect to incur expenses or revenues in 2016 related to the SO_2 allowance program.

A. The Company has installed Flue Gas Desulfurization ("FGD") equipment in the form of Spray Dry Absorbers ("SDAs") at its Karn site, and will be installing SDAs and Dry

Sorbent Injection ("DSI") at its Campbell site in early 2016. As described later in my testimony, these FGDs were installed to comply with MATS, however an added benefit is the significant reduction in SO_2 levels.

Urea Expenses

Q. Are there PSCR expenses for which Consumers Energy is seeking recovery in 2016?

A. Yes. Exhibit A-13 (RCS-3) identifies the projected UBAS expenses through 2020.

Q. Please describe Exhibit A-13 (RCS-3).

A. In 2016, Consumers Energy projects spending $2.74 million for urea. In 2017, Consumers Energy expects to spend $2.80 million for urea. In 2018 through 2020, urea expenses are expected to be $2.85, $2.91, and $2.97 million, respectively.

Q. What is urea and what does Consumers Energy use it for?

A. Urea is a solid chemical that is converted into ammonia. The ammonia reacts with NO_x in the SCR and reduces the amount of NO_x emissions and the need to purchase NO_x allowances.

Q. Has the Michigan Public Service Commission ("MPSC" or the "Commission") previously approved the inclusion of urea in the Company's PSCR?

A. Yes. The Company requested and received approval to recover urea expenses as a PSCR expense in Case No. U-15415 (2008 PSCR Plan case). I recommend the same treatment in 2016.

Aqueous Ammonia Expenses

Q. Are there additional PSCR expenses for which you are seeking recovery in 2016?

A. Yes. Exhibit A-14 (RCS-4) identifies the projected aqueous ammonia expenses through 2020.

Q. Please describe Exhibit A-14 (RCS-4).

A. In 2016, Consumers Energy projects spending $1.47 million for aqueous ammonia as a necessary expense of operating Karn Units 1 & 2 and Zeeland Unit 2 (the Combined Cycle unit). In 2017, Consumers Energy expects to spend $1.50 million for aqueous ammonia associated with the operation of those units. In 2018 through 2020, expenses are expected to be $1.53, $1.56, and $1.59 million, respectively.

Q. How is aqueous ammonia used?

A. Aqueous ammonia performs the same function as urea, reducing the amount of NO_x emissions and the need to purchase NO_x allowances. In 2012, the Company replaced the UBAS at Karn Units 1 & 2 with a NO_x control system that uses aqueous ammonia. This new system was designed to be more reliable and effective at reducing NO_x emissions.

Q. Has the Commission previously approved the inclusion of aqueous ammonia in the Company's PSCR?

A Yes. The Company requested and received approval to recover aqueous ammonia expenses as a PSCR expense in MPSC Case No. U-17095 (2013 PSCR Plan case). I recommend the same treatment in 2016.

Lime Expenses

Q. Are there additional PSCR expenses for which you are seeking recovery in 2016?

A. Yes. Exhibit A-15 (RCS-5) identifies the projected lime expenses through 2020.

Q. Please describe Exhibit A-15 (RCS-5).

A. In 2016, Consumers Energy projects spending $11.06 million for lime. In 2017, Consumers Energy expects to spend $15.42 million for lime. In 2017 through 2020, lime expenses are expected to be $15.73, $16.04, and $16.36 million, respectively.

Q. How will lime be used?

A. The Company has installed, and will be installing, FGD units (a.k.a. SDA and DSI) at its Karn and Campbell sites. SDAs were installed at Karn Units 1 & 2 in 2014 and will be installed at Campbell Unit 3 in early 2016. Also, DSI will be installed at Campbell Units 1 & 2 in early 2016. Lime will be injected into the SDA/DSI where it will react with SO_2 and heavy metals found in the exhaust gases. When used in combination with Pulse Jet Fabric Filters ("PJFF"), SO_2 and heavy metal emissions are reduced, allowing the Company to comply with the new emission standards.

Q. Has the Commission previously approved the inclusion of lime in the Company's PSCR?

A. No. The Company requested recovery of lime expenses in Case No. U-17317 (2014 PSCR Plan case) and Case No. U-17678 (2015 PSCR Plan case), however, the Commission has not yet issued an order in these cases. Consumers Energy is seeking the Commission's approval to include lime expenses in this and all future PSCR Plan cases. Lime performs a function similar to urea and aqueous ammonia, which has been approved by the Commission. Lime removes SO_2, a constituent introduced to the combustion process by the fuel, and is thus a fuel-related expense. Furthermore, lime eliminates the need for SO_2 allowances. In Case No. U-14701-R, proceeds from the sale of excess SO_2 allowances were ordered returned to customers through PSCR rates, thus setting a precedent that these types of costs be addressed in the context of the PSCR.

<u>Activated Carbon Expenses</u>

Q. Are there additional PSCR expenses for which you are seeking recovery in 2016?

A. Yes. Exhibit A-16 (RCS-6) identifies the projected activated carbon expenses through 2020.

Q. Please describe Exhibit A-16 (RCS-6).

A. In 2016, Consumers Energy projects spending $2.69 million for activated carbon. In 2017, Consumers Energy expects to spend $4.55 million for activated carbon. In 2018 through 2020, activated carbon expenses are expected to be $4.64, $4.74, and $4.83 million, respectively.

Q. How will activated carbon be used?

A. Activated carbon will be used at both the Karn and Campbell sites. Activated carbon will be housed in a silo, metered, and blown into the flue gas duct through a series of injection lances for in-flight capture of mercury. The collective equipment is known as the activated carbon injection system. The mercury-laden carbon is captured in the PJFF and disposed with the fly ash. Activated carbon reduces mercury emissions, allowing the Company to comply with standards set forth in MATS.

Q. Has the Commission previously approved the inclusion of activated carbon in the Company's PSCR?

A. No. The Company requested recovery of activated carbon expense in Case No. U-17678 (2015 PSCR Plan case), however, the Commission has not yet issued an order in this case. Consumers Energy is seeking the Commission's approval to include activated carbon in this and all future PSCR Plan cases. Activated carbon performs a function similar to urea, which has been approved by the Commission. Activated carbon removes mercury, a constituent introduced to the combustion process by the fuel, and is thus a fuel-related expense.

Q. Does this conclude your testimony?

A. Yes it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17918
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2016	)	

EXHIBITS

OF

ROBERT C. SCHRAM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2015

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Major Outages in the 2016 PSCR Plan

Line	Unit	Days in 2016	Start Date	Stop Date
	(a)	(b)	(c)	(d)
1	Ludington 4	64	03/17/15	03/05/16
2	DE Karn 1	74	01/01/16	03/15/16
3	Campbell 1	35	01/09/16	02/13/16
4	Ludington 3	35	01/11/16	02/15/16
5	Ludington 5	330	01/31/16	12/26/16
6	Campbell 3	84	03/05/16	05/28/16
7	Ludington 1	112	09/11/16	12/31/16

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No.: U-17918
Exhibit: A-12 (RCS-2)
Witness: RCSchram
Date: September 2015
Page: 1 of 1

2016 PSCR Random Outage Rate Projections

Line	Plant (a)	Availability (b)	Periodic Factor (c)	2016 Projected ROR (d)	Actual ROR 2010-2014 (e)
1	Campbell 1	81.08%	10.55%	9.35%	8.29%
2	Campbell 2	85.68%	4.42%	10.35%	6.22%
3	Campbell 3	61.77%	30.04%	11.70%	10.12%
4	Cobb 4	80.97%	0.00%	19.03%	11.47%
5	Cobb 5	85.88%	0.00%	14.12%	6.02%
6	Karn 1	70.32%	22.13%	9.70%	20.15%
7	Karn 2	82.01%	5.74%	13.00%	14.41%
8	Karn 3	93.49%	0.00%	6.51%	23.42%
9	Karn 4	83.26%	9.50%	8.00%	17.54%
10	Weadock 7	82.60%	0.00%	17.40%	13.15%
11	Weadock 8	82.60%	0.00%	17.40%	12.33%
12	Whiting 1	80.00%	0.00%	20.00%	15.06%
13	Whiting 2	85.00%	0.00%	15.00%	11.54%
14	Whiting 3	85.00%	0.00%	15.00%	11.29%
15	Ludington 1	67.21%	31.49%	1.90%	0.76%
16	Ludington 2	94.31%	4.26%	1.50%	2.58%
17	Ludington 3	78.40%	20.08%	1.90%	0.93%
18	Ludington 4	69.82%	29.12%	1.50%	0.95%
19	Ludington 5	1.51%	74.98%	93.97%	1.28%
20	Ludington 6	93.22%	4.97%	1.90%	1.35%
21	CTs[1]	85.00%	0.00%	15.00%	7.80%
22	Hydros	94.13%	4.25%	1.70%	4.37%
23	Zeeland 2	89.74%	5.87%	4.66%	6.28%
24	Zeeland 1A	95.78%	1.76%	2.50%	1.45%
25	Zeeland 1B	95.77%	1.78%	2.50%	3.27%
26	Jackson 1	87.67%	8.20%	4.50%	-

[1]Does not include the Zeeland CTs.

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No.: U-17918
Exhibit: A-13 (RCS-3)
Witness: RCSchram
Date: September 2015

2016-2020 Urea Expense
(1,000's)

Line No.	Unit (a)	2016 (b)	2017 (c)	2018 (d)	2019 (e)	2020 (f)
1	**Campbell 2**	$634	$647	$660	$673	$686
2	**Campbell 3**	$2,107	$2,149	$2,192	$2,236	$2,281
3	**TTL**	$2,741	$2,796	$2,852	$2,909	$2,967

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No.: U-17918
Exhibit: A-14 (RCS-4)
Witness: RCSchram
Date: September 2015
Page: 1 of 1

2016-2020 Aqueous Ammonia Expense

(1,000's)

Line No.	Unit (a)	2016 (b)	2017 (c)	2018 (d)	2019 (e)	2020 (f)
1	**Karn 1**	$801	$817	$833	$850	$867
2	**Karn 2**	$491	$501	$511	$521	$531
3	**Zeeland 2**	$178	$181	$185	$189	$192
4	**TTL**	$1,470	$1,499	$1,529	$1,560	$1,590

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No.: U-17918
Exhibit: A-15 (RCS-5)
Witness: RCSchram
Date: September 2015
Page: 1 of 1

2016-2020 Lime Expense

(1,000's)

Line No.	Unit (a)	2016 (b)	2017 (c)	2018 (d)	2019 (e)	2020 (f)
1	**Karn 1&2**	$1,786	$1,822	$1,858	$1,895	$1,933
2	**Campbell 1&2**	$7,820	$10,635	$10,848	$11,065	$11,286
3	**Campbell 3**	$1,452	$2,962	$3,021	$3,082	$3,143
4	**TTL**	$11,058	$15,419	$15,727	$16,042	$16,362

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No.: U-17918
Exhibit: A-16 (RCS-6)
Witness: RCSchram
Date: September 2015
Page: 1 of 1

2016-2020 Activated Carbon Expense

(1,000's)

Line No.	Unit (a)	2016 (b)	2017 (c)	2018 (d)	2019 (e)	2020 (f)
1	**Karn 1&2**	$538	$731	$746	$761	$776
2	**Campbell 1&2**	$835	$1,135	$1,158	$1,181	$1,204
3	**Campbell 3**	$1,316	$2,685	$2,738	$2,793	$2,849
4	**TTL**	$2,689	$4,551	$4,642	$4,735	$4,829

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17918
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2016	)	

DIRECT TESTIMONY

OF

JASON M. SHORE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2015

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Jason M. Shore 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 at Consumers Energy?

