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February 20, 2012

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
6545 Mercantile Way
P.O. Box 30221
Lansing, MI 48909

RE: 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 2012

Dear Ms. Kunkle:

Included in this electronic file are Consumers Energy Company's supplemental direct testimony/second direct testimony and exhibits of Company witnesses Richard T. Blumenstock, Shawn D. Burgdorf, Laura M. Collins, Brian D. Gallaway, David B. Kehoe, Richard J. Polena, David F. Ronk, Jr., and Lincoln D. Warriner. Also included is a Proof of Service. This is a paperless filing and is therefore being filed only in a PDF format.

In order to assist the parties, I have indicated below which witnesses have prepared supplemental testimony **in addition** to their previously-filed direct testimony. These witnesses include:

Richard Blumenstock
Shawn Burgdorf
Laura Collins
Brian Gallaway
Richard Polena
Dave Ronk

The following witnesses have filed direct testimony **that replaces** their previously-filed direct testimony:

David B. Kehoe
Lincoln Warriner.

In addition to the supplemental testimony, certain supplemental exhibits are also included with this filing. Exhibits that have been revised have been renumbered. Exhibits that have not been altered are **not** included in this filing. These are Exhibits A-1 (RTB-1), A-2 (RTB-2), A-17 (RJP-3) and A-19 (DFR-2).

Please contact me with any questions.

Sincerely,

Digitally signed by John C. Shea
Date: 2012.02.20 17:25:12 -05'00'

John C. Shea

cc: Hon. Dennis W. Mack
Parties to Attachment 1 to Proof of Service

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-16890
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2012	)	

SUPPLEMENTAL DIRECT TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February, 2012

Q. Please state your name and business address.

A. Richard T. Blumenstock, 1945 West Parnall Road, Jackson, Michigan.

Q. Are you the same Richard T. Blumenstock who previously filed testimony in this case?

A. Yes.

Q. What is the purpose of your supplemental testimony?

A. The purpose of my supplemental testimony is to describe the significant changes in the Midwest Energy Market that have occurred since the original filing of the 2012 PSCR Plan, the expected impact these changes will have on Consumers Energy Company ("Consumers Energy" or the "Company") in 2012, and the intended operating actions the company will take in response to the changes.

Q. Why is the Company filing supplemental direct testimony in this case?

A. The Company is filing supplemental direct testimony because of the significant changes in the cost of fuels experienced since the Company's September 2011 filling of direct testimony and the resulting effect on the Midwest Energy Market. These changes have caused the Company to take extraordinary measures to vary our fuel acquisition strategy, modify our plant operation strategy, and reforecast our PSCR costs.

Q. Are you sponsoring any exhibits?

A. No.

<u>ELECTRIC MARKET CHANGES</u>

Q. Please describe the changes that have occurred in the Midwest Energy Markets since the original filing of the 2012 PSCR Plan.

A. Prices for electricity in the Midwest Energy Market over the last three months of 2011 fell to their lowest level since the inception of the Midwest Energy Market. The average electric price in the fourth quarter of 2011 was $28.08 per MWh. The lowest average electric price for any prior fourth quarter was $29.51 per MWh. The month of December 2011, in particular, had the lowest average electric price of any prior December since the inception of the Midwest Energy Market. The average electric price in December of 2011 was $28.05 per MWh, which is 17% below the previous lowest December average of $33.80 per MWh.

Q. What is driving this change in electric prices in the Midwest Energy Market?

A. The primary driver is the low price for natural gas. Prices for natural gas have continued to drop throughout the last quarter of 2011. According to the Energy Information Administration ("EIA"), the monthly average Henry Hub Spot Gas prices for September through December of 2011 were $3.90, $3.57, $3.24, and $3.17 per Mcf, respectively. Industry analysts attribute the price drop to a recent growth in natural gas production resulting from the application of technological advances and continued drilling in shale plays with high concentrations of natural gas liquids and crude oil. Low natural gas prices have the effect of lowering fuel cost for generators using natural gas as fuel. With such low fuel costs, natural gas fired generators have incremental and average costs below generators having coal or oil as fuel sources. This results in Midwest Independent Transmission System Operator, Inc. ("MISO"), the entity responsible for administering the Midwest Energy Market, committing and dispatching lower cost natural gas-fueled generators before higher cost coal-fueled and oil-fueled generators to meet electric demand requirements.

Q. Does the Company expect these market conditions to continue into 2012?

A. Yes. The Company expects prices for natural gas will continue to be depressed in 2012.

The NYMEX futures for natural gas used in the Company's September 2011 filing of the 2012 PSCR Plan were effective as of August 29, 2011, and showed an average natural gas price for 2012 of $4.39 per MMBtu. The NYMEX futures for natural gas used in this Supplemental filing were effective as of December 28, 2011, and showed an average natural gas price for 2012 of $3.35 per MMBtu. Industry consensus is that prices for natural gas in 2012 will be lower than natural gas prices experienced in 2011. The EIA's latest forecast issued in February of 2012 calls for an average 2012 price of Henry Hub Spot Gas of $3.35 per MMBtu, which is 16% lower than the actual 2011 price of $4.00 per MMBtu. Since electric prices reflect trends in fuel prices, lower natural gas prices in 2012 will result in lower electric prices in 2012.

<u>IMPACT ON CONSUMERS ENERGY</u>

Q. What impact have these market changes had on the Company?

A. MISO has greatly increased usage of natural gas-fueled combined cycle facilities throughout the MISO footprint, including the Company's Zeeland Combined Cycle Plant. Increased usage of natural gas has displaced usage of coal-fueled facilities throughout the MISO footprint, including the Company's coal-fueled facilities. This is simply due to the MISO's commitment and dispatch methodology of using lowest cost generation to meet electric demand.

The best demonstration of the impact can be seen in the utilization factors for the Zeeland Combined Cycle Plant and the coal-fueled fleet of generators as they evolved over the last three months of 2011. Utilization factor is a measure of how much a generator is used and is calculated by dividing a generator's actual generation by the offered capacity.

Through September of 2011, the Zeeland Combined Cycle Plant had a year-to-date utilization factor of 31%. The monthly utilization factors in October, November, and December of 2011 were 39%, 55% and 70%, respectively. Through September of 2011, the Company's coal-fueled fleet of generators had a year-to-date utilization factor of 79%. The monthly utilization factors in October, November and December were 72%, 58% and 55%, respectively. These trends in utilization factor clearly demonstrate that MISO utilized lower cost natural gas-fueled generation to meet electric demands.

Q. Does the Company expect these impacts to continue in 2012?

A. Yes. The Company fully expects the previously described market changes to continue in 2012, ultimately resulting in higher utilization by MISO of natural gas-fueled, combined cycle plants, lower utilization by MISO of coal-fueled plants, and depressed energy prices in the Midwest Energy Market.

<u>CONSUMERS ENERGY'S RESPONSE</u>

Q. How does the Company intend to respond to these market conditions?

A. The Company intends to respond in two ways. First, the Company's coal-fueled generators will be operated using different blends of fuel depending on the variable cost of production and the relative value of energy. Second, the Company's coal-fueled generators are expected to experience increased cycling operations.

Q. Please describe the Company's plan to operate its coal-fueled generators using different fuel blends.

A. Prior to 1988 the Company operated its coal-fueled generators using eastern coal. Beginning in the mid-1990s, after considerable testing of the effect of western coal on the operation of some of the Company's generating plants, the Company utilized a blend of eastern and western coal that reduced its cost of production while still achieving the maximum power output of each generating unit. From time to time, when market prices are below the cost of production for one or more coal-fueled generators, the Company, on a temporary basis, successfully increased the amount of western coal in its fuel blends so as to lower its cost of production with a modest temporary reduction in maximum output. The reason for blending coal in this manner is that the delivered cost of western coal, on a per MMBtu basis, is lower than the delivered cost of eastern coal.

In 2012, during periods when electric prices are near or lower than the generating units' cost of production, the Company's coal-fueled generators are expected to increase their use of western coal above the level where they can achieve full power output using only coal. This will have the effect of lowering the generator's production cost and subsequently its price offer in the Midwest Energy Market for the operating range fueled by coal. Lowering the generator's price offer makes the generator a more valuable resource to the Midwest Energy Market. Loss of the generator's real power capability over the operating range fueled by coal will not be detrimental since electric demand during low electric price periods will be met by MISO through commitment and dispatch of lower cost generation resources.

In 2012, during periods when electric prices are higher than the generator's cost of production, the Company's coal-fueled generators are expected to increase their use of eastern coal to the level necessary to provide maximum output of the generating unit. This will have the effect of increasing the generator's cost of production and price offer in the Midwest Energy Market, but will also provide the generator's full real power capability. The higher price offer will be acceptable in the high electric price period. Further, offering the full real power capability will make the generator a more valuable resource to the Midwest Energy Market.

Q. How will the Company vary fuel blends for its coal-fueled generators according to market demand?

A. Each day, by 11:00 AM, the Company will forecast the next day's market prices. If the forecasted prices are high enough to warrant the use of eastern coal at a given generator, the Company will offer the generator based on a blend of eastern and western coal over the entire operating range of the generator. If the forecasted prices are not high enough to warrant the use of eastern coal at a given generator, the Company will offer the generator based on 100% western coal up to the maximum real power capability achievable on 100% western coal. Some of the Company's coal-fueled generators can produce additional real power in overfire operation. Where possible, the Company will offer the additional real power from overfire operation to the Midwest Energy Market.

By 4:00 PM of the same day, MISO will determine the schedule for real power production from each generator for the next operating day and will inform the Company of the schedule. The Company will then prepare for the next day's fuel blends according to the schedule. Generally, changing fuel blends can only be accomplished once a day due to fuel handling restrictions.

Q. Please describe the Company's ability to experience increased cycling operations at the coal-fueled generators.

A. The Company's coal-fueled generators were originally designed for continuous, base-load operation. The Company intends to shutdown coal-fueled generators for extended time periods when electric prices in the Midwest Energy Market are forecasted to be significantly and consistently below the cost of production for a given generator. Plant personnel are taking measures to lessen the impact of cycling operations as much as possible. As part of the decision to cycle a coal-fueled generator, the Company will consider the cost of cycling operations.

Q. How does the Company offer coal-fueled generators in cycling mode in the Midwest Energy Market?

A. The Company's coal-fueled generators are not feasible to cycle on a daily basis due to the generators having start-up times in the 24-hour range, which is a typical start-up time for coal-fueled generators. MISO makes commitment decisions in the Day-Ahead Market based on a 24-hour operating outlook. This is not a sufficient time period to accommodate typical coal-plant start-up times. Therefore, the Company evaluates the profitability of each of its coal-fueled generators over a longer operating outlook than what MISO considers when making commitment decisions. When the evaluation indicates a generator is likely to receive revenue in excess of the variable cost of operations over the operating outlook, the Company offers the generator as a "Must Run" resource to ensure the generator is committed in the Midwest Energy Market during the period the generator is expected to have a beneficial net energy value. When the evaluation indicates a generator is not likely to receive revenue in excess of the variable cost of operations over the operating outlook, the Company offers the generator as an "Economic" resource, thereby allowing MISO to commit or decommit the generator based on MISO's view of the economic dispatch of the system as well as the reliability needs of the region. These evaluation scenarios are subject to other operational considerations that may result in different resource status offers.

MARKET STRATEGY

Q. Has there been a change in the strategy you laid out in your direct testimony in this case?

A. No. The Company's strategy remains the same - to offer electric demand and generation resource parameters such as availability, capability, and cost into the Midwest Energy Market as accurately as possible.

Q. Is the Company's intention to vary fuel blends according to market demands a change in strategy?

A. No. The Company has always considered fuel blend changes in response to market demands, but generally has not done so in the past since the cost of production of coal-fueled generation was considerably lower than the market price of power. Last year, during periods of low electric prices that occurred primarily during weekends, the Company routinely changed fuel blends (increased western coal use) so as to maximize the net energy value of the generators. The Company fully intends to do the same in 2012, but to a greater extent due to forecasted lower electric prices.

Q. Is the Company's intention to cycle coal-fueled generators a change in strategy?

A. No. The Company has traditionally considered cycling coal-fueled generators, particularly during extended holiday periods in which lower electric prices were expected. However, cycling was not warranted due to electric prices generally being above the production cost of coal-fueled generators. This changed during the last quarter of 2011 when natural gas prices continued to fall making some natural gas fueled combined cycle generating facilities comparable or less costly than some coal-fueled generators.

Q. Is the Company's intent to continue to vary fuel blends and cycle coal-fueled generators in response to market conditions prudent, reasonable and in the best interest of the Company's customers?

A. Yes. The outlook for 2012 is based on actual market conditions leading up to 2012 as well as industry consensus on expected 2012 market conditions. Therefore, the outlook is reasonable. The Company's intended responses to the changing market conditions allows us to be as competitive and valuable as possible, which should result in reduced PSCR expenses. Therefore, the intended responses are prudent and in the best interest of customers.

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-16890
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2012	)	

SECOND DIRECT TESTIMONY

OF

SHAWN D. BURGDORF

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February, 2012

QUALIFICATIONS

Q. Please state your name and business address.

A. Shawn D. Burgdorf, 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 General Engineer in the Transmission and Regulatory Strategies Section of Energy Supply Operations.

Q. Please state your educational background and business experience.

A. I received a Bachelor of Science degree in mechanical engineering in 2005 from the University of Michigan. From January 2006 until the present, I have been employed by Consumers Energy. Initially, I worked as a General Engineer in the Company's production cost modeling group. In that position I supported the development of power supply forecasts. I held this position until August 2009 at which time I transferred into my current position within the Transmission and Regulatory Strategies Section of Energy Supply Operations. In this position, I am responsible for monitoring and analyzing the filings by the Midwest Independent System Operator ("MISO") at the Federal Energy Regulatory Commission ("FERC"). In addition, I support the Company's involvement in stakeholder and transmission planning activities at the 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. Have you ever appeared in any proceedings before the Michigan Public Service Commission ("MPSC" or "Commission")?

A. Yes. I have provided testimony in:

- MPSC Case No. U-16149 regarding the Company's 2010 – 2011 Gas Cost Recovery ("GCR") Plan,
- MPSC Case No. U-16485 regarding the Company's 2011 – 2012 Gas Cost Recovery ("GCR") Plan, and
- MPSC Case No. U-16924 regarding the Company's 2012 – 2013 Gas Cost Recovery ("GCR") Plan

PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to: 1) identify certain transmission and energy market expenses for 2012 for which the Company seeks recovery in the Company's 2012 PSCR plan; 2) identify generation-related credits to total 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-25 (SDB-2)	Transmission and Energy Market Administration Expenses

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

A. Yes.

TRANSMISSION AND ENERGY MARKET EXPENSE

Q. What transmission and energy market expense does the Company seek recovery for in the Company's 2011 PSCR plan?

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

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

A. Yes. In MPSC Case Nos. U-13917, U-14274, U-14701, U-15001, U-15415, U-15675 and U-16045; the Company's PSCR plan cases for 2004, 2005, 2006, 2007, 2008, 2009 and 2010; the Commission approved recovery of expenses incurred under the MISO's TEMT in the Company's PSCR factor. 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. Thus, all of the charges incurred and revenues received through MISO by the Company are based on the FERC-approved TEMT.

Q. Please list each transmission and energy market charge that has been projected for 2012 in the Company's total transmission costs.

A. The transmission and energy-market-related charges included in the total transmission costs projected for 2012 (and shown in Exhibit A-25 (SDB-2) 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 Warriner?

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 MISO-wide rate. Applying this rate to the Company's forecasted monthly coincident peak produces the Company's forecasted expense. This forecasted expense for each plan year is shown on Exhibit A-25 (SDB-2), 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 each plan year is shown on Exhibit A-25 (SDB-2), 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 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 each plan year is shown on Exhibit A-25 (SDB-2), 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 each plan year for this portion of Schedule 10 is shown on Exhibit A-25 (SDB-2) line 18. The second rate is applied to actual volume of MWh of transmission service received. The Company's forecasted expense for each plan year for this portion of Schedule 10 is shown on Exhibit A-25 (SDB-2), 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 each plan year are shown on Exhibit A-25 (SDB-2), 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 each plan year are shown on Exhibit A-25 (SDB-2) 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 each plan year are shown on Exhibit A-25 (SDB-2) 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 each plan year are shown on Exhibit A-25 (SDB-2) 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 TEMT. The Company's forecasted expenses for each plan year are shown on Exhibit A-25 (SDB-2) 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 each plan year are shown on Exhibit A-25 (SDB-2) 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-25 (SDB-2). The total cost for the first year of the plan equals $291,961,785 and can be found on Line 29, column (o) of page 1 of Exhibit A-25 (SDB-2). It is composed of $283,972,303 of transmission expenses (Line 27, column (o)) and $7,989,483 of energy market administration expenses (Line 28, column (o)).

SCHEDULE 2 REACTIVE REVENUE REQUIREMENT CREDIT

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

A. Consumers Energy provides generation-related reactive services that are necessary for the transmission of power. Consumers Energy incurs an expense under the TEMT 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 2012 from Schedule 2?

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

COMPANY ACTIVITIES RELATED TO TRANSMISSION COST MANAGEMENT

Q. 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 MISO transmission system expansion (Regional Expansion Criteria and Benefits ("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 uncertain outcome of the Multi-Value Project rehearing requests as well as the impact of FERC Order 1000 will most likely have a financial impact after 2012.

Q. How have you forecasted the potential changes in costs and revenues from these items?

A. I continue to forecast cost as if the currently filed MISO tariff remained in effect through the planning period.

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 the 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") expenses 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 the MISO stakeholder groups the Company actively follows that impact transmission expenses?

A. Yes. The Company has been very active in the 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 defend against unnecessary transmission cost within Michigan.

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 the MISO before the project is approved.

