Consumers Energy
Count on Us

A CMS Energy Company

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September 30, 2013

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
4300 W. Saginaw
Lansing, MI 48917

RE: Case No. U-17317 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 2014.

Dear Ms. Kunkle:

Included in this electronic file are Consumers Energy Company's Application, Testimony and Exhibits of Consumers' witnesses Dan S. Alfred, Natalie N. Busak, Jim K. Chilson II, David B. Kehoe, Hubert W. Miller III, David F. Ronk, Jr. and Sara T. Walz. Also included is a Proof of Service. This is a paperless filing and is therefore being filed only in a PDF format.

Sincerely,

Digitally signed by John C. Shea
Date: 2013.09.30 16:41:54 -04'00'

John C. Shea

cc: Parties to Case No. U-17095

f1093013-225

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 2014	))))))	Case No. U-17317

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 period January-December 2014. In support of this Application, Consumers Energy says 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, which sets forth the Company's PSCR clause, was approved most recently by the Commission's May 15, 2013 Order in Case No. U-17087.

4. 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 2014. This 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.

5. As more fully described in the accompanying testimony and exhibits, Consumers Energy seeks approval to apply, for each month in calendar year 2014, a uniform maximum PSCR factor of $(00.00040) per kWh for all classes of customers.

6. 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.

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 2014 a maximum monthly PSCR factor of $(00.00040) 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 2014 described in this Application; and

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

Respectfully submitted,

Consumers Energy Company

Digitally signed by Timothy J. Sparks
Date: 2013.09.30 16:44:19 -04'00'

Date: September 30, 2013

By______________________________
Timothy J. Sparks
Vice President of Energy Supply Operations

Digitally signed by John C. Shea
Date: 2013.09.30 16:46:44 -04'00'

____
John C. Shea (P36854)
Robert W. Beach (P73112)
Attorneys for Consumers Energy Company
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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 2014.	))))))	Case No. U-17317

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: 2013.09.30 16:48:39 -04'00'

Timothy J. Sparks,
Vice President of Energy Supply Operations

Subscribed and sworn to before me this 30th day of September, 2013.

Digitally signed by Debra S. Weirich
Date: 2013.09.30 16:50:45 -04'00'

Debra S. Weirich, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 10/31/18
Acting in the County of Jackson

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-17317
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2014	)	

DIRECT TESTIMONY

OF

DANIEL S. ALFRED

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September, 2013

QUALIFICATIONS

Q. Please state your name and business address.

A. Daniel S. Alfred, 1945 W. Parnall Rd, Jackson, Michigan.

Q. By whom are you employed?

A. Consumers Energy Company ("Consumers Energy" or "Company").

Q. What is your position with Consumers Energy?

A. I am a Senior Business Support Consultant II in the Transmission and Regulatory Strategies Section 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 Midwest Independent Transmission 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, FERC, and Michigan Public Service Commission ("MPSC" or "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, have you testified in any utility proceeding before the Michigan Public Service 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
3. Case No. U-14148	10(d)4 Regulatory Asset Recovery
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
8. Case No. U-14126-R	Enhanced Security Costs Reconciliation
9. Case No. U-16564	10d(4) Regulatory Asset Reconciliation
10. Case No. U-16855	Gas General Rate 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 2014 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.

<u>TRANSMISSION AND ENERGY MARKET EXPENSE</u>

Q. What transmission and energy market expense does the Company seek recovery for in the Company's 2014 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 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 U-16890. I am informed by counsel that the Commission's actions with respect to transmission expenses was approved by the Michigan Supreme Court in its order in *Attorney General v Michigan Public Service Commission*, 483 Mich 998 (May 1, 2009).

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 2014 in the Company's total transmission costs.

A. The transmission and energy-market-related charges included in the total transmission costs projected for 2014 (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 Mr. Ronk, 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 Miller?

A. Yes.

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

A. MISO Schedule 1 is a 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 2014 PSCR plan year and the five-year period 2014-2018 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 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 2014 PSCR plan year and the five-year period 2014-2018 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 network transmission service 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"). This rate is calculated per MISO's Attachment O and is updated biannually. The Company's forecasted expense for 2014 PSCR plan year and the five-year period 2014-2018 is shown on Exhibit A-1 (DSA-1), line 17.

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

A. MISO Schedule 10 recovers 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 2014 PSCR plan year and the five-year period 2014-2018 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 2014 PSCR plan year and the five-year period 2014-2018 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 utilized to allocate to MISO's wholesale transmission customers the amount of the FERC Annual Fee that MISO is assessed. 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 2014 PSCR plan year and the five-year period 2014-2018 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 ("FTR") process. 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 2014 PSCR plan year and the five-year period 2014-2018 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 2014 PSCR plan year and the five-year period 2014-2018 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 a 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 2014 PSCR plan year and the five-year period 2014-2018 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 a 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 2014 PSCR plan year and the five-year period 2014-2018 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 Multi-Value Project Usage Rate ("MUR") 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 2014 PSCR plan year and the five-year period 2014-2018 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 plan year, is identified on Exhibit A-1 (DSA-1). The total cost for 2014 equals $374,070,842 and can be found on Line 29, column (o) of page 1 of Exhibit A-1 (DSA-1). It is composed of

$366,129,366 of transmission expenses (Line 27, column (o)) and $7,941,476 of energy market administration expenses (Line 28, column (o)).

<u>SCHEDULE 2 REACTIVE REVENUE REQUIREMENT CREDIT</u>

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 the MISO for providing this service.** Consumers Energy incurs an expense under the MISO Tariff when it receives reactive service within Michigan Joint Zone 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 2014 from Schedule 2?

A. Yes. The Company expects to receive $19,706,000 in 2014. This amount is composed of the FERC approved revenue requirements established in FERC Docket Nos. OA96-77 and ER04-1110.

<u>COMPANY ACTIVITIES RELATED TO TRANSMISSION COST MANAGEMENT</u>

Q. Are there any additional items that may impact your forecast?

A. Yes. Among the more significant items being discussed and/or pending before FERC are methods for funding the MISO transmission system expansion (Regional Expansion Criteria and Benefits or "RECB") and cross-border allocation of costs with PJM regarding both transmission system expansion and the elimination of the Regional

Through and Out Rate on transactions that cross the MISO-PJM Border. The impact of FERC Order 1000 will most likely have a future financial impact also.

Q. Have you include the potential financial impacts from these items in your 2014 forecast?

A. No. I continue to forecast 2014 transmission expenses as if the currently filed MISO tariff will remain in effect for the 2014 PSCR plan year and the five-year period 2014-2018.

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 Michigan Joint Zone transmission owners to assure the application of the formula is consistent with the tariff.

Q. Can you identify some of 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 Subregional 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. What other strategies has the Company used to manage the cost of transmission for its customers?

A. Consumers Energy monitors and intervenes in FERC proceedings involving MISO and the transmission owners providing service to the Company.

Q. What was the purpose of these interventions?

A. The Company generally intervenes in transmission filings to attempt to ensure that issues are resolved according to FERC policy. When the Company believes the filings at FERC will have a negative impact on the Company's transmission cost and are not in accordance with FERC policy, the Company will protest.

Q. Are there other activities Consumers Energy has been engaged in regarding transmission planning and cost allocation?

A. Yes. Consumers Energy is a founding member and actively participates with other companies through the Coalition for Fair Transmission Policy ("CFTP") to develop and advocate industry positions at the federal level supporting policies on transmission planning and cost allocation. The Company is also an active participant within the MISO Northeast Transmission Customers which consists of the Michigan Attorney General, the Association of Businesses Advocating Tariff Equity ("ABATE"), Consumers Energy Company, The Detroit Edison Company, the Michigan Municipal Electric Association ("MMEA"), and the Michigan Public Power Agency ("MPPA"). The group has protested and advocated for fair transmission cost allocation as it pertains to the Multi-Value Project filing by MISO.

Q. Are there any issues that might impact transmission expenses in future years?

A. Yes. Consumers Energy has recently been informed that certain of its facilities may need to be registered as transmission assets based upon a May 23, 2012 letter from Reliability First Corporation (RFC) and recent FERC rulemakings. In the event that the Company registers these transmission assets, it will include any forecasted financial impacts in the 2015 PSCR plan case.

Q. Does this conclude your 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-17317
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2014	)	

EXHIBIT

OF

DANIEL S. ALFRED

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2013

Consumers Energy Company

2014 Transmission and Energy Market Administration Expenses

Case No.: U-17317
Witness: DSAlfred
Exhibit: A-1 (DSA-1)
Page: 1 of 5
Date: September 2013

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	5,675	5,476	5,369	4,775	5,865	7,299	7,587	7,772	6,679	5,439	5,452	5,872	**73,260**
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	3,062,846	2,769,843	2,900,887	2,623,147	2,792,864	3,051,073	3,317,695	3,254,913	2,827,934	2,803,760	2,749,355	3,046,129	**35,200,446**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	386.7062	386.7062	386.7062	386.7062	386.7062	386.7062	386.7062	386.7062	386.7062	386.7062	386.7062	386.7062	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	3,142.2783	3,142.2783	3,142.2783	3,142.2783	3,142.2783	3,201.6578	3,201.6578	3,201.6578	3,201.6578	3,201.6578	3,201.6578	3,201.6578	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0558	0.0558	0.0558	0.0558	0.0558	0.0558	0.0558	0.0558	0.0558	0.0558	0.0558	0.0558	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0920	0.0920	0.0920	0.0920	0.0920	0.0920	0.0920	0.0920	0.0920	0.0920	0.0920	0.0920	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	1,112.5297	1,112.5297	1,112.5297	1,112.5297	1,112.5297	1,112.5297	1,112.5297	1,112.5297	1,112.5297	1,112.5297	1,112.5297	1,112.5297	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	0.3302	0.3302	0.3302	0.3302	0.3302	0.3302	0.3302	0.3302	0.3302	0.3302	0.3302	0.3302	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 341,155	$ 329,192	$ 322,760	$ 287,051	$ 352,577	$ 438,782	$ 456,096	$ 467,217	$ 401,511	$ 326,968	$ 327,749	$ 352,998	**$ 4,404,054**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,194,558	2,117,603	2,076,226	1,846,522	2,268,032	2,822,569	2,933,940	3,005,481	2,582,811	2,103,295	2,108,322	2,270,739	**28,330,098**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	17,832,430	17,207,116	16,870,892	15,004,379	18,429,462	23,368,900	24,290,978	24,883,284	21,383,872	17,413,817	17,455,438	18,800,135	**232,940,704**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	235,599	205,337	222,895	191,840	243,487	293,245	314,976	322,656	268,336	225,801	219,040	243,777	**2,986,988**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	235,839	213,278	223,368	201,982	215,051	234,933	255,463	250,628	217,751	215,890	211,700	234,552	**2,710,434**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	139,666	126,305	132,280	119,616	127,355	139,129	151,287	148,424	128,954	127,851	125,371	138,903	**1,605,140**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	42,222	36,799	39,945	34,380	43,636	52,553	56,447	57,824	48,089	40,466	39,254	43,688	**535,302**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	563,564	509,651	533,763	482,659	513,887	561,397	610,456	598,904	520,340	515,892	505,881	560,488	**6,476,882**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	80,859	73,124	76,583	69,251	73,732	80,548	87,587	85,930	74,657	74,019	72,583	80,418	**929,292**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	6,313,606	6,092,213	5,973,172	5,312,329	6,524,987	8,120,354	8,440,763	8,646,581	7,430,586	6,051,049	6,065,512	6,532,775	**81,503,927**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	1,011,424	914,668	957,941	866,225	922,270	1,007,536	1,095,581	1,074,849	933,851	925,868	907,902	1,005,904	**11,624,020**
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**	**$ 28,306,276**	**$ 27,207,711**	**$ 26,781,535**	**$ 23,831,945**	**$ 29,085,220**	**$ 36,427,448**	**$ 37,941,083**	**$ 38,801,121**	**$ 33,349,671**	**$ 27,392,539**	**$ 27,423,034**	**$ 29,581,782**	**$ 366,129,366**
28	Total Energy Market Administration Expenses	**Lines 21-23**	**686,645**	**619,574**	**650,292**	**586,290**	**631,254**	**694,499**	**754,490**	**742,657**	**643,086**	**630,377**	**617,719**	**684,593**	**7,941,476**
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 28,992,921**	**$ 27,827,285**	**$ 27,431,827**	**$ 24,418,235**	**$ 29,716,474**	**$ 37,121,947**	**$ 38,695,573**	**$ 39,543,778**	**$ 33,992,757**	**$ 28,022,916**	**$ 28,040,753**	**$ 30,266,375**	**$ 374,070,842**

Consumers Energy Company

2015 Transmission and Energy Market Administration Expenses

Case No.: U-17317
Witness: DSAlfred
Exhibit: A-1 (DSA-1)
Page: 2 of 5
Date: September 2013

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	5,743	5,536	5,431	4,828	5,913	7,398	7,680	7,825	6,764	5,497	5,516	5,938	**74,069**
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	3,079,929	2,785,003	2,917,615	2,637,615	2,808,085	3,067,770	3,335,695	3,272,621	2,842,923	2,819,002	2,764,131	3,063,127	**35,393,516**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	382.2934	382.2934	382.2934	382.2934	382.2934	382.2934	382.2934	382.2934	382.2934	382.2934	382.2934	382.2934	
6	Schedule 9 - Network Transmission Servic	Workpaper DSA-5	3,285.8452	3,285.8452	3,285.8452	3,285.8452	3,285.8452	3,329.6497	3,329.6497	3,329.6497	3,329.6497	3,329.6497	3,329.6497	3,329.6497	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basi	Workpaper DSA-6	0.0568	0.0568	0.0568	0.0568	0.0568	0.0568	0.0568	0.0568	0.0568	0.0568	0.0568	0.0568	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0775	0.0775	0.0775	0.0775	0.0775	0.0775	0.0775	0.0775	0.0775	0.0775	0.0775	0.0775	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charg	Workpaper DSA-6	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Right	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 Market	Workpaper DSA-6	0.0740	0.0740	0.0740	0.0740	0.0740	0.0740	0.0740	0.0740	0.0740	0.0740	0.0740	0.0740	
12	Schedule 24 - Balancing Area Cost Adder - Energy Market	Workpaper DSA-6	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Pla	Workpaper DSA-5a	1,349.8786	1,349.8786	1,349.8786	1,349.8786	1,349.8786	1,349.8786	1,349.8786	1,349.8786	1,349.8786	1,349.8786	1,349.8786	1,349.8786	
14	Schedule 26-A - Multi-Value Project Usage Rat	Workpaper DSA-5a	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 345,243	$ 332,799	$ 326,487	$ 290,237	$ 355,462	$ 444,734	$ 461,686	$ 470,403	$ 406,621	$ 330,454	$ 331,597	$ 356,965	**$ 4,452,688**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,195,511	2,116,376	2,076,236	1,845,713	2,260,501	2,828,207	2,936,013	2,991,446	2,585,833	2,101,467	2,108,730	2,270,058	**28,316,091**
17	Schedule 9 - Network Transmission Servic	Line 1 * Line 6	18,870,609	18,190,439	17,845,425	15,864,060	19,429,202	24,632,749	25,571,710	26,054,509	22,521,751	18,303,085	18,366,348	19,771,460	**245,421,347**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basi	Line 1 * Line 2 * Line 7	242,695	211,307	229,510	197,446	249,879	302,549	324,551	330,678	276,621	232,299	225,582	250,935	**3,074,050**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	238,694	215,838	226,115	204,415	217,627	237,752	258,516	253,628	220,327	218,473	214,220	237,392	**2,742,997**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charg	Line 3 * Line 9	140,445	126,996	133,043	120,275	128,049	139,890	152,108	149,232	129,637	128,546	126,044	139,679	**1,613,944**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Right	Line 1 * Line 2 * Line 10	38,455	33,482	36,366	31,285	39,593	47,939	51,425	52,396	43,831	36,808	35,744	39,761	**487,085**
22	Schedule 17 - ISO Cost Adder - Energy Market	(Line 3 * 2) * Line 11	455,829	412,180	431,807	390,367	415,597	454,030	493,683	484,348	420,753	417,212	409,091	453,343	**5,238,240**
23	Schedule 24 - Balancing Area Cost Adder - Energy Market	(Line 3 * 2) * Line 12	81,310	73,524	77,025	69,633	74,133	80,989	88,062	86,397	75,053	74,422	72,973	80,867	**934,389**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Pla	Line 1 * Line 13	7,752,353	7,472,928	7,331,190	6,517,214	7,981,832	9,986,402	10,367,067	10,562,800	9,130,579	7,420,282	7,445,930	8,015,579	**99,984,155**
25	Schedule 26-A - Multi-Value Project Usage Rat	Line 3 * Line 14	1,847,929	1,670,976	1,750,542	1,582,545	1,684,825	1,840,634	2,001,387	1,963,543	1,705,728	1,691,375	1,658,453	1,837,848	**21,235,787**
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**	**$ 31,635,478**	**$ 30,339,659**	**$ 29,920,548**	**$ 26,623,905**	**$ 32,309,377**	**$ 40,414,916**	**$ 42,075,038**	**$ 42,778,238**	**$ 36,979,095**	**$ 30,427,982**	**$ 30,478,905**	**$ 32,881,917**	**$ 406,865,059**
28	Total Energy Market Administration Expenses	**Lines 21-23**	**575,595**	**519,186**	**545,198**	**491,285**	**529,323**	**582,958**	**633,170**	**623,141**	**539,636**	**528,442**	**517,808**	**573,970**	**6,659,715**
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 32,211,073**	**$ 30,858,845**	**$ 30,465,746**	**$ 27,115,191**	**$ 32,838,700**	**$ 40,997,874**	**$ 42,708,209**	**$ 43,401,380**	**$ 37,518,731**	**$ 30,956,424**	**$ 30,996,713**	**$ 33,455,887**	**$ 413,524,773**

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	5,790	5,611	5,493	4,872	5,975	7,481	7,759	7,881	6,833	5,542	5,570	5,991	**74,798**
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	3,112,748	2,814,362	2,948,631	2,665,389	2,837,818	3,099,240	3,370,363	3,307,189	2,872,396	2,848,341	2,792,683	3,095,562	**35,764,722**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	378.4118	378.4118	378.4118	378.4118	378.4118	378.4118	378.4118	378.4118	378.4118	378.4118	378.4118	378.4118	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	3,319.5572	3,319.5572	3,319.5572	3,319.5572	3,319.5572	3,341.8913	3,341.8913	3,341.8913	3,341.8913	3,341.8913	3,341.8913	3,341.8913	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basi	Workpaper DSA-6	0.0581	0.0581	0.0581	0.0581	0.0581	0.0581	0.0581	0.0581	0.0581	0.0581	0.0581	0.0581	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0792	0.0792	0.0792	0.0792	0.0792	0.0792	0.0792	0.0792	0.0792	0.0792	0.0792	0.0792	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Right	Workpaper DSA-6	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	
11	Schedule 17 - ISO Cost Adder - Energy Market	Workpaper DSA-6	0.0760	0.0760	0.0760	0.0760	0.0760	0.0760	0.0760	0.0760	0.0760	0.0760	0.0760	0.0760	
12	Schedule 24 - Balancing Area Cost Adder - Energy Market	Workpaper DSA-6	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Pla	Workpaper DSA-5a	1,370.1560	1,370.1560	1,370.1560	1,370.1560	1,370.1560	1,370.1560	1,370.1560	1,370.1560	1,370.1560	1,370.1560	1,370.1560	1,370.1560	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	0.7713	0.7713	0.7713	0.7713	0.7713	0.7713	0.7713	0.7713	0.7713	0.7713	0.7713	0.7713	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 348,068	$ 337,308	$ 330,214	$ 292,882	$ 359,190	$ 449,723	$ 466,435	$ 473,769	$ 410,769	$ 333,160	$ 334,843	$ 360,151	**$ 4,496,512**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,191,004	2,123,268	2,078,616	1,843,622	2,261,010	2,830,898	2,936,097	2,982,263	2,585,688	2,097,158	2,107,754	2,267,065	**28,304,443**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	19,220,236	18,626,035	18,234,328	16,172,883	19,834,354	25,000,689	25,929,734	26,337,445	22,835,143	18,520,761	18,614,334	20,021,271	**249,347,213**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basi	Line 1 * Line 2 * Line 7	250,281	219,071	237,443	203,806	258,278	312,945	335,394	340,667	285,838	239,561	233,004	258,969	**3,175,257**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	246,530	222,897	233,532	211,099	224,755	245,460	266,933	261,929	227,494	225,589	221,180	245,169	**2,832,566**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	141,941	128,335	134,458	121,542	129,405	141,325	153,689	150,808	130,981	129,884	127,346	141,158	**1,630,871**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Right	Line 1 * Line 2 * Line 10	43,078	37,706	40,868	35,078	44,454	53,863	57,727	58,635	49,198	41,232	40,104	44,573	**546,516**
22	Schedule 17 - ISO Cost Adder - Energy Market	(Line 3 * 2) * Line 11	473,138	427,783	448,192	405,139	431,348	471,084	512,295	502,693	436,604	432,948	424,488	470,525	**5,436,238**
23	Schedule 24 - Balancing Area Cost Adder - Energy Market	(Line 3 * 2) * Line 12	82,177	74,299	77,844	70,366	74,918	81,820	88,978	87,310	75,831	75,196	73,727	81,723	**944,189**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Pla	Line 1 * Line 13	7,933,203	7,687,945	7,526,267	6,675,400	8,186,682	10,250,137	10,631,040	10,798,199	9,362,276	7,593,405	7,631,769	8,208,605	**102,484,928**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	2,400,816	2,170,675	2,274,235	2,055,775	2,188,767	2,390,398	2,599,511	2,550,786	2,215,436	2,196,883	2,153,955	2,387,561	**27,584,796**
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**	**$ 32,734,079**	**$ 31,517,536**	**$ 31,051,091**	**$ 27,579,008**	**$ 33,444,440**	**$ 41,623,575**	**$ 43,320,833**	**$ 43,897,867**	**$ 38,055,624**	**$ 31,338,400**	**$ 31,426,185**	**$ 33,891,948**	**$** 419,880,586
28	Total Energy Market Administration Expenses	**Lines 21-23**	**598,392**	**539,788**	**566,904**	**510,584**	**550,721**	**606,768**	**659,000**	**648,637**	**561,633**	**549,377**	**538,319**	**596,821**	6,926,942
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 33,332,471**	**$ 32,057,324**	**$ 31,617,995**	**$ 28,089,591**	**$ 33,995,161**	**$ 42,230,343**	**$ 43,979,832**	**$ 44,546,504**	**$ 38,617,257**	**$ 31,887,777**	**$ 31,964,504**	**$ 34,488,769**	**$** 426,807,529