A. I am the Director of Planning and Analysis.

Q. How long have you been employed with Consumers Energy?

A. I have been employed with Consumers Energy for 17 years.

Q. Please state your educational background and work experience.

A. I graduated from Michigan State University in May 1998 with a Bachelor of Arts Degree in Accounting. In June 1998, I joined Consumers Energy's General Accounting Department in the Electric Fuel and Reconciliation Section. In July 2000, I transferred to the Financial and Regulatory Reporting Department where I performed various duties until April 2001, when I transferred back to the Company's Electric Fuel and Reconciliation Section within the General Accounting Department. In 2006, I became the Manager of Financial Results within the General Accounting Department. In March 2009, I assumed the role of Director of General Accounting. As Director of General Accounting, my responsibilities included the accounting for electric generation and power supply expenses, power supply cost over- or under-recoveries, accounting for cost of gas sold, gas cost over- or under-recoveries, internal financial statements, corporate budgeting, regulatory reporting requirements, and various other financial analytics and studies. In May 2014, I assumed my current role as Director of Planning and Analysis. As Director of Planning and Analysis, my responsibilities include oversight of the annual budget process, the Long Term Financial Plan ("LTFP") process, O&M analytics, and the sales forecast and outlook.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I have previously testified in Case No. U-13917-R, Consumers Energy's 2004 Power Supply Cost Recovery ("PSCR") Reconciliation Case and Case No. U-14274-R, Consumers Energy's 2005 PSCR Reconciliation Case. I have also testified in Case No. U-16564, Consumers Energy's MCL 460.10d(4) Reconciliation Case, and in Case No. U-16736, Consumers Energy's 2011 Energy Optimization Reconciliation Case. I provided supplemental direct testimony in Case No. U-17082, Consumers Energy's Pilot Revenue Decoupling Mechanism Reconciliation Case. Most recently, I testified in Case No. U-17473, Consumers Energy's Securitization of Qualified Costs, and Case No. U-17882, Consumers Energy's Gas General Rate Case.

Q. Please explain the purpose of your direct testimony in this proceeding.

A. The purpose of my testimony is to present the Company's electric deliveries, generation requirements, and peak demand forecasts for 2016 to 2020.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am providing the following exhibits:

Exhibits	Description
A-17 (JMS-1)	2016 Forecast of Calendar Total Electric Deliveries

A-18 (JMS-2)	Forecast of Annual Calendar Deliveries
A-19 (JMS-3)	Forecast of Total Monthly Generation Requirements
A-20 (JMS-4)	Forecast of Monthly Peak Demand
A-21 (JMS-5)	Forecasted System Load Factor Based on Summer Peak Demand

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

A. Yes.

II. KEY ELECTRIC DELIVERY AND DEMAND VARIABLES

Q. What are the key variables that affect the electric deliveries and demand forecasts?

A. The key variables affecting the forecasts are weather, the economy, and demographics.

Q. Please describe the impact of weather on the forecasting process and the assumptions you made regarding weather variables in the forecast.

A. Weather is the primary variable used in the forecasting models to capture the seasonal variation in deliveries and demand across the year. This is accomplished using a 15-year average of Heating Degree Days (“HDD”) and Cooling Degree Days (“CDD”) in the econometric models.

Q. Please describe the impact of the economy on the forecasting process and the assumptions you made regarding these variables in the forecast.

A. The Company uses economic indicators to capture the growth expectations related to increased economic activity in its service territory. Primarily, this includes employment and industrial production forecasts provided by IHS Global Insight (“Global Insight”).

Q. Please describe the impact of demographics on the forecasting process.

A. Population projections are used in the development of the long-term customer forecast. In particular, the forecast of residential customers is derived from the county level population projections provided by Global Insight.

III. FORECASTING METHODOLOGY

Q. Please briefly describe the process used to prepare the electric deliveries and peak demand forecasts.

A. The electric deliveries and peak demand forecasts are prepared using a combination of econometric and end-use techniques. Typically a six-step process is used in developing the electric deliveries forecast. The first step in the process is gathering the class level historical monthly electric delivery, monthly customer counts, monthly number of billing days, monthly binaries to account for temporal cycles, and daily temperature information. Most observations are entered directly into the modeling framework as dependent and explanatory variables. The daily temperature information, however, is transformed to monthly HDD and CDD variables prior to entering the modeling framework. The second step is importing the Michigan population, manufacturing production, manufacturing employment, and automotive employment variables from Global Insight into the sales modeling framework. The third step is importing electric use forecasts for wholesale, electric vehicles, polycrystalline production, and energy savings from the Company's Smart Energy and Energy Efficiency ("EE") programs. These forecasts are exogenous to the modeling framework and were either adopted by the Commission in prior electric rate cases, reflect current industry expectations, or are based on end-use analyses. The fourth step is reviewing the imported observations to identify data issues before running the econometric models. In situations when erroneous data is observed, it is either corrected where possible or removed from the models. The fifth step is executing the regression functions and reviewing the corresponding statistical metrics. The final step in the sales forecasting process is to combine the regression forecasts with the external forecasts imported in step three.

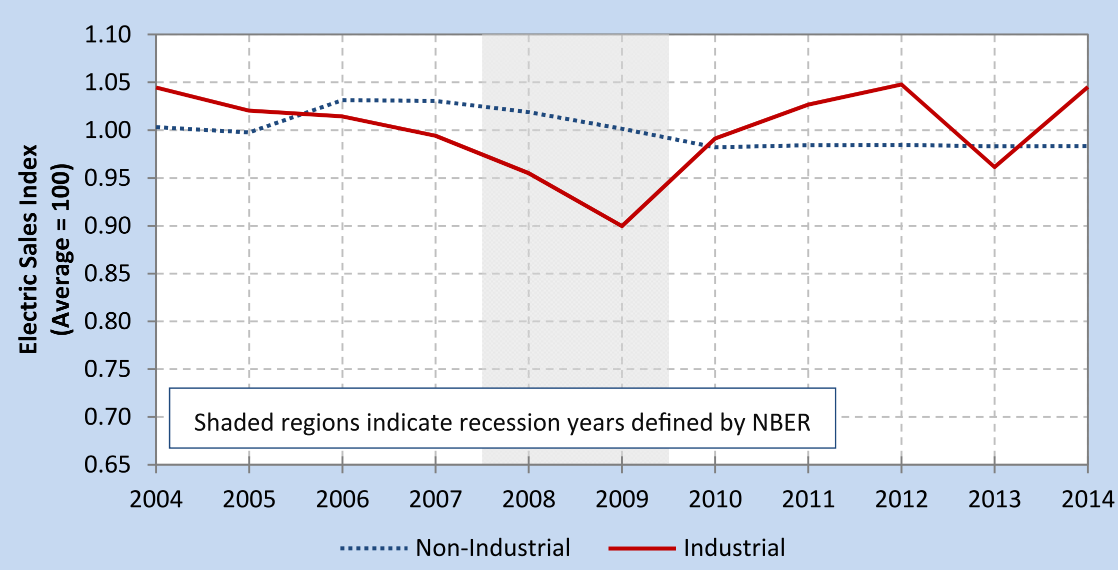
The peak demand forecast process is similar to that of the electric delivery forecast. The first step in the peak demand forecast is importing the Company's monthly system peak demands, corresponding minimum and maximum daily temperature, forecasted base electric deliveries, seasonal binaries, and number of customers into the demand modeling framework. A weighted sum of the minimum and maximum temperatures is used to develop the peak CDD and HDD variables prior to importing into the model framework. The second step is reviewing the imported observations to identify data issues before executing the peak demand econometric model. The third step is regressing the observed peak demands against the seasonal binary, degree day, and forecasted base electric sales. The final step in the peak demand forecasting process is combining the results of the econometric model with the planned peak reductions from the Company's Dynamic Peak Pricing ("DPP") and Direct Load Administration ("DLA").

IV. <u>HISTORICAL AND FORECASTED ELECTRIC DELIVERIES</u>

Q. Please explain the historical growth in electric deliveries.

A. Weather normalized electric deliveries shrank at a 0.39 percent Compounded Annual Growth Rate ("CAGR") from 2004 to 2014, with most of the observed loss occurring in the industrial class. This is especially evident when looking at the trend of industrial and non-industrial deliveries shown in Figure 1. Prior to 2007, non-industrial electric deliveries grew about one percent per year while industrial deliveries decreased about half a percent per year as the automotive sector contracted in Michigan. Although both indexes decreased during the 2007 to 2009 recession, the effect on the industrial class was much more pronounced. Industrial electric deliveries decreased about five percent per year from 2007 to 2009 versus a one percent decrease for non-industrial electric deliveries. Although industrial deliveries returned to near 2004 levels by 2012, much of this gain was lost in 2013.

