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Count on Us

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September 30, 2019

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

RE: Case No. U-20525 – In the Matter of the application of CONSUMERS ENERGY COMPANY for Approval to implement a power supply cost recovery plan and for the 12 months ending December 31, 2020.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case are **Consumers Energy Company's Application and the Testimony and Exhibits of Consumers Energy Company Witnesses Daniel S. Alfred, Eugène M.J.A. Breuring, Joshua W. Hahn, Norman J. Kapala, Kevin C. Lott, Adam J. Mortiz, Stephen J. Nadeau, Angela K. Rissman, Keith G. Troyer, and Andrew G. Volansky.** This is a paperless filing and is therefore being filed only in a PDF format. I have enclosed a Proof of Service showing electronic service upon the parties to MPSC Case Nos. U-18402 and U-20219.

Sincerely,

Digitally signed by
Gary A. Gensch, Jr.
Date: 2019.09.30
13:53:51 -04'00'

Gary A. Gensch, Jr.

cc: Parties per Attachment 1 to MPSC Case Nos. U-18402 and U-20219

fl0919-1-233

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 to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

APPLICATION

Consumers Energy Company ("Consumers Energy" or the "Company") hereby applies for approval of a Power Supply Cost Recovery ("PSCR") Plan and monthly PSCR Factors for the 12-month period January through December 2020. In support of this Application, Consumers Energy states as follows:

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

2. Consumers Energy's retail electric business is subject to the jurisdiction of the Michigan Public Service Commission ("MPSC" or the "Commission") pursuant to certain provisions of 1939 PA 3, as amended by various acts, including 1982 PA 304, 2000 PA 141, 2008 PA 286, and 2016 PA 341, MCL 460.1 *et seq*.; 1909 PA 106, as amended, MCL 460.551 *et seq*.; and 1909 PA 300, as amended, MCL 462.2 *et seq*.

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

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

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

5. Rule C8 of Consumers Energy's electric tariffs requires the Company to file a PSCR Plan, to request approval of specific PSCR Factors for a future 12-month period, and to provide a five-year forecast. Accompanying this Application are the testimony and exhibits of witnesses for Consumers Energy that meet the requirements of Rule C8 with respect to calendar year 2020. The prefiled testimony and exhibits include an evaluation and conclusions as to the reasonableness and prudence of the forecasted costs of fuel and purchased and net interchange power. Also included in these materials is a five-year forecast of the power supply requirements of Consumers Energy's customers, anticipated sources of supply, and projections of power supply costs.

6. As more fully described in the accompanying testimony and exhibits, Consumers Energy seeks approval to apply, for each month in calendar year 2020, a uniform maximum PSCR Factor of $0.00008 per kWh for all classes of customers.

7. The accompanying testimony and exhibits, as provided by Company witnesses Daniel S. Alfred, Eugène M.J.A. Breuring, Joshua W. Hahn, Norman J. Kapala, Kevin C. Lott, Adam J. Moritz, Stephen J. Nadeau, Angela K. Rissman, Keith G. Troyer, and Andrew G. Volansky, are an integral part of this Application, and the relief described therein is incorporated by reference in this Application, as if fully set forth herein. This testimony includes, among

other things, a description of the generation resources required to meet customer capacity needs and any necessary capacity purchases; projected plant outages and projected cost of the various sorbents used in the generation of electricity; projected cost of the fuel used in the generation of electricity; and projected transmission-related and energy market costs.

8. If power supply costs increase for the PSCR Plan year, due to changes in conditions, the factors that are ultimately requested or approved could be higher than set forth above. Consumers Energy reserves the right to amend its filing or seek reopening of the power supply cost review for the PSCR Plan year if circumstances warrant.

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

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

B. Approve for 2020 a maximum monthly PSCR Factor of not less than $0.00008 per kWh for all classes of customers as set forth herein, and more fully explained in the accompanying testimony;

C. Approve the PSCR Plan for 2020 described in this Application; and

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

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Digitally signed by Timothy J. Sparks
Date: 2019.09.30 13:54:26 -04'00'

Date: September 30, 2019

By: _____

Timothy J. Sparks
Vice President of Electric Grid Integration
Consumers Energy Company

Digitally signed by Gary A. Gensch, Jr.
Date: 2019.09.30 14:07:58 -04'00'

_____

Robert W. Beach (P73112)
Gary A. Gensch, Jr. (P66912)
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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

VERIFICATION

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

Date: September 30, 2019

By: Digitally signed by Timothy J. Sparks Date: 2019.09.30 13:56:18 -04'00'

Timothy J. Sparks
Vice President of Electric Grid Integration
Consumers Energy Company

PREFILED EXHIBITS

Exhibit of Daniel S. Alfred

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

Exhibits of Eugène M.J.A. Breuring

Exhibit A-2 (EMB-1)	2020 Forecast of Calendar Total Electric Deliveries;
Exhibit A-3 (EMB-2)	Forecast of Annual Calendar Deliveries;
Exhibit A-4 (EMB-3)	Forecast of Total Monthly Generation Requirements;
Exhibit A-5 (EMB-4)	Forecast of Total Monthly Peak Demand; and
Exhibit A-6 (EMB-5)	Forecasted System Load Factor Based on Summer Peak Demand.

Exhibits of Joshua W. Hahn

Exhibit A-7 (JWH-1)	Monthly Summary for 2020 of Fuel and Purchased and Net Interchange Power Expenses;
Exhibit A-8 (JWH-2)	Annual Summary for Years 2020 through 2024 of Fuel and Purchased and Net Interchange Power Expenses; and
Exhibit A-9 (JWH-3)	Purchased Power Agreements – Projected 2020 Rates.

Exhibits of Norman J. Kapala

Exhibit A-10 (NJK-1)	Major Outages in the 2020 PSCR Plan;
Exhibit A-11 (NJK-2)	2020 PSCR Random Outage Rate Projections;
Exhibit A-12 (NJK-3)	2020-2024 Urea Expense;
Exhibit A-13 (NJK-4)	2020-2024 Aqueous Ammonia Expense;
Exhibit A-14 (NJK-5)	2020-2024 Lime Expense; and
Exhibit A-15 (NJK-6)	2020-2024 Activated Carbon Expense.

Exhibits of Kevin C. Lott

Exhibit A-16 (KCL-1)	Projected As-Burned Coal Costs – 2020;
Exhibit A-17 (KCL-2)	Projected As-Burned Coal Costs (2021-2024);
Exhibit A-18 (KCL-3)	Projected As-Burned Oil & Gas Costs – 2020; and
Exhibit A-19 (KCL-4)	Projected As-Burned Oil & Gas Costs (2021-2024).

Exhibit of Adam J. Moritz

Exhibit A-20 (AJM-1)	Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC).

Exhibit of Angela K. Rissman

Exhibit A-21 (AKR-1)	2020-2024 Coal Contract & Purchase Data.

Exhibits of Andrew G. Volansky

Exhibit A-22 (AGV-1)	Calculation of 2020 PSCR Factor.

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 to implement a Power Supply Cost Recovery Plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

DIRECT TESTIMONY

OF

DANIEL S. ALFRED

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Daniel S. Alfred, and my business address is 1945 W. Parnall Rd, Jackson, Michigan 49201.

Q. By whom are you employed?

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

Q. What is your position with Consumers Energy?

A. I am a Senior Rate and Business Support Analyst in the Transmission and Regulatory Strategies Department of Energy Supply Operations.

Q. Please describe your educational background.

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

Q. Please describe your business experience.

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

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

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

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

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

Case No. U-13730	Gas General Rate Case;
Case No. U-14126	Enhanced Security Costs;
Case No. U-14148	10d(4) Regulatory Asset Recovery;
Case No. U-14347	Electric General Rate Case;
Case No. U-15245	Electric General Rate Case;
Case No. U-15986	Gas General Rate Case;
Case No. U-15704	Gas Cost Recovery Plan;
Case No. U-14126-R	Enhanced Security Costs Reconciliation;
Case No. U-16564	10d(4) Regulatory Asset Reconciliation;
Case No. U-16855	Gas General Rate Case;
Case No. U-17317	2014 Power Supply Cost Recovery ("PSCR") Plan Case;
Case No. U-17678	2015 PSCR Plan Case;
Case No. U-17918	2016 PSCR Plan Case;

Case No. U-18142 2017 PSCR Plan Case;

Case No. U-18402 2018 PSCR Plan Case; and

Case No. U-20219 2019 PSCR Plan Case.

PURPOSE OF DIRECT TESTIMONY

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

A. The purpose of my direct testimony is to: (i) identify the transmission and energy market expenses for 2020 for which the Company seeks recovery in this proceeding; (ii) identify generation-related credits to PSCR costs relating to Schedule 2 Reactive revenues; and (iii) describe the Company's effort to manage its transmission-related costs.

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

A. Yes. I am sponsoring the following exhibit:

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

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

A. Yes.

TRANSMISSION AND ENERGY MARKET EXPENSES

Q. What transmission and energy market expenses does the Company seek recovery for in the Company's 2020 PSCR Plan?

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

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

A. Yes. The Commission approved recovery of expenses incurred under MISO's Tariff in the Company's PSCR factor most recently in the 2017 PSCR Plan, Case No. U-18142.

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

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

Q. Please list each transmission and energy market charge that has been projected for 2020 in the Company's total transmission costs.

A. The transmission and energy market-related charges included in the total transmission costs projected for 2020 and shown in Exhibit A-1 (DSA-1), page 1, are incurred as a result of the mandated expenses charged to Consumers Energy by MISO pursuant to MISO Schedules 1, 2, 9, 10, 10-FERC, 16, 17, 24, 26, and 26-A. The charges imposed pursuant to these schedules are discussed more fully below.

Q. Has the Company forecasted other MISO charges?

A. Yes. As discussed by Company witness Keith G. Troyer in his direct testimony in this case, 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 Eugene M. Breuring?

A. Yes.

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

A. MISO Schedule 1 is the Tariff schedule for service required to schedule the movement of power through, out of, within, or into a control area, and is provided by the transmission

operators within the control area and MISO. The rate for this service is a zonal rate. Applying this rate to the Company's forecasted monthly coincident peak produces the Company's forecasted expense. This forecasted expense for the 2020 PSCR Plan year and the five-year period 2020-2024 is shown on Exhibit A-1 (DSA-1), line 16.

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

A. MISO Schedule 2 is the Tariff schedule for an ancillary service required to be provided by MISO for Reactive Supply and Voltage Control from Generation Sources. The rate for this service is a pricing zone wide rate. Applying the applicable pricing zone rate to the Company's forecasted monthly coincident peak produces the Company's forecasted expense. This forecasted expense for the 2020 PSCR Plan year and the five-year period 2020-2024 is shown on Exhibit A-1 (DSA-1), line 17.

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

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

This rate is calculated per the MISO Tariff Attachment O and is updated biannually. The Company's forecasted expense for the 2020 PSCR Plan year and the five-year period 2020-2024 is shown on Exhibit A-1 (DSA-1), line 18.

Q. As a Transmission Owner, what is the Company's transmission revenue requirment for the 2020 PSCR Plan Year relative to the MJZ?

A. Consumers Energy's Transmission revenue requirement is approximately $6.9 million for the 2020 PSCR Plan year and is included in the calculation of the MISO Schedule 9 forecasted rate for the MJZ.

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

A. MISO Schedule 10 is the Tariff schedule for MISO expenses associated with the operation of MISO in the provision of transmission service within the MISO footprint. MISO assesses Schedule 10 with two rates. The first rate is applied to peak load at a 100% load factor. The Company's forecasted expense for the 2020 PSCR Plan year and the five-year period 2020-2024 for this portion of Schedule 10 is shown on Exhibit A-1 (DSA-1), line 19. The second rate is applied to actual volume of MWh of transmission service received. The Company's forecasted expense for the 2020 PSCR Plan year and the five-year period 2020-2024 for this portion of Schedule 10 is shown on Exhibit A-1 (DSA-1), line 20.

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

A. MISO Schedule 10-FERC is the Tariff schedule for the FERC Annual Fee that MISO is assessed and then allocated to MISO's wholesale transmission customers. The FERC Annual Fee is designed to reimburse the federal government for all of the costs incurred

by FERC under Parts II and III of the Federal Power Act and related statutes per 18 CFR Part 382. The Company's forecasted expenses for the 2020 PSCR Plan year and the five-year period 2020-2024 are shown on Exhibit A-1 (DSA-1), line 21.

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 the MISO Financial Transmission Rights market. In forecasting the Schedule 16 expense, I multiplied the Company's monthly coincident peak load at a 100% load factor against the MISO budgeted Schedule 16 rate to produce the expected expense. The Company's forecasted expenses for the 2020 PSCR Plan year and the five-year period 2020-2024 are shown on Exhibit A-1 (DSA-1), line 22.

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

A. MISO Schedule 17 is designed to recover MISO administrative service costs associated with the Midwest Energy and Operating Reserves Market. The rate is charged to all injections and withdrawals in the market. The Company's forecasted expenses for the 2020 PSCR Plan year and the five-year period 2020-2024 are shown on Exhibit A-1 (DSA-1), line 23.

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

A. MISO Schedule 24 is the Tariff schedule for the Control Area Operator Cost Recovery charge used to recover Control Area costs incurred with the implementation of the Market. This rate is charged on the same basis as Schedule 17. The Company's forecasted expenses for the 2020 PSCR Plan year and the five-year period 2020-2024 are shown on Exhibit A-1 (DSA-1), line 24.

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

A. MISO Schedule 26 is the Tariff schedule for the Network Upgrade Charge from MISO's Transmission Expansion Plan ("MTEP"). This schedule is applied on the same basis as Schedule 9. It reflects the sharing of MTEP project costs as allocated according to Attachment FF of the MISO Tariff. The Company's forecasted expenses for the 2020 PSCR Plan year and the five-year period 2020-2024 are shown on Exhibit A-1 (DSA-1), line 25.

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

A. MISO Schedule 26-A is the Tariff schedule that includes the Multi-Value Project Usage Rate and is a MISO system-wide rate charged to Monthly Net Actual Energy Withdrawals, certain Export Schedules, and Through Schedules. The rate is calculated using the formula included in Attachment MM of the Tariff. The charges under this Schedule 26-A shall be in addition to any charges under Schedules 7, 8, 9, and 26. Grandfathered Agreements will not be charged under this Schedule. The Company's forecasted expenses for the 2020 PSCR Plan year and the five-year period 2020-2024 are shown on Exhibit A-1 (DSA-1), line 26.

Q. Will the Company be providing Blackstart Service in the 2020 Plan Year?

A. Yes. The Company will provide Blackstart Service within the METC Transmission Pricing Zone and collect charges via MISO Schedule 33 as set forth in the MISO Tariff. The Company's forecasted expenses for the 2020 PSCR Plan year and the five-year period 2020-2024 are shown on Exhibit A-1 (DSA-1), line 27.

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. The expenses described above, as well as the total expenses for each plan year, are identified on Exhibit A-1 (DSA-1). The total cost for 2020 equals $468,668,867 and can be found on Exhibit A-1 (DSA-1), page 1, line 31, column (o). It is composed of $461,733,160 of transmission expenses (Exhibit A-1 (DSA-1), line 29, column (o)) and $6,935,707 of energy market administration expenses (Exhibit A-1 (DSA-1). line 30, column (o)).

SCHEDULE 2 REACTIVE REVENUE REQUIREMENT CREDIT

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

A. Consumers Energy provides generation-related reactive services that are necessary for the transmission of power. The Company receives revenue from MISO for providing this service. Consumers Energy incurs an expense under the MISO Tariff when it receives reactive service within the MJZ pricing zone. 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 2020 from Schedule 2?

A. Yes. The Company expects to receive $4,500,000 in 2020. This amount is composed of the FERC-approved revenue requirements established in FERC Docket No. ER-16-1058.

COMPANY ACTIVITIES RELATED TO TRANSMISSION COST MANAGEMENT

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

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

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

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

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

A. Yes. The Company has been very active in MISO's transmission-related groups such as the East Sub-regional Planning Meetings, Michigan Technical Study Task Force, Planning Advisory Committee, Planning Subcommittee, Advisory Committee, Regional Expansion Criteria and Benefits Task Force, and the MISO Board of Directors System Planning

Committee. The Company's focus is to monitor and assure new transmission projects are justified and costs are allocated according to cost causation principles.

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

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

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

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

Q. Does this conclude your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the application of **CONSUMERS ENERGY COMPANY** for Approval to implement a Power Supply Cost Recovery Plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

EXHIBIT

OF

DANIEL S. ALFRED

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2020 Transmission and Energy Market Administration Expenses

Case No.: U-20525
Exhibit No.: A-1 (DSA-1)
Page: 1 of 5
Witness: DSAlfred
Date: September 2019

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper DSA-1	5,338	5,240	5,019	4,842	5,613	6,920	7,319	7,238	6,545	4,992	5,188	5,362	**69,615**
2	Hours per Month	Day in Month * 24	744	672	744	720	744	720	744	744	720	744	720	744	**8,760**
3	Delivered MWhs	Workpaper DSA-3	3129702	2900549	2952120	2702930	2909137	3034389	3390092	3341297	2915095	2809497	2872419	3039465	**35,996,692**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	195.8327886	195.8328	195.8328	195.8328	195.8328	195.8328	195.8328	195.8328	195.8328	195.8328	195.8328	195.8328	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	4171.183559	4171.183559	4171.183559	4171.183559	4171.183559	4460.941512	4460.941512	4460.941512	4460.941512	4460.941512	4460.941512	4460.941512	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0721	0.0721	0.0721	0.0721	0.0721	0.0721	0.0721	0.0721	0.0721	0.0721	0.0721	0.0721	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	1003.914311	1,003.9143	1,003.9143	1,003.9143	1,003.9143	1,003.9143	1,003.9143	1,003.9143	1,003.9143	1,003.9143	1,003.9143	1,003.9143	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.699653319	1.6997	1.6997	1.6997	1.6997	1.6997	1.6997	1.6997	1.6997	1.6997	1.6997	1.6997	
15	Schedule 33 - Blackstart Service	Workpaper DSA-5a	4.2783	4.2783	4.2783	4.2783	4.2783	4.2783	4.2783	4.2783	4.2783	4.2783	4.2783	4.2783	
	Expenses														
16	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 343,409	$ 337,126	$ 322,926	$ 311,485	$ 361,088	$ 445,195	$ 470,893	$ 465,628	$ 421,066	$ 321,187	$ 333,778	$ 344,942	**$ 4,478,724**
17	Schedule 2 - Reactive Support	Line 1 * Line 5	1,045,319	1,026,192	982,969	948,144	1,099,132	1,355,148	1,433,371	1,417,346	1,281,703	977,676	1,016,003	1,049,985	**13,632,988**
18	Schedule 9 - Network Transmission Service	Line 1 * Line 6	22,265,007	21,857,603	20,936,962	20,195,203	23,411,204	30,869,380	32,651,248	32,286,204	29,196,343	22,270,815	23,143,869	23,917,959	**303,001,797**
19	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	286,333	253,891	269,254	251,337	301,074	359,227	392,628	388,239	339,758	267,804	269,325	287,611	**3,666,482**
20	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	317,665	294,406	299,640	274,347	295,277	307,990	344,094	339,142	295,882	285,164	291,551	308,506	**3,653,664**
21	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	165,874	153,729	156,462	143,255	154,184	160,823	179,675	177,089	154,500	148,903	152,238	161,092	**1,907,825**
22	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	23,828	21,128	22,407	20,916	25,055	29,894	32,674	32,308	28,274	22,286	22,413	23,934	**305,116**
23	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	507,012	469,889	478,243	437,875	471,280	491,571	549,195	541,290	472,245	455,139	465,332	492,393	**5,831,464**
24	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	69,479	64,392	65,537	60,005	64,583	67,363	75,260	74,177	64,715	62,371	63,768	67,476	**799,127**
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,358,709	5,260,656	5,039,077	4,860,552	5,634,574	6,947,012	7,348,013	7,265,861	6,570,502	5,011,944	5,208,421	5,382,626	**69,887,947**
26	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	5,319,408	4,929,928	5,017,581	4,594,044	4,944,524	5,157,409	5,761,981	5,679,047	4,954,651	4,775,171	4,882,116	5,166,037	**61,181,897**
27	Schedule 33 - Blackstart Service		22,837	22,419	21,475	20,714	24,012	29,606	31,314	30,964	28,001	21,359	22,196	22,939	**297,836**
28	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**
29	Total Transmission Expenses	**Lines 16-21 + 25-28**	**$ 35,126,562**	**$ 34,137,949**	**$ 33,048,345**	**$ 31,601,082**	**$ 36,227,070**	**$ 45,633,790**	**$ 48,615,218**	**$ 48,051,519**	**$ 43,244,407**	**$ 34,082,024**	**$ 35,321,497**	**$ 36,643,696**	**$ 461,733,160**
30	Total Energy Market Administration Expenses	**Lines 22-24**	**600,319**	**555,409**	**566,187**	**518,795**	**560,918**	**588,829**	**657,129**	**647,775**	**565,234**	**539,795**	**551,512**	**583,804**	**6,935,707**
31	**Total Transmission and Energy Markets Administration Expenses**	**Lines 30 + 31**	**$ 35,726,881**	**$ 34,693,358**	**$ 33,614,533**	**$ 32,119,878**	**$ 36,787,988**	**$ 46,222,618**	**$ 49,272,346**	**$ 48,699,295**	**$ 43,809,641**	**$ 34,621,820**	**$ 35,873,010**	**$ 37,227,500**	**$ 468,668,867**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 Transmission and Energy Market Administration Expenses

Case No.: U-20525
Exhibit No.: A-1 (DSA-1)
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Witness: DSAlfred
Date: September 2019

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper DSA-1	5,334	5,072	5,026	4,763	5,583	6,870	7,230	6,876	6,515	4,982	5,228	5,345	**68,824**
2	Hours per Month	Day in Month * 24	744	672	744	720	744	720	744	744	720	744	720	744	**8,760**
3	Delivered MWhs	Workpaper DSA-3	3114294	2820620	2940044	2690866	2896973	3020474	3374131	3320468	2900657	2795895	2858955	3024730	**35,758,107**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	195.6703447	195.6703	195.6703	195.6703	195.6703	195.6703	195.6703	195.6703	195.6703	195.6703	195.6703	195.6703	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	4762.589514	4762.589514	4762.589514	4762.589514	4762.589514	4830.292653	4830.292653	4830.292653	4830.292653	4830.292653	4830.292653	4830.292653	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0731	0.0731	0.0731	0.0731	0.0731	0.0731	0.0731	0.0731	0.0731	0.0731	0.0731	0.0731	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.1033	0.1033	0.1033	0.1033	0.1033	0.1033	0.1033	0.1033	0.1033	0.1033	0.1033	0.1033	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	1012.179818	1,012.1798	1,012.1798	1,012.1798	1,012.1798	1,012.1798	1,012.1798	1,012.1798	1,012.1798	1,012.1798	1,012.1798	1,012.1798	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.690949084	1.6909	1.6909	1.6909	1.6909	1.6909	1.6909	1.6909	1.6909	1.6909	1.6909	1.6909	
15	Schedule 33 - Blackstart Service	Workpaper DSA-5a	4.323315897	4.3233	4.3233	4.3233	4.3233	4.3233	4.3233	4.3233	4.3233	4.3233	4.3233	4.3233	
	Expenses														
16	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 343,161	$ 326,298	$ 323,350	$ 306,447	$ 359,190	$ 441,975	$ 465,165	$ 442,380	$ 419,129	$ 320,492	$ 336,335	$ 343,852	**$ 4,427,774**
17	Schedule 2 - Reactive Support	Line 1 * Line 5	1,043,696	992,409	983,442	932,034	1,092,448	1,344,232	1,414,762	1,345,465	1,274,749	974,749	1,022,936	1,045,799	**13,466,720**
18	Schedule 9 - Network Transmission Service	Line 1 * Line 6	25,403,416	24,155,110	23,936,844	22,685,572	26,590,027	33,183,534	34,924,639	33,213,965	31,468,277	24,062,532	25,252,055	25,816,453	**330,692,423**
19	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	290,094	249,145	273,347	250,701	303,645	361,576	393,232	373,971	342,886	270,931	275,152	290,679	**3,675,358**
20	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	321,707	291,370	303,707	277,966	299,257	312,015	348,548	343,004	299,638	288,816	295,330	312,455	**3,693,812**
21	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	165,058	149,493	155,822	142,616	153,540	160,085	178,829	175,985	153,735	148,182	151,525	160,311	**1,895,180**
22	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	23,811	20,450	22,436	20,577	24,923	29,678	32,276	30,695	28,144	22,238	22,584	23,859	**301,671**
23	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	510,744	462,582	482,167	441,302	475,104	495,358	553,357	544,557	475,708	458,527	468,869	496,056	**5,864,330**
24	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	69,137	62,618	65,269	59,737	64,313	67,055	74,906	73,714	64,395	62,069	63,469	67,149	**793,830**
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,398,917	5,133,618	5,087,231	4,821,301	5,651,104	6,953,554	7,318,400	6,959,931	6,594,125	5,042,264	5,291,526	5,409,795	**69,661,766**
26	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	5,266,113	4,769,525	4,971,465	4,550,117	4,898,634	5,107,468	5,705,484	5,614,742	4,904,863	4,727,716	4,834,347	5,114,664	**60,465,138**
27	Schedule 33 - Blackstart Service	Line 1 * Line 15	23,060	21,927	21,729	20,593	24,138	29,701	31,259	29,728	28,165	21,537	22,602	23,107	**297,546**
28	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**
29	Total Transmission Expenses	**Lines 16-21 + 25-28**	**$ 38,257,221**	**$ 36,090,895**	**$ 36,058,936**	**$ 33,989,348**	**$ 39,373,982**	**$ 47,896,139**	**$ 50,782,318**	**$ 48,501,171**	**$ 45,487,567**	**$ 35,859,218**	**$ 37,483,808**	**$ 38,519,114**	**$ 488,299,718**
30	Total Energy Market Administration Expenses	**Lines 22-24**	**603,692**	**545,649**	**569,872**	**521,617**	**564,339**	**592,090**	**660,539**	**648,966**	**568,246**	**542,833**	**554,922**	**587,063**	**6,959,831**
31	**Total Transmission and Energy Markets Administration Expenses**	**Lines 30 + 31**	**$ 38,860,913**	**$ 36,636,545**	**$ 36,628,808**	**$ 34,510,964**	**$ 39,938,322**	**$ 48,488,230**	**$ 51,442,857**	**$ 49,150,138**	**$ 46,055,813**	**$ 36,402,052**	**$ 38,038,730**	**$ 39,106,178**	**$ 495,259,549**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2022 Transmission and Energy Market Administration Expenses