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

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

Q. What other strategies has the Company used to reduce the cost of transmission for its customers?

A. Consumers Energy monitors and intervenes in FERC proceedings involving the 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 assure 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, 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, 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. Does this conclude your direct written 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-16890
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EXHIBIT

OF

SHAWN D. BURGDORF

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February, 2012

Consumers Energy Company

2012 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 SDB-1	5,506	5,348	5,131	4,797	5,656	6,879	7,446	7,711	6,356	5,286	5,323	5,705	**71,144**
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 SDB-3	3,106,021	2,961,575	2,978,338	2,739,508	2,867,817	3,187,904	3,463,059	3,456,348	2,950,185	2,940,106	2,998,610	3,244,896	**36,894,367**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper SDB-6	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	
5	Schedule 2 - Reactive Support	Workpaper SDB-4	387.0298	387.0298	387.0298	387.0298	387.0298	387.0298	387.0298	387.0298	387.0298	387.0298	387.0298	387.0298	
6	Schedule 9 - Network Transmission Service	Workpaper SDB-5	2,669.6974	2,669.6974	2,669.6974	2,669.6974	2,669.6974	2,739.9044	2,739.9044	2,739.9044	2,739.9044	2,739.9044	2,739.9044	2,739.9044	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper SDB-6	0.0635	0.0635	0.0635	0.0635	0.0635	0.0635	0.0635	0.0635	0.0635	0.0635	0.0635	0.0635	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper SDB-6	0.0882	0.0882	0.0882	0.0882	0.0882	0.0882	0.0882	0.0882	0.0882	0.0882	0.0882	0.0882	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper SDB-6	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper SDB-6	0.0120	0.0120	0.0120	0.0120	0.0120	0.0120	0.0120	0.0120	0.0120	0.0120	0.0120	0.0120	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper SDB-6	0.0870	0.0870	0.0870	0.0870	0.0870	0.0870	0.0870	0.0870	0.0870	0.0870	0.0870	0.0870	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper SDB-6	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper SDB-5a	707.1956	707.1956	707.1956	707.1956	707.1956	707.1956	707.1956	707.1956	707.1956	707.1956	707.1956	707.1956	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper SDB-5a	0.0214	0.0214	0.0214	0.0214	0.0214	0.0214	0.0214	0.0214	0.0214	0.0214	0.0214	0.0214	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 310,633	$ 301,719	$ 289,477	$ 270,633	$ 319,096	$ 388,094	$ 420,082	$ 435,033	$ 358,588	$ 298,221	$ 300,309	$ 321,860	**$ 4,013,745**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,130,986	2,069,835	1,985,850	1,856,582	2,189,040	2,662,378	2,881,824	2,984,387	2,459,961	2,045,839	2,060,159	2,208,005	**27,534,846**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	14,699,354	14,277,542	13,698,217	12,806,538	15,099,808	18,847,802	20,401,328	21,127,403	17,414,832	14,483,135	14,584,511	15,631,155	**193,071,625**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	260,125	236,360	242,409	219,319	267,212	314,508	351,779	364,298	290,596	249,732	243,368	269,527	**3,309,233**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	273,951	261,211	262,689	241,625	252,941	281,173	305,442	304,850	260,206	259,317	264,477	286,200	**3,254,083**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	140,082	133,567	134,323	123,552	129,339	143,774	156,184	155,881	133,053	132,599	135,237	146,345	**1,663,936**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	49,158	44,666	45,810	41,446	50,497	59,435	66,478	68,844	54,916	47,193	45,991	50,934	**625,367**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	540,448	515,314	518,231	476,674	499,000	554,695	602,572	601,405	513,332	511,578	521,758	564,612	**6,419,620**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	79,514	75,816	76,245	70,131	73,416	81,610	88,654	88,483	75,525	75,267	76,764	83,069	**944,496**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	3,893,819	3,782,082	3,628,621	3,392,417	3,999,898	4,864,799	5,265,779	5,453,185	4,494,935	3,738,236	3,764,402	4,034,551	**50,312,725**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	66,348	63,263	63,621	58,519	61,260	68,098	73,975	73,832	63,020	62,804	64,054	69,315	**788,109**
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**	**$ 21,777,298**	**$ 21,127,579**	**$ 20,307,207**	**$ 18,971,185**	**$ 22,320,595**	**$ 27,572,626**	**$ 29,858,393**	**$ 30,900,869**	**$ 25,477,192**	**$ 21,271,884**	**$ 21,418,518**	**$ 22,968,957**	**$** 283,972,303
28	Total Energy Market Administration Expenses	**Lines 21-23**	**669,119**	**635,797**	**640,286**	**588,252**	**622,913**	**695,740**	**757,704**	**758,731**	**643,773**	**634,039**	**644,513**	**698,615**	7,989,483
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 22,446,418**	**$ 21,763,376**	**$ 20,947,493**	**$ 19,559,437**	**$ 22,943,508**	**$ 28,268,366**	**$ 30,616,097**	**$ 31,659,600**	**$ 26,120,965**	**$ 21,905,922**	**$ 22,063,031**	**$ 23,667,573**	**$** 291,961,785

Consumers Energy Company

2013 Transmission and Energy Market Administration Expenses

Case No.: U-16890
Witness: SDBurgdorf
Exhibit: A-25 (SDB-2)
Page: 2 of 5
Date: February 2012

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 SDB-1	5,539	5,354	5,161	4,837	5,681	6,905	7,482	7,740	6,386	5,326	5,353	5,745	**71,509**
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 SDB-3	3,151,090	2,881,993	2,993,611	2,771,300	2,922,106	3,241,185	3,524,334	3,513,147	3,011,791	2,999,635	3,031,283	3,320,718	**37,362,193**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper SDB-6	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	
5	Schedule 2 - Reactive Support	Workpaper SDB-4	385.1929	385.1929	385.1929	385.1929	385.1929	385.1929	385.1929	385.1929	385.1929	385.1929	385.1929	385.1929	
6	Schedule 9 - Network Transmission Service	Workpaper SDB-5	2,943.8001	2,943.8001	2,943.8001	2,943.8001	2,943.8001	2,956.5332	2,956.5332	2,956.5332	2,956.5332	2,956.5332	2,956.5332	2,956.5332	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper SDB-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 SDB-6	0.0834	0.0834	0.0834	0.0834	0.0834	0.0834	0.0834	0.0834	0.0834	0.0834	0.0834	0.0834	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper SDB-6	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper SDB-6	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper SDB-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	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper SDB-6	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper SDB-5a	931.9520	931.9520	931.9520	931.9520	931.9520	931.9520	931.9520	931.9520	931.9520	931.9520	931.9520	931.9520	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper SDB-5a	0.1628	0.1628	0.1628	0.1628	0.1628	0.1628	0.1628	0.1628	0.1628	0.1628	0.1628	0.1628	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 312,495	$ 302,058	$ 291,169	$ 272,890	$ 320,506	$ 389,561	$ 422,113	$ 436,669	$ 360,280	$ 300,478	$ 302,001	$ 324,117	**$ 4,034,338**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,133,583	2,062,323	1,987,980	1,863,178	2,188,281	2,659,757	2,882,013	2,981,393	2,459,842	2,051,537	2,061,937	2,212,933	**27,544,757**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	16,305,709	15,761,106	15,192,952	14,239,161	16,723,728	20,414,862	22,120,782	22,883,567	18,880,421	15,746,496	15,826,322	16,985,283	**211,080,390**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	247,673	216,233	230,771	209,307	254,023	298,793	334,553	346,089	276,335	238,149	231,635	256,884	**3,140,445**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	262,801	240,358	249,667	231,126	243,704	270,315	293,929	292,996	251,183	250,170	252,809	276,948	**3,116,007**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	142,114	129,978	135,012	124,986	131,787	146,177	158,947	158,443	135,832	135,284	136,711	149,764	**1,685,035**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	45,331	39,577	42,238	38,309	46,493	54,688	61,233	63,344	50,577	43,588	42,396	47,017	**574,790**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	516,779	472,647	490,952	454,493	479,225	531,554	577,991	576,156	493,934	491,940	497,130	544,598	**6,127,400**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	80,668	73,779	76,636	70,945	74,806	82,974	90,223	89,937	77,102	76,791	77,601	85,010	**956,472**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,162,082	4,989,671	4,809,805	4,507,852	5,294,420	6,435,129	6,972,865	7,213,309	5,951,446	4,963,577	4,988,739	5,354,065	**66,642,959**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	513,079	469,263	487,437	451,239	475,795	527,749	573,853	572,031	490,398	488,418	493,571	540,699	**6,083,533**
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**	**$ 25,081,537**	**$ 24,172,990**	**$ 23,386,794**	**$ 21,901,739**	**$ 25,634,242**	**$ 31,144,343**	**$ 33,761,056**	**$ 34,886,498**	**$ 28,807,737**	**$ 24,176,108**	**$ 24,295,727**	**$ 26,102,693**	**$** 323,351,464
28	Total Energy Market Administration Expenses	**Lines 21-23**	**642,778**	**586,003**	**609,826**	**563,748**	**600,525**	**669,216**	**729,446**	**729,437**	**621,613**	**612,319**	**617,127**	**676,625**	7,658,662
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 25,724,314**	**$ 24,758,992**	**$ 23,996,620**	**$ 22,465,487**	**$ 26,234,767**	**$ 31,813,559**	**$ 34,490,503**	**$ 35,615,935**	**$ 29,429,349**	**$ 24,788,427**	**$ 24,912,854**	**$ 26,779,318**	**$** 331,010,126

Consumers Energy Company

2014 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 SDB-1	5,694	5,506	5,317	4,990	5,819	7,054	7,630	7,884	6,536	5,483	5,502	5,909	**73,324**
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 SDB-3	3,227,202	2,959,733	3,060,836	2,851,216	2,976,310	3,308,330	3,590,689	3,583,163	3,082,783	3,062,816	3,114,615	3,341,848	**38,159,541**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper SDB-6	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	
5	Schedule 2 - Reactive Support	Workpaper SDB-4	376.4152	376.4152	376.4152	376.4152	376.4152	376.4152	376.4152	376.4152	376.4152	376.4152	376.4152	376.4152	
6	Schedule 9 - Network Transmission Service	Workpaper SDB-5	3,101.1094	3,101.1094	3,101.1094	3,101.1094	3,101.1094	3,110.1821	3,110.1821	3,110.1821	3,110.1821	3,110.1821	3,110.1821	3,110.1821	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper SDB-6	0.0627	0.0627	0.0627	0.0627	0.0627	0.0627	0.0627	0.0627	0.0627	0.0627	0.0627	0.0627	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper SDB-6	0.0869	0.0869	0.0869	0.0869	0.0869	0.0869	0.0869	0.0869	0.0869	0.0869	0.0869	0.0869	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper SDB-6	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper SDB-6	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper SDB-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	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper SDB-6	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper SDB-5a	929.8436	929.8436	929.8436	929.8436	929.8436	929.8436	929.8436	929.8436	929.8436	929.8436	929.8436	929.8436	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper SDB-5a	0.3085	0.3085	0.3085	0.3085	0.3085	0.3085	0.3085	0.3085	0.3085	0.3085	0.3085	0.3085	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 321,240	$ 310,633	$ 299,970	$ 281,522	$ 328,292	$ 397,967	$ 430,463	$ 444,793	$ 368,743	$ 309,336	$ 310,407	$ 333,369	**$ 4,136,735**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,143,308	2,072,542	2,001,399	1,878,312	2,190,360	2,655,233	2,872,048	2,967,657	2,460,249	2,063,884	2,071,036	2,224,237	**27,600,265**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	17,657,717	17,074,709	16,488,599	15,474,536	18,045,356	21,939,225	23,730,690	24,520,676	20,328,150	17,053,129	17,112,222	18,378,066	**227,803,074**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	265,618	231,992	248,032	225,269	271,449	318,446	355,930	367,779	295,061	255,775	248,382	275,648	**3,359,382**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	280,444	257,201	265,987	247,771	258,641	287,494	312,031	311,377	267,894	266,159	270,660	290,407	**3,316,064**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	145,547	133,484	138,044	128,590	134,232	149,206	161,940	161,601	139,034	138,133	140,469	150,717	**1,720,995**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	46,600	40,700	43,514	39,521	47,623	55,868	62,444	64,523	51,765	44,873	43,576	48,359	**589,365**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	529,261	485,396	501,977	467,599	488,115	542,566	588,873	587,639	505,576	502,302	510,797	548,063	**6,258,165**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	82,616	75,769	78,357	72,991	76,194	84,693	91,922	91,729	78,919	78,408	79,734	85,551	**976,884**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,294,530	5,119,719	4,943,979	4,639,920	5,410,760	6,559,117	7,094,707	7,330,887	6,077,458	5,098,333	5,116,000	5,494,446	**68,179,855**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	995,731	913,205	944,399	879,723	918,320	1,020,762	1,107,882	1,105,560	951,171	945,010	960,993	1,031,104	**11,773,859**
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**	**$ 27,106,134**	**$ 26,115,484**	**$ 25,332,409**	**$ 23,757,641**	**$ 27,559,409**	**$ 33,329,448**	**$ 36,067,691**	**$ 37,212,330**	**$ 30,889,760**	**$ 26,131,759**	**$ 26,232,169**	**$ 28,179,994**	**$** 347,914,228
28	Total Energy Market Administration Expenses	**Lines 21-23**	**658,477**	**601,866**	**623,849**	**580,111**	**611,931**	**683,127**	**743,239**	**743,890**	**636,261**	**625,583**	**634,107**	**681,974**	7,824,414
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 27,764,611**	**$ 26,717,350**	**$ 25,956,258**	**$ 24,337,752**	**$ 28,171,340**	**$ 34,012,576**	**$ 36,810,929**	**$ 37,956,220**	**$ 31,526,021**	**$ 26,757,341**	**$ 26,866,276**	**$ 28,861,968**	**$** 355,738,642

Consumers Energy Company

2015 Transmission and Energy Market Administration Expenses

Case No.: U-16890
Witness: SDBurgdorf
Exhibit: A-25 (SDB-2)
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Date: February 2012

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 SDB-1	5,798	5,601	5,415	5,085	5,877	7,150	7,722	7,946	6,627	5,576	5,601	6,005	**74,403**
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 SDB-3	3,280,308	3,013,229	3,111,955	2,896,653	3,019,828	3,353,471	3,628,406	3,621,951	3,123,560	3,095,599	3,147,616	3,376,383	**38,668,959**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper SDB-6	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	
5	Schedule 2 - Reactive Support	Workpaper SDB-4	371.2864	371.2864	371.2864	371.2864	371.2864	371.2864	371.2864	371.2864	371.2864	371.2864	371.2864	371.2864	
6	Schedule 9 - Network Transmission Service	Workpaper SDB-5	3,191.0863	3,191.0863	3,191.0863	3,191.0863	3,191.0863	3,179.6174	3,179.6174	3,179.6174	3,179.6174	3,179.6174	3,179.6174	3,179.6174	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper SDB-6	0.0633	0.0633	0.0633	0.0633	0.0633	0.0633	0.0633	0.0633	0.0633	0.0633	0.0633	0.0633	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper SDB-6	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper SDB-6	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper SDB-6	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper SDB-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	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper SDB-6	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper SDB-5a	932.6373	932.6373	932.6373	932.6373	932.6373	932.6373	932.6373	932.6373	932.6373	932.6373	932.6373	932.6373	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper SDB-5a	0.4625	0.4625	0.4625	0.4625	0.4625	0.4625	0.4625	0.4625	0.4625	0.4625	0.4625	0.4625	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 327,107	$ 315,993	$ 305,499	$ 286,881	$ 331,564	$ 403,383	$ 435,654	$ 448,291	$ 373,877	$ 314,582	$ 315,993	$ 338,785	$ **4,197,609**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,152,719	2,079,575	2,010,516	1,887,991	2,182,050	2,654,698	2,867,074	2,950,242	2,460,515	2,070,293	2,079,575	2,229,575	**27,624,822**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	18,501,919	17,873,275	17,279,733	16,226,674	18,754,014	22,734,264	24,553,005	25,265,240	21,071,324	17,729,546	17,809,037	19,093,602	**236,891,633**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	273,058	238,253	255,021	231,754	276,778	325,868	363,669	374,218	302,032	262,603	255,271	282,807	**3,441,333**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	288,011	264,562	273,230	254,326	265,141	294,435	318,574	318,007	274,249	271,794	276,361	296,446	**3,395,135**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	147,942	135,897	140,349	130,639	136,194	151,242	163,641	163,350	140,873	139,612	141,957	152,275	**1,743,970**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	47,451	41,403	44,316	40,273	48,097	56,628	63,197	65,030	52,486	45,634	44,360	49,145	**598,020**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	537,971	494,170	510,361	475,051	495,252	549,969	595,059	594,000	512,264	507,678	516,209	553,727	**6,341,709**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	83,976	77,139	79,666	74,154	77,308	85,849	92,887	92,722	79,963	79,247	80,579	86,435	**989,925**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,407,431	5,223,701	5,050,231	4,742,461	5,481,109	6,668,356	7,201,825	7,410,736	6,180,587	5,200,385	5,223,701	5,600,487	**69,391,011**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	1,517,109	1,393,588	1,439,248	1,339,673	1,396,640	1,550,946	1,678,101	1,675,116	1,444,615	1,431,683	1,455,740	1,561,543	**17,884,002**
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**	**$ 28,617,295**	**$ 27,526,843**	**$ 26,755,825**	**$ 25,102,399**	**$ 28,825,491**	**$ 34,785,192**	**$ 37,583,543**	**$ 38,607,199**	**$ 32,250,071**	**$ 27,422,498**	**$ 27,559,636**	**$ 29,557,520**	**$** 364,593,514
28	Total Energy Market Administration Expenses	**Lines 21-23**	**669,397**	**612,711**	**634,343**	**589,479**	**620,657**	**692,446**	**751,143**	**751,752**	**644,713**	**632,560**	**641,148**	**689,307**	7,929,655
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 29,286,692**	**$ 28,139,554**	**$ 27,390,168**	**$ 25,691,878**	**$ 29,446,148**	**$ 35,477,638**	**$ 38,334,685**	**$ 39,358,951**	**$ 32,894,784**	**$ 28,055,058**	**$ 28,200,784**	**$ 30,246,827**	**$** 372,523,168

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 SDB-1	5,885	5,724	5,516	5,165	6,002	7,246	7,811	8,007	6,719	5,658	5,695	6,095	**75,523**
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 SDB-3	3,338,678	3,161,051	3,135,923	2,942,114	3,063,814	3,399,498	3,675,254	3,670,260	3,170,625	3,139,070	3,191,801	3,423,531	**39,311,619**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper SDB-6	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	$ 56.4172	
5	Schedule 2 - Reactive Support	Workpaper SDB-4	366.2731	366.2731	366.2731	366.2731	366.2731	366.2731	366.2731	366.2731	366.2731	366.2731	366.2731	366.2731	
6	Schedule 9 - Network Transmission Service	Workpaper SDB-5	3,395.5685	3,395.5685	3,395.5685	3,395.5685	3,395.5685	3,383.9463	3,383.9463	3,383.9463	3,383.9463	3,383.9463	3,383.9463	3,383.9463	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper SDB-6	0.0633	0.0633	0.0633	0.0633	0.0633	0.0633	0.0633	0.0633	0.0633	0.0633	0.0633	0.0633	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper SDB-6	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper SDB-6	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	0.0451	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper SDB-6	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper SDB-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	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper SDB-6	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	0.0128	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper SDB-5a	905.5074	905.5074	905.5074	905.5074	905.5074	905.5074	905.5074	905.5074	905.5074	905.5074	905.5074	905.5074	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper SDB-5a	0.4486	0.4486	0.4486	0.4486	0.4486	0.4486	0.4486	0.4486	0.4486	0.4486	0.4486	0.4486	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 332,015	$ 322,932	$ 311,197	$ 291,395	$ 338,616	$ 408,799	$ 440,675	$ 451,733	$ 379,067	$ 319,209	$ 321,296	$ 343,863	**$ 4,260,796**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,155,517	2,096,547	2,020,363	1,891,801	2,198,371	2,654,015	2,860,959	2,932,749	2,460,989	2,072,373	2,085,925	2,232,435	**27,662,046**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	19,982,921	19,436,234	18,729,956	17,538,111	20,380,202	24,520,075	26,432,005	27,095,258	22,736,735	19,146,368	19,271,574	20,625,153	**255,894,594**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	277,155	252,181	259,777	235,400	282,665	330,244	367,861	377,091	306,225	266,465	259,555	287,045	**3,501,665**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	293,136	277,540	275,334	258,318	269,003	298,476	322,687	322,249	278,381	275,610	280,240	300,586	**3,451,560**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	150,574	142,563	141,430	132,689	138,178	153,317	165,754	165,529	142,995	141,572	143,950	154,401	**1,772,954**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	48,163	43,823	45,143	40,907	49,120	57,388	63,925	65,529	53,214	46,305	45,104	49,881	**608,504**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	547,543	518,412	514,291	482,507	502,465	557,518	602,742	601,923	519,983	514,807	523,455	561,459	**6,447,106**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	85,470	80,923	80,280	75,318	78,434	87,027	94,087	93,959	81,168	80,360	81,710	87,642	**1,006,377**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,328,911	5,183,124	4,994,779	4,676,946	5,434,855	6,561,307	7,072,918	7,250,398	6,084,104	5,123,361	5,156,865	5,519,068	**68,386,634**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	1,497,682	1,418,001	1,406,729	1,319,789	1,374,382	1,524,965	1,648,665	1,646,425	1,422,296	1,408,141	1,431,795	1,535,746	**17,634,618**
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**	**$ 30,019,912**	**$ 29,131,124**	**$ 28,141,565**	**$ 26,346,449**	**$ 30,418,273**	**$ 36,453,198**	**$ 39,313,524**	**$ 40,243,431**	**$ 33,812,793**	**$ 28,755,099**	**$ 28,953,201**	**$ 31,000,296**	**$ 382,588,866**
28	Total Energy Market Administration Expenses	**Lines 21-23**	**681,176**	**643,158**	**639,714**	**598,732**	**630,020**	**701,933**	**760,753**	**761,411**	**654,365**	**641,473**	**650,270**	**698,983**	**8,061,987**
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 30,701,088**	**$ 29,774,282**	**$ 28,781,279**	**$ 26,945,181**	**$ 31,048,293**	**$ 37,155,131**	**$ 40,074,278**	**$ 41,004,842**	**$ 34,467,158**	**$ 29,396,572**	**$ 29,603,471**	**$ 31,699,279**	**$ 390,650,854**

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 2012	))))))	Case No. U-16890

SUPPLEMENTAL DIRECT TESTIMONY

OF

LAURA M. COLLINS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February, 2012

Q. Please state your name and business address.

A. Laura M. Collins, 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 II in the Revenue Section of the Rates Department.