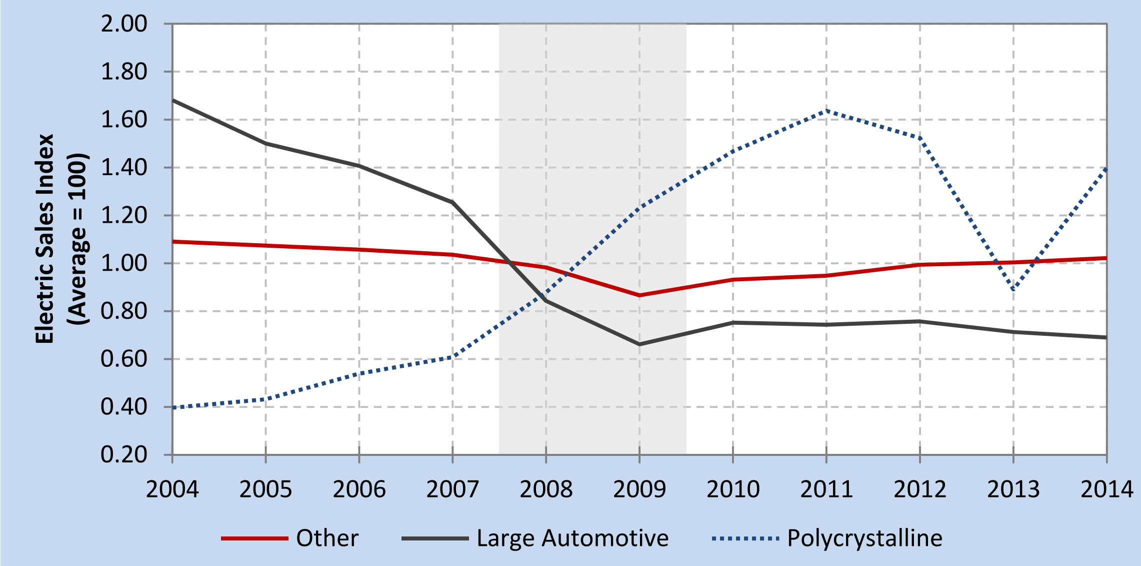
Figure 1 - Historical Electric Sales



Q. What caused the increase in industrial electric deliveries in 2012 and then a sudden decrease in 2013?

A. Industrial electric deliveries increased 5.31 percent per year from 2009 to 2012. However, the increase is not homogeneous across all sectors in the class. As shown in Figure 2, electric deliveries grew precipitously in polycrystalline manufacturing until 2012. The sudden decrease in 2013 is attributed to international trade restrictions imposed by East Asian countries. While the polycrystalline industry was booming, the large automotive and other industrial sectors exhibited only moderate growth in electric deliveries. Indeed, over the past decade electric deliveries in these latter two sectors decreased 1.7 percent per year while increasing 14 percent per year in the polycrystalline industry. Polycrystalline manufacturing rebounded in 2014, increasing the industrial electric deliveries close to 2012 levels.

Figure 2 - Historical Industrial Sales



Q. Are you expecting the trend in industrial deliveries to continue?

A. Total electric deliveries are expected to increase in the short-term as the polycrystalline industry returns to 2012 levels by 2018. As mentioned earlier, the short-term ebb of polycrystalline production reflects trade policy issues in that industry. In the long-run, however, as these issues are resolved, electric deliveries are expected to return to the pre-2013 levels.

Q. What are the electric delivery expectations from 2014 to 2020?

A. Total electric deliveries are expected to increase 0.4 percent per year from 2014 to 2020. The 2016 monthly class level results of the electric deliveries forecast process is shown in Exhibit A-17 (JMS-1). The annual class level results for 2016 to 2020 is shown in Exhibit A-18 (JMS-2).

Q. Are you assuming continued energy efficiency savings as part of your electric deliveries forecast?

A. Yes. Energy efficiency savings are predicted to continue growing at one percent per year through the forecast period.

Q. Please describe the process used to determine the Company's total generation requirements.

A. Consistent with prior PSCR Plan filings, the forecasted total electric deliveries are increased by a line loss factor of 6.4 percent to determine the Company's total generation requirements shown in Exhibit A-19 (JMS-3).

V. FORECASTED PEAK DEMAND

Q. Please describe the forecasted growth in peak demand.

A. The Company uses regression analysis based on the predicted level of electric deliveries to forecast the peak demand. Weather normal peak demand grew at a 1.6 percent CAGR from 2003 to 2007, but reversed much of this trend during the 2007 to 2009 recession. Looking forward, peak demand is expected to increase 2.0 percent per year from 2014 to 2020. The monthly system level results of the electric peak demand forecast process is shown in Exhibit A-20 (JMS-4).

Q. Please explain the impact to the peak demand forecast from the Company's future Smart Energy programs.

A. The peak demand forecast is reduced by approximately 59 megawatts ("MW") in 2016, and increasing to 265 MW by 2020, for the Company's load administration, peak pricing, prepaid meters, and web portal programs. These programs are being implemented as part of the Company's Smart Energy infrastructure investments in which customers are provided technology and information to better manage their impact on the Company's system.

Q. To what extent is the Company's EE program expected to impact peak demand?

A. The EE program is projected to reduce peak demand 335 MW in 2016. The cumulative reductions produced by the EE program are expected to be 515 MW by 2020.

Q. Please explain the process used to identify the peak demand impacts of the Company's Smart Energy and EE programs.

A. The Company developed hourly load profiles for the Smart Energy and EE programs. The monthly energy savings associated with each of these programs are integrated with the corresponding load shape to develop hourly demand savings curves.

Q. Please explain Exhibit A-21 (JMS-5).

A. Exhibit A-21 (JMS-5) provides a summary of the system load factor based on the Company's official 2016 to 2020 electric delivery and summer peak demand forecasts.

Q. Does this conclude your testimony?

A. Yes.

STATE OF MICHIGAN

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EXHIBITS

OF

JASON M. SHORE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2015

Michigan Public Service Commission
Consumers Energy Company
2016 Forecast of Calendar Total Electric Deliveries
(MWh)

Case No.: U-17918
Exhibit: A-17 (JMS-1)
Witness: JMShore
Date: September 2015

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Month	Residential	Commercial	Industrial	Street Lighting	Inter-departmental	Wholesale	Total
1	January	1,277,542	967,474	1,008,355	14,783	1,926	29,804	3,299,885
2	February	1,011,895	893,247	1,046,944	14,133	4,410	25,900	2,996,529
3	March	1,025,292	972,063	1,081,304	12,059	3,700	27,833	3,122,250
4	April	869,944	893,048	1,084,625	9,881	3,395	27,971	2,888,865
5	May	854,373	998,199	1,130,135	9,020	1,797	28,953	3,022,477
6	June	993,015	1,077,159	1,157,528	9,649	5,690	30,547	3,273,588
7	July	1,298,720	1,147,094	1,110,424	11,157	2,600	32,721	3,602,715
8	August	1,192,669	1,090,419	1,145,388	12,323	3,219	31,145	3,475,164
9	September	925,136	1,001,820	1,130,370	14,184	3,211	30,137	3,104,857
10	October	851,658	955,723	1,208,032	15,483	2,789	31,162	3,064,848
11	November	916,710	929,121	1,129,231	17,035	2,918	29,978	3,024,993
12	December	1,198,260	987,636	1,066,663	17,311	3,102	29,100	3,302,072
13	Annual	12,415,214	11,913,004	13,298,998	157,018	38,757	355,251	38,178,242

Michigan Public Service Commission
Consumers Energy Company
2016 Forecast of Calendar Full Service Electric Deliveries
(MWh)

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Month	Residential	Commercial	Industrial	Street Lighting	Inter-departmental	Wholesale	Total
1	January	1,277,542	882,058	757,962	14,783	1,926	29,804	2,964,075
2	February	1,011,895	812,933	820,876	14,133	4,410	25,900	2,690,147
3	March	1,025,292	885,502	834,075	12,059	3,700	27,833	2,788,460
4	April	869,944	810,414	840,401	9,881	3,395	27,971	2,562,007
5	May	854,373	908,211	864,296	9,020	1,797	28,953	2,666,650
6	June	993,015	988,610	888,375	9,649	5,690	30,547	2,915,886
7	July	1,298,720	1,049,282	827,381	11,157	2,600	32,721	3,221,862
8	August	1,192,669	1,001,133	853,292	12,323	3,219	31,145	3,093,782
9	September	925,136	907,102	859,169	14,184	3,211	30,137	2,738,938
10	October	851,658	866,703	925,846	15,483	2,789	31,162	2,693,641
11	November	916,710	849,281	872,559	17,035	2,918	29,978	2,688,481
12	December	1,198,260	903,764	822,561	17,311	3,102	29,100	2,974,098
13	Annual	12,415,214	10,864,995	10,166,793	157,018	38,757	355,251	33,998,028

Michigan Public Service Commission
Consumers Energy Company
2016 Forecast of Calendar ROA Service Electric Deliveries
(MWh)

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Month	Residential	Commercial	Industrial	Street Lighting	Inter-departmental	Wholesale	Total
1	January	-	85,416	250,393	-	-	-	335,809
2	February	-	80,314	226,068	-	-	-	306,382
3	March	-	86,561	247,229	-	-	-	333,790
4	April	-	82,634	244,224	-	-	-	326,858
5	May	-	89,989	265,839	-	-	-	355,828
6	June	-	88,549	269,153	-	-	-	357,702
7	July	-	97,811	283,042	-	-	-	380,853
8	August	-	89,286	292,096	-	-	-	381,382
9	September	-	94,719	271,200	-	-	-	365,919
10	October	-	89,020	282,187	-	-	-	371,206
11	November	-	79,840	256,672	-	-	-	336,511
12	December	-	83,872	244,102	-	-	-	327,973
13	Annual	-	1,048,009	3,132,205	-	-	-	4,180,214

Michigan Public Service Commission
Consumers Energy Company
Forecast of Annual Calendar Deliveries
(MWh)