Case No.: U-20525
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Witness: DSAlfred
Date: September 2019

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper DSA-1	5,335	5,023	5,024	4,755	5,588	6,873	7,176	6,832	6,525	4,985	5,223	5,330	**68,669**
2	Hours per Month	Day in Month * 24	744	696	744	720	744	720	744	744	720	744	720	744	**8,784**
3	Delivered MWhs	Workpaper DSA-3	3108024	2814562	2934357	2685526	2891943	3015168	3367137	3314193	2895691	2791605	2854451	3012997	**35,685,654**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	197.7287347	197.7287	197.7287	197.7287	197.7287	197.7287	197.7287	197.7287	197.7287	197.7287	197.7287	197.7287	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	5117.323205	5117.323205	5117.323205	5117.323205	5117.323205	5148.698811	5148.698811	5148.698811	5148.698811	5148.698811	5148.698811	5148.698811	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0723	0.0723	0.0723	0.0723	0.0723	0.0723	0.0723	0.0723	0.0723	0.0723	0.0723	0.0723	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.1026	0.1026	0.1026	0.1026	0.1026	0.1026	0.1026	0.1026	0.1026	0.1026	0.1026	0.1026	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	1002.636702	1,002.6367	1,002.6367	1,002.6367	1,002.6367	1,002.6367	1,002.6367	1,002.6367	1,002.6367	1,002.6367	1,002.6367	1,002.6367	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.696828003	1.6968	1.6968	1.6968	1.6968	1.6968	1.6968	1.6968	1.6968	1.6968	1.6968	1.6968	
15	Schedule 33 - Blackstart Service	Workpaper DSA-5a	4.332175174	4.3322	4.3322	4.3322	4.3322	4.3322	4.3322	4.3322	4.3322	4.3322	4.3322	4.3322	
	Expenses														
16	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 343,220	$ 323,176	$ 323,199	$ 305,885	$ 359,533	$ 442,173	$ 461,677	$ 439,537	$ 419,768	$ 320,725	$ 336,020	$ 342,892	**$ 4,417,805**
17	Schedule 2 - Reactive Support	Line 1 * Line 5	1,054,857	993,255	993,326	940,112	1,104,993	1,358,982	1,418,923	1,350,881	1,290,121	985,720	1,032,728	1,053,849	**13,577,747**
18	Schedule 9 - Network Transmission Service	Line 1 * Line 6	27,300,247	25,705,955	25,707,795	24,330,590	28,597,795	35,386,810	36,947,636	35,175,859	33,593,727	25,667,370	26,891,407	27,441,385	**352,746,578**
19	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	286,969	252,778	270,230	247,503	300,608	357,779	386,012	367,501	339,650	268,161	271,886	286,695	**3,635,770**
20	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	318,883	288,774	301,065	275,535	296,713	309,356	345,468	340,036	297,098	286,419	292,867	309,133	**3,661,348**
21	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	164,725	149,172	155,521	142,333	153,273	159,804	178,458	175,652	153,472	147,955	151,286	159,689	**1,891,340**
22	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	19,846	17,481	18,688	17,116	20,789	24,743	26,695	25,415	23,489	18,545	18,803	19,827	**251,436**
23	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	503,500	455,959	475,366	435,055	468,495	488,457	545,476	536,899	469,102	452,240	462,421	488,106	**5,781,076**
24	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	68,998	62,483	65,143	59,619	64,201	66,937	74,750	73,575	64,284	61,974	63,369	66,889	**792,222**
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,348,935	5,036,566	5,036,926	4,767,090	5,603,164	6,891,084	7,195,033	6,850,004	6,541,906	4,998,359	5,236,723	5,343,824	**68,849,614**
26	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	5,273,782	4,775,828	4,979,099	4,556,876	4,907,130	5,116,221	5,713,452	5,623,615	4,913,490	4,736,874	4,843,512	5,112,538	**60,552,417**
27	Schedule 33 - Blackstart Service	Line 1 * Line 15	23,112	21,762	21,763	20,598	24,210	29,775	31,088	29,597	28,266	21,597	22,627	23,090	**297,484**
28	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**
29	Total Transmission Expenses	**Lines 16-21 + 25-28**	**$ 40,116,730**	**$ 37,549,265**	**$ 37,790,925**	**$ 35,588,522**	**$ 41,349,418**	**$ 50,053,985**	**$ 52,679,748**	**$ 50,354,684**	**$ 47,579,498**	**$ 37,435,179**	**$ 39,081,056**	**$ 40,075,094**	**$ 509,654,104**
30	Total Energy Market Administration Expenses	**Lines 22-24**	**592,344**	**535,923**	**559,197**	**511,790**	**553,485**	**580,137**	**646,922**	**635,889**	**556,875**	**532,759**	**544,593**	**574,821**	**6,824,734**
31	**Total Transmission and Energy Markets Administration Expenses**	**Lines 30 + 31**	**$ 40,709,074**	**$ 38,085,189**	**$ 38,350,121**	**$ 36,100,312**	**$ 41,902,903**	**$ 50,634,121**	**$ 53,326,670**	**$ 50,990,573**	**$ 48,136,373**	**$ 37,967,938**	**$ 39,625,648**	**$ 40,649,915**	**$ 516,478,838**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2023 Transmission and Energy Market Administration Expenses

Case No.: U-20525
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Witness: DSAlfred
Date: September 2019

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper DSA-1	5,331	5,009	5,028	4,757	5,585	6,879	7,127	6,775	6,530	4,984	5,223	5,342	**68,571**
2	Hours per Month	Day in Month * 24	744	672	744	720	744	720	744	744	720	744	720	744	**8,760**
3	Delivered MWhs	Workpaper DSA-3	3103520	2810653	2930410	2681135	2887774	3010675	3362348	3308214	2890661	2786904	2850238	3014845	**35,637,377**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	198.1339176	198.1339	198.1339	198.1339	198.1339	198.1339	198.1339	198.1339	198.1339	198.1339	198.1339	198.1339	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	5354.768362	5354.768362	5354.768362	5354.768362	5354.768362	5308.242713	5308.242713	5308.242713	5308.242713	5308.242713	5308.242713	5308.242713	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0728	0.0728	0.0728	0.0728	0.0728	0.0728	0.0728	0.0728	0.0728	0.0728	0.0728	0.0728	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.1039	0.1039	0.1039	0.1039	0.1039	0.1039	0.1039	0.1039	0.1039	0.1039	0.1039	0.1039	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	986.2648071	986.2648	986.2648	986.2648	986.2648	986.2648	986.2648	986.2648	986.2648	986.2648	986.2648	986.2648	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.69371579	1.6937	1.6937	1.6937	1.6937	1.6937	1.6937	1.6937	1.6937	1.6937	1.6937	1.6937	
15	Schedule 33 - Blackstart Service	Workpaper DSA-5a	4.329709204	4.3297	4.3297	4.3297	4.3297	4.3297	4.3297	4.3297	4.3297	4.3297	4.3297	4.3297	
	Expenses														
16	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 342,950	$ 322,262	$ 323,508	$ 306,044	$ 359,319	$ 442,545	$ 458,488	$ 435,882	$ 420,116	$ 320,669	$ 336,025	$ 343,706	**$ 4,411,515**
17	Schedule 2 - Reactive Support	Line 1 * Line 5	1,056,186	992,475	996,312	942,528	1,106,599	1,362,913	1,412,013	1,342,392	1,293,837	987,568	1,034,860	1,058,517	**13,586,199**
18	Schedule 9 - Network Transmission Service	Line 1 * Line 6	28,544,499	26,822,631	26,926,330	25,472,770	29,906,946	36,514,045	37,829,491	35,964,287	34,663,424	26,458,122	27,725,120	28,358,925	**365,186,590**
19	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	288,726	245,054	272,358	249,344	302,507	360,556	385,997	366,965	342,282	269,968	273,770	289,363	**3,646,893**
20	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	322,456	292,027	304,470	278,570	300,040	312,809	349,348	343,723	300,340	289,559	296,140	313,242	**3,702,723**
21	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	164,487	148,965	155,312	142,100	153,052	159,566	178,204	175,335	153,205	147,706	151,063	159,787	**1,888,781**
22	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	19,830	16,831	18,706	17,125	20,777	24,763	26,511	25,204	23,508	18,542	18,803	19,874	**250,473**
23	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	502,770	455,326	474,726	434,344	467,819	487,729	544,700	535,931	468,287	451,478	461,739	488,405	**5,773,255**
24	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	68,898	62,396	65,055	59,521	64,109	66,837	74,644	73,442	64,173	61,869	63,275	66,930	**791,150**
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,257,451	4,940,310	4,959,410	4,691,687	5,508,393	6,784,264	7,028,672	6,682,119	6,440,420	4,915,886	5,151,292	5,269,053	**67,628,957**
26	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	5,256,481	4,760,447	4,963,282	4,541,081	4,891,068	5,099,228	5,694,862	5,603,174	4,895,958	4,720,223	4,827,493	5,106,291	**60,359,588**
27	Schedule 33 - Blackstart Service	Line 1 * Line 15	23,080	21,688	21,772	20,597	24,182	29,783	30,856	29,335	28,273	21,581	22,614	23,131	**296,892**
28	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**
29	Total Transmission Expenses	**Lines 16-21 + 25-28**	**$ 41,258,316**	**$ 38,547,858**	**$ 38,924,753**	**$ 36,646,720**	**$ 42,554,106**	**$ 51,067,709**	**$ 53,369,932**	**$ 50,945,215**	**$ 48,539,856**	**$ 38,133,282**	**$ 39,820,377**	**$40,924,015**	**$ 520,732,138**
30	Total Energy Market Administration Expenses	**Lines 22-24**	**591,498**	**534,553**	**558,487**	**510,990**	**552,705**	**579,330**	**645,855**	**634,577**	**555,968**	**531,889**	**543,817**	**575,208**	**6,814,878**
31	**Total Transmission and Energy Markets Administration Expenses**	**Lines 30 + 31**	**$ 41,849,814**	**$ 39,082,411**	**$ 39,483,241**	**$ 37,157,711**	**$ 43,106,811**	**$ 51,647,039**	**$ 54,015,787**	**$ 51,579,791**	**$ 49,095,824**	**$ 38,665,172**	**$ 40,364,194**	**$41,499,223**	**$ 527,547,016**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2024 Transmission and Energy Market Administration Expenses

Case No.: U-20525
Exhibit No.: A-1 (DSA-1)
Page: 5 of 5
Witness: DSAlfred
Date: September 2019

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper DSA-1	5,382	5,171	5,014	4,805	5,429	6,855	7,073	6,645	6,513	4,962	5,122	5,456	**68,427**
2	Hours per Month	Day in Month * 24	744	672	744	720	744	720	744	744	720	744	720	744	**8,760**
3	Delivered MWhs	Workpaper DSA-3	3079096	2856559	2908214	2660857	2786240	2988351	3339359	3246357	2869813	2821116	2819795	3073935	**35,449,692**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	$ 64.3352	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	198.0211354	198.0211	198.0211	198.0211	198.0211	198.0211	198.0211	198.0211	198.0211	198.0211	198.0211	198.0211	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	5527.468495	5527.468495	5527.468495	5527.468495	5527.468495	5493.448141	5493.448141	5493.448141	5493.448141	5493.448141	5493.448141	5493.448141	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0728	0.0728	0.0728	0.0728	0.0728	0.0728	0.0728	0.0728	0.0728	0.0728	0.0728	0.0728	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.1039	0.1039	0.1039	0.1039	0.1039	0.1039	0.1039	0.1039	0.1039	0.1039	0.1039	0.1039	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	0.0530	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	0.0810	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	974.8525	974.8525	974.8525	974.8525	974.8525	974.8525	974.8525	974.8525	974.8525	974.8525	974.8525	974.8525	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.7682	1.7682	1.7682	1.7682	1.7682	1.7682	1.7682	1.7682	1.7682	1.7682	1.7682	1.7682	
15	Schedule 33 - Blackstart Service	Workpaper DSA-5a	4.3493	4.3493	4.3493	4.3493	4.3493	4.3493	4.3493	4.3493	4.3493	4.3493	4.3493	4.3493	
	Expenses														
16	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 346,267	$ 332,666	$ 322,556	$ 309,099	$ 349,292	$ 441,013	$ 455,022	$ 427,511	$ 419,034	$ 319,233	$ 329,526	$ 351,023	**$ 4,402,240**
17	Schedule 2 - Reactive Support	Line 1 * Line 5	1,065,795	1,023,932	992,814	951,394	1,075,106	1,357,421	1,400,538	1,315,861	1,289,769	982,586	1,014,267	1,080,435	**13,549,917**
18	Schedule 9 - Network Transmission Service	Line 1 * Line 6	29,750,089	28,581,560	27,712,947	26,556,752	30,010,002	37,657,214	38,853,351	36,504,260	35,780,409	27,258,627	28,137,507	29,973,125	**376,775,840**
19	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	291,519	252,965	271,557	251,833	294,065	359,308	383,078	359,917	341,400	268,759	268,475	295,523	**3,638,401**
20	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	319,918	296,796	302,163	276,463	289,490	310,490	346,959	337,296	298,174	293,114	292,977	319,382	**3,683,223**
21	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	163,192	151,398	154,135	141,025	147,671	158,383	176,986	172,057	152,100	149,519	149,449	162,919	**1,878,834**
22	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	20,022	17,374	18,651	17,296	20,197	24,678	26,310	24,720	23,448	18,459	18,439	20,297	**249,890**
23	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	498,814	462,763	471,131	431,059	451,371	484,113	540,976	525,910	464,910	457,021	456,807	497,977	**5,742,850**
24	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	68,356	63,416	64,562	59,071	61,855	66,341	74,134	72,069	63,710	62,629	62,599	68,241	**786,983**
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,246,877	5,040,790	4,887,597	4,683,684	5,292,717	6,682,548	6,894,811	6,477,948	6,349,495	4,837,243	4,993,206	5,318,950	**66,705,865**
26	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	5,444,383	5,050,898	5,142,234	4,704,863	4,926,562	5,283,930	5,904,574	5,740,130	5,074,334	4,988,229	4,985,893	5,435,257	**62,681,287**
27	Schedule 33 - Blackstart Service	Line 1 * Line 15	23,409	22,489	21,806	20,896	23,613	29,814	30,761	28,901	28,328	21,581	22,277	23,730	**297,607**
28	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**
29	Total Transmission Expenses	**Lines 16-21 + 25-28**	**$ 42,653,448**	**$ 40,755,494**	**$ 39,809,809**	**$ 37,898,010**	**$ 42,410,518**	**$ 52,282,121**	**$ 54,448,080**	**$ 51,365,881**	**$ 49,735,043**	**$ 39,120,891**	**$ 40,195,577**	**$ 42,962,344**	**$ 533,637,215**
30	Total Energy Market Administration Expenses	**Lines 22-24**	**587,191**	**543,552**	**554,344**	**507,426**	**533,422**	**575,132**	**641,420**	**622,699**	**552,067**	**538,108**	**537,845**	**586,516**	**6,779,723**
31	**Total Transmission and Energy Markets Administration Expenses**	**Lines 30 + 31**	**$ 43,240,639**	**$ 41,299,046**	**$ 40,364,153**	**$ 38,405,436**	**$ 42,943,941**	**$ 52,857,253**	**$ 55,089,501**	**$ 51,988,580**	**$ 50,287,110**	**$ 39,658,999**	**$ 40,733,422**	**$ 43,548,859**	**$ 540,416,938**

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 to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

DIRECT TESTIMONY

OF

EUGÈNE M.J.A. BREURING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

Q. Please state your name and business address.

A. My name is Eugène M.J.A. Breuring, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Rate Analyst II in the Planning, Budgeting and Analysis Department.

Q. Please describe your qualifications.

A. In 1992, I graduated from Grand Valley State University with a Bachelor of Business Administration in accounting. In 1996, I graduated from Thunderbird School of Global Management with a Master of Business Administration in international management. I have also attended trade-specific conferences and seminars related to Michigan and United States economies, Michigan economic forecasts, as well as regression modeling.

Prior to joining Consumers Energy in 2013, I worked at the Kellogg Company, Tecumseh Products Company, and Stryker Corporation, mostly in a financial planning, budgeting, and forecasting capacity. In January of 2013, I accepted the position of Senior Rate Analyst II, which is my current position at Consumers Energy. In this capacity, I am responsible for preparing the Company's official electric and natural gas sales and customer forecasts, sponsoring the sales and customer forecast testimony and exhibits, conducting industry research, and conducting various economic studies. I am also responsible for creating the Company's revenue forecast related to the gas and electric business.

Q. Have you sponsored testimony in any previous cases before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I have presented the Company's electric sales and revenues forecasts in the following Commission cases:

Case No. U-17771	2016 – 2017 Energy Optimization Plan and 2017 Amended Energy Waste Reduction ("EWR") Plan;
Case No. U-17990	2016 General Electric Rate Case;
Case No. U-18142	2017 Power Supply Cost Recovery ("PSCR") Plan;
Case No. U-18231	2017 Biennial Renewable Energy Plan;
Case No. U-18261	2018-2021 EWR Plan;
Case No. U-18322	2017 General Electric Rate Case;
Case No. U-18402	2018 PSCR Plan;
Case No. U-20134	2018 General Electric Rate Case; and
Case No. U-20165	2018 Integrated Resouce Plan ("IRP").

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

A. The purpose of my direct testimony is to present the Company's electric deliveries, generation requirements, and peak demand forecasts for the years 2020 to 2024, in support of the Company's 2020 PSCR Plan.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am providing the following exhibits:

Exhibit A-2 (EMB-1)	2020 Forecast of Calendar Total Electric Deliveries;
Exhibit A-3 (EMB-2)	Forecast of Annual Calendar Deliveries;
Exhibit A-4 (EMB-3)	Forecast of Total Monthly Generation Requirements;

Exhibit A-5 (EMB-4)	Forecast of Total Monthly Peak Demand; and
Exhibit A-6 (EMB-5)	Forecasted System Load Factor Based on Summer Peak Demand.

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

A. Yes.

SECTION I. KEY ELECTRIC DELIVERY AND DEMAND VARIABLES

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

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

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

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

Q. What are econometrics or econometric techniques?

A. These are quantitative economic statistical techniques or tools that model the economy using mathematical and statistical relationships. A basic tool for econometrics is the regression model, as will be discussed below.

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

A. The Company uses economic indicators to capture the growth expectations related to increased or decreased economic activity in its service territory. Primarily, this includes employment and industrial production forecasts provided by IHS Markit, a leading publishing company that provides industry-specific data and analysis.

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

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

SECTION II. FORECASTING METHODOLOGY

Q. What is forecasting?

A. Forecasting is predicting the future values of data. For purposes of this direct testimony, the Company will forecast electric deliveries and peak demand for the Company's electric service territory.

Q. Are there different types of analyses used in preparing forecasts?

A. Yes.

Q. What type of analysis was utilized for forecasting electric deliveries and peak demand for the Company's electric service territory?

A. Statistical modeling, or a regression analysis to forecast electric deliveries and peak demand for the Company's electric service territory was used.

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

A. The electric deliveries and peak demand forecasts are prepared using a combination of econometric and end-use techniques.

Q. What process is involved in developing the electric deliveries forecast?

A. Typically, a six-step process is used in developing the electric deliveries forecast. The first step in the process is gathering the class-level historical monthly electric delivery, monthly customer counts, monthly number of billing days, monthly binaries to account

for temporal cycles, and daily temperature information. Most observations are entered directly into the modeling framework as dependent and explanatory variables. The daily temperature information, however, is transformed to monthly HDD and CDD variables prior to entering the modeling framework. The second step is importing the economic and demographic variables from IHS Markit into the sales modeling framework. The third step is importing electric-use forecasts for wholesale, electric vehicles, polycrystalline production, and energy savings from the Company's EWR programs. These forecasts are exogenous to the modeling framework and were either adopted by the Commission in prior electric rate cases, or reflect current industry expectations, or are based on end-use analyses. The fourth step is reviewing the imported observations to identify data issues before running the econometric models. In situations when erroneous data is observed, it is either corrected where possible or removed from the models. The fifth step is executing the regression functions and reviewing the corresponding statistical metrics. The final step in the sales forecasting process is to combine the regression forecasts with the external forecasts imported in step three.

Q. What is the process involved in developing the electric peak demand forecast?

A. The peak demand forecast process is similar to that of the electric delivery forecast. The first step in the peak demand forecast is importing the Company's monthly system peak demands, corresponding minimum and maximum daily temperature, forecasted base electric deliveries, seasonal binaries, and number of customers into the demand modeling framework. A weighted sum of the minimum and maximum temperatures is used to develop the peak CDD and HDD variables prior to importing into the model framework. The second step is reviewing the imported observations to identify data issues before

executing the peak demand econometric model. The third step is regressing the observed peak demands against the seasonal binary, degree day, and forecasted base electric sales. The final step in the peak demand forecasting process is combining the results of the econometric model with the planned peak reductions from the Company's direct control and Peak Time-of-Use ("TOU") programs.

Q. In utilizing the regression models, what evaluation process is followed to ensure that the models' results are satisfactory?

A. Regression modeling is used to develop the electric deliveries and customer count forecast models based on weather and economic variables. Each model is selected based on its ability to properly explain variation in historical data – i.e., how well it fits the data – along with the statistical significance of the model coefficients. Particularly, regression model performance is evaluated based on the adjusted coefficient of multiple determination ("R_a^2") and Mean Absolute Percent Error ("MAPE").

Q. Please explain the use of R_a^2 and MAPE.

A. Both of these statistical tests are used to evaluate how well the models fit the historical data, and also provide a good indication of how well the models will perform in the forecast period. The R_a^2 measures the ability of the models to explain variations in the historical data. An R_a^2 of unity suggests that a model explains all of the variations in the data whereas an R_a^2 of zero suggests it explains none of the variations. For example, if regression models have R_a^2 values above 0.9, this suggests that at least 90% of the variation in the data is explained by the models. In most cases, the models used in the Company's forecasting process have values between 0.90 and 0.97. In addition, to gauge overall model performance, the MAPE values are considered. Essentially, the MAPE is

used to measure the model errors in which smaller values suggest better model performance. MAPE values of less than 3% are generally considered ideal, although higher values may also be deemed acceptable based on other considerations, such as the R_a^2. The regression models used in the Company's forecasting process generally have MAPE values between 0.2% and 2.1%.

Q. Please explain the criteria used when considering the t-statistics and p-values associated with the model coefficients.

A. Regression analysis is used to develop models that minimize the variance between the actual data and estimates from the models based on the relationship between dependent and independent variables. A numerical coefficient ("β") is estimated for each independent variable in the model and represents the best linear unbiased estimate for that variable's contribution toward explaining the dependent variable. The t-statistics and p-values are used to gauge the relevance of each independent variable in the model. The t-statistic and p-values measure the statistical significance of including a particular independent variable based on a probability distribution. A t-statistic above two and p-value below 5% for a particular β suggests the independent variable is statistically significant and is appropriate to include in the regression model. Independent variables with t-statistics below two and p-values above 5% suggest the variable should be excluded from the model since it does little to explain the dependent variable. In addition, the direction (positive or negative coefficient sign) and magnitude of each coefficient are also considered when determining to include or exclude variables from the models. The models' independent variable t-statistics and p-values are within these ranges and are, therefore, considered relevant.

1 **SECTION III. HISTORICAL AND FORECASTED ELECTRIC DELIVERIES**

2 **Q. Please explain the Company's historical levels of electric deliveries for the five-year**
3 **period from 2013 to 2018.**

4 A. In the past five years, weather-normalized electric deliveries increased at a 0.3%
5 Compound Annual Growth Rate ("CAGR") from 2013 to 2018, with most of the
6 observed gain occurring in the industrial class (1.7% for the same period) as shown in
7 Figure 1.

Figure 1 - Historical Electric Cycle-Billed, Weather-Adjusted Deliveries by Class

8 **Q. What is the cause of the lack of growth in weather-normalized residential and**
9 **commercial deliveries from 2013 to 2018 in the Company's service territory?**

10 A. In large part, the retraction in the residential and commercial sectors is caused by a nearly
11 flat population growth in the electric service territory during this period, coupled with
12 increased energy efficiency efforts, starting in 2008.

Q. Was there a similar decrease in industrial deliveries in the Company's service territory from 2013 to 2018?

A. No. There was a pronounced decrease in industrial sales in 2013 and a subsequent bounce-back in 2014 to 2016.

Q. To what do you attribute the sudden decrease and rebound in industrial sales from 2013 to 2016?

A. Following the 2008 recession, industrial electric deliveries increased 5.2% per year from 2009 to 2012. However, the increase is not homogeneous across all sectors in the class. As shown in Figure 2, electric deliveries grew precipitously in polycrystalline manufacturing until 2012. The sudden decrease in 2013 is attributed to international trade restrictions imposed by East Asian countries. Since 2013, the polycrystalline production has picked up world-wide, as evidenced in Figure 2. While the polycrystalline industry was booming, the other industrial sectors exhibited only moderate growth in electric deliveries. Indeed, from the start of the recession in 2007 until 2016, electric deliveries in the other industrial sector decreased 0.8% per year while increasing 8.9% per year in the polycrystalline industry.