Consumers Energy Company

2017 Transmission and Energy Market Administration Expenses

Case No.: U-17317
Witness: DSAlfred
Exhibit: A-1 (DSA-1)

Date: September 2013

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	5,813	5,593	5,516	4,884	6,027	7,521	7,798	7,883	6,858	5,569	5,588	6,008	**75,058**
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	3,145,072	2,843,488	2,979,535	2,693,142	2,867,172	3,130,988	3,405,149	3,341,131	2,901,930	2,877,972	2,821,581	3,127,729	**36,134,889**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	376.8756	376.8756	376.8756	376.8756	376.8756	376.8756	376.8756	376.8756	376.8756	376.8756	376.8756	376.8756	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	3,534.8320	3,534.8320	3,534.8320	3,534.8320	3,534.8320	3,520.3076	3,520.3076	3,520.3076	3,520.3076	3,520.3076	3,520.3076	3,520.3076	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0604	0.0604	0.0604	0.0604	0.0604	0.0604	0.0604	0.0604	0.0604	0.0604	0.0604	0.0604	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0823	0.0823	0.0823	0.0823	0.0823	0.0823	0.0823	0.0823	0.0823	0.0823	0.0823	0.0823	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	
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	0.0740	0.0740	0.0740	0.0740	0.0740	0.0740	0.0740	0.0740	0.0740	0.0740	0.0740	0.0740	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	1,390.8051	1,390.8051	1,390.8051	1,390.8051	1,390.8051	1,390.8051	1,390.8051	1,390.8051	1,390.8051	1,390.8051	1,390.8051	1,390.8051	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.1363	1.1363	1.1363	1.1363	1.1363	1.1363	1.1363	1.1363	1.1363	1.1363	1.1363	1.1363	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 349,451	$ 336,225	$ 331,597	$ 293,604	$ 362,316	$ 452,128	$ 468,780	$ 473,890	$ 412,271	$ 334,783	$ 335,925	$ 361,173	**$ 4,512,142**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,190,778	2,107,865	2,078,846	1,840,660	2,271,429	2,834,481	2,938,876	2,970,910	2,584,613	2,098,820	2,105,981	2,264,268	**28,287,525**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	20,547,978	19,770,315	19,498,133	17,264,119	21,304,432	26,476,233	27,451,358	27,750,584	24,142,269	19,604,593	19,671,479	21,150,008	**264,631,502**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	261,222	235,121	247,876	212,395	270,839	327,073	350,423	354,243	298,241	250,257	243,011	269,985	**3,320,687**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	258,839	234,019	245,216	221,646	235,968	257,680	280,244	274,975	238,829	236,857	232,216	257,412	**2,973,901**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	143,415	129,663	135,867	122,807	130,743	142,773	155,275	152,356	132,328	131,236	128,664	142,624	**1,647,751**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	38,924	35,035	36,935	31,648	40,357	48,736	52,215	52,785	44,440	37,290	36,210	40,230	**494,804**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	465,471	420,836	440,971	398,585	424,341	463,386	503,962	494,487	429,486	425,940	417,594	462,904	**5,347,964**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	83,030	75,068	78,660	71,099	75,693	82,658	89,896	88,206	76,611	75,978	74,490	82,572	**953,961**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	8,084,750	7,778,773	7,671,681	6,792,692	8,382,382	10,460,245	10,845,498	10,963,717	9,538,142	7,745,394	7,771,819	8,355,957	**104,391,051**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	3,573,862	3,231,161	3,385,756	3,060,317	3,258,074	3,557,858	3,869,397	3,796,651	3,297,571	3,270,347	3,206,267	3,554,155	**41,061,418**
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**	**$35,412,296**	**$33,825,143**	**$33,596,971**	**$29,810,241**	**$36,218,184**	**$44,510,472**	**$46,361,851**	**$46,739,326**	**$40,646,263**	**$33,674,286**	**$33,697,362**	**$36,357,583**	**$ 450,849,977**
28	Total Energy Market Administration Expenses	**Lines 21-23**	**587,424**	**530,939**	**556,566**	**501,332**	**540,392**	**594,780**	**646,073**	**635,478**	**550,536**	**539,208**	**528,294**	**585,706**	**6,796,729**
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$35,999,720**	**$34,356,081**	**$34,153,537**	**$30,311,573**	**$36,758,575**	**$45,105,252**	**$47,007,925**	**$47,374,804**	**$41,196,800**	**$34,213,494**	**$34,225,656**	**$36,943,289**	**$ 457,646,706**

Consumers Energy Company

2018 Transmission and Energy Market Administration Expenses

Case No.: U-17317
Witness: DSAlfred
Exhibit: A-1 (DSA-1)
Page: 5 of 5
Date: September 2013

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	5,858	5,627	5,550	4,920	6,077	7,587	7,865	7,896	6,910	5,616	5,630	6,049	**75,585**
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	3,170,085	2,866,567	3,003,145	2,715,109	2,890,251	3,155,896	3,431,688	3,366,994	2,925,839	2,901,443	2,844,681	3,152,668	**36,424,366**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	$ 60.1154	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	374.4989	374.4989	374.4989	374.4989	374.4989	374.4989	374.4989	374.4989	374.4989	374.4989	374.4989	374.4989	
6	Schedule 9 - Network Transmission Servic	Workpaper DSA-5	3,698.5121	3,698.5121	3,698.5121	3,698.5121	3,698.5121	3,750.4323	3,750.4323	3,750.4323	3,750.4323	3,750.4323	3,750.4323	3,750.4323	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basi	Workpaper DSA-6	0.0601	0.0601	0.0601	0.0601	0.0601	0.0601	0.0601	0.0601	0.0601	0.0601	0.0601	0.0601	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charg	Workpaper DSA-6	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	0.0456	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	
12	Schedule 24 - Balancing Area Cost Adder - Energy Market	Workpaper DSA-6	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Pla	Workpaper DSA-5a	1,362.6384	1,362.6384	1,362.6384	1,362.6384	1,362.6384	1,362.6384	1,362.6384	1,362.6384	1,362.6384	1,362.6384	1,362.6384	1,362.6384	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.3626	1.3626	1.3626	1.3626	1.3626	1.3626	1.3626	1.3626	1.3626	1.3626	1.3626	1.3626	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 352,156	$ 338,269	$ 333,640	$ 295,768	$ 365,321	$ 456,096	$ 472,808	$ 474,671	$ 415,397	$ 337,608	$ 338,450	$ 363,638	**$ 4,543,823**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,193,815	2,107,305	2,078,469	1,842,535	2,275,830	2,841,323	2,945,434	2,957,043	2,587,787	2,103,186	2,108,429	2,265,344	**28,306,500**
17	Schedule 9 - Network Transmission Servic	Line 1 * Line 6	21,665,884	20,811,528	20,526,742	18,196,680	22,475,858	28,454,530	29,497,150	29,613,414	25,915,487	21,062,428	21,114,934	22,686,365	**282,021,000**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basi	Line 1 * Line 2 * Line 7	261,937	227,259	248,165	212,898	271,729	328,305	351,679	353,065	299,010	251,116	243,621	270,477	**3,319,261**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	259,947	235,058	246,258	222,639	237,001	258,783	281,398	276,094	239,919	237,918	233,264	258,519	**2,986,798**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charg	Line 3 * Line 9	144,556	130,715	136,943	123,809	131,795	143,909	156,485	153,535	133,418	132,306	129,717	143,762	**1,660,951**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	43,584	37,813	41,292	35,424	45,213	54,626	58,516	58,746	49,752	41,783	40,536	45,005	**552,290**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	488,193	441,451	462,484	418,127	445,099	486,008	528,480	518,517	450,579	446,822	438,081	485,511	**5,609,352**
23	Schedule 24 - Balancing Area Cost Adder - Energy Market	(Line 3 * 2) * Line 12	83,690	75,677	79,283	71,679	76,303	83,316	90,597	88,889	77,242	76,598	75,100	83,230	**961,603**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Pla	Line 1 * Line 13	7,982,336	7,667,567	7,562,643	6,704,181	8,280,754	10,338,338	10,717,151	10,759,393	9,415,832	7,652,578	7,671,654	8,242,600	**102,995,027**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	4,319,479	3,905,913	4,092,010	3,699,540	3,938,184	4,300,145	4,675,932	4,587,782	3,986,675	3,953,434	3,876,091	4,295,747	**49,630,932**
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**	**$ 37,182,109**	**$ 35,425,614**	**$ 35,226,872**	**$ 31,300,049**	**$ 37,978,472**	**$ 47,123,429**	**$ 49,100,038**	**$ 49,176,997**	**$ 42,995,526**	**$ 35,732,573**	**$ 35,718,161**	**$ 38,528,452**	**$ 475,488,292**
28	Total Energy Market Administration Expenses	**Lines 21-23**	**615,467**	**554,942**	**583,059**	**525,230**	**566,614**	**623,950**	**677,592**	**666,152**	**577,573**	**565,203**	**553,716**	**613,746**	**7,123,245**
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 37,797,576**	**$ 35,980,556**	**$ 35,809,931**	**$ 31,825,279**	**$ 38,545,087**	**$ 47,747,379**	**$ 49,777,630**	**$ 49,843,149**	**$ 43,573,099**	**$ 36,297,777**	**$ 36,271,877**	**$ 39,142,197**	**$ 482,611,537**

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-17317
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2014	)	

DIRECT TESTIMONY

OF

NATALIE N. BUSACK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September, 2013

Q. Please state your name and business address.

A. Natalie N. Busack, One Energy Plaza, Jackson, Michigan.

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 I in the Revenue 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 Company in April 2002.

Q. Since joining Consumers, 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. 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 PSCR factor and preparation of economic studies relating to the operations of the Company's business units.

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

A. Yes, I sponsored testimony in the following cases:

Case No. U-15943 - Reconciliation of the 2008 and 2009 Electric Choice Incentive Mechanism

Case No. U-16759 - Residual Balance filing

Case No. U-17095 – PSCR Plan Case 2013

Case No. U-16890-R – Reconciliation of PSCR 2012

Case No. U-17133 – GCR Plan Case 2013-2014

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

A. The purpose of my testimony is to present the calculation of the 2014 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 2014 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 2014 PSCR factor including: (i) total power supply costs provided by Ms. Walz; (ii) transmission expenses provided by Mr. Alfred; (iii) Schedule 2 Reactive Revenue provided by Mr. Alfred; (iv) NO_x allowance expenses, urea costs and aqueous ammonia costs provided by Mr. Kehoe.

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

A. The 2014 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 NO_x allowance costs, urea costs and aqueous ammonia costs ("Total Environmental Costs") shown on Line 9 and the projected 2013 underrecovery on line 10. That sum, shown on Line 11, is divided by total system energy requirements (measured in units of kilowatthours or kWh) on Line 12, provided to me by Company witness Miller, to determine the average cost per kWh of requirements on Line 13. From this quotient is subtracted the base recovery factor (shown on Line 14) collected through the standard tariffs as approved by the Commission. This remaining expense per kWh amount ($(0.00037) set forth on Line 15) is multiplied by the Line and Transformation Loss Factor on Line 16 to determine the 2014 per kWh PSCR factor of $(0.00040) at sales, shown on Line 17.

Q. Please describe the 2013 underrecovery shown on line 9 of Exhibit A-2 (NNB-1).

A. In its December 21, 2006 order in MPSC Case No. U-15001, the Commission authorized Consumers Energy to include prior years' underrecoveries (and overrecoveries) in the current year's PSCR plan. *See*, December 21, 2006 order at Page 9, Ordering Paragraph. The basis of the 2013 underrecovery on line 10 is the Company's booked year-to-date August actual underrecovery and the sum of the projected PSCR recoveries for each month remaining in 2013, including interest. The Company projects that by the end of the 2013 plan year, the total principal underrecovery will be $1,867,006. Including interest, the projected underrecovery is $1,897,878.

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 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 underrecovery for the PSCR 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	)	
for Approval of a Power Supply Cost	)	Case No. U-17317
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2014	)	

EXHIBIT

OF

NATALIE N. BUSACK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2013

Case No. U-17317
Witness: NNBusack
Exhibit A-2 (NNB-1)
Page 1 of 1
September, 2013

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Calculation of 2014 PSCR Factor

Line			
1	System Power Supply Costs[1]		$ 1,586,475,000
	System Transmission Expenses		
2	Total Transmission Expenses[2]	$ 374,070,842	
3	Less: Schedule 2 Reactive Revenue[3]	(19,706,000)	
4	Net Transmission Expenses		$ 354,364,842
	Environmental Costs		
5	NOx Allowance Costs[4]	$ 103	
6	Urea Costs[5]	2,643,000	
7	Aqueous Amonia[6]	1,732,000	
8	Lime Expense[7]	777,000	
9	Total Environmental Costs		$ 5,152,103
10	2013 Underrecovery[8]		$ 1,897,878
11	Total System Power Supply Costs		$ 1,947,889,823
12	Total System Requirements in kWh[9]		35,200,446,000
	Jurisdictional Factor Calculation		
13	Average Cost at Requirements (Line 11 / Line 12)		$ 0.05533
14	Less: Base Recovery Factor[10]		$ 0.05570
15	Remaining Cost per kWh (Line 13 - Line 14)		$ (0.00037)
16	Line & Transformation Loss Factor[11]		1.086
17	2014 PSCR Factor at Sales (Line 15 x Line 16)		$ (0.00040)

Sources:
[1] Exhibit A-21 (STW-1), Page 1, Line 26
[2] Exhibit A-1 (DSA-1), line 29
[3] DSAlfred Testimony, Page 8, Line 1
[4] Exhibit A-10 (DBK-3), Line 22
[5] Exhibit A-11 (DBK-4), Line 3
[6] Exhibit A-12 (DBK-5), Line 4
[7] Exhibit A-13 (DBK-6), Line 3
[8] NNB Workpaper NNB 1
[9] Exhibit A-16 (HWM-3), Page 2, Line 13
[10] Per Order in Case No. U-17087
[11] 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-17317
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2014	)	

DIRECT TESTIMONY

OF

JIM K. CHILSON II, PE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September, 2013

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

A. Jim K. Chilson II, 1945 Parnall Rd, Jackson, Michigan.

Q. By whom are you employed?

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 and 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 rail cars for coal delivery;

- managing the projection of volumes and prices of #6 fuel oil for Karn 3&4, natural gas for Zeeland and Karn 3&4, and #2 fuel oil and natural gas for the combustion turbines;
- supervising the purchase of natural gas for the Cobb, Zeeland and Karn 3&4 Plants;
- preparation of testimony and filings for presentation before the MPSC.

Q. Have you testified in other cases?

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

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

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.

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 – 2014
Exhibit A-5 (JKC-3), Estimated As-Burned Oil & Gas Costs – 2014
Exhibit A-6 (JKC-4), Estimated As-Burned Coal Costs (2015-2018)
Exhibit A-7 (JKC-5), Estimated As-Burned Oil & Gas Costs (2015-2018)

COAL COSTS

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 blended 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 Consumers Energy's coal purchasing strategy?

A. Yes. Consumers Energy 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 Consumers Energy's 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. Consumers Energy purchases and secures quantities over time that typically enables 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 2014.

A. No. The Company is continuing to layer coal purchases in order to maintain a diverse portfolio of contracts; however, the Company intends to purchase coal closer to the 70% than the 90%.

ENVIRONMENTAL CONSIDERATIONS

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

A. During 2014, the Michigan Natural Resources and Environmental Protection Act, 1994 PA 451 (NREPA), will require the use of fuel with a maximum of 1.67 pounds of sulfur dioxide (SO_2) per million Btu heat input to meet the sulfur dioxide emission limit at the JCWeadock and DEKarn plants at Essexville, the BCCobb Plant at Muskegon, the JRWhiting Plant at Erie, and the JHCampbell Plant Units 1&2 at West Olive. The federal Environmental Protection Agency ("EPA") has established 1.2 pounds SO_2 per million Btu heat input as the maximum sulfur dioxide emission limit for JHCampbell Unit 3. Also, (NREPA) has stipulated that the Company must keep stack emission opacity levels at all plants below 20%. These restrictions dictate the quality of coal purchased to meet system requirements. Additionally, under the EPA's Acid Rain Program and the State's NOx Budget Trading Program, emissions of SO_2 and NOx are monitored to account for transferable emission allowances. These emission allowances have an economic value, and to the extent various fuel alternatives affect the value of emission allowances that are required to be surrendered, such value also is considered in the Company's coal supply purchasing program.

COAL PURCHASE CONTRACTS

Q. How many annual and multiyear contracts will Consumers Energy have during 2014?

A. Presently the Company has seven multiyear long-term and annual coal purchase contracts that will be in effect during 2014. Six of these purchase contracts provide for the 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) and the remaining one purchase contract provides for the eastern coal supply for these same plants.

Q. Does Exhibit A-3 (JKC-1) list these contracts?

A. Yes, it does.

Q. Briefly describe the data contained in Exhibit A-3 (JKC-1).

A. 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 volumes we currently expect to nominate for 2014.

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 2014?

A. Yes. We anticipate soliciting for additional western coal before the end of 2013 for delivery in 2014.

COAL PRICE DETERMINATION

Q. Please describe how coal prices were projected for 2014?

A. The Company based the projected coal prices on the present coal contracts with fixed pricing, the present coal contracts tied to an index using the projected index price and the remaining open position was estimated based on the current 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 2014, the Company expects to have in effect five 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.

Q. Do you anticipate entering into any new coal transportation agreements in 2014?

A. Yes. The agreements to provide vessel shipments and terminal services of coal will expire on December 31, 2013. The Company is in the process of competitively bidding for the new vessel services. The Company anticipates selecting the lowest cost provider and entering into a new agreement during the 4^{th} quarter of 2013.

<u>COAL TRANSPORTATION RATE DETERMINATION</u>

Q. What procedure was used to determine freight rates?

A. Freight rates were determined either by the fixed contract pricing or according to the performance of indices to which the rates are tied. Additionally, fuel surcharges were included as defined in each of the transportation contracts or in the railroad published tariffs.

<u>COAL TONNAGE DETERMINATION</u>

Q. How were the coal tonnages determined for 2014?

A. As described in witness 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. 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 2014 and do you expect to purchase more?