Q. Are you the same Laura M. Collins that provided direct testimony in this docket?

A. Yes.

Q. What is the purpose of your supplemental testimony?

A. The purpose of my supplemental testimony is to update the calculation of the 2012 PSCR plan factor based on the changes presented in the supplemental filings of the other Company witnesses.

Q. What changes have been made to the plan factor calculation?

A. The system power supply costs, transmission expense, urea costs, aqueous ammonia cost and total system requirements have been updated to reflect the changes made by the other witnesses in this case.

Q. What is the result of those changes?

A. Updating the items listed above resulted in a 2012 PSCR Factor of $0.00342/kWh. This is a decrease of $0.00211/kWh from the original filed factor of $0.00553/kWh.

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

A. Yes, I am sponsoring the following exhibit:

Exhibit A-26 (LMC-2) Supplemental Calculation of 2012 PSCR Factor.

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

A. Yes.

Q. Please summarize Exhibit A-26 (LMC-2).

A. Exhibit A-26 (LMC-2) is intended to replace Exhibit A-4 (LMC-1) which was previously distributed to the parties but which is not being introduced into this record by the Company. Exhibit A-26 (LMC-2) shows the updated calculation of the 2012 PSCR factor including: (i) total power supply costs provided by Mr. Polena; (ii) transmission expenses provided by Mr. Burgdorf; (iii) Schedule 2 Reactive Revenue due to service to retail open access ("ROA") customers, also provided by Mr. Burgdorf; and (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-26 (LMC-2).

A. The 2012 PSCR factor is calculated by first summing the total system power supply costs on Line 1, the net transmission expenses on line 4, and the total of NO_x allowance costs, urea costs, and aqueous ammonia costs ("Total Environmental Costs") shown on Line 8. That sum, shown on Line 9, is divided by total system kWh requirements on Line 10, provided to me by Company witness Warriner, to determine the average cost per kWh of requirements on Line 11. From this quotient is subtracted the base recovery factor (shown on Line 12) collected through the standard tariffs as approved by the Commission[1]. This remaining per kWh amount ($0.00315 set forth on Line 13) is multiplied by the Line and Transformation Loss Factor on Line 14 to determine the 2012 per kWh PSCR factor of $0.00342 at sales, shown on Line 15. Exhibit A-26 (LMC-2) includes the most recent calculation of the 2012 PSCR factor and is intended to replace the previously-filed Exhibit A-4 (LMC-1).

[1][1] See Rule C8. Power Supply Cost Recovery Clause; Paragraph B.(1).

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-16890
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2012	)	

EXHIBIT

OF

LAURA M. COLLINS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February, 2012

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Calculation of 2012 PSCR Factor

Line			
1	System Power Supply Costs[1]		$ 1,633,233,000
	System Transmission Expenses		
2	Total Transmission Expenses[2]	$ 291,961,785	
3	Less: Schedule 2 Reactive Revenue[3]	(19,706,000)	
4	Net Transmission Expenses		$ 272,255,785
	Environmental Costs		
5	NOx Allowance Costs[4]	$ 405	
6	Urea Costs[5]	5,537,000	
7	Aqueous Amonia[6]	505,000	
8	Total Environmental Costs		$ 6,042,405
9	Total System Power Supply Costs		$ 1,911,531,190
10	Total System Requirements in kWh[7]		36,894,368,000
	Jurisdictional Factor Calculation		
11	Average Cost at Requirements (Line 8 / Line 9)		$ 0.05181
12	Less: Base Recovery Factor[8]		$ 0.04866
13	Remaining Cost per kWh (Line 10 - Line 11)		$ 0.00315
14	Line & Transformation Loss Factor[9]		1.086
15	2012 PSCR Factor at Sales (Line 12 x Line 13)		$ 0.00342

Sources:
[1]Exhibit A-38 (RJP-1R), Line 26
[2]Exhibit A-25 (SDB-2), page 1 of 5, line 29, column "o"
[3]SDBurgdorf Testimony, Page 8, Line 5
[4]Exhibit A-35 (DBK-8), page 1 of 5, line 22
[5]Exhibit A-36 (DBK-9), line 5, column "2012"
[6]Exhibit A-37 (DBK-10), line 3, column "2012"
[7]Exhibit A-44 (LDW-9), page 3 of 3, line 13 "Total," column "2012"
[8]Per Order in Case No. U-15645
[9]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-16890
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2012	)	

SUPPLEMENTAL DIRECT TESTIMONY

OF

BRIAN D. GALLAWAY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February, 2012

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

A. Brian D. Gallaway, 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 Director of Fossil Fuel Supply in the Energy Supply Operations Department.

Q. Are you the same Brian D. Gallaway that submitted direct testimony in this case?

A. Yes, I am.

Q. What is the purpose of this supplemental testimony?

A. I am filing this supplemental direct testimony to supplement my original direct testimony filed in this proceeding. In my original direct testimony, filed with the 2012 PSCR plan case application of Consumers Energy Company ("Consumers Energy" or the "Company"), I explained the new Cross State Air Pollution Rule ("CSAPR"), detailed the potential impacts of the rule, and outlined some of the considerations being evaluated by the Company in developing a compliance strategy for the new rule. I also indicated in my original testimony that once the Company's compliance strategy had been finalized, and depending on the impact on PSCR cost, that it may be necessary to file supplemental testimony to resolve PSCR cost issues. This supplemental direct testimony discusses the actions taken by the Company since the original filing of the 2012 PSCR plan case, specifically with regard to fuel purchases to comply with CSAPR, the current status of CSAPR, and how the recent drop in the price of natural gas has affected fuel utilized for generation. This supplemental direct testimony also summarizes the decision made by the Company on another open issue at the time the 2012 PSCR plan case was filed, that being the Company's decision regarding the use of the SEMCO lateral pipeline connecting the

Zeeland Plant to the ANR pipeline system.

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

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

Exhibit A-27 (BDG-6), NYMEX Henry Hub Prices

Exhibit A-28 (BDG-7), Coal Contract & Annual Purchase Data

Exhibit A-29 (BDG-8), Estimated As-Burned Coal Costs – 2012

Exhibit A-30 (BDG-9), Estimated As-Burned Oil & Gas Costs – 2012

Exhibit A-31 (BDG-10), Estimated As-Burned Coal Costs (2013-2016)

Exhibit A-32 (BDG-11), Estimated As-Burned Oil & Gas Costs (2013-2016)

These exhibits replace, respectively, Exhibits A-5 (BDG-1), Exhibits A-6 (BDG-2), Exhibits A-7 (BDG-3), Exhibits A-8 (BDG-4), and Exhibits A-9 (BDG-5) in my original direct testimony.

CSAPR – Prior to December 30, 2011

Q. Can you briefly summarize the CSAPR from your original direct testimony and the decisions being evaluated by the Company at that time as a result of the CSAPR?

A. Yes. The CSAPR was finalized on August 8, 2011 and required coal-fired plants in 28 states, including Michigan, to reduce and SO_2 and NO_X emissions beginning with a first stage reduction in 2012 and a second stage reduction in 2014. The Company's SO_2 emissions allocated under CASPR would require actual SO_2 emissions to be reduced by approximately 15% in 2012 and 50% in 2014. Because of the lack of time available to physically modify the generating units to meet these requirements (through the installation of back end control equipment to remove SO_2 after combustion), the Company's only option to meet the first stage emission reduction by January 1, 2012 was to reduce the sulfur content of the fuel burned prior to the combustion process.

Q. How did the Company plan to reduce the sulfur content of its fuels prior to the combustion process to comply with the CSAPR?

A. The only practical means to accomplish this is to reduce the fuel input in total, or by adjusting fuel blends to increase the use of lower sulfur western coal and decrease the use of higher sulfur eastern coal. Since the Company already maximizes its use of western coal with the objective of achieving full unit capability when needed, any increase in western coal burn to comply with the CSAPR would result in generating units operating at a derated capacity, which we anticipated would translate into higher PSCR costs as the energy lost from that derated capacity is replaced with higher cost generation.

Q. How does a sudden and/or significant change in western coal blend affect the Company's coal purchasing strategy and the coal commitments the Company has already made for 2012?

A. Prior to filing the 2012 PSCR plan, the Company had made contractual commitments for eastern and western coal at levels consistent with our normal purchasing strategy and consistent with our projected western coal blends. As is typically done, room was left for spot coal purchases to account for minor western coal blend variations, unit availability, and other factors that affect coal unit dispatch and therefore fuel burned. To comply with the CSAPR, it would be necessary for most of the Company's coal fleet to operate at very high blends of western coal, greatly reducing the amount of eastern coal needed in 2012. This translated into an immediate oversupply of contract eastern coal and an undersupply of contract western coal. Efforts would be necessary to reduce the Company's eastern commitments for 2012 and increase western coal commitments through spot purchases in 2012.

Q. Between the time that CSPAR was finalized (August 11, 2011) and the 2012 PSCR plan was filed (September 30, 2011), please summarize the actions taken by the Company to reduce its eastern coal commitments?

A. As noted in my original testimony, the Company:

1. Did not purchase 4th quarter 2011 spot eastern coal as it typically would have done following its normal coal purchasing strategy.
2. Exercised an option with an eastern supplier to ship low sulfur coal rather than mid sulfur coal in 2012 by paying slightly more to reflect a difference in market price between the two coals.
3. Mutually agreed with an eastern coal supplier to discontinue all negotiations for an eastern coal commitment that had been planned for 2013 delivery.
4. Delayed issuing an RFP for vessel delivery of eastern coal from Lake Erie ports to the BCCobb plant.

Q. To what extent were these actions included in the original 2012 PSCR plan?

A. All of the above four actions were included in the plan. As noted in my original direct testimony, the Company knew its compliance strategy would include reducing eastern coal burn, which led directly to the Company taking the four actions noted above. However, the Company anticipated that further action would be necessary to fully comply with the CSPAR and thus I included reference to the anticipation that a supplemental filing would be necessary once compliance requirements had been evaluated.

Q. What actions did the Company take after the 2012 PSCR plan case was filed to reduce the sulfur content of the fuels?

A. Discussions continued with the eastern coal suppliers from whom the Company had firm coal purchases in 2012 in an attempt to reduce or eliminate the Company's contractual obligation to take the coal or to reduce its sulfur content. Items considered to accomplish this included: (1) terminating the agreement(s) with the suppliers consent, (2) converting a higher sulfur eastern coal to lower sulfur eastern coal, (3) converting a higher sulfur eastern coal to a lower sulfur western coal (for suppliers that had coal to offer in both the eastern and western markets), (4) sell coal back to the supplier, or (5) where suppliers were willing, sell the coal to a third party trader. As could be expected, this was a difficult task because the CSAPR was causing a great deal of uncertainty in the eastern coal market. That market was becoming stagnant because of the uncertainty. Also contributing to the stagnation of the eastern coal market was the fact that the industry was beginning to get some indication of what SO_2 allowance prices might be, even though the market was still developing. Speculation that SO_2 allowance prices in 2012 could be several to many thousands of dollars per ton significantly impacted the price and trading volumes of eastern coal in the market. As a result, eastern coal spot prices have fallen from approximately $81/ton at the time the original 2012 PSCR plan was prepared, to under $70/ton as of the time that this supplemental direct testimony was being prepared, and are currently in the mid $60/ton range.

Q. Did the Company consider invoking contractual provisions such "Force Majeure" clauses to reduce or eliminate its contractual obligations under its eastern coal contracts for 2012?

A. Yes. I am informed by counsel that all of the Company's eastern coal contracts have

Force Majeure provisions that, under certain circumstances, would excuse the performance of a party under the contract in the event of the occurrence of certain stated events that are completely outside of the party's control that prevent performance. I am further informed by counsel that these events are typically natural events or so-called "Acts of God," but that the definition of "Force Majeure may also include government-imposed rules and regulations. I am further informed by counsel that Force Majeure clauses typically do not extend to circumstances that only lead to less than desirable economic consequences for either party. For example, if the EPA through the CSAPR had outlawed the burning of the higher sulfur eastern coal, then it is possible that the Company could have declared Force Majeure and may have been excused from performance under the contract. However, the CSAPR did not outlaw the burning of higher sulfur eastern coal, but instead made it more expensive to burn it. Hence, coal suppliers could argue that the Company's efforts to reduce or eliminate higher sulfur eastern coal burn is a negative economic consequence rather than a valid Force Majeure event.

Q. Absent the ability to declare Force Majeure, was the Company successful in reducing its eastern coal contract commitments with its coal suppliers?

A. Yes. Of the five eastern coal agreements identified to be in effect for 2012 in my original filed Exhibit A-5 (BDG-1), the Company was successful in negotiating termination arrangements with four of them.

Q. Can you elaborate further on which eastern coal contracts were terminated and the net impact on this supplemental filing?

A. Yes. Contracts "I", "K", "L", and "M" identified in my original Exhibit A-5 (BDG-1) are no longer in place for 2012. The total eastern tonnage removed from the 2012 PSCR plan affected by these agreements is 803,000 tons and the contractual purchase obligation eliminated is approximately $58,938,000. To be excused from this contractual obligation, the Company agreed to pay termination fees totaling $1,716,000. The agreement with one of the suppliers also required the Company to purchase 187,500 tons of western coal in 2012 as part of the settlement.

Q. Do you believe the $1,716,000 expense the Company incurred to terminate these four eastern coal contracts should be an expense recoverable through the PSCR process?

A. Yes. All of the affected contracts were prudently entered into to provide security of supply and to provide price risk protection to Consumers Energy's electric customers, using methods that have been reviewed in testimony and discovery in the PSCR process for many years. The Company's contractual commitments for eastern coal were at approximately 67% of its total expected delivery requirements, which is at the lower end of the typical 70% to 90% targeted range.

The actions initiated and finally taken by the Company to terminate the contracts were in response to new environmental regulations for which no other options existed. Inasmuch as the new CSAPR rule was finalized on August 8, 2011, there was not time to engineer, construct, and install backend pollution control equipment to enable compliance by January 1, 2012. The Company's only viable option to reduce SO_2 emissions was to reduce the sulfur input to the combustion process through the fuel it burns.

Q. What are the Company's plans for recovering the expense it incurred for terminating the four eastern coal agreements?

A. According to accounting rules, because the termination fees were paid in 2011, they were booked in the year they were incurred (2011). For this reason, they have been included in the Company's 2011 actual fuel expense and will be resolved in the 2011 PSCR reconciliation proceeding.

<u>CSAPR – After December 30, 2011</u>

Q. What is the current status of the CSAPR?

A. On December 30, 2011, the D.C. Circuit Court issued an order staying the CSAPR pending the court's resolution of the petitions for review of the rule. The court has set the process in motion to hear oral arguments in April of 2012. It is uncertain when the CSAPR will come back into effect.

Q. How does the stay of the CSAPR impact the Company's decision to terminate the four eastern coal agreements and its plan to recover the termination fees through the PSCR process?

A. It has no impact. Because the Company's prudent decisions to enter into the contracts for the benefit of its electric customers and because of the Company's prudent decisions to relieve itself of the obligations of the contracts due to the CSAPR, the Company will still seek to recover these contract termination fees in the PSCR process as noted above. The Company made coal purchasing and termination decisions with the known facts it had at the time the decisions were made. All eastern coal termination agreements were finalized before the stay was issued.

Q. Are there other factors that have affected coal and gas burn since the time the 2012 PSCR plan case was filed?

A. Yes. Natural gas prices have decreased substantially and are projected to be at lower levels for a longer period of time than was previously projected. Exhibit A-27 (BDG-6) shows the NYMEX Henry Hub gas prices at the time the 2012 PSCR plan case was prepared and how those values have progressively declined each month through the end of 2011.

Q. How have these declining natural gas prices affected coal utilization over this period?

A. Natural gas generation prior to the filing of the 2012 PSCR plan case were generally the marginal units in the MISO region, closely related to the MISO LMP, and higher in cost than coal generation. As natural gas prices have declined, so has the cost of natural gas generation and so have MISO LMP's, to a point where gas combined cycle units often operate at a lower cost than some coal units, and are therefore dispatched ahead of some coal units. Higher cost coal units, those that typically burn a blend of eastern and western coal to achieve full generation capacity, are finding it necessary to increase their western blend, and sacrificing MW production if necessary, to stay competitive with natural gas. Mr. Blumenstock and Mr. Polena have more discussion on this topic in their supplemental direct testimony.

Q. At the time the 2012 PSCR Plan Case was filed, what effect did you expect the CSAPR to have on coal burn, gas burn, and on total PCSR costs?

A. Because of the limitations being imposed on SO_2 emissions and the anticipation that SO_2 allowance prices would be very high, it was expected there would be significant reductions in eastern coal burn, and possibly moderate reductions in total coal burn. The reductions in coal burn would largely be attributable to the large increase in dispatch cost, especially for coal units, and especially for coal units that burn large amounts of higher sulfur eastern coal, due to the expectation that the SO_2 allowance price included in the dispatch cost calculation would be very large. It was also expected that burn volumes of gas would increase and displace higher sulfur coal generation. At that time, the cost of gas generation was higher than coal generation. These impacts would likely decrease overall coal burn and cost, increase gas burn and cost, and total PSCR expense would be higher because of higher levels of gas generation and the inclusion of expensive SO_2 allowance costs on the coal units.

Q. Now that the CSAPR has been stayed and with natural gas prices projected to be lower, how would you compare the coal and natural gas burn with that if the CSAPR had been implemented?