Case No.: U-17918
Exhibit: A-18 (JMS-2)
Witness: JMShore
Date: September 2015

Line No.	Description	(a) 2016	(b) 2017	(c) 2018	(d) 2019	(e) 2020
1	Total Deliveries					
2	Residential	12,415,214	12,321,697	12,402,713	12,304,051	12,330,033
3	Commercial	11,913,004	11,867,418	11,853,388	11,763,567	11,772,191
4	Industrial	13,298,998	13,753,612	13,919,697	14,140,118	14,360,869
5	Street Lighting	157,018	153,899	150,812	147,743	144,677
6	Interdepartmental	38,757	38,633	38,562	38,722	38,728
7	Wholesale	355,251	356,822	358,404	359,867	359,867
8	Total Deliveries	38,178,242	38,492,080	38,723,576	38,754,068	39,006,365
9	Total Full Service					
10	Residential	12,415,214	12,321,697	12,402,713	12,304,051	12,330,033
11	Commercial	10,864,995	10,821,490	10,808,368	10,726,184	10,736,582
12	Industrial	10,166,793	10,544,103	10,650,893	10,808,884	10,964,826
13	Street Lighting	157,018	153,899	150,812	147,743	144,677
14	Interdepartmental	38,757	38,633	38,562	38,722	38,728
15	Wholesale	355,251	356,822	358,404	359,867	359,867
16	Total Full Service	33,998,028	34,236,643	34,409,751	34,385,451	34,574,713
17	Total ROA Service					
18	Residential	-	-	-	-	-
19	Commercial	1,048,009	1,045,928	1,045,020	1,037,382	1,035,610
20	Industrial	3,132,205	3,209,508	3,268,805	3,331,234	3,396,042
21	Street Lighting	-	-	-	-	-
22	Interdepartmental	-	-	-	-	-
23	Wholesale	-	-	-	-	-
24	Total ROA Service	4,180,214	4,255,437	4,313,825	4,368,617	4,431,652

Michigan Public Service Commission
Consumers Energy Company
Forecast of Total Monthly Generation Requirements
(MWh)

Case No.: U-17918
Exhibit: A-19 (JMS-3)
Witness: JMShore
Date: September 2015

		(a)	(b)	(c)	(d)	(e)
Line No.	Month	2016	2017	2018	2019	2020
1	January	3,522,861	3,552,434	3,581,897	3,584,840	3,600,614
2	February	3,199,047	3,144,274	3,170,876	3,173,538	3,269,892
3	March	3,334,648	3,364,456	3,391,003	3,393,779	3,408,665
4	April	3,084,564	3,112,435	3,137,402	3,139,966	3,153,719
5	May	3,229,565	3,259,267	3,283,711	3,286,397	3,300,787
6	June	3,497,921	3,527,869	3,554,208	3,557,132	3,572,812
7	July	3,847,891	3,878,254	3,907,966	3,910,936	3,927,520
8	August	3,710,831	3,740,887	3,770,660	3,773,698	3,790,384
9	September	3,314,643	3,343,274	3,370,258	3,373,021	3,387,844
10	October	3,274,563	3,304,524	3,329,338	3,332,062	3,346,665
11	November	3,231,614	3,260,562	3,285,523	3,288,214	3,302,642
12	December	3,526,877	3,533,970	3,561,977	3,564,900	3,580,564
13	Annual	40,775,024	41,022,205	41,344,820	41,378,484	41,642,109

Michigan Public Service Commission
Consumers Energy Company
Forecast of Monthly Full Service Generation Requirements
(MWh)

Case No.: U-17918
Exhibit: A-19 (JMS-3)
Witness: JMShore
Date: September 2015

Line No.	Month	(a) 2016	(b) 2017	(c) 2018	(d) 2019	(e) 2020
1	January	3,162,163	3,182,478	3,208,110	3,205,163	3,214,694
2	February	2,869,958	2,806,967	2,830,049	2,827,290	2,917,932
3	March	2,976,120	2,997,224	3,020,160	3,017,335	3,026,555
4	April	2,733,481	2,752,767	2,773,909	2,770,693	2,778,735
5	May	2,847,366	2,868,255	2,888,650	2,885,307	2,893,828
6	June	3,113,709	3,135,097	3,157,391	3,154,436	3,164,482
7	July	3,438,811	3,461,737	3,487,069	3,483,904	3,494,653
8	August	3,301,183	3,325,690	3,350,986	3,347,974	3,358,968
9	September	2,921,604	2,946,168	2,968,581	2,965,475	2,974,864
10	October	2,875,845	2,901,711	2,921,652	2,918,396	2,927,549
11	November	2,870,162	2,895,263	2,904,247	2,912,768	2,922,268
12	December	3,174,596	3,178,025	3,200,476	3,197,350	3,207,481
13	Annual	36,284,998	36,451,382	36,711,281	36,686,092	36,882,009

Michigan Public Service Commission
Consumers Energy Company
Forecast of Monthly ROA Generation Requirements
(MWh)

Case No.: U-17918
Exhibit: A-19 (JMS-3)
Witness: JMShore
Date: September 2015

Line No.	Month	(a) 2016	(b) 2017	(c) 2018	(d) 2019	(e) 2020
1	January	360,698	369,955	373,786	379,677	385,920
2	February	329,089	337,307	340,827	346,248	351,959
3	March	358,528	367,232	370,844	376,444	382,110
4	April	351,082	359,667	363,492	369,273	374,984
5	May	382,199	391,011	395,061	401,091	406,959
6	June	384,213	392,772	396,817	402,696	408,331
7	July	409,080	416,517	420,897	427,033	432,867
8	August	409,648	415,197	419,673	425,723	431,416
9	September	393,039	397,107	401,677	407,546	412,980
10	October	398,718	402,814	407,687	413,666	419,116
11	November	361,451	365,299	381,276	375,445	380,374
12	December	352,281	355,946	361,502	367,550	373,083
13	Annual	4,490,026	4,570,823	4,633,539	4,692,392	4,760,099

Michigan Public Service Commission
Consumers Energy Company
Forecast of Total Monthly Peak Demand
(MW)

Case No.: U-17918
Exhibit: A-20 (JMS-4)
Witness: JMShore
Date: September 2015

Line No.	Month	(a) 2016	(b) 2017	(c) 2018	(d) 2019	(e) 2020
1	January	5,940	5,990	6,070	6,065	6,097
2	February	5,733	5,701	5,765	5,809	5,882
3	March	5,733	5,764	5,832	5,877	5,908
4	April	5,325	5,370	5,438	5,447	5,475
5	May	6,070	6,121	6,195	6,222	6,260
6	June	7,743	7,784	7,866	7,913	7,959
7	July	8,382	8,339	8,332	8,326	8,371
8	August	7,938	7,912	7,950	7,969	8,022
9	September	7,084	7,117	7,193	7,221	7,264
10	October	5,822	5,863	5,931	5,952	5,990
11	November	5,797	5,846	5,916	5,923	5,953
12	December	6,147	6,159	6,233	6,246	6,279
13	Peak Demand	8,382	8,339	8,332	8,326	8,371

Michigan Public Service Commission
Consumers Energy Company
Forecast of Monthly Full Service Peak Demand
(MW)

Case No.: U-17918
Exhibit: A-20 (JMS-4)
Witness: JMShore
Date: September 2015

Line No.	Month	(a) 2016	(b) 2017	(c) 2018	(d) 2019	(e) 2020
1	January	5,420	5,460	5,539	5,526	5,549
2	February	5,243	5,173	5,232	5,267	5,353
3	March	5,227	5,245	5,302	5,332	5,360
4	April	4,775	4,806	4,867	4,868	4,887
5	May	5,483	5,547	5,615	5,633	5,656
6	June	7,161	7,190	7,264	7,298	7,341
7	July	7,780	7,726	7,715	7,702	7,705
8	August	7,344	7,311	7,343	7,351	7,393
9	September	6,488	6,513	6,579	6,599	6,638
10	October	5,238	5,278	5,344	5,357	5,382
11	November	5,263	5,307	5,354	5,365	5,386
12	December	5,643	5,645	5,711	5,719	5,752
13	Peak Demand	7,780	7,726	7,715	7,702	7,705

Michigan Public Service Commission
Consumers Energy Company
Forecast of Monthly ROA Service Peak Demand
(MW)

Case No.: U-17918
Exhibit: A-20 (JMS-4)
Witness: JMShore
Date: September 2015

Line No.	Month	(a) 2016	(b) 2017	(c) 2018	(d) 2019	(e) 2020
1	January	520	530	531	539	548
2	February	490	528	533	542	529
3	March	507	519	530	545	547
4	April	550	565	571	579	588
5	May	587	574	580	589	604
6	June	581	594	602	614	618
7	July	602	613	617	624	666
8	August	593	601	608	619	629
9	September	596	604	614	621	626
10	October	584	585	587	595	608
11	November	533	539	563	558	567
12	December	504	514	522	527	527
13	Peak Demand	602	613	617	624	666

Michigan Public Service Commission
Consumers Energy Company
Forecasted System Load Factor Based on Summer Peak Demand

Case No.: U-17918
Exhibit: A-21 (JMS-5)
Witness: JMShore
Date: September 2015

Line No.	Month	(a) 2016	(b) 2017	(c) 2018	(d) 2019	(e) 2020
1	Total Deliveries (GWh)	38,178	38,492	38,724	38,754	39,006
2	System Efficiency (%)	93.6%	93.8%	93.7%	93.7%	93.7%
3	Generation Requirements (GWh)	40,775	41,022	41,345	41,378	41,642
4	Summer Peak Demand (MW)	8,382	8,339	8,332	8,326	8,371
5	System Load Factor (%)	55.5%	56.2%	56.6%	56.7%	56.8%

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17918
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2016	)	

DIRECT TESTIMONY

OF

SARA T. WALZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2015

Q. Please state your name and business address.

A. Sara T. Walz, 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

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

Q. In what capacity are you employed?

A. I am a General Engineering Technical Analyst in the Electric Sourcing and Resource Planning Section of the Energy Supply Operations Department.

QUALIFICATIONS

Q. Please briefly describe your educational background.

A. I received a Bachelor of Arts Degree in Mathematics in 2006 from Michigan State University and a Master of Science Degree in Applied Mathematics in 2007 from North Carolina State University.

Q. Please describe your business and professional experience.

A. I joined the Company's Transactions and Resource Planning Department in January 2008. I was responsible for the Financial Transmission Rights monthly and annual allocation and auction. In September 2009, I began working in the Production Cost Modeling area of Transactions and Resource Planning, where I have been the primary modeler for near-term fuel and purchased power expenses using the PROMOD production cost modeling software.

Q. What are your present responsibilities and duties as a General Engineering Technical Analyst?

A. Presently, I am responsible for modeling and analysis of fuel and purchased and net interchange power costs that are used in developing the Power Supply Cost Recovery ("PSCR") Plan and updating the PSCR Factor. Additionally, I am responsible for replacement power cost analysis, generation unit outage analysis, fuel strategy scenario development, and related matters.

