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September 30, 2022

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

RE: Case No. U-21257 – 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, 2023.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case are **Consumers Energy Company's Application with Supporting Testimony and Exhibits of Consumers Energy Company Witnesses Daniel S. Alfred, Eugène M.J.A. Breuring, Joshua W. Hahn, Nathan J. Hoffman, Kevin C. Lott, Stephen J. Nadeau, Angela K. Rissman, Andrew G. Volansky, and Emily M. Walainis.**

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-20525, U-20802, U-20697, and U-20963.

Sincerely,

RWB
Digitally signed by Robert W. Beach
Date: 2022.09.30 15:59:05 -04'00'

Robert W. Beach

cc: Parties per Attachment 1 to the Proof of Service

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, 2023	))))))	Case No. U-21257

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 2023. 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 1.9 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 2023. 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 2023, a uniform maximum PSCR Factor of $0.02700 per kWh for all classes of customers.

7. As explained in the testimony and exhibits accompanying this Application, the Company has observed a significant power supply cost underrecovery in 2022 due to actual costs exceeding the cost projections in the 2022 PSCR Plan, particularly with respect to natural gas costs. Pursuant to the roll-in methodology approved by the Commission for use in PSCR proceedings under MCL 460.6j, the Company incorporates prior year over and underrecoveries

into the uniform maximum factor set in PSCR plan cases. See MPSC Case No. U-15001, December 21, 2006 Order Approving Temporary Factors, pages 7-9. Therefore, in this PSCR Plan case the Company has incorporated the current 2022 power supply cost underrecovery into the proposed uniform maximum PSCR Factor for the calendar year 2023.

8. The accompanying testimony and exhibits, as provided by Company witnesses Daniel S. Alfred, Eugène M.J.A. Breuring, Joshua W. Hahn, Nathan J. Hoffman, Kevin C. Lott, Stephen J. Nadeau, Angela K. Rissman, Andrew G. Volansky, and Emily M. Walainis, 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.

9. 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 2023 a maximum monthly PSCR Factor of not less than $0.02700 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 2023 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

Date: September 30, 2022

By: ______________________________
Timothy J. Sparks
Vice President of Electric Supply
Consumers Energy Company

____
Robert W. Beach (P73112)
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Spencer A. Sattler (P70524)
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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, 2023	))))))	Case No. U-21257

VERIFICATION

Timothy J. Sparks, being first duly sworn, deposes and says that he is the Vice President of Electric Supply 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, 2022

By: Tim Sparks

Timothy J. Sparks
Vice President of Electric Supply
Consumers Energy Company

PREFILED EXHIBITS

Exhibit of Daniel S. Alfred

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

Exhibits of Eugène M.J.A. Breuring

A-2 (EMB-1)	2023 Forecast of Calendar Total Electric Deliveries;
A-3 (EMB-2)	Forecast of Annual Calendar Deliveries;
A-4 (EMB-3)	Forecast of Total Monthly Generation Requirements;
A-5 (EMB-4)	Forecast of Total Monthly Peak Demand; and
A-6 (EMB-5)	Forecasted System Load Factor Based on Summer Peak Demand.

Exhibits of Joshua W. Hahn

A-7 (JWH-1)	Monthly Summary of the Projected 2023 Fuel and Purchased and Net Interchange Power Expenses;
A-8 (JWH-2)	Annual Summary for Years 2023 through 2027 of Fuel and Purchased and Net Interchange Power Expenses;
A-9 (JWH-3)	Purchased Power Agreements – Projected 2023 Rates; and
A-10 (JWH-4)	Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRCs).

Exhibits of Nathan J. Hoffman

A-11 (NJH-1)	Major Outages in the 2023 PSCR Plan;
A-12 (NJH-2)	2023 PSCR Random Outage Rate Projections;
A-13 (NJH-3)	2023-2027 Urea Expense;
A-14 (NJH-4)	2023-2027 Aqueous Ammonia Expense;
A-15 (NJH-5)	2023-2027 Lime Expense; and

A-16 (NJH-6)	2023-2027 Activated Carbon Expense.

Exhibits of Kevin C. Lott

A-17 (KCL-1)	Projected As-Burned Coal Costs – 2023;
A-18 (KCL-2)	Projected As-Burned Coal Costs (2024 – 2027);
A-19 (KCL-3)	Projected As-Burned Oil & Gas Costs – 2023; and
A-20 (KCL-4)	Projected As-Burned Oil & Gas Costs (2024 – 2027).

Exhibit of Stephen J. Nadeau

A-21 (SJN-1)	2023 Forecasted Natural Gas Prices and 2022 Comparison of Forecasted vs. Actual Natural Gas Prices.

Exhibit of Angela K. Rissman

A-22 (AKR-1)	Coal Contract & Purchase Data.

Exhibits of Andrew G. Volansky

A-23 (AGV-1)	Calculation of 2023 PSCR Factor; and
A-24 (AGV-2)	Forecasted 2022 PSCR Under-Recovery.

Exhibit of Emily M. Walainis

A-25 (EMW-1)	New and Amended PPAs not Previously Included in the Company's PSCR Plan.

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, 2023	))))))	Case No. U-21257

DIRECT TESTIMONY

OF

DANIEL S. ALFRED

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

QUALIFICATIONS

Q. Please state your name and business address.

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

Q. By whom are you employed?

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

Q. What is your position with Consumers Energy?

A. I am a Principal Rate Analyst in the Electric Supply Regulatory Strategies group.

Q. Please describe your educational background.

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

Q. Please describe your business experience.

A. In January of 1998, I joined Consumers Energy as a Rate Analyst in the Financial Analysis and Planning Section of the Rates Department and was promoted to General Rate Analyst in October of 1999. During August of 2001, I transferred to a position in the Revenue Requirements section of the Rates Department. In February of 2004, I was promoted to a Senior Rate Analyst in the Revenue section of the Rates and Business Support Department. In March of 2013, I assumed the position of Senior Rate and Business Support Consultant in the Transmission and Regulatory Strategies Section of Energy Supply Operations. In June of 2020, I was promoted to my current position of Principal Rate Analyst.

Q. What are your responsibilities as Principal Rate Analyst?

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;

Case No. U-20219 2019 PSCR Plan Case;

Case No. U-20525 2020 PSCR Plan Case;

Case No. U-20802 2021 PSCR Plan Case; and

Case No. U-21048 2022 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 2023 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 2023 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 2021 PSCR Plan, Case No. U-20802.

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 2023 in the Company's total transmission costs.

A. The transmission and energy-market-related charges included in the total transmission costs projected for 2023 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, 26-A and 33. 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 Emily M. Walainis in her 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 2023 PSCR Plan year and the five-year period 2023 through 2027 is shown on Exhibit A-1 (DSA-1), line 16, Schedule 1 – System Control and Dispatch.

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 2023 PSCR Plan year and the five-year period 2023 through 2027 is shown on Exhibit A-1 (DSA-1), line 17, Schedule 2 – Reactive Support.

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 Agency which all reside within the METC footprint. The rate that is assessed to load in the joint zone is an average of the joint zone members' revenue requirements. The MJZ was approved by FERC in Docket No. ER02-2458.

This rate is calculated per the MISO Tariff Attachment O. The Company's forecasted expense for the 2023 PSCR Plan year and the five-year period 2023 through 2027 is shown on Exhibit A-1 (DSA-1), line 18, Schedule 9 – Network Transmission Service.

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 2023 PSCR Plan year and the five-year period 2023 through 2027 for this portion of Schedule 10 is shown on Exhibit A-1 (DSA-1), line 19, Schedule 10 ISO Cost Recovery Adder – Demand Basis. The second rate is applied to actual volume of MWh of transmission service received. The Company's forecasted expense for the 2023 PSCR Plan year and the five-year period 2023 through 2027 for this portion of Schedule 10 is shown on Exhibit A-1 (DSA-1), line 20, Schedule 10 – ISO Cost Recovery Adder – Energy Basis.

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 2023 PSCR Plan year and the five-year period 2023 through 2027 are shown on Exhibit A-1 (DSA-1), line 21, Schedule 10 – FERC – ISO Cost Recovery Adder – FERC Annual Charge.

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 2023 PSCR Plan year and the five-year period 2023 through 2027 are shown on Exhibit A-1 (DSA-1), line 22, Schedule 16 – Financial Transmission Rights

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 2023 PSCR Plan year and the five-year period 2023 through 2027 are shown on Exhibit A-1 (DSA-1), line 23, Schedule 17, ISO Cost Adder – Energy Markets.

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 MISO Market. This rate is charged on the same basis as Schedule 17. The Company's forecasted expenses for the 2023 PSCR Plan year and the five-year period 2023 through 2027 are shown on Exhibit A-1 (DSA-1), line 24, Schedule 24 – Balancing Area Cost Adder – Energy Markets.

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 2023 PSCR Plan year and the five-year period 2023 through 2027 are shown on Exhibit A-1 (DSA-1), line 25, Schedule 26 – Network Upgrade Charge from Transmsision Expansion Plan.

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

A. MISO Schedule 26-A is the Tariff schedule that includes the Multi-Value Project Usage Rate and is a MISO System-wide rate charged to Monthly Net Actual Energy Withdrawals, certain Export Schedules, and Through Schedules. The rate is calculated using the formula included in Attachment MM of the Tariff. The charges under this Schedule 26-A shall be in addition to any charges under Schedules 7, 8, 9, and 26. Grandfathered Agreements will not be charged this Schedule. The Company's forecasted expenses for the 2023 PSCR Plan year and the five-year period 2023 through 2027 are shown on Exhibit A-1 (DSA-1), line 26, Schedule 26-A – Multi-Value Project Usage Rate.

Q. Will the Company be providing Blackstart Service in the 2023 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 2023 PSCR Plan year and the five-year period 2023 through 2027 are shown on Exhibit A-1 (DSA-1), line 27, Schedule 33 – Blackstart Service.

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

A. Each of the expenses described above, as well as the total expenses for each plan year, is identified on Exhibit A-1 (DSA-1). The total cost for 2023 equals $505,387,405 and can be found on Exhibit A-1 (DSA-1), page 1, line 31, column (o). It is composed of $497,991,964 of transmission expenses (line 29, column (o)) and $7,395,441 of energy market administration expenses (line 30, column (o)).

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

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

A. Consumers Energy provides generation-related reactive services that are necessary for the transmission of power. The Company receives revenue from 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 2023 from Schedule 2?

A. Yes. The Company expects to receive $4,500,000 in 2023. 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 addressing transmission planning and project approvals. It is primarily through this stakeholder process that the Company works to, advocate for and 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, advocate and assure new transmission projects are justified and costs are allocated according to cost causation principles.

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

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

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

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

Q. Does this conclude your direct testimony?

A. Yes, it does.

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	)	Case No. U-21257
cost recovery plan for the 12 months	)	
ending December 31, 2023	)	
	)	

EXHIBIT

OF

DANIEL S. ALFRED

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.:	U-21257
Exhibit:	A-1 (DSA-1)
Page:	1 of 5
Witness:	DSAlfred
Date:	September 2022