A. Similar to the case if CSAPR had been implemented, the Company expected to see a significant reduction in eastern coal burn, a moderate increase in western coal burn and increases in gas fired generation. The supplemental direct testimony offered by both Mr. Blumenstock and Mr. Polena elaborate further on the impacts that lower gas prices are expected to have on coal and gas generation in this supplemental filing.

Q. How do the burn volumes in this supplemental filing compare with the burn volumes in the original 2012 PSCR plan filing?

A. Eastern coal burn volume decreased from 1,482 kTons to 152 kTons, western coal volume increased from 8,422 kTons to 9,122 kTons, and gas increased from 22.5 Bcf to 30.9 Bcf. On a per unit total cost basis, coal cost decreased from $3.22/MMBtu to $3.00/MMBtu and gas cost decreased from $5.66/Mcf to $4.31/Mcf.

Q. Have you updated the exhibits from your original testimony to include the changes in coal, oil, and gas volume and cost that you have discussed here?

A. Yes. Exhibit A-28 (BDG-7), Exhibit A-29 (BDG-8), Exhibit A-30 (BDG-9), Exhibit A-31 (BDG-10), and Exhibit A-32 (BDG-11) reflect the Company's updated projections and reflect the stay on the CSAPR, the termination of four eastern coal agreements, and updated fuel pricing.

Q. Does the Company's termination of four of its eastern coal agreements have any negative impact on this supplemental filing, inasmuch as the agreements were terminated in anticipation of CSAPR and that the CSPAR has been stayed?

A. No. Over 800,000 tons of now unneeded eastern coal with a contractual commitment of almost $59 million was terminated at a cost of $1.7 million. Eastern contract commitments and burn in the original 2012 PSCR plan were 935 kTons and 1,482 kTons, respectively. Eastern contract commitments and burn in this supplemental filing are 132 kTons and 151 kTons, respectively. The elimination of the four eastern contracts has actually helped the Company align its contractual eastern coal requirements with the current projected burn resulting from substantially lower natural prices and our ability to economically take advantage of higher western coal blends.

In other words, termination of the four eastern coal contracts was prudent due to the fact it enabled the Company to lower is PSCR cost as a result of lower gas prices, which caused lower MISO LMPs, which in turn enabled the Company to significantly reduce its expected eastern coal burn, regardless of the status of CSAPR.

SEMCO Lateral Pipeline Decision

Q. In the original 2012 PSCR Plan Case filing in September, the Company stated that it had a decision to make by the end of 2011 regarding the use if the SEMCO pipeline, that being whether to make an additional final annual demand charge payment and purchase the pipeline or to extend the transportation services contract and continue making annual demand charge payments. At the time, you indicated the Company assumed it would be making the final annual demand charge payment and purchasing the pipeline. What was the Company's decision?

A. The Company has decided that it will exercise its option to extend the transportation services contract with SEMCO for the lateral pipeline for an additional five years, with the option to purchase the pipeline at that time or extend the transportation service contract an additional five years.

Q. How did the Company reach this decision?

A. The Company reached this decision through an economic analysis examining its estimated cost of owning and operating the pipeline. The SEMCO transportation agreement detailed cost requirements for four options available to the Company. The four options evaluated were:

1. Option 1 – Pay an additional final annual demand charge in 2011 and purchase the pipeline.
2. Option 2 – Extend the transportation services contract for five years, pay an additional annual demand charge, and purchase the pipeline at the end of the period.
3. Option 3 – Extent the transportation services contract for ten years and purchase the pipeline at the end of that period.
4. Option 4 – Extend the transportation services contract for five years, renew the transportation services contract for another five years, and purchase the pipeline at the end of that period.

Option 2, the option selected by the Company, was the least cost alternative.

Q. What is the impact of this decision in this supplemental filing compared to the original 2012 plan case filing last September?

A. This decision will reduce PSCR expense by $2,995,000 in 2012 and increase PSCR expense by $700,000 for each of the remaining years in the plan (2013-2016). This change in PSCR expense is included in Exhibit A-30 (BDG-9) and Exhibit A-32 (BDG-11).

Q. Does this conclude your prepared supplemental 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-16890
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2012	)	

EXHIBITS

OF

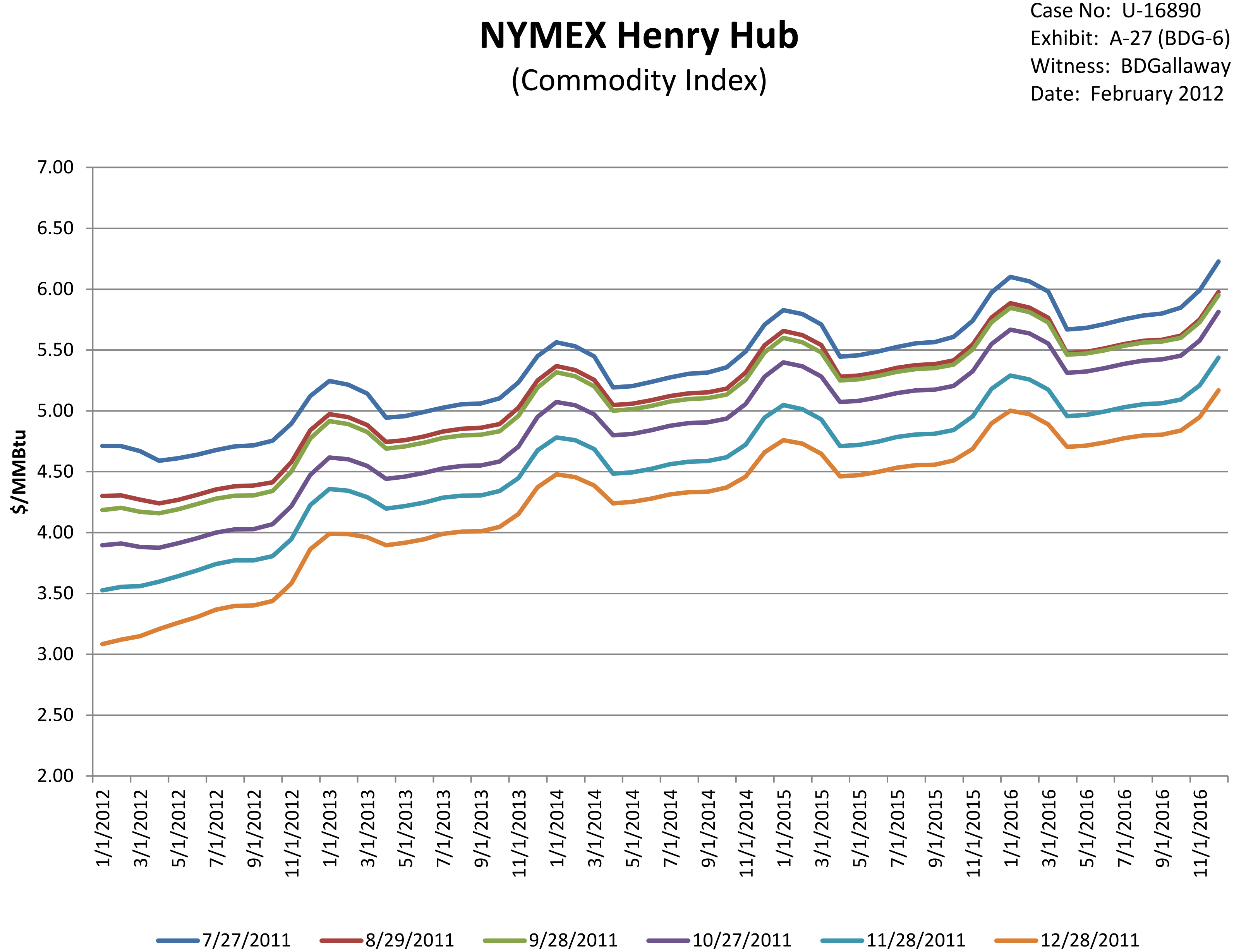
BRIAN D. GALLAWAY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February, 2012

Case No: U-16890
Exhibit: A-27 (BDG-6)
Witness: BDGallaway
Date: February 2012



MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-16890
Exhibit: A-28 (BDG-7)
Witness: BDGallaway
Date: February 2012

Coal Contract & Annual Purchase Data

Line	(a) Supplier	(b) Coal Type	(c) Contract Start Date	(d) Contract End Date	(e) 2012 Volume (Tons)
1	A	Western	1/1/2012	12/31/2012	561,600
2	B	Western	1/1/2012	12/31/2014	936,000
3	C	Western	1/1/2010	12/31/2012	936,000
4	D	Western	1/1/2010	12/31/2012	1,310,400
5	E	Western	1/1/2011	12/31/2013	873,303
6	F	Western	1/1/2011	12/31/2013	258,570
7	G	Western	1/1/2011	12/31/2013	300,000
8	H	Western	1/1/2011	12/31/2013	555,979
9	~~I~~	~~Eastern~~	~~1/1/2012~~	~~12/31/2012~~	~~132,000~~
10	J	Eastern	1/1/2012	12/31/2014	132,000
11	~~K~~	~~Eastern~~	~~1/1/2010~~	~~12/31/2012~~	~~407,000~~
12	~~L~~	~~Eastern~~	~~1/1/2011~~	~~12/31/2012~~	~~132,000~~
13	~~M~~	~~Eastern~~	~~1/1/2012~~	~~12/31/2012~~	~~132,000~~
14	N	Western	1/1/2012	12/31/2014	1,600,560
15	O	Western	1/1/2012	12/31/2012	187,200
16	P	Western	1/1/2012	12/31/2012	150,000
17	Q	Western	1/1/2012	12/31/2012	130,000
18	R	Western	1/1/2012	12/31/2012	93,600
19	S	Western	1/1/2012	3/31/2012	327,600
20	T	Western	1/1/2012	12/31/2012	100,000
21				**Total**	**8,452,812**

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Estimated As-Burned Coal Costs - 2012

Line	(a) Plant	(b)	(c) Burn Volume (Tons)	(d) Burn Dollars
1	JHCampbell 1-2		2,011,271	$ 110,401,608
2	JHCampbell 3 (CE Owned)		2,621,303	$ 133,365,248
3	BCCobb 4-5		970,479	$ 48,730,934
4	DEKarn 1-2		1,699,737	$ 88,125,132
5	JCWeadock 7-8		986,722	$ 51,157,256
6	JRWhiting 1-3		984,403	$ 53,362,260
			9,273,915	$ 485,142,438
7		Total Primary Fuel		$ 485,142,438
8		Total Auxilliary Fuel		$ 8,852,683
9		Total Freeze/Dust Treatment		$ 1,577,109
10		State Air Emission Fees		$ 701,133
11		Total Coal Cost		$ 496,273,363

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-16890
Exhibit: A-30 (BDG-9)
Witness: BDGallaway
Date: February 2012
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Estimated As-Burned Oil & Gas Costs - 2012

Line	(a) Plant	(b)	(c) Burn Volume (BBLS/MCF)		(d) Burn Dollars
1	Zeeland Generating Station		28,200,513	$	108,365,327
2	DEKarn 3-4 - Oil		0	$	1
3	DEKarn 3-4 - Gas		2,744,763	$	14,818,428
4	BCCobb 1-3		-	$	-
5	Combustion Turbines - Oil		-	$	-
6	Combustion Turbines - Gas		-	$	503,940
				$	123,687,696
7		Total Primary Fuel		$	123,687,696
8		Total Auxilliary Fuel		$	9,678,508
9		State Air Emission Fees		$	62,287
10		Total Oil & Gas Cost		$	133,428,490

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-16890
Exhibit: A-31 (BDG-10)
Witness: BDGallaway
Date: February 2012

Estimated As-Burned Coal Costs
2013 - 2016

Line	(a)	(b)	(c)	(d)	(e)	(f)
	Burn Volume (Tons)					
	Plant		2013	2014	2015	2016
1	JHCampbell 1-2		1,846,628	2,023,642	2,356,673	2,154,147
2	JHCampbell 3 (CE Owned)		2,695,747	2,880,280	2,563,911	3,190,581
3	BCCobb 4-5		1,001,770	1,058,260	282,301	-
4	DEKarn 1-2		1,805,956	1,534,801	1,949,703	1,892,382
5	JCWeadock 7-8		986,675	1,041,532	285,051	-
6	JRWhiting 1-3		1,056,796	1,080,438	298,465	-
7		Total Burn Tonnage	9,393,571	9,618,952	7,736,104	7,237,110
	Burn Dollars					
	Plant		2013	2014	2015	2016
8	JHCampbell 1-2		$ 99,063,702	$ 116,116,748	$ 138,139,916	$ 128,146,020
9	JHCampbell 3 (CE Owned)		$ 144,442,080	$ 165,324,308	$ 150,156,924	$ 189,512,385
10	BCCobb 4-5		$ 51,630,380	$ 57,160,203	$ 15,487,456	$ -
11	DEKarn 1-2		$ 96,058,641	$ 85,700,208	$ 112,830,019	$ 111,848,829
12	JCWeadock 7-8		$ 52,271,526	$ 58,521,489	$ 16,211,719	$ -
13	JRWhiting 1-3		$ 58,821,743	$ 62,189,018	$ 17,365,086	$ -
14		Total Primary Fuel	$ 502,288,073	$ 545,011,974	$ 450,191,118	$ 429,507,235
15		Total Primary Fuel	$ 502,288,073	$ 545,011,974	$ 450,191,118	$ 429,507,235
16		Total Auxilliary Fuel	$ 9,071,193	$ 8,890,690	$ 7,052,825	$ 5,944,842
17		Total Freeze/Dust Treatment	$ 1,641,331	$ 1,710,683	$ 1,344,410	$ 1,264,038
18		State Air Emission Fees	$ 701,133	$ 711,650	$ 722,325	$ 733,160
19		Total Coal Burn Cost	$ 513,701,730	$ 556,324,997	$ 459,310,679	$ 437,449,275

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-16890
Exhibit: A-32 (BDG-11)
Witness: BDGallaway
Date: February 2012
Page: 1 of 1

Estimated As-Burned Oil & Gas Costs
2013 - 2016

Line	(a)	(b)	(c)	(d)	(e)	(f)
	Burn Volume (BBLS/MCF)					
	Plant		2013	2014	2015	2016
1	Zeeland Generating Station		15,021,147	12,554,618	26,456,593	30,212,003
2	DEKarn 3-4 - Oil		1	0	2,273	1,472
3	DEKarn 3-4 - Gas		1,736,785	1,746,875	2,308,868	2,260,218
4	BCCobb 1-3		-	-	-	-
5	Combustion Turbines - Oil		-	-	-	-
6	Combustion Turbines - Gas		-	-	-	-
7						
	Burn Dollars					
	Plant		2013	2014	2015	2016
8	Zeeland Generating Station		$ 69,033,578	$ 64,609,409	$ 140,894,903	$ 164,821,251
9	DEKarn 3-4 - Oil		$ 48	$ 4	$ 140,506	$ 90,341
10	DEKarn 3-4 - Gas		$ 12,314,811	$ 13,288,554	$ 16,757,871	$ 16,803,780
11	BCCobb 1-3		$ -	$ -	$ -	$ -
12	Combustion Turbines - Oil		$ -	$ -	$ 1	$ 2
13	Combustion Turbines - Gas		$ 503,940	$ 503,940	$ 503,940	$ 503,940
14		Total Primary Fuel	$ 81,852,377	$ 78,401,906	$ 158,297,221	$ 182,219,314
15		Total Primary Fuel	$ 81,852,377	$ 78,401,906	$ 158,297,221	$ 182,219,314
16		Total Auxilliary Fuel	$ 6,368,971	$ 6,108,957	$ 12,652,673	$ 14,590,278
18		State Air Emission Fees	$ 62,287	$ 63,221	$ 64,169	$ 65,132
19		Total Oil & Gas Burn Cost	$ 88,283,635	$ 84,574,084	$ 171,014,064	$ 196,874,723

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-16890
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2012	)	

SECOND DIRECT TESTIMONY

OF

DAVID B. KEHOE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February, 2012

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 Masters 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 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 (the "Commission")?

A. Yes. I sponsored testimony in the following cases: Case Nos. U-13917 and U-13917-R (2004 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 (2011 PSCR Plan case); Case No. U-16536 (2011 Depreciation Practices for Lake Winds Energy Park); Case No. U-16794 (2011 Electric Rate case).

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 plant 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 2012 PSCR plan year; 3) compare the projected ROR for fossil, hydro, Ludington and peaker units with actual ROR experienced in the five-year period 2006-2010; 4) address availability of generating units for the five-year forecast period;

5) identify forecasted air emissions allowances for the 2012 PSCR plan year, as well as the period 2013 through 2016; 6) identify forecasted urea expenses for the 2012 PSCR plan year, as well as the period 2013 through 2016; and 7) identify forecasted aqueous ammonia expenses for the 2012 PSCR plan year, as well as the period 2013 through 2016, 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-33 (DBK-6)	Major Outages in the 2012 PSCR Plan.
Exhibit A-34 (DBK-7)	2012 PSCR Random Outage Rate Projections.
Exhibit A-35 (DBK-8)	2012-2016 NOx Allowance Budget.
Exhibit A-36 (DBK-9)	2012-2016 Urea Expenses.
Exhibit A-37 (DBK-10)	2012-2016 Aqueous Ammonia Expenses.

Major Generating Plant Outages for 2012

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 outages that have been reflected by Company witness Polena in the dispatch of the Company's generating plants in this case.

A. Exhibit A-33 (DBK-6) describes those outages.

Q. Please describe the major activities, planned start dates and durations for each of the outages listed on Exhibit A-33 (DBK-6).

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

Ludington 1

The outage at Ludington 1 is scheduled to begin January 3, 2012 and is projected to last for 66 days. The outage is for cavitation repairs, penstock inspection and testing and thrust bearing replacement.

Ludington 5

The outage at Ludington 5 is scheduled to begin March 19, 2012 and is projected to last for 35 days. The outage is for cavitation repairs, penstock inspection and testing and shaft packing.

Campbell 3

The outage at Campbell 3 is scheduled to begin March 31, 2012 and is projected to last for 30 days. The outage will be to perform turbine valve maintenance and SCR catalyst cleaning and maintenance.

Karn 3

The outage at Karn 3 is scheduled to begin April 14, 2012 and is projected to last for 46 days. The outage is for boiler repairs and stack work.

Whiting 2

The outage at Whiting 2 is scheduled to begin September 8, 2012 and is projected to last for 55 days. The outage is for a turbine/generator inspection, boiler work, replacing the economizer.

Ludington 6

The outage at Ludington 6 is scheduled to begin September 10, 2012 and is projected to last for 56 days. The outage is for shaft packing, cavitation repairs, penstock inspection and testing and thrust bearing replacement.

Miscellaneous Outages

Q. Are there other outages projected for 2012?

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

Mothballed Generating Units

Q. Please define what is meant by 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. 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. Does Consumers Energy have additional generating units in a mothball status?

A. Yes. Consumers Energy received approval from Midwest ISO ("Independent Transmission System Operator") to mothball the following Combustion Turbine Units (CTs) effective October 14, 2010;

- Thetford 1,2, 5, 6 & 7

- Weadock A
- Whiting A

Q. Does Consumers Energy intend to mothball additional units?

A. Yes. In August 2011, Consumers Energy filed a request with Midwest ISO to mothball the following Combustion Turbine Units (CTs);

- Campbell A
- Gaylord 1-4
- Morrow A & B
- Thetford 3, 4, 8 & 9
- Straits

Midwest ISO is expected to approve this request in February 2012.