A. The Company presently has approximately 6.07 million tons of coal committed for 2014 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 2013 for 2014 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 2014?

A. Approximately 2 to 3 million tons of coal is expected to be purchased on a spot basis.

Q. What was considered when estimating spot prices for 2014?

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 and permitting issues, alternative fuel prices, strikes, and other factors. Lower natural gas prices have reduced the demand for coal resulting in relatively low prices. Spot prices are expected to remain relatively low throughout 2014.

TYPES OF COAL

Q. What types of coal does Consumers Energy expect to utilize in 2014?

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 2014?

A. On a system-wide basis, we expect to burn approximately 8.6 million tons of western coal or approximately 97% by weight of our total coal burn requirements in 2014.

Q. How much eastern coal is expected to be burned in 2014?

A. The Company presently has a single eastern coal contract in effect for 2014 with a contract volume of 264,000 tons. Because of the anticipated lower cost of natural gas in 2014 relative to eastern coal and power available off the market, 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 believes it has purchased enough eastern coal to ensure an adequate supply for the estimated high demand days. At this time, no additional purchases are planned for 2014.

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 2014. 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 plant inventory location, the total monthly delivered cost of coal for the current month is added to the cost in inventory at the end of the previous month and divided by the delivered coal volume for the current month plus the volume in inventory at the end of the previous month. This average cost of fuel in inventory is then multiplied by the current month burn volume to arrive at the as-burned cost for the current month. The current month's ending inventory is then calculated by subtracting the current month burn cost and volume, respectively, from the starting inventory values for the current month, plus any purchase cost and volume. It is important to note that although the coal cost for this case are developed based on as-burned, the generation units are dispatched based on the replacement cost of fuel. 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 to replace coal that is consumed from inventory. Coal units are dispatched at this spot coal price so their production at this price can be compared to the current market.

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 insure all lading can be removed from the railcars during winter months and to insure compliance with railroad operating rules and tariffs; the application of any necessary or required dust inhibitors to insure compliance with railroad operating rules and tariffs; applicable harbor maintenance fees; as well as the cost of transporting the coal to the plant.

2015 – 2018 PROJECTED COAL COSTS

Q. How were the coal prices determined to obtain the coal cost projections for the years 2015-2018?

A. In a manner similar to 2014, 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 tonnage.

Q. Where do the coal cost projections appear?

A. These costs are shown in Exhibit A-6 (JKC-4).

Q. Are any new contracts anticipated for the 2015-2018 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 2015 - 2018. The pricing for any new supply and transportation contracts are modeled as previously described in my testimony.

OIL AND NATURAL GAS COST PROJECTIONS

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 Consumers Energy's oil and gas fired generating units, those being the Zeeland Plant, the DEKarn 3&4 Plant, the BCCobb Plant, and all of the combustion turbine units.

Q. What types of fuel do these units burn?

A. The Zeeland plant burns natural gas, as well as the BCCobb Plant for start-up and over-firing. DEKarn 3&4 can burn natural gas, No. 6 fuel oil (both low and mid-sulfur), or a combination thereof. The combustion turbines burn either natural gas or No. 2 fuel oil.

Q. Holding the discussion for the Zeeland plant 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 and the combustion turbine at the Karn/Weadock complex 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 Company natural gas utility or the Michigan Consolidated Gas Company ("MichCon") pursuant to the Michigan Public Service Commission (MPSC) approved tariff rates (Consumers Energy Rate GS-3 and MichCon 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 units typically have more expensive variable costs, and as a result 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

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 3&4 units 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, oil is purchased over a period of months to minimize the cost of oil in inventory and within inventory constraints. Additionally, oil is purchased in varying qualities and prices and blended in the storage tanks at the plant to provide additional gas and oil blending flexibility. For example, low sulfur oil is available on site to enable the units to run entirely on oil without blending with gas. Lower cost mid-sulfur oil is also available in storage to blend with a typical mixture of approximately 30% natural gas. The midsulfur oil, when mixed in varying degrees with low sulfur oil, accommodates the ability to burn any mixture of oil and gas. Finally, 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 employing strategies to minimize cost and to insure 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 MichCon 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. We have not seen it prudent to purchase additional storage, over and above that amount provided for in our 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 the Consumers Energy gas customers if storage were used by the electric utility to benefit its electric customers, from both a supply and cost standpoint; (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, and; (4) as stated previously for Karn 3&4, we have the ability to maintain an oil inventory that can be used to operationally hedge the cost of gas against the cost of oil, which reduces the need to store gas.

ZEELAND PLANT 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 Consumers Energy done to assure a reliable and economic supply of fuel for the Zeeland facility?

A. Consumers Energy has entered into a contract with a third party (which was competitively bid) 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 firm transportation and storage 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 firm 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 firm 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 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 the MISO accepts offers from Zeeland in the MISO energy market. These purchases of gas on behalf of the Company are conducted on a day ahead, intraday and real-time basis and gas is stored on an as-needed basis to balance against dispatch requests from MISO. The pricing of the gas management services contract is based on published indices. If necessary, gas storage 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. What is the status of the contract with the Agent?

A. The Company's contract with the previous agent expired on May 31, 2013.

Q. Did the Company renew the current contract?

A. No. As is the Company's practice, contracts are entered into through a competitive bidding process, with the lowest cost bid meeting all the requirements being accepted,

Q. Has the Company selected a new Agent?

A. Yes.

Q. Has any of the services of the previous contract changed?

A. No. The services provided by the Agent selected are similar to terms of the previous contract, although at a reduced price.

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 firm transportation of up to 186,000 Mcf of gas per day.

Q. Have you developed fuel cost projections for the Company's oil-fired and natural gas-fired generating units for the year 2014?

A. Yes. These fuel cost projections are shown in Exhibit A-5 (JKC-3).

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 2014?

A. 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 projection of the relationship between crude oil and No. 6 oil and No. 2 oil. The price of gas for Karn 3&4 and the Weadock combustion turbine is based on the market gas prices (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 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 MichCon the gas index associated with the pricing of the gas to Consumers Energy by the Agent as defined within the 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 also based on the market gas projections provided by the Risk Management Department, but with seasonally firm transportation provided through the MichCon 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 MichCon's Rate No. GS-2 and gas service for the Morrow and Thetford units is provided pursuant to Consumers Energy Company's Gas Rate GS-3.

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

A. Yes. Service from the DCP Midstream Partners Bay Area Pipeline is temporarily unavailable for transporting gas to the Karn 3 & 4 plant. Currently, the Company is transporting gas to the plant through the Consumers Energy distribution system. The Company anticipates that the service will be restored by May 1, 2014.

Q. Will this have any effect on Karn 3 & 4 operations?

A. The temporary disruption in service from the DCP pipeline will have minimal impact on gas service to Karn 3 & 4. The Karn 3 & 4 units are considered peaking units. The Company anticipates that the gas service from the DCP pipeline will not likely be required prior to May 1, 2014.

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

New York Mercantile Exchange 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 city gate.

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

A. The Company has determined historical relationships between the MichCon city gate 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 city gate price.

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

A. The Zeeland gas management services agreement was 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. Also, to the extent it is available; DEKarn 3&4 also burns low cost on-spec waste oil. 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 2015 through 2018?

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

Q. How were your oil and natural gas projections determined for the years 2015 through 2018?

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

2014.

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-17317
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2014	)	

EXHIBITS

OF

JIM K. CHILSON II, PE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2013

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-17317
Exhibit: A-3 (JKC-1)
Witness: JKChilson
Date: September 2013

Coal Contract & Annual Purchase Data

Line	(a) Supplier Contract No	(b) Coal Type	(c) Contract Start Date	(d) Contract End Date	(e) 2014 Volume (Tons)
1	121	Western	1/1/2012	12/31/2014	1,310,400
2	125	Western	1/1/2012	12/31/2014	533,520
3	137	Western	1/1/2013	12/31/2015	1,067,040
4	142	Western	1/1/2013	12/31/2015	889,200
5	153	Western	1/1/2014	12/31/2015	1,067,040
6	154	Western	1/1/2014	12/31/2014	936,000
7	122	Eastern	1/1/2012	12/31/2014	264,000
8				**Total**	**6,067,200**

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-17317
Exhibit: A-4 (JKC-2)
Witness: JKChilson
Date: September 2013
Page: 1 of 1

Estimated As-Burned Coal Costs - 2014

Line	(a) Plant	(b)	(c) Burn Volume (Tons)	(d) Burn Dollars
1	JHCampbell 1-2		1,897,597	$ 92,691,928
2	JHCampbell 3 (CE Owned)		2,637,685	$ 123,046,354
3	BCCobb 4-5		994,880	$ 49,189,027
4	DEKarn 1-2		1,227,366	$ 56,645,711
5	JCWeadock 7-8		982,621	$ 45,536,159
6	JRWhiting 1-3		970,740	$ 46,821,351
			8,710,890	$ 413,930,531
7		Total Primary Fuel		$ 413,930,531
8		Total Auxilliary Fuel		$ 8,019,961
9		Total Freeze/Dust Treatment		$ 1,424,888
10		State Air Emission Fees		$ 752,254
11		Total Coal Cost		$ 424,127,633

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-17317
Exhibit: A-5 (JKC-3)
Witness: JKChilson
Date: September 2013
Page: 1 of 1

Estimated As-Burned Oil & Gas Costs - 2014

Line	(a) Plant	(b)	(c) Burn Volume (BBLS/MCF)	(d) Burn Dollars
1	Zeeland Generating Station		10,437,648	$ 45,575,583
2	DEKarn 3-4 - Oil		-	$ -
3	DEKarn 3-4 - Gas		1,138,964	$ 9,202,694
4	BCCobb 1-3		-	$ -
5	Combustion Turbines - Oil		-	$ -
6	Combustion Turbines - Gas		-	$ 503,940
				$ 55,282,217
7		Total Primary Fuel		$ 55,282,217
8		Total Auxilliary Fuel		$ 4,154,544
9		State Air Emission Fees		$ 67,966
10		Total Oil & Gas Cost		$ 59,504,727

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-17317
Exhibit: A-6 (JKC-4)
Witness: JKChilson
Date: September 2013
Page: 1 of 1

Estimated As-Burned Coal Costs
2015 - 2018

Line	(a)	(b)	(c)	(d)	(e)	(f)
	Burn Volume (Tons)					
	Plant		2015	2016	2017	2018
1	JHCampbell 1-2		1,924,774	2,086,352	2,122,108	1,844,099
2	JHCampbell 3 (CE Owned)		3,000,647	2,501,017	3,174,810	2,873,759
3	BCCobb 4-5		977,117	311,613	-	-
4	DEKarn 1-2		1,550,403	1,958,307	1,805,389	1,577,427
5	JCWeadock 7-8		1,016,156	310,765	-	-
6	JRWhiting 1-3		1,075,046	345,072	-	-
7		Total Burn Tonnage	9,544,143	7,513,127	7,102,307	6,295,284
	Burn Dollars					
	Plant		2015	2016	2017	2018
8	JHCampbell 1-2		$ 91,617,420	$ 96,572,844	$ 103,208,450	$ 93,620,896
9	JHCampbell 3 (CE Owned)		$ 136,357,815	$ 115,762,408	$ 153,971,577	$ 145,676,325
10	BCCobb 4-5		$ 44,103,632	$ 13,036,686	$ -	$ -
11	DEKarn 1-2		$ 71,320,939	$ 91,422,759	$ 88,318,462	$ 80,708,368
12	JCWeadock 7-8		$ 46,891,919	$ 13,916,610	$ -	$ -
13	JRWhiting 1-3		$ 52,459,558	$ 16,092,209	$ -	$ -
14		Total Primary Fuel	$ 442,751,282	$ 346,803,516	$ 345,498,489	$ 320,005,589
15		Total Primary Fuel	$ 442,751,282	$ 346,803,516	$ 345,498,489	$ 320,005,589
16		Total Auxilliary Fuel	$ 9,103,700	$ 7,637,701	$ 6,639,229	$ 5,855,236
17		Total Freeze/Dust Treatment	$ 1,437,938	$ 1,151,118	$ 1,127,651	$ 998,549
18		State Air Emission Fees	$ 763,538	$ 774,991	$ 786,616	$ 798,415
19		Total Coal Burn Cost	$ 454,056,458	$ 356,367,326	$ 354,051,985	$ 327,657,789

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-17317
Exhibit: A-7 (JKC-5)
Witness: JKChilson
Date: September 2013
Page: 1 of 1

Estimated As-Burned Oil & Gas Costs
2015 - 2018

Line	(a)	(b)	(c)	(d)	(e)	(f)
	Burn Volume (BBLS/MCF)					
	Plant		2015	2016	2017	2018
1	Zeeland Generating Station		7,455,488	17,919,830	21,699,563	17,373,088
2	Thetford New Generation		-	-	15,458,001	30,347,850
3	DEKarn 3-4 - Oil		3,815	9,291	5,315	4,885
4	DEKarn 3-4 - Gas		1,669,240	2,054,883	1,405,951	935,849
5	BCCobb 1-3		-	-	-	-
6	Combustion Turbines - Oil		-	-	-	-
7	Combustion Turbines - Gas		-	-	-	-
	Burn Dollars					
	Plant		2015	2016	2017	2018
8	Zeeland Generating Station		$ 34,426,762	$ 83,997,343	$ 104,957,369	$ 85,009,414
9	Thetford New Generation		$ -	$ -	$ 75,698,994	$ 152,191,060
10	DEKarn 3-4 - Oil		$ 233,831	$ 538,667	$ 299,669	$ 270,549
11	DEKarn 3-4 - Gas		$ 12,007,664	$ 14,102,703	$ 11,086,361	$ 8,863,348
12	BCCobb 1-3		$ -	$ -	$ -	$ -
13	Combustion Turbines - Oil		$ -	$ -	$ -	$ -
14	Combustion Turbines - Gas		$ 503,940	$ 503,940	$ 503,940	$ 503,940
15		Total Primary Fuel	$ 47,172,196	$ 99,142,653	$ 192,546,333	$ 246,838,312
16		Total Primary Fuel	$ 47,172,196	$ 99,142,653	$ 192,546,333	$ 246,838,312
17		Total Auxilliary Fuel	$ 3,558,409	$ 7,816,013	$ 15,069,190	$ 20,918,714
18		State Air Emission Fees	$ 68,985	$ 70,020	$ 79,557	$ 80,751
19		Total Oil & Gas Burn Cost	$ 50,799,590	$ 107,028,686	$ 207,695,080	$ 267,837,777

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-17317
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2014	)	

DIRECT TESTIMONY

OF

DAVID B. KEHOE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2013

Q. Please state your name and business address.

A. David B. Kehoe, 1945 W. Parnall Road, Jackson, Michigan.

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 Staff, Electric Generation.

Q. Please describe your educational background.

A. I received a Bachelor of Science (Chemistry) degree in December 1977 from the University of Michigan. I also received a Master's degree (Business Administration) in May 1982 from the University of Detroit.

Q. Please describe your business experience.

A. In 1978 I began working as an Associate Engineer for The Detroit Edison Company ("Detroit Edison"). In this capacity I worked at Detroit Edison's Engineering Research Department largely serving as an analytical chemist specializing in instrumental analytical chemistry. From mid 1982 to September 1989 I held the position of Fuels Engineer, and was responsible for both the operation of Detroit Edison's fuels laboratory as well as for consulting with the operating power plants on fuel and combustion product impacts. Additionally, from 1985 until 1989 I was in charge of the Polychlorinated Biphenyls ("PCB") analysis laboratory. This laboratory analyzed soil and oil samples for the presence of PCBs and was part of Detroit Edison's program to remove PCBs from existing equipment and to verify the absence of PCBs from soil samples that came from remediation of transformer-oil spills. While at Detroit Edison, I was also a member of the American Chemical Society, the ASTM Committee on Corrosion and Deposits from Combustion Gasses, and ASTM D-5 Committee.

In 1998 I left the position of Senior Engineer at Detroit Edison and went to CQ Inc., a subsidiary of the Electric Power Research Institute. While at CQ Inc., I held the position of Project Manager, and consulted with utilities, coal companies, and engineering firms on fuel selection and fuel impacts. Additionally, I served on the Department of Energy coal research project peer review panel.

In 1998, I left CQ Inc. and joined CMS Generation, a subsidiary of CMS Energy, as a Plant Support Manager. My responsibilities included negotiation of long-term service agreements, power purchase agreements, operation and maintenance agreements for new and existing power plants, providing operations review and cost estimates in development of new power plants, and providing technical assistance to existing power generating assets. In 2000, I became the Asset Manager for the Jorf Lasfar Energy Company in ("Jorf Lasfar") Morocco, and was responsible for representing CMS Energy's interests in that project. In that capacity I also served on the Management Committee of Jorf Lasfar, which functions as that project's board of directors. As such, I was responsible for dividend declarations, cash management policy, setting annual goals and objectives, reviewing performance and establishing salary bonus structure for the project management. In addition, I also served in a similar capacity for the GasAtacama project in northern Chile. In April of 2004, I accepted the position of Director of Staff, Electric Generation.

Q. What are your responsibilities as Director of Staff, Electric Generation?

A. As Director of Staff, Electric Generation, I am responsible for strategic planning for the electric generation business of Consumers Energy. This function includes air quality and regulatory oversight as well as financial planning and budgeting.

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

A. Yes. I sponsored testimony in the following cases: Case Nos. U-13917 and U-13917-R (2004 Power Supply Cost Recovery ("PSCR") Plan and Reconciliation cases); Case Nos. U-14274 and U-14274-R (2005 PSCR Plan and Reconciliation cases); Case Nos. U-14701 and U-14701-R (2006 PSCR Plan and Reconciliation cases); Case No. U-14347 (2006 Electric Rate case); Case Nos. U-15001 and U-15001-R (2007 PSCR Plan and Reconciliation cases); Case Nos. U-15415 and U-15415-R (2008 PSCR Plan and Reconciliation cases); Case No. U-15245 (2008 Electric Rate case); Case Nos. U-15675 and U-15675-R (2009 PSCR Plan and Reconciliation case); Case No. U-15645 (2009 Electric Rate case); Case No. U-16113 (2009 Show Cause Order); Case No. U-16054 (2009 Depreciation Practices for Electric and Common Utility Plant); Case No. U-16055 (2009 Depreciation Practices for Ludington Pumped Storage Plant); Case No. U-16045 and U-16045-R (2010 PSCR Plan and Reconciliation cases); Case No. U-16191 (2010 Electric Rate case); Case No. U-16432 and U-16432-R (2011 PSCR Plan and Reconciliation cases); Case No. U-16536 (2011 Depreciation Practices for Lake Winds Energy Park); Case No. U-16794 (2011 Electric Rate case); Case No. U-16890 and U-16890-R (2012 PSCR Plan and Reconciliation cases); Case No. U-17087 (2013 Electric Rate case); Case No. U-17095 (2012 PSCR Plan case); Case No. U-17453 (2013 Accounting Practices for certain Electric and Common Utility Plant); and Case No. U-17473 (2013 Financing Order Approving the Securitization of Qualified Costs).

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 Pump Storage Plant ("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 2014 PSCR plan year; 3) compare the projected ROR for fossil, hydro, Ludington and peaker units with actual ROR experienced in the five-year period 2008-2012; 4) address availability of generating units for the five-year forecast period; 5) identify forecasted air emissions allowances for the 2014 PSCR plan year, as well as the period 2015 through 2018; 6) identify forecasted urea expenses for the 2014 PSCR plan year, as well as the period 2015 through 2018; 7) identify forecasted aqueous ammonia expenses for the 2014 PSCR plan year, as well as the period 2015 through 2018, and request this expense be included in all future PSCR Plan cases; and 8) identify forecasted lime expenses for the 2014 PSCR plan year, as well as the period 2015 through 2018, 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-8 (DBK-1)	Major Outages in the 2014 PSCR Plan.
Exhibit A-9 (DBK-2)	2014 PSCR Random Outage Rate Projections.
Exhibit A-10 (DBK-3)	2014-2018 NO_x Allowance Budget.
Exhibit A-11 (DBK-4)	2014-2018 Urea Expenses.
Exhibit A-12 (DBK-5)	2014-2018 Aqueous Ammonia Expenses.
Exhibit A-13 (DBK-6)	2014-2018 Lime Expenses.

Major Generating Plant Outages for 2014

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 Walz in the dispatch of the Company's generating plants in this case.

A. Exhibit A-8 (DBK-1) describes those major outages.

Q. Please describe the significant activities, planned start dates and durations for each of the major outages listed on Exhibit A-8 (DBK-1).