2023 Transmission and Energy Market Administration Expenses

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper DSA-1	5,101	4,860	4,750	4,399	5,223	6,624	7,143	6,856	6,328	4,794	4,905	5,229	**66,213**
2	Hours per Month	Day in Month * 24	744	672	744	720	744	720	744	744	720	744	720	744	**8,760**
3	Delivered MWhs	Workpaper DSA-3	3,019,342	2,841,598	2,964,887	2,690,571	2,739,108	3,003,434	3,388,737	3,269,148	2,827,094	2,793,441	2,769,697	3,042,058	**35,349,115**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	195.8452038	195.8452	195.8452	195.8452	195.8452	195.8452	195.8452	195.8452	195.8452	195.8452	195.8452	195.8452	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	5132.084672	5132.084672	5132.084672	5132.084672	5132.084672	5218.860275	5218.860275	5218.860275	5218.860275	5218.860275	5218.860275	5218.860275	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	
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	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	1091.740791	1,091.7408	1,091.7408	1,091.7408	1,091.7408	1,091.7408	1,091.7408	1,091.7408	1,091.7408	1,091.7408	1,091.7408	1,091.7408	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.55	1.5500	1.5500	1.5500	1.5500	1.5500	1.5500	1.5500	1.5500	1.5500	1.5500	1.5500	
15	Schedule 33 - Blackstart Service	Workpaper DSA-5a	4.282132712	4.2821	4.2821	4.2821	4.2821	4.2821	4.2821	4.2821	4.2821	4.2821	4.2821	4.2821	
	Expenses														
16	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 436,009	$ 415,412	$ 406,009	$ 375,991	$ 446,455	$ 566,166	$ 610,504	$ 585,961	$ 540,882	$ 409,717	$ 419,251	$ 446,893	**$ 5,659,249**
17	Schedule 2 - Reactive Support	Line 1 * Line 5	999,060	951,864	930,317	861,535	1,022,995	1,297,296	1,398,892	1,342,655	1,239,361	938,813	960,659	1,023,998	**12,967,447**
18	Schedule 9 - Network Transmission Service	Line 1 * Line 6	26,180,172	24,943,416	24,378,770	22,576,364	26,807,378	34,570,194	37,277,515	35,778,914	33,026,360	25,017,385	25,599,542	27,287,383	**343,443,392**
19	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	248,975	214,257	231,843	207,777	254,940	312,869	348,617	334,602	298,897	233,961	231,682	255,190	**3,173,608**
20	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	264,796	249,208	260,021	235,963	240,220	263,401	297,192	286,704	247,936	244,985	242,902	266,789	**3,100,117**
21	Schedule 10 - FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	193,238	181,862	189,753	172,197	175,303	192,220	216,879	209,225	180,934	178,780	177,261	194,692	**2,262,343**
22	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	22,772	19,597	21,205	19,004	23,318	28,616	31,886	30,604	27,338	21,399	21,190	23,341	**290,269**
23	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	537,443	505,805	527,750	478,922	487,561	534,611	603,195	581,908	503,223	497,233	493,006	541,486	**6,292,143**
24	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	69,445	65,357	68,192	61,883	62,999	69,079	77,941	75,190	65,023	64,249	63,703	69,967	**813,030**
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,569,269	5,306,176	5,186,060	4,802,637	5,702,694	7,231,788	7,798,136	7,484,642	6,908,831	5,233,422	5,355,204	5,708,286	**72,287,146**
26	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	4,679,981	4,404,478	4,595,574	4,170,385	4,245,617	4,655,323	5,252,542	5,067,180	4,381,995	4,329,834	4,293,030	4,715,191	**54,791,129**
27	Schedule 33 - Blackstart Service	Line 1 * Line 15	21,844	20,812	20,341	18,837	22,368	28,365	30,587	29,357	27,098	20,527	21,005	22,390	**283,532**
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**	**$ 38,595,345**	**$ 36,689,486**	**$ 36,200,687**	**$ 33,423,685**	**$ 38,919,970**	**$ 49,119,622**	**$ 53,232,863**	**$ 51,121,240**	**$ 46,854,295**	**$ 36,609,424**	**$ 37,302,536**	**$ 39,922,811**	**$ 497,991,964**
30	Total Energy Market Administration Expenses	**Lines 22-24**	**629,660**	**590,758**	**617,147**	**559,809**	**573,878**	**632,306**	**713,022**	**687,703**	**595,584**	**582,881**	**577,900**	**634,794**	**7,395,441**
31	**Total Transmission and Energy Markets Administration Expenses**	**Lines 30 + 31**	**$ 39,225,005**	**$ 37,280,244**	**$ 36,817,834**	**$ 33,983,494**	**$ 39,493,848**	**$ 49,751,928**	**$ 53,945,885**	**$ 51,808,942**	**$ 47,449,879**	**$ 37,192,304**	**$ 37,880,436**	**$ 40,557,605**	**$ 505,387,405**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21257
Exhibit: A-1 (DSA-1)

Witness: DSAlfred
Date: September 2022

2024 Transmission and Energy Market Administration Expenses

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper DSA-1	5,091	4,937	4,777	4,423	5,273	6,624	7,139	6,859	6,317	4,787	4,889	5,216	**66,333**
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	2,972,111	2,859,017	2,919,171	2,661,974	2,726,509	2,977,858	3,363,364	3,228,787	2,794,684	2,768,163	2,738,502	3,012,735	**35,022,874**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	195.9159312	195.9159	195.9159	195.9159	195.9159	195.9159	195.9159	195.9159	195.9159	195.9159	195.9159	195.9159	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	5679.059581	5679.059581	5679.059581	5679.059581	5679.059581	5967.183562	5967.183562	5967.183562	5967.183562	5967.183562	5967.183562	5967.183562	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	
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	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	1083.7987	1,083.7987	1,083.7987	1,083.7987	1,083.7987	1,083.7987	1,083.7987	1,083.7987	1,083.7987	1,083.7987	1,083.7987	1,083.7987	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.6200	1.6200	1.6200	1.6200	1.6200	1.6200	1.6200	1.6200	1.6200	1.6200	1.6200	1.6200	
15	Schedule 33 - Blackstart Service	Workpaper DSA-5a	4.2837	4.2837	4.2837	4.2837	4.2837	4.2837	4.2837	4.2837	4.2837	4.2837	4.2837	4.2837	
	Expenses														
16	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 435,153	$ 421,974	$ 408,271	$ 378,024	$ 450,662	$ 566,152	$ 610,202	$ 586,246	$ 539,954	$ 409,185	$ 417,833	$ 445,833	**$ 5,669,488**
17	Schedule 2 - Reactive Support	Line 1 * Line 5	997,457	967,249	935,838	866,506	1,033,008	1,297,733	1,398,704	1,343,793	1,237,683	937,933	957,756	1,021,938	**12,995,599**
18	Schedule 9 - Network Transmission Service	Line 1 * Line 6	28,913,518	28,037,859	27,127,345	25,117,621	29,944,049	39,526,203	42,601,570	40,929,084	37,697,210	28,567,453	29,171,205	31,126,056	**388,759,173**
19	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	248,486	217,641	233,135	208,900	257,342	312,861	348,444	334,765	298,384	233,657	230,899	254,584	**3,179,098**
20	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	260,654	250,736	256,011	233,455	239,115	261,158	294,967	283,165	245,094	242,768	240,167	264,217	**3,071,506**
21	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	190,215	182,977	186,827	170,366	174,497	190,583	215,255	206,642	178,860	177,162	175,264	192,815	**2,241,464**
22	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	22,727	19,906	21,323	19,107	23,537	28,615	31,870	30,619	27,291	21,371	21,119	23,285	**290,771**
23	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	529,036	508,905	519,612	473,831	485,319	530,059	598,679	574,724	497,454	492,733	487,453	536,267	**6,234,072**
24	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	68,359	65,757	67,141	61,225	62,710	68,491	77,357	74,262	64,278	63,668	62,986	69,293	**805,526**
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,517,891	5,350,780	5,177,016	4,793,478	5,714,559	7,179,006	7,737,574	7,433,807	6,846,813	5,188,607	5,298,264	5,653,317	**71,891,112**
26	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	4,814,819	4,631,607	4,729,057	4,312,398	4,416,945	4,824,130	5,448,649	5,230,635	4,527,388	4,484,425	4,436,373	4,880,630	**56,737,056**
27	Schedule 33 - Blackstart Service	Line 1 * Line 15	21,809	21,149	20,462	18,946	22,587	28,375	30,583	29,382	27,062	20,508	20,941	22,345	**284,147**
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**	**$ 41,402,003**	**$ 40,083,972**	**$ 39,075,962**	**$ 36,101,694**	**$ 42,254,764**	**$ 54,188,202**	**$ 58,687,949**	**$ 56,379,519**	**$ 51,600,447**	**$ 40,263,698**	**$ 40,950,701**	**$ 43,863,734**	**$** 544,852,644
30	Total Energy Market Administration Expenses	**Lines 22-24**	**620,122**	**594,569**	**608,077**	**554,163**	**571,566**	**627,165**	**707,906**	**679,605**	**589,023**	**577,772**	**571,558**	**628,845**	7,330,369
31	**Total Transmission and Energy Markets Administration Expenses**	**Lines 30 + 31**	**$ 42,022,124**	**$ 40,678,541**	**$ 39,684,038**	**$ 36,655,858**	**$ 42,826,330**	**$ 54,815,367**	**$ 59,395,855**	**$ 57,059,124**	**$ 52,189,470**	**$ 40,841,470**	**$ 41,522,258**	**$ 44,492,579**	**$** 552,183,012

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21257
Exhibit: A-1 (DSA-1)
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Witness: DSAlfred
Date: September 2022

2025 Transmission and Energy Market Administration Expenses

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper DSA-1	5,009	4,791	4,726	4,342	5,177	6,530	7,075	6,745	6,234	4,716	4,805	5,127	**65,276**
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	2,898,550	2,728,885	2,856,324	2,605,039	2,665,724	2,911,536	3,290,704	3,157,921	2,732,234	2,702,897	2,673,475	2,946,636	**34,169,926**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	198.9244835	198.9245	198.9245	198.9245	198.9245	198.9245	198.9245	198.9245	198.9245	198.9245	198.9245	198.9245	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	6356.788686	6356.788686	6356.788686	6356.788686	6356.788686	6577.614166	6577.614166	6577.614166	6577.614166	6577.614166	6577.614166	6577.614166	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	
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	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	1082.605042	1,082.6050	1,082.6050	1,082.6050	1,082.6050	1,082.6050	1,082.6050	1,082.6050	1,082.6050	1,082.6050	1,082.6050	1,082.6050	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.6	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	
15	Schedule 33 - Blackstart Service	Workpaper DSA-5a	4.349460805	4.3495	4.3495	4.3495	4.3495	4.3495	4.3495	4.3495	4.3495	4.3495	4.3495	4.3495	
	Expenses														
16	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 428,083	$ 409,458	$ 403,905	$ 371,142	$ 442,482	$ 558,154	$ 604,693	$ 576,479	$ 532,831	$ 403,044	$ 410,720	$ 438,171	**$ 5,579,164**
17	Schedule 2 - Reactive Support	Line 1 * Line 5	996,321	952,972	940,050	863,796	1,029,833	1,299,047	1,407,363	1,341,697	1,240,111	938,045	955,911	1,019,798	**12,984,944**
18	Schedule 9 - Network Transmission Service	Line 1 * Line 6	31,838,218	30,452,960	30,040,024	27,603,295	32,909,125	42,954,144	46,535,694	44,364,402	41,005,381	31,017,292	31,608,030	33,720,539	**424,049,103**
19	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	244,449	218,728	230,642	205,097	252,671	308,442	345,298	329,187	294,448	230,151	226,968	250,209	**3,136,291**
20	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	254,203	239,323	250,500	228,462	233,784	255,342	288,595	276,950	239,617	237,044	234,464	258,420	**2,996,703**
21	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	185,507	174,649	182,805	166,723	170,606	186,338	210,605	202,107	174,863	172,985	171,102	188,585	**2,186,875**
22	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	22,358	20,006	21,095	18,759	23,110	28,211	31,582	30,109	26,931	21,050	20,759	22,885	**286,856**
23	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	515,942	485,742	508,426	463,697	474,499	518,253	585,745	562,110	486,338	481,116	475,879	524,501	**6,082,247**
24	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	66,667	62,764	65,695	59,916	61,312	66,965	75,686	72,632	62,841	62,167	61,490	67,773	**785,908**
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,422,269	5,186,350	5,116,024	4,701,032	5,604,651	7,069,793	7,659,278	7,301,907	6,749,048	5,105,115	5,202,344	5,550,041	**70,667,851**
26	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	4,637,681	4,366,216	4,570,118	4,168,063	4,265,158	4,658,457	5,265,126	5,052,673	4,371,574	4,324,636	4,277,561	4,714,618	**54,671,882**
27	Schedule 33 - Blackstart Service	Line 1 * Line 15	21,784	20,837	20,554	18,887	22,517	28,404	30,772	29,336	27,115	20,510	20,901	22,298	**283,914**
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**	**$ 44,030,515**	**$ 42,023,492**	**$ 41,756,622**	**$ 38,328,496**	**$ 44,932,828**	**$ 57,320,121**	**$ 62,349,424**	**$ 59,476,738**	**$ 54,636,988**	**$ 42,450,823**	**$ 43,110,001**	**$ 46,164,679**	**$ 576,580,726**
30	Total Energy Market Administration Expenses	**Lines 22-24**	**604,967**	**568,512**	**595,216**	**542,372**	**558,921**	**613,430**	**693,014**	**664,851**	**576,110**	**564,333**	**558,128**	**615,159**	**7,155,011**
31	**Total Transmission and Energy Markets Administration Expenses**	**Lines 30 + 31**	**$ 44,635,482**	**$ 42,592,003**	**$ 42,351,839**	**$ 38,870,868**	**$ 45,491,749**	**$ 57,933,551**	**$ 63,042,438**	**$ 60,141,588**	**$ 55,213,098**	**$ 43,015,156**	**$ 43,668,129**	**$ 46,779,838**	**$ 583,735,737**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21257
Exhibit: A-1 (DSA-1)