Q. Does Consumers Energy intend to mothball additional units?

A. Yes. On December 2, 2011, Consumers Energy announced the following coal fired generating units would be mothballed in 2015;

- B.C. Cobb 4 & 5
- J.C. Weadock 7 & 8
- J.R. Whiting 1-3

The Company intends to file these requests with Midwest ISO in early 2012.

<u>Random Outage Rate ("ROR") Projections</u>

Q. How are the random outage rate 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 (2006-2010) and are modified to reflect current operating conditions. This is shown in my

Exhibit A-34 (DBK-7). Significant exceptions to the five-year average are described below.

Campbell 2

The 2012 ROR is projected to be 3.39% higher than the five-year average. Random outage rates typically increase prior to scheduled maintenance, which in this case is spring 2013.

Karn 1

The 2012 ROR is projected to be 20.46% lower than the five-year average. In 2008 and into 2009, we experienced a turbine failure due to a cracked rotor that has now been repaired.

Weadock 7

The 2012 ROR is projected to be 9.88% lower than the five-year average. We expect the ROR to decrease due in part to the 2007 boiler feed pump repairs that were made. Also, in 2009, we completed the removal of coal slag and in 2006 performed a generator overhaul.

Whiting 2

The 2012 ROR is projected to be 3.52% higher than the five-year average. Random outage rates typically increase prior to scheduled maintenance, which in this case is fall of 2012.

Availability

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

A. Yes. The 2012 projected availability for each of the generating units is also shown in column b of Exhibit A-34 (DBK-7).

Q. Do you have an availability projection for the five-year, 2012 – 2016 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.

NOx Allowances

Q. Please describe how the Company proposes to recover NOx allowance expenses.

A. The Company requested and received approval in MPSC Case No. U-13917 to recover NOx allowance expenses as PSCR expenses. I recommend the same treatment for the recovery of NOx emission expense in 2012.

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

A. Yes. Exhibit A-35 (DBK-8).

Q. Please describe Exhibit A-35 (DBK-8).

A. Exhibit A-35 (DBK-8) is the Company's projection of NOx emission allowance expense for the PSCR Plan year 2012 and the remainder of the five-year forecast years, 2013 through 2016. The exhibit presents an annual tabulation of the allowance inventory, forecasted emissions and a summary of the allowances 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. In March 2005, the EPA adopted CAIR, which required additional coal-fired electric generating plant emission controls for nitrogen oxides and sulfur dioxide. CAIR was appealed to the U.S. Court of Appeals for the District of Columbia and on July 11, 2008, the Court issued its decision, vacating CAIR and the CAIR federal implementation plan in their entirety. The decision remanded CAIR back to the EPA to form a new rule. In

December 2008, the Court revised its earlier decision and remanded the rule back to EPA for redrafting but left the existing rule in place. On July 7, 2011, the EPA replaced CAIR with CSAPR.

Q. Please provide more information on CSAPR.

A. CSAPR requires Michigan, and 27 other states, to reduce emissions of nitrogen oxides and sulfur dioxide through a phased-in approach. Phase I was to be effective January 1, 2012 and Phase II is to be effective January 1, 2014. However, on December 30, 2011, the United States Court of Appeals for the D.C. Circuit issued a stay on CSAPR.

Q. How does the court issued stay affect recovery of NOx allowances and expenses?

A. For now, the method of calculation will remain the same as in previous years. However, because the Company has implemented a number of operational changes to meet the emissions standards required by CSAPR, we have updated Exhibit A-35 (DBK-8) to reflect those changes.

Q. What operational changes did the Company make?

A. Company witness Brian D. Gallaway and David F. Ronk identify these changes in their Supplemental Testimony.

Q. How has Consumers Energy calculated the cost of the allowances set forth on Exhibit A-35 (DBK-8)?

A. Consumers Energy has calculated the "average cost" of each of the NOx 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 NOx emission allowance expenses reflected elsewhere in this filing?

A. Yes, they are reflected in the overall PSCR factor calculated by company witness Laura M. Collins.

<u>SO_2 Allowances</u>

Q. Does Consumers Energy expect to incur any expenses or revenues in 2012 related to the SO_2 allowance program?

A. No, but we do expect to incur expenses related to SO_2 in the future.

<u>Urea Expenses</u>

Q. Are there additional PSCR expenses for which you are seeking recovery in 2012?

A. Yes, Exhibit A-36 (DBK-9) identifies the projected urea expenses thru 2016.

Q. Please describe Exhibit A-36 (DBK-9).

A. In 2012, Consumers Energy projects spending $5.54 million for urea. In 2013, Consumers Energy expects to spend $4.25 million for urea. In 2014 through 2016, expenses are expected to be $4.99, $4.51 & $5.06 million, respectively.

Q. Why do projected urea expenses fluctuate in the next five years?

A. Urea expenses are projected to fluctuate because Consumers Energy is replacing the existing Karn 1 & 2 Urea Based Ammonia System ("UBAS") with aqueous ammonia – which is discussed later in my testimony. Also, J.H. Campbell 2 will begin using urea in 2013.

Q. Please explain why urea expenses have increased in the supplemental filing?

A. Urea expenses identified in the supplemental filing reflect current market prices as Consumers contract for pelletized urea expired in 2011.

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 NOx in the SCR and reduces the amount of NOx emissions and the need to purchase NOx 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 2012.

Aqueous Ammonia Expenses

Q. Are there additional PSCR expenses for which you are seeking recovery in 2012?

A. Yes, Exhibit A-37 (DBK-5) identifies the projected aqueous ammonia expenses thru 2016.

Q. Please describe Exhibit A-14 (DBK-10).

A. In 2012, Consumers Energy projects spending $505,000 for aqueous ammonia at Karn 1 & 2. In 2013, Consumers Energy expects to spend $2.22 million for aqueous ammonia. In 2014 through 2016, expenses are expected to be $1.97, $2.53 & $2.47 million, respectively.

Q. Please explain why aqueous ammonia expenses have decreased in the supplemental filing?

A. Aqueous ammonia expenses have decreased as a result of changes in unit availability and aqueous ammonia costs.

Q. How will aqueous ammonia be used?

A. As mentioned earlier in my testimony, the Company is replacing the UBAS at Karn 1 & 2 with aqueous ammonia. This new system was designed to be more reliable and effective at reducing NOx emissions.

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

A. No. Consumers Energy is seeking the Commission's approval to include aqueous ammonia in this and all future PSCR plan cases.

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-16890
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2012	)	

EXHIBITS

OF

DAVID B. KEHOE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February, 2012

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U–16890
Exhibit: A-33 (DBK-6)
Witness: DBKehoe
Date: February 2012
Page: Page 1 of 1

MAJOR OUTAGES IN THE 2012 PSCR PLAN

Line	Unit	Days in 2011	Start Date	Stop Date
	(a)	(b)	(d)	(d)
1	Ludington 1	66	01/03/12	03/09/12
2	Ludington 5	35	03/19/12	04/23/12
3	JH Campbell 3	30	03/31/12	04/30/12
4	DE Karn 3	46	04/14/12	05/30/12
5	JR Whiting 2	55	09/08/12	11/02/12
6	Ludington 6	56	09/10/12	11/05/12

2012 PSCR Random Outage Rate Projections

Line	Plant (a)	Availability (b)	Periodic Factor (c)	2012 Projected ROR (d)	Actual ROR 2006-2010 (e)
1	Campbell 1	91.92%	0.04%	8.04%	8.64%
2	Campbell 2	90.15%	1.40%	8.57%	5.18%
3	Campbell 3	82.24%	8.99%	9.64%	4.68%
4	Cobb 4	83.85%	2.47%	14.03%	13.36%
5	Cobb 5	84.19%	7.23%	9.25%	9.75%
6	Karn 1	85.28%	8.69%	6.60%	27.06%
7	Karn 2	86.14%	7.63%	6.74%	11.60%
8	Karn 3	81.43%	12.57%	6.87%	7.17%
9	Karn 4	89.25%	3.01%	7.98%	7.58%
10	Weadock 7	84.55%	8.50%	7.60%	17.48%
11	Weadock 8	84.21%	9.77%	6.67%	11.96%
12	Whiting 1	90.80%	2.20%	7.15%	10.56%
13	Whiting 2	74.78%	16.06%	10.91%	7.39%
14	Whiting 3	86.62%	5.61%	8.23%	7.42%
15	Ludington 1	77.19%	21.32%	1.90%	1.34%
16	Ludington 2	91.40%	6.83%	1.90%	3.83%
17	Ludington 3	94.12%	4.06%	1.90%	3.97%
18	Ludington 4	94.81%	3.36%	1.90%	1.28%
19	Ludington 5	85.54%	12.80%	1.90%	1.27%
20	Ludington 6	81.64%	16.78%	1.90%	5.77%
21	CTs[1]	44.41%	47.75%	15.00%	11.41%
22	Hydros	95.30%	3.04%	1.70%	1.85%
23	Zeeland CC	90.09%	5.66%	4.50%	3.05%[2]
24	Zeeland 1A	95.73%	1.82%	2.50%	2.56%[2]
25	Zeeland 1B	95.78%	1.77%	2.50%	1.75%[2]

[1] Does not include the Zeeland CTs.
[2] 2008-2010 ROR

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-16890
Exhibit A-35 (DBK-8)
Witness: DBKehoe
Date: February 2012

2012-2016 NO_X ALLOWANCE BUDGET

Line No.	2012 Ozone Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
1	Beginning Bank from 2011	458	$1.08	$495.35
2	2012 Inventory	7,429	$0.00	$0.00
3	Forecasted Purchases	0	$23.71	$0.00
4	**Total**	**7,887**	**$0.06**	**$495.35**
5	Forecasted Emissions	6,450		
6	Banked Allowances Surrendered	-458	$0.06	$28.77
7	2012 Inventory Surrendered	-5,992	$0.06	$376.32
8	Forecasted Purchases Surrendered	0	$0.06	$0.00
9	**Ending Balance**	**1,437**	**$0.06**	
10	**Total Expense**			**$405.09**

Line No.	2012 Annual Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
11	Beginning Bank from 2011	2,109	$0.00	$0.00
12	Projected Allocation from the EPA	16,300	$0.00	$0.00
13	Forecasted Purchases	0	$238.80	$0.00
14	**Total**	**18,409**	**$0.00**	**$0.00**
15	Forecasted Emissions	15,674		
16	Banked Allowances Surrendered	-2,109	$0.00	$0.00
17	2012 Inventory Surrendered	-13,565	$0.00	$0.00
18	Forecasted Purchases Surrendered	0	$0.00	$0.00
19	**Ending Balance**	**2,735**	**$0.00**	
20	**Total Annual Season Expense**			**$0.00**

20	**Total Ozone Season Expense**		**$405.09**
21	**Total Annual Season Expense**	+	**$0.00**
22	**Total Expense for 2012**		**$405.09**

2012-2016 NOX ALLOWANCE BUDGET

Line No.	2013 Ozone Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
23	Beginning Bank from 2012	1,437	$0.06	$90.27
24	2013 Inventory	7,429	$0.00	$0.00
25	Forecasted Purchases	0	$15.48	$0.00
26	**Total**	**8,866**	**$0.01**	**$90.27**
27	Forecasted Emissions	5,443		
28	Banked Allowances Surrendered	-1,437	$0.01	$14.63
29	2013 Inventory Surrendered	-4,006	$0.01	$40.79
30	Forecasted Purchases Surrendered	0	$0.01	$0.00
31	**Ending Balance**	**3,423**	$0.01	
32	**Total Ozone Season Expense**			**$55.42**

Line No.	2013 Annual Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
33	Beginning Bank from 2012	2,735	$0.00	$0.00
34	Projected Allocation from the EPA	16,300	$0.00	$0.00
35	Forecasted Purchases	0	$139.74	$0.00
36	**Total**	**19,035**	**$0.00**	**$0.00**
37	Forecasted Emissions	13,166		
38	Banked Allowances Surrendered	-2,735	$0.00	$0.00
39	2013 Inventory Surrendered	-10,431	$0.00	$0.00
40	Forecasted Purchases Surrendered	0	$0.00	$0.00
41	**Ending Balance**	**5,869**	**$0.00**	
42	**Total Annual Season Expense**			**$0.00**

43	**Total Ozone Season Expense**		**$55.42**
44	**Total Annual Season Expense**	+	**$0.00**
45	**Total Expense for 2013**		**$55.42**

2012-2016 NOX ALLOWANCE BUDGET

Line No.	2014 Ozone Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
46	Beginning Bank from 2013	3,423	$0.01	$32.61
47	Projected Allocation from the EPA	7,429	$0.00	$0.00
48	Forecasted Purchases	0	$593.11	$0.00
49	**Total**	**10,852**	**$0.00**	**$32.61**
50	Forecasted Emissions	5,471		
51	Banked Allowances Surrendered	-3,423	$0.00	$10.29
52	2014 Inventory Surrendered	-2,048	$0.00	$6.15
53	Forecasted Purchases Surrendered	0	$0.00	$0.00
54	**Ending Balance**	**5,381**	**$0.00**	
55	**Total Ozone Season Expense**			**$16.44**

Line No.	2014 Annual Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
56	Beginning Bank from 2013	5,869	$0.00	$0.00
57	Projected Allocation from the EPA	16,300	$0.00	$0.00
58	Forecasted Purchases	0	$332.14	$0.00
59	**Total**	**22,169**	**$0.00**	**$0.00**
60	Forecasted Emissions	12,774		
61	Banked Allowances Surrendered	-5,869	$0.00	$0.00
62	2013 Inventory Surrendered	-6,905	$0.00	$0.00
63	Forecasted Purchases Surrendered	0	$0.00	$0.00
64	**Ending Balance**	**9,395**	**$0.00**	
65	**Total Annual Season Expense**			**$0.00**

66	**Total Ozone Season Expense**		**$16.44**
67	**Total Annual Season Expense**	+	**$0.00**
68	**Total Expense for 2013**		**$16.44**

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-16890
Exhibit A-35 (DBK-8)
Witness: DBKehoe
Date: February 2012

2012-2016 NOX ALLOWANCE BUDGET

Line No.	2015 Ozone Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
69	Beginning Bank from 2014	0	$0.00	$0.00
70	Projected Allocation from the EPA	5,935	$0.00	$0.00
71	Forecasted Purchases	0	$664.28	$0.00
72	**Total**	**5,935**	**$0.00**	**$0.00**
73	Forecasted Emissions	2,421		
74	Banked Allowances Surrendered	0	$0.00	$0.00
75	2015 Inventory Surrendered	-2,421	$0.00	$0.00
76	Forecasted Purchases Surrendered	0	$0.00	$0.00
77	**Ending Balance**	**3,514**	**$0.00**	
78	**Total Ozone Season Expense**			**$0.00**

Line No.	2015 Annual Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
79	Beginning Bank from 2014	0	$0.00	$0.00
80	Projected Allocation from the EPA	16,556	$0.00	$0.00
81	Forecasted Purchases	0	$372.00	$0.00
82	**Total**	**16,556**	**$0.00**	**$0.00**
83	Forecasted Emissions	5,332		
84	Banked Allowances Surrendered	0	$0.00	$0.00
85	2015 Inventory Surrendered	-5,332	$0.00	$0.00
86	Forecasted Purchases Surrendered	0	$0.00	$0.00
87	**Ending Balance**	**11,224**	**$0.00**	
88	**Total Annual Season Expense**			**$0.00**

89	**Total Ozone Season Expense**		**$0.00**
90	**Total Annual Season Expense**	+	**$0.00**
91	**Total Expense for 2015**		**$0.00**

2012-2016 NOX ALLOWANCE BUDGET

Line No.	2016 Ozone Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
92	CAIR Replacement Rule	3,514	$0.00	$0.00
93	Projected Allocation from the EPA	5,935	$0.00	$0.00
94	Forecasted Purchases	0	$678.25	$0.00
95	**Total**	**9,449**	**$0.00**	**$0.00**
96	Forecasted Emissions	2,496		
97	Banked Allowances Surrendered	-2,496	$0.00	$0.00
98	2016 Inventory Surrendered	0	$0.00	$0.00
99	Forecasted Purchases Surrendered	0	$0.00	$0.00
100	**Ending Balance**	**6,953**	**$0.00**	
101	**Total Ozone Season Expense**			**$0.00**

Line No.	2016 Annual Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
102	CAIR Replacement Rule	11,224	$0.00	$0.00
103	Projected Allocation from the EPA	16,556	$0.00	$0.00
104	Forecasted Purchases	0	$379.82	$0.00
105	**Total**	**27,780**	**$0.00**	**$0.00**
106	Forecasted Emissions	5,541		
107	Banked Allowances Surrendered	-5,541	$0.00	$0.00
108	2016 Inventory Surrendered	0	$0.00	$0.00
109	Forecasted Purchases Surrendered	0	$0.00	$0.00
110	**Ending Balance**	**22,239**	**$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 2016**		**$0.00**

2012-2016 Urea Expense

(1,000's)

Line No.	Unit (a)	2012 (b)	2013 (c)	2014 (d)	2015 (e)	2016 (f)
1	**Karn 1**	$1,524	$0	$0	$0	$0
2	**Karn 2**	$1,152	$0	$0	$0	$0
3	**Campbell 2**	$0	$1,247	$1,643	$1,687	$1,478
4	**Campbell 3**	$2,861	$3,005	$3,351	$2,818	$3,582
5	**TTL**	$5,537	$4,252	$4,993	$4,505	$5,060

Case No: U-16890
Exhibit: A-37 (DBK-10)
Witness: DBKehoe
February 2012

2012-2016 Aqueous Ammonia Expense

(1,000's)

Line No.	Unit (a)	2012 (b)	2013 (c)	2014 (d)	2015 (e)	2016 (f)
1	**Karn 1**	$359	$1,197	$1,129	$1,413	$1,363
2	**Karn 2**	$146	$1,025	$842	$1,121	$1,104
3	**TTL**	$505	$2,222	$1,971	$2,534	$2,467

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	Case No. U-16890
for Approval of a Power Supply Cost	)	
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2012	)	

SUPPLEMENTAL DIRECT TESTIMONY

OF

RICHARD J. POLENA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February, 2012

Q. Please state your name and business address.

A. Richard J. Polena, 1945 West Parnall Road, Jackson, Michigan.

Q. By whom are you employed?

A. Consumers Energy.

Q. Have you previously testified in this case.

A. Yes.

Q. What is the purpose of your supplemental direct testimony in this proceeding, Mr. Polena?

A. The purpose of my supplemental direct testimony in this case is to update the forecasted costs of fuel and purchased and net interchange power needed to fulfill the Company's system requirements. These costs are shown on a monthly basis for 2012 and on a yearly basis for 2012 through 2016.

Q. Are you sponsoring any updated exhibits?

A. Yes, I am sponsoring Exhibits A-38 (RJP-1R) and A-39 (RJP-2R), all of which were prepared by me.

Q. What changes have been incorporated into this supplemental filing?

A. The major changes that have occurred since the original filing in September, 2011 are: a decrease in the projected cost of natural gas and a corresponding decrease in the projected cost of power purchased from MISO; incorporation of an assumption that the Company's coal fueled plants will utilize 100% western coal; a decision to mothball seven of the Consumers Energy coal units (Cobb 4 and 5, Weadock 7 and 8, and Whiting 1, 2, and 3) beginning on April 1, 2015; **a decision to mothball Thetford Units 3, 4, 8, and 9; Gaylord Units 1, 2, 3 and 4; Campbell Unit A; Morrow Units A and B; and the**

Straights combustion turbines beginning on March 1, 2012; and an updated load forecast.