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

Ludington 2

The outage at Ludington Unit 2 is scheduled to begin November 9, 2013, and is projected to last for 253 days. This will be the first unit outage of Ludington's multiyear $800 million overhaul and upgrade. The outage is necessary to replace and upgrade all major components including the water turbine (aka – runner), wicket gates, generator/pump, and stator.

Ludington 6

The outage at Ludington Unit 6 is scheduled to begin January 13, 2014, and is projected to last for 35 days. The outage is for cavitation repairs, penstock inspection and testing and shaft packing.

Karn 1

The outage at Karn Unit 1 is scheduled to begin March 15, 2014, and is projected to last for 60 days. The outage is for replacement of the Low Pressure ("LP") rotor, generator rewind, boiler repairs and the Spray Dry Absorber ("SDA") and Activated Carbon Injection (ACI) tie-in.

Ludington 1

The outage at Ludington Unit 1 is scheduled to begin April 07, 2014, and is projected to last for 28 days. The outage is to up-grade the existing ISO Phase Buss Duct and Cooling System.

Zeeland 1A

The outage at Zeeland Unit 1A is scheduled to begin April 12, 2014, and is projected to last for 28 days. The outage is necessary to inspect and maintain the hot gas path equipment.

Karn 2

The outage at Karn Unit 2 is scheduled to begin September 06, 2014, and is projected to last for 89 days. The outage is necessary to replace the Low Pressure (LP) rotor, inspect the High Pressure (HP) turbine and repair the boiler.

Ludington 3

The outage at Ludington Unit 3 is scheduled to begin September 14, 2014, and is projected to last for 35 days. The outage is necessary to repair cavitation damage, inspect and test the penstock, and repack the main shaft.

Ludington 4

The outage at Ludington Unit 4 is scheduled to begin September 14, 2014, and is projected to last for 238 days. This will be the second unit outage of Ludington's multi-year $800 million overhaul and upgrade. The outage is necessary to replace and upgrade all major components including the water turbine (aka – runner), wicket gates, generator/pump, and stator.

Miscellaneous Outages

Q. Are there other outages projected for 2014?

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

A. Cobb Units 1-3 were "mothballed" in 2009 and are expected to continue in that status. Consumers Energy will continue to evaluate the economics and timing of returning these units to service.

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

A. Mothballing 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 their operation.

Q. Did Consumers Energy file a request with MISO to mothball Cobb 4 & 5, Weadock 7 & 8 and Whiting 1-3?

A. Yes. The Company filed three (3) applications with MISO (one for each site – Cobb, Weadock and Whiting) in February 2012.

Q. What is the status of these applications?

A. MISO approved the Company's plans to suspend operation of these units effective April 16, 2015, providing a series of network upgrades were completed. The Company subsequently filed additional documents with MISO declaring the Company's intention to suspend operation of these units on April 16, 2016. MISO approved the Company's April 16, 2016 suspension date without any prerequisite network upgrades.

Q. Does Consumers Energy have additional generating units in a mothball status?

A. Please refer to Dave Ronk's testimony for the current status of the combustion turbines.

<u>ROR Projections</u>

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 (2008-2012) and are modified to reflect current operating conditions. This is shown in my Exhibit A-9 (DBK-2). Significant exceptions to the five-year average are described below.

<u>Campbell 2</u>

The 2014 ROR for Campbell Unit 2 is projected to be 5.81% higher than the five-year average. The increase in random outage rate is result of the unit burning 100% western coal.

Karn 1

The 2014 ROR Karn Unit 1 is projected to be 12.85% lower than the five-year average. In 2008 and into 2009, this unit experienced a turbine failure due to a cracked rotor that has now been repaired.

Whiting 2

The 2014 ROR for Whiting Unit 2 is projected to be 5.78% higher than the five-year average. This unit is one of seven that will be mothballed in 2016 due to increasingly stringent emissions standards. Because these units are not expected to operate beyond 2016, spending has been reduced, increasing ROR projections.

Availability

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

A. Yes. The 2014 projected availability for each of the generating units is also shown in column b of Exhibit A-9 (DBK-2).

Q. Do you have an availability projection for the five-year, 2014-2018 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. Please describe how the Company proposes to recover NO_x allowance expenses.

A. The Company requested and received approval in MPSC Case No. U-13917 to recover NO_x allowance expenses as PSCR expenses. I recommend the same treatment for the recovery of NO_x emission expense in 2014.

Q. Do you have an exhibit related to NO_x emission allowance expense?

A. Yes. Exhibit A-10 (DBK-3).

Q. Please describe Exhibit A-10 (DBK-3).

A. Exhibit A-10 (DBK-3) is the Company's projection of NO_x emission allowance expense for the PSCR Plan year 2014 and the remainder of the five-year forecast years, 2015 through 2018. The exhibit presents an annual tabulation of the allowance inventory, forecasted emissions, and a summary of the projected allowances that will be surrendered to the U.S. Environmental Protection Agency ("EPA") for compliance under 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 US Court of Appeals for the District of Columbia stayed the rule pending judicial review.

In a final ruling on August 21, 2012, the US Court of Appeals vacated the rule in its entirety and ordered that the "EPA must continue administering CAIR pending the promulgation of a valid replacement." In July 2013, the United States Supreme Court granted the government's request to review the ruling of the Court of Appeals. The Company is currently complying with CAIR and anticipates that rule will remain in effect for at least the next few years.

Q. How has Consumers Energy calculated the cost of the allowances set forth on Exhibit A-10 (DBK-3)?

A. Consumers Energy has calculated the "average cost" of each of the NO_x allowances inventory in accordance with 18 CFR 101, Uniform System of Accounts for Public Utilities and Licensees Subject to the Provisions of The Federal Power Act. Using the "average cost" methodology, allowances allocated to the Company by the EPA at zero cost are averaged with the cost of allowances that were exchanged and purchased. Banked allowances from the previous year are carried forward into the current inventory at the average cost of the previous year's inventory account. Forecasted purchases are based on a forecasted allowance market price. Allowances are expensed at the average cost of the inventory account, regardless of the actual cost of the individual allowance.

Q. Are these NO_x emission allowance expenses reflected elsewhere in this filing?

A. Yes, they are reflected in the overall PSCR factor calculated by Company witness Natalie N. Busack.

SO_2 Allowances

Q. Does Consumers Energy expect to incur any expenses or revenues in 2014 related to the SO_2 allowance program?

A. No.

Urea Expenses

Q. Are there additional PSCR expenses for which you are seeking recovery in 2014?

A. Yes, Exhibit A-11 (DBK-4) identifies the projected Urea Based Ammonia System ("UBAS") expenses through 2018.

Q. Please describe Exhibit A-11 (DBK-4).

A. In 2014, Consumers Energy projects spending $2.64 million for urea. In 2015, Consumers Energy expects to spend $2.80 million for urea. In 2016 through 2018, expenses are expected to be $2.17, $2.64, and $2.45 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 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 MPSC Case No. U-15415. I recommend the same treatment in 2014.

Aqueous Ammonia Expenses

Q. Are there additional PSCR expenses for which you are seeking recovery in 2014?

A. Yes, Exhibit A-12 (DBK-5) identifies the projected aqueous ammonia expenses through 2018.

Q. Please describe Exhibit A-12 (DBK-5).

A. In 2014, Consumers Energy projects spending $1.73 million for aqueous ammonia as a necessary expense of operating Karn Units 1 & 2 and Zeeland Unit 2 (the Combined Cycle ("CC") unit). In 2015, Consumers Energy expects to spend $1.97 million for aqueous ammonia associated with the operation of those units. In 2016 through 2018, expenses are expected to be $2.42, $2.31, and $2.05 million, respectively.

Q. Has Zeeland CC always used aqueous ammonia?

A. Yes, the Zeeland CC has always used aqueous ammonia to control NOx emissions.

Q. Why has Zeeland CC been added to Exhibit A-12 (DBK-5)?

A. Low natural gas prices have increased Zeeland's utilization and aqueous ammonia usage/expense to a level which warrants identification.

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 1 & 2 with a NOx 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 as a PSCR expense?

A. No. The Company requested recovery of aqueous ammonia expenses in MPSC Case No. U-16890 (2012 PSCR Plan case) and in MPSC Case No. U-17095 (2013 PSCR Plan case), however the Commission has not yet issue an order in either case. Consumers Energy is seeking the Commission's approval to include aqueous ammonia expenses in these and all future PSCR plan cases as aqueous ammonia performs the same function as urea and urea expenses have been approved by the Commission.

Lime Expenses

Q. Are there additional PSCR expenses for which you are seeking recovery in 2014?

A. Yes, Exhibit A-13 (DBK-6) identifies the projected lime expenses through 2018.

Q. Please describe Exhibit A-13 (DBK-6).

A. In 2014, Consumers Energy projects spending $777,000 for lime. In 2015, Consumers Energy expects to spend $2.79 million for lime. In 2016 through 2018, expenses are expected to be $5.03, $7.37, and $7.52 million, respectively.

Q. How will lime be used?

A. As mentioned earlier in my testimony (see page 6, lines 1 through 5), the Company is installing a Spray Dry Absorber ("SDA") at Karn Unit 1. Lime is injected into the SDA where it reacts 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 metals emissions are reduced, allowing the Company to comply with emission standards and/or the need to purchase allowances.

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

A. No. Consumers Energy is seeking the Commission's approval to include lime in this and all future PSCR plan cases. Lime performs a function similar to urea and aqueous ammonia and those expenses have been approved by the Commission. Lime removes sulfur, a constituent introduced to the combustion process by the fuel, and 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-17317
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2014	)	

EXHIBITS

OF

DAVID B. KEHOE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2013

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-17317
Exhibit: A-8 (DBK-1)
Witness: DBKehoe
Date: September 2013
Page: Page 1 of 1

Major Outages in the 2014 PSCR Plan

Line	Unit	Days in 2011	Start Date	Stop Date
	(a)	(b)	(c)	(d)
1	Ludington 2	253	11/09/13	07/20/14
2	Ludington 6	35	01/13/14	02/17/14
3	DE Karn 1	60	03/15/14	05/14/14
4	Ludington 1	28	04/07/14	05/05/14
5	Zeeland 1A	28	04/12/14	05/10/14
6	DE Karn 2	89	09/06/14	12/04/14
7	Ludington 3	35	09/14/14	10/19/14
8	Ludington 4	238	09/14/14	05/10/15

2014 PSCR Random Outage Rate Projections

Line	Plant (a)	Availability (b)	Periodic Factor (c)	2014 Projected ROR (d)	Actual ROR 2008-2012 (e)
1	Campbell 1	88.45%	4.38%	7.49%	8.64%
2	Campbell 2	84.91%	3.85%	11.69%	5.88%
3	Campbell 3	83.26%	7.29%	10.20%	5.17%
4	Cobb 4	78.64%	7.45%	15.03%	10.19%
5	Cobb 5	84.62%	3.02%	12.75%	9.46%
6	Karn 1	67.32%	18.79%	17.10%	29.95%
7	Karn 2	62.28%	28.07%	13.42%	14.11%
8	Karn 3	93.13%	0.00%	6.87%	14.21%
9	Karn 4	84.95%	0.00%	15.05%	9.87%
10	Weadock 7	82.23%	6.45%	12.10%	12.05%
11	Weadock 8	82.31%	6.45%	12.01%	11.31%
12	Whiting 1	89.21%	0.00%	10.79%	14.11%
13	Whiting 2	80.37%	4.44%	15.90%	10.12%
14	Whiting 3	88.81%	0.15%	11.06%	11.77%
15	Ludington 1	81.16%	17.26%	1.90%	0.77%
16	Ludington 2	55.37%	43.56%	1.90%	2.25%
17	Ludington 3	85.33%	13.02%	1.90%	3.41%
18	Ludington 4	65.51%	33.22%	1.90%	1.11%
19	Ludington 5	87.94%	10.36%	1.90%	1.07%
20	Ludington 6	79.68%	18.78%	1.90%	4.99%
21	CTs[1]	85.00%	0.00%	15.00%	12.43%
22	Hydros	95.05%	3.31%	1.70%	2.51%
23	Zeeland 2	89.47%	6.32%	4.50%	4.96%
24	Zeeland 1A	89.92%	7.78%	2.50%	2.36%
25	Zeeland 1B	95.51%	2.04%	2.50%	2.53%

[1]Does not include the Zeeland CTs.

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-17317
Exhibit A-10 (DBK-3)
Witness: DBKehoe
Date: September 2013

2014-2018 NO_X ALLOWANCE BUDGET

Line No.	2014 Ozone Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
1	Beginning Bank from 2013	4,854	$0.05	$248.35
2	2014 Inventory	7,444	$0.00	$0.00
3	Forecasted Purchases	0	$21.50	$0.00
4	**Total**	**12,298**	**$0.02**	**$248.35**
5	Forecasted Emissions	5,096		
6	Banked Allowances Surrendered	-4,854	$0.02	$98.03
7	2014 Inventory Surrendered	-242	$0.02	$4.88
8	Forecasted Purchases Surrendered	0	$0.02	$0.00
9	**Ending Balance**	**7,202**	**$0.02**	$0.00
10	**Total Expense**			**$102.91**

Line No.	2014 Annual Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
11	Beginning Bank from 2013	6,999	$0.00	$0.00
12	2014 inventory	16,280	$0.00	$0.00
13	Forecasted Purchases	0	$33.52	$0.00
14	**Total**	**23,279**	**$0.00**	**$0.00**
15	Forecasted Emissions	12,137		
16	Banked Allowances Surrendered	-6,999	$0.00	$0.00
17	2014 Inventory Surrendered	-5,138	$0.00	$0.00
18	Forecasted Purchases Surrendered	0	$0.00	$0.00
19	**Ending Balance**	**11,142**	**$0.00**	$0.00
20	**Total Annual Season Expense**			**$0.00**

20	**Total Ozone Season Expense**		**$102.91**
21	**Total Annual Season Expense**	+	**$0.00**
22	**Total Expense for 2014**		**$102.91**

2014-2018 NOX ALLOWANCE BUDGET

Line No.	2015 Ozone Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
23	Beginning Bank from 2014	7,202	$0.02	$145.44
24	2015 Inventory	7,444	$0.00	$0.00
25	Forecasted Purchases	0	$42.14	$0.00
26	**Total**	**14,646**	**$0.01**	**$145.44**
27	Forecasted Emissions	5,234		
28	Banked Allowances Surrendered	-5,234	$0.01	$51.97
29	2015 Inventory Surrendered	0	$0.01	$0.00
30	Forecasted Purchases Surrendered	0	$0.01	$0.00
31	**Ending Balance**	**9,413**	**$0.01**	$0.00
32	**Total Ozone Season Expense**			**$51.97**

Line No.	2015 Annual Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
33	Beginning Bank from 2014	11,142	$0.00	$0.00
34	2015 Inventory	14,481	$0.00	$0.00
35	Forecasted Purchases	0	$29.79	$0.00
36	**Total**	**25,623**	**$0.00**	**$0.00**
37	Forecasted Emissions	12,730		
38	Banked Allowances Surrendered	-11,142	$0.00	$0.00
39	2015 Inventory Surrendered	-1,587	$0.00	$0.00
40	Forecasted Purchases Surrendered	0	$0.00	$0.00
41	**Ending Balance**	**12,894**	**$0.00**	$0.00
42	**Total Annual Season Expense**			**$0.00**

43	**Total Ozone Season Expense**		**$51.97**
44	**Total Annual Season Expense**	+	**$0.00**
45	**Total Expense for 2015**		**$51.97**

2014-2018 NOX ALLOWANCE BUDGET

Line No.	2016 Ozone Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
46	Beginning Bank from 2015	9,413	$0.01	$93.47
47	Projected Allocation from the EPA	6,654	$0.00	$0.00
48	Forecasted Purchases	0	$37.65	$0.00
49	**Total**	**16,067**	**$0.01**	**$93.47**
50	Forecasted Emissions	2,317		
51	Banked Allowances Surrendered	-2,317	$0.01	$13.48
52	2016 Inventory Surrendered	0	$0.01	$0.00
53	Forecasted Purchases Surrendered	0	$0.01	$0.00
54	**Ending Balance**	**13,750**	**$0.01**	$0.00
55	**Total Ozone Season Expense**			**$13.48**

Line No.	2016 Annual Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
56	Beginning Bank from 2015	12,894	$0.00	$0.00
57	Projected Allocation from the EPA	14,481	$0.00	$0.00
58	Forecasted Purchases	0	$25.95	$0.00
59	**Total**	**27,375**	**$0.00**	**$0.00**
60	Forecasted Emissions	7,603		
61	Banked Allowances Surrendered	-7,603	$0.00	$0.00
62	2016 Inventory Surrendered	0	$0.00	$0.00
63	Forecasted Purchases Surrendered	0	$0.00	$0.00
64	**Ending Balance**	**19,772**	**$0.00**	$0.00
65	**Total Annual Season Expense**			**$0.00**

66	**Total Ozone Season Expense**		**$13.48**
67	**Total Annual Season Expense**	+	**$0.00**
68	**Total Expense for 2016**		**$13.48**

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-17317
Exhibit A-10 (DBK-3)
Witness: DBKehoe
Date: September 2013

2014-2018 NOX ALLOWANCE BUDGET

Line No.	2017 Ozone Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
69	Beginning Bank from 2016	13,750	$0.01	$79.99
70	Projected Allocation from the EPA	6,654	$0.00	$0.00
71	Forecasted Purchases	0	$18.01	$0.00
72	**Total**	**20,404**	**$0.00**	**$79.99**
73	Forecasted Emissions	2,571		
74	Banked Allowances Surrendered	-2,571	$0.00	$10.08
75	2017 Inventory Surrendered	0	$0.00	$0.00
76	Forecasted Purchases Surrendered	0	$0.00	$0.00
77	**Ending Balance**	**17,833**	**$0.00**	$0.00
78	**Total Ozone Season Expense**			**$10.08**

Line No.	2017 Annual Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
79	Beginning Bank from 2016	19,772	$0.00	$0.00
80	Projected Allocation from the EPA	14,481	$0.00	$0.00
81	Forecasted Purchases	0	$16.16	$0.00
82	**Total**	**34,253**	**$0.00**	**$0.00**
83	Forecasted Emissions	5,950		
84	Banked Allowances Surrendered	-5,950	$0.00	$0.00
85	2017 Inventory Surrendered	0	$0.00	$0.00
86	Forecasted Purchases Surrendered	0	$0.00	$0.00
87	**Ending Balance**	**28,302**	**$0.00**	$0.00
88	**Total Annual Season Expense**			**$0.00**

89	**Total Ozone Season Expense**		**$10.08**
90	**Total Annual Season Expense**	+	**$0.00**
91	**Total Expense for 2017**		**$10.08**

2014-2018 NOX ALLOWANCE BUDGET

Line No.	**2018 Ozone Season**	**Allowances**	**Average Cost $/Allowance**	**Inventory $**
	(a)	(b)	(c)	(d)
92	Beginning Bank from 2017	0	$0.00	$0.00
93	Projected Allocation from the EPA	4,729	$0.00	$0.00
94	Forecasted Purchases	0	$822.92	$0.00
95	**Total**	**4,729**	**$0.00**	**$0.00**
96	Forecasted Emissions	2,642		
97	Banked Allowances Surrendered	0	$0.00	$0.00
98	2018 Inventory Surrendered	-2,642	$0.00	$0.00
99	Forecasted Purchases Surrendered	0	$0.00	$0.00
100	**Ending Balance**	**2,087**	**$0.00**	$0.00
101	**Total Ozone Season Expense**			**$0.00**

Line No.	**2018 Annual Season**	**Allowances**	**Average Cost $/Allowance**	**Inventory $**
	(a)	(b)	(c)	(d)
102	Beginning Bank from 2017	0	$0.00	$0.00
103	Projected Allocation from the EPA	9,933	$0.00	$0.00
104	Forecasted Purchases	0	$514.48	$0.00
105	**Total**	**9,933**	**$0.00**	**$0.00**
106	Forecasted Emissions	6,151		
107	Banked Allowances Surrendered	0	$0.00	$0.00
108	2018 Inventory Surrendered	-6,151	$0.00	$0.00
109	Forecasted Purchases Surrendered	0	$0.00	$0.00
110	**Ending Balance**	**3,782**	**$0.00**	$0.00
111	**Total Annual Season Expense**			**$0.00**

112	**Total Ozone Season Expense**			**$0.00**
113	**Total Annual Season Expense**		+	**$0.00**
114	**Total Expense for 2018**			**$0.00**

Case No: U-17317
Exhibit: A-11 (DBK-4)
Witness: DBKehoe
September 2013

2014-2018 Urea Expense

(1,000's)

Line No.	Unit (a)	2014 (b)	2015 (c)	2016 (d)	2017 (e)	2018 (f)
1	**Campbell 2**	$648	$631	$499	$475	$406
2	**Campbell 3**	$1,995	$2,164	$1,672	$2,169	$2,045
3	**TTL**	$2,643	$2,795	$2,171	$2,644	$2,451

Case No: U-17317
Exhibit: A-12 (DBK-5)
Witness: DBKehoe
September 2013

2014-2018 Aqueous Ammonia Expense

(1,000's)

Line No.	**Unit** (a)	**2014** (b)	**2015** (c)	**2016** (d)	**2017** (e)	**2018** (f)
1	**Karn 1**	$942	$856	$1,304	$1,303	$1,159
2	**Karn 2**	$652	$974	$973	$859	$745
3	**Zeeland 2**	$138	$143	$143	$143	$143
4	**TTL**	$1,732	$1,973	$2,420	$2,305	$2,047

Case No: U-17317
Exhibit: A-13 (DBK-6)
Witness: DBKehoe
September 2013

2014-2018 Lime Expense

(1,000's)

Line No.	Unit (a)	2014 (b)	2015 (c)	2016 (d)	2017 (e)	2018 (f)
1	**Karn 1&2**	$777	$2,790	$2,188	$4,465	$4,554
2	**Campbell 3**	-	-	$2,846	$2,903	$2,961
3	**TTL**	$777	$2,790	$5,034	$7,368	$7,515

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-17317
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2014	)	

DIRECT TESTIMONY

OF

HUBERT MILLER III

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2013

I. INTRODUCTION & QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Hubert W. Miller III and my business address is One Energy Plaza, Jackson, Michigan.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Analyst in the Rates & Business Support section of the Rates & Regulation Department.