Figure 2 - Industrial Electric Sales - Consumers Energy

Q. What are the electric delivery expectations from 2020 to 2024?

A. Total electric deliveries are expected to decrease 0.2% per year from 2020 to 2024. The 2020 monthly class level results of the electric deliveries forecast process is shown in Exhibit A-2 (EMB-1). The annual class level results for 2020 to 2024 is shown in Exhibit A-3 (EMB-2).

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

A. Yes. EWR savings are projected to continue growing at around 1.5% through 2019. From 2020 to 2024, the Company is expected to grow EWR savings to 2.0%, as filed in the Company's IRP, Case No. U-20165.

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

A. Per the 2016 System Loss Study, the forecasted total electric deliveries are increased by a line loss factor of 7.35% to determine the Company's total bundled generation requirements shown in Exhibit A-4 (EMB-3).

Q. Is the 2016 System Loss Study the latest available?

A. The 2016 System Loss Study was the latest available at the time the forecast, used in these exhibits, was created.

SECTION IV. FORECASTED PEAK DEMAND

Q. What are the expectation for the growth in peak demand?

A. The Company uses regression analysis based on the predicted level of electric deliveries to forecast the peak demand. Weather-normal peak demand grew at a 1.6% CAGR from 2003 to 2007, but reversed much of this trend during the 2007 to 2009 recession.

Looking forward, peak demand is expected to decrease 0.9% per year from 2020 to 2024. The monthly system level results of the electric peak demand forecast process is shown in Exhibit A-5 (EMB-4).

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

A. The peak demand forecast is reduced by approximately 256 MW in 2020, and increasing to 453 MW by 2024, for the Company's direct control and peak TOU programs. These programs are being implemented as part of the Company's Smart Energy infrastructure investments in which customers are provided technology and information to better manage their impact on the Company's system.

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

A. The EWR program is projected to reduce peak demand 623 MW in 2020. The cumulative reductions produced by the EWR program are expected to be 861 MW by 2024.

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

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

Q. To what extent is the Company's Conservation Voltage Reduction ("CVR") program expected to impact peak demand?

A. The Company's CVR program is expected to reduce peak demand 24 MW in 2020. The cumulative reductions produced by the Company's CVR program are expected to be 72 MW by 2024.

Q. Please explain Exhibit A-6 (EMB-5).

A. Exhibit A-6 (EMB-5) provides a summary of the system load factor based on the Company's official 2020 to 2024 electric delivery and summer peak demand forecasts.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

EXHIBITS

OF

EUGÈNE M.J.A. BREURING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2020 Forecast of Calendar Total Electric Deliveries
(MWh)

Case No.: U-20525
Exhibit No.: A-2 (EMB-1)

Witness: EMBreuring
Date: September 2019

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	**Month**	**Residential**	**Commercial**	**Industrial**	**Street Lighting**	**Inter-departmental**	**Wholesale**	**Total**
1	January	1,296,906	1,060,036	837,278	14,454	2,311	30,113	3,241,097
2	February	1,006,498	998,347	948,683	11,887	3,393	25,089	2,993,897
3	March	999,725	1,057,824	964,561	11,927	2,979	28,721	3,065,736
4	April	849,580	971,511	966,822	9,848	2,630	32,106	2,832,497
5	May	818,029	1,059,416	1,111,207	8,923	2,967	31,168	3,031,711
6	June	1,052,759	1,132,234	941,211	7,878	2,867	30,983	3,167,933
7	July	1,365,242	1,203,573	882,414	8,552	2,848	33,170	3,495,799
8	August	1,173,615	1,159,615	1,096,912	9,299	3,126	33,500	3,476,066
9	September	958,493	1,071,768	972,458	10,840	2,932	32,101	3,048,592
10	October	861,128	1,073,382	972,727	12,669	3,188	28,735	2,951,829
11	November	919,163	969,776	1,041,308	14,096	1,076	29,818	2,975,237
12	December	1,159,364	1,099,466	824,596	15,175	5,105	31,144	3,134,850
13	Annual	12,460,502	12,856,947	11,560,176	135,548	35,424	366,648	37,415,244

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2020 Forecast of Calendar Full Service Electric Deliveries
(MWh)

Case No.: U-20525
Exhibit No.: A-2 (EMB-1)
Page: 2 of 3
Witness: EMBreuring
Date: September 2019

Line No.	Month	(a) Residential	(b) Commercial	(c) Industrial	(d) Street Lighting	(e) Inter-departmental	(f) Wholesale	(g) Total
1	January	1,296,906	976,075	606,663	14,454	2,311	30,113	2,926,522
2	February	1,006,498	922,199	742,145	11,887	3,393	25,089	2,711,211
3	March	999,725	976,301	738,485	11,927	2,979	28,721	2,758,137
4	April	849,580	889,487	742,751	9,848	2,630	32,106	2,526,402
5	May	818,029	971,511	883,566	8,923	2,967	31,168	2,716,164
6	June	1,052,759	1,043,369	697,061	7,878	2,867	30,983	2,834,917
7	July	1,365,242	1,114,455	646,013	8,552	2,848	33,170	3,170,280
8	August	1,173,615	1,068,060	835,521	9,299	3,126	33,500	3,123,121
9	September	958,493	985,262	736,853	10,840	2,932	32,101	2,726,481
10	October	861,128	985,662	733,389	12,669	3,188	28,735	2,624,772
11	November	919,163	895,701	823,278	14,096	1,076	29,818	2,683,133
12	December	1,159,364	1,020,026	609,315	15,175	5,105	31,144	2,840,129
13	Annual	12,460,502	11,848,109	8,795,039	135,548	35,424	366,648	33,641,270

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2020 Forecast of Calendar ROA Service Electric Deliveries
(MWh)

Case No.: U-20525
Exhibit No.: A-2 (EMB-1)

Witness: EMBreuring
Date: September 2019

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	**Month**	**Residential**	**Commercial**	**Industrial**	**Street Lighting**	**Inter-departmental**	**Wholesale**	**Total**
1	January	-	83,960	230,615	-	-	-	314,575
2	February	-	76,147	206,538	-	-	-	282,686
3	March	-	81,523	226,076	-	-	-	307,600
4	April	-	82,023	224,071	-	-	-	306,094
5	May	-	87,906	227,641	-	-	-	315,547
6	June	-	88,865	244,150	-	-	-	333,015
7	July	-	89,118	236,401	-	-	-	325,519
8	August	-	91,555	261,391	-	-	-	352,946
9	September	-	86,506	235,605	-	-	-	322,111
10	October	-	87,720	239,338	-	-	-	327,057
11	November	-	74,074	218,030	-	-	-	292,104
12	December	-	79,440	215,281	-	-	-	294,721
13	Annual	-	1,008,838	2,765,137	-	-	-	3,773,975

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Forecast of Annual Calendar Deliveries
(MWh)

Case No.: U-20525
Exhibit No.: A-3 (EMB-2)
Page: 1 of 1
Witness: EMBreuring
Date: September 2019

Line No.	Description	(a) 2020	(b) 2021	(c) 2022	(d) 2023	(e) 2024
1	Total Deliveries					
2	Residential	12,460,502	12,420,658	12,536,633	12,318,227	12,304,111
3	Commercial	12,856,947	12,649,448	12,465,174	12,514,258	12,018,880
4	Industrial	11,560,176	11,609,053	11,635,473	11,847,138	12,184,795
5	Street Lighting	135,548	135,548	135,548	135,548	135,548
6	Interdepartmental	35,424	35,309	35,292	35,297	35,399
7	Wholesale	366,648	368,089	369,811	371,416	371,280
8	Total Deliveries	37,415,244	37,218,105	37,177,930	37,221,884	37,050,012
9	Total Full Service					
10	Residential	12,460,502	12,420,658	12,536,633	12,318,227	12,304,111
11	Commercial	11,848,109	11,652,051	11,480,679	11,530,076	11,071,865
12	Industrial	8,795,039	8,839,051	8,853,032	9,002,013	9,320,127
13	Street Lighting	135,548	135,548	135,548	135,548	135,548
14	Interdepartmental	35,424	35,309	35,292	35,297	35,399
15	Wholesale	366,648	368,089	369,811	371,416	371,280
16	Total Full Service	33,641,270	33,450,706	33,410,995	33,392,578	33,238,329
17	Total ROA Service					
18	Residential	-	-	-	-	-
19	Commercial	1,008,838	997,397	984,494	984,182	947,015
20	Industrial	2,765,137	2,770,002	2,782,441	2,845,125	2,864,668
21	Street Lighting	-	-	-	-	-
22	Interdepartmental	-	-	-	-	-
23	Wholesale	-	-	-	-	-
24	Total ROA Service	3,773,975	3,767,399	3,766,935	3,829,306	3,811,683

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Forecast of Total Monthly Generation Requirements
(MWh)

Case No.: U-20525
Exhibit No.: A-4 (EMB-3)

Witness: EMBreuring
Date: September 2019

Line No.	Month	(a) 2020	(b) 2021	(c) 2022	(d) 2023	(e) 2024
1	January	3,469,234	3,454,213	3,447,851	3,449,454	3,424,873
2	February	3,205,660	3,123,674	3,118,001	3,119,531	3,165,231
3	March	3,284,121	3,270,276	3,264,601	3,266,438	3,243,602
4	April	3,033,308	3,020,429	3,015,077	3,016,637	2,995,472
5	May	3,249,716	3,236,396	3,230,940	3,232,713	3,210,736
6	June	3,393,823	3,379,196	3,373,157	3,375,014	3,350,925
7	July	3,741,975	3,724,791	3,716,913	3,718,356	3,689,333
8	August	3,722,242	3,702,174	3,693,700	3,692,780	3,668,924
9	September	3,262,759	3,248,542	3,242,455	3,243,843	3,220,644
10	October	3,162,500	3,148,942	3,143,378	3,145,158	3,122,807
11	November	3,187,696	3,174,246	3,168,704	3,170,425	3,148,273
12	December	3,357,567	3,343,003	3,337,019	3,338,924	3,314,915
13	Annual	40,070,601	39,825,883	39,751,796	39,769,272	39,555,734

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Forecast of Monthly Full Service Generation Requirements
(MWh)

Case No.: U-20525
Exhibit No.: A-4 (EMB-3)
Page: 2 of 3
Witness: EMBreuring
Date: September 2019

Line No.	Month	(a) 2020	(b) 2021	(c) 2022	(d) 2023	(e) 2024
1	January	3,129,703	3,114,314	3,108,022	3,103,531	3,079,097
2	February	2,900,549	2,820,638	2,814,561	2,810,664	2,856,559
3	March	2,952,120	2,940,059	2,934,356	2,930,420	2,908,213
4	April	2,702,931	2,690,880	2,685,525	2,681,145	2,660,857
5	May	2,909,137	2,896,988	2,891,943	2,887,784	2,867,189
6	June	3,034,390	3,020,490	3,015,166	3,010,685	2,988,351
7	July	3,390,633	3,374,150	3,367,137	3,362,359	3,335,323
8	August	3,341,296	3,321,789	3,314,575	3,306,908	3,285,540
9	September	2,915,095	2,900,676	2,895,690	2,890,672	2,869,813
10	October	2,809,497	2,795,911	2,791,604	2,786,914	2,767,150
11	November	2,872,419	2,858,970	2,854,450	2,850,248	2,830,589
12	December	3,039,466	3,024,747	3,012,997	3,014,855	2,992,985
13	Annual	35,997,234	35,759,613	35,686,026	35,636,184	35,441,667

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Forecast of Monthly ROA Generation Requirements
(MWh)

Case No.: U-20525
Exhibit No.: A-4 (EMB-3)
Page: 3 of 3
Witness: EMBreuring
Date: September 2019

Line No.	Month	(a) 2020	(b) 2021	(c) 2022	(d) 2023	(e) 2024
1	January	339,531	339,899	339,829	345,923	345,777
2	February	305,111	303,037	303,439	308,867	308,672
3	March	332,002	330,217	330,245	336,018	335,388
4	April	330,377	329,549	329,552	335,493	334,615
5	May	340,579	339,408	338,997	344,929	343,547
6	June	359,434	358,705	357,990	364,329	362,574
7	July	351,343	350,642	349,776	355,997	354,009
8	August	380,945	380,385	379,125	385,873	383,384
9	September	347,664	347,866	346,765	353,171	350,831
10	October	353,003	353,031	351,774	358,244	355,657
11	November	315,277	315,276	314,254	320,177	317,684
12	December	318,102	318,257	324,022	324,069	321,930
13	Annual	4,073,367	4,066,270	4,065,769	4,133,089	4,114,067

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Forecast of Total Monthly Peak Demand
(MW)

Case No.: U-20525
Exhibit No.: A-5 (EMB-4)

Witness: EMBreuring
Date: September 2019

Line No.	Month	(a) 2020	(b) 2021	(c) 2022	(d) 2023	(e) 2024
1	January	5,820	5,823	5,823	5,828	5,798
2	February	5,698	5,546	5,499	5,542	5,634
3	March	5,495	5,495	5,493	5,506	5,490
4	April	5,359	5,328	5,321	5,332	5,327
5	May	6,118	6,104	6,106	6,115	5,939
6	June	7,464	7,412	7,413	7,429	7,403
7	July	7,860	7,746	7,694	7,643	7,593
8	August	7,793	7,428	7,379	7,335	7,202
9	September	7,072	7,044	7,053	7,067	7,047
10	October	5,504	5,497	5,498	5,507	5,481
11	November	5,658	5,645	5,640	5,646	5,593
12	December	5,811	5,797	5,793	5,803	5,911
13	Peak Demand	7,860	7,746	7,694	7,643	7,593

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Forecast of Monthly Full Service Peak Demand
(MW)

Case No.: U-20525
Exhibit No.: A-5 (EMB-4)
Page: 2 of 3
Witness: EMBreuring
Date: September 2019

Line No.	Month	(a) 2020	(b) 2021	(c) 2022	(d) 2023	(e) 2024
1	January	5,338	5,334	5,335	5,331	5,382
2	February	5,240	5,072	5,023	5,009	5,171
3	March	5,019	5,026	5,024	5,028	5,014
4	April	4,842	4,763	4,755	4,757	4,805
5	May	5,613	5,583	5,588	5,585	5,429
6	June	6,920	6,870	6,873	6,879	6,855
7	July	7,319	7,230	7,176	7,127	7,073
8	August	7,238	6,876	6,832	6,775	6,645
9	September	6,545	6,515	6,525	6,530	6,513
10	October	4,992	4,982	4,985	4,984	4,962
11	November	5,188	5,228	5,223	5,223	5,122
12	December	5,362	5,345	5,330	5,342	5,456
13	Peak Demand	7,319	7,230	7,176	7,127	7,073

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Forecast of Monthly ROA Service Peak Demand
(MW)

Case No.: U-20525
Exhibit No.: A-5 (EMB-4)
Page: 3 of 3
Witness: EMBreuring
Date: September 2019

Line No.	Month	(a) 2020	(b) 2021	(c) 2022	(d) 2023	(e) 2024
1	January	482	489	488	497	416
2	February	458	474	475	533	464
3	March	476	469	469	478	477
4	April	518	565	567	575	523
5	May	505	521	517	530	510
6	June	544	542	540	551	548
7	July	541	515	517	517	520
8	August	555	552	547	560	557
9	September	527	529	529	537	533
10	October	512	515	513	523	519
11	November	470	417	417	423	471
12	December	450	453	463	461	455
13	Peak Demand	555	565	567	575	557

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Forecasted System Load Factor Based on Summer Peak Demand

Case No.: U-20525
Exhibit No.: A-6 (EMB-5)
Page: 1 of 1
Witness: EMBreuring
Date: September 2019

Line No.	Month	(a) 2020	(b) 2021	(c) 2022	(d) 2023	(e) 2024
1	Total Deliveries (GWh)	37,415	37,218	37,178	37,222	37,050
2	System Efficiency (%)	93.4%	93.5%	93.5%	93.6%	93.7%
3	Generation Requirements (GWh)	40,071	39,826	39,752	39,769	39,556
4	Summer Peak Demand (MW)	7,860	7,746	7,694	7,643	7,593
5	System Load Factor (%)	58.2%	58.7%	59.0%	59.4%	59.5%

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 to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

DIRECT TESTIMONY

OF

JOSHUA W. HAHN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

Q. Please state your name and business address.

A. My name is Joshua W. Hahn, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

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

Q. In what capacity are you employed?

A. I am a Senior Engineer in the Electric Supply Operations and Power Supply Cost Recovery Section of the Electric Grid Integration Department.

QUALIFICATIONS

Q. Please briefly describe your educational background.

A. I received a Bachelor of Science in mechanical engineering in 2008 from Michigan Technological University.

Q. Please describe your business and professional experience.

A. I joined the Company's Transactions and Resource Planning Department in January 2010. I was responsible for analysis of Financial Transmission Rights ("FTRs") and acquisition of FTRs through monthly and annual allocations and auctions, as well as maintaining the Company's short-term Load and Market Price models using MetrixIDR™. In June 2012, I assumed primary responsibilities for the maintenance of the PROMOD IV Full Transmission production cost model. From January to September 2013, I assumed temporary responsibility for maintenance of the PROMOD IV production cost model and all analyses developed using the tool, including all fuel and purchased and net interchange forecasting. Later, in June 2015, I was again assigned

responsibility to maintain the model and perform all analyses developed using PROMOD IV. In January 2016, I permanently assumed responsibilities as the primary PROMOD IV modeler for near-term fuel and purchased power expenses.

Q. What are your present responsibilities and duties as a Senior Engineer?

A. I am responsible for modeling and analysis of fuel and purchased and net interchange power costs that are used in developing the Power Supply Cost Recovery ("PSCR") Plan and updating the PSCR factor. Additionally, I am responsible for generation unit outage analyses.

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

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

Case No. U-17918-R	2016 PSCR Reconciliation;
Case No. U-18402	2018 PSCR Plan;
Case No. U-20068	2017 PSCR Reconciliation;
Case No. U-20219	2019 PSCR Plan; and
Case No. U-20202	2018 PSCR Reconciliation.

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

A. The purpose of my direct testimony is to forecast costs of fuel and purchased and net interchange power needed to fulfill the Company's system requirements for 2020 in support of the Company's 2020 PSCR Plan.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring:

Exhibit A-7 (JWH-1)	Monthly Summary for 2020 of Fuel and Purchased and Net Interchange Power Expenses;
Exhibit A-8 (JWH-2)	Annual Summary for Years 2020 through 2024 of Fuel and Purchased and Net Interchange Power Expenses; and
Exhibit A-9 (JWH-3)	Purchased Power Agreements – Projected 2020 Rates.

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

A. Yes, they were.

POWER SUPPLY COSTS

Q. What are the Company's forecasts of 2020 costs of fuel and purchased and net interchange power?

A. These forecasts are shown in Exhibit A-7 (JWH-1), pages 1 through 3.

Q. Do you consider the forecast data set forth in Exhibit A-7 (JWH-1) to be a reasonable forecast for 2020?

A. Yes. This plan was developed using an economic dispatch computer program which is used to produce the Company's budget and operating forecasts for fuel and purchased and net interchange power. This 2020 forecast was produced using up-to-date assumptions and data that were reviewed by the responsible departments before they were input to the program. The results have been reviewed for reasonableness and for consistency with input and assumptions.

Q. Did you use the same economic dispatch program for this case as was used for the Company's 2019 PSCR Plan case, Case No. U-20219?

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

Q. Have there been any major changes to the PROMOD IV model used to develop the fuel and purchased and net interchange power and expenses shown in Exhibits A-7 (JWH-1) and A-8 (JWH-2)?

A. No.

Q. Please further describe Exhibit A-7 (JWH-1).

A. This exhibit details the Company's planned sources and corresponding costs of energy to be supplied in 2020. Total system requirements (expressed in units of MWh) are shown on page 1, line 13; the corresponding annual non-capacity-related expenses, including fuel and variable purchased and net interchange PSCR expense (expressed in units of thousands of dollars) are shown on page 1, line 26. Exhibit A-7 (JWH-1), page 1, lines 27 through 32, present the fixed and capacity-related costs included in PSCR expense. Additional information about Exhibit A-7 (JWH-1), page 1, lines 27 through 32, is provided in more detail below.

Exhibit A-7 (JWH-1), pages 2 and 3, summarize the Purchased and Interchange ("P&I") power quantity and expense projected to be incurred by the Company in 2020. These pages detail the expenses associated with purchases from (i) Non-Utility Generators ("NUGs") and (ii) utilities and markets shown in the "Purchased (NUGs)" and "Net Interchange" categories shown on Exhibit A-7 (JWH-1), page 1.

Q. Explain how PSCR costs were allocated between capacity-related and non-capacity-related costs.

A. Certain expenses represent the cost of capacity in the form of Zonal Resource Credits purchased through bi-lateral agreements. The actual price paid is allocated to each month for which the purchase applies. These expenses are shown on Exhibit A-7 (JWH-1), page 1, line 27.

For most Company-owned resources, there is no capacity-related cost included in PSCR expense. The exception to this generalization is presented on Exhibit A-7 (JWH-1), page 1, line 28, where the capacity component of the Transfer Price associated with the Company's owned renewable resources for which recovery is sought under Public Act 295 of 2008 to its PSCR costs is provided, complementing the energy (or non-capacity-related) component of the Transfer Price presented on Exhibit A-7 (JWH-1), page 1, line 18.

Exhibit A-7 (JWH-1), page 1, line 29, provides the capacity-related payments associated with the Palisades Nuclear Power Plant ("Palisades") Power Purchase Agreement ("PPA"), as identified in the contract for energy and capacity. The projected energy delivered and non-capacity-related expenses for the Palisades PPA are shown on Exhibit A-7 (JWH-1), page 1, lines 3 and 16, respectively.

PPAs include both capacity-related and non-capacity-related costs. Some PPAs define payments as "capacity" payments, "fixed energy" payments, and "variable energy" payments. Capacity payments and fixed energy payments are generally regarded as fixed costs because they are expected to be incurred regardless of the amount of energy delivered by the supplier. Non-capacity or variable energy payments generally reflect the

cost of fuel and variable labor and, thus, vary depending on the amount of energy delivered.

Other PPAs provide for a single price to be paid for each unit of energy to be delivered based on a capacity price and a combined fixed and variable energy price. Generally, these types of contracts are not dispatchable by the Company and, thus, the amount to be paid is likely limited by the physical capability of the supplying facility. In these instances, we have estimated the fixed energy costs based on the rates upon which the contracts were originally modeled.

Other PPAs are included in the Company's rates based on the amount of cost allowed under state law to be transferred from the Company's Incremental Cost of Compliance with Public Act 295 of 2008 to its PSCR costs. To estimate the amount of capacity, fixed energy, and variable energy expense associated with these transfer expenses, we used the energy and capacity schedules approved by the Commission that resulted in the transfer expenses.

Non-capacity or variable cost-related expense for the Company's PPAs (excluding the Palisades PPA) is shown on Exhibit A-7 (JWH-1), page 1, line 24. Capacity or fixed cost-related expense for the Company's PPAs (excluding the Palisades PPA) is shown on Exhibit A-7 (JWH-1), page 1, lines 30 and 31.

Q. How were these figures derived?

A. They were derived from PROMOD IV, which simulates the dispatch of the Company's generating resources and purchased and interchange power resources to meet projected customer electric demand requirements. Exhibit A-7 (JWH-1), pages 1 through 3, show the monthly results for 2020, which were then totaled to obtain the annual results that are

also shown on Exhibit A-8 (JWH-2), along with the years 2021 through 2024. The main inputs to PROMOD IV were projected system loads, unit heat rates, maintenance schedules, unit random outage rates, fuel costs, unit net demonstrated capabilities, and P&I power availability and costs. The model used by PROMOD IV is structured to align as closely as possible with the way that the Midcontinent Independent System Operator, Inc. ("MISO") operates and administers the Midwest Energy Market.

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

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

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

A. Coal, oil, and natural gas costs were provided by Company witness Kevin C. Lott. His direct testimony and exhibits set forth and explain the relevant assumptions and calculations.

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

A. That information was provided by Company witness Norman J. Kapala. His direct testimony and exhibits set forth and explain the relevant assumptions and calculations.

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

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

A. Yes. Included in this PSCR Plan case is an upgrade to Ludington Pumped Storage Plant ("Ludington") Unit 3 resulting in an increase in generating capacity of 37 MW

(Consumers Energy share) assumed to be in-service beginning May 2020. This upgrade is part of the major unit overhaul project at Ludington which began in 2013. As part of that project, upgrades to Ludington Units 1, 2, 4, 5, and 6 have already been completed resulting in an increase in generating capacity of 37 MW for each upgraded unit.

Three wind facilities are included as part of the Company's Renewable Energy Plan. All three of these facilities have a Commercial Operations Date ("COD") of January 1, 2021. The first facility is a 150 MW facility, the second is a 166 MW facility, and the final is a 234 MW facility.

The retirement date of the coal fired generating units at D.E. Karn, Units 1 and 2, has been changed from May 31, 2031 to May 31, 2023 to align with the Company's 2018 Integrated Resource Plan ("IRP") approved in Case No. U-20165.

Three additional solar blocks are included, modeled as three units. These units reflect the additions of solar generation consistent with the Company's approved Proposed Course of Action ("PCA") from its IRP approved in June of 2019. The solar generation additions from the PCA are assumed to be 50% Company owned and 50% PPAs. The PCA called for a 300 MW block with a COD of June 1, 2022, a 300 MW block with a COD of June 1, 2023, and a 500 MW block with a COD of June 1, 2024. To reflect the assumption that only 50% of the additions are Company owned, a 150 MW block with a COD of June 1, 2022, a 150 MW block with a COD of June 1, 2023, and a 250 MW block with a COD of June 1, 2024 have been added as Company-owned resources in the model.