Witness: DSAlfred
Date: September 2022

2026 Transmission and Energy Market Administration Expenses

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper DSA-1	4,962	4,736	4,656	4,293	5,158	6,511	7,010	6,704	6,172	4,671	4,763	5,083	**64,720**
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	2,862,371	2,691,610	2,823,365	2,564,823	2,629,580	2,866,254	3,245,982	3,114,195	2,693,313	2,665,825	2,636,137	2,901,273	**33,694,727**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	200.7574606	200.7575	200.7575	200.7575	200.7575	200.7575	200.7575	200.7575	200.7575	200.7575	200.7575	200.7575	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	6932.074564	6932.074564	6932.074564	6932.074564	6932.074564	6894.788343	6894.788343	6894.788343	6894.788343	6894.788343	6894.788343	6894.788343	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	
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	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	1074.30226	1,074.3023	1,074.3023	1,074.3023	1,074.3023	1,074.3023	1,074.3023	1,074.3023	1,074.3023	1,074.3023	1,074.3023	1,074.3023	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.58	1.5800	1.5800	1.5800	1.5800	1.5800	1.5800	1.5800	1.5800	1.5800	1.5800	1.5800	
15	Schedule 33 - Blackstart Service	Workpaper DSA-5a	4.389538638	4.3895	4.3895	4.3895	4.3895	4.3895	4.3895	4.3895	4.3895	4.3895	4.3895	4.3895	
	Expenses														
16	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 424,093	$ 404,830	$ 397,986	$ 366,965	$ 440,844	$ 556,496	$ 599,161	$ 572,968	$ 527,543	$ 399,205	$ 407,109	$ 434,478	**$ 5,531,678**
17	Schedule 2 - Reactive Support	Line 1 * Line 5	996,129	950,884	934,808	861,943	1,035,474	1,307,124	1,407,336	1,345,812	1,239,118	937,670	956,237	1,020,523	**12,993,057**
18	Schedule 9 - Network Transmission Service	Line 1 * Line 6	34,395,946	32,833,628	32,278,534	29,762,561	35,754,513	44,891,691	48,333,354	46,220,406	42,556,097	32,203,211	32,840,872	35,048,699	**447,119,512**
19	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	242,170	208,799	227,262	202,789	251,735	307,526	342,139	327,182	291,526	227,958	224,973	248,101	**3,102,160**
20	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	251,030	236,054	247,609	224,935	230,614	251,370	284,673	273,115	236,204	233,793	231,189	254,442	**2,955,028**
21	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	183,192	172,263	180,695	164,149	168,293	183,440	207,743	199,308	172,372	170,613	168,713	185,681	**2,156,463**
22	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	22,150	19,097	20,786	18,548	23,025	28,127	31,293	29,925	26,664	20,850	20,577	22,692	**283,734**
23	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	509,502	479,107	502,559	456,538	468,065	510,193	577,785	554,327	479,410	474,517	469,232	516,427	**5,997,661**
24	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	65,835	61,907	64,937	58,991	60,480	65,924	74,658	71,626	61,946	61,314	60,631	66,729	**774,979**
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,330,532	5,088,410	5,002,385	4,612,470	5,541,076	6,994,739	7,530,997	7,201,771	6,630,822	5,017,700	5,117,057	5,461,066	**69,529,025**
26	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	4,522,546	4,252,744	4,460,916	4,052,420	4,154,737	4,528,681	5,128,651	4,920,428	4,255,434	4,212,004	4,165,097	4,584,011	**53,237,669**
27	Schedule 33 - Blackstart Service	Line 1 * Line 15	21,780	20,791	20,439	18,846	22,641	28,580	30,771	29,426	27,093	20,502	20,908	22,314	**284,092**
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**	**$ 46,369,418**	**$ 44,170,404**	**$ 43,752,635**	**$ 40,269,077**	**$ 47,601,928**	**$ 59,051,647**	**$ 63,866,824**	**$ 61,092,417**	**$ 55,938,209**	**$ 43,424,656**	**$ 44,134,155**	**$ 47,261,314**	**$ 596,932,684**
30	Total Energy Market Administration Expenses	**Lines 22-24**	**597,486**	**560,111**	**588,282**	**534,077**	**551,570**	**604,244**	**683,736**	**655,878**	**568,020**	**556,681**	**550,440**	**605,848**	**7,056,374**
31	**Total Transmission and Energy Markets Administration Expenses**	**Lines 30 + 31**	**$ 46,966,904**	**$ 44,730,515**	**$ 44,340,918**	**$ 40,803,154**	**$ 48,153,498**	**$ 59,655,892**	**$ 64,550,560**	**$ 61,748,295**	**$ 56,506,229**	**$ 43,981,337**	**$ 44,684,595**	**$ 47,867,162**	**$ 603,989,058**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

2027 Transmission and Energy Market Administration Expenses

Case No.: U-21257
Exhibit: A-1 (DSA-1)

Witness: DSAlfred
Date: September 2022

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	4,951	4,723	4,652	4,285	5,169	6,535	7,010	6,709	6,170	4,665	4,758	5,074	**64,701**
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	2,856,416	2,686,317	2,818,117	2,559,883	2,624,513	2,866,098	3,239,889	3,108,199	2,687,647	2,660,824	2,631,083	2,887,793	**33,626,780**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	$ 85.4707	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	200.8384409	200.8384	200.8384	200.8384	200.8384	200.8384	200.8384	200.8384	200.8384	200.8384	200.8384	200.8384	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	7064.995387	7064.995387	7064.995387	7064.995387	7064.995387	7016.411616	7016.411616	7016.411616	7016.411616	7016.411616	7016.411616	7016.411616	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	0.0656	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	
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	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	0.0890	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper DSA-6	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper DSA-5a	1056.30725	1,056.3073	1,056.3073	1,056.3073	1,056.3073	1,056.3073	1,056.3073	1,056.3073	1,056.3073	1,056.3073	1,056.3073	1,056.3073	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.56	1.5600	1.5600	1.5600	1.5600	1.5600	1.5600	1.5600	1.5600	1.5600	1.5600	1.5600	
15	Schedule 33 - Blackstart Service	Workpaper DSA-5a	4.391309263	4.3913	4.3913	4.3913	4.3913	4.3913	4.3913	4.3913	4.3913	4.3913	4.3913	4.3913	
	Expenses														
16	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 423,128	$ 403,680	$ 397,627	$ 366,204	$ 441,766	$ 558,578	$ 599,121	$ 573,458	$ 527,344	$ 398,704	$ 406,706	$ 433,684	**$ 5,529,999**
17	Schedule 2 - Reactive Support	Line 1 * Line 5	994,264	948,564	934,341	860,505	1,038,058	1,312,541	1,407,811	1,347,507	1,239,150	936,871	955,674	1,019,067	**12,994,353**
18	Schedule 9 - Network Transmission Service	Line 1 * Line 6	34,975,735	33,368,131	32,867,783	30,270,405	36,516,278	45,854,424	49,182,709	47,075,954	43,290,457	32,730,146	33,387,048	35,601,719	**455,120,791**
19	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	241,619	208,206	227,057	202,368	252,262	308,676	342,117	327,462	291,416	227,672	224,750	247,647	**3,101,252**
20	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	250,508	235,590	247,149	224,502	230,170	251,357	284,138	272,589	235,707	233,354	230,746	253,259	**2,949,069**
21	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	182,811	171,924	180,360	163,833	167,969	183,430	207,353	198,925	172,009	170,293	168,389	184,819	**2,152,114**
22	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	22,099	19,043	20,767	18,509	23,073	28,233	31,291	29,951	26,654	20,824	20,556	22,651	**283,651**
23	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	508,442	478,164	501,625	455,659	467,163	510,165	576,700	553,259	478,401	473,627	468,333	514,027	**5,985,567**
24	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	65,698	61,785	64,817	58,877	60,364	65,920	74,517	71,489	61,816	61,199	60,515	66,419	**773,416**
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,229,320	4,988,963	4,914,154	4,525,813	5,459,651	6,903,295	7,404,362	7,087,194	6,517,295	4,927,460	5,026,356	5,359,770	**68,343,634**
26	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	4,456,010	4,190,655	4,396,263	3,993,418	4,094,240	4,471,112	5,054,227	4,848,791	4,192,729	4,150,885	4,104,489	4,504,957	**52,457,776**
27	Schedule 33 - Blackstart Service	Line 1 * Line 15	21,739	20,740	20,429	18,815	22,697	28,699	30,782	29,463	27,094	20,485	20,896	22,282	**284,120**
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**	**$ 46,777,135**	**$ 44,538,454**	**$ 44,187,163**	**$ 40,627,863**	**$ 48,225,090**	**$ 59,874,112**	**$ 64,514,619**	**$ 61,763,342**	**$ 56,495,202**	**$ 43,797,870**	**$ 44,527,053**	**$47,629,204**	**$ 602,957,107**
30	Total Energy Market Administration Expenses	**Lines 22-24**	**596,239**	**558,993**	**587,209**	**533,046**	**550,600**	**604,318**	**682,509**	**654,699**	**566,871**	**555,649**	**549,404**	**603,097**	**7,042,634**
31	**Total Transmission and Energy Markets Administration Expenses**	**Lines 30 + 31**	**$ 47,373,374**	**$ 45,097,447**	**$ 44,774,372**	**$ 41,160,909**	**$ 48,775,689**	**$ 60,478,430**	**$ 65,197,128**	**$ 62,418,041**	**$ 57,062,073**	**$ 44,353,519**	**$ 45,076,457**	**$48,232,301**	**$ 609,999,741**

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, 2023	))))))	Case No. U-21257

DIRECT TESTIMONY

OF

EUGÈNE M.J.A. BREURING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

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 III 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 degree in Accounting. In 1996, I graduated from Thunderbird School of Global Management with a Master of Business Administration degree 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. In 2020, I was promoted to Senior Analyst III, which is my current position at Consumers Energy. In this capacity, I am responsible for preparing the Company's official electric 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 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 cases:

U-17771	2016 – 2017 Energy Optimization Plan and 2017 Amended Energy Waste Reduction ("EWR") Plan;
U-17990	General Electric Rate Case;
U-18142	2017 Power Supply Cost Recovery ("PSCR") Plan;
U-18231	2017 Biennial Renewable Energy Plan;
U-18261	2018-2021 EWR Plan;
U-18322	General Electric Rate Case;
U-18402	2018 PSCR Plan;
U-20134	General Electric Rate Case;
U-20165	2018 Integrated Resource Plan ("IRP");
U-20219	2019 PSCR Plan;
U-20372	2019 EWR Electric and Gas Biennial Plan;
U-20525	2020 PSCR Plan;
U-20697	General Electric Rate Case;
U-20802	2021 Power Supply Cost Recovery Plan;
U-20875	2022-2025 Energy Waste Reduction Plan;
U-20963	General Electric Rate Case;
U-21048	2022 Power Supply Cost Recovery Plan;
U-21090	2021 Integrated Resource Plan (IRP); and
U-21224	General Electric Rate Case.

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 2023 to 2027, in support of the Company's 2023 PSCR Plan.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am providing the following exhibits:

Exhibits	Description
A-2 (EMB-1)	2023 Forecast of Calendar Electric Deliveries;
A-3 (EMB-2)	Forecast of Annual Calendar Deliveries;
A-4 (EMB-3)	Forecast of Monthly Generation Requirements;
A-5 (EMB-4)	Forecast of Monthly Peak Demand; and
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 commercial 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 seven-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, distributed generation, 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 regulatory cases, reflect current industry expectations, or are based on end-use analyses. The fourth step imports a COVID-19 variable that is used by the regression models to incorporate the impact of the pandemic to projected deliveries. The fifth 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 sixth 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 like 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. An average of the minimum and maximum temperatures is used to develop the peak CDD and HDD variables prior to importing them into the model framework. The second step is reviewing the imported observations to identify data issues before executing the peak demand econometric model. The third step is regressing the observed peak demands against the seasonal binary, degree day, and forecasted base electric sales.

The final step in the peak demand forecasting process is combining the results of the econometric model with the Company's projected peak demand adjustments, which consist of the following: (1) EWR; (2) Dynamic Peak Pricing ("DPP") programs; (3) Conservation Voltage Reduction ("CVR"); and (4) Residential Summer On-Peak rate ("RSP").

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 statistical tests are used to evaluate how well the models fit the historical data, and 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%.