Q. Please describe your qualifications.

A. In May 2002, I graduated from the University of Michigan-Flint with a baccalaureate in Economics. In May 2008, I graduated from Eastern Michigan University with a Masters in Applied Economics and am currently completing a Masters in Mathematics from Eastern Michigan University as well. I have also attended various industry seminars addressing marginal cost pricing, the benefits of financial hedges in power markets, the use of dynamic pricing to promote energy efficiency, and the use of statistically adjusted end-use models to forecast electric sales.

In September 2002, I accepted the position of Rate Analyst in the Pricing section of the Rates & Regulation Department with Consumers Energy. In this position my primary responsibilities included electric and natural gas rate design, industry research, and various financial studies. In November 2004, I was promoted to the position of General Rate Analyst, which expanded the scope of my duties to include sponsoring rate design testimony and exhibits in filings with the Michigan Public Service Commission ("MPSC" or the "Commission"). In April 2009, I was promoted to the position of Senior

Rate Analyst, which expanded my responsibilities to include coordinating the electric and natural gas rate design models and financial forecast studies associated with the Company's electric contribution in aid of construction.

In February 2012, I accepted a senior analyst position in the Economic Portfolio Management section of the Company's Work Process & Business Management Department. In this position I analyzed the benefits of technology investment initiatives for increasing operational performance in the Company's Distribution organization, researching the use of mathematical algorithms to optimize Distribution's operational portfolio, and participated in assessing risks to Distribution's electric and gas assets.

In February 2013, I accepted my current position as Principal Analyst in the Rates & Regulation Department. In this capacity I am responsible for preparing the Company's official electric and natural gas sales and customer forecasts, sponsoring the sales and customer forecast testimony and exhibits, industry research, and various economic studies.

Q. Please list the cases in which you have testified.

A. I have testified in the following cases:

Case No.	Description
U-14547	2006 General Natural Gas Rate Case
U-15001R	2007 Power Supply Cost Recovery ("PSCR") Reconciliation
U-15245	2008 General Electric Rate Case
U-15415R	2008 PSCR Reconciliation
U-15675	2009 PSCR Plan
U-15744	Stranded Cost Recovery Reconciliation

U-15805	Public Act 295 Renewable Energy and Energy Optimization Compliance Case
U-16045	2010 PSCR Plan
U-16191	2010 General Electric Rate Case
U-16485	2011 Gas Cost Recovery Case
U-17281	2012 Energy Optimization Plan Reconciliation
U-17351	Amended Energy Optimization Plan
U-17301	2013 Biennial Renewable Energy Plan Review Case
U-17429	Certificate of Necessity for the Thetford Generating Plant

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 2014 – 2018.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am providing the following five exhibits:

Exhibits	Description
A-14 (HWM-1)	2014 Forecast of Calendar Total Deliveries
A-15 (HWM-2)	Forecast of Annual Calendar Deliveries
A-16 (HWM-3)	Forecast of Total Monthly Requirements
A-17 (HWM-4)	Forecast of Monthly Peak Demand
A-18 (HWM-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, economic indicators, 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 sales 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 economic indicators 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 sales 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 sales modeling framework as dependent and explanatory variables. The daily temperature information, however, is transformed to monthly HDD and CDD variables prior to entering the sales modeling framework. The second step is importing the quarterly Michigan population, manufacturing production, manufacturing employment, and automotive employment variables from IHS Global Insight into the sales modeling framework. The third step is importing forecasts for wholesale, electric vehicles, polycrystalline industrial production electric use, and Energy Efficiency ("EE"). These forecasts are external to the sales 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, then 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.

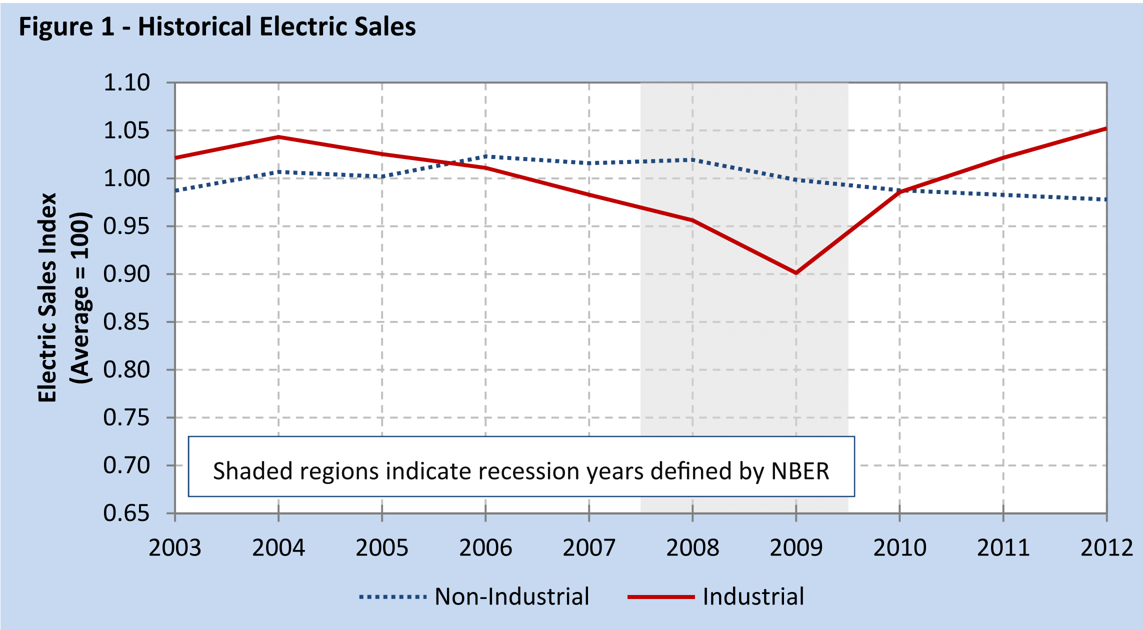
The peak demand forecast process is similar to that of the electric sales forecast. The first step in the peak demand forecast is importing the Company's monthly system peak demands, corresponding minimum and maximum daily temperature, forecasted base electric sales, seasonal binaries, and number of 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 Company's Dynamic Peak Pricing ("DPP"), Direct Load Management ("DLM"), and EE forecasts.

IV. HISTORICAL AND FORECASTED ELECTRIC DELIVERIES

Q. Please explain the historical growth in electric deliveries.

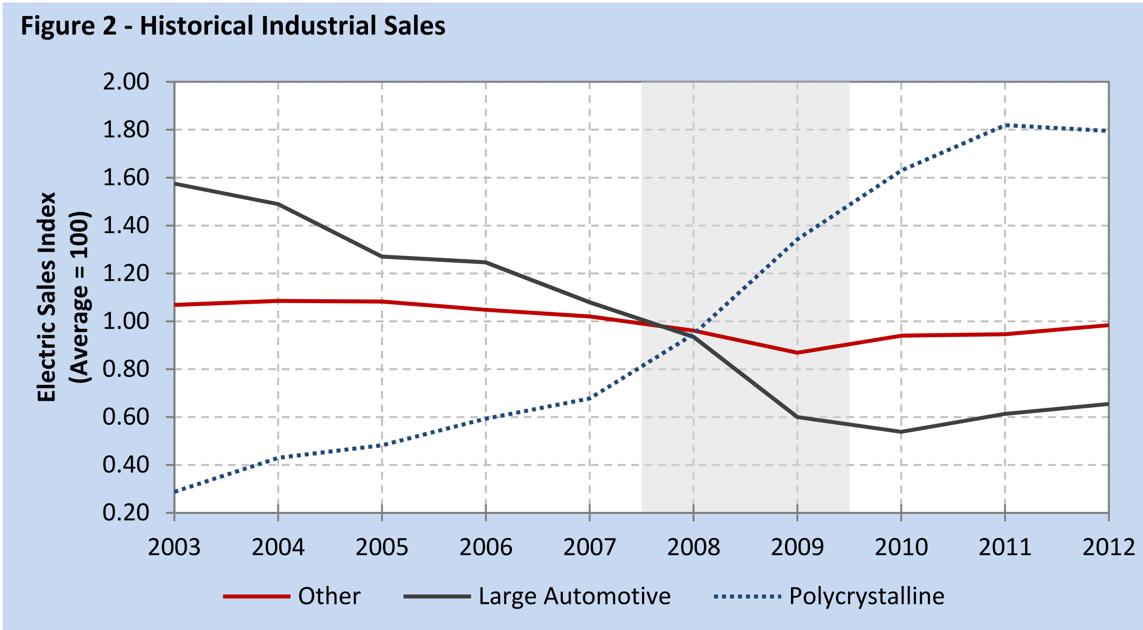
A. Weather normalized electric deliveries grew at a 0.04 percent compounded annual growth rate ("CAGR") from 2003 to 2012, with most of the observed growth occurring in the industrial class. This is especially evident when looking at the trend of industrial and nonindustrial deliveries shown in Figure 1. Prior to 2007 nonindustrial electric deliveries grew at 1.2 percent CAGR while industrial deliveries decreased at 0.34 percent 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 4.25 percent per year from 2007 to 2009 versus a 0.86 percent decrease for nonindustrial electric deliveries. On the other hand, industrial deliveries return to near 2004 levels by 2012 while nonindustrial deliveries continue to decrease.



Q. What factors fueled the increase in industrial class electric deliveries following the recent recession?

A. Industrial electric deliveries increased 5.31 percent per year from 2009 to 2012. However, the increase was not homogeneous across all sectors in the class. Electric deliveries grew precipitously in polycrystalline manufacturing while automotive and other industrial sectors exhibited only a moderate rebound in electric deliveries. Indeed, over the past ten years large automotive and other industrial electric deliveries have decreased while the polycrystalline industry electric deliveries have increased six fold. This is particularly evident when observing the industrial sector trends shown in Figure 2.



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

A. No, total electric sales are expected to decrease in the short-term as polycrystalline industrial production electric sales recede to 2008 levels before returning to near 2012 levels by 2018. The short-term ebb of polycrystalline industrial production electric sales reflects trade policy and over-production issues facing that industry. In the long-run, however, as these issues are resolved, electric sales are expected to follow and return to current levels.

Q. What are the electric delivery expectations over the next five years?

A. Total electric deliveries are expected to recover over the next five years. The 2014 monthly class level results of the electric deliveries forecast process is shown in Exhibit A-14 (HWM-1). The annual class level results for 2014 – 2018 is shown in Exhibit A-15 (HWM-2).

Q. Are you assuming continued energy efficiency savings as part of your electric sales 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 7.2 percent to determine the Company's total generation requirements shown in Exhibit A-16 (HWM-3).

V. FORECASTED PEAK DEMAND

Q. Please describe the forecasted growth in peak demand.

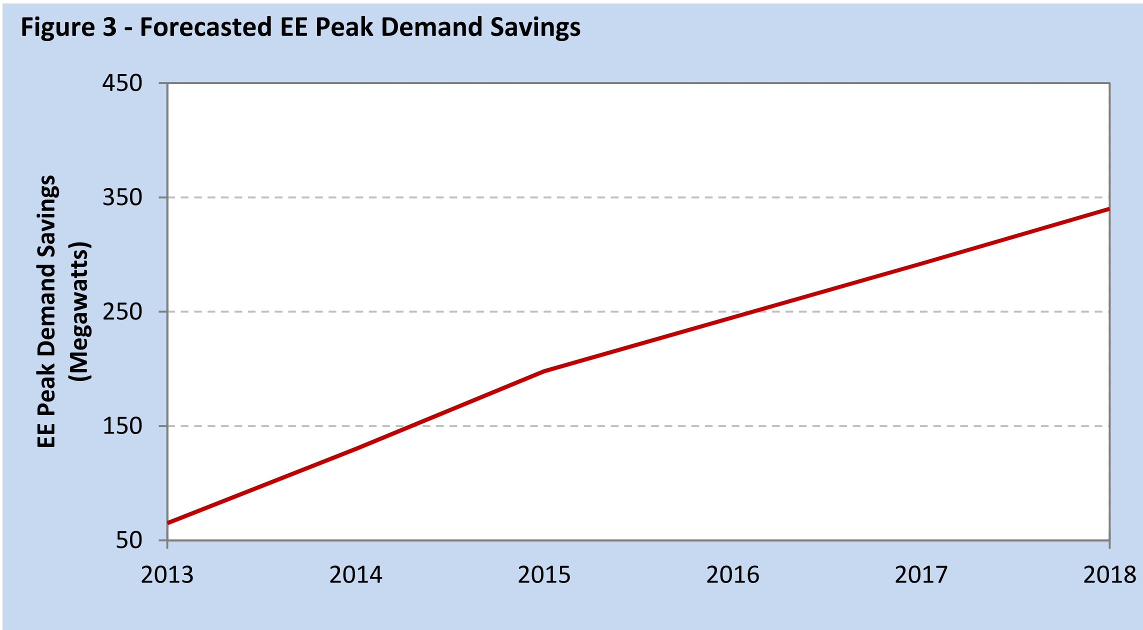
A. The Company uses regression analysis based on the predicted level of electric deliveries to forecast the peak demand. Weather normal peak demand grew at a 1.6 percent CAGR from 2003 to 2007, but reversed much of this trend during the 2007 to 2009 recession. Looking forward, peak demand is expected to increase a modest 0.3 percent per year from 2012 to 2018. The monthly system level results of the electric peak demand forecast process is shown in Exhibit A-17 (HWM-4).

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

A. The peak demand forecast is reduced by approximately 16 megawatts in 2014 and 415 MW in 2018 for the Company's load management and peak pricing programs. These forecasts are being implemented as part of the Company's smart energy infrastructure investments.

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 130 megawatts in 2014. The cumulative reductions produced by the EE program are expected to be 340 megawatts by 2018. The cumulative EE program peak demand reduction curve is shown in Figure 3.



Q. Please explain the process used to identify the peak demand impacts of the EE program.

A. The Company developed hourly load profiles for its total system, electric choice, EE program, DLM program, and DPP program. The EE program monthly energy savings are integrated with the EE load shape to develop the hourly EE demand savings curves.

Q. Please explain Exhibit A-18 (HWM-5).

A. Exhibit A-18 (HWM-5) provides a summary of the system load factor based on the Company's official 2014 - 2018 electric delivery and summer peak demand forecasts.

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-17317
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2014	)	

EXHIBITS

OF

HUBERT MILLER III

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2013

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY
2014 FORECAST OF CALENDAR TOTAL ELECTRIC DELIVERIES
(MWh)

Case No. U-17317
Exhibit: A-14 (HWM-1)
Witness: H.W. Miller III
Date: September 2013

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Month	Residential	Commercial	Industrial	Street Lighting	Inter-departmental	Wholesale	Total
1	January	1,290,566	971,237	850,267	20,998	3,259	25,821	3,162,148
2	February	1,020,739	903,530	928,640	14,858	3,350	21,449	2,892,566
3	March	1,026,368	956,029	971,667	15,810	3,152	27,306	3,000,331
4	April	890,865	893,434	944,901	13,078	3,298	24,711	2,770,287
5	May	896,169	958,238	1,017,721	11,364	3,185	25,358	2,912,035
6	June	1,012,677	1,060,184	1,037,390	9,806	4,964	26,846	3,151,867
7	July	1,255,923	1,113,846	992,799	10,844	3,196	28,935	3,405,542
8	August	1,175,965	1,120,442	1,014,083	12,945	4,027	29,016	3,356,479
9	September	966,156	984,814	1,006,103	14,030	3,264	27,919	3,002,287
10	October	875,181	991,033	1,036,479	16,441	3,207	27,520	2,949,860
11	November	971,329	904,765	989,939	18,119	2,922	26,980	2,914,052
12	December	1,248,570	968,494	895,584	19,158	3,538	29,371	3,164,716
13	Annual	12,630,508	11,826,047	11,685,572	177,451	41,362	321,232	36,682,171

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY
2014 FORECAST OF CALENDAR FULL SERVICE ELECTRIC DELIVERIES
(MWh)

Case No. U-17317
Exhibit: A-14 (HWM-1)
Witness: H.W. Miller III
Date: September 2013

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Month	Residential	Commercial	Industrial	Street Lighting	Inter-departmental	Wholesale	Total
1	January	1,290,566	882,050	620,965	20,998	3,259	25,821	2,843,659
2	February	1,020,739	821,670	715,110	14,858	3,350	21,449	2,597,176
3	March	1,026,368	866,592	738,095	15,810	3,152	27,306	2,677,322
4	April	890,865	810,382	711,417	13,078	3,298	24,711	2,453,751
5	May	896,169	870,116	759,377	11,364	3,185	25,358	2,565,569
6	June	1,012,677	973,227	771,598	9,806	4,964	26,846	2,799,118
7	July	1,255,923	1,019,939	724,791	10,844	3,196	28,935	3,043,627
8	August	1,175,965	1,026,490	733,831	12,945	4,027	29,016	2,982,275
9	September	966,156	892,452	754,098	14,030	3,264	27,919	2,657,920
10	October	875,181	903,672	773,939	16,441	3,207	27,520	2,599,959
11	November	971,329	818,291	743,807	18,119	2,922	26,980	2,581,446
12	December	1,248,570	882,763	662,217	19,158	3,538	29,371	2,845,618
13	Annual	12,630,508	10,767,645	8,709,244	177,451	41,362	321,232	32,647,441

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY
2014 FORECAST OF CALENDAR ROA SERVICE ELECTRIC DELIVERIES
(MWh)

Case No. U-17317
Exhibit: A-14 (HWM-1)
Witness: H.W. Miller III
Date: September 2013

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Month	Residential	Commercial	Industrial	Street Lighting	Inter-departmental	Wholesale	Total
1	January	-	89,187	229,302	-	-	-	318,489
2	February	-	81,860	213,530	-	-	-	295,390
3	March	-	89,437	233,572	-	-	-	323,009
4	April	-	83,052	233,484	-	-	-	316,536
5	May	-	88,122	258,344	-	-	-	346,466
6	June	-	86,957	265,792	-	-	-	352,749
7	July	-	93,907	268,008	-	-	-	361,915
8	August	-	93,952	280,252	-	-	-	374,204
9	September	-	92,362	252,005	-	-	-	344,367
10	October	-	87,361	262,540	-	-	-	349,901
11	November	-	86,474	246,132	-	-	-	332,606
12	December	-	85,731	233,367	-	-	-	319,098
13	Annual	-	1,058,402	2,976,328	-	-	-	4,034,730

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY
FORECAST OF ANNUAL CALENDAR ELECTRIC DELIVERIES
(MWh)