Q. Have you provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I provided testimony in the following MPSC cases:

- U-17095, the 2013 PSCR Plan Case;
- U-17095-R, the 2013 PSCR Reconciliation Case;
- U-17317, the 2014 PSCR Plan Case and Revised Case;
- U-17317-R, the 2014 PSCR Reconciliation Case; and
- U-17678, the 2015 PSCR Plan Case.

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

A. The purpose of my testimony is to forecast costs of fuel and purchased and net interchange power needed to fulfill the Company's system requirements for 2016. These costs are shown on a monthly basis for 2016 and on an annual basis for 2016 through 2020.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exhibits A-22 (STW-1), a monthly summary of the projected 2016 fuel and purchased and net interchange power expenses; A-23 (STW-2), an annual summary for years 2016-2020 of fuel and purchased and net interchange power expenses; and A-24 (STW-3), a list of the entities from which the Company expects to purchase power for years 2016-2020.

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

A. Yes.

<u>POWER SUPPLY COSTS</u>

Q. What are the Company's forecasts of 2016 costs of fuel and purchased and net interchange power?

A. These forecasts are shown in Exhibit A-22 (STW-1), pages 1-3.

Q. Do you consider the forecast data set forth in this exhibit to be a reasonable forecast for 2016?

A. Yes, I do. This PSCR Plan was developed using an economic dispatch computer program, which is used to produce the Company’s budget and operating forecasts for fuel and purchased and net interchange power. This 2016 forecast was produced using up-to-date assumptions and data that were reviewed by the responsible departments before they were input into the program. The results have been reviewed for reasonableness and for consistency with input and assumptions.

Q. Did you use the same economic dispatch program for this case as was used for the Company’s 2015 PSCR Plan case, MPSC Case No. U-17678?

A. Yes. I used the PROMOD Production Costing Program for this case.

Q. Please further describe Exhibit A-22 (STW-1).

A. This exhibit details the Company’s planned sources and corresponding costs of energy to be supplied in 2016.

Q. How were these figures derived?

A. They were derived from PROMOD, which simulates the dispatch of the Company's generating resources and purchased and interchange power resources to meet projected customer electric demand requirements. Pages 1-3 of Exhibit A-22 (STW-1) show the monthly results for 2016, which were then totaled to obtain the annual results, which are also shown on Exhibit A-23 (STW-2), along with the years 2017 through 2020. The main inputs to PROMOD were projected system loads, unit heat rates, maintenance schedules, unit random outage rates, fuel costs, unit net demonstrated capabilities, and purchased and interchange power availability and costs. The model used by PROMOD is structured to align as closely as possible with the way that the Midcontinent Independent System Operator ("MISO") operates and administers the Midwest Energy Market.

Q. Who provided you with the input data relating to projected system loads and system generation requirements?

A. The system load and system generation requirements data was provided to me by Company witness Jason M. Shore. His testimony and exhibits set forth and explain the relevant assumptions and calculations.

Q. What was the source of your input information for fuel costs?

A. Coal, oil, and natural gas costs were provided by Company witness Jim K. Chilson II. His testimony and exhibits set forth and explain the relevant assumptions and calculations.

Q. Who provided input information for Consumers Energy's generating units?

A. The input information for Consumers Energy's generating units was provided by Company witness Robert C. Schram. His testimony and exhibits set forth and explain the relevant assumptions and calculations.

<u>CONSUMERS ENERGY OWNED GENERATING UNITS</u>

Q. Are there any major changes to Consumers Energy's owned units for this PSCR Plan case?

A. Yes. Included in this PSCR Plan case is an upgrade to the Ludington 4 Unit resulting in an increase in generating capacity of 25.5 MW, assumed to be in-service beginning March 2016; an upgrade to the Ludington 5 Unit resulting in an increase in generating capacity of 25.5 MW, assumed to be in-service beginning January 2017; an upgrade to the Ludington 1 Unit resulting in an increase in generating capacity of 25.5 MW, assumed to be in-service beginning August 2017; an upgrade to the Ludington 3 Unit resulting in an increase in generating capacity of 25.5 MW, assumed to be in-service beginning August 2018; and an upgrade to the Ludington 6 Unit resulting in an increase in generating capacity of 25.5 MW, assumed to be in-service beginning August 2019. These upgrades are part of the major unit overhaul project at the Ludington Pumped Storage Plant which began in 2013. Additionally, there is the addition of 6 MW of nameplate capacity at the Company-owned solar generating facility assumed to be phased in beginning May 2016.

Q. What other major changes to Consumers Energy's owned units are included in this PSCR Plan case?

A. Consumers Energy is planning to retire seven of the Company's coal units (Cobb 4 and 5; Weadock 7 and 8; and Whiting 1, 2, and 3) in lieu of retrofitting the units to comply with the Mercury and Air Toxics Standard rule that would otherwise be effective for these units on April 16, 2016. Additionally, this case reflects the Company's continued decision to mothball or place in extended reserve shutdown status several combustion turbine ("CT") units. Additionally, the Company is securing 542 MW of capacity with the Jackson Plant, a natural gas-fueled generating unit, assumed to be in the Company's service January 2016.

Q. Please describe the Jackson Plant.

A. The Jackson Plant is a 542 MW natural gas-fueled combined cycle generating plant built by the Kinder Morgan Power Company that went into commercial operation in 2002. The plant has six General Electric LM6000 CT and one General Electric 7EA CT. Each CT's hot turbine exhaust flow is connected to its own Heat Recovery Steam Generator ("HRSG") that produces steam. Steam from the seven HRSGs feeds two Steam Turbine Generators.

Q. Please describe any limiting factors that could restrict the economic dispatch of the Jackson Plant.

A. Based on the Jackson Plant air permit,[1] the 7EA CT cannot exceed 113.1 tons of Nitrogen Oxide ("NO_x") emissions in a rolling 12-month period, and each LM6000 CT cannot exceed 80.4 tons of NO_x emissions in a rolling 12-month period.[2]

[1] Renewable Operating Permit No: MI-ROP-N6626-2014a,
[2] Page 20 of 56 and page 25 of 56 in ROP No: MI-ROP-N6626-2014a.

Q. How has the limitation of NO_x emissions been modeled in PROMOD?

A. Economic dispatch of the Jackson Plant has been limited using a price adder on the incremental cost of energy. For modeling purposes, a price per pound of NO_x emissions was applied as a dispatch fee so that the facility does not exceed the approximate limit of 595 tons of emissions in calendar year 2016.

Q. Is this a reasonable approach to limiting the economic dispatch of the facility?

A. Yes. By including the dispatch fee in the incremental cost of energy, the commitment and dispatch of the facility will respond to price signals, which will result in increased production during periods of relatively high energy prices compared to the variable cost to produce power and decreased production during periods of relatively low energy prices compared to the variable cost to produce power.

Q. On line 4 of Exhibit A-22 (STW-1) you use the term “Station Power.” Please explain that term.

A. Station Power is the amount of electricity that a generating unit uses to operate its own generating unit components such as motors, pumps, lighting, heating, etc. When a generating unit is operating, all of the Station Power is subtracted from the gross output of the generating unit to provide the net output that is reported on lines 1 and 2 of Exhibit A-22 (STW-1). When a generating unit is offline, Station Power usage is accounted for as negative generation. Lines 1 and 2 of Exhibit A-22 (STW-1) reflect the steam generation after subtracting the forecasted station power used during periods where units are offline. The total system requirement on line 13 of Exhibit A-22 (STW-1) includes Station Power used while offline, so I show a separate line item, line 4, to balance the exhibit.

POWER PURCHASE AGREEMENTS

Q. On line 11 of Exhibit A-22 (STW-1) you use the term "Purchased (NUGs)." Please explain that term.

A. That term refers to forecasted purchases of energy from Non-Utility Generators ("NUGs") with whom the Company has Power Purchase Agreements. A list of the entities from which power is projected to be purchased for the years 2016 through 2020 is found on Exhibit A-24 (STW-3), pages 1-18, under the headings "Existing Energy-Only Agreements," "Green Generation Program Agreements," "Existing Energy & Capacity Agreements," and "Renewable Energy Plan Agreements." This exhibit also outlines the rates for such purchases and the current duration of the contracts.

Q. How were purchases from the suppliers listed on Exhibit A-24 (STW-3) estimated?

A. The estimate was made using one of two methods.

1. For non-dispatchable suppliers, the Company has a history of deliveries so the historical monthly average was used.

2. For dispatchable suppliers, the respective Power Purchase Agreements state that the Company can vary the hourly energy purchased from the supplier from a stated minimum up to the amount of capacity available at the time, not to exceed the contract capacity. These suppliers were dispatched in a manner similar to our own generating units and interchange sources.

Q. Are there any changes in the existing sources of purchased power for this PSCR Plan case?

A. Yes. The agreement with Jackson County was terminated February 20, 2015. The contracts under Public Act 295 of 2008 at the Scenic View Dairy Fennville and Scenic

View Dairy Freeport facilities terminate December 31, 2015 and are replaced with agreements through Experimental Advanced Renewable Program Anaerobic Digester ("EARP AD"). Combined, the EARP AD program provides for 0.8 MW of nameplate capacity effective in September 2015, increasing to 1.8 MW of nameplate capacity effective in January 2016 and to 2.9 MW of nameplate capacity by January 2017.

Q. Are there any new sources of purchased power for this PSCR Plan case?

A. No.

Q. Are the Renewable Resource Program suppliers included in this PSCR Plan case?

A. Yes, the Renewable Resource Program approved by the Commission in its January 25, 2005 Order in Case No. U-14843 is modeled in this case. The suppliers are comprised of wind and landfill gas units and are shown on Exhibit A-24 (STW-3) listed under the category of Green Generation Program Agreements. The energy charge for all of the Green Generation contracts that is recoverable in the PSCR is the average PSCR rate for the year.

Q. Are there any changes in the representation of the Midland Cogeneration Venture Limited Partnership ("MCV") in this case?

A. No, the MCV facility is dispatched and its energy is priced according to the terms in the Settlement Agreement that was approved by the Commission in its June 20, 2008 Order in Case No. U-15320.

Q. Are there any changes in the representation of any of the other NUGs?

A. Yes. As in last year's Case No. U-17678, the Cadillac, Genesee, and Grayling wood-fueled units are dispatched on the cost of production based on a wood price, instead of the 12-month rolling average coal price that is the contract dispatch price for these units. The Reduced Dispatch Agreements ("RDA") for the wood-fired units were most recently included as Exhibit A-38 (DFR-12) in Case No. U-15001-R. The projected hold harmless amount resulting from this dispatch is $2,991,000 and the projected customer benefit (offset to PSCR) is $1,017,000. These amounts are included as credits in lines 24 and 38 on Exhibit A-22 (STW-1) and Exhibit A-23 (STW-2). However, in Case No. U-17678, the Ada unit was dispatched on the cost of production based on natural gas under an RDA. That RDA has since been terminated.