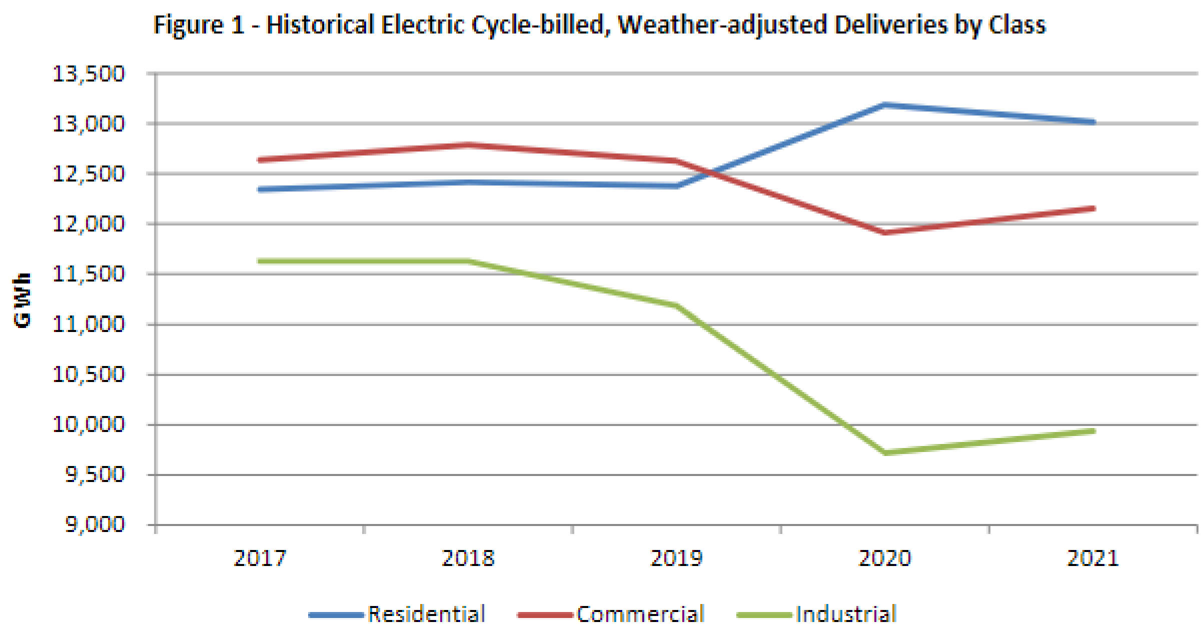
Q. Please explain the criteria used when considering the t-statistics and p-values associated with the model coefficients.

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 whether to include or exclude variables from the models. The models' independent variable t-statistics and p-values are within acceptable ranges and are, therefore, considered relevant.

<u>SECTION III. HISTORICAL AND FORECASTED ELECTRIC DELIVERIES</u>

Q. Please explain the Company's historical levels of electric deliveries for the five-year period from 2017 to 2021.

A. In the past five years, weather-normalized electric deliveries decreased at a -1.1% Compound Annual Growth Rate ("CAGR") from 2017 to 2021, with most of the observed loss occurring in the industrial class (-3.8%), followed by the commercial class (-1.0%). The residential class showed an increase of 1.3% during this five-year period. These changes are graphically depicted in Figure 1.



Q. What is the cause of the sudden Residential increase and Commercial/Industrial ("C&I") decrease of the 2020 weather-normalized deliveries, as shown in Figure 1?

A. Following 2019, the Company's deliveries were impacted by the COVID-19 virus and the resulting pandemic. In 2020, the pandemic caused significant customer behavioral changes, such as an increase in remote working and temporary cessations or reductions in in-person operations for some C&I customers.

Q. How did COVID-19 impact the different customer classes?

A. COVID-19 and the ensuing pandemic had an inverse effect on the Company's residential and C&I customer classes. In 2020, the residential deliveries increased 6.5% over 2019 on a weather-adjusted basis. Conversely, weather-adjusted C&I deliveries decreased by 5.7% and 13.1%, respectively.

In 2020, executive orders from the Governor's office and other public health organization orders were issued to mitigate the spread of COVID-19. These orders encouraged Michiganders to stay at home and limit large social gatherings, pushing electric deliveries away from C&I and more toward the residential class. The "Stay at Home" order was in effect from March 24 until May 15, 2020. In addition to the residential and commercial customer classes, the industrial customer class was directly impacted due to plant closures and cutbacks by the "Big Three" auto manufacturers in the middle of March 2020. In 2021, however, each customer class showed a trend toward pre-pandemic levels (2019). Deliveries to the residential class were reduced by 1.3% (after its steep increase of 6.5% in 2020), while deliveries to C&I classes gained 2.0% and 2.2%, respectively (after respective declines of 5.7% and 13.1% in 2020).

Q. What are the electric delivery expectations from 2023 to 2027?

A. Total electric deliveries are expected to decrease approximately 1.2% per year on average from 2023 to 2027. The 2023 monthly class level results of the electric deliveries forecast process are shown in Exhibit A-2 (EMB-1). The annual class level results for 2023 to 2027 are shown in Exhibit A-3 (EMB-2), along with five-year CAGRs.

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 1.9% in the forecast period.

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

A. The forecasted total electric deliveries are increased by a line loss factor as determined by the 2021 System Loss Study to arrive at the Company's total bundled generation requirements shown in Exhibit A-4 (EMB-3).

SECTION IV. FORECASTED PEAK DEMAND

Q. What are the expectations 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. Full service peak demand is expected to decrease by approximately 0.5% per year on average from 2023 to 2027. The monthly system level results of the electric peak demand forecast process is shown in Exhibit A-5 (EMB-4).

Q. What is the impact to the peak demand forecast from the Company's Smart Energy programs?

A. The peak demand forecast is reduced by approximately 11 MW in the period 2023 to 2027 for the Company's DPP programs, which consist of Peak Time Rewards ("PTR") and Critical Peak Pricing ("CPP").

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 by 745 MW in 2023. The cumulative reductions produced by the EWR program are expected to be 1030 MW by 2027.

Q. To what extent is the CVR program expected to impact peak demand?

A. The Company's CVR program is expected to reduce peak demand by 44 MW in 2023. The cumulative reductions produced by the Company's CVR program are expected to be 91 MW by 2027.

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

A. The RSP rate is expected to reduce the Company's peak demand by approximately 114 MW in each of the years between 2023 and 2027.

Q. How did the Company derive this RSP peak demand reduction?

A. During the summer of 2019, the Company had an RSP pilot program in place with approximately 48,000 residential customers. This pilot group exhibited behavior that shifted an average of 3.5% load from the on-peak hours (2PM to 7PM) to the off-peak hours (7PM to 2PM) in the month of July.

Q. Are capacity-side demand response ("DR") resources accounted for in the Company's peak demand forecast?

A. No, capacity-side DR resources, such as Residential AC Peak Cycling and Commercial and Industrial DR, are registered with Midcontinent Independent System Operator, Inc. and are accounted for outside of this peak demand forecast.

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 2023 to 2027 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	)	Case No. U-21257
cost recovery plan for the 12 months	)	
ending December 31, 2023	)	
	)	

EXHIBITS

OF

EUGÈNE M.J.A. BREURING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2023 Forecast of Calendar Total Electric Deliveries
(MWh)

Case No.: U-21257
Exhibit No.: A-2 (EMB-1)

Witness: EMBreuring
Date: September 2022

Line No.	Month	(a) Residential	(b) Commercial	(c) Industrial	(d) Street Lighting	(e) Inter-departmental	(f) Wholesale	(g) Total
1	January	1,179,333	1,092,298	828,134	11,279	3,829	26,646	3,141,519
2	February	1,050,420	962,887	897,549	9,911	3,029	23,466	2,947,262
3	March	1,041,313	1,047,565	953,079	9,439	3,395	26,862	3,081,654
4	April	909,391	906,158	972,777	7,905	2,207	30,029	2,828,467
5	May	892,425	1,000,220	960,526	7,086	2,805	29,152	2,892,214
6	June	1,024,731	1,114,636	979,283	6,189	2,265	28,978	3,156,082
7	July	1,314,854	1,211,337	951,736	6,911	2,604	31,023	3,518,465
8	August	1,245,534	1,127,662	1,003,449	8,127	3,100	31,333	3,419,205
9	September	890,301	1,060,187	962,646	8,728	2,844	30,024	2,954,730
10	October	850,681	1,012,800	1,064,458	10,366	2,780	26,876	2,967,960
11	November	947,814	972,670	947,211	11,153	2,629	27,888	2,909,365
12	December	1,158,087	1,004,958	938,707	12,353	2,402	29,004	3,145,510
13	Annual	12,504,883	12,513,379	11,459,555	109,447	33,888	341,281	36,962,432

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2023 Forecast of Calendar Full Service Electric Deliveries
(MWh)

Case No.: U-21257
Exhibit No.: A-2 (EMB-1)

Witness: EMBreuring
Date: September 2022

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Month	Residential	Commercial	Industrial	Street Lighting	Inter-departmental	Wholesale	Total
1	January	1,179,333	1,017,732	595,918	11,279	3,829	26,646	2,834,737
2	February	1,050,420	891,808	690,871	9,911	3,029	23,466	2,669,505
3	March	1,041,313	969,678	732,172	9,439	3,395	26,862	2,782,859
4	April	909,391	830,488	746,646	7,905	2,207	30,029	2,526,665
5	May	892,425	922,417	716,403	7,086	2,805	29,152	2,570,288
6	June	1,024,731	1,028,454	728,335	6,189	2,265	28,978	2,818,952
7	July	1,314,854	1,124,465	702,178	6,911	2,604	31,023	3,182,035
8	August	1,245,534	1,040,566	742,236	8,127	3,100	31,333	3,070,896
9	September	890,301	981,058	744,608	8,728	2,844	30,024	2,657,563
10	October	850,681	932,929	798,780	10,366	2,780	26,876	2,622,411
11	November	947,814	898,375	711,981	11,153	2,629	27,888	2,599,840
12	December	1,158,087	930,385	722,987	12,353	2,402	29,004	2,855,218
13	Annual	12,504,883	11,568,355	8,633,115	109,447	33,888	341,281	33,190,969

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2023 Forecast of Calendar ROA Service Electric Deliveries
(MWh)

Case No.: U-21257
Exhibit No.: A-2 (EMB-1)

Witness: EMBreuring
Date: September 2022

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Month	Residential	Commercial	Industrial	Street Lighting	Inter-departmental	Wholesale	Total
1	January	-	74,566	232,216	-	-	-	306,782
2	February	-	71,079	206,678	-	-	-	277,757
3	March	-	77,887	220,907	-	-	-	298,795
4	April	-	75,670	226,131	-	-	-	301,801
5	May	-	77,803	244,123	-	-	-	321,926
6	June	-	86,182	250,948	-	-	-	337,130
7	July	-	86,872	249,558	-	-	-	336,430
8	August	-	87,096	261,213	-	-	-	348,309
9	September	-	79,129	218,038	-	-	-	297,167
10	October	-	79,871	265,678	-	-	-	345,549
11	November	-	74,294	235,231	-	-	-	309,525
12	December	-	74,573	215,719	-	-	-	290,292
13	Annual	-	945,023	2,826,440	-	-	-	3,771,463

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

Case No.: U-21257
Exhibit No.: A-3 (EMB-2)
Page: 1 of 1
Witness: EMBreuring
Date: September 2022

		(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Description	2023	2024	2025	2026	2027	2023-2027 CAGR
1	Total Deliveries						
2	Residential	12,504,883	12,572,487	12,469,597	12,323,590	12,296,987	
3	Commercial	12,513,379	12,251,982	12,010,455	11,837,426	11,843,379	
4	Industrial	11,459,555	11,322,608	11,182,773	11,029,291	11,007,624	
5	Street Lighting	109,447	108,894	107,894	106,894	106,790	
6	Interdepartmental	33,888	32,869	32,821	32,785	32,757	
7	Wholesale	341,281	343,260	-	-	-	
8	Total Deliveries	36,962,432	36,632,101	35,803,540	35,329,987	35,287,537	-1.2%
9	Total Full Service						
10	Residential	12,504,883	12,572,487	12,469,597	12,323,590	12,296,987	
11	Commercial	11,568,355	11,325,996	11,101,291	10,939,692	10,945,681	
12	Industrial	8,633,115	8,530,471	8,435,155	8,327,886	8,311,444	
13	Street Lighting	109,447	108,894	107,894	106,894	106,790	
14	Interdepartmental	33,888	32,869	32,821	32,785	32,757	
15	Wholesale	341,281	343,260	-	-	-	
16	Total Full Service	33,190,969	32,913,978	32,146,759	31,730,848	31,693,659	-1.1%
17	Total ROA Service						
18	Residential	-	-	-	-	-	
19	Commercial	945,023	925,986	909,163	897,734	897,698	
20	Industrial	2,826,440	2,792,137	2,747,618	2,701,405	2,696,180	
21	Street Lighting	-	-	-	-	-	
22	Interdepartmental	-	-	-	-	-	
23	Wholesale	-	-	-	-	-	
24	Total ROA Service	3,771,463	3,718,123	3,656,781	3,599,139	3,593,878	-1.2%

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

Case No.: U-21257
Exhibit No.: A-4 (EMB-3)
Page: 1 of 3
Witness: EMBreuring
Date: September 2022