Case No. U-17317
Exhibit: A-15 (HWM-2)
Witness: H.W. Miller III
Date: September 2013

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Description	2014	2015	2016	2017	2018
1	Total Deliveries					
2	Residential	12,630,508	12,507,173	12,419,629	12,378,955	12,359,883
3	Commercial	11,826,047	11,754,231	11,685,301	11,609,650	11,540,211
4	Industrial	11,685,572	12,116,287	12,692,726	13,195,311	13,595,126
5	Street Lighting	177,451	177,482	177,503	177,528	177,675
6	Interdepartmental	41,362	41,376	41,370	41,375	41,439
7	Wholesale	321,232	322,798	324,374	325,967	327,381
8	Total Deliveries	36,682,171	36,919,347	37,340,903	37,728,786	38,041,715
9	Total Full Service					
10	Residential	12,630,508	12,507,173	12,419,629	12,378,955	12,359,883
11	Commercial	10,767,645	10,700,840	10,638,720	10,570,634	10,508,859
12	Industrial	8,709,244	9,075,780	9,571,124	10,025,707	10,422,835
13	Street Lighting	177,451	177,482	177,503	177,528	177,675
14	Interdepartmental	41,362	41,376	41,370	41,375	41,439
15	Wholesale	321,232	322,798	324,374	325,967	327,381
16	Total Full Service	32,647,441	32,825,449	33,172,720	33,520,166	33,838,072
17	Total ROA Service					
18	Residential	-	-	-	-	-
19	Commercial	1,058,402	1,053,391	1,046,581	1,039,016	1,031,352
20	Industrial	2,976,328	3,040,507	3,121,602	3,169,604	3,172,291
21	Street Lighting	-	-	-	-	-
22	Interdepartmental	-	-	-	-	-
23	Wholesale	-	-	-	-	-
24	Total ROA Service	4,034,730	4,093,898	4,168,183	4,208,620	4,203,643

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY
FORECAST OF TOTAL MONTHLY REQUIREMENTS
(MWh)

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Month	2014	2015	2016	2017	2018
1	January	3,402,085	3,423,993	3,463,092	3,499,066	3,523,555
2	February	3,113,195	3,133,267	3,169,073	3,201,912	3,224,351
3	March	3,219,400	3,240,559	3,277,620	3,311,863	3,334,948
4	April	2,971,439	2,990,713	3,025,187	3,056,672	3,078,043
5	May	3,134,109	3,154,336	3,190,532	3,223,728	3,246,254
6	June	3,424,559	3,446,590	3,485,444	3,521,360	3,545,777
7	July	3,697,992	3,721,686	3,763,755	3,802,776	3,829,024
8	August	3,645,158	3,668,273	3,709,788	3,747,874	3,773,594
9	September	3,231,380	3,252,263	3,289,554	3,323,688	3,347,104
10	October	3,174,890	3,195,489	3,231,884	3,265,475	3,288,398
11	November	3,126,585	3,146,894	3,182,821	3,216,001	3,238,671
12	December	3,404,716	3,426,762	3,465,890	3,502,067	3,526,592
13	Annual	39,545,508	39,800,825	40,254,640	40,672,482	40,956,311

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY
FORECAST OF MONTHLY FULL SERVICE REQUIREMENTS
(MWh)

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Month	2014	2015	2016	2017	2018
1	January	3,062,846	3,079,929	3,112,748	3,145,072	3,170,085
2	February	2,769,843	2,785,003	2,814,362	2,843,488	2,866,567
3	March	2,900,887	2,917,615	2,948,631	2,979,535	3,003,145
4	April	2,623,147	2,637,615	2,665,389	2,693,142	2,715,109
5	May	2,792,864	2,808,085	2,837,818	2,867,172	2,890,251
6	June	3,051,073	3,067,770	3,099,240	3,130,988	3,155,896
7	July	3,317,695	3,335,695	3,370,363	3,405,149	3,431,688
8	August	3,254,913	3,272,621	3,307,189	3,341,131	3,366,994
9	September	2,827,934	2,842,923	2,872,396	2,901,930	2,925,839
10	October	2,803,760	2,819,002	2,848,341	2,877,972	2,901,443
11	November	2,749,355	2,764,131	2,792,683	2,821,581	2,844,681
12	December	3,046,129	3,063,127	3,095,562	3,127,729	3,152,668
13	Annual	35,200,446	35,393,516	35,764,722	36,134,889	36,424,366

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY
FORECAST OF MONTHLY ROA REQUIREMENTS
(MWh)

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Month	2014	2015	2016	2017	2018
1	January	339,239	344,064	350,344	353,994	353,470
2	February	343,352	348,264	354,711	358,424	357,784
3	March	318,513	322,944	328,989	332,328	331,803
4	April	348,292	353,098	359,798	363,530	362,934
5	May	341,245	346,251	352,714	356,556	356,003
6	June	373,486	378,820	386,204	390,372	389,881
7	July	380,297	385,991	393,392	397,627	397,336
8	August	390,245	395,652	402,599	406,743	406,600
9	September	403,446	409,340	417,158	421,758	421,265
10	October	371,130	376,487	383,543	387,503	386,955
11	November	377,230	382,763	390,138	394,420	393,990
12	December	358,587	363,635	370,328	374,338	373,924
13	Annual	4,345,062	4,407,309	4,489,918	4,537,593	4,531,945

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY
FORECAST OF MONTHLY PEAK DEMAND
(MW)

Case No. U-17317
Exhibit: A-17 (HWM-4)
Witness: H.W. Miller III
Date: September 2013

Line No.	(a) Month	(b) 2014	(c) 2015	(d) 2016	(e) 2017	(f) 2018
1	January	6,157	6,235	6,295	6,320	6,360
2	February	6,013	6,081	6,139	6,154	6,187
3	March	5,830	5,894	5,958	5,985	6,024
4	April	5,321	5,381	5,436	5,455	5,490
5	May	6,369	6,445	6,517	6,550	6,600
6	June	7,867	7,971	8,065	8,112	8,179
7	July	8,143	8,244	8,338	8,383	8,448
8	August	8,341	8,402	8,464	8,472	8,485
9	September	7,291	7,385	7,466	7,500	7,554
10	October	5,973	6,043	6,104	6,132	6,173
11	November	6,018	6,086	6,146	6,170	6,211
12	December	6,379	6,455	6,521	6,548	6,589

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY
FORECAST OF MONTHLY FULL SERVICE PEAK DEMAND
(MW)

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Month	2014	2015	2016	2017	2018
1	January	5,675	5,743	5,790	5,813	5,858
2	February	5,476	5,536	5,611	5,593	5,627
3	March	5,369	5,431	5,493	5,516	5,550
4	April	4,775	4,828	4,872	4,884	4,920
5	May	5,865	5,913	5,975	6,027	6,077
6	June	7,299	7,398	7,481	7,521	7,587
7	July	7,587	7,680	7,759	7,798	7,865
8	August	7,772	7,825	7,881	7,883	7,896
9	September	6,679	6,764	6,833	6,858	6,910
10	October	5,439	5,497	5,542	5,569	5,616
11	November	5,452	5,516	5,570	5,588	5,630
12	December	5,872	5,938	5,991	6,008	6,049

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY
FORECAST OF MONTHLY ROA PEAK DEMAND
(MW)

Case No. U-17317
Exhibit: A-17 (HWM-4)
Witness: H.W. Miller III
Date: September 2013

Line No.	(a) Month	(b) 2014	(c) 2015	(d) 2016	(e) 2017	(f) 2018
1	January	482	492	505	507	502
2	February	537	545	528	561	560
3	March	461	463	465	469	474
4	April	546	553	564	571	570
5	May	504	532	542	523	523
6	June	568	573	584	591	592
7	July	556	564	579	585	583
8	August	569	577	583	589	589
9	September	612	621	633	642	644
10	October	534	546	562	563	557
11	November	566	570	576	582	581
12	December	507	517	530	540	540

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY
FORECASTED SYSTEM LOAD FACTOR BASED ON SUMMER PEAK DEMAND

Case No. U-17317
Exhibit: A-18 (HWM-5)
Witness: H.W. Miller III
Date: September 2013

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Description	2014	2015	2016	2017	2018
1	Total Deliveries (GWh)	36,682	36,919	37,341	37,729	38,042
2	System Efficiency (%)	92.8%	92.8%	92.8%	92.8%	92.9%
3	Generation Requirements (GWh)	39,546	39,801	40,255	40,672	40,956
4	Summer Peak Demand (MW)	8,341	8,402	8,464	8,472	8,485
5	System Load Factor (%)	54.1%	54.1%	54.1%	54.8%	55.1%

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-17317
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2014	)	

DIRECT TESTIMONY

OF

DAVID F. RONK, JR.

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2013

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.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as 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; (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. I provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission") in:

- 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;
- MPSC Case No. U-10973-R (direct), the Company's 1996 PSCR Reconciliation case;
- 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;
- MPSC Case No. U-12488 (direct and rebuttal), regarding certain terms and conditions of service for retail open access customers;
- 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;
- 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;
- MPSC Case No. U-14274 (direct and rebuttal), the Company's 2005 PSCR Plan case, regarding electric capacity requirements and costs for 2005;

- 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;
- MPSC Case No. U-13917-R (direct), the Company's 2004 PSCR Reconciliation case, regarding power supply costs incurred in 2004;
- MPSC Case No. U-14701 (direct, supplemental and rebuttal), the Company's 2006 PSCR Plan case, regarding electric capacity requirements and costs for 2006;
- MPSC Case No. U-14274-R (direct and supplemental), the Company's 2005 PSCR Reconciliation case, regarding power supply costs incurred in 2005;
- MPSC Case No. U-15001 (direct), the Company's 2007 PSCR Plan case, regarding electric capacity requirements and costs for 2007;
- 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;
- MPSC Case No. U-14701-R (direct and supplemental), the Company's 2006 PSCR Reconciliation case, regarding power supply costs incurred in 2006;
- MPSC Case No. U-15290 (direct and supplemental), regarding the Company's balanced energy initiative;
- MPSC Case No. U-15415 (direct), the Company's 2008 PSCR Plan case, regarding electric capacity requirements and costs for 2008;
- MPSC Case No. U-15001-R (direct and supplemental), the Company's 2007 PSCR Reconciliation case, regarding power supply costs incurred in 2007;
- 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;

- MPSC Case No. U-15675 (direct), regarding the Company's 2009 PSCR Plan, regarding electric capacity requirements and costs for 2009;
- MPSC Case No. U-15805/U-15889 (direct and rebuttal), regarding the 2009 renewable energy plan and energy optimization plan;
- MPSC Case No. U-15415R (direct and rebuttal), the Company's 2008 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2008;
- MPSC Case No. U-16045 (direct and rebuttal), the Company's 2010 PSCR Plan, regarding electric capacity requirements and costs for 2010;
- 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;
- 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;
- MPSC Case No. U-16300 (direct and rebuttal), the Company's 2009 Renewable Cost Reconciliation Case, regarding renewable energy costs incurred in 2009;
- MPSC Case No. U-16432 (direct and second rebuttal), the Company's 2011 PSCR Plan, regarding electric capacity requirements and costs for 2011;
- MPSC Case No. U-16543 (direct and rebuttal), the Company's application for approval of a Renewable Energy Plan amendment;

- 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;
- MPSC Case No. U-16045R (direct and rebuttal), the Company's 2010 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2010;
- MPSC Case No. U-16301 (direct), the Company's 2010 Renewable Cost Reconciliation Case, regarding renewable energy costs incurred in 2010;
- MPSC Case No. U-16890 (direct and supplemental), the Company's 2012 PSCR Plan, regarding electric capacity requirements and costs for 2012;
- MPSC Case No. U-16581 (direct), the Company's application for biennial review of its Renewable Energy Plan;
- MPSC Case No. U-16432R (direct), the Company's 2011 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2011;
- MPSC Case No. U-16655 (direct), the Company's 2011 Renewable Cost Reconciliation Case, regarding renewable energy costs incurred in 2011;
- MPSC Case No. U-17087 (direct and rebuttal) regarding capacity planning matters associated with the test year beginning January 1, 2013;
- MPSC Case No. U-17095 (direct and rebuttal) regarding the Company's 2013 PSCR Plan, specifically addressing electric capacity requirements and costs for 2013;
- MPSC Case No. U-16890R (direct), the Company's 2012 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2012;
- 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;

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

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony will address: (1) the selection of an appropriate capacity planning reserve margin target for 2014 through 2018; (2) the resources required to satisfy the capacity planning reserve margin target; (3) the resources previously approved by the Commission; (4) the resources already purchased for the planning period; and (5) the resources remaining to be purchased for the planning period.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring:

Exhibit A-19 (DFR-1)	Summer Peak Projected Zonal Resource Credits, Demand and Margins;
Exhibit A-20 (DFR-2)	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 (such as Consumers Energy) maintains to assure that sufficient capacity exists to provide adequate electric supply in each seasonal 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 period beginning on June 1, 2013, 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 loss of load expectation 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 load serving entities. The MISO LOLE Work Group is in the process of performing an updated study that will cover the 12-month period beginning June 1, 2014.

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

A. For the 12-month period beginning June 1, 2013, the MISO LOLE Working Group determined that, using capacity discounted for forced outages, a capacity planning reserve margin target (or "unforced" capacity planning reserve margin target) for MISO of at least 6.2% of the Company's demand at time of MISO's coincident peak demand was sufficient to satisfy ReliabilityFirst Corporation's ("RFC") capacity planning criteria

[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.

of expecting to interrupt firm load no more frequently than one occasion in 10 years. RFC 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 ("FERC") to establish, monitor and enforce reliability standards in the United States. Simulations of the 2013 LOLE analysis were completed for years 2017 and 2022 to determine appropriate capacity planning reserve margin targets for years beyond the 2013 planning year. Projected planning reserve margin targets were interpolated from the 2013, 2017 and 2022 results for the years 2014-2018 that are included in this plan and ramp down from a value of 6.2% in 2013 to 6.0% in 2018, as shown on Line 3 of Exhibit A-19 (DFR-1).

Q. How is Consumers Energy planning to meet the 6.2% reserve target for 2014?

A. To facilitate compliance with the planning reserve margin target, MISO has established Zonal Resource Credits ("ZRC") 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 a Load Serving Entity ("LSE"), is required to comply with the 6.2% unforced capacity reserve margin requirement by having ZRCs equal to annual firm peak demand at the time of MISO's coincident peak demand times 1.062 for the five months ended May 31, 2014. For purposes of this plan we have assumed that a similar capacity reserve margin requirement will apply to the 2014 MISO Planning Year coincident peak demand for the 7 months beginning June 1, 2014. This reserve margin 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 participant's resources within the MISO's market footprint through tariff requirements on market participants to use the Module E Capacity Tracking ("MECT") tool.

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

A. To determine the amount of ZRCs represented by the capacity planning reserve margin target we utilize the demand forecast discussed in the direct testimony of Hubert W. Miller III. Mr. Miller's forecast of 8,341 MW of demand shown on Exhibit A-17 (HWM-4), page 1, line 8 includes jurisdictional and non-jurisdictional demand from the Company's distribution and wholesale customers adjusted for the ZRCs expected to be offset by energy efficiency, direct load management, and dynamic peak pricing programs at the time of the Company's peak demand. Mr. Miller also prepares an estimate of the amount of demand expected to be offset by Retail Open Access suppliers of 569 MW at the time of the Company's peak demand, as shown on Exhibit A-17 (HWM-4), page 3, line 8. Based on these assumptions the resulting demand expected to be served with ZRCs of 7,772 MW is shown on Exhibit A-19 (DFR-1), line 35. 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 209 ZRCs. Since the ZRCs provided by energy optimization, direct load management, and dynamic peak pricing programs that are expected to offset the Company's peak demand are available as capacity resources, the Company's final ZRC requirement is increased by 143 ZRCs, the sum of Lines 25, 28 and 29, Column (a) of Exhibit A-19 (DFR-1). The resulting capacity requirement of 7,706 ZRCs is shown on Line 36, Column (a) of Exhibit A-19 (DFR-1).

RESOURCES PLANNED TO SATISFY RESERVE MARGIN REQUIREMENT

Q. What resources are required to meet the 6.2% zonal reserve margin target for 2014?

A. Lines 4 through 30 of Exhibit A-19 (DFR-1) 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 6.2% capacity planning reserve margin under peak load conditions. In 2014, the Company expects to have 5,619 of ZRCs from its owned units during the peak load period (Consumers Energy is a summer-peaking system) as shown on Line 8, Column (a) of Exhibit A-19 (DFR-1). The Company also has long-term contracts with several Non-Utility Generators ("NUG") for 2,413 ZRCs as shown on Line 23 Column (a) of Exhibit A-19 (DFR-1). Beginning in June 2013, the Company is also able to provide ZRCs in the form of load modifying resources, including the energy efficiency, dynamic peak pricing, and direct load management programs, the Company's interruptible service provision (Provision GI), as well as a new resource provided under a program described below, as the Metal Melting pilot program. Cumulatively, these resources provide for 330 ZRCs as shown in Line 30, Column (a) of Exhibit A-19 (DFR-1). The compilation of all resources for 2014 totaling 8,382 ZRCs, when compared to the forecast of peak demand expected to be served with 7,706 ZRCs as shown on Line 36, Column (a) of Exhibit A-19 (DFR-1), provide a reserve margin of

8.78% as shown on Line 38, Column (a) of Exhibit A-19 (DFR-1). The 676 MW difference between the ZRCs for total capacity on line 32 and the demand expected to be served with ZRCs on line 36 represents the amount of ZRCs available to satisfy the capacity planning reserve margin target and is shown on Exhibit A-19 (DFR-1), line 37. The capacity planning reserve margin target for 2014 resulting from multiplying 7,706 by 0.062 is 447.8 ZRCs, resulting in a surplus of 198.7 ZRCs.

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

Q. To what extent have the owned resources providing 5,619 ZRCs and NUG resources providing 2,413 ZRCs been included in previous PSCR plans?

A. Owned resources providing 5,619 ZRCs and NUG resources providing 2,413 ZRCs have been included in previous PSCR plans, most recently in MPSC Case No. U-17095. While the Commission has yet to conclude its consideration of PSCR Plans presented in MPSC Case No. U-16890 and MPSC Case U-17095 the six resources included in this PSCR plan that were not included in the last PSCR Plan approved by the Commission (see MPSC Case No. U-16432) were previously approved in MPSC Case No. U-15805.

Q. What resources included in Exhibit A-19 (DFR-1) have been approved by the Commission but not included in previous PSCR plan cases?

A. The Company’s interruptible service provision (Provision GI), providing 121 ZRCs has been approved by the Commission, most recently in MPSC Case No. U-17087, but has not been included as a capacity resource in prior PSCR plans. Previously, the Company has used interruptible service to reduce its forecast of customer demand. However in this plan, the Company has elected to show interruptible service as a capacity resource. The option to qualify load modifying resources to receive ZRCs was made available to load serving entities in MISO beginning in the 2013 Planning Year.

The Metal Melting pilot program, providing 66 ZRCs was most recently approved by the Commission in MPSC Case No. U-17087. The Metal Melting pilot program is expected to incentivize program participants to reduce their demand during certain periods of high demand within MISO. The program provides for discounted retail rates during certain periods, in exchange for exposure to higher retail prices reflecting high market energy prices during periods in which either 1) MISO market prices exceed a specified target amount, or 2) demand within MISO requires the MISO to declare a system emergency event. A portion of the capacity for the program will be treated as a load modifying resource, providing for 66 ZRCs, as shown on Line 27, Column (a) of Exhibit A-19 (DFR-1).

<u>RESOURCES NOT PREVIOUSLY APPROVED BY THE COMMISSION</u>

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

A. No.

<u>RESOURCES REMAINING TO BE PURCHASED FOR 2014</u>

Q. Does Consumers need to acquire additional capacity for summer 2014?

A. No. The Company is however evaluating whether it can remove Karn Units 3 and 4 from service for planning years 2014 and 2015 and replace the Karn Unit 3 and 4 capacity with ZRCs at a lower cost than the Company’s cost of maintaining Karn Units 3 and 4 for service. If the Company concludes that such a strategy is likely to be successful, then that additional capacity will be acquired prior to Planning Year 2014. Additionally, the Company is evaluating its capacity needs for years beyond 2014 and may make capacity purchases in the near future to address those later year needs. In so doing it may acquire capacity for 2014 as part of a larger transaction to address capacity needs for later years.

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 1) participating in the Planning Resource Auction ("PRA"); 2) self-scheduling resources into the auction; or 3) 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 options.