Q. Please explain line 40 of Exhibit A-22 (STW-1).

A. Line 40 represents the projected payments to the Biomass Merchant Plants in excess of the Company's avoided cost as required under Public Act 286 of 2008 and the Commission's August 11, 2009 Order in Case No. U-16048.

NET INTERCHANGE POWER

Q. On line 12 of Exhibit A-22 (STW-1) you use the term "Net Interchange." Please explain this.

A. This term refers to purchases from and sales to other entities for energy and capacity. The details are shown on Exhibit A-22 (STW-1) and also on Exhibit A-23 (STW-2), pages 2 and 3. Lines 27 and 28 detail the energy received and lines 31 through 33 detail the energy delivered. Lines 36 and 37 detail the costs for energy received and lines 42 through 45 detail the revenues for energy delivered. Line 35 details the purchase of Zonal Resource Credits to meet the Company's net peak demand coincident with MISO's peak demand plus planning reserve margin requirements. This is explained in Company witness David F. Ronk, Jr.'s testimony. Lines 27, 28, 36, and 37 detail the purchase of on-peak and off-peak energy from the Midwest Energy Market. Lines 31 and 42 represent the sale of energy to the MISO market.

Q. Please explain lines 32 and 44 of Exhibit A-22 (STW-1).

A. Lines 32 and 44 represent a sale to the Midwest Energy Market from the Company-owned oil and gas units. This is an estimate of the sale associated with the MISO Reliability Assessment Commitment process. MISO must ensure that sufficient resources are available and online to meet the forecasted MISO load for each hour of the next operating day. The Company has estimated the amount of increased generation at the oil and gas units that MISO uses for this purpose on line 32 and has represented it as a sale. The Company will be reimbursed in full for this use of its units and, therefore, this increased generation cost is fully offset by the revenue shown on Line 44 and, therefore, does not affect the PSCR Factor.

Q. Please explain line 43 of Exhibit A-22 (STW-1).

A. Line 43 represents revenue from the sale of capacity, although no sale of capacity is projected in this case.

Q. Does the Company have agreements with other entities that involve transactions classified as “Purchased and Interchange Power”?

A. No.

CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17918
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2016	)	

EXHIBITS

OF

SARA T. WALZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2015

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-17918
Exhibit: A-22 (STW-1)
Witness: STWalz
Date: September 2015
Page: 1 of 3

CONSUMERS ENERGY COMPANY

SUMMARY BY SOURCE

YEAR		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2016
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)**	**(i)**	**(j)**	**(k)**	**(l)**	**(m)**	**(n)**	**(o)**
	ENERGY (MWH)													
1	COAL STEAM	1,276,145	1,268,948	959,971	726,507	595,660	880,560	1,057,526	997,174	917,116	784,758	997,773	1,143,816	11,605,953
2	GAS & OIL	518,681	508,554	567,967	589,459	630,484	571,328	657,177	538,798	312,877	444,003	370,874	414,784	6,124,985
3	NUCLEAR PPA	602,864	562,203	589,000	563,990	577,610	543,477	558,369	557,520	554,075	583,359	571,795	601,064	6,865,325
4	STATION POWER	11,678	9,601	15,865	13,887	11,781	7,147	4,890	6,131	6,780	9,934	7,117	6,178	110,988
5	CE OWNED RENEWABLES	109,658	97,727	110,561	116,327	102,361	77,467	66,074	62,023	69,086	88,000	97,246	105,511	1,102,042
6	PEAKERS	106,472	55,684	46,473	34,392	42,310	43,636	93,598	30,843	29,926	7,520	0	1,400	492,255
7	PUMPED STORAGE	41,909	56,987	21,658	71,223	94,795	120,016	119,375	121,944	55,999	21,870	40,899	79,386	846,060
8	TOTAL GENERATED	2,667,406	2,559,703	2,311,496	2,115,784	2,055,003	2,243,632	2,557,009	2,314,432	1,945,858	1,939,443	2,085,703	2,352,138	27,147,607
9	LESS : PUMPING	-59,170	-78,059	-19,320	-97,910	-128,454	-160,795	-169,428	-155,410	-83,905	-29,320	-52,278	-108,419	-1,142,467
10	TOTAL GENERATED	2,608,236	2,481,644	2,292,176	2,017,874	1,926,548	2,082,837	2,387,581	2,159,022	1,861,953	1,910,123	2,033,426	2,243,719	26,005,139
11	PURCHASED (NUGs)	932,401	796,503	935,583	783,612	816,170	711,324	809,383	677,889	649,958	710,061	650,114	610,391	9,083,388
12	NET INTERCHANGE	-378,415	-408,228	-251,575	-67,838	104,438	319,530	241,768	464,324	409,679	255,577	186,652	320,536	1,196,448
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13	TOTAL SYSTEM REQUIREMENTS	3,162,222	2,869,918	2,976,184	2,733,647	2,847,157	3,113,691	3,438,733	3,301,235	2,921,590	2,875,761	2,870,192	3,174,646	36,284,976
	EXPENSES ($*1000)													
14	COAL STEAM	32,483	32,316	25,611	18,673	15,349	22,172	26,748	25,152	23,051	19,528	24,894	28,500	294,477
15	GAS & OIL	16,436	15,892	18,021	15,650	17,202	16,428	20,978	15,819	9,259	12,290	11,577	13,244	182,796
16	NUCLEAR PPA	33,303	27,422	28,021	26,458	27,710	31,588	34,783	35,680	31,725	27,094	26,728	28,761	359,276
17	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
18	CE OWNED RENEWABLES	5,491	4,849	4,836	4,618	4,127	3,213	4,025	3,906	3,266	4,256	4,751	5,234	52,571
19	PEAKERS	4,313	2,318	1,949	1,257	1,557	1,617	3,412	1,184	1,150	383	85	150	19,374
20	PUMPED STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
		------	------	------	-----	-----	-----	------	-----	-----	-----	-----	-----	------
21	TOTAL GENERATED	92,026	82,797	78,439	66,656	65,945	75,019	89,946	81,741	68,451	63,552	68,034	75,889	908,494
22	LESS : PUMPING	0	0	0	0	0	0	0	0	0	0	0	0	0
23	TOTAL GENERATED	92,026	82,797	78,439	66,656	65,945	75,019	89,946	81,741	68,451	63,552	68,034	75,889	908,494
24	PURCHASED (NUGs)	65,415	58,150	64,065	55,712	57,745	53,792	62,064	57,418	49,638	53,451	50,116	48,395	675,961
25	NET INTERCHANGE	-14,854	-15,434	-7,861	-949	3,404	8,795	1,234	10,451	12,513	9,443	7,735	12,546	27,024
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26	TOTAL SYSTEM COST	142,586	125,514	134,643	121,419	127,094	137,606	153,244	149,610	130,602	126,446	125,885	136,830	1,611,480

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-17918
Exhibit: A-22 (STW-1)
Witness: STWalz
Date: September 2015
Page: 2 of 3

CONSUMERS ENERGY COMPANY

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2016
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	RECEIVED (MWH)													
27	MARKET ON PEAK	5,293	2,096	14,765	42,702	69,881	212,006	152,573	243,208	215,644	76,818	140,077	178,929	1,353,991
28	MARKET OFF PEAK	15,791	26,184	37,254	108,448	209,578	314,325	408,716	385,989	311,297	281,743	159,195	201,837	2,460,359
29	PURCHASED (NUGs)	932,401	796,503	935,583	783,612	816,170	711,324	809,383	677,889	649,958	710,061	650,114	610,391	9,083,388
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30	TOTAL RECEIVED	953,485	824,782	987,602	934,762	1,095,629	1,237,655	1,370,672	1,307,086	1,176,898	1,068,622	949,387	991,157	12,897,738
	DELIVERED (MWH)													
31	EXTERNAL SALES	399,499	436,508	303,594	218,989	175,021	189,907	212,476	164,874	117,262	102,984	112,620	60,230	2,493,963
32	MISO RAC	0	0	0	0	0	16,894	107,044	0	0	0	0	0	123,938
		-----	-----	-----	-----	-----	------	-----	-----	-----	-----	-----	-----	------
33	TOTAL DELIVERED	399,499	436,508	303,594	218,989	175,021	206,801	319,521	164,874	117,262	102,984	112,620	60,230	2,617,902
34	NET (MWH)	553,986	388,275	684,008	715,774	920,608	1,030,854	1,051,151	1,142,213	1,059,636	965,638	836,766	930,927	10,279,836

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-17918
Exhibit: A-22 (STW-1)
Witness: STWalz
Date: September 2015

CONSUMERS ENERGY COMPANY

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2016
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)**	**(i)**	**(j)**	**(k)**	**(l)**	**(m)**	**(n)**	**(o)**
	EXPENSE ($*1000)													
35	PURCHASE OF ZONAL RESOURCE CREDITS	1,045	977	1,045	1,011	1,045	1,264	1,306	1,306	1,264	1,306	1,264	1,306	14,141
36	MARKET ON PEAK ENERGY	1,498	1,342	1,862	2,832	3,931	8,773	7,159	9,355	8,716	4,051	6,188	7,768	63,476
37	MARKET OFF PEAK ENERGY	568	843	1,289	3,038	5,171	7,472	10,138	9,271	7,187	7,862	4,580	5,982	63,401
38	PURCHASED (NUGs) ENERGY	43,460	37,448	42,164	35,252	35,639	32,399	40,052	35,421	29,934	31,869	28,658	26,310	418,605
39	PURCHASED (NUGs) CAPACITY	20,833	19,579	20,778	19,337	20,984	20,270	20,889	20,874	18,582	20,460	20,335	20,963	243,885
40	CASE NO. U-16048 COST RECOVERY	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	13,472
		-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	------
41	TOTAL EXPENSE	68,526	61,313	68,261	62,593	67,892	71,301	80,667	77,350	66,806	66,671	62,148	63,451	816,979
	CREDIT ($*1000)													
42	EXTERNAL SALE ENERGY	17,966	18,596	12,057	7,830	6,743	7,906	11,413	9,481	4,654	3,777	4,297	2,510	107,229
43	EXTERNAL SALE CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0
44	MISO RAC	0	0	0	0	0	808	5,956	0	0	0	0	0	6,764
		----	----	----	----	----	-----	-----	-----	----	----	----	----	------
45	TOTAL CREDIT	17,966	18,596	12,057	7,830	6,743	8,714	17,369	9,481	4,654	3,777	4,297	2,510	113,993
46	NET EXPENSE	50,560	42,717	56,204	54,763	61,149	62,587	63,298	67,869	62,152	62,894	57,851	60,941	702,986