Q. Please describe any limiting factors that could restrict the economic dispatch of the Jackson natural gas-fueled combined cycle plant.

A. Based on the Company's current operation of the unit in compliance with the state air permit,[1] the 7EA combustion turbine cannot exceed 113.1 tons of Nitrogen Oxide ("NO_x") emissions in a rolling 12-month period and each LM6000 combustion turbine cannot exceed 95 tons of NO_x emissions in a rolling 12-month period.[2] The 95 tons of NO_x emissions limit comes into effect beginning after the spring 2020 Jackson Plant stack extension outage. Before this outage the limit was 80.4 tons of NO_x emissions.

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

A. Economic dispatch of the Jackson Plant has been limited using a price adder on the incremental cost of energy when necessary to comply with the state air permit. For modeling purposes, a price per pound of NO_x emissions was applied as a dispatch fee (when necessary) so that the facility does not exceed the state air permit limit of 683 tons of NO_X emissions in each calendar year.

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

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

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

Q. On Exhibit A-7 (JWH-1), page 1, line 4, you use the term "Station Power." Please explain that term.

A. Station Power is the amount of electricity that a generating unit uses to operate its own generating unit components such as motors, pumps, lighting, heating, etc. When a generating unit is operating, all of the Station Power is subtracted from the gross output of the generating unit to provide the net output that is reported on Exhibit A-7 (JWH-1), page 1, lines 1 and 2. When a generating unit is offline, Station Power usage is accounted for as negative generation. Exhibit A-7 (JWH-1), page 1, lines 1 and 2, reflects the steam generation after subtracting the forecasted Station Power used during periods where units are offline. The total system requirement on Exhibit A-7 (JWH-1), page 1, line 13, includes Station Power used while offline, so I show a separate line item, line 4, to balance the exhibit.

PPAs

Q. On Exhibit A-7 (JWH-1), page 1, line 11, you use the term "Purchased (NUGs)." Please explain that term.

A. That term refers to forecasted purchases of energy from NUGs with whom the Company has PPAs. A list of the entities from which power is projected to be purchased for the years 2020 through 2024 is found on Exhibit A-9 (JWH-3), pages 1 through 11, under the headings "Existing Energy-Only Agreements," "Green Generation Program Agreements," "Existing Energy & Capacity Agreements," and "Renewable Energy Plan Agreements." This exhibit also outlines the rates for such purchases and the current duration of the contracts.

Q. How were purchases from the suppliers listed on Exhibit A-9 (JWH-3) estimated?

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

(1) For non-dispatchable suppliers, we have a history of deliveries, so the historical monthly average was used; and

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

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

A. Yes. The Company has incorporated two placeholder units into the model to estimate the energy and capacity expenses associated with any contract in which the contract termination date falls within the planning period but said contract would qualify for a new contract, as provided for in Case Nos. U-18090 and U-20165 as discussed by Company witness Keith G. Troyer.

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

A. Yes. A total of 584 MW of Public Utility Regulatory Policies Act of 1978 ("PURPA") solar units were added. The Commission's September 11, 2019 Order in Case No. U-20615 approved the Company's settlement agreement for 584 MW of additional PURPA contracts with Qualified Facilities as described by Company witness Troyer. The Company has modeled 170 MW to be available as of June 1, 2020, 150 MW to be available as of June 1, 2021, 150 MW to be available as of June 1, 2022 and 114 MW to be available as of June 1, 2023. A 100 MW solar Renewable Energy Plan unit has also been added with a COD of January 1, 2021.

Three additional solar blocks are included modeled as three units. These units reflect the additions of solar generation consistent with the Company's approved PCA from its IRP. The solar generation additions from the PCA are assumed to be 50% Company owned and 50% PPAs. The PCA called for a 300 MW block with a COD of June 1, 2022, a 300 MW block with a COD of June 1, 2023, and a 500 MW block with a COD of June 1, 2024. To reflect the assumption that only 50% of the additions are PPAs, a 150 MW block with a COD of June 1, 2022, a 150 MW block with a COD of June 1, 2023, and a 250 MW block with a COD of June 1, 2024 have been added as PPA resources in the model.

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

A. Yes, the Renewable Resource Program (or Green Generation Program) approved by the Commission in its January 25, 2005 Order in Case No. U-14843 is modeled in this case. The suppliers are comprised of wind and landfill gas units and are shown on Exhibit A-9 (JWH-3), listed under the category of Green Generation Program Agreements. The energy charge for all of the Green Generation Program contracts that is recoverable in the PSCR is the average PSCR rate for the year.

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

A. No, the MCV facility is dispatched and its energy is priced according to the terms in the Settlement Agreement that was approved by the Commission in its June 10, 2008 Order in Case No. U-15320.

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

A. Yes. As in last year's PSCR Plan, Case No. U-20219, the Cadillac, Genesee, and Grayling wood-fueled units are dispatched on the cost of production based on a wood price, instead of the 12-month rolling-average coal price that is the contract-dispatch price for these units. The Reduced Dispatch Agreements ("RDAs") for the wood-fired units were most recently included as Exhibit A-38 (DFR-12) in Case No. U-15001-R. The Ada RDA is priced based on an annual fixed price of natural gas, as approved in Case No. U-16045. The projected hold-harmless amount resulting from this dispatch is $1,006,000 and the projected customer benefit (offset to PSCR) is $990,000. These amounts are included as credits on Exhibit A-7 (JWH-1) and Exhibit A-8 (JWH-2), page 1, line 24, and page 3, line 46.

Q. Please explain Exhibit A-7 (JWH-1), page 3, line 46.

A. Exhibit A-7 (JWH-1), line 46, represents the projected payments to the Biomass Merchant Plants in excess of the Company's avoided cost as required under Public Act 286 of 2008 and the Commission's August 11, 2009 Order in Case No. U-16048.

NET INTERCHANGE POWER

Q. On Exhibit A-7 (JWH-1), page 1, line 12, you use the term "Net Interchange." Please explain this.

A. This term refers to purchases from, and sales to, other entities for energy and capacity. The details are shown on Exhibit A-7 (JWH-1) and also on Exhibit A-8 (JWH-2), pages 2 and 3. Exhibit A-7 (JWH-1), page 2, lines 35 and 36, detail the energy received and Exhibit A-7 (JWH-1), page 2, lines 39 through 41, detail the energy delivered.

Exhibit A-7 (JWH-1), page 3, lines 43 and 44, detail the costs for energy received and page 3, lines 48 through 51, detail the revenues for energy delivered.

Q. Please explain Exhibit A-7 (JWH-1), page 2, line 40, and page 3, line 50.

A. Page 2, line 40, and page 3, line 50, represent a sale to the Midwest Energy Market from the Company-owned oil and gas units. This is an estimate of the sale associated with the MISO Reliability Assessment Commitment process. MISO must ensure that sufficient resources are available and online to meet the forecasted MISO load for each hour of the next operating day. The Company estimated the amount of increased generation at the oil and gas units that MISO uses for this purpose on Exhibit A-7 (JWH-1), page 2, line 40, and has represented it as a sale. The Company will be reimbursed in full for this use of its units and, therefore, this increased generation cost is fully offset by the revenue shown on Exhibit A-7 (JWH-1), page 2, line 50, and, as a result, does not affect the PSCR factor.

Q. Please explain Exhibit A-7 (JWH-1), page 3, line 49.

A. Exhibit A-7 (JWH-1), page 3, line 49, represents revenue from the sale of capacity, although no sale of capacity is projected in this case.

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

A. No.

Q. Does this conclude 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 to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

EXHIBITS

OF

JOSHUA W. HAHN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20525
Exhibit No.: A-7 (JWH-1)
Page: 1 of 3
Witness: JWHahn
Date: September 2019

Monthly Summary for 2020 of Fuel and Purchased and Net Interchange Power Expenses

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		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2020
						S U M M A R Y B Y S O U R C E								
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	ENERGY (MWH)													
1	COAL STEAM	1,069,077	885,933	898,438	838,323	846,140	984,403	1,014,513	1,022,968	944,450	545,163	746,195	1,058,470	10,854,074
2	GAS & OIL	566,673	502,020	386,810	436,431	178,647	509,533	633,337	494,415	481,247	443,656	534,141	530,303	5,697,213
3	NUCLEAR PPA	602,325	560,570	591,765	566,616	580,989	548,400	562,836	561,285	555,552	586,749	573,311	600,621	6,891,019
4	STATION POWER	7,443	7,651	9,291	9,547	10,156	7,247	7,099	7,841	8,206	14,752	11,088	7,437	107,757
5	CE OWNED RENEWABLES	139,800	122,285	139,501	141,781	125,052	95,769	82,675	78,059	90,148	114,809	124,980	134,813	1,389,672
6	PEAKERS	155,329	138,967	159,567	94,292	97,595	71,553	150,604	47,410	59,867	130,163	87,060	134,736	1,327,143
7	PUMPED STORAGE	120,567	118,446	113,323	125,338	81,965	118,256	125,721	122,785	141,871	74,192	117,128	162,120	1,421,713
8	TOTAL GENERATED	2,661,214	2,335,871	2,298,694	2,212,327	1,920,544	2,335,161	2,576,785	2,334,763	2,281,341	1,909,485	2,193,903	2,628,500	27,688,590
9	LESS : PUMPING	-151,788	-160,088	-146,691	-164,825	-109,819	-154,179	-151,472	-167,085	-180,535	-101,658	-153,436	-212,731	-1,854,307
10	TOTAL GENERATED	2,509,426	2,175,783	2,152,003	2,047,502	1,810,725	2,180,982	2,425,313	2,167,678	2,100,806	1,807,828	2,040,467	2,415,769	25,834,283
11	PURCHASED (NUGs)	866,936	783,214	867,684	834,073	917,467	716,360	807,410	718,431	741,018	822,418	767,983	796,837	9,639,833
12	NET INTERCHANGE	-246,657	-58,447	-67,574	-178,659	180,940	137,054	157,930	455,174	73,253	179,241	63,954	-173,142	523,068
13	TOTAL SYSTEM REQUIREMENTS	3,129,705	2,900,550	2,952,114	2,702,917	2,909,132	3,034,396	3,390,654	3,341,283	2,915,077	2,809,486	2,872,404	3,039,465	35,997,184
	VARIABLE EXPENSES ($*1000)													
14	COAL STEAM	24,048	19,474	19,703	17,829	17,810	20,830	21,329	21,543	19,850	11,692	15,782	22,144	232,035
15	GAS & OIL	13,638	11,990	8,283	9,378	5,088	10,961	14,670	10,687	10,643	9,870	11,833	12,665	129,708
16	NUCLEAR PPA VARIABLE	4,663	3,710	3,816	3,686	3,768	4,369	4,956	4,840	4,369	3,773	3,638	3,991	49,577
17	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
18	CE OWNED RENEWABLES	4,214	3,558	3,755	3,443	3,059	2,503	2,895	2,883	2,558	3,335	3,581	4,038	39,823
19	PEAKERS	4,455	3,921	4,393	2,422	2,535	1,830	3,969	1,238	1,589	3,461	2,375	3,906	36,093
20	PUMPED STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
21	TOTAL GENERATED	51,018	42,653	39,950	36,757	32,261	40,494	47,819	41,192	39,009	32,130	37,208	46,744	487,236
22	LESS : PUMPING	0	0	0	0	0	0	0	0	0	0	0	0	0
23	TOTAL GENERATED	51,018	42,653	39,950	36,757	32,261	40,494	47,819	41,192	39,009	32,130	37,208	46,744	487,236
24	PURCHASED (NUGs) VARIABLE COST[1]	32,391	29,408	30,900	28,676	30,384	25,925	30,951	27,664	24,692	25,176	22,902	23,550	332,619
25	NET INTERCHANGE, EXCLUDING ZRC	-10,757	-4,437	-2,467	-5,492	4,301	1,817	2,445	9,965	29	4,014	534	-7,434	-7,483
26	**TOTAL FUEL, VARIABLE PURCHASED AND NET INTERCHANGE**	**72,652**	**67,623**	**68,384**	**59,941**	**66,946**	**68,236**	**81,215**	**78,820**	**63,730**	**61,320**	**60,644**	**62,860**	**812,372**
27	ZONAL RESOURCE CREDIT PURCHASE	102	95	102	98	102	99	102	102	99	102	99	102	1,203
28	OWNED RENEWABLE CAPACITY	2,455	2,072	2,187	2,005	1,782	1,458	1,686	1,680	1,490	1,942	2,086	2,352	23,198
29	NUCLEAR PPA CAPACITY	33,221	26,434	27,188	26,260	26,848	31,132	35,308	34,483	31,129	26,880	25,919	28,438	353,238
30	PURCHASED (NUG) CAPACITY	22,384	21,151	22,117	21,466	21,851	22,199	23,233	23,005	21,853	22,217	21,252	21,490	264,218
31	PURCHASED (NUG) FIXED ENERGY	7,480	7,044	7,478	5,974	6,179	5,993	6,166	6,153	5,976	6,161	5,994	6,174	76,772
32	INDEPENDENT ADMINISTRATOR EXPENSE	40	40	0	0	0	0	0	0	0	40	40	40	200
33	**TOTAL CAPACITY AND NUG FIXED COSTS**	65,681	56,836	59,072	55,804	56,762	60,881	66,495	65,422	60,547	57,342	55,390	58,597	718,829
34	**TOTAL POWER SUPPLY COSTS**	138,334	124,460	127,456	115,745	123,708	129,118	147,710	144,243	124,277	118,662	116,033	121,457	1,531,201

[1]Purchased (NUG) variable costs include costs associated with PURPA variable energy payments, non-capacity renewable energty plan transfer costs, the green generation program, energy only NUGs and certain hydro plant contract costs

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2020
		P U R C H A S E D A N D I N T E R C H A N G E P O W E R R E P O R T												
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)**	**(i)**	**(j)**	**(k)**	**(l)**	**(m)**	**(n)**	**(o)**
	PURCHASED AND NET INTERCHANGE RECEIVED (MWH)													
35	MARKET ON PEAK	3,896	6,582	18,201	4,188	115,418	177,605	188,235	281,591	114,114	70,491	47,560	6,032	1,033,914
36	MARKET OFF PEAK	125,706	217,287	106,339	105,713	195,914	181,072	199,354	294,631	207,416	249,965	235,580	204,516	2,323,491
37	PURCHASED (NUGs)	866,936	783,214	867,684	834,073	917,467	716,360	807,410	718,431	741,018	822,418	767,983	796,837	9,639,833
38	TOTAL RECEIVED	996,538	1,007,083	992,225	943,974	1,228,799	1,075,037	1,194,999	1,294,653	1,062,547	1,142,874	1,051,123	1,007,386	12,997,239
	NET INTERCHANGE DELIVERED (MWH)													
39	EXTERNAL SALES	376,259	282,316	192,114	288,560	130,393	219,026	187,393	121,048	248,276	141,216	219,186	383,690	2,789,475
40	MISO RAC	0	0	0	0	0	2,597	42,266	0	0	0	0	0	44,863
41	TOTAL DELIVERED	376,259	282,316	192,114	288,560	130,393	221,623	229,659	121,048	248,276	141,216	219,186	383,690	2,834,338
42	NET (MWH)	620,279	724,767	800,111	655,414	1,098,407	853,414	965,340	1,173,605	814,271	1,001,659	831,937	623,696	10,162,900

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2020
		PURCHASED AND INTERCHANGE POWER REPORT												
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	VARIABLE PURCHASED AND NET INTERCHANGE EXPENSE ($*1000)													
43	MARKET ON PEAK ENERGY	982	1,052	1,445	963	4,068	5,362	6,021	7,903	3,825	2,887	2,169	1,030	37,708
44	MARKET OFF PEAK ENERGY	3,047	4,968	2,548	2,283	4,184	3,532	4,492	6,040	4,176	5,262	5,025	4,594	50,151
45	PURCHASED (NUGs) ENERGY	31,169	28,186	29,678	27,454	29,162	24,702	29,729	26,442	23,470	23,953	21,680	22,328	317,953
46	CASE NO. U-16048 COST RECOVERY	1,222	1,222	1,222	1,222	1,222	1,222	1,222	1,222	1,222	1,222	1,222	1,222	14,666
47	TOTAL EXPENSE	36,419	35,428	34,894	31,922	38,636	34,820	41,464	41,607	32,693	33,324	30,096	29,174	420,478
	NET INTERCHANGE CREDIT ($*1000)													
48	EXTERNAL SALE ENERGY	14,785	10,458	6,460	8,738	3,951	6,963	6,430	3,978	7,972	4,134	6,660	13,059	93,589
49	EXTERNAL SALE CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0
50	MISO RAC	0	0	0	0	0	114	1,638	0	0	0	0	0	1,752
51	TOTAL CREDIT	14,785	10,458	6,460	8,738	3,951	7,078	8,068	3,978	7,972	4,134	6,660	13,059	95,342
52	NET EXPENSE	21,634	24,971	28,434	23,184	34,685	27,742	33,396	37,629	24,721	29,190	23,436	16,115	325,136

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20525
Exhibit No.: A-8 (JWH-2)

Witness: JWHahn
Date: September 2019

Annual Summary for Years 2020 through 2024 of Fuel and Purchased and Net Interchange Power Expenses

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		2020	2021	2022	2023	2024
			SUMMARY BY SOURCE			
(a)	(b)	(c)	(d)	(e)	(f)	(g)
	ENERGY (MWH)					
1	COAL STEAM	10,854,074	10,457,971	10,701,920	8,090,168	7,860,645
2	GAS & OIL	5,697,213	5,405,298	5,171,164	4,227,418	2,693,227
3	NUCLEAR PPA	6,891,019	6,872,421	1,963,434	0	0
4	STATION POWER	107,757	112,057	107,828	135,115	132,570
5	CE OWNED RENEWABLES	1,389,672	2,788,578	2,947,031	3,176,358	3,563,862
6	PEAKERS	1,327,143	723,615	393,546	172,430	19,709
7	PUMPED STORAGE	1,421,713	1,399,577	1,440,159	1,283,098	1,177,194
8	TOTAL GENERATED	27,688,590	27,759,518	22,725,082	17,084,587	15,447,207
9	LESS : PUMPING	-1,854,307	-1,815,434	-1,871,016	-1,666,361	-1,506,744
10	TOTAL GENERATED	25,834,283	25,944,084	20,854,065	15,418,225	13,940,462
11	PURCHASED (NUGs)	9,639,833	8,954,759	8,545,436	7,181,813	6,607,270
12	NET INTERCHANGE	523,068	860,787	6,286,544	13,036,131	15,151,399
13	TOTAL SYSTEM REQUIREMENTS	35,997,184	35,759,630	35,686,045	35,636,169	35,699,131
	VARIABLE EXPENSES ($*1000)					
14	COAL STEAM	232,035	230,431	241,687	193,736	192,316
15	GAS & OIL	129,708	124,286	119,537	103,004	70,599
16	NUCLEAR PPA VARIABLE	49,577	50,665	14,223	0	0
17	STATION POWER	0	0	0	0	0
18	CE OWNED RENEWABLES	39,823	86,506	86,993	87,696	88,829
19	PEAKERS	36,093	20,556	11,679	5,402	604
20	PUMPED STORAGE	0	0	0	0	0
21	TOTAL GENERATED	487,236	512,444	474,118	389,837	352,348
22	LESS : PUMPING	0	0	0	0	0
23	TOTAL GENERATED	487,236	512,444	474,118	389,837	352,348
24	PURCHASED (NUGs) VARIABLE COST[1]	332,619	320,697	325,560	300,951	300,624
25	NET INTERCHANGE, EXCLUDING ZRC	-7,483	727	133,443	275,990	318,712
26	**TOTAL FUEL, VARIABLE PURCHASED AND NET INTERCHANGE**	**812,372**	**833,868**	**933,122**	**966,778**	**971,684**
27	ZONAL RESOURCE CREDIT PURCHASE	1,203	497	0	0	0
28	OWNED RENEWABLE CAPACITY	23,198	50,392	50,676	51,085	51,745
29	NUCLEAR PPA CAPACITY	353,238	361,246	101,478	0	0
30	PURCHASED (NUG) CAPACITY	264,218	269,347	265,647	264,024	265,434
31	PURCHASED (NUG) FIXED ENERGY	76,772	75,198	82,717	80,270	83,103
32	INDEPENDENT ADMINISTRATOR EXPENSE	200	200	200	200	200
33	**TOTAL CAPACITY AND NUG FIXED COSTS**	**718,829**	**756,881**	**500,718**	**395,580**	**400,483**
34	**TOTAL POWER SUPPLY COSTS**	**1,531,201**	**1,590,749**	**1,433,840**	**1,362,358**	**1,372,167**

[1]Purchased (NUG) variable costs include costs associated with PURPA variable energy payments, non-capacity renewable energy plan transfer costs, the green generation program, energy only NUGs and certain hydro plant contract costs

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20525
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PURCHASED AND INTERCHANGE POWER REPORT

(a)	(b)	2020 (c)	2021 (d)	2022 (e)	2023 (f)	2024 (g)
	PURCHASED AND NET INTERCHANGE RECEIVED (MWH)					
35	MARKET ON PEAK	1,033,914	1,622,253	3,807,217	5,284,732	6,015,431
36	MARKET OFF PEAK	2,323,491	2,145,034	4,267,906	8,508,910	9,418,119
37	PURCHASED (NUGs)	9,639,833	8,954,759	8,545,436	7,181,813	6,607,270
38	TOTAL RECEIVED	12,997,239	12,722,046	16,620,559	20,975,455	22,040,819
	NET INTERCHANGE DELIVERED (MWH)					
39	EXTERNAL SALES	2,789,475	2,868,466	1,762,019	738,341	266,614
40	MISO RAC	44,863	38,034	26,560	19,170	15,536
41	TOTAL DELIVERED	2,834,338	2,906,500	1,788,579	757,511	282,150
42	NET (MWH)	10,162,900	9,815,546	14,831,980	20,217,944	21,758,669

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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P U R C H A S E D A N D I N T E R C H A N G E P O W E R R E P O R T

(a)	(b)	2020 (c)	2021 (d)	2022 (e)	2023 (f)	2024 (g)
	VARIABLE PURCHASED AND NET INTERCHANGE EXPENSE ($*1000)					
43	MARKET ON PEAK ENERGY	37,708	50,875	104,519	130,029	146,364
44	MARKET OFF PEAK ENERGY	50,151	44,958	90,258	176,027	184,267
45	PURCHASED (NUGs) ENERGY	317,953	305,696	310,198	285,221	284,524
46	CASE NO. U-16048 COST RECOVERY	14,666	15,000	15,363	15,729	16,100
47	TOTAL EXPENSE	420,478	416,529	520,338	607,007	631,255
	NET INTERCHANGE CREDIT ($*1000)					
48	EXTERNAL SALE ENERGY	93,589	93,522	59,882	25,807	8,439
49	EXTERNAL SALE CAPACITY	0	0	0	0	0
50	MISO RAC	1,752	1,584	1,452	4,259	3,480
51	TOTAL CREDIT	95,342	95,106	61,334	30,066	11,919
52	NET EXPENSE	325,136	321,424	459,004	576,941	619,336

Line	EXISTING ENERGY-ONLY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
1	Great Lakes Tissue Company	Three-month rolling average incremental running cost	0.10¢/kWh	None	Terminated by mutual consent or by either party giving the other at least six months' written notice of its desire to terminate the Agreement at the end of any yearly period.
2	Jackson County	Agreement Terminated			
3	Michigan State University	Three-month rolling average incremental running cost	0.10¢/kWh (not to exceed $200/month)	None	Terminated by mutual consent or by either party giving the other at least 30 days' written notice of its desire to terminate the Agreement at the end of any yearly period.
4	Western Michigan University	Hourly incremental running cost	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/month)	None	Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period.
5	Grand Valley State University	90% of the hourly incremental running cost	None	None	Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period.
6	City of Midland, MI	90% of (Consumers Energy's Real Time Load Node LMP Minus $5/MWh)	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/month)	None	Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period.
7	North American Biofuels – Green Meadow Farms	Agreement Terminated			
8	MAHLE Engine Components USA	90% of (Consumers Energy's Real Time Load Node LMP Minus $5/MWh)	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/month)	None	Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period.

Line	GREEN GENERATION PROGRAM AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
1	Michigan Wind I LLC (Wind) (PPA 1)	Agreement Terminated.			
2	Michigan Wind I LLC (Wind) (PPA 2)	Average PSCR rate	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/month)	None	December 18, 2028. After this date, the agreement shall continue in effect until terminated by mutual agreement or by either party giving the other party at least 365 days' written notice of termination.
3	Bay Windpower I, Mackinaw City, LLC. (Wind)	Agreement Terminated.			
4	Rathbun Generating Station (Landfill Gas)	Agreement Terminated.			
5	North American Natural Resources, Inc. Venice Park Generating Station (Landfill Gas)	Average PSCR rate	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/month)	None	February 10, 2026. After this date, the agreement shall continue in effect until terminated by mutual agreement or by either party giving the other party at least 365 days' written notice of termination.
6	Zeeland Farm Services, Inc. (Landfill Gas)	Agreement Terminated			
7	C&C Energy, formerly Gas Recovery Systems, LLC. C&C Electric 2 Plant (Landfill Gas)	Average PSCR rate	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/month)	None	February 28, 2027. After this date, the agreement shall continue in effect until terminated by mutual agreement or by either party giving the other party at least 365 days' written notice of termination.