Q. What are the Company's updated forecasts of 2012 costs of fuel and purchased and net interchange power to fulfill system requirements?

A. This forecast is shown in Exhibit A-38 (RJP-1R), Pages 1-3.

Q. Who provided you with the updated projection of system loads and system generation requirements?

A. The data was provided to me by company witness Mr. Warriner, and his testimony and exhibits in this supplemental filing set forth and explain the relevant assumptions and calculations.

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

A. Updated coal, oil and natural gas costs were provided by company witness Mr. Gallaway.

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

A. That information was provided by company witness Mr. Kehoe.

Q. Are there any major updates to Consumers Energy's owned units for this supplemental filing?

A. Yes. The addition of 150 MW of nameplate wind capacity at the Cross Winds Energy Park was assumed to be in-service beginning on December 31, 2014 in the original filing. The in-service date for this wind capacity has been moved to December 31, 2015.

Q. Are there any changes in the existing sources of purchased power for this supplemental filing?

A. Yes, the Hope Renewable Energy – Hubbardston contract, shown on line 8 of Exhibit A-17 (RJP-3) was terminated on November 8, 2011.

Q. Are there other changes to your original testimony filed in this case?

A. Yes. The credits resulting from the Reduced Dispatch Agreements (RDAs) described in my original testimony on page 8, line 22 through page 9, line 8 have changed. The updated hold harmless amount is $610,000 and the updated customer benefit (offset to PSCR) is $295,000. These amounts are included as credits in lines 24 and 40 on Exhibit A-38 (RJP-1R) and Exhibit A-39 (RJP-2R).

Q. What other changes to your original testimony have been made.

A. On Exhibits A-39 (RJP-2R), lines 27, 36 and 37 detail the purchase of seasonal dispatchable capacity and energy. These lines were all zero in the original filing since there was adequate reserve margin in all the years in original PSCR plan case. Since the decision was made to mothball the seven Consumers Energy coal units mentioned above, it is necessary to purchase summer capacity to meet reserve margin requirements in years 2015 and 2016. This is explained in Mr. Ronk's testimony. In this supplemental filing, line 37 now reflects the purchase of summer capacity from the MISO capacity market.

Q. Does this conclude your supplemental direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	Case No. U-16890
for Approval of a Power Supply Cost	)	
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2012	)	

EXHIBITS

OF

RICHARD J. POLENA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February, 2012

MICHIGAN PUBLIC SERVICE COMMISSION

CASE NO.: U-16890
EXHIBIT: A-38 (RJP-1R)
WITNESS: RJPOLENA
DATE: FEBRUARY, 2012
PAGE: 1 OF 3

CONSUMERS ENERGY COMPANY

SUMMARY BY SOURCE

YEAR		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2012
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	ENERGY (MWH)													
1	COAL STEAM	1,397,224	1,368,727	1,356,769	934,861	1,437,117	1,351,439	1,477,089	1,447,812	1,233,470	1,306,280	1,329,098	1,486,938	16,126,823
2	GAS & OIL	372,816	361,543	380,418	363,393	208,208	339,957	341,251	385,807	301,872	231,750	270,928	207,050	3,764,992
3	NUCLEAR PPA	586,510	547,473	583,827	115,531	196,789	548,246	563,492	562,049	546,849	577,973	565,123	584,630	5,978,492
4	STATION POWER	7,438	6,674	8,667	13,785	7,044	6,127	5,208	5,134	7,503	9,366	7,755	7,080	91,782
5	CE OWNED RENEWABLES	35,131	32,890	42,992	47,181	42,117	35,198	27,513	24,134	22,784	27,984	57,172	62,825	457,922
6	PEAKERS	0	0	0	0	0	6,402	52,147	54,141	0	0	0	0	112,690
7	PUMPED STORAGE	49,658	61,531	57,107	57,675	54,948	81,845	122,655	127,966	73,173	32,858	60,773	49,220	829,408
8	TOTAL GENERATED	2,448,778	2,378,839	2,429,780	1,532,426	1,946,223	2,369,213	2,589,356	2,607,042	2,185,651	2,186,211	2,290,848	2,397,743	27,362,109
9	LESS : PUMPING	-71,045	-76,730	-83,265	-87,046	-65,207	-120,579	-173,048	-173,227	-111,674	-37,340	-86,687	-81,862	-1,167,709
10	TOTAL GENERATED	2,377,733	2,302,110	2,346,515	1,445,380	1,881,016	2,248,634	2,416,307	2,433,815	2,073,976	2,148,871	2,204,161	2,315,881	26,194,400
11	PURCHASED (NUGs)	776,715	744,105	741,152	663,579	731,800	679,243	849,500	795,004	589,721	398,138	299,494	319,819	7,588,269
12	NET INTERCHANGE	-48,426	-84,642	-109,326	630,548	254,997	260,026	197,248	227,528	286,487	393,098	494,968	609,207	3,111,713
13	TOTAL SYSTEM REQ	3,106,022	2,961,574	2,978,340	2,739,508	2,867,813	3,187,903	3,463,055	3,456,347	2,950,184	2,940,106	2,998,623	3,244,907	36,894,382
	EXPENSES ($*1000)													
14	COAL STEAM	43,171	42,323	42,347	29,759	44,340	41,486	45,446	44,643	37,787	39,602	40,311	45,058	496,273
15	GAS & OIL	11,523	10,926	11,522	10,954	6,813	11,818	12,916	15,370	11,132	7,878	9,569	7,826	128,247
16	NUCLEAR PPA	30,106	24,528	25,212	4,972	8,769	28,959	32,590	33,106	28,212	25,210	24,317	25,407	291,389
17	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
18	CE OWNED RENEWABLES	0	0	0	0	0	0	0	0	0	0	1,766	1,952	3,718
19	PEAKERS	42	42	59	42	42	306	2,192	2,288	42	42	42	42	5,181
20	PUMPED STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
21	TOTAL GENERATED	84,843	77,818	79,141	45,728	59,963	82,569	93,145	95,407	77,173	72,732	76,005	80,285	924,809
22	LESS : PUMPING	0	0	0	0	0	0	0	0	0	0	0	0	0
23	TOTAL GENERATED	84,843	77,818	79,141	45,728	59,963	82,569	93,145	95,407	77,173	72,732	76,005	80,285	924,809
24	PURCHASED (NUGs)	57,950	54,529	55,663	51,314	56,147	54,605	62,923	61,091	51,478	45,846	41,366	43,434	636,347
25	NET INTERCHANGE	-2,714	-4,052	-5,761	18,652	5,579	5,020	552	764	5,431	12,897	15,747	19,960	72,077
26	TOTAL SYSTEM COST	140,079	128,296	129,043	115,694	121,690	142,194	156,621	157,262	134,082	131,475	133,118	143,679	1,633,233

MICHIGAN PUBLIC SERVICE COMMISSION

CASE NO.: U-16890
EXHIBIT: A-38 (RJP-1R)
WITNESS: RJPOLENA
DATE: FEBRUARY, 2012
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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	2012
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)**	**(i)**	**(j)**	**(k)**	**(l)**	**(m)**	**(n)**	**(o)**
	RECEIVED (MWH)													
27	SUMMER OPTIONS	0	0	0	0	0	0	0	0	0	0	0	0	0
28	MARKET ON PEAK	34,354	17,651	9,751	189,296	66,169	163,733	93,416	126,543	136,453	225,238	222,303	271,559	1,556,465
29	MARKET OFF PEAK	118,938	117,253	187,715	479,693	348,508	273,693	369,952	375,633	312,098	234,834	296,643	347,558	3,462,518
30	PURCHASED (NUGs)	776,715	744,105	741,152	663,579	731,800	679,243	849,500	795,004	589,721	398,138	299,494	319,819	7,588,269
31	TOTAL RECEIVED	930,007	879,010	938,618	1,332,568	1,146,476	1,116,669	1,312,867	1,297,180	1,038,271	858,210	818,441	938,936	12,607,253
	DELIVERED (MWH)													
32	EXTERNAL SALES	201,718	219,546	306,792	38,441	158,434	154,096	217,096	204,630	147,700	66,974	23,978	9,910	1,749,317
33	MISO RAC	0	0	0	0	1,245	23,303	49,023	70,019	14,364	0	0	0	157,954
34	TOTAL DELIVERED	201,718	219,546	306,792	38,441	159,679	177,400	266,120	274,649	162,064	66,974	23,978	9,910	1,907,271
35	NET (MWH)	728,289	659,464	631,826	1,294,127	986,797	939,269	1,046,748	1,022,531	876,208	791,235	794,462	929,026	10,699,982

MICHIGAN PUBLIC SERVICE COMMISSION

CASE NO.: U-16890
EXHIBIT: A-38 (RJP-1R)
WITNESS: RJPOLENA
DATE: FEBRUARY, 2012
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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	2012
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	EXPENSE ($*1000)													
36	SUMMER OPTION ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0
37	SUMMER OPTION CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0
38	MARKET ON PEAK ENERGY	1,678	1,022	315	6,941	2,380	6,853	4,891	6,257	5,792	9,151	9,007	10,779	65,066
39	MARKET OFF PEAK ENERGY	3,146	3,232	4,955	13,095	9,080	6,158	9,102	9,030	6,795	6,168	7,579	9,523	87,864
40	PURCHASED (NUGs) ENERGY	35,748	33,753	34,152	31,821	34,713	33,224	40,754	38,984	30,433	23,978	20,112	21,289	378,961
41	PURCHASED (NUGs) CAPACITY	21,176	19,873	20,674	18,700	20,631	20,602	21,284	21,239	20,275	21,042	20,451	21,292	247,238
42	CASE NO. U-16048 COST RECOVERY	1,026	903	837	793	803	780	885	869	770	826	803	853	10,148
		-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	------
43	TOTAL EXPENSE	62,775	58,783	60,933	71,350	67,607	67,616	76,917	76,378	64,065	61,165	57,952	63,736	789,277
	CREDIT ($*1000)													
44	EXTERNAL SALE ENERGY	7,539	8,305	11,030	1,385	5,753	6,162	10,341	9,701	5,581	2,422	839	342	69,400
45	EXTERNAL SALE CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0
46	MISO RAC	0	0	0	-1	128	1,829	3,099	4,822	1,575	0	0	0	11,453
		----	----	----	----	----	-----	-----	-----	----	----	----	----	------
47	TOTAL CREDIT	7,539	8,305	11,030	1,384	5,881	7,991	13,441	14,523	7,156	2,422	839	342	80,853
48	NET EXPENSE	55,236	50,477	49,902	69,966	61,726	59,625	63,476	61,855	56,909	58,743	57,113	63,394	708,424

MICHIGAN PUBLIC SERVICE COMMISSION

CASE NO.: U-16890
EXHIBIT: A-39 (RJP-2R)
WITNESS: RJPOLENA
DATE: FEBRUARY, 2012

CONSUMERS ENERGY COMPANY

SUMMARY BY SOURCE

YEAR		2012	2013	2014	2015	2016
(a)	(b)	(c)	(d)	(e)	(f)	(g)
	ENERGY (MWH)					
1	COAL STEAM	16,126,823	16,167,947	16,450,126	13,395,859	12,622,003
2	GAS & OIL	3,764,992	1,967,198	1,693,452	3,508,060	3,956,546
3	NUCLEAR PPA	5,978,492	5,932,360	6,778,835	6,163,752	6,178,041
4	STATION POWER	91,782	100,288	93,892	89,235	82,459
5	CE OWNED RENEWABLES	457,922	672,497	672,568	673,603	1,211,963
6	PEAKERS	112,690	88,873	42,991	128,588	165,035
7	PUMPED STORAGE	829,408	993,311	1,004,688	905,880	991,026
8	TOTAL GENERATED	27,362,109	25,922,474	26,736,551	24,864,978	25,207,072
9	LESS : PUMPING	-1,167,709	-1,388,231	-1,386,810	-1,228,776	-1,320,003
10	TOTAL GENERATED	26,194,400	24,534,243	25,349,740	23,636,202	23,887,069
11	PURCHASED (NUGs)	7,588,269	5,629,854	4,920,711	7,041,261	9,400,193
12	NET INTERCHANGE	3,111,713	7,198,087	7,889,082	7,991,489	6,024,352
		--------	--------	--------	--------	--------
13	TOTAL SYSTEM REQ	36,894,382	37,362,183	38,159,534	38,668,952	39,311,614
	EXPENSES ($*1000)					
14	COAL STEAM	496,273	513,702	556,325	459,311	437,449
15	GAS & OIL	128,247	83,306	81,640	163,003	186,491
16	NUCLEAR PPA	291,389	294,804	338,601	317,309	327,248
17	STATION POWER	0	0	0	0	0
18	CE OWNED RENEWABLES	3,718	20,485	21,279	22,660	53,836
19	PEAKERS	5,181	4,977	2,934	8,011	10,384
20	PUMPED STORAGE	0	0	0	0	0
		------	------	------	------	------
21	TOTAL GENERATED	924,809	917,274	1,000,779	970,294	1,015,408
22	LESS : PUMPING	0	0	0	0	0
23	TOTAL GENERATED	924,809	917,274	1,000,779	970,294	1,015,408
24	PURCHASED (NUGs)	636,347	595,103	580,267	695,045	822,012
25	NET INTERCHANGE	72,077	218,222	266,594	431,006	365,367
		-------	-------	-------	-------	-------
26	TOTAL SYSTEM COST	1,633,233	1,730,599	1,847,640	2,096,345	2,202,787

MICHIGAN PUBLIC SERVICE COMMISSION

CASE NO.: U-16890
EXHIBIT: A-39 (RJP-2R)
WITNESS: RJPOLENA
DATE: FEBRUARY, 2012

CONSUMERS ENERGY COMPANY

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		2012	2013	2014	2015	2016
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**
	RECEIVED (MWH)					
27	SUMMER OPTIONS	0	0	0	0	0
28	MARKET ON PEAK	1,556,465	3,395,333	3,781,361	4,070,699	2,798,321
29	MARKET OFF PEAK	3,462,518	4,827,398	4,734,932	4,563,935	4,097,317
30	PURCHASED (NUGs)	7,588,269	5,629,854	4,920,711	7,041,261	9,400,193
		--------	--------	--------	--------	--------
31	TOTAL RECEIVED	12,607,253	13,852,585	13,437,004	15,675,895	16,295,831
	DELIVERED (MWH)					
32	EXTERNAL SALES	1,749,317	917,947	530,457	490,716	718,848
33	MISO RAC	157,954	106,697	96,753	152,429	152,439
		------	-------	------	-------	-------
34	TOTAL DELIVERED	1,907,271	1,024,644	627,210	643,145	871,287
35	NET (MWH)	10,699,982	12,827,940	12,809,794	15,032,750	15,424,544

CONSUMERS ENERGY COMPANY

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		2012	2013	2014	2015	2016
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**
	EXPENSE ($*1000)					
36	SUMMER OPTION ENERGY	0	0	0	0	0
37	SUMMER OPTION CAPACITY	0	0	0	89,633	98,427
38	MARKET ON PEAK ENERGY	65,066	143,337	171,968	216,190	164,779
39	MARKET OFF PEAK ENERGY	87,864	126,494	131,127	164,123	155,880
40	PURCHASED (NUGs) ENERGY	378,961	337,243	322,707	438,198	570,167
41	PURCHASED (NUGs) CAPACITY	247,238	246,813	246,810	246,811	242,681
42	CASE NO. U-16048 COST RECOVERY	10,148	11,047	10,750	10,035	9,164
		------	------	------	------	------
43	TOTAL EXPENSE	789,277	864,933	883,362	1,164,991	1,241,098
	CREDIT ($*1000)					
44	EXTERNAL SALE ENERGY	69,400	42,908	26,733	25,550	40,483
45	EXTERNAL SALE CAPACITY	0	0	0	0	0
46	MISO RAC	11,453	8,700	9,769	13,390	13,236
		------	------	------	------	------
47	TOTAL CREDIT	80,853	51,608	36,501	38,940	53,719
48	NET EXPENSE	708,424	813,325	846,860	1,126,051	1,187,379

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 2012	))))))	Case No. U-16890

SUPPLEMENTAL DIRECT TESTIMONY

OF

DAVID F. RONK, JR.

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February, 2012

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 Resource Planning.

Q. Have you provided direct testimony in this case?

A. Yes. In September 2011 I filed direct testimony in this case.

PURPOSE OF SUPPLEMENTAL DIRECT TESTIMONY

Q. What is the purpose of this supplemental direct testimony?

A. This supplemental direct testimony is being offered to: (1) revise and replace the summer peak projected planning resource credits, demand and margins exhibit; and (2) describe the resources remaining to be purchased for the planning period;

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring:

Exhibit A-40 (DFR-1R)	Revised Summer Peak Projected Planning Resource Credits, Demand and Margins.

SUMMER PEAK PROJECTED PLANNING RESOURCE CREDITS, DEMAND, AND MARGINS

Q. Please describe Exhibit A-40 (DFR-1R).

A. Exhibit A-40 (DFR-1R) provides the restated projected summer peak planning resource credits, demand and margins.

Q. Why is it necessary to restate the projected summer peak planning resource credits, demand and margins?

A. Since the September 2011 filing in this proceeding, there has been significant changes to the demand forecast as shown in Mr. Warriner's testimony and to the resources that are expected to be available and/or acquired by Consumers Energy to achieve the required capacity planning reserve margin[1].

Q. What were the significant changes to the Company's resources?

A. On December 2, 2011, the Company announced the cancellation of a proposed clean coal plant project and the suspension of operation[2] of Cobb Units 4 and 5; Weadock Units 7 and 8; and Whiting Units 1, 2 and 3, effective in early 2015[3]. For purposes of this presentation the Company assumes the suspension of operation will occur on April 1, 2015. Also, in my direct testimony, I stated that the Company had assumed that Thetford Units 3, 4, 8, and 9; Gaylord Units 1, 2, 3 and 4; Campbell Unit A; Morrow Units A and B; and Straits combustion turbines would remain in service through at least 2016[4]. For purposes of this presentation the Company now assumes that it will remove Thetford Units 3, 4, 8, and 9; Gaylord Units 1, 2, 3 and 4; Campbell Unit A; Morrow Units A and B; and Straits combustion turbines from service, effective March 1, 2012 and will retire

[1] The required planning reserve margin applicable for the 12- month period beginning June 1, 2012 is 3.79%. Previously, the Company assumed that the required planning reserve margin would be 3.81%.

[2] MISO refers to an action to suspend operation of an available generating unit for periods in excess of 2 months as placing the unit in "Extended Reserve Shutdown." Within the electric utility industry, reference to suspending operation of an available generating unit for an extended time period, similar to the treatment of preparing clothes for long term storage with protection from damage or deterioration, is sometimes called placing the unit in "mothballs" or "mothballing" the unit.

[3] The Company's original announcement called for suspending service effective January 1, 2015. Subsequently the Company believes that the suspension of service may be delayed until April 1, 2015.

[4] Ronk Direct Testimony, page 14, line 23.

Thetford Units 3, 4, 8, and 9; Gaylord Units 1, 2, 3 and 4; Campbell Unit A; Morrow Units A and B; and Straits combustion turbines effective March 1, 2015. The Company has also updated its load forecast which is detailed in Mr. Warriner's supplemental testimony.