Line No.	Month	(a) 2023	(b) 2024	(c) 2025	(d) 2026	(e) 2027
1	January	3,347,447	3,297,243	3,219,156	3,177,589	3,170,984
2	February	3,140,391	3,157,189	3,022,130	2,979,844	2,973,942
3	March	3,286,310	3,238,143	3,170,144	3,131,732	3,125,850
4	April	3,015,228	2,985,269	2,922,830	2,877,192	2,871,658
5	May	3,085,414	3,065,204	2,999,920	2,957,884	2,952,252
6	June	3,366,095	3,332,684	3,261,210	3,209,781	3,208,934
7	July	3,750,645	3,719,763	3,641,003	3,590,248	3,583,354
8	August	3,643,835	3,597,392	3,520,211	3,470,452	3,463,638
9	September	3,146,765	3,109,071	3,041,041	2,997,070	2,990,773
10	October	3,165,159	3,133,682	3,061,793	3,018,946	3,013,151
11	November	3,102,663	3,066,043	2,994,850	2,952,433	2,946,653
12	December	3,354,335	3,320,893	3,249,356	3,203,264	3,191,638
13	Annual	39,404,287	39,022,576	38,103,641	37,566,435	37,492,827

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

Case No.: U-21257
Exhibit No.: A-4 (EMB-3)

Witness: EMBreuring
Date: September 2022

Line No.	Month	(a) 2023	(b) 2024	(c) 2025	(d) 2026	(e) 2027
1	January	3,019,342	2,972,111	2,898,550	2,862,371	2,856,416
2	February	2,841,598	2,859,017	2,728,885	2,691,610	2,686,317
3	March	2,964,887	2,919,171	2,856,324	2,823,365	2,818,117
4	April	2,690,571	2,661,974	2,605,039	2,564,823	2,559,883
5	May	2,739,108	2,726,509	2,665,724	2,629,580	2,624,513
6	June	3,003,434	2,977,858	2,911,536	2,866,254	2,866,098
7	July	3,388,737	3,363,364	3,290,704	3,245,982	3,239,889
8	August	3,269,148	3,228,787	3,157,921	3,114,195	3,108,199
9	September	2,827,094	2,794,684	2,732,234	2,693,313	2,687,647
10	October	2,793,441	2,768,163	2,702,897	2,665,825	2,660,824
11	November	2,769,697	2,738,502	2,673,475	2,636,137	2,631,083
12	December	3,042,058	3,012,735	2,946,636	2,901,273	2,887,793
13	Annual	35,349,115	35,022,874	34,169,926	33,694,727	33,626,780

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

Case No.: U-21257
Exhibit No.: A-4 (EMB-3)

Witness: EMBreuring
Date: September 2022

Line No.	Month	(a) 2023	(b) 2024	(c) 2025	(d) 2026	(e) 2027
1	January	328,104	325,133	320,605	315,218	314,568
2	February	298,792	298,172	293,245	288,234	287,624
3	March	321,423	318,972	313,819	308,367	307,733
4	April	324,657	323,295	317,791	312,369	311,774
5	May	346,306	338,695	334,196	328,303	327,740
6	June	362,661	354,827	349,674	343,528	342,837
7	July	361,908	356,399	350,299	344,267	343,465
8	August	374,687	368,605	362,290	356,257	355,439
9	September	319,672	314,387	308,807	303,757	303,126
10	October	371,718	365,518	358,895	353,120	352,327
11	November	332,966	327,542	321,374	316,296	315,571
12	December	312,277	308,158	302,719	301,991	303,845
13	Annual	4,055,171	3,999,703	3,933,715	3,871,708	3,866,048

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

Case No.: U-21257
Exhibit No.: A-5 (EMB-4)
Page: 1 of 3
Witness: EMBreuring
Date: September 2022

		(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Month	2023	2024	2025	2026	2027	2023-2027 CAGR
1	January	5,564	5,548	5,459	5,405	5,393	
2	February	5,357	5,389	5,282	5,220	5,205	
3	March	5,212	5,235	5,177	5,100	5,094	
4	April	4,912	4,934	4,845	4,787	4,777	
5	May	5,783	5,820	5,717	5,688	5,698	
6	June	7,194	7,182	7,080	7,051	7,074	
7	July	7,684	7,672	7,598	7,525	7,523	
8	August	7,443	7,422	7,313	7,262	7,267	
9	September	6,856	6,836	6,744	6,674	6,670	
10	October	5,340	5,325	5,243	5,190	5,183	
11	November	5,407	5,382	5,290	5,240	5,234	
12	December	5,686	5,668	5,570	5,526	5,520	
13	Peak Demand	7,684	7,672	7,598	7,525	7,523	-0.5%

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

Case No.: U-21257
Exhibit No.: A-5 (EMB-4)

Witness: EMBreuring
Date: September 2022

		(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Month	2023	2024	2025	2026	2027	2023-2027 CAGR
1	January	5,101	5,091	5,009	4,962	4,951	
2	February	4,860	4,937	4,791	4,736	4,723	
3	March	4,750	4,777	4,726	4,656	4,652	
4	April	4,399	4,423	4,342	4,293	4,285	
5	May	5,223	5,273	5,177	5,158	5,169	
6	June	6,624	6,624	6,530	6,511	6,535	
7	July	7,143	7,139	7,075	7,010	7,010	
8	August	6,856	6,859	6,745	6,704	6,709	
9	September	6,328	6,317	6,234	6,172	6,170	
10	October	4,794	4,787	4,716	4,671	4,665	
11	November	4,905	4,889	4,805	4,763	4,758	
12	December	5,229	5,216	5,127	5,083	5,074	
13	Peak Demand	7,143	7,139	7,075	7,010	7,010	-0.5%

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

Case No.: U-21257
Exhibit No.: A-5 (EMB-4)

Witness: EMBreuring
Date: September 2022

		(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Month	2023	2024	2025	2026	2027	2023-2027 CAGR
1	January	463	457	451	443	442	
2	February	497	452	492	483	482	
3	March	462	458	451	443	442	
4	April	513	511	502	494	493	
5	May	560	547	540	531	530	
6	June	570	558	550	540	539	
7	July	541	533	523	514	513	
8	August	588	563	568	559	557	
9	September	528	519	510	501	500	
10	October	546	537	527	519	518	
11	November	502	494	484	477	476	
12	December	458	452	444	443	446	
13	Peak Demand	588	563	568	559	557	-1.3%

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

Case No.: U-21257
Exhibit No.: A-6 (EMB-5)
Page: 1 of 1
Witness: EMBreuring
Date: September 2022

Line No.	Month	(a) 2023	(b) 2024	(c) 2025	(d) 2026	(e) 2027
1	Total Deliveries (GWh)	36,962	36,632	35,804	35,330	35,288
2	System Efficiency (%)	93.8%	93.9%	94.0%	94.0%	94.1%
3	Generation Requirements (GWh)	39,404	39,023	38,104	37,566	37,493
4	Summer Peak Demand (MW)	7,684	7,672	7,598	7,525	7,523
5	System Load Factor (%)	58.5%	58.1%	57.2%	57.0%	56.9%

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	)	Case No. U-21257
12 months ending December 31, 2023	)	
______________________________	)	

DIRECT TESTIMONY

OF

JOSHUA W. HAHN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

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 Power Supply Cost Supply Recovery ("PSCR") Section of the Electric Supply Operations Department.

<u>QUALIFICATIONS</u>

Q. Please briefly describe your educational background.

A. I received a Bachelor of Science Degree 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 assumed responsibilities as the primary 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 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;
- Case No. U-18402 2018 PSCR Plan case;
- Case No. U-20068 2017 PSCR Reconciliation case;
- Case No. U-20219 2019 PSCR Plan case;
- Case No. U-20202 2018 PSCR Reconciliation case;
- Case No. U-20525 2020 PSCR Plan case;
- Case No. U-20220 2019 PSCR Reconciliation case;
- Case No. U-20649 2020 Voluntary Green Pricing case;
- Case No. U-20802 2021 PSCR Plan case;
- Case No. U-20526 2020 PSCR Reconciliation case;
- Case No. U-21009 2020 Renewable Energy Reconciliation case;
- Case No. U-21048 2022 PSCR Plan case; and
- Case No. U-20803 2021 PSCR Reconciliation case.

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 2023 through 2027 in support of the Company's 2023 PSCR Plan.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring:

Exhibit A-7 (JWH-1)	Monthly Summary of the Projected 2023 Fuel and Purchased and Net Interchange Power Expenses;
Exhibit A-8 (JWH-2)	Annual Summary for Years 2023 through 2027 of Fuel and Purchased and Net Interchange Power Expenses;
Exhibit A-9 (JWH-3)	Purchased Power Agreements – Projected 2023 Rates; and
Exhibit A-10 (JWH-4)	Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRCs).

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

A. Yes, they were.

<u>POWER SUPPLY COSTS</u>

Q. What are the Company's forecasts of 2023 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 2023?

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 2023 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 2022 PSCR Plan case, Case No. U-21048?

A. No. I used the Aurora Production Costing program for this case, which was the same platform used in the Company's 2021 Integrated Resource Plan ("IRP") filing, Case No. U-21090.

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 2023. 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. Page 1, lines 27 through 32, present the fixed and capacity-related costs included in PSCR expense. Additional information about page 1, lines 27 through 32, is provided in more detail below. Page 1, line 41 presents the expenses attributed to the Long-Term Industrial Load Retention Rate ("LTILRR").

Exhibit A-7 (JWH-1), pages 2 and 3, summarize the Purchased and Net Interchange ("P&I") power quantity and expense projected to be incurred by the Company in 2023. These pages detail the quantity and 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.

Line 34 on Exhibits A-7 (JWH-1) and A-8 (JWH-2) are taken from Company witness Daniel S. Alfred's Exhibit A-1 (DSA-1).

Lines 35 and 37 through 39 on Exhibits A-7 (JWH-1) and A-8 (JWH-2) are taken from Company witness Nathan J. Hoffman's Exhibits A-13 (NJH-3) through A-16 (NJH-6).

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 ("ZRCs") 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, complementing the energy (or non-capacity-related) component of the Transfer Price presented on Exhibit A-7 (JWH-1), page 1, line 18.

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 PSCR rates based on the amount of cost allowed to be transferred from the Company's Incremental Cost of Compliance authorized per 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, the Company 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 is shown on Exhibit A-7 (JWH-1), page 1, line 24. Capacity or fixed cost-related expense for the Company's PPAs is shown on page 1, lines 30 and 31.

Q. How were these figures derived?

A. They were derived from Aurora, which simulates the dispatch of the Company's generating resources and P&I power resources to meet projected customer electric demand requirements. Exhibit A-7 (JWH-1), pages 1 through 3, show the monthly results for 2023, which were then totaled to obtain the annual results that are also shown on Exhibit A-8 (JWH-2), along with the years 2024 through 2027. The main inputs to Aurora 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 Aurora is structured to align as closely as possible with the way that the Midcontinent Independent System Operator, Inc. ("MISO") operates and administers the 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 Nathan J. Hoffman. His direct testimony and exhibits set forth and explain the relevant assumptions and calculations.

CONSUMERS ENERGY-OWNED GENERATING UNITS

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

A. Yes. Two Company owned renewable facilities have revised Commercial Operation Dates ("COD"). The first is the 201 MW wind facility Heartland Wind Farm, which has an updated COD of December 31, 2023. The second is the 150 MW solar facility Mustang Mile Solar Project, which has an updated COD of May 31, 2024[1].

[1] When the Company filed its 2022 PSCR Plan filing (Case No. U-21048), the COD for both Heartland Wind Farm and Mustang Mile Solar Project was December 31, 2022.

Three additional solar blocks are included and modeled as three units. The solar generation additions from the 2021 IRP Proposed Course of Action ("PCA") are assumed to be 50% Company owned and 50% PPAs. The 2021 IRP PCA called for a 500 MW block with a COD of June 1, 2025, a 204 MW block with a COD of June 1, 2026, and a 500 MW block with a COD of June 1, 2027. To reflect the assumption that only 50% of the additions are Company owned, a 250 MW block with a COD of June 1, 2025, a 102 MW block with a COD of June 1, 2026, and a 250 MW block with a COD of June 1, 2027 have been added as Company owned resources in the model.

The gas and oil-fired generating units Karn 3 and Karn 4 retirement dates have been changed to May 31, 2031; also the CMS units of Dearborn Industrial Generation ("DIG"), Kalamazoo River Generation Station, and Livingston Generation Station have been removed from the model to align with the Company's 2021 IRP Settlement Agreement.

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,[2] 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.[3]

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

A. Economic dispatch of the Jackson Plant has been limited using a dispatch adder on the incremental cost of energy when necessary to comply with the state air permit. For

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

modeling purposes, the Jackson Plant has been limited to an annual generation amount that corresponds to the annual NOx limit.

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

A. Yes. By including the dispatch adder 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.

<u>POWER PURCHASE AGREEMENTS</u>

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 and capacity from NUGs with whom the Company has PPAs. A list of the entities from which power is projected to be purchased for the years 2023 through 2027 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 following units were added and replaced place holder IRP expansion units based on the 2020 IRP Request for Proposal ("RFP").