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 Company's own 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 planning year begin?

A. The planning year will be the 12 month period beginning June 1, 2014.

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 2014. MISO will then post the results the fifth 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 Capacity Verification 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 3^{1st} 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^{st} prior to the PRA. MISO continues to consider alternatives than may allow capacity completed later than March 1^{st} but prior to the start of a planning year to be available for use in that planning year.

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 planning year. For purposes of the PSCR plan we have assumed that the difference in daily expense and daily revenue will not be material and will be addressed in the PSCR reconciliation.

SYSTEM SUPPORT RESOURCE

Q. Please explain the term System Support Resource.

A. A System Support Resource ("SSR") is a generation resource that MISO has determined is necessary to be maintained in service so as to allow MISO to operate the transmission system within applicable reliability standards. Any MISO Generation Owner planning to remove a generation resource located in the MISO region from service for economic reasons for periods of 2 months or more is required to provide notice to MISO in the form prescribed in MISO's tariff Attachment Y at least twenty-six weeks prior to initiating the shutdown process. When MISO receives the notice, it performs a study simulating system conditions without the specific generating unit in-service. If MISO determines that the resource is needed to maintain power system reliability, then MISO declares the generating unit to be a SSR and negotiates an agreement to maintain the generating unit in service until transmission system improvements can be built that will alleviate the need for the SSR.

Q. Will the Company have any units designated as an SSR in 2014?

A. Yes. In my supplemental testimony in MPSC Case No. U-16890, I stated that the Company planned to remove Gaylord Units 1, 2 and 3and the Straits combustion turbines (as well as other small combustion turbines) from service, effective March 1, 2012. On February 14, 2012, however, the Company received notice from MISO that its transmission study showed that by removing these units, it would create a violation of its reliability standards. As a result, these units would need to be designated as SSRs until the appropriate transmission upgrades are made.

Q. Will the Company be compensated for maintaining these units in service?

A. The Company is in the process of negotiating the SSR agreement but believes that it will receive compensation for any fixed and variable operating and maintenance expense that could have been avoided through retirement or suspension (mothball) of its resources.

Q. How will MISO allocate these costs?

A. Costs will be allocated to the load serving entities that benefit from the operation of the SSR unit.

Q. What is the length of an SSR service agreement?

A. The agreement has an initial term of 12 months.

Q. Can the agreement be extended?

A. Yes. MISO will periodically review the reliability requirements of its region and determine if any SSR agreements need to be extended.

Q. How will the SSR costs impact PSCR costs?

A. SSR fixed and variable operating costs and revenues received from MISO will be reconciled through the PSCR reconciliation such that any PSCR costs incurred in maintaining the units in service will be offset to the extent that revenues were received from MISO in recognition of those expenses.

<u>BLACK START SERVICE</u>

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 2014?

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.

Q. Will the Company be compensated for providing Black Start services?

A. The Company has considered petitioning FERC for a tariff to obtain compensation for providing this service but has not made such a filing at this time.

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 retired Thetford Units 5 through 9 and has, for purposes of this PSCR plan, modeled Morrow Units A and B, Whiting Unit A, and Weadock Unit A in extended reserve shut down status for the next several years. The Company has recently made arrangements to potentially allow Morrow Units A and B and Gaylord 4 to be retired in late 2013 or 2014. We anticipate that Thetford Unit 1 will be placed in extended reserve shutdown status or retired in 2014 as well.

MIDCONTINENT ENERGY MARKETS

Q. With regards to serving Consumers Energy's bundled load, will all of the charges incurred and revenues received by Consumers Energy under the MISO's Transmission and Energy and Operating Reserves Market Tariff be included in net PSCR costs to be recovered from Consumers Energy's PSCR customers in 2014 and later years?

A. Yes. All of the expense 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 2014 PSCR reconciliation case, with the exception of certain revenues anticipated to be received as a result of providing service under SSR agreements. As noted in prior testimony, to the extent that the revenue is provided to offset PSCR costs incurred we plan to credit that revenue against PSCR expense, however under the SSR agreement the Company is required to incur expense that is not PSCR expense and we intend to credit any revenue received as a result of those expenses to offset those expenses.

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

A. Exhibit A-20 (DFR-2) 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 and revenues in charges associated with FTRs and Auction Revenue Rights

("ARR") (Line 13 through 24 of Exhibit A-20 (DFR-2)), Asset Energy (Lines 2 and 26 of Exhibit A-20 (DFR-2)), Revenue Neutrality Uplift (Line 36 of Exhibit A-20 (DFR-2)), Revenue Sufficiency Guarantee (Lines 10, 11, 37 and 38 of Exhibit A-20 (DFR-2)), and Uninstructed Deviation (Line 39 of Exhibit A-20 (DFR-2)).

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

A. Yes. Daniel Alfred, in his direct testimony, discusses his forecast of expenditures for (i) Day-Ahead Market Administration Amount, (ii) Financial Transmission Rights Market Administration Amount, and (iii) Real-Time Market Administration Amount. He was 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 we've previously used to estimate the prices experienced in bilateral markets. Consumers Energy will include all settled charges incurred and revenues received in the 2014 PSCR reconciliation case.

Q. If MISO makes a change to settlement charges after the 2014 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

Q. Are you familiar with the Renewable Resource Program ("RRP")?

A. Yes. The RRP was approved by the Commission in January 2005 in MPSC Case No. U-13843. Under this program 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 the Midland Cogeneration Venture Limited Partnership 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 Renewable Resources Program (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

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

A. Yes. The Company's Renewable Energy Plan ("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 May 10, 2011 Order in MPSC Case No. U-16543. The Plan was amended a second time with the Commission's May 1, 2012 Order in MPSC Case No. U-16581 approving the settlement agreement in the Company's RE Plan Biennial Review. A third amendment to the RE Plan is being considered in MPSC Case No. U-17301.

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 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. In general, 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. In the case of 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. The Cross Winds Energy Center project approved on June 28, 2013 uses the annual Transfer Price shown in column J of Exhibit S-1 (JJH-1) in MPSC Case U-16655 as the basis for energy and capacity expense. For agreements not approved as of June 28, 2013 the Company assumes that the value of energy equals the monthly schedule of average on-peak and off-peak locational marginal prices shown on lines 14 through 29 on page 2 of Exhibit A-29 (JSR-1) in MPSC Case No. U-17301. 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. For resources not approved by the Commission as of June 28, 2013, the value of capacity for new resources is based on the schedule of capacity costs included on page 3 in Exhibit A-29 (JSR-1) in MPSC Case No. U-17301. 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 increased by the system average forced outage rate.

Consistent with the Company's filing in MPSC Case No. U-17301, the Company further reduces the PSCR costs associated with the RE Plan by the amount by which the otherwise calculated annual surcharge revenue required is less than zero.

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 Renewable Energy Plan or this PSCR plan because of the minimal amount of experience the Company had with MISO's Ancillary Service Market and the amount of ancillary services expected to be provided by these resources at the time the Renewable Energy 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 Efficiency Optimization program expected to reduce the need to acquire capacity and generate electricity. The Energy Optimization Program was revised in MPSC Case No. U-16412, revised again in MPSC Case No. U-16670, revised again in MPSC Case No. U-17138 and is proposed to be revised again in MPSC Case No. U-17351.

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

A. Yes. As discussed in Mr. Miller'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 2014 PSCR plan.

Q. What additional adjustments have been forecasted?

A. Mr. Miller has also made an adjustment to demand during peak load conditions for Direct Load Management and dynamic peak pricing programs, which is forecasted on Exhibit A-19 (DFR-1) on Lines 28 and 29.

SUMMARY

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 6.2%. I have demonstrated that the Company has adequate resources in 2014 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 included certain costs incurred under the Renewable Energy 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 management, and dynamic peak pricing 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-17317
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2014	)	

EXHIBITS

OF

DAVID F. RONK, JR.

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2013

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No.: U-17317
Witness: DFRonk Jr.
Exhibit: A-19 (DFR-1)
Date: September 2013
Page: 1 of 1

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

Line	Description	(a) 2014	(b) 2015	(c) 2016	(d) 2017	(e) 2018
1	MISO Diversity Factor	-2.69%				
2	Transmission Losses	3.90%				
3	Reserve Margin	6.20%	6.10%	6.10%	6.00%	6.00%
4	ZRCs for Owned Capacity					
5	Net Demonstrated Capability less EFORd	5,483	5,619	5,624	4,758	5,399
6	ZRCs for Projected Unit Upgrades/Re-ratings/Additions	136	37	23	641	25
7	ZRCs for Projected Retirements/remove/return from/to service	0	-32	-890	0	0
8	Subtotal PRCs for Owned Capacity	5,619	5,624	4,758	5,399	5,425
9	ZRCs for Transactions: (Annual Contracted Amounts)					
10	ZRCs for Projected Summer Capacity Purchases	0	0	800	150	150
11	ZRCs for Projected Self Generation/Load Shift	0	0	0	0	0
12	Subtotal ZRCs for Purchases	0	0	800	150	150
13	ZRCs for Non-Utility Generation Projects (NUGs)					
14	ZRCs for MCV Contract Capacity	1,209	1,209	1,209	1,209	1,209
15	ZRCs for Palisades PPA	719	719	719	719	719
16	ZRCs for Other NUGs	416	416	399	398	396
17	ZRCs for PA 295 Wind NUGs	49	49	49	49	49
18	ZRCs for PA 295 Landfill Gas NUGs	16	16	16	14	14
19	ZRCs for PA 295 Anaerobic Digestion NUGs	3	5	4	4	4
20	ZRCs for PA 295 Existing Solar NUGs	0	1	1	1	1
21	ZRCs for PA 295 New EARP Solar NUGs	0	2	2	2	2
22	ZRCs for PA 295 Hydro NUGs	0	0	0	0	0
23	Subtotal ZRCs for NUGs	2,413	2,417	2,399	2,396	2,394
24	ZRCs for Load Modifying Resources					
25	Energy Efficiency	127	194	241	289	337
26	Demand from Interruptible Customers	121	121	121	121	121
27	Demand from Metal Melting Pilot	66	66	66	66	66
28	Smart Grid-Dynamic Peak Pricing	0	32	56	79	115
29	Demand expected to be offset by Direct Load Control/Demand response (AC Cycling)	16	29	41	56	75
30	Subtotal ZRCs for Load Modifying Resources	330	442	525	611	714
31	Total ZRCs (Owned Generation, Purchases, NUGs)	8,032	8,042	7,957	7,946	7,969
32	Total ZRCs (Including LMR Additions)	8,382	8,511	8,514	8,593	8,726
33	System Peak Load	8,484	8,657	8,802	8,896	9,012
34	Demand expected to be served by Retail Open Access Suppliers	569	577	583	589	589
35	Non-Coincident Peak Load*	7,772	7,825	7,881	7,883	7,896
36	Coincident to MISO Peak Load	7,706	7,870	8,007	8,095	8,211
37	Margin -- MW	676	641	507	498	515
38	Margin Reserve -- %	8.78%	8.15%	6.33%	6.16%	6.27%

*See Exhibit A-17 (HWM-4), page 2, line 8

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No.: U-17317
Witness: DFRonk Jr.
Exhibit: A-20 (DFR-2)
Date: September 2013

MIDCONTINENT INDEPENDENT TRANSMISSION 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 Agrmnts
7	Day Ahead Congestion Rebate on Option B Grandfathered Agrmnts
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 Agrmnts
11	Day Ahead Losses Rebate on Option B Grandfathered Agrmnts
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 Amt
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 Agrmnts
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 Agrmnts
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 Dist Amount
48	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amt
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

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-17317
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2014	)	

DIRECT TESTIMONY

OF

SARA T. WALZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2013

Q. Please state your name and business address.

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

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.

<u>QUALIFICATIONS</u>

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 ("FTR") 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 MPSC Case No. U-17095, the 2013 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 2014. These costs are shown on a monthly basis for 2014 and on an annual basis for 2014 through 2018.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exhibits A-21 (STW-1), a monthly summary of the projected 2014 fuel and purchased and net interchange power expenses; A-22 (STW-2), an annual summary for years 2014-2018 of fuel and purchased and net interchange power expenses; and A-23 (STW-3), a list of the entities from which the Company expects to purchase power for years 2014-2018.

POWER SUPPLY COSTS

Q. What are the Company's forecasts of 2014 costs of fuel and purchased and net interchange power?

A. These forecasts are shown in Exhibit A-21 (STW-1), Pages 1-3.

Q. Do you consider the forecast data set forth in this exhibit to be a reasonable forecast for 2014?

A. Yes, I do. This 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 2014 forecast was produced using up-to-date assumptions and data that were reviewed by the responsible departments before they were input to 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 2013 PSCR Plan Case, MPSC Case No. U-17095?

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

Q. Please further describe Exhibit A-21 (STW-1).

A. This exhibit details the Company’s planned sources and corresponding costs of energy to be supplied in 2014.

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 requirements. Pages 1-3 of Exhibit A-21 (STW-1) show the monthly results for 2014, which were then totaled to obtain the annual results, which are also shown on

Exhibit A-22 (STW-2) along with the years 2015 through 2018. 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") dispatches the system.

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 Hubert M. Miller, a witness in this case. 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 Jim K. Chilson, a witness in this case. His testimony and exhibits set forth and explain the relevant assumptions and calculations.

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

A. That information was provided by David B. Kehoe, also a witness in this case. His testimony and exhibits set forth and explain the relevant assumptions and calculations.

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

A. Yes. There is an addition of 105.4 MW of nameplate wind capacity at the Cross Winds Energy Park assumed to be in-service beginning the fourth quarter of 2014. This new wind capacity and commercial operation date were most recently included in the Company's supplemental testimony for the Renewable Energy Plan filing in MPSC Case

No. U-17301, filed on July 29, 2013. The updates for the Cross Winds Energy Park were approved by the Commission in the June 28, 2013 and September 24, 2013 Orders in MPSC Case No. U-15805 regarding the project's Turbine Purchase Agreement and Engineering Procurement and Construction Agreement. Also included in this PSCR plan case is an upgrade to the Ludington 2 Unit resulting in an increase in generating capacity of 25.5 MW assumed to be in-service beginning July of 2014; an upgrade to the Ludington 4 Unit resulting in an increase in generating capacity of 25.5 MW assumed to be in-service beginning May 1, 2015; an upgrade to the Ludington 5 Unit resulting in an increase in generating capacity of 25.5 MW assumed to be in-service beginning May 1, 2016; an upgrade to the Ludington 1 Unit resulting in an increase in generating capacity of 25.5 MW assumed to be in-service beginning May 1, 2017 and an upgrade to the Ludington 3 Unit resulting in an increase in generating capacity of 25.5 MW assumed to be in-service beginning May 1, 2018. These upgrades are part of the major unit overhaul project at the Ludington Pumped Storage Plant beginning in 2013. Additionally, there is the addition of 0.3 MW of nameplate capacity at the Company owned solar generating facility assumed to be in-service beginning July 1, 2015. This capacity has most recently been included in the supplemental testimony for the Company's Renewable Energy Plan, MPSC Case No. U-17301, filed on July 29, 2013. The proposed solar facility has been approved by the Commission in the May 20, 2011 Order for MPSC Case No. U-16543, the Company's Amended Renewable Energy Plan.

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

A. The Company is also proposing an addition of 730 MW of nameplate capacity at the Thetford Generating Station, assumed to be in-service June 1, 2017. This capacity was the focus of the Company's Application for Approval of a Certificate of Necessity, MPSC Case No. U-17429, filed July 12, 2013. The Company is also proposing to suspend the operation of 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 ("MATS") rule that would be otherwise be effective for these units on April 1, 2016. This case also reflects the Company's decision to mothball or place in extended reserve shutdown status the following combustion turbine units: Campbell Unit A, Morrow Units A and B, Weadock Unit A, Whiting Unit A, and Cobb Units 1-3. Gaylord Unit 4 has been assumed to retire as of September 2013. Thetford Units 5-9 are assumed to retire as of October 2013. The Thetford Units 1-4 are assumed to be available for Black Start operation only, as explained in David F. Ronk's direct testimony in this case. Gaylord Units 1-3 and Straits Unit 1 are assumed to be designated as System Support Resources, as explained in David F. Ronk's direct testimony in this case.

Q. On Line 4 of Exhibit A-21 (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-21 (STW-1). When a generating unit is off-line, station power usage is accounted for as negative generation. Lines 1 and 2 of Exhibit A-21 (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-21 (STW-1) includes station power used while off line, so I show a separate line item, Line 4, to balance the exhibit.

Q. On Line 11 of Exhibit A-21 (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 that power is projected to be purchased from for the years 2014 through 2018 is found on Exhibit A-23 (STW-3), Pages 1-19, 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-23 (STW-3) estimated?

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

1. For nondispatchable suppliers, we have 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 case?

A. Yes, the contract for capacity and energy at the North American Biofuels Green Meadow Farms facility was terminated and replaced with an energy only agreement. This energy only agreement is for 0.8 MW of nameplate capacity beginning March 1, 2013.

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

A. Yes, there is an addition of 2.36 MW of nameplate capacity for the Experimental Advanced Renewable Program Anaerobic Digester contracts, assumed to be in service as of July 2015. This capacity has most recently been included in the supplemental testimony for the Company's Renewable Energy Plan, MPSC Case No. U-17301, filed on July 29, 2013. The program has been approved by the Commission in the May 20, 2011 Order for MPSC Case No. U-16543, the Company's Amended Renewable Energy Plan.

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

A. No.

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

A. Yes, the Renewable Resource Program approved by the Commission in its January 25, 2005 Order in MPSC 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-23 (STW-3) listed under the category of Green Generation Program Agreements. The energy charge for all 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 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 MPSC Case No. U-15320.

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

A. No. As in last year's Case No. U-17095, the Cadillac, Genesee, and Grayling wood fueled units are dispatched on the cost of production based on a wood price, and the Ada unit is again dispatched on the cost of production based on natural gas, instead of the 12-month rolling average coal price that is the contract dispatch price for these units. The Reduced Dispatch Agreements ("RDAs") for the wood fired units were most recently included as Exhibit A-38 (DFR-12) in Case No. U-15001-R. The Reduced Dispatch Agreement for the Ada unit was most recently included as Exhibit A-20 (DFR-4) in Case No. U-16045. The projected hold harmless amount resulting from this dispatch is $1,433,000 and the projected customer benefit (offset to PSCR) is $782,000. These amounts are included as credits in Lines 24 and 38 on Exhibit A-21 (STW-1) and Exhibit A-22 (STW-2).

Q. On Line 12 of Exhibit A-21 (STW-1) you use the term "Net Interchange." Please explain this.

A. This phrase refers to purchases from and sales to other entities for energy and capacity. The details are shown on Exhibit A-21 (STW-1) and also on Exhibit A-22 (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 (“ZRC”) to meet the Company’s net peak demand plus MISO reserve margin requirements. This is explained in Mr. Ronk’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 Line 40 of Exhibit A-21 (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 2008 PA 286 and the Commission’s August 11, 2009 Order in MPSC Case No. U-16048.

Q. Please explain Lines 32 and 44 of Exhibit A-21 (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 RAC (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. We have estimated the amount of increased generation at the oil and gas units that MISO uses for this purpose on Line 32 and have represented it as a sale. We will be reimbursed in full for this use of our 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-21 (STW-1).