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-17918
Exhibit: A-23 (STW-2)
Witness: STWalz
Date: September 2015

CONSUMERS ENERGY COMPANY

YEAR	SUMMARY BY SOURCE	2016	2017	2018	2019	2020
(a)	(b)	(c)	(d)	(e)	(f)	(g)
	ENERGY (MWH)					
1	COAL STEAM	11,605,953	11,713,623	11,362,324	11,164,658	11,522,242
2	GAS & OIL	6,124,985	5,326,149	5,161,397	5,454,303	5,241,184
3	NUCLEAR PPA	6,865,325	6,846,533	6,843,661	6,845,845	6,863,360
4	STATION POWER	110,988	83,685	87,841	88,200	83,059
5	CE OWNED RENEWABLES	1,102,042	1,102,516	1,108,459	1,112,810	1,112,263
6	PEAKERS	492,255	359,508	402,931	254,882	1,580,820
7	PUMPED STORAGE	846,060	1,194,620	1,250,144	1,316,967	1,514,985
8	TOTAL GENERATED	27,147,607	26,626,635	26,216,756	26,237,666	27,917,912
9	LESS : PUMPING	-1,142,467	-1,583,082	-1,644,302	-1,711,031	-1,964,030
10	TOTAL GENERATED	26,005,139	25,043,553	24,572,454	24,526,634	25,953,882
11	PURCHASED (NUGs)	9,083,388	8,663,235	8,113,851	8,297,292	8,064,442
12	NET INTERCHANGE	1,196,448	2,744,588	4,024,986	3,862,170	2,863,671
		--------	--------	--------	--------	--------
13	TOTAL SYSTEM REQ	36,284,976	36,451,376	36,711,291	36,686,097	36,881,995
	EXPENSES ($*1000)					
14	COAL STEAM	294,477	302,173	299,606	309,330	332,131
15	GAS & OIL	182,796	168,229	164,809	174,940	172,148
16	NUCLEAR PPA	359,276	368,440	378,962	389,257	401,128
17	STATION POWER	0	0	0	0	0
18	CE OWNED RENEWABLES	52,571	52,597	54,108	56,147	57,531
19	PEAKERS	19,374	15,461	17,192	9,827	12,787
20	PUMPED STORAGE	0	0	0	0	0
		------	------	------	------	------
21	TOTAL GENERATED	908,494	906,901	914,677	939,501	975,725
22	LESS : PUMPING	0	0	0	0	0
23	TOTAL GENERATED	908,494	906,901	914,677	939,501	975,725
24	PURCHASED (NUGs)	675,961	670,134	651,775	655,361	658,968
25	NET INTERCHANGE	27,024	64,415	104,384	103,721	67,427
		-------	-------	-------	-------	-------
26	TOTAL SYSTEM COST	1,611,480	1,641,449	1,670,836	1,698,584	1,702,120

CONSUMERS ENERGY COMPANY

YEAR	ERCHANGE POWER REPORT	2016	2017	2018	2019	2020
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**
	RECEIVED (MWH)					
27	MARKET ON PEAK	1,353,991	1,428,782	1,923,312	1,527,469	1,329,344
28	MARKET OFF PEAK	2,460,359	3,674,814	4,127,016	4,360,061	3,959,677
29	PURCHASED (NUGs)	9,083,388	8,663,235	8,113,851	8,297,292	8,064,442
		--------	--------	--------	--------	--------
30	TOTAL RECEIVED	12,897,738	13,766,831	14,164,179	14,184,822	13,353,462
	DELIVERED (MWH)					
31	EXTERNAL SALES	2,493,963	2,257,858	1,915,312	1,917,495	2,356,681
32	MISO RAC	123,938	101,150	110,030	107,865	68,668
		-------	------	------	------	------
33	TOTAL DELIVERED	2,617,902	2,359,008	2,025,342	2,025,360	2,425,349
34	NET (MWH)	10,279,836	11,407,823	12,138,836	12,159,462	10,928,113

CONSUMERS ENERGY COMPANY

YEAR	:RCHANGE POWER REPORT	2016	2017	2018	2019	2020
(a)	(b)	(c)	(d)	(e)	(f)	(g)
	EXPENSE ($*1000)					
35	PURCHASE OF ZONAL RESOURCE CREDITS	14,141	10,947	7,481	7,772	6,672
36	MARKET ON PEAK ENERGY	63,476	66,887	82,265	72,538	65,786
37	MARKET OFF PEAK ENERGY	63,401	93,726	110,902	117,713	109,257
38	PURCHASED (NUGs) ENERGY	418,605	413,353	394,993	409,529	412,446
39	PURCHASED (NUGs) CAPACITY	243,885	242,979	242,622	231,319	231,732
40	CASE NO. U-16048 COST RECOVERY	13,472	13,802	14,160	14,513	14,790
		------	------	------	------	------
41	TOTAL EXPENSE	816,979	841,694	852,424	853,384	840,683
	CREDIT ($*1000)					
42	EXTERNAL SALE ENERGY	107,229	101,312	89,975	87,905	110,245
43	EXTERNAL SALE CAPACITY	0	0	0	0	0
44	MISO RAC	6,764	5,833	6,290	6,397	4,043
		------	------	------	------	------
45	TOTAL CREDIT	113,993	107,146	96,265	94,302	114,288
46	NET EXPENSE	702,986	734,549	756,159	759,083	726,395

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY
PURCHASED POWER AGREEMENTS

Line	Existing Energy–Only Agreements	Projected 2016 Rates	Termination of Agreement
1	Great Lakes Tissue Company	Energy: Three-month rolling average incremental running cost Administrative Charge: 0.10¢/kWh	Terminated by mutual consent or by either party giving the other at least six months' written notice of its desire to terminate the Agreement at the end of any yearly period.
2	Jackson County	Energy: Agreement Terminated Administrative Charge: Agreement Terminated	This agreement was terminated on February 20, 2015.
3	Michigan State University	Energy: Three-month rolling average incremental running cost Administrative Charge: 0.10¢/kWh (not to exceed $200/month)	Terminated by mutual consent or by either party giving the other at least 30 days' written notice of its desire to terminate the Agreement at the end of any yearly period.
4	Western Michigan University	Energy: Hourly incremental running cost Administrative Charge: 0.10¢/kWh (minimum of $346/month, but not to exceed $3,438/month)	Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period.
5	Grand Valley State University	Energy: 90% of the hourly incremental running cost Administrative Charge: None	Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period.
6	City of Midland, MI	Energy: 90% of (Consumers Energy's Real Time Load Node LMP Minus $5/MWh) Administrative Charge: 0.10¢/kWh (minimum of $346/month, but not to exceed $3,438/month)	Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period.

Line	Existing Energy–Only Agreements	Projected 2016 Rates	Termination of Agreement
7	North American Biofuels – Green Meadow Farms	Energy: Agreement Terminated Administrative Charge: Agreement Terminated	This agreement was terminated October 20, 2014.
8	MAHLE Engine Components USA	Energy: 90% of (Consumers Energy's Real Time Load Node LMP Minus \$5/MWh) Administrative Charge: 0.10¢/kWh (minimum of \$346/month, but not to exceed \$3,438/month)	Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period.

Line	Green Generation Program Agreements	Projected 2016 Rates	Termination of Agreement
1	Michigan Wind I LLC (Wind) (PPA 1)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $346/month, but not to exceed $3,438/month)	December 18, 2018. After this date, the agreement shall continue in effect until terminated by mutual agreement or by either party giving the other party at least 365 days' written notice of termination.
2	Michigan Wind I LLC (Wind) (PPA 2)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $346/month, but not to exceed $3,438/month)	December 18, 2028. After this date, the agreement shall continue in effect until terminated by mutual agreement or by either party giving the other party at least 365 days' written notice of termination.
3	Bay Windpower I, Mackinaw City, LLC. (Wind)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $346/month, but not to exceed $3,438/month).	December 3, 2018. After this date, the agreement shall automatically renew for subsequent one year periods and shall continue in effect until terminated by mutual agreement or by either party giving the other party at least one year's written notice of termination.
4	Rathbun Generating Station (Landfill Gas)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $346/month, but not to exceed $3,438/month).	January 29, 2018.
5	North American Natural Resources, Inc. Venice Park Generating Station (Landfill Gas)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $346/month, but not to exceed $3,438/month).	February 10, 2026. After this date, the agreement shall continue in effect until terminated by mutual agreement or by either party giving the other party at least 365 days' written notice of termination.

Line	Green Generation Program Agreements	Projected 2016 Rates	Termination of Agreement
6	Zeeland Farm Services, Inc. (Landfill Gas)	Energy: Agreement Terminated. Capacity: Agreement Terminated. Administrative Charge: Agreement Terminated.	This agreement was terminated on February 17, 2013.
7	C&C Energy, formerly Gas Recovery Systems, LLC. C&C Electric 2 Plant (Landfill Gas)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $346/month, but not to exceed $3,438/month).	February 28, 2027. After this date, the agreement shall continue in effect until terminated by mutual agreement or by either party giving the other party at least 365 days' written notice of termination.

Line	Existing Energy & Capacity Agreements	Projected 2016 Rates	Termination of Agreement
1	Ada Cogeneration Ltd Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.024¢/kWh On-Peak 3.822¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	January 5, 2026. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
2	Adrian Energy Associates	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.476¢/kWh On-Peak 4.253¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	December 13, 2029. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
3	C&C Energy, formerly Gas Recovery Systems	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.374¢/kWh On-Peak 4.155¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $346/month, but not to exceed $3,438/month)	February 20, 2030. After this date, the Agreement may continue until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination.