Line	EXISTING ENERGY & CAPACITY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
1	Ada Cogeneration Ltd Partnership	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (not to exceed $2,000/month)	4.024¢/kWh On-Peak, 3.822¢/kWh Off-Peak	January 5, 2026. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
2	Adrian Energy Associates	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (not to exceed $2,000/month)	4.476¢/kWh On-Peak, 4.253¢/kWh Off-Peak	December 13, 2029. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
3	C&C Energy, formerly Gas Recovery Systems	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/month)	4.374¢/kWh On-Peak, 4.155¢/kWh Off-Peak	February 20, 2030. After this date, the Agreement may continue until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination.
4	Cadillac Renewable Energy	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (not to exceed $2,000/month)	4.320¢/kWh On-Peak, 4.110¢/kWh Off-Peak	July 16, 2028. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
5	WM Renewable Energy, LLC. (formerly Bio Energy Partners)	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (minimum of $200/month, but not to exceed $2,000/month)	4.19¢/kWh On-Peak, 3.98¢/kWh Off-Peak	May 4, 2027. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of any yearly period.

Line	EXISTING ENERGY & CAPACITY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
6	Black River Limited Partnership	Agreement Terminated			
7	Beaverton, City of	2.71¢/kWh	0.10¢/kWh	3.51¢/kWh On-Peak, 2.75¢/kWh Off-Peak	December 31, 2023. After this date the Agreement may continue until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
8	Hope Renewable Energy – Hubbardston	Agreement Terminated.			
9	Commonwealth Power Company – Irving	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (not to exceed $2,000/month)	4.034¢/kWh On-Peak, 3.832¢/kWh Off-Peak	August 25, 2030. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
10	Commonwealth Power Company – LaBarge	5.4¢/kWh	0.10¢/kWh	$8,768.50/ZRC-month	May 31, 2039
11	Commonwealth Power Company – Middleville	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (not to exceed $2,000/month)	4.034¢/kWh On-Peak, 3.832¢/kWh Off-Peak	January 1, 2031. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.

Line	EXISTING ENERGY & CAPACITY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
12	Genesee Power Station Limited Partnership	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (minimum of $200/month, but not to exceed $2,000/month)	4.65¢/kWh On-Peak, 4.42¢/kWh Off-Peak	December 13, 2030. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of any yearly period.
13	Granger Electric Company – Grand Blanc	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/month)	4.402¢/kWh On-Peak, 4.182¢/kWh Off-Peak	July 27, 2029. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination.
14	Granger Electric Company – Pinconning	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (minimum of $242/month, but not to exceed $2,420/month)	4.348¢/kWh On-Peak, 4.136¢/kWh Off-Peak	January 22, 2028. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective on January 22 of any year.
15	Granger Electric of Byron Center	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (minimum of $267/month, but not to exceed $2,670/month)	4.184¢/kWh On-Peak, 3.970¢/kWh Off-Peak	April 10, 2026. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective on April 10 of any year.
16	Granger Electric Company – Ottawa	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/month)	4.374¢/kWh On-Peak, 4.155¢/kWh Off-Peak	June 21, 2029. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination.
17	Granger Electric Company – Seymour	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/month)	4.374¢/kWh On-Peak, 4.155¢/kWh Off-Peak	November 21, 2030. After this date, the Agreement may continue until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination.

Line	EXISTING ENERGY & CAPACITY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
18	Grayling Generating Station Limited Partnership	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/month)	4.18¢/kWh On-Peak, 3.97¢/kWh Off-Peak	December 31, 2027. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
19	Grenfell Hydro, Inc	Agreement Terminated.			
20	Hillman Power Company LLC	4.0¢/kWh	0.10¢/kWh (not to exceed $2,000/month)	$11,708.75/ZRC-month	May 31, 2022 The term of this Power Purchase Agreement shall be the period commencing on the Commercial Operation Date of the Hillman Generating Plant and continuing until May 31, 2022.
21	Kent County	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (not to exceed $2,000/month)	5.34¢/kWh On-Peak, 4.54¢/kWh Off-Peak	February 11, 2022. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
22	Michiana Hydroelectric Co Bellevue	Agreement Terminated.			

Line	EXISTING ENERGY & CAPACITY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
23	Michigan Power Limited Partnership	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (not to exceed $2,000/month)	3.880¢/kWh On-Peak, 3.686¢/kWh Off-Peak	October 23, 2030. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
24	Midland Cogeneration Venture Limited Partnership	Cost of Production	0.10¢/kWh (not to exceed $2,000/month)	1.014¢/kWh	March 16, 2025. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
25	North American Natural Resources, Inc.- (Peoples)	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/month)	4.374¢/kWh On-Peak, 4.155¢/kWh Off-Peak	September 8, 2030. After this date, the Agreement may continue until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination.
26	Rathbun Generating Station (Landfill Gas)	4.76¢/kWh	0.10¢/kWh - applied to rate in Exhibit A	$8,768.50/ZRC-month	May 31, 2039
27	STS Hydropower Ltd – Cascade Hydro Plant	Agreement Terminated.			
28	STS Hydropower Ltd – Fallasburg Hydro Plant	Agreement Terminated.			

Line	EXISTING ENERGY & CAPACITY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
29	STS Hydropower Ltd – Morrow Hydro Plant	2.71¢/kWh	0.10¢/kWh	3.97¢/kWh On-Peak, 3.37¢/kWh Off-Peak	December 31, 2019. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
30	T.E.S. Filer City Station Limited Partnership	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (not to exceed $2,000/month)	6.24¢/kWh On-Peak, 5.30¢/kWh Off-Peak	June 17, 2025. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
31	Thornapple Association, Inc	Agreement Terminated.			
32	Viking Energy of Lincoln Limited Partnership	4.0¢/kWh	0.10¢/kWh (not to exceed $2,000/month)	$11,708.75/ZRC-month	May 31, 2027 The term of this Agreement shall be the period commencing on the Commercial Operation Date of the Lincoln Michigan Plant and continuing until May 31, 2029
33	Viking Energy of McBain Limited Partnership	4.0¢/kWh	0.10¢/kWh (not to exceed $2,000/month)	$11,708.75/ZRC-month	May 31, 2027 The term of this Agreement shall be the period commencing on the Commercial Operation Date of the McBain Michigan Plant and continuing until May 31, 2029

Line	EXISTING ENERGY & CAPACITY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
34	White's Bridge Hydro Company	Agreement Terminated.			
35	Boyce Hydro (formerly Wolverine Power Corporation)	4.67¢/kWh On-Peak, 3.66¢/kWh Off-Peak	None	2.33¢/kWh On-Peak, 1.97¢/kWh Off-Peak	May 31, 2022.
35	STS Hydropower Ltd – Thornapple Ada Hydro Plant	Agreement Terminated.			
36	Entergy Nuclear Power Marketing, LLC	0.664¢/kWh	None	4.736¢/kWh	April 12, 2022.

Line	RENEWABLE ENERGY PLAN AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
1	Elk Rapids Hydroelectric Power LLC	Agreement Terminated.			
2	River Fork Solar	Monthly Transfer Rate	None		May 31, 2041.
3	Fremont Community Digestor LLC (Anaerobic Digestor)	Monthly Transfer Rate	None		December 26, 2032.
4	WM Renewable Energy LLC, Northern Oaks Landfill Plant (Landfill Gas)	Monthly Transfer Rate	None		November 10, 2030.
5	North American Natural Resources Inc, Lennon Generating Station (Landfill Gas)	Monthly Transfer Rate	None		December 15, 2030.
6	Michigan Wind 2 (Wind)	Monthly Transfer Rate	None		December 31, 2031.
7	Harvest II Wind Farm (Wind)	Monthly Transfer Rate	None		October 31, 2032.
8	Beebe Renewable Energy, formerly Blissfield Energy (Wind)	Monthly Transfer Rate	None		December 17, 2032.
9	WM Renewable Energy LLC, Pine Tree Acres Landfill Plant (Landfill Gas)	Monthly Transfer Rate	None		February 28, 2032.
10	Heritage Stoney Corners Wind Farm I, LLC, Phase 2 (Wind)	Monthly Transfer Rate	None		December 31, 2031.
11	Heritage Stoney Corners Wind Farm I, LLC, Phase 3 (Wind)	Monthly Transfer Rate	None		December 31, 2031.

12	Heritage Garden Wind Farm I, LLC (Wind)	Monthly Transfer Rate	None		September 13, 2032.
Line	**RENEWABLE ENERGY PLAN AGREEMENTS**	**Energy**	**Administrative Charge**	**Capacity**	**Termination of Agreement**
13	Geronimo Apple Blossom Wind Farm	Monthly Transfer Rate	None		October 31, 2032.
14	Experimental Advanced Renewable Program (EARP) (Solar)	Monthly Transfer Rate	None		Individual contracts have specific termination dates. All agreements will terminate by April 30, 2023.
15	Experimental Advanced Renewable Program (EARP) Expansion (Solar)	Monthly Transfer Rate	None		Individual contracts have specific termination dates. All agreements will terminate by August 31, 2029.
16	Experimental Advanced Renewable Program (EARP) FiT (Anaerobic Digester)	Monthly Transfer Rate	None		Individual contracts have specific termination dates. All agreements will terminate by June 30, 2036.

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 to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

DIRECT TESTIMONY

OF

NORMAN J. KAPALA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

Q. Please state your name and business address.

A. My name is Norman J. Kapala, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director of Coal Generation.

Q. Please describe your educational background.

A. In 1996, I received a Bachelor of Science in mechanical engineering from Michigan Technological University. In 2008, I received a Master of Science in manufacturing management from Kettering University.

Q. Please describe your business experience.

A. From 1990 to 1994, I served our country as a Rifleman in the United States Marine Corps. In May 1996, I joined Chrysler Corporation and held various positions with progressing levels of responsibility at the Trenton Engine Plant, progressing from a Technical Advisor to Area Manager. In September 2002, I joined Delphi Corporation as a Production Supervisor and, in September 2004, and progressed to a Senior Manufacturing Engineer. In July 2008, I joined Consumers Energy at the D.E. Karn ("Karn")/J.C. Weadock ("Weadock") Generating Complex and progressed through positions from Senior Engineer to the Site Business Manager. In June 2015, I transferred to the B.C. Cobb ("Cobb") Generating Complex and J.H. Campbell ("Campbell") Generating Complex as the Site Business Manager for both facilities. Following the closure of seven of the Company's coal-fired units at its Cobb, Weadock, and J.R. Whiting sites in 2016, I was promoted to Executive Director of Coal Generation.

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

A. Yes. I have sponsored testimony in the following MPSC cases:

Case No. U-20165	2018 Integrated Resource Plan ("IRP");
Case No. U-20202	2018 Power Supply Cost Recovery ("PSCR") Reconciliation; and
Case No. U-20219	2019 Power Supply Cost Recovery Plan.

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

A. The purpose of my direct testimony is to: (i) identify and explain the major fossil and Ludington outages that are planned for this period; (ii) identify and support Consumers Energy's periodic outage plans and Random Outage Rate ("ROR") projections for the 2020 PSCR Plan year; (iii) compare the projected ROR for fossil, hydro, the Ludington Pumped Storage Plant ("Ludington"), and peaker units with actual ROR experienced in the five-year historical period 2014 through 2018; (iv) address availability of generating units for the five-year forecast period; (v) identify forecasted urea expenses for the 2020 PSCR Plan year, as well as the forecast period 2021 through 2024; (vi) identify forecasted aqueous ammonia expenses for the 2020 PSCR Plan year, as well as the forecast period 2021 through 2024; (vii) identify forecasted lime expenses for the 2020 PSCR Plan year, as well as the forecast period 2021 through 2024; and (viii) identify forecasted activated carbon expenses for the 2020 PSCR Plan year, as well as the forecast period 2021 through 2024.

Q. Are you sponsoring exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-10 (NJK-1)	Major Outages in the 2020 PSCR Plan;
Exhibit A-11 (NJK-2)	2020 PSCR Random Outage Rate Projections;
Exhibit A-12 (NJK-3)	2020-2024 Urea Expense;
Exhibit A-13 (NJK-4)	2020-2024 Aqueous Ammonia Expense;
Exhibit A-14 (NJK-5)	2020-2024 Lime Expense; and
Exhibit A-15 (NJK-6)	2020-2024 Activated Carbon Expense.

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

A. Yes.

MAJOR GENERATING PLANT OUTAGES FOR 2020

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 summarize the major outages.

A. Exhibit A-10 (NJK-1) summarizes the major outages. Company witness Joshua W. Hahn includes these major outages in his modeling of the dispatch of the Company's generating plants in this case.

Q. Please describe the major outages listed on Exhibit A-10 (NJK-1).

A. I describe the individual outages, including planned start dates, duration and significant work scope in the following testimony.

Ludington Unit 3

The outage at Ludington Unit 3 began May 13, 2019 and is scheduled to conclude May 20, 2020 – or 140 days in 2020. This is the sixth and final planned unit outage of Ludington's multiyear $800 million overhaul and upgrade. The outage is necessary to replace and upgrade most all major components including the water turbine (a.k.a. – runner), wicket gates, generator/pump, and stator.

Karn Unit 4

The outage at Karn Unit 4 is scheduled to begin January 1, 2020 and is projected to last for 135 days – concluding May 15, 2020. The outage is necessary for the upgrade of the cooling towers and replacement of the turbine electro-hydraulic control ("EHC") system. The cooling tower upgrade work for Karn Unit 4 is a continuation of the work performed in 2019. The purpose of the EHC system replacement is to address various issues with the current system, resulting in improved reliability of the unit. The outage is scheduled to take place during a period in which Karn Unit 4 is not projected to be dispatched based upon the forward energy market pricing that is used in the modeling of the PSCR Plan.

Campbell Unit 1

The outage at Campbell Unit 1 is scheduled to begin February 27, 2020 and is projected to last for 84 days – concluding May 21, 2020. The outage is necessary for turbine inspection and overhaul, including low pressure and high pressure turbine blading replacement. Other Balance of Plant ("BOP") work will also be performed.

Karn Unit 3

The outage at Karn Unit 3 is scheduled to begin March 2, 2020 and is projected to last for 30 days – concluding April 1, 2020. The outage is necessary for BOP work, which includes all of the supporting components and auxiliary systems of the power plant.

Jackson Unit 1

The outage at Jackson Unit 1 is scheduled to begin March 1, 2020 and is projected to last for 42 days – concluding April 12, 2020. The outage is necessary for upgrade of the turbine Digital Control System ("DCS"), increase of the stack height, and various inspections pursuant to the General Electric long-term service agreement. The Company has received a revised air permit from the Michigan Department of Environment, Great Lakes, and Energy ("EGLE") (formerly the Michigan Department of Environmental Quality) to increase the 12-month rolling Nitrogen Oxide ("NO_x") emissions from the Jackson Plant. Approval of that revised air permit was predicated on increasing the stack height by 35 feet from the existing height of 105 feet. The dispatch of the Jackson Plant in the Midcontinent Independent System Operator, Inc. ("MISO") energy market has historically been limited through a dispatch adder to ensure compliance with the Company's air permit. The revised air permit results in a reduction to that dispatch adder in the future; resulting in increased capacity factor, all else being equal.

Karn Unit 1

The outage at Karn Unit 1 is scheduled to begin April 17, 2020 and is projected to last for 45 days – concluding June 1, 2020. The outage is necessary for replacement of two layers of catalyst for the Selective Catalytic Reduction ("SCR"). The catalyst is being replaced because it is at end of life.

Zeeland Unit 3

The outage at Zeeland Unit 3 is scheduled to begin May 2, 2020 and is projected to last for 30 days – concluding June 1, 2020. The outage is necessary for replacement of the existing cooling tower fill material and drift eliminator material, upgrade of the computer equipment and DCS software, and other BOP repairs.

Zeeland Unit 4

The outage at Zeeland Unit 4 is scheduled to begin May 2, 2020 and is projected to last for 30 days – concluding June 1, 2020. The outage is necessary for replacement of the existing cooling tower fill material and drift eliminator material, upgrade of the computer equipment and DCS software, and other BOP repairs.

Zeeland Unit 5

The outage at Zeeland Unit 5 is scheduled to begin May 2, 2020 and is projected to last for 30 days – concluding June 1, 2020. The outage is necessary for replacement of the existing cooling tower fill material and drift eliminator material, upgrade of the computer equipment and DCS software, and other BOP repairs.

Campbell Unit 2

The outage at Campbell Unit 2 is scheduled to begin October 7, 2020 and is projected to last for 34 days – concluding November 10, 2020. The outage is necessary for upgrade of the DCS and simulator, SCR catalyst management, and turbine valve inspection.

Karn Unit 2

The outage at Karn Unit 2 is scheduled to begin October 9, 2020 and is projected to last for 42 days – concluding November 20, 2020. The outage is necessary for Pulse Jet Fabric Filter ("PJFF") Bag Replacement and replacement of the catalyst for the SCR.

MISCELLANEOUS OUTAGES

Q. Are other outages projected for 2020?

A. Yes. In addition to the major outages which I have just discussed, there are other planned outages scheduled for various generating plants whose planned durations are less than 28 days. These outages are scheduled to remove screens from valves after turbine inspections, to remove zebra mussels from raw water piping, and to perform work on other equipment that will not operate for extended periods without attention. To the extent possible, all of these planned outages have been scheduled during periods in which the forward market pricing used in modeling of the PSCR Plan is projected to be low.

ROR PROJECTIONS

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

A. The ROR projections in this case are developed using a five-year average (2014 through 2018) and are modified to reflect current operating conditions and recent investments. This is shown in Exhibit A-11 (NJK-2). Generating units which have a projected ROR that varies from their five-year average ROR by more than 10% are described below.

Campbell Unit 1

The 2020 ROR for Campbell Unit 1 is projected to be 10.19% higher than the five-year average. The increase in projected ROR is based upon projected investment in the unit through the end of 2020.

Karn Unit 1

The 2020 ROR for Karn Unit 1 is projected to be 14.97% higher than the five-year average. The increase in projected ROR is the result of reduced investment in the unit based upon its retirement in May 2023.

Karn Unit 2

The 2020 ROR for Karn Unit 2 is projected to be 11.51% higher than the five-year average. The increase in projected ROR is the result of reduced investment in the unit based upon its retirement in May 2023.

Ludington Unit 2

The 2020 ROR for Ludington Unit 2 is projected to be 11.60% lower than the five-year average. The five-year average ROR was elevated as a result of the catastrophic thrust bearing failure in 2018.

Ludington Unit 5

The 2020 ROR for Ludington Unit 5 is projected to be 27.42% lower than the five-year average. The five-year average ROR was elevated as a result of the catastrophic thrust bearing failure in 2015. The subsequent overhaul and upgrade in 2016 and early 2017 significantly improved the projected ROR.

AVAILABILITY

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

A. Yes. The 2020 projected availability for each of the generating units is shown in Exhibit A-11 (NJK-2), column (b).

NO_x EMISSION ALLOWANCES

Q. Does Consumers Energy expect to incur expenses in 2020 related to the NO_x emission allowance program?

A. No.

Q. Please explain why Consumers Energy does not expect to incur expenses in 2020 related to the NO_x emission allowance program.

A. The Company has installed SCR units which have significantly reduced NO_x emissions and the associated need to purchase NO_x emissions allowances. These SCRs were initially installed for compliance with the Clean Air Interstate Rule ("CAIR").

Q. Please provide background on the status of CAIR.

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

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

Q. Please describe CSAPR.

A. CSAPR is a cap and trade rule that is much like CAIR, which it replaced. CSAPR governs the emission of SO_2 and NO_x from fossil-fueled EGUs through the use of an allowance-based cap and trade program, except that it restricts interstate trading for use only for addressing relatively small changes in year-to-year emissions variability. Under this program, NO_x is regulated on both an annual basis and on a seasonal basis during the ozone season (May through September). Each allowance (annual or ozone) permits the

emission of one ton of NO_x, with the emissions cap and number of allocated allowances decreasing over time. SO_2 is regulated on an annual basis only, with the emissions cap decreasing over time. Phase I of CSAPR was effective from January 1, 2015 through December 31, 2016, and Phase II became effective on January 1, 2017.

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

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

<u>SO_2 EMISSION ALLOWANCES</u>

Q. Does Consumers Energy expect to incur expenses in 2020 related to the SO_2 emission allowance program?

A. No. The Company does not expect to incur expenses related to the consumption of SO_2 emission allowances.

Q. Please explain why Consumers Energy does not expect to incur expenses in 2020 related to the SO_2 emission allowance program.

A. The Company has installed Flue Gas Desulfurization ("FGD") equipment in the form of Spray Dry Absorbers ("SDAs") at its Karn site, and SDAs and Dry Sorbent Injection ("DSI") at its Campbell site. The FGD units were installed to comply with the EPA's Mercury and Toxics Standards ("MATS"); however, an added co-benefit is the significant reduction in SO_2 emission levels.

Q. Can you please describe MATS?

A. Yes. MATS is another Federal rule that was finalized by the EPA in December 2011 and regulates emission of mercury, acid gases, certain metals, and organic constituents via emission rate limits or the use of work practices for coal- and oil-fired EGUs. Unlike prior

regulations which permit allowance purchases or emission averaging over multiple units, MATS requires unit-by-unit control equipment. Compliance with MATS was required by April 16, 2015; however, the Company received an extension from the EGLE which pushed compliance to April 16, 2016. Consumers Energy has five coal-fired units and two oil-fired units subject to MATS.

Urea Expenses

Q. Are there urea expenses for which Consumers Energy is seeking recovery in 2020?

A. Yes. Exhibit A-12 (NJK-3) identifies the projected urea expenses through 2024.

Q. Please describe Exhibit A-12 (NJK-3).

A. In 2020, Consumers Energy projects spending $1.9 million for urea as a necessary expense of operating Campbell Units 2 and 3. In 2021, Consumers Energy expects to spend $1.8 million for urea. For the years 2022 through 2024, urea expenses are expected to be $1.9 million, $1.6 million, and $1.9 million, respectively.

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

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

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

A. Yes. The Company requested and received approval to recover urea expenses as a PSCR expense in Case No. U-15415 (2008 PSCR Plan case) and in subsequent PSCR Plan cases. I recommend the same treatment in 2020.

Aqueous Ammonia Expenses

Q. Are there aqueous ammonia expenses for which you are seeking recovery in 2020?

A. Yes. Exhibit A-13 (NJK-4) identifies the projected aqueous ammonia expenses for the years 2020 through 2024.

Q. Please describe Exhibit A-13 (NJK-4).

A. In 2020, Consumers Energy projects spending $1.1 million for aqueous ammonia as a necessary expense of operating Karn Units 1 and 2 and Zeeland Unit 2 (the Combined Cycle unit). In 2021, Consumers Energy also expects to spend $1.1 million for aqueous ammonia associated with the operation of those units. For the years 2022 through 2024, expenses are expected to be $1.1 million, $0.5 million, and $0.1 million, respectively.

Q. Why does the projected expense for aqueous ammonia begin to significantly decrease in 2023?

A. The June 7, 2019 Order in Case No. U-20165 approved a contested settlement agreement in the Company's 2018 IRP under MCL 460.6t. Consistent with the Company's IRP, the settlement agreement included the provision to retire Karn Units 1 and 2 on May 31, 2023 at the end of the 2022-2023 MISO Planning Year. As a result of the Karn Unit 1 and 2 retirements, Zeeland will be the sole user of aqueous ammonia – see Exhibit A-13 (NJK 4).

Q. How is aqueous ammonia used?

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

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

A. Yes. The Company requested and received approval to recover aqueous ammonia expense as a PSCR expense in Case No. U-17095 (2013 PSCR Plan case) and in subsequent PSCR Plan cases. I recommend the same treatment in 2020.

Lime Expenses

Q. Are there lime expenses for which you are seeking recovery in 2020?

A. Yes. Exhibit A-14 (NJK-5) identifies the projected lime expenses for the years from 2020 through 2024.

Q. Please describe Exhibit A-14 (NJK-5).

A. In 2020, Consumers Energy projects spending $8.0 million for lime. In 2021, Consumers Energy expects to spend $7.7 million for lime. In the years from 2022 through 2024, lime expenses are expected to be $7.9 million, $6.9 million, and $7.1 million, respectively.

Q. When the Karn Units 1 and 2 are retired on May 31, 2023, why doesn't the 2023 and 2024 lime expense reflect a significant decrease similar to aqueous ammonia?

A. While Karn Units 1 and 2 are responsible for approximately 87% of the $1.1 million 2022 aqueous ammonia expense, they are responsible for only 14% of the $7.9 million 2022 lime expense – see Exhibit A-14 (NJK-5).

Q. How will lime be used?

A. The Company has installed FGD units (a.k.a. SDA and DSI) at its Karn and Campbell sites. SDAs were installed at Karn Units 1 and 2 in 2014, and were installed at Campbell Unit 3 in early 2016. DSI was installed at Campbell Units 1 and 2 in early 2016. Lime will be injected into the SDA/DSI where it will react with SO_2 and heavy metals found in the

exhaust gases. When used in combination with PJFFs, SO_2 and heavy metal emissions are reduced, allowing the Company to comply with the current emission standards.

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

A. Yes. The Company requested and received approval to recover lime expenses as a PSCR expense in Case No. U-17317 (2014 PSCR Plan case) and in subsequent PSCR Plan cases. I recommend the same treatment in 2020.

Activated Carbon Expenses

Q. Are there activated carbon expenses for which you are seeking recovery in 2020?

A. Yes. Exhibit A-15 (NJK-6) identifies the projected activated carbon expenses for the years from 2021 through 2024.

Q. Please describe Exhibit A-15 (NJK-6).

A. In 2020, Consumers Energy projects spending $1.3 million for activated carbon as a necessary expense of operating Campbell Units 1 through 3 and Karn Units 1 and 2. In 2021, Consumers Energy expects to spend $1.2 million for activated carbon. In the years from 2022 through 2024, activated carbon expenses are forecasted to be $1.3 million, $1.1 million, and $1.0 million, respectively.