A. Line 43 represents revenue from the sale of capacity, although no sales have been modeled in this case.

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

A. No.

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-17317
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2014	)	

EXHIBITS

OF

SARA T. WALZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2013

MICHIGAN PUBLIC SERVICE COMMISSION

CASE NO.: U-17317
EXHIBIT: A-21 (STW- 1)
WITNESS: STWALZ
DATE: SEPTEMBER 2013

CONSUMERS ENERGY COMPANY

SUMMARY BY SOURCE

YEAR		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2014
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	ENERGY (MWH)													
1	COAL STEAM	1,526,683	1,308,425	1,353,882	872,156	1,161,991	1,170,321	1,411,906	1,456,236	1,099,981	1,161,082	1,214,740	1,434,989	15,172,392
2	GAS & OIL	232,539	188,836	192,769	152,117	65,074	93,015	219,284	158,262	55,348	15,124	-4,558	14,874	1,382,686
3	NUCLEAR PPA	592,797	536,360	583,654	558,928	571,896	548,828	563,353	561,466	547,640	578,392	565,007	584,770	6,793,092
4	STATION POWER	8,281	8,958	10,409	14,451	9,980	9,162	7,301	5,546	10,091	10,941	10,779	9,252	115,150
5	CE OWNED RENEWABLES	65,481	57,876	73,283	74,415	65,233	52,410	42,596	39,550	40,211	52,414	97,043	105,396	765,907
6	PEAKERS	0	0	0	0	0	0	21,980	8,255	0	0	0	0	30,235
7	PUMPED STORAGE	91,756	32,237	37,824	83,914	77,663	93,869	132,330	131,715	38,965	40,505	11,264	74,518	846,558
8	TOTAL GENERATED	2,517,537	2,132,692	2,251,822	1,755,981	1,951,837	1,967,605	2,398,750	2,361,029	1,792,235	1,858,457	1,894,274	2,223,798	25,106,019
9	LESS : PUMPING	-124,018	-39,825	-57,823	-117,023	-107,431	-137,349	-174,298	-191,024	-53,392	-53,803	-16,599	-99,507	-1,172,093
10	TOTAL GENERATED	2,393,519	2,092,867	2,193,999	1,638,958	1,844,406	1,830,256	2,224,452	2,170,005	1,738,844	1,804,654	1,877,675	2,124,292	23,933,927
11	PURCHASED (NUGs)	728,229	418,481	336,779	361,689	437,197	451,998	734,343	561,197	403,960	333,517	336,977	388,670	5,493,035
12	NET INTERCHANGE	-58,904	258,495	370,108	622,499	511,260	768,818	358,898	523,711	685,130	665,588	534,702	533,167	5,773,472
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13	TOTAL SYSTEM REQUIREMENTS	3,062,844	2,769,842	2,900,886	2,623,146	2,792,863	3,051,072	3,317,693	3,254,912	2,827,933	2,803,759	2,749,354	3,046,128	35,200,434
	EXPENSES ($*1000)													
14	COAL STEAM	42,452	35,705	37,565	24,150	32,176	32,674	43,184	44,141	30,222	31,349	32,454	38,056	424,128
15	GAS & OIL	8,602	7,031	7,196	5,550	2,746	3,717	8,821	8,809	2,445	1,086	392	1,148	57,542
16	NUCLEAR PPA	31,821	24,897	25,835	25,239	26,132	30,009	34,106	33,643	29,931	26,125	24,615	26,989	339,342
17	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
18	CE OWNED RENEWABLES	2,190	1,944	1,911	1,746	1,462	1,355	1,869	1,852	1,213	1,671	4,167	4,572	25,953
19	PEAKERS	42	42	60	42	42	42	1,088	437	42	42	42	42	1,963
20	PUMPED STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
		-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	------
21	TOTAL GENERATED	85,107	69,619	72,567	56,728	62,558	67,797	89,068	88,881	63,853	60,272	61,670	70,807	848,927
22	LESS : PUMPING	0	0	0	0	0	0	0	0	0	0	0	0	0
23	TOTAL GENERATED	85,107	69,619	72,567	56,728	62,558	67,797	89,068	88,881	63,853	60,272	61,670	70,807	848,927
24	PURCHASED (NUGs)	61,072	45,967	44,763	41,833	46,143	46,386	61,091	54,364	43,801	42,574	42,234	45,499	575,726
25	NET INTERCHANGE	-4,373	8,026	12,058	18,393	12,822	21,750	4,371	8,699	20,484	21,758	18,980	18,854	161,822
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26	TOTAL SYSTEM COST	141,806	123,612	129,388	116,954	121,523	135,933	154,529	151,944	128,137	124,603	122,884	135,160	1,586,475

MICHIGAN PUBLIC SERVICE COMMISSION

CASE NO.: U-17317
EXHIBIT: A-21 (STW- 1)
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CONSUMERS ENERGY COMPANY

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2014
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	RECEIVED (MWH)													
27	MARKET ON PEAK	16,517	139,758	205,145	276,199	179,474	296,731	109,998	182,674	329,540	403,624	400,871	367,091	2,907,622
28	MARKET OFF PEAK	154,656	172,068	204,645	372,692	422,331	542,862	519,292	559,663	398,926	270,213	158,928	203,167	3,979,443
29	PURCHASED (NUGs)	728,229	418,481	336,779	361,689	437,197	451,998	734,343	561,197	403,960	333,517	336,977	388,670	5,493,035
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30	TOTAL RECEIVED	899,402	730,307	746,570	1,010,580	1,039,002	1,291,591	1,363,633	1,303,534	1,132,426	1,007,354	896,777	958,928	12,380,101
	DELIVERED (MWH)													
31	EXTERNAL SALES	230,077	53,331	39,682	26,392	90,545	70,775	254,743	173,390	43,337	8,249	25,098	37,091	1,052,709
32	MISO RAC	0	0	0	0	0	0	15,649	45,236	0	0	0	0	60,884
		-----	-----	-----	-----	-----	------	-----	-----	-----	-----	-----	-----	------
33	TOTAL DELIVERED	230,077	53,331	39,682	26,392	90,545	70,775	270,392	218,626	43,337	8,249	25,098	37,091	1,113,594
34	NET (MWH)	669,325	676,976	706,887	984,188	948,457	1,220,816	1,093,241	1,084,907	1,089,089	999,105	871,679	921,836	11,266,507

MICHIGAN PUBLIC SERVICE COMMISSION

CASE NO.: U-17317
EXHIBIT: A-21 (STW- 1)
WITNESS: STWALZ
DATE: SEPTEMBER 2013
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CONSUMERS ENERGY COMPANY

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2014
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	EXPENSE ($*1000)													
35	PURCHASE OF ZONAL RESOURCE CREDITS	3	3	3	3	3	0	0	0	0	0	0	0	13
36	MARKET ON PEAK ENERGY	245	4,869	7,538	10,056	6,478	11,616	5,901	7,989	12,454	15,299	15,306	14,459	112,208
37	MARKET OFF PEAK ENERGY	4,494	5,030	5,718	9,297	9,867	13,362	12,452	14,104	9,877	6,717	4,383	5,746	101,048
38	PURCHASED (NUGs) ENERGY	38,975	25,820	22,866	21,411	23,914	24,857	38,926	32,212	22,564	20,601	20,645	23,280	316,070
39	PURCHASED (NUGs) CAPACITY	20,992	19,043	20,793	19,318	21,125	20,425	21,061	21,048	20,133	20,869	20,485	21,115	246,407
40	CASE NO. U-16048 COST RECOVERY	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	13,249
		-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	------
41	TOTAL EXPENSE	65,813	55,868	58,022	61,189	62,491	71,365	79,444	76,456	66,131	64,589	61,923	65,705	788,995
	CREDIT ($*1000)													
42	EXTERNAL SALE ENERGY	9,114	1,875	1,201	963	3,526	3,227	12,812	8,925	1,851	258	709	1,351	45,811
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	1	1,171	4,469	-5	0	0	0	5,636
		----	----	----	----	----	-----	-----	-----	----	----	----	----	------
45	TOTAL CREDIT	9,114	1,875	1,201	963	3,526	3,229	13,982	13,394	1,847	258	709	1,351	51,447
46	NET EXPENSE	56,699	53,994	56,821	60,226	58,965	68,136	65,461	63,063	64,284	64,331	61,214	64,354	737,548

MICHIGAN PUBLIC SERVICE COMMISSION

CASE NO.: U-17317
EXHIBIT: A-22 (STW- 2)
WITNESS: STWALZ
DATE: SEPTEMBER 2013

CONSUMERS ENERGY COMPANY

SUMMARY BY SOURCE

YEAR		2014	2015	2016	2017	2018
(a)	(b)	(c)	(d)	(e)	(f)	(g)
	ENERGY (MWH)					
1	COAL STEAM	15,172,392	16,566,419	13,010,224	12,329,238	10,846,620
2	GAS & OIL	1,382,686	1,011,770	2,428,293	5,085,952	6,644,822
3	NUCLEAR PPA	6,793,092	6,780,138	6,798,738	6,780,463	6,777,693
4	STATION POWER	115,150	96,857	90,746	77,616	92,669
5	CE OWNED RENEWABLES	765,907	1,107,569	1,104,512	1,095,601	1,096,045
6	PEAKERS	30,235	33,568	44,935	76,005	35,058
7	PUMPED STORAGE	846,558	1,162,908	1,254,639	1,265,467	1,312,767
8	TOTAL GENERATED	25,106,019	26,759,229	24,732,086	26,710,342	26,805,674
9	LESS : PUMPING	-1,172,093	-1,583,408	-1,679,466	-1,673,256	-1,737,434
10	TOTAL GENERATED	23,933,927	25,175,822	23,052,620	25,037,086	25,068,240
11	PURCHASED (NUGs)	5,493,035	4,996,938	7,055,832	7,630,898	6,866,088
12	NET INTERCHANGE	5,773,472	5,220,777	5,656,305	3,466,943	4,490,084
		--------	--------	--------	--------	--------
13	TOTAL SYSTEM REQ	35,200,434	35,393,536	35,764,758	36,134,927	36,424,411
	EXPENSES ($*1000)					
14	COAL STEAM	424,128	454,057	356,367	354,052	327,658
15	GAS & OIL	57,542	48,582	104,187	203,175	265,411
16	NUCLEAR PPA	339,342	345,706	356,190	365,295	375,720
17	STATION POWER	0	0	0	0	0
18	CE OWNED RENEWABLES	25,953	49,381	49,953	49,354	50,403
19	PEAKERS	1,963	2,217	2,842	4,520	2,427
20	PUMPED STORAGE	0	0	0	0	0
		------	------	------	------	------
21	TOTAL GENERATED	848,927	899,943	869,539	976,396	1,021,618
22	LESS : PUMPING	0	0	0	0	0
23	TOTAL GENERATED	848,927	899,943	869,539	976,396	1,021,618
24	PURCHASED (NUGs)	575,726	556,952	640,795	679,973	647,700
25	NET INTERCHANGE	161,822	149,241	236,424	143,561	140,738
		-------	-------	-------	-------	-------
26	TOTAL SYSTEM COST	1,586,475	1,606,136	1,746,758	1,799,929	1,810,056

CONSUMERS ENERGY COMPANY

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		2014	2015	2016	2017	2018
(a)	(b)	(c)	(d)	(e)	(f)	(g)
	RECEIVED (MWH)					
27	MARKET ON PEAK	2,907,622	2,822,239	2,595,945	1,518,437	1,772,224
28	MARKET OFF PEAK	3,979,443	3,580,306	4,103,629	3,763,452	4,676,684
29	PURCHASED (NUGs)	5,493,035	4,996,938	7,055,832	7,630,898	6,866,088
30	TOTAL RECEIVED	12,380,101	11,399,482	13,755,406	12,912,787	13,314,996
	DELIVERED (MWH)					
31	EXTERNAL SALES	1,052,709	1,083,883	927,644	1,720,937	1,910,751
32	MISO RAC	60,884	97,885	115,624	94,009	48,091
33	TOTAL DELIVERED	1,113,594	1,181,768	1,043,268	1,814,946	1,958,842
34	NET (MWH)	11,266,507	10,217,714	12,712,138	11,097,841	11,356,154

MICHIGAN PUBLIC SERVICE COMMISSION

CASE NO.: U-17317
EXHIBIT: A-22 (STW- 2)
WITNESS: STWALZ
DATE: SEPTEMBER 2013

CONSUMERS ENERGY COMPANY

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		2014	2015	2016	2017	2018
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**
	EXPENSE ($*1000)					
35	PURCHASE OF ZONAL RESOURCE CREDITS	13	0	50,101	45,516	17,029
36	MARKET ON PEAK ENERGY	112,208	117,657	122,013	77,978	87,117
37	MARKET OFF PEAK ENERGY	101,048	88,453	121,225	112,383	135,591
38	PURCHASED (NUGs) ENERGY	316,070	296,942	384,798	424,600	392,407
39	PURCHASED (NUGs) CAPACITY	246,407	246,546	242,298	241,426	241,075
40	CASE NO. U-16048 COST RECOVERY	13,249	13,463	13,698	13,946	14,218
		------	------	------	------	------
41	TOTAL EXPENSE	788,995	763,062	934,134	915,849	887,436
	CREDIT ($*1000)					
42	EXTERNAL SALE ENERGY	45,811	48,001	44,746	83,878	93,181
43	EXTERNAL SALE CAPACITY	0	0	0	0	0
44	MISO RAC	5,636	8,868	12,170	8,437	5,818
		------	------	------	------	------
45	TOTAL CREDIT	51,447	56,869	56,916	92,315	98,999
46	NET EXPENSE	737,548	706,194	877,219	823,534	788,438

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY
PURCHASED POWER AGREEMENTS

Line	Existing Energy–Only Agreements	Projected 2014 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: Three-month rolling average incremental running cost Administrative Charge: 0.10¢/kWh	Seller may terminate by giving at least 180 days written notice to Consumers. Consumers may terminate if the Seller breaches the contract, or if the Seller is in default of any of its obligations for longer than 90 days.
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 $341/month, but not to exceed $3,411/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.

Line	Existing Energy–Only Agreements	Projected 2014 Rates	Termination of Agreement
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 \$341/month, but not to exceed \$3,411/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.
7	North American Biofuels – Green Meadow Farms	Energy: 90% of (Consumers Energy's Real Time Load Node LMP Minus \$5/MWh) Administrative Charge: 0.10¢/kWh (minimum of \$341/month, but not to exceed \$3,411/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 2014 Rates	Termination of Agreement
1	Michigan Wind I LLC (Wind) (PPA 1)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $341/month, but not to exceed $3,411/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 $341/month, but not to exceed $3,411/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 $341/month, but not to exceed $3,411/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 $341/month, but not to exceed $3,411/month).	January 29, 2018.

Line	Green Generation Program Agreements	Projected 2014 Rates	Termination of Agreement
5	North American Natural Resources, Inc. Venice Park Generating Station (Landfill Gas)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $341/month, but not to exceed $3,411/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.
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 $341/month, but not to exceed $3,411/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 2014 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 $341/month, but not to exceed $3,411/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 2014 Rates	Termination of Agreement
4	Cadillac Renewable Energy	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.320¢/kWh On-Peak 4.110¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	July 16, 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 at the end of a calendar year.
5	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.
6	Black River Limited Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 1.93¢/kWh On-Peak 1.64¢/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.

Line	Existing Energy & Capacity Agreements	Projected 2014 Rates	Termination of Agreement
7	Beaverton, City of	Energy: 3.60¢/kWh On-Peak 2.82¢/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.
8	Hope Renewable Energy – Hubbardston	Energy: Agreement Terminated. Capacity: Agreement Terminated. Administrative Charge: Agreement Terminated.	This agreement was terminated on November 8, 2011.
9	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.
10	Commonwealth Power Company – LaBarge	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.42¢/kWh On-Peak 3.87¢/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.

Line	Existing Energy & Capacity Agreements	Projected 2014 Rates	Termination of Agreement
11	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.
12	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.
13	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 $341/month, but not to exceed $3,411/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.

Line	Existing Energy & Capacity Agreements	Projected 2014 Rates	Termination of Agreement
14	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 $235/month, but not to exceed $2,349/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.
15	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 $256/month, but not to exceed $2,562/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.
16	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 $341/month, but not to exceed $3,411/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.

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY
PURCHASED POWER AGREEMENTS

Line	Existing Energy & Capacity Agreements	Projected 2014 Rates	Termination of Agreement
17	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 $341/month, but not to exceed $3,411/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.
18	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 $341/month, but not to exceed $3,411/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.
19	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.

Line	Existing Energy & Capacity Agreements	Projected 2014 Rates	Termination of Agreement
20	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.
21	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.
22	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.
23	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.

Line	Existing Energy & Capacity Agreements	Projected 2014 Rates	Termination of Agreement
24	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.
25	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 $341/month, but not to exceed $3,411/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.
26	STS Hydropower Ltd – Cascade Hydro Plant	Energy: 3.60¢/kWh On-Peak 2.82¢/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.
	STS Hydropower Ltd –	Energy: 3.60¢/kWh On-Peak	December 31, 2017. After this date the Agreement may

Line	Existing Energy & Capacity Agreements	Projected 2014 Rates	Termination of Agreement
27	Fallasburg Hydro Plant	2.82¢/kWh Off-Peak Capacity: 3.09¢/kWh On-Peak 2.63¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	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	STS Hydropower Ltd – Morrow Hydro Plant	Energy: 3.60¢/kWh On-Peak 2.82¢/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.
29	T.E.S. Filer City Station Limited Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 6.34¢/kWh On-Peak 5.38¢/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.
30	Thornapple Association, Inc	Energy: 3.60¢/kWh On-Peak 2.82¢/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.
31	Viking Energy of Lincoln	Energy: Twelve-month rolling average	December 31, 2018. After this date the Agreement may

Line	Existing Energy & Capacity Agreements	Projected 2014 Rates	Termination of Agreement
	Limited Partnership	cost of CE coal generation Capacity: 4.30¢/kWh On-Peak 3.66¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	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	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.
33	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.
34	Boyce Hydro (formerly Wolverine Power Corporation)	Energy: 5.12¢/kWh On-Peak 2.17¢/kWh Off-Peak Capacity: 0.91¢/kWh On-Peak 0.77¢/kWh Off-Peak Administrative Charge: None	May 31, 2022.
35	Entergy Nuclear Power Marketing, LLC	Energy: 0.615¢/kWh	April 11, 2022.

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY
PURCHASED POWER AGREEMENTS

Line	Existing Energy & Capacity Agreements	Projected 2014 Rates	Termination of Agreement
		Capacity: 4.385¢/kWh Administrative Charge: None	

Line	Renewable Energy Plan Agreements	Projected 2014 Rates	Termination of Agreement

Line	Renewable Energy Plan Agreements	Projected 2014 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.

Line	Renewable Energy Plan Agreements	Projected 2014 Rates	Termination of Agreement
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.
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.

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY
PURCHASED POWER AGREEMENTS

Line	Renewable Energy Plan Agreements	Projected 2014 Rates	Termination of Agreement
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 $341/month, but not to exceed $3,411/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.

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY
PURCHASED POWER AGREEMENTS

Line	Renewable Energy Plan Agreements	Projected 2014 Rates	Termination of Agreement
17	Experimental Advanced Renewable Program (EARP) FiT (Anaerobic Digester)	Energy: Monthly Transfer Rate Administrative Charge: None	May 31, 2035.

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-17317
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2014	)	

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Debra S. Weirich, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on September 30, 2013, she served an electronic copy of the Application, Testimony and Exhibits of Consumers Energy's witnesses Dan S. Alfred, Natalie N. Busak, Jim K. Chilson, II, David B. Kehoe, Hubert W. Miller III, David F. Ronk, Jr. and Sara T. Walz, upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Debra S. Weirich
Digitally signed by Debra S. Weirich
Date: 2013.09.30 16:53:16 -04'00'

Debra S. Weirich

Subscribed and sworn to before me this 30th day of September, 2013.

Digitally signed by Dorothy H. Wright
Date: 2013.09.30 16:56:13 -04'00'

Dorothy H. Wright, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 08/17/19
Acting in the County of Jackson

Attachment 1 to Case No. U-17317 - E-Mail Service List Parties to Case No. U-17095		
Party	**Name**	**E-mail Address**
Counsel for the Michigan Public Service Commission Staff	Spencer A. Sattler, Esq.	sattlers@michigan.gov
Counsel for Attorney General Bill Schuette	Donald E. Erickson, Esq.	ericksond@michigan.gov
Counsel for Midland Cogeneration Venture Limited Partnership ("MCV")	Richard J. Aaron, Esq. David R. Whitfield, Esq. Gary B. Pasek, Esq.	raaron@wnj.com dwhitfield@wnj.com gbpasek@midcogen.com
Counsel for the Michigan Community Action Agency Association ("MCAAA")	Don L. Keskey, Esq.	donkeskey@publiclawresourcecenter.com
Counsel for the Michigan Environmental Council ("MEC") and Natural Resources Defense Council ("NRDC")	Christopher M. Bzdok, Esq. Katherine E. Redman, Esq. Ruth Ann Liebziet Kimberly Flynn	chris@envlaw.com kate@envlaw.com ruthann@envlaw.com kimberly@envlaw.com
Counsel for Michigan Power Limited Partnership and Ada Cogeneration Limited Partnership	David E. S. Marvin, Esq.	dmarvin@fraserlawfirm.com
Counsel for the Association of Businesses Advocating Tariff Equity ("ABATE")	Robert A. W. Strong, Esq. Leland R. Rosier, Esq.	rstrong@clarkhill.com lrrosier@clarkhill.com