Q. Are there other changes?

A. Yes. The Company previously planned for the construction of the Cross Winds Energy Park with nameplate capacity of approximately 150 MW that was scheduled to begin operation in late 2014. Consistent with the Company's October 14, 2011 application in MPSC Case No. U-16581, the Company now anticipates the 150 MW Cross Winds Energy Park will commence commercial operation on December 31, 2015[5].

Q. What is the new reserve margin in Exhibit A-40 (DFR-1R)?

A. The Company now expects have 5,628 of Planning Resource Credits ("PRCs") from its owned units during the peak load period (Consumers Energy is a summer-peaking system) as shown on Line 5, Column (a) of Exhibit A-40 (DFR-1R). The Company also expects to be credited with 2,404 PRCs from generators providing capacity and energy to the Company under long term power purchase agreements. This update, along with revised forecast of peak demand expected to be served with PRCs as shown on Line 31, Column (a) of Exhibit A-40 (DFR-1R), provide an updated reserve margin of 6.36% as shown on Line 33, Column (a) of Exhibit A-40 (DFR-1R).

[5] MPSC Case No. U-16581 Application, page 3.

RESOURCES REMAINING TO BE PURCHASED FOR 2012

Q. Does Consumers need to acquire additional capacity for summer 2012?

A. No. However, due to the cessation of service of Weadock Units 7 and 8; Whiting Units 1, 2, and 3; and Cobb Units 4 and 5, effective April 1, 2015, the Company will need to purchase from others or otherwise acquire approximately 850 MW in 2012 and 900 MW in 2016 in order to meet the planning reserve margin requirement of 3.79% that is effective for the 12 month period beginning June 1, 2012.[6]

Q. Does this complete your supplemental direct testimony?

A. Yes, it does.

[6]The required planning reserve margin may be different for subsequent periods.

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 2012	))))))	Case No. U-16890

EXHIBIT

OF

DAVID F. RONK, JR.

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February, 2012

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No.: U-16890
Witness: DFRonk Jr.
Exhibit: A-40 (DFR-1R)
Date: February 2012
Page: 1 of 1

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

Line	Description	(a) 2012	(b) 2013	(c) 2014	(d) 2015	(e) 2016
1	PRCs for Owned Capacity					
2	Net Demonstrated Capability less EFORd	5745.3	5628.2	5643.2	5659.9	4797.9
3	PRCs for Projected Unit Upgrades/Re-ratings/Additions	-0.9	15.0	16.7	21.0	-1.9
4	PRCs for Projected Retirements/remove/return from/to service	-116.2			-883.0	47.5
5	PRCs for Total Owned Capacity	5628	5643	5660	4798	4844
6	PRCs for Transactions: (Annual Contracted Amounts)					
7	PRCs for Projected Summer Capacity Purchases	0.0	0.0	0.0	850.0	900.0
10	PRCs for Projected Self Generation/Load Shift	0.0	0.0	0.0	0.0	0.0
11	PRCs for Purchases Subtotal	0.0	0.0	0.0	850.0	900.0
12	PRCs for Non-Utility Generation Projects (NUGs)					
13	PRCs for MCV Contract Capacity	1186.0	1186.0	1186.0	1186.0	1186.0
14	PRCs for Palisades PPA	761.7	761.7	761.7	761.7	761.7
15	PRCs for Other NUGs	422.0	421.0	421.0	421.0	403.0
16	PRCs for PA 295 Wind NUGs	18.3	40.6	40.6	40.6	40.6
17	PRCs for PA 295 Landfill Gas NUGs	14.2	14.2	14.2	14.2	14.2
18	PRCs for PA 295 Anaerobic Digestion NUGs	1.6	3.9	3.9	3.9	2.3
19	PRCs for PA 295 Existing Solar NUGs	0.0	0.0	0.5	0.5	0.5
20	PRCs for PA 295 New EARP Solar NUGs	0.0	0.0	0.4	0.6	0.6
21	PRCs for PA 295 Hydro NUGs	0.3	0.3	0.3	0.3	0.3
22	PRCs for NUGs Subtotal	2404.1	2427.7	2428.6	2428.8	2409.2
23	PRCs for Total Capacity	8032.3	8070.9	8088.5	8076.7	8152.7
24	Peak Demand Forecast (Absent Energy Efficiency & Direct Load Control)	8356.0	8451.0	8665.0	8820.0	8953.0
25	Demand expected to be offset by Energy Efficiency	-57.0	-117.0	-177.0	-238.0	-283.0
26	Smart Grid-Dynamic Peak Pricing	0.0	0.0	0.0	-23.0	-43.0
27	Demand expected to be offset by Direct Load Control/Demand response (AC Cycling)	0.0	-4.0	-12.0	-21.0	-32.0
28	Resulting Peak Demand Forecast*	8299.0	8330.0	8476.0	8538.0	8595.0
29	Demand expected to be served by Retail Open Access Suppliers	-588.0	-590.0	-592.0	-592.0	-588.0
30	Demand from Interruptible Customers	-159.0	-159.0	-159.0	-159.0	-159.0
31	Demand to be served with PRC Capacity (coincident)	7552.0	7581.0	7725.0	7787.0	7848.0
32	Margin -- MW	480	490	364	290	305
33	Margin Reserve -- %	6.36%	6.46%	4.71%	3.72%	3.88%

*See Exhibit A-22 (LDW-3), page 1, line 13

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 2012	))))))	Case No. U-16890

SECOND DIRECT TESTIMONY

OF

LINCOLN D. WARRINER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February, 2012

Q. Please state your name and business address.

A. My name is Lincoln D. Warriner, and my business address is One Energy Plaza, Jackson, Michigan.

Q. By whom are you employed?

A. Consumers Energy Company (hereinafter, “the Company").

Q. What is your position with the Company?

A. I am a Senior Business Support Consultant - Lead in the Rates and Business Support Department.

Q. Please describe your educational background.

A. I received a Bachelor of Science Degree in Business Administration, major in Accounting, from Central Michigan University in 1987. In 1994, I received a Master of Science in Administration Degree from Central Michigan University.

Q. What is your business experience?

A. I began working for the Company in June 1987 as a region accountant at the Grand Rapids Service Center. While there, I performed various reviews of internal accounting control procedures and workflow processes. In 1989, I transferred to a similar position at the Lansing Service Center. In 1991, I took a position as a Management Systems and Planning Analyst in the Southern Region Administration and Planning Department. My primary responsibility in this position was to provide analytical support to region management on issues concerning operating, maintenance, and construction budgets and other performance measurements. In February 1994, I took a position as an Administrative Supervisor responsible for the supervision of several administrative functions including region accounts payable, miscellaneous accounts receivable, cash receipts and disbursements, payroll, records center, and mail room operations. In February 1995, I transferred to the Electric SBU Planning Department, which since has been consolidated within the Rates and Business Support Department. In this department, I have been responsible for coordinating the development of financial plans, budgets, analysis, and forecasts for the Electric SBU. Since 1997, my responsibilities have included the electric deliveries forecast, and completing various financial and economic studies for the Electric business unit. During 2007 I accepted additional supervisory responsibility for the Company's gas deliveries forecasts and electric revenue forecasts.

Q. Have you testified in other cases before the Michigan Public Service Commission?

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

a. U-16191 – January 2010 electric rate case. I presented adjustments to 2008 historical actual sales and revenues for the purpose of developing the projected test year sales and revenue. I also presented the Company's forecast of electric deliveries, generation requirements, and peak demand for the years 2009-2013.

b. U-16412 – September 2010 energy optimization plan amendment. I explained the historical and forecasted sales and revenue data that the Company used in developing its amended Energy Optimization Plan.

c. U-16418 – August 2010 gas rate case. I adopted the testimony of Linda J. Clark regarding the Company's forecast of gas deliveries and provided rebuttal testimony concerning adjustments to the Company's forecast that were proposed by interveners in that case.

d. U-16432 – September 2010 power supply cost recovery plan case. I presented the Company's official forecasts of electric deliveries, generation requirements, and peak demand forecasts for 2011-2015.

e. U-16543 – February 2011 renewable energy plan amendment. I explained the historical and forecasted sales and revenue data that the Company used in developing its amended renewable energy plan.

f. U-16794 - June 2011 electric rate case. I presented adjustments to 2010 historical actual sales and revenues for the purpose of developing the projected test year sales and revenue. I also presented the Company's forecast of electric deliveries, generation requirements, and peak demand for the years 2011-2015.

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

A. My purpose is to present Consumers Energy's amended and restated official forecasts of electric deliveries, generation requirements, and peak demand for the years 2012 - 2016.

Q. What is your relationship to the development of the electric deliveries, generation requirements, and peak demand forecasts?

A. I am responsible for the overall development of the electric deliveries, generation requirements, and peak demand forecasts. My responsibilities include coordination of the collection of needed information from internal and external sources, and development of forecast models and forecast data. I am also responsible for refining and updating the methods used to develop the forecast when appropriate.

This forecast includes projections of load to be supplied by alternate energy suppliers as well as load to be supplied by Consumers Energy. Because load supplied by alternate energy suppliers is included, this forecast is referred to as a forecast of total electric deliveries. Retail open access deliveries and full service sales are subsets of total electric deliveries presented in this forecast.

The forecasts presented also include adjustments to the forecast to reflect the planned impact of the Company's Energy Optimization Plan, as well as peak demand reductions expected from planned direct load management and dynamic peak pricing programs.

Also, as in the past, these forecasts include jurisdictional and non-jurisdictional sales.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibits A-41 (LDW-6) through A-45 (LDW-10).

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

A. Yes.

Q. Please describe Exhibits A-41 (LDW-6) and A-42 (LDW-7).

A. Page 1 of Exhibit A-41 (LDW-6) identifies the monthly calendar forecast of the Company's electric deliveries by customer class for the year 2012. Page 2 identifies the retail open access portion of the monthly calendar forecast and Page 3 identifies the full service portion of the monthly calendar forecast. Page 1 of Exhibit A-42 (LDW-7) shows the annual cycle-billed forecast of the Company's electric deliveries by customer class for the years 2012 through 2016. Pages 2 and 3 subdivide the cycle-billed forecast into retail open access and full service components respectively.

Q. What is the difference between calendar deliveries and cycle-billed deliveries?

A. The difference is due to timing. Cycle-billed sales reflect usage based on when meters are read and usage is billed. Calendar sales reflect usage during a specific calendar month or year. Due to the nature of the Company's meter reading schedule, Cycle-billed sales lag Calendar month sales. The difference between Cycle-billed sales and Calendar sales for any time period is known as unbilled sales. Projected unbilled sales are forecast at a total system level considering indicators of the differences between the billing cycle duration and the number of calendar days in a specific time period, as well as differences in indicators of calendar month and billing month heating degree days and cooling degree days. Unbilled sales projections are then allocated to each class using proportional ratios developed from the cycle-billed sales forecast. As I mentioned, the numbers shown on A-41 (LDW-6) are calendar sales and the numbers shown on A-42 (LDW-7) are cycle-billed.

Q. Please describe generally how these projections of cycle-billed deliveries were made.

A. The forecast reflects a separate projection for each customer class and, where appropriate, analyzes certain classes in more detail. Projection techniques vary from category to category based upon the availability of information, the accuracy required in the forecast, and the need to determine the influence of specific input assumptions for each category.

Forecast methodology was the combined result of regression (statistical) models, customer input, and professional judgment. The forecast was based primarily on regression analysis. Independent variables in the regression analysis include economic variables that are obtained from a separate economic forecast, weather variables, and trend variables. In addition, the impacts of future factors, or "forward-looking" items (such as expected customer use changes due to the Company's Energy Optimization Plan, and the expected introduction of Plug-In Hybrid Electric Vehicles) not fully present in past data, are applied as adjustments to the forecast when appropriate.

Q. How has the Company's Energy Optimization Plan been reflected in the electric deliveries forecast?

A. Adjustments for energy efficiency were calculated at a customer class level for the Residential, Commercial, and Industrial classes. Cumulative annual impacts for residential Energy Optimization programs were applied directly to the residential usage forecast. Cumulative annual impacts for Energy Optimization programs targeted to business customers were split between the Commercial class forecast and the Industrial class forecast in proportion to usage volumes for each class. Adjustments to monthly sales are in proportion to forecasted monthly sales volumes.

Q. How are the anticipated usage impacts associated with plug-in hybrid electric vehicles reflected in the electric deliveries forecast?

A. The adjustment made to the forecast for plug-in hybrid vehicles (PHEV) considers various independent estimates of plug-in hybrid electric vehicle saturation over a long range time horizon. This analysis starts with an estimate of the U.S. PHEV stock, from which an estimate of electric vehicles served in the Consumers Energy service area was derived. The electric use forecast considers a mix of different electric range vehicles and estimates of utilization for each type of vehicle. The forecast aligns with President Obama's energy policy goal of having 1 million plug-in hybrid electric vehicles in service by 2015.

Q. Please describe how the cycle-billed forecast of residential deliveries was developed.

A. The Residential class forecasts were developed from forecasts of customer growth and average use per customer.

1. Customer statistics were analyzed using a regression model to estimate changes in residential customers based on projected changes in household indicators for the state of Michigan. These Michigan level indicators were further refined to represent the historical and projected trends for the geographic area of Michigan served by Consumers Energy.
2. Average use forecast were developed from regression models that quantify the influence of billing cycle duration, weather conditions and seasonal factors on the average monthly usage of the residential class. Economic factors such as the average household size, average household income, and electricity price trends are also included. For purposes of this forecast, future weather conditions are assumed to be equal to a 15-year average of historical weather conditions from 1996 to 2010.
3. The forecast of monthly average use was then multiplied by the forecast of monthly residential customers to project the total residential deliveries. The result of this calculation was then adjusted for the anticipated reductions associated with Energy Optimization programs and appliance and lighting efficiency improvements. Additional loads for plug-in hybrid vehicles are also considered in the forecast.

Q. How was the Commercial Class forecast developed?

A. The Commercial forecast was developed using regression analysis that quantifies the influence of weather conditions, economic conditions, and seasonal factors on monthly commercial class usage. Economic conditions are quantified by electric service area indicators of service sector employment. For purposes of this forecast, future weather conditions are assumed to be equal to a 15-year average of historical weather conditions from 1996 to 2010. Adjustments to the forecast for Energy Optimization programs were also factored into the Commercial class usage forecast.

Q. How was the Industrial Class forecast developed?

A. The industrial class forecasts were developed from forecasts of GM/Delphi/Nexteer customer usage and other industrial customer usage.

1. The GM/Delphi/Nexteer usage forecast was developed using regression analysis that quantifies the influence of Michigan Transportation Equipment employment and seasonal factors on monthly usage of GM/Delphi/Nexteer accounts.
2. The Industrial Other usage forecast was analyzed in two subsets of customer usage. The largest subset utilizes regression analysis to quantify the influence of electric service area manufacturing employment trends, combined with increasing trends in manufacturing productivity on the monthly usage of industrial customers other than General Motors, Delphi, Nexteer, and a large producer of polycrystalline silicon. The Industrial Other forecast also includes anticipated industrial class Energy Optimization program reductions. The second subset of the Industrial Other forecast includes a large producer of semiconductor and solar energy components, which is included in the Industrial Other category, but is analyzed individually based on

expected monthly maximum billing demands, billing days, hours per day, and load factor considerations. The results of this approach were reconciled with customer developed usage projections provided to the Company. The forecast of rate E-1 economic development sales is derived from this semiconductor and solar energy component producer forecast.

Q. Please describe how other classes of sales were forecasted.

A. Wholesale usage was estimated based on the 2011 power supply cost recovery application of Alpena Power Company in MPSC Case number U-16420.

Streetlighting usage was forecast using the July 2011 light inventory levels for various types of lighting fixtures. Energy consumption is estimated by multiplying the number of each type of fixture by its associated wattage and the number of operating hours in each billing month.

Interdepartmental usage was forecast using actual monthly usage results for the twelve month time period ending August, 2011.

Q. What growth rates are reflected in the forecast shown on Page 1 of Exhibit A-42 (LDW-7)?

A. The compound average annual growth rates are shown on Page 1 of Exhibit A-42 (LDW-7). The starting point for the forecasted growth rate is 2012. The growth rates shown on the exhibit, however, are not used to forecast sales. Growth rates are calculated after the forecast has been developed.

Q. Please comment generally upon the growth patterns shown on Page 1 of Exhibit A-42 (LDW-7).

A. Overall, the projected average growth of 1.5% annually for the period 2012-2016 is a modest increase from the 0.0% annual average historical change that has been experienced from 2002-2012. The projected growth for the forecast period is different than historical changes in growth for a variety of reasons.

Residential sales are projected to remain flat from 2012-2016, compared to the average 0.1% yearly rate of decline from 2002-2012. The reasons for this projected trend include slow household growth in our service area, the planned energy savings resulting from the Company's Energy Optimization plan, and national end-use efficiency standards.

Commercial sales for the forecast period are projected to grow at an average rate of 0.4% per year, up modestly from the flat growth during 2002-2012. The slow growth rate in the commercial sales class reflects both the economic expectations for Michigan and Energy Optimization energy savings. Industrial sales are projected to grow at an average 3.9% per year from 2012-2016, which represents an improvement from the historical industrial sales growth average of 0.3% per year from 2002-2012 due to several factors. The economic outlook used in this forecast indicates that Michigan manufacturing employment is expected to show growth after the severe decline experienced in 2009. Productivity gains will result in increased manufacturing output, causing electric demand to grow. This growth is offset in part by Energy Optimization usage reductions. The industrial deliveries outlook also reflects continued growth in market demand for polycrystalline silicon, which has resulted in production capacity expansions within our service area.

Q. Please explain how the forecast of electric deliveries is split between retail open access deliveries and full service sales.

A. The Company's level of ROA load is currently capped at 10% of prior year weather-normalized retail deliveries. Customers currently active in retail open access enrolled during 2009, so actual usage for ROA customers for the twelve month period ending August 2011 was used as an estimate of future use. Full service sales are calculated by subtracting the ROA deliveries from the total deliveries forecasted. The 2012 monthly calendar forecast of ROA deliveries is shown on Page 2 of Exhibit A-41 (LDW-6). The full service calendar forecast for 2012 is shown on Page 3 of Exhibit A-42 (LDW-7). The forecast of annual cycle-billed ROA deliveries is shown on Page 2 of Exhibit A-42 (LDW-7). Page 3 of Exhibit A-42 (LDW-7) shows the annual projections of full service cycle-billed sales.

Q. Please describe Exhibit A-43 (LDW-8).

A. Exhibit A-43 (LDW-8) shows projected peak demands for the years 2012-2016. Page 1 of this exhibit shows the peak demand forecast that is consistent with the forecasts of total electric deliveries. Page 2 identifies the reduction from the total deliveries peak associated with the forecast of retail open access deliveries. Page 3 is the remaining full service peak demand to be served by Consumers Energy.

Q. Please describe generally how the projections of monthly peak demand shown on Exhibit A-43 (LDW-8) were developed.

A. The monthly peak forecast was developed as part of a monthly regression analysis that quantifies the influence of base loads, cooling loads, and heating loads. The monthly peak forecast was developed utilizing regression models that quantify the influence of overall changes in energy usage, household growth, and high and low daily temperatures on the day of the system peak. For purposes of this forecast, future weather conditions are assumed to be equal to a 15-year average of historical peak day weather conditions from 1996 to 2010. A rank and average method was used to estimate peak day weather conditions for each month.