Q. When Karn Units 1 and 2 are retired on May 31, 2023, why doesn't the 2023 and 2024 activated carbon expense reflect a significant decrease similar to aqueous ammonia expense?

A. While Karn Units 1 and 2 are responsible for approximately 87% of the $1.1 million 2023 aqueous ammonia expense, they are responsible for only 18% of the $1.3 million 2022 activated carbon expense.

Q. How will activated carbon be used?

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

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

A. Yes. The Company requested and received approval to recover activated carbon expenses as a PSCR expense in Case No. U-17678 (2015 PSCR Plan case) and in subsequent PSCR Plan cases. I recommend the same treatment in 2020.

Q. Has the Company implemented any continuous improvement efforts targeted at reducing expense for chemical reagents?

A. Yes. During 2019 the Company undertook two separate projects targeted at reducing chemical reagent expense which is recovered through the PSCR mechanism. The first of these initiatives was a project aimed at optimizing the chemical reagent consumption rates on all applicable generation units. The second project was the initiation of a Commodity Chemicals Request For Proposal ("RFP"). The Commodity Chemicals RFP included aqueous ammonia, granular urea, hydrated lime, pebble lime, and powdered activated carbon.

Q. What is the status of the Company's continuous improvement efforts targeted at reducing expense for chemical reagents?

A. The chemical reagent consumption optimization project has been completed and the benefits of that project are reflected in projected chemical reagent expenses for the 2020 PSCR Plan year as well as the five-year forecast period through 2024. The Commodity Chemicals RFP is still in progress with continued evaluation of various hydrated limes and activated carbons. At this point in time, the projected chemical reagent expenses for the 2020 PSCR Plan year and the five-year forecast period only reflect the competitive results for urea. The competitive results for the remaining chemical reagents will be passed on to customers through the PSCR mechanism as they are realized.

Q. What testing has the Company performed to evaluate the efficacy of the alternative chemical reagents?

A. The Company has conducted and will continue to conduct operational testing with the alternative chemicals at the applicable generating facilities. The operational testing associated with the alternative chemicals requires strict coordination in order to properly measure system performance relative to typical performance.

Q. Can you quantify the projected chemical reagent cost reduction resulting from the Company's continuous improvement efforts?

A. Yes. Based upon a comparison of the chemical reagent cost adders (cents/MMBtu) for activated carbon, hydrated lime, pebble lime, urea, and aqueous ammonia used in the 2020 PSCR Plan versus the chemical reagent cost adders used by the Company in its 2019 PSCR Plan, the Company is projecting a cost reduction of almost $3.2 million.

A majority of this savings is attributable to the chemical reagent consumption optimization project, primarily at the Campbell site.

Q. Does this conclude your direct testimony?

A. Yes it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

EXHIBITS

OF

NORMAN J. KAPALA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20525
Exhibit No.: A-10 (NJK-1)
Page: 1 of 1
Witness: NJKapala
Date: September 2019

Major Outages in the 2020 PSCR Plan

	(a)	(b)	(c)	(d)
Line No.	**Unit**	**Days in 2020**	**Start Date**	**End Date**
1	**Ludington 3**	140	1/1/2020	5/20/2020
2	**Karn 4**	135	1/1/2020	5/15/2020
3	**Campbell 1**	84	2/27/2020	5/21/2020
4	**Karn 3**	30	3/2/2020	4/1/2020
5	**Jackson 1**	42	3/1/2020	4/12/2020
6	**Karn 1**	45	4/17/2020	6/1/2020
7	**Zeeland 3**	30	5/2/2020	6/1/2020
8	**Zeeland 4**	30	5/2/2020	6/1/2020
9	**Campbell 2**	34	10/7/2020	11/10/2020
10	**Zeeland 5**	30	5/2/2020	6/1/2020
11	**Karn 2**	42	10/9/2020	11/20/2020

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20525
Exhibit No.: A-11 (NJK-2)
Page: 1 of 1
Witness: NJKapala
Date: September 2019

2020 PSCR Random Outage Rate Projections

	(a)	(b)	(c)	(d)	(e)
Line No.	**Unit**	**Availability**	**Periodic Factor**	**2020 Projected ROR**	**Actual ROR 2014-2018**
1	**Campbell 1**	60.11%	22.94%	22.00%	11.81%
2	**Campbell 2**	55.28%	30.02%	21.00%	13.75%
3	**Campbell 3**	89.00%	6.32%	5.00%	7.32%
4	**Karn 1**	45.30%	24.50%	40.00%	25.03%
5	**Karn 2**	58.56%	21.92%	25.00%	13.49%
6	**Karn 3**	64.16%	8.34%	30.00%	31.94%
7	**Karn 4**	39.19%	39.71%	35.00%	33.62%
8	**Ludington 1**	89.31%	7.45%	3.50%	8.74%
9	**Ludington 2**	92.26%	4.39%	3.50%	15.10%
10	**Ludington 3**	58.32%	39.56%	3.50%	8.98%
11	**Ludington 4**	89.14%	7.63%	3.50%	5.14%
12	**Ludington 5**	85.50%	11.40%	3.50%	30.92%
13	**Ludington 6**	87.55%	9.27%	3.50%	6.95%
14	**Hydros**	83.94%	10.70%	6.00%	6.73%
15	**Zeeland CC**	85.51%	10.93%	4.00%	3.78%
16	**Zeeland 1A**	89.23%	6.07%	5.00%	3.59%
17	**Zeeland 1B**	89.22%	6.08%	5.00%	3.16%
18	**Jackson 1**	81.86%	12.64%	6.30%	3.23%

[1]Jackson acquired in December 2015.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20525
Exhibit No.: A-12 (NJK-3)
Page: 1 of 1
Witness: NJKapala
Date: September 2019

2020-2024 Urea Expense

Line No.	(a) Unit	(b) 2020	(c) 2021	(d) 2022	(e) 2023	(f) 2024
1	**Campbell 2**	$314,840	$281,987	$282,693	$284,423	$316,917
2	**Campbell 3**	$1,544,761	$1,536,906	$1,609,179	$1,312,593	$1,607,296
3	**Total**	$1,859,601	$1,818,892	$1,891,872	$1,597,015	$1,924,213

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20525
Exhibit No.: A-13 (NJK-4)
Page: 1 of 1
Witness: NJKapala
Date: September 2019

2020-2024 Aqueous Ammonia Expense

Line No.	(a) Unit	(b) 2020	(c) 2021	(d) 2022	(e) 2023	(f) 2024
1	**Karn 1**	$646,577	$623,990	$637,921	$285,603	$0
2	**Karn 2**	$327,598	$316,541	$306,335	$118,072	$0
3	**Zeeland**	$130,913	$134,097	$139,476	$124,943	$106,395
4	**Total**	$1,105,088	$1,074,628	$1,083,731	$528,619	$106,395

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20525
Exhibit No.: A-14 (NJK-5)
Page: 1 of 1
Witness: NJKapala
Date: September 2019

2020-2024 Lime Expense

Line No.	(a) Unit	(b) 2020	(c) 2021	(d) 2022	(e) 2023	(f) 2024
1	**Karn 1**	$569,875	$549,967	$562,245	$251,722	$0
2	**Karn 2**	$567,285	$548,139	$530,465	$204,460	$0
3	**Campbell 1**	$1,580,663	$1,587,151	$1,707,017	$1,892,111	$1,697,324
4	**Campbell 2**	$2,350,185	$2,104,942	$2,110,215	$2,123,127	$2,365,683
5	**Campbell 3**	$2,893,109	$2,878,398	$3,013,756	$2,458,292	$3,010,229
6	**Total**	$7,961,118	$7,668,597	$7,923,698	$6,929,713	$7,073,237

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20525
Exhibit No.: A-15 (NJK-6)
Page: 1 of 1
Witness: NJKapala
Date: September 2019

2020-2024 Activated Carbon Expense

Line No.	(a) Unit	(b) 2020	(c) 2021	(d) 2022	(e) 2023	(f) 2024
1	**Karn 1**	$167,712	$115,610	$118,191	$52,915	$0
2	**Karn 2**	$117,847	$113,870	$110,198	$42,474	$0
3	**Campbell 1**	$402,443	$404,095	$434,613	$481,738	$432,145
4	**Campbell 2**	$236,797	$212,087	$212,619	$213,920	$238,359
5	**Campbell 3**	$363,340	$361,492	$378,492	$308,732	$378,049
6	**Total**	$1,288,139	$1,207,153	$1,254,112	$1,099,779	$1,048,553

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 to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

DIRECT TESTIMONY

OF

KEVIN C. LOTT, PE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

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

A. My name is Kevin C. Lott, and my business address is 1945 Parnall Road, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Fuels Transportation & Planning Director in the Electric Grid Integration Department.

QUALIFICATIONS

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

A. I graduated in 2002 with a Bachelor of Science in electrical engineering from Michigan State University. I have been employed by Consumers Energy since 2002. Since joining the Company, I have held a variety of engineering and supervisory positions. In 2017, I joined the Electric Grid Integration Department as the Railcar Fleet Manager in the Fossil Fuel Supply group. I have since been promoted to Fuels Transportation & Planning Director.

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

A. My duties include:

- the preparation of short- and long-term projections specifying purchase volumes;
- the optimization of the distribution of coal to the generating plants to minimize the delivered cost of coal;
- managing plant fuel inventories;
- administering the coal transportation contracts;
- managing the projection of volumes of No. 6 fuel oil for D.E. Karn ("Karn") 3 & 4; and natural gas for Zeeland, Jackson, and Karn 3 & 4 Plants; and

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

Q. Have you testified in other cases?

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

- MPSC Case No U-20219 (direct and rebuttal), the Company's 2019 PSCR Plan regarding projected as-burned costs and volumes of coal, oil, and natural gas used for electric generation in 2019.

PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. I am sponsoring direct testimony with respect to the Company's projected as-burned costs and volumes of coal, oil, and natural gas used for electric generation.

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

A. Yes, I am sponsoring the following exhibits:

Exhibit A-16 (KCL-1)	Projected As-Burned Coal Costs – 2020;
Exhibit A-17 (KCL-2)	Projected As-Burned Coal Costs (2021 – 2024);
Exhibit A-18 (KCL-3)	Projected As-Burned Oil & Gas Costs – 2020; and
Exhibit A-19 (KCL-4)	Projected As-Burned Oil & Gas Costs (2021 – 2024).

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

A. Yes.

AS-BURNED COAL COSTS

Q. Please explain Exhibit A-16 (KCL-1).

A. Exhibit A-16 (KCL-1) summarizes the projected as-burned coal costs and tonnage at each of the Company's coal-fired generating plants for the year 2020. The total cost includes primary fuel, auxiliary fuel, freeze protection and dust inhibiting treatments, and state air emission fees.

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

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

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

A. The total monthly delivered cost of coal for each generating plant is determined based on the cost of contract and spot coal purchases allocated to the plant; the application of any necessary or required freeze protection treatments to ensure all lading can be removed from

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

COAL PRICE DETERMINATION

Q. What is the source of the projected coal commodity prices that are included in the as-burned coal cost calculations?

A. Company witness Angela K. Rissman provided the pricing for all coal contracts, as well as projected future market and spot coal purchases.

COAL TRANSPORTATION CONTRACTS

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

A. Coal is transported by rail from the mines either directly to generating plants or to lake terminal facilities, where the coal is transferred to lake vessels for delivery. During 2020, the Company expects to have in effect two contracts that will provide for the shipment of coal on railroads and one or more contracts that will provide vessel services and terminal services for shipments.

Q. Are there any coal transportation agreements that will become effective in 2020?

A. Yes. There is an agreement to provide rail transportation service from the Powder River Basin to the Chicago interchange that will take effect in 2020. There is also an agreement to provide vessel transportation services to the Karn site that will take effect in 2020.

COAL TRANSPORTATION RATE DETERMINATION

Q. What process was used to determine freight rates?

A. Freight rates were determined by contract pricing. Additionally, forecasted fuel surcharges were included according to the terms of the transportation contracts.

COAL TONNAGE DETERMINATION

Q. How were the coal tonnages determined for 2020?

A. As described in Company witness Joshua W. Hahn's direct testimony, a computer model is used to determine production estimates (i.e., MWh production and MMBtu coal burn requirements to support that production) for each generating unit. Besides fuel price, the model uses a variety of inputs, but those most closely related to fuel volume determination include fuel mix, coal quality, and generating unit efficiency. Using the MMBtu coal burn requirements determined from the model, along with inventory considerations, the monthly purchase volumes of coal are determined for each plant. A comparison of these purchase requirements with the amount of coal available under contract determines the need for spot coal purchases.

Q. How many tons of coal has the Company purchased under contract for delivery in 2020 and do you expect to purchase more?

A. The Company presently has approximately 4.3 million tons of coal committed for 2020 from the multiyear or annual purchases shown in Ms. Rissman's Exhibit A-21 (AKR-1). At this time, the Company anticipates purchasing approximately 375 thousand tons of additional coal in 2019 for 2020 delivery.

1 **SPOT COAL PURCHASES**

2 **Q. How much coal do you expect to purchase on a spot basis during 2020?**

3 A. Approximately 1.6 million tons of coal is expected to be purchased on a spot basis in 2020.

4 **2021 – 2024 PROJECTED AS-BURNED COAL COSTS**

5 **Q. Please explain Exhibit A-15 (KCL-2).**

6 A. Exhibit A-17 (KCL-2) summarizes the projected as-burned coal costs and tonnage at each
7 of the Company's coal-fired generating plants for the years 2021 – 2024. The total cost
8 includes primary fuel, auxiliary fuel, freeze protection and dust inhibiting treatments, and
9 state air emission fees.

10 **Q. How were the projected as-burned coal costs for the years 2021 – 2024 determined?**

11 A. In a manner similar to 2020, existing supply and transportation contracts were adjusted
12 based on the expected performance of the indices to which the contracts are tied. Any
13 contracts with fixed price components had those fixed prices included without escalation.
14 Forecasted commodity prices provided by Ms. Rissman and transportation costs, as
15 described above, were utilized for open position (unsecured) tonnage.

16 **Q. Are any new contracts anticipated for the 2021 – 2024 time period?**

17 A. Yes. It is anticipated that the Company will be entering into new supply and transportation
18 contracts to replace those contracts which will expire during 2021 – 2024. The pricing for
19 any new coal supply is provided by Ms. Rissman and modeled accordingly. The pricing
20 for any future transportation contracts is modeled in the same manner as existing contracts.

OIL AND NATURAL GAS PROJECTIONS

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

A. I am supplying the oil and gas fuel cost projections for the Company's oil- and gas-fired generating units, which are Karn Units 3 & 4, the Zeeland Plant, and the Jackson Plant.

Q. Please explain Exhibit A-18 (KCL-3).

A. Exhibit A-18 (KCL-3) summarizes the projected as-burned fuel costs and volumes for the Company's oil-fired and natural gas-fired generating plants for the year 2020.

Q. What is the source of the projected oil and gas commodity prices that are used in these projections?

A. Company witness Stephen J. Nadeau provided these fuel price projections.

Q. Have you developed as-burned oil and natural gas cost projections for the years 2021 – 2024?

A. Yes, these annual cost projections are shown in Exhibit A-19 (KCL-4).

Q. How were your oil and natural gas projections determined for the years 2021 – 2024?

A. The methods used to determine these projected as-burned costs are the same as those used to determine the projected as-burned costs for 2020.

Q. Does this complete your prepared direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

EXHIBITS

OF

KEVIN C. LOTT

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20525
Exhibit No.: A-16 (KCL-1)
Page: 1 of 1
Witness: KCLott
Date: September 2019

Projected As-Burned Coal Costs - 2020

Line	(a) Plant	(b) Burn Volume (Tons)	(c) Burn Dollars
1	JHCampbell 1-2	1,661,358	$ 62,261,020
2	JHCampbell 3 (CE Owned)	3,221,655	$ 120,672,302
3	DEKarn 1-2	1,216,374	$ 49,101,274
4	Total	6,099,388	$ 232,034,597

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20525
Exhibit No.: A-17 (KCL-2)
Page: 1 of 1
Witness: KCLott
Date: September 2019

Projected As-Burned Coal Costs
2021 - 2024

Line	(a)	(b)	(c)	(d)	(e)	(f)
	Burn Volume (Tons)					
	Plant		2021	2022	2023	2024
1	JHCampbell 1-2		1,579,261	1,756,472	1,578,676	1,463,252
2	JHCampbell 3 (CE Owned)		3,090,631	3,077,805	2,657,607	3,076,137
3	DEKarn 1-2		1,224,077	1,232,007	418,134	0
4		Total Burn Tonnage	5,893,969	6,066,284	4,654,417	4,539,389
	Burn Dollars					
	Plant		2021	2022	2023	2024
5	JHCampbell 1-2		$ 60,038,047	$ 68,158,083	$ 64,513,041	$ 61,092,590
6	JHCampbell 3 (CE Owned)		$ 117,483,090	$ 119,386,964	$ 108,569,606	$ 128,271,893
7	DEKarn 1-2		$ 48,418,266	$ 49,572,300	$ 17,101,233	$ -
8		Total Primary Fuel	$ 225,939,403	$ 237,117,347	$ 190,183,880	$ 189,364,483
9		Total Primary Fuel	$ 225,939,403	$ 237,117,347	$ 190,183,880	$ 189,364,483
10		Total Auxilliary Fuel	$ 3,211,813	$ 3,263,150	$ 2,466,961	$ 1,883,876
11		Total Freeze/Dust Treatment	$ 931,018	$ 958,038	$ 736,458	$ 718,703
12		State Air Emission Fees	$ 348,773	$ 348,773	$ 348,773	$ 348,773
13		Total Coal Burn Cost	$ 230,431,007	$ 241,687,308	$ 193,736,072	$ 192,315,835

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20525
Exhibit No.: A-18 (KCL-3)
Page: 1 of 1
Witness: KCLott
Date: September 2019

Projected As-Burned Oil & Gas Costs - 2020

Line	(a) Plant	(b) Burn Volume (BBLS/MCF)	(c) Burn Dollars
1	Zeeland Generating Station	43,417,134	$ 113,649,018
2	Jackson Plant	15,145,344	$ 44,844,047
3	DEKarn 3-4 - Oil	0	$ 20
4	DEKarn 3-4 - Gas	638,482	$ 7,291,559
5	Combustion Turbines - Gas	0	$ 16,386
6	Total		$ 165,801,030

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20525
Exhibit No.: A-19 (KCL-4)
Page: 1 of 1
Witness: KCLott
Date: September 2019

Projected As-Burned Oil & Gas Costs
2021 - 2024

Line	(a)	(b)	(c)	(d)	(e)	(f)
	Burn Volume (BBLS/MCF)					
	Plant		2021	2022	2023	2024
1	Zeeland Generating Station		37,168,747	34,106,371	29,452,094	18,720,028
2	Jackson Plant		12,246,325	9,498,688	3,983,579	1,543,948
3	DEKarn 3-4 - Oil		0	674	66,880	55,431
4	DEKarn 3-4 - Gas		572,941	465,869	0	0
5	Combustion Turbines - Gas		0	0	0	0
	Burn Dollars					
	Plant		2021	2022	2022	2023
6	Zeeland Generating Station		$ 97,929,055	$ 91,954,861	$ 81,995,645	$ 53,997,706
7	Jackson Plant		$ 36,486,412	$ 29,205,398	$ 14,050,794	$ 6,424,653
8	DEKarn 3-4 - Oil		$ 13	$ 38,889	$ 3,889,540	$ 3,275,102
9	DEKarn 3-4 - Gas		$ 6,960,250	$ 6,705,973	$ 5,455,094	$ 5,455,094
10	Combustion Turbines - Gas		$ -	$ -	$ -	$ -
		Total Primary Fuel	$ 141,375,730	$ 127,905,120	$ 105,391,073	$ 69,152,555
11		Total Primary Fuel	$ 141,375,730	$ 127,905,120	$ 105,391,073	$ 69,152,555
12		Total Auxilliary Fuel	$ 3,389,955	$ 3,233,859	$ 2,937,785	$ 1,974,047
13		State Air Emission Fees	$ 76,232	$ 76,232	$ 76,232	$ 76,232
14		Total Oil & Gas Burn Cost	$ 144,841,917	$ 131,215,211	$ 108,405,090	$ 71,202,834

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 to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

DIRECT TESTIMONY

OF

ADAM J. MORITZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

Q. Please state your name and business address.

A. My name is Adam J. Moritz, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

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

Q. In what capacity are you employed?

A. I am a General Engineer II in the Integrated Resource Planning and Analytics section of the Electric Grid Integration Department.

QUALIFICATIONS

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Science Degree in Chemical Engineering with a minor in Mineral Processing from Michigan Technological University in 2014. I joined the Company's Resource Planning department in July 2015. I was responsible for maintaining the Strategist models used in production cost forecasts, strategic studies, and Integrated Resource Plans ("IRPs"). In August 2016, I began working closely with the Company's subject matter expert witness on capacity planning and assumed primary responsibility for forecasting the Company's Planning Reserve Margin Requirement ("PRMR") capacity position by August 2017. I have supported model development as well as provided support for development of testimony and exhibits filed with the Michigan Public Service Commission ("MPSC" or the "Commission").

Q. Have you previously provided testimony before the Commission?

A. Yes. I provided testimony in:

- MPSC Case No. U-20219, the Company's 2019 Power Supply Cost Recover ("PSCR") Plan and five-year forecast, regarding the capacity forecast.

PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. My direct testimony will address: (i) the selection of an appropriate capacity planning reserve margin target for 2020 through 2024; (ii) the resources required to satisfy the capacity planning reserve margin target; (iii) the resources previously approved by the Commission; (iv) the resources included in this PSCR Plan that have not been previously approved by the Commission; (v) the resources remaining to be purchased for the planning period; (vi) the Company's long-term capacity planning options; and (vii) how costs from the Midcontinent Independent System Operator, Inc. ("MISO") capacity market are treated in PSCR cases.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring:

Exhibit A-20 (AJM-1)	Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC).

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

A. Yes.

CAPACITY PLANNING RESERVE MARGIN TARGET

Q. What is a capacity planning reserve margin target?

A. The capacity planning reserve margin target is the amount of capacity that a Load Serving Entity ("LSE") (such as Consumers Energy) maintains to assure that sufficient capacity exists to provide adequate electric supply in each Planning Year ("PY") period.

MISO's PY begins on June 1st of each year and concludes on May 31st of the following calendar year. For example, PY 2020 is the time period from June 1, 2020 through May 31, 2021. Generally, the capacity planning reserve margin target is designed to include consideration of demand forecast variances, generator forced outages and derates,[1] and transmission import limitations.

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

A. The Company relies on MISO to determine the appropriate capacity planning reserve margin that Consumers Energy should maintain. For PY 2019, the MISO Loss of Load Expectation ("LOLE") Working Group performed an LOLE study which considered the probability that various amounts of generation resources would be inadequate to serve firm demand in the MISO footprint. Upon determining the amount of generation resources that would be necessary to achieve an LOLE of less than one occasion every 10 years, a reserve margin (expressed as a percentage of peak firm demand) is calculated and assigned to all LSEs.

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

A. For PY 2019, MISO Staff, with consultation by the LOLE Working Group, determined that, using capacity discounted for forced outages, a capacity planning reserve margin target (or "unforced" capacity planning reserve margin target) for MISO of at least 7.9% of the Company's demand at the time of MISO's coincident peak demand was sufficient to satisfy ReliabilityFirst Corporation's ("RF") capacity planning criteria of

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

expecting to interrupt firm load no more frequently than one occasion in 10 years. For PY 2020, MISO Staff with consultation by the LOLE Working Group determined that, using capacity discounted for forced outages, a capacity planning reserve margin target for MISO of at least 8.9% of each LSE's demand at the time of MISO's coincident peak demand was sufficient to satisfy RF's capacity planning criteria[2]. RF is the regional reliability organization that represents the North American Electric Reliability Corporation ("NERC") in portions of the MISO footprint and portions of the area served by other regional transmission organizations. NERC is the electric reliability organization appointed by the Federal Energy Regulatory Commission to establish, monitor, and enforce reliability standards in the United States. On September 10, 2019, MISO's LOLE Working Group projected planning reserve margin targets of 8.9% for PY 2020, 8.8% for PY 2023, and 8.9% for PY 2025. The Company has interpolated these values and rounded to the nearest tenth of a percent to project a planning reserve margin target of 8.9% for PY 2021, 8.8% for PY 2022, and 8.9% for PY 2024 as shown on Exhibit A-20 (AJM-1), line 7.

Q. How is Consumers Energy planning to meet the 7.9% reserve target for the first five months of 2020 and 8.9% for the last seven months of 2020?

A. To facilitate compliance with the planning reserve margin target, MISO has established Zonal Resource Credits ("ZRCs") for each PY, which are a measure of a resource's available capacity after discounting for the resource's effective forced outage rate. One ZRC of capacity is expected to be sufficient to serve one MW of forecasted demand,

[2] September 10, 2019 LOLE meeting: https://cdn.misoenergy.org/20190910%20LOLEWG%20Item%2002a%20LOLE%20PRM%20and%20LRR%20Review379988.pdf

providing an appropriate discount for generator forced outages or effective load carrying capability. Within MISO's footprint, Consumers Energy, as an LSE, is required to comply with the appropriate unforced capacity reserve margin requirement by having ZRCs equal to annual firm peak demand at the time of MISO's coincident peak demand times 1.079 for the five months ending May 31, 2020 and annual firm peak demand at the time of MISO's coincident peak demand times 1.089 for the seven months beginning June 1, 2020. This amount of capacity provides an adequate reserve to cover load forecast error, weather variability, and transmission contingencies while considering the benefits that result from demand diversity over the MISO footprint. ZRCs eliminate the potential for double-counting MISO market participants' resources within the MISO market footprint through tariff requirements on market participants to use the Module E Capacity Tracking tool.