-Heathlands Solar: 30MW unit with a COD of 12/31/2023

-Cereal City Solar: 100MW unit with a COD of 12/31/2023

-Jackson County Solar: 125MW unit with a COD of 5/31/2024

The following units were added and replaced place holder IRP expansion units based on the 2021 IRP RFP.

-Confluence Solar: 150 MW unit with a COD of 12/31/2024

-Heartwood Solar: 150 MW unit with a COD of 12/31/2024

The Company has also incorporated 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.

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

A. Yes. Three additional solar blocks are included and modeled as three units. The solar generation additions from the 2021 IRP PCA are assumed to be 50% Company owned and 50% PPAs. The 2021 IRP PCA called for a 500 MW block with a COD of June 1, 2025, a 204 MW block with a COD of June 1, 2026, and a 500 MW block with a COD of June 1, 2027. To reflect the assumption that only 50% of the additions are Company owned, a

250 MW block with a COD of June 1, 2025, a 102 MW block with a COD of June 1, 2026, and a 250 MW block with a COD of June 1, 2027 have been added as PPAs 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 contracts that are recoverable in the PSCR is the average PSCR rate for the year.

Q. What is the impact of the Reduced Dispatch Agreements ("RDAs") in place with Cadillac, Genesee, Grayling, and the Ada Cogeneration Facilities?

A. As in last year's PSCR Plan, Case No. U-21048, 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 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 $2,424,000 and the projected customer benefit (offset to PSCR) is $250,000. 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 53.

Q. Please explain Exhibit A-7 (JWH-1), page 3, line 54.

A. Line 54 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 term.

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 43 and 44, detail the energy received and Exhibit A-7 (JWH-1), page 2, lines 47 through 49, detail the energy delivered. Exhibit A-7 (JWH-1), page 3, lines 51 and 52, detail the costs for energy received and page 3, lines 56 through 59, detail the revenues for energy delivered.

Q. Please explain Exhibit A-7 (JWH-1), page 2, line 48, and page 3, line 58.

A. Exhibit A-7 (JWH-1), page 2, line 48, and page 3, line 58, represent a sale to the 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. We have estimated the amount of increased generation at the oil and gas units that MISO uses for this purpose on page 2, line 48 and have represented it as a sale. The Company will be reimbursed in full for this use of our units and, therefore, this increased generation cost is fully offset by the revenue shown on page 3, line 58 and, as a result, does not affect the PSCR factor. Currently there is no amount forecasted for this as the units are set to dispatch economically in the model.

Q. Please explain Exhibit A-7 (JWH-1), page 3, line 57.

A. Exhibit A-7 (JWH-1), page 3, line 57, 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.

<u>CAPACITY PLANNING RESERVE MARGIN TARGET</u>

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 2023 is the time period from June 1, 2023 through May 31, 2024. Generally, the capacity planning reserve margin target is designed to include consideration of demand forecast variances, generator forced outages and derates,[4] 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 2022, the MISO Loss of Load Expectation ("LOLE") Working Group performed a LOLE study which considered the

3 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.

probability that various amounts of generation resources would be inadequate to serve firm demand in the MISO footprint. Upon determining the amount of generation resources that would be necessary to achieve a LOLE of less than one occasion every ten years, a reserve margin (expressed as a percentage of peak firm demand) is calculated and assigned to all LSEs.

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

A. For PY 2022, 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 8.7% of the Company's demand at the time of MISO's coincident peak demand was sufficient to satisfy ReliabilityFirst Corporation's ("RF") capacity planning criteria of expecting to interrupt firm load no more frequently than one occasion in ten years. For PY 2023, 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 8.3% of each LSE's demand at the time of MISO's coincident peak demand was sufficient to satisfy RF's capacity planning criteria.[5] 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 ("FERC") to establish, monitor,

[5] September 7, 2021 LOLE meeting:
https://cdn.misoenergy.org/20210907%20LOLEWG%20Item%2003%20PY%202022-23%20Preliminary%20LOLE%20Study%20Results586120.pdf

and enforce reliability standards in the United States. On September 7, 2021, MISO's LOLE Working Group projected planning reserve margin targets of 8.7% for PY 2022, 7.4% for PY 2025, and 7.5% for PY 2027. The Company has interpolated these values and rounded to the nearest tenth of a percent to project a planning reserve margin target of 8.3% for PY 2023, 7.8% for PY 2024, and 7.4% for PY 2026 as shown on line 7 of Exhibit A-10 (JWH-4).

Q. How is Consumers Energy planning to meet the 8.7% planning reserve margin target for the first five months of 2023 and 8.3% for the last seven months of 2023?

A. To facilitate compliance with the planning reserve margin target, MISO has established 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, 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 1.087 for the five months ending May 31, 2023 and annual firm peak demand at the time of MISO's coincident peak demand times 1.083 for the seven months beginning June 1, 2023[6]. 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

[6] FERC has conditionally accepted a Seasonal/SAC filing (ER22-495) from MISO that would modify the ZRCs needed for peak demand season, beginning June 1, 2023,

market participants' resources within the MISO market footprint through tariff requirements on market participants to use the Module E Capacity Tracking tool.

Q. How does the Company 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 Breuring. The forecasted bundled non-coincident peak demand for PY 2023 is 7,787 MW, shown on line 1 of Exhibit A-10 (JWH-4), and the internal demand response ("DR") programs adjust the peak downward by 881 MW, shown on line 2 of Exhibit A-10 (JWH-4), for an adjusted non-coincident peak demand of 6,906 MW, shown on line 3 of Exhibit A-10 (JWH-4). 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 97.39%, shown on line 4 of Exhibit A-10 (JWH-4). The resulting coincident peak demand of 6,726 MW is shown on line 5 of Exhibit A-10 (JWH-4). 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 1.036.[7] The final adjustment made is to apply the planning reserve margin target percentage. Total Planning Reserve Margin Requirement ("PRMR"), as shown on line 8 of Exhibit A-10 (JWH-4), is then calculated by increasing

[7] 2023-2024 Transmission Loss Percentage.xlsx: https://www.misoenergy.org/planning/resource-adequacy

the bundled coincident peak demand by transmission losses and planning reserve margin which results in 7,546 ZRCs in PY 2023.

Q. Are there any planned changes to the amount of ZRCs needed for peak demand season or capacity for the upcoming MISO PY?

A. Yes, FERC has conditionally accepted a Seasonal/SAC filing (ER22-495) from MISO that would modify the ZRCs needed for peak demand season. With the current requirements Consumers Energy is required to meet the peak demand and load requirements for the summer season. With the proposed tariff, Consumers Energy would be required to meet the peak demand and load requirements of four seasons: Summer, Fall, Winter, Spring. In addition, the calculation of ZRCs available would be modified to provide weighted credit to generators based on their availability during MISO's highest risk and greatest need during the season. Since this tariff has not been fully accepted by FERC at the time of filing, all forecasts and information within this testimony continue to follow MISO's currently approved resource adequacy requirements laid out in BPM011-R26.

Q. What programs are included in internal DR programs shown on line 2 of Exhibit A-10 (JWH-4)?

A. Internal DR programs include Energy Efficiency ("EE"), Dynamic Peak Pricing ("DPP") programs (consisting of Peak Time Rewards ("PTR") and Critical Peak Pricing ("CPP")), Summer Peak On-Peak Rate ("RSP"), and Conservation Voltage Reduction ("CVR").

Q. How is the PY 2023 forecasted non-coincident peak demand of 7,787 MW shown on line 1 of Exhibit A-10 (JWH-4) derived from the demand forecast discussed in the direct testimony of Company witness Breuring?

A. Mr. Breuring's forecast of 7,684 MW of demand shown on Exhibit A-5 (EMB-4), page 1, line 7 occurs in July 2023 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, DPP, RSP, and CVR at the time of the Company's peak demand. The demand expected to be offset by EE, DPP, RSP, and CVR amounts to 913 MW at the time of the Company's 2023 peak demand. Adding that amount to the 7,684 MW provided by Mr. Breuring provides a gross demand of 8,597 MW; however, because this load is at the generation level it must be reduced by the transmission loss factor previously mentioned, resulting in 8,298 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 demand expected to be offset by ROA suppliers is 511 MW at the time of the Company's peak demand. Subtracting this ROA load from 8,298 MW results in the forecasted non-coincident peak demand at the distribution level of 7,787 MW as shown on line 1 of Exhibit A-10 (JWH-4).

RESOURCES PLANNED TO SATISFY RESERVE MARGIN REQUIREMENT

Q. What resources are required to meet the 8.7% planning reserve margin target for the first five months of 2023 and 8.3% for the last seven months of 2023?

A. Lines 9 through 31 of Exhibit A-10 (JWH-4) 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 8.3% capacity planning reserve margin under peak load conditions of 2023. In 2023, the Company expects to have 5,778 ZRCs from owned units during the peak load period (Consumers Energy is a summer-peaking system), as shown on line 17 of Exhibit A-10 (JWH-4). The Company is able to provide ZRCs in the form of load modifying resources, including Air Conditioning Peak Cycling ("ACPC"), Commercial and Industrial ("C&I") DR, Smart Thermostat ("STP"), 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[8] times one plus the reserve margin requirement or, in this case, 655.1 ZRCs shown on line 18 of Exhibit A-10 (JWH-4). The Company also has long-term contracts with several NUGs for a total of 1,845 ZRCs, as shown on line 31 of Exhibit A-10 (JWH-4). The compilation of all resources for PY 2023 totaling 8,278 ZRCs, as shown on line 32 of Exhibit A-10 (JWH-4), when compared to the PRMR of 7,546 MW provides an unforced capacity surplus of 732 ZRCs, as shown on line 33 of Exhibit A-10 (JWH-4).

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

RESOURCES PREVIOUSLY APPROVED BY THE COMMISSION

Q. To what extent have the owned resources and NUG resources providing ZRCs in 2023 been included in previous PSCR Plans and/or the IRP?

A. Owned and NUG resources have been included in previous PSCR plans, most recently in MPSC Case No. U-21048. While the Commission has yet to conclude its consideration of the PSCR Plan presented in MPSC Case No. U-21048, most of the resources included in this PSCR Plan were included in the last PSCR Plan. The resources included pursuant to the 2021 IRP settlement are discussed above.

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 PPA resources.

Q. What resources are included as part of the Company's IRP?

A. As discussed above, the 2021 IRP Settlement includes a 500 MW block of solar with a COD of June 1, 2025, a 204 MW block of solar with a COD of June 1, 2026, and a 500 MW block of solar with a COD of June 1, 2027 which are assumed to be 50% owned and 50% PPA.

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 Emily M. Walainis.

RESOURCES REMAINING TO BE PURCHASED FOR 2023

Q. Does Consumers Energy need to acquire additional capacity for 2023?

A. The Company's current projected capacity position does not require the purchase of any additional ZRC's at this time.

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[9] explains how to obtain capacity for resources and how to fulfill PRMR obligations.

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.

Q. Does this conclude your direct testimony?

A. Yes.

[9] MISO BPM 11: https://www.misoenergy.org/legal/business-practice-manuals/.