The Company forecasts chronological hourly demands using MetrixLT load modeling software, which is available from ITRON. MetrixLT is a specialized tool for developing medium and long range load shapes that are consistent with monthly sales and peak forecasts. Separate load shapes were developed to predict hourly estimates of total load before energy efficiency adjustments, retail open access load, Energy Optimization adjustments, direct load control program adjustments, and dynamic peak pricing program adjustments. The full service load shape is then calculated outside the MetrixLT model by subtracting the hourly values for Energy Optimization, direct load control, dynamic peak pricing programs, and ROA load from the hourly total load values.

Q. Please describe how the summer peak demand forecast is adjusted to incorporate the effect of Energy Optimization programs.

A. The peak demand adjustments for Energy Optimization are derived from the Company's Energy Optimization plan.

Q. Are any other adjustments included in the summer peak demand forecast?

A. Yes, there are two programs under development that are expected to reduce load at peak demand times.

The first program, direct load management was initially incorporated into the Company's May 1, 2007 Balanced Energy Initiative filing in Case Number U-15290. In that case, the Company presented load control as an adjustment to the generation resources required to meet the forecasted peak demand. In this plan case forecast, an updated estimate of load control impacts are recognized as part of the Company's peak demand forecast, starting in 2013.

The other program under development is the Company's dynamic peak pricing program. This program is being developed as a component of the Company's Smart Grid project. The forecast includes adjustments for demand response starting in 2015.

Q. Please explain how the projections on Exhibit A-44 (LDW-9) and Exhibit A-45 (LDW-10) were developed for system efficiency, generation requirements, and load factors.

A. System efficiency is projected to remain constant at 92.76%. In other words, the level of line loss is projected to be 7.24% of generation requirements. This estimate was based on the 12-month average system efficiency for the period ending April 2007. Generation requirements are equal to calendar sales divided by system efficiency. Annual load factors are developed by using the following equation: Annual load factor based on the summer peak equals annual generation requirements divided by the product of hours per year multiplied by summer peak demand. Hours in a regular year are 8,760 and hours in a leap year are 8,784.

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for Approval of a Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for the Year 2012	))))))	Case No. U-16890

EXHIBITS

OF

LINCOLN D. WARRINER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February, 2012

FORECAST OF TOTAL ELECTRIC DELIVERIES
(CALENDAR MONTH - MWh)

Year: 2012

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line		Residential	Commercial	Industrial	Street Lighting	Interdepart-mental	Wholesale	Total
1	January	1,280,688	968,257	902,893	16,922	3,779	26,785	3,199,324
2	February	994,793	918,853	1,080,058	16,531	3,927	21,517	3,035,679
3	March	1,052,804	945,352	1,046,368	15,832	3,489	27,151	3,090,995
4	April	860,951	881,423	1,076,023	13,349	2,667	24,667	2,859,079
5	May	867,268	984,058	1,105,547	11,642	3,856	25,313	2,997,685
6	June	988,123	1,085,524	1,165,827	10,448	3,498	27,172	3,280,592
7	July	1,260,694	1,140,976	1,097,456	11,566	3,866	28,563	3,543,120
8	August	1,256,996	1,129,768	1,124,596	13,352	4,077	29,285	3,558,073
9	September	948,655	1,013,144	1,067,514	14,916	3,761	28,913	3,076,903
10	October	857,517	994,279	1,178,893	17,074	3,881	28,566	3,080,210
11	November	1,003,080	963,411	1,097,588	18,551	3,516	27,923	3,114,069
12	December	1,212,159	1,002,609	1,048,899	20,334	4,075	30,415	3,318,492
13	Total	12,583,728	12,027,653	12,991,663	180,517	44,393	326,268	38,154,222

14 Formulas:
15 Line 13 = Line 1 + Line 2 + Line 3 + Line 4 + Line 5 + Line 6 + Line 7 + Line 8 + Line 9 + Line 10 + Line 11 + Line 12
16 Column (h) = Column (b) + Column (c) + Column (d) + Column (e) + Column (f) + Column (g)
17 Exhibit A-41 (LDW-6) Page 1 = Exhibit A-41 (LDW-6) Page 2 + Exhibit A-41 (LDW-6) Page 3

FORECAST OF RETAIL OPEN ACCESS DELIVERIES
(CALENDAR MONTH - MWh)

Year: 2012

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line		Residential	Commercial	Industrial	Street Lighting	Interdepart-mental	Wholesale	Total
1	January	0	90,407	221,286	0	0	0	311,693
2	February	0	80,992	202,626	0	0	0	283,619
3	March	0	89,254	225,109	0	0	0	314,362
4	April	0	83,418	220,674	0	0	0	304,092
5	May	0	91,984	240,620	0	0	0	332,604
6	June	0	93,476	254,937	0	0	0	348,412
7	July	0	101,050	254,576	0	0	0	355,626
8	August	0	105,491	271,180	0	0	0	376,671
9	September	0	96,202	239,214	0	0	0	335,416
10	October	0	94,404	253,670	0	0	0	348,074
11	November	0	87,134	231,539	0	0	0	318,673
12	December	0	87,221	214,790	0	0	0	302,010
13	Total	0	1,101,033	2,830,220	0	0	0	3,931,253

14 Formulas:
15 Line 13 = Line 1 + Line 2 + Line 3 + Line 4 + Line 5 + Line 6 + Line 7 + Line 8 + Line 9 + Line 10 + Line 11 + Line 12
16 Column (h) = Column (b) + Column (c) + Column (d) + Column (e) + Column (f) + Column (g)

FORECAST OF FULL SERVICE DELIVERIES
(CALENDAR MONTH - MWh)

Year: 2012

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line		Residential	Commercial	Industrial	Street Lighting	Interdepart-mental	Wholesale	Total
1	January	1,280,688	877,849	681,607	16,922	3,779	26,785	2,887,631
2	February	994,793	837,861	877,432	16,531	3,927	21,517	2,752,061
3	March	1,052,804	856,098	821,259	15,832	3,489	27,151	2,776,632
4	April	860,951	798,005	855,349	13,349	2,667	24,667	2,554,987
5	May	867,268	892,075	864,927	11,642	3,856	25,313	2,665,081
6	June	988,123	992,048	910,890	10,448	3,498	27,172	2,932,180
7	July	1,260,694	1,039,925	842,880	11,566	3,866	28,563	3,187,494
8	August	1,256,996	1,024,277	853,416	13,352	4,077	29,285	3,181,402
9	September	948,655	916,942	828,301	14,916	3,761	28,913	2,741,487
10	October	857,517	899,876	925,223	17,074	3,881	28,566	2,732,136
11	November	1,003,080	876,276	866,050	18,551	3,516	27,923	2,795,396
12	December	1,212,159	915,388	834,110	20,334	4,075	30,415	3,016,481
13	Total	12,583,728	10,926,620	10,161,443	180,517	44,393	326,268	34,222,969

14 Formulas:
15 Line 13 = Line 1 + Line 2 + Line 3 + Line 4 + Line 5 + Line 6 + Line 7 + Line 8 + Line 9 + Line 10 + Line 11 + Line 12
16 Column (h) = (Total Generation Requirements - ROA Generation Requirements) x System Efficiency

FORECAST OF TOTAL ELECTRIC DELIVERIES
(CYCLE BILLED - GWh)

Line	(a)	(b) 2012	(c) 2013	(d) 2014	(e) 2015	(f) 2016
1	Residential	12,543	12,458	12,404	12,438	12,552
2	Residential	12,536	12,443	12,380	12,406	12,513
3	PHEV	7	16	24	32	39
4	Commercial	11,991	12,041	12,034	12,043	12,183
5	Industrial	12,948	13,622	14,336	14,763	15,103
6	GM/Delphi/Nexteer	866	947	1,021	1,039	999
7	E-1 Economic Development	2,351	2,600	2,656	2,719	2,719
8	Industrial Other	9,731	10,075	10,658	11,005	11,385
9	Street Lighting	183	183	184	184	185
10	Interdepartmental	44	44	44	44	44
11	Wholesale	326	328	330	331	333
12	Total	38,035	38,676	39,332	39,804	40,400

Annual Average Growth Rate (AAR) in Percent

Line		1992 - 2012F	2002 - 2012F	2012F - 2016F
13	Residential	1.3%	-0.1%	0.0%
14	Commercial	1.6%	0.0%	0.4%
15	Industrial	0.9%	0.3%	3.9%
16	Total	1.1%	0.0%	1.5%

17 Formulas:
18 Line 12 = Line 1 + Line 4 + Line 5 + Line 9 + Line 10 + Line 11
19 Line 1 = Line 2 + Line 3
20 Line 5 = Line 6 + Line 7

FORECAST OF RETAIL OPEN ACCESS DELIVERIES
(CYCLE BILLED - GWh)

Line	(a)	(b) 2011	(c) 2012	(d) 2013	(e) 2014	(f) 2015
1	Residential	0	0	0	0	0
2	Residential Domestic	0	0	0	0	0
3	PHEV	0	0	0	0	0
4	Commercial	1,101	1,101	1,101	1,101	1,101
5	Industrial	2,830	2,830	2,830	2,830	2,830
6	General Motors & Delphi	0	0	0	0	0
7	E-1 Economic Development	0	0	0	0	0
8	Industrial Other	2,830	2,830	2,830	2,830	2,830
9	Street Lighting	0	0	0	0	0
10	Interdepartmental	0	0	0	0	0
11	Wholesale	0	0	0	0	0
12	Total	3,931	3,931	3,931	3,931	3,931

13 Formulas:
14 Line 12 = Line 1 + Line 4 + Line 5 + Line 9 + Line 10+ Line 11
15 Line 1 = Line 2 + Line 3
16 Line 5 = Line 6 + Line 7+ Line 8

FORECAST OF FULL SERVICE DELIVERIES
(CYCLE BILLED - GWh)

Line	(a)	(b) 2011	(c) 2012	(d) 2013	(e) 2014	(f) 2015
1	Residential	12,543	12,458	12,404	12,438	12,552
2	Residential Domestic	12,536	12,443	12,380	12,406	12,513
3	PHEV	7	16	24	32	39
4	Commercial	10,890	10,940	10,933	10,942	11,082
5	Industrial	10,118	10,792	11,506	11,933	12,273
6	General Motors & Delphi	866	947	1,021	1,039	999
7	E-1 Economic Development	2,351	2,600	2,656	2,719	2,719
8	Industrial Other	6,901	7,245	7,828	8,175	8,555
9	Street Lighting	183	183	184	184	185
10	Interdepartmental	44	44	44	44	44
11	Wholesale	326	328	330	331	333
12	Total	34,103	34,745	35,400	35,873	36,469

13 Formulas:
14 Line 12 = Line 1 + Line 4 + Line 5 + Line 9 + Line 10 + Line 11
15 Line 1 = Line 2 + Line 3
16 Line 5 = Line 6 + Line 7 + Line 8
17 Exhibit A-42 (LDW-7) Page 3 = Exhibit A-42 (LDW-7) Page 1 - Exhibit A-42 (LDW-7) Page 2, except for Line 12

MONTHLY PEAK DEMAND FORECAST

	(a)	(b)	(c)	(d)	(e)	(f)
Line		2012	2013	2014	2015	2016
1	January	5,987	6,016	6,171	6,278	6,369
2	February	5,803	5,832	5,984	6,079	6,179
3	March	5,615	5,651	5,807	5,900	5,995
4	April	5,295	5,312	5,465	5,560	5,645
5	May	6,182	6,207	6,348	6,428	6,553
6	June	7,449	7,478	7,625	7,718	7,814
7	July	8,008	8,042	8,190	8,282	8,375
8	August	8,299	8,330	8,476	8,538	8,595
9	September	6,909	6,937	7,084	7,175	7,267
10	October	5,826	5,866	6,023	6,120	6,208
11	November	5,830	5,864	6,018	6,113	6,202
12	December	6,175	6,212	6,369	6,468	6,561

Summer Peak (MW)

	2012	2013	2014	2015	2016
13	8,299	8,330	8,476	8,538	8,595

Winter Peak (MW)

	2012	2013	2014	2015	2016
14	6,175	6,212	6,369	6,468	6,561

MONTHLY REDUCTION IN PEAK LOAD ASSOCIATED WITH RETAIL OPEN ACCESS

	(a)	(b)	(c)	(d)	(e)	(f)
Line		2012	2013	2014	2015	2016
1	January	481	477	477	480	484
2	February	455	478	478	478	455
3	March	484	490	490	485	479
4	April	498	475	475	475	480
5	May	526	526	529	551	551
6	June	570	573	571	568	568
7	July	562	560	560	560	564
8	August	588	590	592	592	588
9	September	553	551	548	548	548
10	October	540	540	540	544	550
11	November	507	511	516	512	507
12	December	470	467	460	463	466

Summer Peak Reduction (MW)

	2012	2013	2014	2015	2016
13	588	590	592	592	588

Winter Peak Reduction (MW)

	2012	2013	2014	2015	2016
14	470	467	460	463	466

MONTHLY PEAK LOAD TO BE SERVED BY CONSUMERS ENERGY

	(a)	(b)	(c)	(d)	(e)	(f)
Line		2012	2013	2014	2015	2016
1	January	5,506	5,539	5,694	5,798	5,885
2	February	5,348	5,354	5,506	5,601	5,724
3	March	5,131	5,161	5,317	5,415	5,516
4	April	4,797	4,837	4,990	5,085	5,165
5	May	5,656	5,681	5,819	5,877	6,002
6	June	6,879	6,905	7,054	7,150	7,246
7	July	7,446	7,482	7,630	7,722	7,811
8	August	7,711	7,740	7,884	7,946	8,007
9	September	6,356	6,386	6,536	6,627	6,719
10	October	5,286	5,326	5,483	5,576	5,658
11	November	5,323	5,353	5,502	5,601	5,695
12	December	5,705	5,745	5,909	6,005	6,095

Summer Full Service Peak (MW)

	2012	2013	2014	2015	2016
13	7,711	7,740	7,884	7,946	8,007

Winter Full Service Peak (MW)

	2012	2013	2014	2015	2016
14	5,705	5,745	5,909	6,005	6,095

MONTHLY GENERATION REQUIREMENTS

Based on Total System Deliveries (MWh)

	(a)	(b)	(c)	(d)	(e)	(f)
Line		2012	2013	2014	2015	2016
1	January	3,442,039	3,486,993	3,563,105	3,616,243	3,674,664
2	February	3,267,359	3,187,729	3,265,469	3,318,965	3,466,835
3	March	3,317,233	3,332,535	3,399,760	3,450,875	3,474,834
4	April	3,067,309	3,099,172	3,179,088	3,224,525	3,269,892
5	May	3,226,385	3,280,674	3,334,916	3,378,407	3,422,445
6	June	3,563,500	3,616,795	3,683,894	3,729,037	3,775,064
7	July	3,846,450	3,907,691	3,974,046	4,011,763	4,058,679
8	August	3,862,413	3,919,206	3,989,235	4,028,023	4,076,325
9	September	3,311,820	3,373,364	3,444,413	3,485,190	3,532,255
10	October	3,315,368	3,374,897	3,438,078	3,470,689	3,514,269
11	November	3,342,124	3,374,885	3,458,180	3,491,172	3,535,315
12	December	3,570,483	3,646,353	3,667,392	3,701,927	3,749,075
13	Total	41,132,483	41,600,294	42,397,576	42,906,816	43,549,652

MONTHLY REDUCTION IN GENERATION REQUIREMENTS ASSOCIATED WITH RETAIL OPEN ACCESS

Based on Retail Open Access Deliveries (MWh)

	(a)	(b)	(c)	(d)	(e)	(f)
Line		2012	2013	2014	2015	2016
1	January	336,018	335,903	335,903	335,935	335,986
2	February	305,784	305,736	305,736	305,736	305,784
3	March	338,895	338,924	338,924	338,920	338,911
4	April	327,800	327,872	327,872	327,872	327,778
5	May	358,568	358,568	358,606	358,579	358,631
6	June	375,596	375,610	375,564	375,566	375,566
7	July	383,391	383,357	383,357	383,357	383,425
8	August	406,065	406,059	406,072	406,072	406,065
9	September	361,635	361,573	361,630	361,630	361,630
10	October	375,262	375,262	375,262	375,090	375,199
11	November	343,514	343,602	343,565	343,556	343,514
12	December	325,587	325,635	325,544	325,544	325,544
13	Total	4,238,115	4,238,101	4,238,035	4,237,857	4,238,033

MONTHLY GENERATION REQUIREMENTS TO BE SUPPLIED BY CONSUMERS ENERGY

Based on Full Service Deliveries (MWh)

	(a)	(b)	(c)	(d)	(e)	(f)
Line		2012	2013	2014	2015	2016
1	January	3,106,021	3,151,090	3,227,202	3,280,308	3,338,678
2	February	2,961,575	2,881,993	2,959,733	3,013,229	3,161,051
3	March	2,978,338	2,993,611	3,060,836	3,111,955	3,135,923
4	April	2,739,509	2,771,300	2,851,216	2,896,653	2,942,114
5	May	2,867,817	2,922,106	2,976,310	3,019,828	3,063,814
6	June	3,187,904	3,241,185	3,308,330	3,353,471	3,399,498
7	July	3,463,059	3,524,334	3,590,689	3,628,406	3,675,254
8	August	3,456,348	3,513,147	3,583,163	3,621,951	3,670,260
9	September	2,950,185	3,011,791	3,082,783	3,123,560	3,170,625
10	October	2,940,106	2,999,635	3,062,816	3,095,599	3,139,070
11	November	2,998,610	3,031,283	3,114,615	3,147,616	3,191,801
12	December	3,244,896	3,320,718	3,341,848	3,376,383	3,423,531
13	Total	36,894,368	37,362,193	38,159,541	38,668,959	39,311,619

MISCELLANEOUS FORECASTS

	(a)	(b)	(c)	(d)	(e)	(f)
Line		2012	2013	2014	2015	2016
1	Calendar Sales (GWh Deliveries)	38,154	38,588	39,328	39,800	40,397
2	System Efficiency (%)	92.76%	92.76%	92.76%	92.76%	92.76%
3	Generation Requirements (GWh)	41,132	41,600	42,398	42,907	43,550
4	Summer Peak (MW)	8,299	8,330	8,476	8,538	8,595
5	Annual Load Factor based on the Summer Peak (%)	56.4%	57.0%	57.1%	57.4%	57.7%

6 Note: The forecasts on this exhibit reflect the forecast of total electric deliveries before any adjustment for retail open access.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for Approval of a Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for the Year 2012	))))))	Case No. U-16890

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Judy A. Jones, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on February 20, 2012, she served an electronic copy of the Supplemental Direct Testimony/Second Direct Testimony and Exhibits of Consumers Energy witnesses Richard T. Blumenstock, Shawn D. Burgdorf, Laura M. Collins, Brian D. Gallaway, David B. Kehoe, Richard J. Polena, David F. Ronk, Jr., and Lincoln D. Warriner, upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Judy A. Jones
Digitally signed by Judy A. Jones
Date: 2012.02.20 17:27:25 -05'00'

Judy A. Jones

Subscribed and sworn to before me this 20th day of February, 2012.

Sharon K. Davis
Digitally signed by Sharon K. Davis
Date: 2012.02.20 17:31:14 -05'00'

Sharon K. Davis, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 07/28/16
Acting in the County of Jackson

ATTACHMENT 1 TO CASE NO. U-16890

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