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

A. To determine the amount of ZRCs represented by the capacity planning reserve margin target, the Company utilizes the demand forecast discussed in the direct testimony of Company witness Eugène M.J.A. Breuring. The forecasted bundled non-coincident peak demand for PY 2020 is 7,963 MW, shown on Exhibit A-20 (AJM-1), line 1, and the internal Demand Response ("DR") programs adjust the peak by downward 641 MW, shown on Exhibit A-20 (AJM-1), line 2, for an adjusted non-coincident peak demand of 7,322 MW, shown on Exhibit A-20 (AJM-1), line 3. However, because the Company's peak demand traditionally occurs at a period different than MISO's peak demand, capacity requirements are reduced based on the Company's demand coincident with

MISO's peak demand. Historical data of the Company's demand at the time of MISO's peak demand indicates that this diversity in peak demand periods reduces the Company's requirements by a load diversity factor of 95.07%, shown on Exhibit A-20 (AJM-1), line 4. The resulting coincident peak demand of 6,961 MW is shown on Exhibit A-20 (AJM-1), line 5. A second adjustment is needed in order to convert this load from demand at the distribution level to the generation level which is accomplished by multiplying this load by a transmission loss factor of 1.037 [3]. The final adjustment made is to apply the planning reserve margin target percentage. Total PRMR, as shown on Exhibit A-20 (AJM-1), line 8, is then calculated by increasing the bundled coincident peak demand by transmission losses and planning reserve margin which results in 7,861 ZRCs in PY 2020.

Q. What programs are included in internal demand response programs shown on Exhibit A-20 (AJM-1), line 2?

A. Internal demand response programs include Energy Efficiency ("EE"), Time of Use ("TOU"), and Conservation Voltage Reduction ("CVR").

Q. How is the PY 2020 forecasted non-coincident peak demand of 7,963 MW, shown on Exhibit A-20 (AJM-1), line 1, derived from the demand forecast discussed in the direct testimony of Company witness Breuring?

A. Mr. Breuring's forecast of 7,860 MW of demand shown on Exhibit A-5 (EMB-4), page 1, line 7, occurs in July 2020 and includes jurisdictional and non-jurisdictional demand from the Company's distribution and wholesale customers adjusted for the demand expected to be offset by EE, Peak Power Savers Air Conditioning Peak Cycling

[3] 2020-2021 Transmission Loss Percentage.xlsx: https://www.misoenergy.org/planning/resource-adequacy

("ACPC"), Commercial and Industrial ("C&I") DR, TOU, and CVR at the time of the Company's peak demand. The demand expected to be offset by EE, ACPC, C&I DR, TOU, and CVR amount to 904 MW at the time of the Company's 2020 peak demand. Adding that amount to the 7,860 MW provided by Mr. Breuring provides a gross demand of 8,764 MW, however because this load is at the generation level it must be reduced by the transmission loss factor previously mentioned, resulting in 8,451 MW of gross demand. Mr. Breuring also prepares an estimate of the amount of demand expected to be offset by Retail Open Access ("ROA") suppliers of 541 MW at the time of the Company's peak demand as shown on Exhibit A-5 (EMB-4), page 3, line 7. However, for the Planning Resource Auction ("PRA"), MISO calculates the forecasted peak demand to be offset by ROA suppliers differently, where current year ROA is equal to the previous year's ratio of ROA to System Peak Load multiplied by the current year's System Peak Load. As before, this load is at the generation level and is converted to the distribution level by reducing by the transmission loss factor. An estimate for the amount of demand expected to be offset by ROA suppliers is 488 MW at the time of the Company's peak demand. Subtracting this ROA load from 8,451 MW results in the forecasted non-coincident peak demand at the distribution level of 7,963 MW as shown on Exhibit A-20 (AJM-1), line 1. The resources applicable for the 2019 PY were presented in Case No. U-20219 and updated in Case No. U-20154.

RESOURCES PLANNED TO SATISFY RESERVE MARGIN REQUIREMENT

Q. What resources are required to meet the 7.9% planning reserve margin target for the first five months of 2020 and 8.9% for the last seven months of 2020?

A. The resources required to meet the 7.9% capacity planning reserve margin target for the first five months of 2020 were presented in Case No. U-20219. Exhibit A-20 (AJM-1), lines 9 through 31, provide a description of the resources currently available to the Company and the resources that are expected to be acquired by Consumers Energy to achieve the 7.9% capacity planning reserve margin under peak load conditions of 2019. In 2020, the Company expects to have 5,259 ZRCs from owned units during the peak load period (Consumers Energy is a summer-peaking system), as shown on Exhibit A-20 (AJM-1), line 17. The Company is able to provide ZRCs in the form of load modifying resources, including ACPC, the Company's Energy Intensive Primary tariff ("Rate EIP"), C&I DR, and the Company's interruptible service provision ("Rate GI"). MISO regards these load modifying resources as resources not requiring a reserve margin to be maintained and, therefore, will be awarded ZRCs equal to the equivalent generating capacity[4] times one plus the reserve margin requirement or, in this case, 556 ZRCs shown on Exhibit A-20 (AJM-1), line 18. The Company also has long-term contracts with several Non-Utility Generators ("NUGs") including capacity acquired through a reverse capacity auction in September 2014 for a total of 2,586 ZRCs, as shown on Exhibit A-20 (AJM-1), line 31. The compilation of all resources for PY 2020 totaling 8,401 ZRCs, as shown on Exhibit A-20 (AJM-1), line 32, when compared to the PRMR of 7,861 MW

[4] The equivalent generation capacity is equal to customer demand multiplied by the sum of one plus transmission losses.

provides an unforced capacity surplus of 540 ZRCs, as shown on Exhibit A-20 (AJM-1), line 33.

RESOURCES PREVIOUSLY APPROVED BY THE COMMISSION

Q. To what extent have the owned resources providing 5,259 ZRCs and NUG resources providing 2,586 ZRCs in 2020 been included in previous PSCR plans?

A. Owned and NUG resources have been included in previous PSCR plans, most recently in Case No. U-20219 and updated in Case No. U-20154. While the Commission has yet to conclude its consideration of the PSCR Plan presented in Case No. U-20219, most of the resources included in this PSCR Plan were included in the last PSCR Plan.

RESOURCES NOT PREVIOUSLY APPROVED BY THE COMMISSION

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

A. Yes, resources included in the Company's IRP and Power Purchase Agreement ("PPA") resources.

Q. What resources are included as part of the Company's IRP filed in Case No. U-20165?

A. The Proposed Course of Action ("PCA") recommended by the Company in the IRP includes 150 MW from the Gratiot wind farm project, 166 MW from the Crescent wind farm project, 234 MW of additional wind project(s), and 100 MW from the River Fork solar project in 2021. Furthermore, the PCA includes 300 MW in 2022, 300 MW in 2023, and 500 MW in 2024 of solar all of which is assumed to by 50% owned and 50% PPA. By PY 2024 these IRP resources represent a total 350 ZRCs of solar and 84 ZRCs of wind. Moreover, the PCA includes a forecast of increasing demand response

as shown on Exhibit A-20 (AJM-1), line 18. Finally, the Commission's February 22, 2018 Order in Case No. U-18090 directed the Company to execute 150 MW of additional capacity through new Public Utility Regulatory Policies Act of 1978 ("PURPA") contracts with Qualifying Facilities ("QFs") in the "PURPA queue." This amount was then increased to 584 MW as part of the IRP settlement approved by the Commission in Case No. U-20165 and the Company expects all 584 MW to be available for PY 2023, as shown on Exhibit A-20 (AJM-1), line 28, column (g).

Q. What PPA resources have been included in this PSCR Plan that have not been previously approved by the Commission?

A. The PPA resources included in this PSCR Plan that have not been previously approved by the Commission are addressed in the direct testimony of Company witness Keith G. Troyer.

Q. How are the contracts in place with QFs in accordance with PURPA that will be terminating during the time period from 2020 to 2024 represented in this case?

A. As discussed in the testimony of Company witness Troyer, several PPAs are expected to terminate before the end of 2024 and the QFs that are parties to those PPAs are expected to sign new PURPA-based contracts. The Company has shown these expected new PURPA-based contracts in the New Contracts w/Existing PURPA QFs resource in Exhibit A-20 (AJM-1), line 27.

Q. How are new contracts with QFs in accordance with PURPA that will be commencing during the time period from 2020 to 2024 represented in this case?

A. As discussed in the direct testimony of Company witness Troyer, several PPAs for solar energy and capacity are expected to come online between 2020 and 2024. The Company

has shown these expected new PURPA-based contracts in the New Contracts w/Solar PURPA QFs resource in Exhibit A-20 (AJM-1), line 28.

RESOURCES REMAINING TO BE PURCHASED FOR 2020

Q. Does Consumers Energy need to acquire additional capacity for 2020?

A. No.

LONG-TERM CAPACITY PLANNING OPTIONS

Q. Should the pace at which the Company pursues DR and load reduction programs be considered as an option in this proceeding for reducing the Company's capacity surplus from 2020 through 2024?

A. No. The purpose for increasing DR and load reduction programs included in this PSCR Plan is to partially offset the Palisades Nuclear Power Plant ("Palisades") PPA termination in PY 2021 and the early retirement of D.E. Karn Units 1 and 2 in PY 2023. From 2020 through 2024, there is an addition of 345 ZRCs through load modifying resources treated as capacity and 323 ZRCs from internal DR programs. The Company intends to grow these programs as discussed in the IRP filed in Case No. U-20165. The DR Program levels are addressed through the Company's electric rate case and IRP proceedings. EE levels for calendar years 2018 through 2021 have already been approved in the Commission's January 23, 2018 Order in Case No. U-18261.

Q. Should additional new capacity from new renewable resources be considered as an option for reducing the Company's capacity surplus from 2020 through 2024 in this proceeding?

A. No. The Company's Renewable Enegy Plan includes 136 ZRCs of new renewable resources becoming available in PY 2021. The purpose of these new renewable

resources is not for adding capacity to meet the Company's planning reserve margin but to comply with the 15% renewable generation statutory mandate by 2021, as discussed in Case No. U-18231. The additional new renewable resources added from PY 2022 through PY 2023 are consistent with the IRP approved in Case No. U-20165.

Q. Does Exhibit A-20 (AJM-1) assume an early termination of the Palisades PPA?

A. No. Since MISO requires the Company to fulfill its capacity needs for the entire PY which, for 2021, begins June 1, 2021 and ends May 31, 2022, the Palisades contract provides no capacity value to meet the Company's capacity obligation with MISO since the contract terminates on April 11, 2022.

Q. Is long-term capacity planning best handled through the PSCR?

A. No. This 2020 PSCR Plan is only seeking to set the appropriate pricing mechanisms for recovery of power supply costs in 2020. The best place to address the Company's capacity needs and the resources secured to meet those needs is through the IRP, most recently filed in Case No. U-20165.

MISO CAPACITY MARKET

Q. What are the Company's options for meeting its PRMR?

A. The Company can meet its PRMR by the tariffs and procedures established by MISO. MISO Business Practice Manual 11[5] explains how to obtain capacity for resources and how to fulfill PRMR obligations.

[5] MISO Business Practice Manual 11: https://www.misoenergy.org/legal/business-practice-manuals/

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

A. Capacity costs and revenues associated with the MISO capacity market are invoiced by MISO on a daily basis over the course of the PY and are recovered through annual PSCR reconciliations.

SUMMARY

Q. Please summarize your direct testimony.

A. My direct testimony explains the selection of a PRMR of 7,861 ZRCs for PY 2020; the 8,401 ZRCs from Company resources required to satisfy the capacity PRMR in PY 2020; that no resources remain to be purchased for the planning period; the Company's long-term capacity planning options; and that costs and revenues associated with the PRA are invoiced by MISO on a daily basis over the course of the PY.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

EXHIBIT

OF

ADAM J. MORITZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20525
Exhibit No.: A-20 (AJM-1)
Page: 1 of 1
Witness: AJMoritz
Date: September 2019

Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC)

Line No.	(a)	(c) PY 2019-20	(d) PY 2020-21	(e) PY 2021-22	(f) PY 2022-23	(g) PY 2023-24	(h) PY 2024-25
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	7,878	7,963	7,970	8,052	8,107	8,156
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	549	641	721	785	846	943
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	7,329	7,322	7,250	7,267	7,261	7,214
4	Load Diversity Factor coincident to MISO, %.	95.07%	95.07%	95.07%	95.07%	95.07%	95.07%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	6,968	6,961	6,892	6,909	6,903	6,858
6	Transmission Losses, %	4.10%	3.70%	3.70%	3.70%	3.70%	3.70%
7	Planning Reserve Margin % UCAP Basis	7.90%	8.90%	8.90%	8.80%	8.80%	8.90%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	7,826	7,861	7,783	7,795	7,789	7,745
9	Company Owned, In-State, Non-Intermittent, ZRC	5,078	5,155	5,175	5,244	4,829	4,831
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	17	17	17	17	17	17
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	64	75	161	236	311	436
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	11	11	11	11	11	11
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	5,170	5,259	5,364	5,508	5,168	5,295
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 4)	444	556	643	724	826	901
19	PPA, In-State, Non-Intermittent, ZRC	2,364	2,366	1,572	1,557	1,557	1,557
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	40	40	40	34	34	34
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	68	69	119	194	269	394
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	5	4	4	4	3	3
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	2	3	16	23	24	24
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	-	85	160	235	292	292
29	Other Forward Capacity Contract, ZRC - In-State	20	20	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	2,499	2,586	1,911	2,046	2,178	2,303
32	Total Planning Resources, ZRC (line 17 + line 18 + line 31)	8,113	8,401	7,918	8,278	8,173	8,499
33	UCAP Surplus/(Shortfall), ZRC (line 32 - line 8)	286	540	134	484	384	754

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 to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

DIRECT TESTIMONY

OF

STEPHEN J. NADEAU

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

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

A. My name is Stephen J. Nadeau, and my business address is 1945 Parnall Road, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Manager of Natural Gas Supply for Generation in Fossil Fuel Supply.

QUALIFICATIONS

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

A. I graduated from Alma College in 2001 with a Bachelor of Science Degree in Biochemistry, and from Spring Arbor University in 2011 with a Master of Business Administration. I began working on contract for Consumers Energy in 2002 and became a Company employee in 2005. I have held several positions in the Laboratory Services and Environmental Strategies Departments, and began working in the Fossil Fuel Supply group in February of 2007.

Q. What are your duties as the Manager of Natural Gas Supply for Generation?

A. My duties include managing the natural gas supply used at the Company's electric generating plants; administering the Fuels Management System that tracks all coal shipments, inventory levels, coal consumption, and accounting information; and the preparation of testimony and filings for presentation before the Michigan Public Service Commission ("MPSC" or the "Commission").

Q. Have you previously testified before the MPSC?

A. Yes. I provided testimony in:

Case No. U-16432-R (2011 Power Supply Cost Recovery ("PSCR") Reconciliation);

Case No. U-16890-R (2012 PSCR Reconciliation);

Case No. U-17095-R (2013 PSCR Reconciliation);

Case No. U-17317-R (2014 PSCR Reconciliation);

Case No. U-17678-R (2015 PSCR Reconciliation);

Case No. U-20068 (2017 PSCR Reconciliation);

Case No. U-20202 (2018 PSCR Reconciliation); and

Case No. U-20219 (2019 PSCR Plan).

PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. I am sponsoring direct testimony with respect to the Company's oil and natural gas commodity price forecasts and procurement strategy for electric generation.

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

A. No.

PRICE PROJECTIONS

Q. On what were the Company's oil and gas commodity price forecasts based?

A. These forecasts were based on price information assembled by the Corporate Risk Management Department within the Company, and were indicative of the future market prices for oil and gas at the time they were prepared.

Q. What were your underlying assumptions for your price projections for 2020?

A. The price of No. 6 and No. 2 oil was based on crude oil projections provided by the Corporate Risk Management Department and our approximation of the relationship between crude oil and No. 6 and No. 2 oil. The price of gas for D.E. Karn ("Karn") Units 3 and 4 was based on the market gas prices (monthly New York Mercantile Exchange ("NYMEX") Henry Hub), provided by the Corporate Risk Management Department, to

which the cost of transportation was added. The prices of gas for the Zeeland and Jackson plants were based on gas market prices (monthly NYMEX Henry Hub) provided by the Corporate Risk Management Department, which were adjusted to the proper gas index and in accordance with the gas management services contract. Also included in the price projections were the demand charges associated with the use of the associated lateral pipelines.

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

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

Q. How did the Company determine its projection for the city gates used for index pricing?

A. The Company has determined historical relationships between the respective city gate and the NYMEX Henry Hub based on actual trades. This relationship was then used to adjust the projected NYMEX Henry Hub price to arrive at a projection for the city gate price.

OIL AND NATURAL GAS PROCUREMENT

Q. What types of fuels are burned at the Company's oil and natural gas generating plants?

A. The Zeeland and Jackson plants burn natural gas. Karn Units 3 and 4 can burn natural gas and No. 6 fuel oil.

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

A. The No. 6 oil burned at Karn Units 3 and 4 will be purchased on a spot basis as needed. A portion of the gas for Karn Units 3 and 4 will be purchased on a spot basis, and the remainder under a gas management services contract, but with spot pricing terms.

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

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

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

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

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

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

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

A. The available storage provided for in the gas transportation agreement with the gas utility is utilized to store gas purchased when prices are lower. The Company does not believe it would be prudent to purchase additional storage over and above that amount provided for in the gas transportation agreement for several reasons. These reasons include, but are not

limited to: (i) the difficulty in accurately predicting the production on these units and the concern that additional storage would be purchased and not used; (ii) recognition of the potential impacts to Consumers Energy gas customers if storage were used by the electric utility to benefit its electric customers, from both a supply and cost standpoint; and (iii) any gas storage purchased by the electric utility from the gas utility would be provided pursuant to tariffs and would only be available to the Karn Units 3 and 4 plants for a portion of its needs on a seasonal basis.

ZEELAND AND JACKSON PLANTS NATURAL GAS

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

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

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

A. Consumers Energy has entered into a contract with a third party (which was competitively bid) to act as a gas management service agent ("Agent") on behalf of the Company with regard to the gas supply for the Zeeland Plant. The Agent's obligations under the contract include purchasing the gas, transporting the gas utilizing primary or secondary firm transportation from its purchase origin to the point of delivery (i.e., the SEMCO interconnection), and storing gas when necessary. Entering into an agreement such as this allows the Company to take advantage of the Agent's diversity of gas purchasing/transportation contracts, gas purchasing experience, as well as the portfolio of arrangements the Agent has with ANR and other pipelines in North America. This

experience and expertise enables the Agent to provide transportation and balancing services to the Company more economically than if the Company were required to obtain firm transportation and storage directly from ANR and other pipeline companies. In addition to the transportation provided for under this service contract, the Company also has a contract with SEMCO that was assigned to the Company at the time of the Zeeland Plant purchase which provides firm gas transportation from SEMCO's point of interconnection with the ANR pipeline system to the Zeeland Plant. The contract with SEMCO was extended for five years in 2017 with more favorable contract extension terms than the original contract.

Q. How does the gas management services contract work?

A. In addition to procuring the gas commodity and transportation service, the Agent is responsible for providing gas pricing information to the Company which is relied upon by the Company to bid energy from the Zeeland Plant into the Midcontinent Independent System Operator, Inc. ("MISO") energy market. The Agent is then responsible for purchasing gas as directed by the Company in the day-ahead gas market. The Agent also purchases gas as directed by the Company in the intraday market as MISO accepts offers from Zeeland in the MISO energy market. The Agent also provides services to balance gas nomination against dispatch requests from MISO. The pricing of the gas management services contract is based on published indices.

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

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

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

A. Yes. The Company pays a fixed annual demand charge as provided for in the December 17, 1999 Transportation Services Contract (and subsequently amended in 2017) assumed by the Company from the previous owner of the Zeeland Plant at the time the Zeeland Plant was acquired by the Company, for transportation of up to 186,000 Mcf of gas per day.

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

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

Q. Does the Company pay for the use of the lateral pipeline that connects the Jackson Plant to the Vector interconnection point?

A. Yes. The Company pays an annual demand charge as provided for in the March 12, 2002 Transportation Services Contract assumed by the Company from the previous owner of the Jackson Plant which provides firm gas transportation from the point of interconnection with the Vector pipeline to the Jackson Plant.

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

A. Similar to the Zeeland gas management services agreement, the Company has entered into a competitively bid contract with a third-party agent to manage the gas supply for the Jackson Plant.

Q. Does the method for managing the gas supplies for the Jackson, Zeeland, and Karn plants through the use of gas management services agents ensure a reliable and reasonably priced gas supply to these facilities?

A. Yes. The requirements for the Agents to hold the necessary firm transportation assets with the pipeline companies to deliver the gas to the plants' delivery point (or utilize firm transportation assets held by the Company) and the methods previously described for the pricing of the gas ensures these facilities are reliable and competitive participants in the MISO energy market.

Q. Does this complete your direct testimony?

A. Yes, it does.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

DIRECT TESTIMONY

OF

ANGELA K. RISSMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

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

A. My name is Angela K. Rissman, and my business address is 1945 Parnall Road, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Manager of Coal Procurement in Fossil Fuel Supply.

QUALIFICATIONS

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

A. I graduated from Western Michigan University in 1996 with a Bachelor of Business Administration in Accountancy and from Central Michigan University in 1999 with a Master of Science in Administration. I began working for CMS Enterprises in 2005 and for Consumers Energy in 2007. I have held several positions of increasing responsibility in the Electric Grid Integration organization, and specifically began work in the Fossil Fuel Supply group in November 2013. I was promoted to Manager of Coal Procurement in November 2017.

Q. What are your duties as the Manager of Coal Procurement?

A. My responsibilities include purchasing the coal used at the Company's electric generating plants; negotiating and managing associated contracts; assuring coal quality standards are met; supporting relevant accounting functions; and the preparation of testimony and exhibits for presentation before the Michigan Public Service Commission ("MPSC" or the "Commission").

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

A. Yes. I provided testimony in:

MPSC Case No. U-20202	2018 Power Supply Cost Recovery ("PSCR") Reconciliation;
MPSC Case No. U-20219	2019 PSCR Plan;
MPSC Case No. U-20068	2017 PSCR Reconciliation;
MPSC Case No. U-18142	2017 PSCR Plan; and
MPSC Case No. U-18402	2018 PSCR Plan.

PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. I am sponsoring direct testimony with respect to the Company's coal purchases and coal procurement strategy for electric generation for the 2020-2024 period.

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

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

Exhibit A-21 (AKR-1)	2020-2024 Coal Contract & Purchase Data.

COAL PURCHASE STRATEGY

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

A. The Fuel Supply Department endeavors to secure coal supplies in quantity and quality sufficient to meet the needs of the Company's coal-fired generating units in an economical manner. Coal from different regions are evaluated and purchased based on total delivered blended cost. Spot, annual, and multi-year contracts are made with coal suppliers to ensure a secure supply of fuel at the most economical value available. All

contracts are competitively bid and to the extent possible, structured to allow volume flexibility in response to potential changes in market conditions.

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

A. Yes. The Company layers its coal purchases in such a way that each year it has a portfolio of coal purchase contracts. The portfolio for a given year will consist of contracts with various coal quality specifications, volumes, term lengths, and prices. Although these purchases are competitively bid, the pricing of these contracts is reflective of the market at the time the purchase was made. Some contracts within the portfolio may be above or below the market at the time of delivery depending on how the market has changed relative to the time the purchase was made. Maintaining such a portfolio minimizes price risk to customers and protects them from price volatility in the market. In addition to providing stability in pricing, procuring coal supplies in such a manner also mitigates supply risk to our customers in the event coal supplies become constrained. Quantities of coal are secured over time that typically positions the Company to have approximately 70% to 90% of its anticipated total volume secured by the fall of each year for the following calendar year; approximately 40% to 50% secured for the next calendar year; and approximately 20% to 25% secured for the third calendar year.

Q. Have there been any changes to your coal purchase strategy for 2020 from the previous PSCR filings?

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

ENVIRONMENTAL CONSIDERATIONS

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

A. In September 2014, the Company reached an agreement with the Environmental Protection Agency and the U.S. Department of Justice regarding emission limits for emission of nitrogen oxides, sulfur dioxides, and particulate matter at each of our coal-fired units. These restrictions dictate the quality of coal that can be purchased. In order to comply with this agreement, the Company will purchase only western and/or low sulfur eastern coal.

COAL PURCHASE CONTRACTS

Q. Please describe Exhibit A-21 (AKR-1).

A. Exhibit A-21 (AKR-1) shows all current and expected coal contracts providing for delivery for the 2020-2024 period.

The contracts provide western coal supply to our coal plants. Column (a) lists the suppliers, which for the purpose of this exhibit are represented by contract number. Column (b) identifies the coal type, that is, whether it is eastern coal (originating typically in the Central Appalachian regions of Kentucky and West Virginia) or western coal (originating typically in the Powder River Basin region in Wyoming and Montana). Column (c) is the date that the contract was fully executed and columns (d) and (e) identify the starting and ending dates for the contract, respectively. Column (f) identifies the contract commitment volumes or the volume we presently expect to nominate. Column (g) defines the contract price ($/ton).

Q. Could you briefly explain "nominate"?

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

Q. Do you anticipate entering into any additional coal supply contracts from which tonnage would be received in 2020?

A. Yes. We anticipate soliciting for additional coal before the end of 2019 for delivery in 2020.

Q. Do you anticipate entering into any additional coal supply contracts from which tonnage would be received in the 2021-2024 time period?

A. Yes. It is anticipated that the Company will be entering into new coal contracts to provide a secure supply of coal following the Company's coal procurement strategy previously discussed.

COAL PRICE DETERMINATION 2020 - 2024

Q. What coal commodity prices were used to develop the as-burned cost of coal included in the direct testimony sponsored by Company witness Kevin C. Lott?