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, 2023	))))))	Case No. U-21257

EXHIBITS

OF

JOSHUA W. HAHN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Monthly Summary of the Projected 2023 Fuel and Purchased and Net Interchange Power Expenses

Case No.: U-21257
Exhibit No.: A-7 (JWH-1)
Page: 1 of 3
Witness: JWHahn
Date: September 2022

SUMMARY BY SOURCE

YEAR		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2023
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	ENERGY (MWH)													
1	COAL STEAM	1,158,787	1,046,647	1,135,804	494,467	789,044	849,425	877,741	877,741	853,135	781,982	790,236	881,573	10,536,584
2	GAS & OIL	710,321	697,354	799,342	596,937	264,024	1,423,259	1,495,329	1,465,167	1,121,589	1,007,342	1,129,167	1,161,382	11,871,213
3	NUCLEAR PPA	0	0	0	0	0	0	0	0	0	0	0	0	0
4	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
5	CE OWNED RENEWABLES	198,975	206,881	215,577	196,077	177,845	143,629	117,037	109,715	164,685	214,709	229,658	207,533	2,182,321
6	PEAKERS	47,174	72,748	119,232	0	0	0	37,509	41,490	0	0	0	0	318,153
7	PUMPED STORAGE	49,635	54,104	20,198	59,318	55,297	117,073	191,499	209,280	80,922	42,748	40,349	73,552	993,973
8	TOTAL GENERATED	2,164,892	2,077,734	2,290,153	1,346,799	1,286,210	2,533,386	2,719,115	2,703,393	2,220,330	2,046,782	2,189,409	2,324,041	25,902,244
9	LESS : PUMPING	-69,663	-59,859	-26,232	-77,036	-82,220	-152,043	-238,294	-271,792	-105,093	-65,923	-52,402	-90,320	-1,290,876
10	TOTAL GENERATED	2,095,229	2,017,875	2,263,922	1,269,763	1,203,990	2,381,343	2,480,821	2,431,601	2,115,238	1,980,858	2,137,007	2,233,720	24,611,368
11	PURCHASED (NUGs)	721,871	959,574	1,247,237	507,578	461,416	651,559	837,138	810,734	496,502	581,525	419,541	361,734	8,056,409
12	NET INTERCHANGE	202,239	-135,848	-546,280	913,235	1,073,696	-29,476	70,783	26,811	215,359	231,058	213,144	446,600	2,681,320
13	**TOTAL SYSTEM REQUIREMENTS**	3,019,339	2,841,601	2,964,879	2,690,576	2,739,102	3,003,426	3,388,742	3,269,146	2,827,099	2,793,441	2,769,692	3,042,054	35,349,097
	VARIABLE EXPENSES ($*1000)													
14	COAL STEAM	29,708	27,264	30,126	13,357	21,024	22,361	23,048	22,978	22,259	20,278	20,483	22,925	275,813
15	GAS & OIL	51,051	48,378	46,630	18,621	12,027	62,082	67,829	67,104	48,674	43,561	52,979	56,544	575,479
16	NUCLEAR PPA VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
17	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
18	CE OWNED RENEWABLES	6,946	7,343	6,935	5,242	4,803	4,218	4,223	3,935	5,208	6,682	6,986	6,329	68,850
19	PEAKERS	4,439	6,525	8,830	88	88	88	2,325	4,445	88	88	88	489	27,582
20	PUMPED STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
21	TOTAL GENERATED	92,144	89,510	92,521	37,308	37,943	88,749	97,424	98,463	76,229	70,608	80,536	86,286	947,723
22	LESS : PUMPING	0	0	0	0	0	0	0	0	0	0	0	0	0
23	TOTAL GENERATED	92,144	89,510	92,521	37,308	37,943	88,749	97,424	98,463	76,229	70,608	80,536	86,286	947,723
24	PURCHASED (NUGs) VARIABLE COST[1]	48,371	66,245	79,374	25,167	21,862	32,893	46,573	44,251	23,437	24,918	15,001	13,909	442,001
25	NET INTERCHANGE, EXCLUDING ZRC	13,636	-14,535	-45,313	42,039	48,619	-8,720	-10,130	-15,659	8,159	10,768	9,372	19,563	57,799
26	**TOTAL FUEL, VARIABLE PURCHASED AND NET INTERCHANGE**	**154,151**	**141,220**	**126,582**	**104,514**	**108,424**	**112,921**	**133,868**	**127,056**	**107,824**	**106,294**	**104,909**	**119,758**	**1,447,522**
27	ZONAL RESOURCE CREDIT PURCHASE	186	186	186	186	186	0	0	0	0	0	0	0	929
28	OWNED RENEWABLE CAPACITY	4,046	4,277	4,040	3,053	2,798	2,457	2,460	2,293	3,034	3,892	4,070	3,687	40,107
29	NUCLEAR PPA CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0
30	PURCHASED (NUG) CAPACITY	22,297	21,195	22,038	21,675	21,843	21,561	22,357	22,282	21,333	21,182	20,436	21,197	259,395
31	PURCHASED (NUG) FIXED ENERGY	5,989	5,614	6,101	5,985	6,184	6,054	6,197	6,195	6,025	6,116	5,924	6,005	72,389
32	INDEPENDENT ADMINISTRATOR EXPENSE	105	105	0	0	0	0	0	0	0	105	105	105	525
33	**TOTAL CAPACITY AND NUG FIXED COSTS**	**32,623**	**31,377**	**32,365**	**30,899**	**31,011**	**30,071**	**31,014**	**30,770**	**30,391**	**31,295**	**30,535**	**30,993**	**373,345**
34	TOTAL TRANSMISSION AND ENERGY MARKETS ADMINISTRATION	39,225	37,280	36,818	33,983	39,494	49,752	53,946	51,809	47,450	37,192	37,880	40,558	505,387
35	ACTIVATED CARBON	189	189	189	189	189	189	189	189	189	189	189	189	2,271
36	MISO - SCHEDULE 2 (REACTIVE)	-375	-375	-375	-375	-375	-375	-375	-375	-375	-375	-375	-375	-4,500
37	AQUEOUS AMMONIA EXPENSE	67	67	67	67	67	67	67	67	67	67	67	67	799
38	UREA EXPENSE	345	345	345	345	345	345	345	345	345	345	345	345	4,145
39	LIME EXPENSE	684	684	684	684	684	684	684	684	684	684	684	684	8,205
40	**TOTAL POWER SUPPLY COSTS**	**226,909**	**210,787**	**196,675**	**170,307**	**179,839**	**193,655**	**219,738**	**210,545**	**186,576**	**175,692**	**174,234**	**192,219**	**2,337,175**
41	LONG-TERM INDUSTRIAL LOAD RETENTION RATE (LTILRR)	12,016	10,376	9,218	8,432	9,345	7,926	7,906	7,936	8,413	9,346	9,008	8,953	108,876
42	**TOTAL POWER SUPPLY COSTS LESS HSC PAYMENTS**	**214,892**	**200,411**	**187,456**	**161,875**	**170,494**	**185,729**	**211,832**	**202,610**	**178,162**	**166,346**	**165,227**	**183,266**	**2,228,299**

[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

Monthly Summary of the Projected 2023 Fuel and Purchased and Net Interchange Power Expenses

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2023
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	PURCHASED AND NET INTERCHANGE RECEIVED (MWH)													
43	MARKET ON PEAK	105,953	47,686	15,709	321,595	462,570	71,488	55,566	18,641	169,523	143,253	130,724	184,792	1,727,500
44	MARKET OFF PEAK	316,181	185,209	57,076	617,692	650,977	273,536	409,336	491,888	249,104	238,774	212,552	360,670	4,062,996
45	PURCHASED (NUGs)	721,871	959,574	1,247,237	507,578	459,915	611,642	797,409	773,233	466,078	558,595	402,646	356,993	7,862,771
46	TOTAL RECEIVED	1,144,005	1,192,469	1,320,021	1,446,865	1,573,463	956,667	1,262,311	1,283,762	884,705	940,623	745,922	902,455	13,653,267
	NET INTERCHANGE DELIVERED (MWH)													
47	EXTERNAL SALES	219,897	368,744	619,066	26,051	39,852	374,502	394,119	483,718	203,267	150,969	130,133	98,863	3,109,181
48	MISO RAC	0	0	0	0	0	0	0	0	0	0	0	0	0
49	TOTAL DELIVERED	219,897	368,744	619,066	26,051	39,852	374,502	394,119	483,718	203,267	150,969	130,133	98,863	3,109,181
50	NET (MWH)	924,108	823,725	700,955	1,420,814	1,533,611	582,165	868,192	800,044	681,438	789,654	615,789	803,592	10,544,086

Monthly Summary of the Projected 2023 Fuel and Purchased and Net Interchange Power Expenses

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2023
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)**	**(i)**	**(j)**	**(k)**	**(l)**	**(m)**	**(n)**	**(o)**
	VARIABLE PURCHASED AND NET INTERCHANGE EXPENSE ($*1000)													
51	MARKET ON PEAK ENERGY	9,428	4,383	1,332	16,107	22,721	3,563	2,598	278	8,636	7,528	6,778	9,333	92,684
52	MARKET OFF PEAK ENERGY	26,430	15,525	4,377	27,521	28,266	12,230	18,757	22,843	11,681	11,014	9,743	16,423	204,809
53	PURCHASED (NUGs) ENERGY	47,009	64,883	78,012	23,805	20,500	31,530	45,211	42,889	22,074	23,556	13,638	12,546	425,652
54	CASE NO. U-16048 COST RECOVERY	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	16,349
55	TOTAL EXPENSE	84,229	86,153	85,083	68,795	72,849	48,685	67,928	67,373	43,753	43,459	31,522	39,664	739,494
	NET INTERCHANGE CREDIT ($*1000)													
56	EXTERNAL SALE ENERGY	22,222	34,444	51,022	1,586	2,368	24,514	31,483	38,780	12,157	7,770	7,149	6,192	239,687
57	EXTERNAL SALE CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0
58	MISO RAC	0	0	0	0	0	0	0	0	0	0	0	0	0
59	TOTAL CREDIT	22,222	34,444	51,022	1,586	2,368	24,514	31,483	38,780	12,157	7,770	7,149	6,192	239,687
60	NET EXPENSE	62,007	51,709	34,061	67,209	70,481	24,171	36,445	28,593	31,596	35,689	24,373	33,472	499,807

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Annual Summary for Years 2023 through 2027 of Fuel and Purchased and Net Interchange Power Expense

Case No.: U-21257
Exhibit No.: A-8 (JWH-2)

Witness: JWHahn
Date: September 2022

YEAR		2023	2024	2025	2026	2027
		SUMMARY BY SOURCE				
(a)	(b)	(c)	(d)	(e)	(f)	(g)
	ENERGY (MWH)					
1	COAL STEAM	10,536,584	9,328,784	3,193,406	0	0
2	GAS & OIL	11,871,213	16,670,003	15,175,694	14,164,949	15,268,899
3	NUCLEAR PPA	0	0	0	0	0
4	STATION POWER	0	0	0	0	0
5	CE OWNED RENEWABLES	2,182,321	3,050,346	4,101,578	3,781,488	4,823,098
6	PEAKERS	318,153	350,554	419,186	502,761	641,033
7	PUMPED STORAGE	993,973	890,717	716,707	710,760	708,854
8	TOTAL GENERATED	25,902,244	30,290,403	23,606,570	19,159,958	21,441,884
9	LESS : PUMPING	-1,290,876	-1,157,333	-932,863	-928,096	-932,277
10	TOTAL GENERATED	24,611,368	29,133,070	22,673,707	18,231,862	20,509,607
11	PURCHASED (NUGs)	8,056,409	8,413,583	11,966,605	13,593,970	14,144,482
12	NET INTERCHANGE	2,681,320	-2,523,800	-470,392	1,225,855	-1,027,304
13	**TOTAL SYSTEM REQUIREMENTS**	35,349,097	35,022,853	34,169,919	33,051,687	33,626,784
	VARIABLE EXPENSES ($*1000)					
14	COAL STEAM	275,813	253,727	90,319	301	301
15	GAS & OIL	575,479	658,021	545,399	498,183	532,468
16	NUCLEAR PPA VARIABLE	0	0	0	0	0
17	STATION POWER	0	0	0	0	0
18	CE OWNED RENEWABLES	68,850	83,524	82,856	83,013	83,131
19	PEAKERS	27,582	18,691	21,244	25,112	30,525
20	PUMPED STORAGE	0	0	0	0	0
		0				
21	TOTAL GENERATED	947,723	1,013,963	739,818	606,609	646,426
22	LESS : PUMPING	0	0	0	0	0
23	TOTAL GENERATED	947,723	1,013,963	739,818	606,609	646,426
24	PURCHASED (NUGs) VARIABLE COST[1]	442,001	403,812	489,559	553,786	600,557
25	NET INTERCHANGE, EXCLUDING ZRC	57,799	-176,386	-72,555	7,807	-101,852
26	**TOTAL FUEL, VARIABLE PURCHASED AND NET INTERCHANGE**	**1,447,522**	**1,241,389**	**1,156,822**	**1,168,201**	**1,145,130**
27	ZONAL RESOURCE CREDIT PURCHASE	929	0	0	0	0
28	OWNED RENEWABLE CAPACITY	40,107	48,655	48,266	48,358	48,426
29	NUCLEAR PPA CAPACITY	0	0	0	0	0
30	PURCHASED (NUG) CAPACITY	259,395	270,291	224,596	190,504	187,265
31	PURCHASED (NUG) FIXED ENERGY	72,389	76,336	78,540	75,648	75,363
32	INDEPENDENT ADMINISTRATOR EXPENSE	525	250	250	250	250
33	**TOTAL CAPACITY AND NUG FIXED COSTS**	**373,345**	**395,531**	**351,651**	**314,759**	**311,304**
34	TOTAL TRANSMISSION AND ENERGY MARKETS ADMINISTRATION	505,387	552,183	583,736	603,989	610,000
35	ACTIVATED CARBON	2,271	2,214	916	0	0
36	MISO - SCHEDULE 2 (REACTIVE)	-4,500	-4,500	-4,500	-4,500	-4,500
37	AQUEOUS AMMONIA EXPENSE	799	318	324	288	318
38	UREA EXPENSE	4,145	4,326	1,393	0	0
39	LIME EXPENSE	8,205	7,763	2,834	0	0
40	**TOTAL POWER SUPPLY COSTS**	**2,337,175**	**2,199,225**	**2,093,176**	**2,082,737**	**2,062,253**
41	LONG-TERM INDUSTRIAL LOAD RETENTION RATE (LTILRR)	108,876	92,829	88,107	91,888	83,581
42	**TOTAL POWER SUPPLY COSTS LESS LTILRR PAYMENTS**	**2,228,299**	**2,106,395**	**2,005,069**	**1,990,849**	**1,978,672**