Line	Existing Energy & Capacity Agreements	Projected 2016 Rates	Termination of Agreement
4	WM Renewable Energy, LLC. (formerly Bio Energy Partners)	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.19¢/kWh On-Peak 3.98¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $200/month, but not to exceed $2,000/month)	May 4, 2027. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of any yearly period.
5	Black River Limited Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 2.12¢/kWh On-Peak 1.80¢/kWh Off-Peak Administrative Charge: 0.125¢/kWh	December 31, 2017. After this date the Agreement may continue until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
6	Beaverton, City of	Energy: 3.26¢/kWh On-Peak 2.55¢/kWh Off-Peak Capacity: 3.51¢/kWh On-Peak 2.75¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2023. After this date the Agreement may continue until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
7	Hope Renewable Energy – Hubbardston	Energy: Agreement Terminated. Capacity: Agreement Terminated. Administrative Charge: Agreement Terminated.	This agreement was terminated on November 8, 2011.

Line	Existing Energy & Capacity Agreements	Projected 2016 Rates	Termination of Agreement
8	Commonwealth Power Company – Irving	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.034¢/kWh On-Peak 3.832¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	August 25, 2030. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
9	Commonwealth Power Company – LaBarge	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.48¢/kWh On-Peak 3.93¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2017. After this date the Agreement may continue until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
10	Commonwealth Power Company – Middleville	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.034¢/kWh On-Peak 3.832¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	January 1, 2031. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
11	Genesee Power Station Limited Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.65¢/kWh On-Peak 4.42¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $200/month, but not to exceed $2,000/month)	December 13, 2030. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of any yearly period.

Line	Existing Energy & Capacity Agreements	Projected 2016 Rates	Termination of Agreement
12	Granger Electric Company – Grand Blanc	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.402¢/kWh On-Peak 4.182¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $346/month, but not to exceed $3,438/month)	July 27, 2029. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination.
13	Granger Electric of Pinconning	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.348¢/kWh On-Peak 4.136¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $236/month, but not to exceed $2,357/month)	January 22, 2028. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective on January 22 of any year.
14	Granger Electric of Byron Center	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.184¢/kWh On-Peak 3.970¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $258/month, but not to exceed $2,576/month)	April 10, 2026. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective on April 10 of any year.

Line	Existing Energy & Capacity Agreements	Projected 2016 Rates	Termination of Agreement
15	Granger Electric Company – Ottawa	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.374¢/kWh On-Peak 4.155¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $346/month, but not to exceed $3,438/month)	June 21, 2029. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination.
16	Granger Electric Company – Seymour	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.374¢/kWh On-Peak 4.155¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $346/month, but not to exceed $3,438/month)	November 21, 2030. After this date, the Agreement may continue until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination.
17	Grayling Generating Station Limited Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.18¢/kWh On-Peak 3.97¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $346/month, but not to exceed $3,438/month)	December 31, 2027. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.

Line	Existing Energy & Capacity Agreements	Projected 2016 Rates	Termination of Agreement
18	Grenfell Hydro, Inc	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.02¢/kWh On-Peak 3.42¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2018. After this date the Agreement may continue until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
19	Hillman Power Company LLC	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 3.85¢/kWh On-Peak 3.27¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2015. After this date the Agreement may continue until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
20	Kent County	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 5.34¢/kWh On-Peak 4.54¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	February 11, 2022. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
21	Michiana Hydroelectric Co Bellevue	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 5.36¢/kWh On-Peak 4.76¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2018. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.

Line	Existing Energy & Capacity Agreements	Projected 2016 Rates	Termination of Agreement
22	Michigan Power Limited Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 3.880¢/kWh On-Peak 3.686¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	October 23, 2030. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
23	Midland Cogeneration Venture Limited Partnership	Energy: Cost of Production Capacity: 1.014¢/kWh Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	March 16, 2025. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
24	North American Natural Resources, Inc.- (Peoples)	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.374¢/kWh On-Peak 4.155¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $346/month, but not to exceed $3,438/month)	September 8, 2030. After this date, the Agreement may continue until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination.
25	STS Hydropower Ltd – Cascade Hydro Plant	Energy: 3.26¢/kWh On-Peak 2.55¢/kWh Off-Peak Capacity: 4.25¢/kWh On-Peak 3.61¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2018. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.

Line	Existing Energy & Capacity Agreements	Projected 2016 Rates	Termination of Agreement
26	STS Hydropower Ltd – Fallasburg Hydro Plant	Energy: 3.26¢/kWh On-Peak 2.55¢/kWh Off-Peak Capacity: 3.09¢/kWh On-Peak 2.63¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2017. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
27	STS Hydropower Ltd – Morrow Hydro Plant	Energy: 3.26¢/kWh On-Peak 2.55¢/kWh Off-Peak Capacity: 3.97¢/kWh On-Peak 3.37¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2019. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
28	T.E.S. Filer City Station Limited Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 6.45¢/kWh On-Peak 5.47¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	June 17, 2025. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
29	Thornapple Association, Inc	Energy: 3.26¢/kWh On-Peak 2.55¢/kWh Off-Peak Capacity: 3.35¢/kWh On-Peak 2.85¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2016. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.

Line	Existing Energy & Capacity Agreements	Projected 2016 Rates	Termination of Agreement
30	Viking Energy of Lincoln Limited Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.30¢/kWh On-Peak 3.66¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2018. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
31	Viking Energy of McBain Limited Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.30¢/kWh On-Peak 3.66¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2018. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
32	White's Bridge Hydro Company	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 3.76¢/kWh On-Peak 3.20¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2016. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
33	Boyce Hydro (formerly Wolverine Power Corporation)	Energy: 4.67¢/kWh On-Peak 3.66¢/kWh Off-Peak Capacity: 2.33¢/kWh On-Peak 1.97¢/kWh Off-Peak Administrative Charge: None	May 31, 2022.

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY
PURCHASED POWER AGREEMENTS

Line	Existing Energy & Capacity Agreements	Projected 2016 Rates	Termination of Agreement
34	Entergy Nuclear Power Marketing, LLC	Energy: 0.646¢/kWh Capacity: 4.604¢/kWh Administrative Charge: None	April 11, 2022.

Line	Renewable Energy Plan Agreements	Projected 2016 Rates	Termination of Agreement
1	Elk Rapids Hydroelectric Power LLC	Energy: Monthly Transfer Rate Administrative Charge: None	October 12, 2019.
2	Scenic View Dairy LLC, Freeport Plant (Anaerobic Digestor)	Energy: Monthly Transfer Rate Administrative Charge: None	December 31, 2015.
3	Zeeland Farm Services Inc, Plant 2 (Landfill Gas)	Energy: Monthly Transfer Rate Administrative Charge: None	October 12, 2016.
4	Fremont Community Digestor LLC (Anaerobic Digestor)	Energy: Monthly Transfer Rate Administrative Charge: None	December 26, 2032.
5	WM Renewable Energy LLC, Northern Oaks Landfill Plant (Landfill Gas)	Energy: Monthly Transfer Rate Administrative Charge: None	November 10, 2030.
6	North American Natural Resources Inc, Lennon Generating Station (Landfill Gas)	Energy: Monthly Transfer Rate Administrative Charge: None	December 15, 2030.
7	Michigan Wind 2 (Wind)	Energy: Monthly Transfer Rate Administrative Charge: None	December 31, 2031.
8	Harvest II Wind Farm (Wind)	Energy: Monthly Transfer Rate Administrative Charge: None	October 31, 2032.
9	Beebe Renewable Energy, formerly Blissfield Energy (Wind)	Energy: Monthly Transfer Rate Administrative Charge: None	December 17, 2032.

Line	Renewable Energy Plan Agreements	Projected 2016 Rates	Termination of Agreement
10	WM Renewable Energy LLC, Pine Tree Acres Landfill Plant (Landfill Gas)	Energy: Monthly Transfer Rate Administrative Charge: None	February 28, 2032.
11	Heritage Stoney Corners Wind Farm I, LLC, Phase 2 (Wind)	Energy: Monthly Transfer Rate Administrative Charge: None	December 31, 2031.
12	Heritage Stoney Corners Wind Farm I, LLC, Phase 3 (Wind)	Energy: Monthly Transfer Rate Administrative Charge: None	December 31, 2031.
13	Heritage Garden Wind Farm I, LLC (Wind)	Energy: Monthly Transfer Rate Administrative Charge: None	September 13, 2032.
14	Scenic View Dairy Fennville Plant (Anaerobic Digester)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $346/month, but not to exceed $3,438/month).	December 31, 2015. Consumers Energy filed for and received approval as a PA 295 contract (Renewable Energy Plan) on October 26, 2010 in MPSC Case No.U-15805.
15	Experimental Advanced Renewable Program (EARP) (Solar)	Energy: Monthly Transfer Rate Administrative Charge: None	Individual contracts have specific termination dates. All agreements will terminate by April 30, 2023.
16	Experimental Advanced Renewable Program (EARP) Expansion (Solar)	Energy: Monthly Transfer Rate Administrative Charge: None	Individual contracts have specific termination dates. All agreements will terminate by August 31, 2029.
17	Experimental Advanced Renewable Program (EARP) FiT (Anaerobic Digester)	Energy: Monthly Transfer Rate Administrative Charge: None	Individual contracts have specific termination dates. All agreements will terminate by June 30, 2036.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the application of CONSUMERS ENERGY COMPANY for Approval of a Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for the Year 2016	))))))	Case No. U-17918

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Tara L. Hilliard, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on September 30, 2015, she served an electronic copy of Consumers Energy Company's Application, and the Testimony and Exhibits of Consumers Energy Company's witnesses Daniel S. Alfred, Natalie N. Busack, Jim K. Chilson II, David F. Ronk, Jr., Robert C. Schram, Jason M. Shore, and Sara T. Walz, upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Digitally signed by Tara L. Hilliard
Date: 2015.09.30 16:40:52 -04'00'

Tara L. Hilliard

Subscribed and sworn to before me this 30th day of September, 2015.

Digitally signed by Samantha O'Rourke
Date: 2015.09.30 16:40:08 -04'00'

Samantha O'Rourke, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 10/30/21
Acting in the County of Jackson

Attachment 1 to Case No. U-17918 - E-Mail Service List (Parties to Case No. U-17678)		
Party	**Name**	**E-mail Address**
Counsel for the Michigan Public Service Commission Staff	Lauren D. Donofrio, Esq. Bryan A. Brandenburg, Esq.	donofriol@michigan.gov brandenburgb@michigan.gov
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Counsel for Ada Cogeneration Limited Partnership and Michigan Power Limited Partnership	David E. S. Marvin, Esq.	dmarv@fraserlawfirm.com