A. For existing contracts, the Company based the projected coal prices on the actual coal contract pricing, whether based on a fixed price or on a price tied to an index using the

projected index price. For the remaining open position, the prices were estimated based on the spot market projections for that period.

Q. What was considered when estimating spot prices?

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

Q. What spot prices for coal were assumed in this filing?

A. The spot prices for coal assumed in this filing are included in the table below:

YEAR	WESTERN ($/Ton)	EASTERN ($/Ton)
2020	$12.15	$52.36
2021	$12.40	$53.00
2022	$12.65	$56.69
2023	$13.10	$63.49
2024	$13.45	$67.80

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

EXHIBIT

OF

ANGELA K. RISSMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20525
Exhibit No.: A-21 (AKR-1)
Page: 1 of 1
Witness: AKRissman
Date: September 2019

2020 - 2024 Coal Contract & Purchase Data

Line No.	(a) Supplier Contract No	(b) Coal Type	(c) Contract Execution Date	(d) Contract Start Date	(e) Contract End Date	(f) Volume (Tons)	(g) Price ($/Ton)	
1	332	Western	11/28/2018	1/1/2019	12/31/2021	78,000	$11.65	*
2	334	Western	1/22/2019	1/1/2019	12/31/2021	187,200	$12.60	*
3	332	Western	11/28/2018	1/1/2019	12/31/2021	1,588,080	$12.20	
4	334	Western	1/22/2019	1/1/2019	12/31/2021	1,115,400	INDEX	
5	340	Western	N/A	1/1/2020	12/31/2020	1,318,200	$11.75	**
6		2020 UNCOMMITTED AS OF 2020 PSCR PLAN CASE				1,986,031		
7					**2020 Total**	**6,272,911**		
8	332	Western	11/28/2018	1/1/2019	12/31/2021	1,588,080	$12.75	
9	334	Western	1/22/2019	1/1/2019	12/31/2021	366,600	INDEX	
10		2021 UNCOMMITTED AS OF 2020 PSCR PLAN CASE				4,175,147		
11					**2021 Total**	**6,129,827**		

* = TONS CARRIED OVER FROM 2019 INTO 2020 PER CONTRACT PROVISIONS
** = NOT FULLY EXECUTED AT DATE OF PLAN FILING

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 to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

DIRECT TESTIMONY

OF

KEITH G. TROYER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

Q. Please state your name and business address.

A. My name is Keith G. Troyer, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

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

Q. In what capacity are you employed?

A. I am the Director of Electric Grid Integration Contracts and Settlements in the Electric Supply Section of the Electric Grid Integration Department.

QUALIFICATIONS

Q. Please describe your educational background and business experience.

A. I received the degree of Bachelor of Science in Engineering with a specialty in Civil Engineering from Michigan State University in 2008. In 2015, I became a Registered Professional Engineer in the state of Michigan. In 2018, I received a Master of Business Administration ("MBA") through Michigan State University's Executive MBA Program. In July 2009, I joined Consumers Energy as an Electric System Owner. In January 2011, I accepted a position as an Engineer in the Transactions and Resource Planning Section of Energy Supply. In that role, I was responsible for administration and coordination of the Company's Experimental Advanced Renewable Program ("EARP") – Solar ("EARP-Solar"), part of the Company's Renewable Energy ("RE") Plan. I was involved in the development and implementation of the EARP-Solar expansion in 2011. In June 2013, I began taking on additional responsibilities associated with the RE Plan, including the calculation of the Transfer Price associated with RE and capacity and the tracking of

RE Credits ("RECs"). In 2014, I was also responsible for supervision of the implementation of the EARP-Anaerobic Digestion ("EARP-AD") pilot. In December 2016, I transitioned to a new role where my supervisory and direct responsibilities included administering Power Purchase Agreements ("PPAs"), issuing solicitations for energy and capacity, and managing the Company's capacity position with Midcontinent Independent System Operator, Inc. ("MISO").

Q. What are your responsibilities as Director of Electric Grid Integration Contracts and Settlements?

A. My responsibilities include oversight of the Company's distribution and PPAs, solicitations for energy and capacity, RE compliance, distributed generation programs, and electric wholesale settlement activities.

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

A. Yes. I provided testimony in:

- Case No. U-17095-R (direct), the Company's 2013 Power Supply Cost Recovery ("PSCR") Reconciliation case, regarding 2013 RE Plan expenses recovered through PSCR;
- Case No. U-17631 (direct), the Company's 2013 RE Reconciliation case, regarding 2013 RE Plan expenses recovered through PSCR, RE compliance, and new renewable capacity compliance;
- Case No. U-17317-R (direct), the Company's 2014 PSCR Reconciliation case, regarding 2014 RE Plan expenses recovered through PSCR;
- Case No. U-17792 (direct and rebuttal), the 2015 biennial review of the Company's RE Plan, regarding RE Plan expenses recovered through the PSCR, RE compliance, new renewable capacity compliance, and RE programs;
- Case No. U-17803 (direct), the Company's 2014 Renewable Cost Reconciliation case, regarding 2014 RE Plan expenses recovered through PSCR, RE compliance, and new renewable capacity compliance;

- Case No. U-17678-R (direct), the Company's 2015 PSCR Reconciliation case, regarding 2015 RE Plan expenses recovered through PSCR;

- Case No. U-17918 (rebuttal), the Company's 2016 PSCR Plan and five-year forecast, regarding the impacts of net electric metering on energy supply;

- Case No. U-18081 (direct and revised), the Company's 2015 Renewable Reconciliation case, regarding 2015 RE Plan expenses recovered through PSCR, RE compliance, and new renewable capacity compliance;

- Case No. U-18090 (direct, rebuttal, reopened rebuttal, second reopened rebuttal, affidavit, and third reopened rebuttal), the Company's 2016 Public Utilities Regulatory Policy Act case to establish a method and calculation for avoided costs;

- Case No. U-17918-R (direct), the Company's 2016 PSCR Reconciliation case, regarding 2016 RE Plan expenses recovered through PSCR;

- Case No. U-18241 (direct), the Company's 2016 RE Cost Reconciliation case, regarding 2016 RE Plan expenses recovered through PSCR;

- Case No. U-18402 (direct and rebuttal), the Company's 2018 PSCR Plan and five-year forecast, regarding long-term PPAs and capacity forecast;

- Case No. U-18231 (direct and rebuttal), the 2017 biennial review of the Company's RE Plan, regarding the Company's Request for Proposal ("RFP") process for new resources, the cost of new renewable energy resources included in the RE Plan, and the risks that may drive performance to vary, associated with these topics;

- Case No. U-18351 (rebuttal), the Company's 2017 Application to comply with Section 61 of 2016 PA 342, regarding customer credits in voluntary RE programs and competitive solicitations;

- Case No. U-20165 (direct, rebuttal, and second rebuttal), the Company's 2018 Integrated Resource Plan, regarding long-term PPAs, proposed changes to the Company's PURPA avoided cost implementation, the Company's proposal to utilize competitive solicitations and the implementation of the Financial Compensation Mechanism;

- Case No. U-20219 (direct and rebuttal), the Company's 2019 PSCR Plan and five-year forecast, regarding long term PPAs and MISO revenue and expenses;

- Case No. U-20202 (direct), the Company's 2018 PSCR Plan and five-year forecast, regarding long-term PPAs and capacity forecast;

- Case No. U-20469 (affidavit), the Company's Application requesting an Order Rescinding Avoided Cost Rates, regarding the Company's avoided costs, obligations to enter new PPAs, and establishment of new avoided costs in the Company's Integrated Resource Plan;

- Case No. U-20496 (direct), the Company's Application for approval of Amendments to the PPA with Viking Energy of Lincoln, LLC, Viking Energy of McBain, LLC, and Hillman Power Company;

- Case No. U-20604 (direct), the Company's Application for approval of PPAs with Commonwealth Power Company and North American Natural resources, Inc.; and

- Case No. U-15805-S (affidavit), the Company's Application for approval of a RE purchase agreement with River Fork Solar, LLC.

PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. My direct testimony will address: (i) the PPA resources included in this PSCR Plan that have not been previously approved by the Commission; (ii) applicable changes to PPA resources included in this PSCR Plan that have previously been approved by the Commission; (iii) the Company's Blackstart Resource Agreement; (iv) PSCR treatment of MISO revenue and expenses; and (v) the portion of expenses associated with the Company's Renewable Resource Program ("RRP") and RE Plan included in this PSCR Plan.

Q. Are you sponsoring any exhibits?

A. No.

PPA RESOURCES NOT PREVIOUSLY APPROVED BY THE COMMISSION

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

A. Yes.

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

A. There are resources included in this PSCR Plan that have not been previously approved by the Commission. They can be categorized into the following groups:

- PURPA Obligations; and
- New Solar Facilities.

Q. Please explain the PPAs, not previously approved by the Commission, that are included in this PSCR filing associated with the Company's PURPA obligation.

A. On August 28, 2019, the Company executed a PPA, in accordance with PURPA, with Grenfell, Inc. for the output of the Belding Plant. On September 27, 2019, the Company filed an application in Case No. U-20604 requesting approval of the PPA. The Company anticipates that the Commission will approve its application, and therefore, the Company has included its forecast of expenses associated with the new PPA in this PSCR Plan. Grenfell, Inc previously had a PPA with the Company that terminated on December 31, 2018. The rates included in the PPA attached to the Company's application for Commission approval of the PPA in Case No. U-20604 were used to forecast the expense associated with this PPA in this PSCR Plan case.

The Company has several other contracts in place with facilities that have, or are expected to, meet the requirements of Qualifying Facilities ("QFs"), in accordance with PURPA, that will terminate during the time period from 2020 to 2024, as discussed later in my direct testimony. The Company forecasts that at the end of the current contract terms, these facilities will execute new PURPA-based agreements at the PURPA rates established in Case No. U-18090 and Case No. U-20165, as applicable.

On September 11, 2019, the Commission approved the Company's settlement agreement with PURPA QF developers in MPSC Case No. U-20615. This settlement agreement will result in the execution of 170[1] MW of new PPAs with PURPA QFs at the full avoided cost rates established in MPSC Case No. U-18090. Additionally, the settlement agreement is expected to result in the execution of 414 MW of new PPAs with PURPA QFs at the reduced avoided cost rates established in MPSC Case No. U-18090.

Q. Please explain the PPAs, not previously approved by the Commission, that are included in this PSCR filing associated with new solar facilities.

A. On June 7, 2019, the Commission's Order in MPSC Case No. U-20165 approved the settlement agreement in the Company's Integrated Resources Plan ("IRP"). The IRP includes the addition of new solar resources to the Company's portfolio of supply assets to be acquired through a competitive solicitation process. In accordance with this settlement agreement, the Company expects that 50% of the new solar assets will be sourced through PPAs and the other 50% will be Company-owned solar projects. PURPA QFs of any technology up to 20 MW in size will be eligible to participate in the annual competitive solicitations as well. The Company estimates that the rates paid under the new PPAs will be similar to the rates included in the recently executed PPA with River Fork Solar, LLC. Therefore, the Company has forecast expenses for the new IRP solar PPAs at the River Fork Solar rates, however, the actual rates will be determined in the annual competitive solicitations.

[1] The Commission's July 31, 2017 Order in Case No. U-18090 required to the Company to enter into 150 MW of PPPs with PURPA QFs which is included in the 170 MW approved in Case No. U-20615.

Q. Please explain the IRP competitive solicitations.

A. The details for administering the competitive solicitations are included in the IRP settlement agreement in MPSC Case No. U-20165. The Company will use an Independent Administrator to conduct the solicitation, complete the proposal evaluations, and provide a blind ranking of projects to the Company for selection. The Company has included the cost associated with the service agreement with the Independent Administrator in this PSCR Plan case as shown on Exhibit A-7 (JWH-1), page 1, line 32.

Q. Are there any additional contracts included in this PSCR Plan case that were not previously included in the 2019 PSCR Plan?

A. Yes. On April 18, 2019, the Commission issued an Order in Case No. U-20496 approving PPA amendments with Viking Energy of Lincoln, LLC and Viking Energy of McBain, LLC. The amendments, as detailed in that filing, include a PPA term that ends May 31, 2027. On July 2, 2019, the Commission issued an Order in Case No. U-20496 approving a PPA amendment with Hillman Power Company, LLC. The amendment, as detailed in that filing, includes a PPA term that ends May 31, 2022. On September 26, 2019 the Commission issued an order in Case No. U-20604 approving PPAs with North American Natural Resources, Inc. for the output of the Rathbun facility and with Commonwealth Power Company for the output of the LaBarge facility. The PPAs, as detailed in that filing, include PPA terms that end on May 31, 2039.

BLACK START SERVICE

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

A. Normally, electric generating units rely on external power supply to initiate operations. Black Start service refers to the process of restoring a generation resource without relying on the external electric power transmission network.

Q. Will the Company have any generation resources designated for Black Start service in 2020?

A. Yes. Ludington Pumped Storage Units 2, 3, and 5 are maintained in accordance with the July 1, 2013 Blackstart Resource Agreement with Michigan Electric Transmission Company, LLC ("METC"), as amended, to be available for Black Start service as part of METC's system restoration plan. The forecast of revenue related to Black Start is discussed in the direct testimony of Company witness Daniel S. Alfred.

TERMINATION OF COMMISSION-APPROVED PPAS

Q. Does the Company have any PPAs, previously approved by the Commission, that have terminated or will terminate in 2020?

A. Yes. In addition to the PPAs previously discussed in my direct testimony, the following PPAs will, or are expected to be, terminate(d) by the end of 2020:

- The Agreement with Elk Rapids Hydroelectric Power LLC for the output of the Elk Rapids Hydroelectric Power Plant will terminate on October 12, 2019;
- The Company anticipates exercising its election to terminate the PPA with STS Hydropower, LLC for the output of the Morrow Hydro Plant effective December 31, 2020;
- The Agreement with STS Hydropower, LLC for the output of the Fallasburg Hydro Plant terminated on May 31, 2019; and
- The Agreement with STS Hydropower, LLC for the output of the Cascade Hydro Plant terminated on December 31, 2018.

Q. Does the Company's election to terminate any of these agreements mean that the Company is unwilling to continue buying energy or capacity from the aforementioned generating resources that are PURPA QFs?

A. No. The Company's termination of the aforementioned contracts only means that the Company is exercising its contractual right to terminate the existing terms of those Agreements. The Company anticipates negotiating new contracts which are based on the Company's avoided costs, in accordance with the Commission's Orders in Case No. U-18090, Case No. U-20165, and the Commission's determinations in any subsequent cases which set the Company's avoided costs, with eligible PURPA QFs that have an installed capacity up to the Company's PURPA obligation, currently set at 20 MW.

Q. Please discuss the Company's obligations to purchase energy and capacity from QFs.

A. As discussed above, under PURPA, as well as the Federal Energy Regulatory Commission Orders implementing PURPA, the Company is currently obligated to buy the energy and capacity through PURPA contracts with QFs up to 20 MW in size. The MPSC has the authority to determine when the Company must purchase from QFs and the price the Company must pay for energy and capacity (i.e., the Company's avoided cost). The Commission's May 31, 2017 Order in Case No. U-18090 directed the Company to pay the full avoided cost (energy and capacity) to QFs with expired PURPA-based PPAs regardless of whether the capacity is needed. The Commission's June 7, 2019 Order in Case No. U-20165 approved the Company's IRP settlement agreement, which maintains that the Company will pay the applicable full avoided cost

(energy and capacity) to QFs with expired PURPA-based PPAs regardless of whether the capacity is needed. Therefore, the Company expects the majority of eligible QFs to execute new PURPA-based agreements at the applicable full avoided cost rate once their existing PURPA-based PPAs expire.

MISO ENERGY MARKETS

Q. With regard to serving Consumers Energy's bundled load, will all of the charges incurred and revenues received by Consumers Energy under MISO's Transmission, Energy, and Operating Reserve Markets Tariff be included in net PSCR costs to be recovered from Consumers Energy's PSCR customers in 2020?

A. Yes. All of the expenses incurred with MISO and all of the revenues received from MISO, to the extent the revenues received were from the output of jurisdictional facilities sold to MISO, are expected to be included in PSCR costs reconciled in the Company's 2020 PSCR Reconciliation case. As with prior PSCR Plan filings, to the extent that the revenue is provided to offset PSCR costs incurred, the Company plans to credit that revenue against PSCR expense. Consumers Energy will include all MISO settled charges incurred and revenues received during the year in the 2019 PSCR Reconciliation case. In this filing, MISO revenues and expenditures are forecast and presented in the direct testimony and exhibits of Company witnesses Alfred and Joshua W. Hahn.

RENEWABLE RESOURCE PROGRAM

Q. Are you familiar with the RRP?

A. Yes. The RRP was approved by the Commission in January 2005 in Case No. U-13843. Under this RRP, the Company contracts to purchase energy generated by renewable technologies and then allocates the cost of that energy between power supply costs

recoverable from PSCR customers and RE costs to be recovered from either voluntary contributions from customers or the Renewable Resource Fund. The Renewable Resource Fund is funded, in part, by a contribution from Midland Cogeneration Venture, LP in accordance with a Settlement Agreement filed and approved by the Commission in Case No. U-15320.

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

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

RE PLAN

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

A. Yes. The Company's RE Plan was approved by the Commission in its May 26, 2009 Order in Case No. U-15805. The RE Plan addresses the measures necessary to comply with MCL 460.1001 *et seq.* The RE Plan was amended with the Commission's Orders in Case Nos. U-16543, U-16581, U-17301, U-17752, U-17792, and U-18231.

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

A. As discussed in Case No. U-18231, the Company recovers a portion of the expenses related to its RE Plan through the PSCR via the transfer price mechanism. At the time that an order is issued by the MPSC approving a RE Plan resource, the most recently Commission-approved transfer price schedule is assigned to the resource to determine the amount of expense to be recovered through the PSCR. The transfer price schedule assigned to a resource remains with that resource through its duration. All additional costs are expected to be recovered as Incremental Cost of Compliance and are not included in this PSCR.

Q. Are there any limits to the amount of expense recovered through PSCR for the resources included in the Company's RE Plan?

A. Yes. For PPA resources, the amount of expense recovered through the PSCR is limited on an annual basis to the lesser of (i) the value of energy, capacity, and ancillary services; and (ii) the actual amount paid to the supplier. For new Company-owned resources, the amount of expense recovered through the PSCR is limited on an annual basis to the lesser of (i) the value of energy, capacity, and ancillary services; and (ii) the forecast of the levelized cost of energy for the facility.

SUMMARY

Q. Please summarize your direct testimony.

A. My direct testimony explains: (i) PPA resources included in this PSCR Plan that have not been previously approved by the Commission; (ii) applicable changes to PPA resources included in this PSCR Plan that have previously been approved by the Commission; (iii) the Company's Blackstart Resource Agreement; (iv) PSCR treatment of MISO

revenue and expenses; and (v) the portion of expenses associated with the Company's RRP and RE Plan included in this PSCR Plan.

Q. Does this complete your direct testimony?

A. Yes, it does.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

DIRECT TESTIMONY

OF

ANDREW G. VOLANSKY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

Q. Please state your name and business address.

A. My name is Andrew G. Volansky. My business address is One Energy Plaza, Jackson, Michigan 49201.

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

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

Q. Please state your educational background.

A. I graduated from Wayne State University in 1992 with a Bachelor of Science Degree, majoring in psychology and in 2001 with a Bachelor of Business Administration degree, majoring in accounting. I am also a Certified Public Accountant registered in the state of Michigan.

Q. Please describe your business experience.

A. After receiving my accounting degree in 2001, I worked as a staff auditor at Arthur Andersen LLP (2001-2002) and George Johnson and Company (2002-2003) working on financial audits, compliance audits, and income tax returns. In 2004, I joined Consumers Energy as an Accounting Analyst in the Technical Accounting and External Financial Reporting Department and was promoted throughout the years to a Senior Accounting Analyst. In 2016, I accepted the position of Senior Rate Analyst II in the Revenue Requirement Section of the Rates and Regulation Department.

Q. What are your responsibilities as Senior Rate Analyst?

A. I am responsible for developing, analyzing, and reviewing the Company's monthly return studies. These include studies pertaining to balance sheet working capital, cost of capital,

return on investment, and return on equity. Additionally, I assist in the development of analyses related to the Company's revenue requirements and the preparation of electric and gas rate case filings at the Michigan Public Service Commission ("MPSC" or the "Commission"). I am also responsible for forecasting the Power Supply Cost Recovery ("PSCR") Factor on a monthly basis.

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

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

Case No. U-18402 – 2018 PSCR Plan Case;

Case No. U-18424 – Gas Rate Case;

Case No. U-20219 – 2019 PSCR Plan Case; and

Case No. U-20618 – Mid-Michigan Pipeline Act 9.

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

A. The purpose of my direct testimony is to present the calculation of the 2020 PSCR Factor.

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

A. Yes, I am sponsoring the following exhibit:

Exhibit A-22 (AGV-1) Calculation of 2020 PSCR Factor.

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

A. Yes.

Q. Please summarize Exhibit A-22 (AGV-1).

A. Exhibit A-22 (AGV-1) shows the calculation of the 2020 PSCR Factor including: (1) system power supply costs provided by Company witness Joshua W. Hahn; (2) transmission expenses provided by Company witness Daniel S. Alfred; (3) Schedule 2 Reactive Revenue provided by Mr. Alfred; and (4) urea costs and aqueous ammonia costs,

lime expense, and activated carbon expense provided by Company witness Norman J. Kapala.

Q. Please describe in more detail the calculations in Exhibit A-22 (AGV-1).

A. The 2020 PSCR Factor is calculated by first summing the system power supply costs on line 1, the net transmission expenses on line 4, the total of urea costs, aqueous ammonia costs, lime expense, and activated carbon expense ("Total Environmental Costs") shown on line 9. That sum, shown on line 10, is divided by total system energy requirements (measured in units of kilowatt hours ("kWh")) on line 11, provided by Company witness Eugene M. Breuing, to determine the average cost per kWh of requirements on line 12. From this quotient is subtracted the Base Recovery Factor (shown on line 13) collected through the standard tariffs as approved by the Commission. This remaining expense per kWh amount of $0.00007, set forth on line 14, is multiplied by the Line and Transformation Loss Factor on line 15 to determine the 2020 per kWh PSCR Factor of $0.00008 at sales, shown on line 16.

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

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

Q. What is the purpose of this policy?

A. The Company's policy is intended to match costs with the customers who cause the Company to incur those costs. And while it is unlikely that the Company will succeed in exactly matching costs with customers who incurred the costs, the monthly calculations described above attempt to minimize any over and under recovery for the PSCR Plan year. Any amounts over collected are subject to refund with interest at the Company's authorized return on equity, which is currently 10.00%.

Q. Does this conclude 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 to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

EXHIBIT

OF

ANDREW G. VOLANSKY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2019

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Consumers Energy Company

Calculation of 2020 PSCR Factor

Line				
1	System Power Supply Costs[1]		$	1,531,201,425
	System Transmission Expenses			
2	Total Transmission Expenses[2]	$ 468,668,867		
3	Less: Schedule 2 Reactive Revenue[3]	(4,500,000)		
4	Net Transmission Expenses		$	464,168,867
	Environmental Costs			
5	Urea Costs[4]	1,859,601		
6	Aqueous Ammonia[5]	1,105,088		
7	Lime Expense[6]	7,961,118		
8	Activated Carbon[7]	1,288,139		
9	Total Environmental Costs		$	12,213,946
10	Total System Power Supply Costs		$	2,007,584,238
11	Total System Requirements in kWh[8]			35,997,234,000
	Jurisdictional Factor Calculation			
12	Average Cost at Requirements (Line 10 / Line 11)		$	0.05577
13	Less: Base Recovery Factor[9]		$	0.05570
14	Remaining Cost per kWh (Line 12 - Line 13)		$	0.00007
15	Line & Transformation Loss Factor[10]			1.0793
16	2020 PSCR Factor at Sales (Line 14 x Line 15)		$	0.00008

Sources:
[1]Exhibit A-7 (JWH-1), Page 1, Line 34
[2]Exhibit A-1 (DSA-1), line 31
[3]DSAlfred Testimony, Page 9
[4]Exhibit A-12 (NJK-3), Line 3
[5]Exhibit A-13 (NJK-4), Line 4
[6]Exhibit A-14 (NJK-5), Line 4
[7]Exhibit A-15 (NJK-6), Line 4
[8]Exhibit A-4 (EMB-3), Page 2, Line 13
[9]Per Order in Case No. U-18322/ Rule C-8, Section B(1) of Company Tariffs
[10]Per Rule C-8 of the Company Tariffs

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 to implement a power supply cost recovery plan for the 12 months ending December 31, 2020.	))))))	Case No. U-20525

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Crystal L. Chacon, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on September 30, 2019, she served an electronic copy of **Consumers Energy Company's Application and the Testimony and Exhibits of Consumers Energy Company Witnesses Daniel S. Alfred, Eugène M.J.A. Breuring, Joshua W. Hahn, Norman J. Kapala, Kevin C. Lott, Adam J. Mortiz, Stephen J. Nadeau, Angela K. Rissman, Keith G. Troyer, and Andrew G. Volansky** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Crystal L. Chacon

Digitally signed by Crystal L. Chacon
Date: 2019.09.30 13:57:30 -04'00'

Crystal L. Chacon

Subscribed and sworn to before me this 30th day of September, 2019.

Melissa K. Harris

Digitally signed by Melissa K. Harris
Date: 2019.09.30 13:58:06 -04'00'

Melissa K. Harris, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 06/11/20
Acting in the County of Jackson

ATTACHMENT 1 TO CASE NO. U-20525
(Parties to Case Nos. U-20219 and U-18402)

Administrative Law Judge

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