[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

Annual Summary for Years 2023 through 2027 of Fuel and Purchased and Net Interchange Power Expense

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		2023	2024	2025	2026	2027
(a)	(b)	(c)	(d)	(e)	(f)	(g)
	PURCHASED AND NET INTERCHANGE RECEIVED (MWH)					
43	MARKET ON PEAK	1,727,500	468,678	802,458	1,101,075	690,956
44	MARKET OFF PEAK	4,062,996	2,064,938	3,290,660	4,410,258	3,903,815
45	PURCHASED (NUGs)	7,862,771	7,839,388	10,603,816	11,813,305	11,965,247
46	TOTAL RECEIVED	13,653,267	10,373,004	14,696,935	17,324,637	16,560,019
	NET INTERCHANGE DELIVERED (MWH)					
47	EXTERNAL SALES	3,109,181	5,057,420	4,563,515	4,285,479	5,622,076
48	MISO RAC	0	0	0	0	0
49	TOTAL DELIVERED	3,109,181	5,057,420	4,563,515	4,285,479	5,622,076
50	NET (MWH)	10,544,086	5,315,584	10,133,420	13,039,158	10,937,943

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Annual Summary for Years 2023 through 2027 of Fuel and Purchased and Net Interchange Power Expense

Case No.: U-21257
Exhibit No.: A-8 (JWH-2)

Witness: JWHahn
Date: September 2022

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		2023	2024	2025	2026	2027
(a)	(b)	(c)	(d)	(e)	(f)	(g)
	VARIABLE PURCHASED AND NET INTERCHANGE EXPENSE ($*1000)					
51	MARKET ON PEAK ENERGY	92,684	22,965	38,125	52,847	33,181
52	MARKET OFF PEAK ENERGY	204,809	91,120	138,687	188,920	168,067
53	PURCHASED (NUGs) ENERGY	425,652	387,152	472,583	536,436	591,930
54	CASE NO. U-16048 COST RECOVERY	16,349	16,659	16,976	17,349	8,628
55	TOTAL EXPENSE	739,494	517,897	666,371	795,552	801,806
	NET INTERCHANGE CREDIT ($*1000)					
56	EXTERNAL SALE ENERGY	239,687	290,474	249,370	233,965	303,105
57	EXTERNAL SALE CAPACITY	0	0	0	0	0
58	MISO RAC	0	0	0	0	0
59	TOTAL CREDIT	239,687	290,474	249,370	233,965	303,105
60	NET EXPENSE	499,807	227,423	417,001	561,587	498,701

Line	EXISTING ENERGY-ONLY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
1	Cheboygan Hydro Plant	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	T.B. Simon Power Plant	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	The Power Plant - WMU	Hourly incremental running cost	0.10¢/kWh (minimum of $378/month, but not to exceed $3,780/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	The Michigan Alternative and Renewable Energy Center	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	Midland Gas to Energy Plant	90% of (Consumers Energy's Real Time Load Node LMP Minus $5/MWh)	0.10¢/kWh (minimum of $378/month, but not to exceed $3,780/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	Muskegon Tech Center Plant	90% of (Consumers Energy's Real Time Load Node LMP Minus $5/MWh)	0.10¢/kWh (minimum of $378/month, but not to exceed $3,780/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.
9	Grand Rapids Water Resource Recovery Facility	Real-time LMP	$1/MWh for Delivered Energy		Automatic renew for subsequent (1) month periods and shall continue in effect unless and until terminated by mutual agreement or by either party giving the other Party at least one (1) month's written notice
10	Otsego Paper Inc.	Real-time LMP	$1/MWh for Delivered Energy		Automatic renew for subsequent (1) month periods and shall continue in effect unless and until terminated by mutual agreement or by either party giving the other Party at least one (1) month's written notice

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 $378/month, but not to exceed $3,780/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	Rathbun Generating Station (Landfill Gas)	Agreement Terminated.			
4	Venice Park Generating Facility	Average PSCR rate	0.10¢/kWh (minimum of $378/month, but not to exceed $3,780/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.
5	Zeeland Farm Services, Inc. (Landfill Gas)	Agreement Terminated			
6	C&C Electric 2 Plant	Average PSCR rate	0.10¢/kWh (minimum of $378/month, but not to exceed $3,780/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 $378/month, but not to exceed $3,780/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	Granger Venice Park	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	Alverno Hydro Plant	6.607¢/kWh	0.10¢/kWh (minimum of $200/month, but not to exceed	$11,708.75/ZRC-month	May 31, 2039
7	Beaverton, City of	2.71¢/kWh	0.10¢/kWh	3.51¢/kWh On-Peak, 2.75¢/kWh Off-Peak	May 31, 2039
8	Hope Renewable Energy – Hubbardston	Agreement Terminated.			
9	Irving Hydroelectric	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	Energy Developments (Byron Center)	6.396¢/kWh	None	$11,708.75/ZRC-month	May 31, 2039
14	Energy Developments (Coopersville)	6.396¢/kWh	None	$11,708.75/ZRC-month	May 31, 2039
15	Energy Developments (Grand Blanc)	6.396¢/kWh	None	$11,708.75/ZRC-month	May 31, 2039
16	Energy Developments (Pinconning)	6.396¢/kWh	None	$11,708.75/ZRC-month	May 31, 2039

Line	EXISTING ENERGY & CAPACITY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
17	Grayling Generating Station Limited Partnership	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (minimum of $378/month, but not to exceed $3,780/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.
18	Belding Plant	5.405¢/kWh	0.10¢/kWh (not to exceed $2,000/month)	$8768.50/ZRC-month	May 31, 2039.
19	Hillman Power Company LLC	Agreement Terminated.			
20	Mass Burn Incinerator Plant	6.315¢/kWh	0.10¢/kWh (not to exceed $2,000/month)	$11,708.75/ZRC-month	May 31, 2039.
21	Michiana Hydroelectric Co Bellevue	7.068¢/kWh	0.10¢/kWh (not to exceed $2,000/month)	$11,708.75/ZRC-month	May 31, 2039.

Line	EXISTING ENERGY & CAPACITY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
22	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.
23	Midland Cogeneration Venture Limited Partnership	Cost of Production	0.10¢/kWh (not to exceed $2,000/month)	1.014¢/kWh	May 31, 2030. Thereafter, the Agreement shall continue in effect unless and until terminated by mutual agreement or by either Party giving the other Party at least one year's written notice of termination to be effective on May 31, 2030, or at the end of any Planning Period thereafter.
24	North American Natural Resources, Inc.- (Peoples)	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (minimum of $378/month, but not to exceed $3,780/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.
25	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
26	STS Hydropower Ltd – Cascade Hydro Plant	5.335¢/kWh	0.10¢/kWh (not to exceed $2,000/month)	$8,768.50/ZRC-month	May 31, 2039

Line	EXISTING ENERGY & CAPACITY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
27	STS Hydropower Ltd – Morrow Hydro Plant	2.71¢/kWh	0.10¢/kWh	3.97¢/kWh On-Peak, 3.37¢/kWh Off-Peak	31-May-27
28	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.
29	STS Hydropower Ltd – Fallasburg Hydro Plant	5.4¢/kWh	None	$4,503/ZRC-month	May 31, 2039.
30	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
31	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
32	White's Bridge Hydro Company	7.068¢/kWh	0.10¢/kWh (not to exceed $2,000/month)	$11,708.75/ZRC-month	May 31, 2039.
33	Boyce Hydro (formerly Wolverine Power Corporation)	Agreement Terminated			
34	STS Hydropower Ltd – Thornapple Ada Hydro Plant	4.076¢/kWh	None	$11,708.75/ZRC-month	May 31, 2023.
35	Kleber Hydro	6.607¢/kWh	None	None	May 31, 2039.
36	Tower Hydro	6.607¢/kWh	None	None	May 31, 2039.
37	Good Fruits Storage, LLC	LMP	None	PRA	May 31, 2031.
38	Hazel Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
39	Bingham Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
40	Temperance Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
41	13 Mile Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
42	Captain Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
43	Coldwater Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
44	Geddes 1 Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
45	Interchange Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
46	Jack Francis Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
47	May Shannon Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
48	Stoneheart Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
49	Workman Road Solar	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
50	Arthur Solar Farm	4.155¢/kWh	None	PRA	May 31, 2042.
51	Golden Solar Farm	4.155¢/kWh	None	PRA	May 31, 2042.
52	Robert Swift Solar Farm	4.155¢/kWh	None	PRA	May 31, 2042.
53	Angola Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
54	Geddes 2 Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
55	Bullhead Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.

56	Hendershot Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
57	Hogan Solar	4.155¢/kWh	None	PRA	May 31, 2042.
58	Entergy Nuclear Power Marketing, LLC	Agreement Terminated			
59	Allegheny Solar	4.155¢/kWh	None	PRA	October 1, 2041.
60	Aluminum Solar	4.155¢/kWh	None	PRA	May 31, 2042.
61	Blue Elk Solar I	4.155¢/kWh	None	PRA	May 31, 2044.
62	Blue Elk Solar III	4.155¢/kWh	None	PRA	May 31, 2043.
63	Blue Elk Solar IV	4.155¢/kWh	None	PRA	May 31, 2043.
64	Blue Elk Solar VII	4.155¢/kWh	None	PRA	May 31, 2043.
65	Calhoun Solar Energy LLC	3.747¢/kWh	None	$2,775.83/ZRC-month	May 31, 2047.
66	Cement City Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2043.
67	Greenstone Solar	4.155¢/kWh	None	PRA	May 31, 2043.
68	Johnsfield Solar	4.155¢/kWh	None	PRA	May 31, 2042.
69	Letts Creek Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2043.
70	Lightfoot Solar	4.155¢/kWh	None	PRA	May 31, 2043.
71	Lyons Road Solar	4.155¢/kWh	None	PRA	May 31, 2042.
72	Macbeth Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2042.
73	Midcontinent Solar	4.155¢/kWh	None	PRA	May 31, 2043.
74	Lake City Solar	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2043.
75	Morey Road Solar	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2043.
76	Surrey Road Solar	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2043.
77	Pullman Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2043.
78	Shipsterns Solar	4.155¢/kWh	None	PRA	May 31, 2043.
79	Surbrook Solar	4.155¢/kWh	None	PRA	May 31, 2042.
80	TART Solar	4.155¢/kWh	None	PRA	May 31, 2043.

81	Thorn Lake Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2045.
82	Topanga Solar	4.155¢/kWh	None	PRA	May 31, 2042.
83	Wilford Solar	4.155¢/kWh	None	PRA	May 31, 2043.
84	Woodley Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2042.
85	Elk Rapids Hydroelectric Power LLC	7.068¢/kWh	None	$11,708.75/ZRC-month	May 31, 2039.
86	Bay Windpower I, Mackinaw City, LLC. (Wind)	3.876¢/kWh	0.10¢/kWh (not to exceed $2,000/month)	$5,551.92/ZRC-month	May 31, 2024.
87	Addle Solar, LLC	4.155¢/kWh	None	PRA	July 4, 2044.
88	Byrne Solar	4.155¢/kWh	None	PRA	May 1, 2043.
89	Cereal City Solar	2.687¢/kWh	None	$14,228.8/ZRC-month	May 31, 2048.
90	Confluence Solar Project	4.985¢/kWh	None		December 31, 2049.
91	Copenhagen Solar, LLC	4.155¢/kWh	None	PRA	July 4, 2044.
92	DSC Corp Center Solar	4.155¢/kWh	None	PRA	May 31, 2032.
93	Heartwood Solar, LLC	4.985¢/kWh	None		December 31, 2049.
94	Holly Solar, LLC	4.155¢/kWh	None	PRA	April 4, 2045.
95	Jackson County Solar Project	2.687¢/kWh	None	$14,228.8/ZRC-month	December 31, 2043.
96	Michigan Apple Packers Cooperative, Inc	4.155¢/kWh	None	PRA	May 31, 2030.
97	Olivier Solar, LLC	4.155¢/kWh	None	PRA	April 5, 2045.
98	Puck Solar, LLC	4.155¢/kWh	None	PRA	July 4, 2044.
99	Shoreline Solar, LLC	4.155¢/kWh	None	PRA	April 5, 2045.
100	South Christian High School	4.155¢/kWh	None	PRA	May 31, 2032.
101	Sunbelievable Solar, LLC	4.155¢/kWh	None	PRA	July 4, 2044.
102	Heathlands Solar LLC	3.835¢/kWh	None	$2,775.83/ZRC-month	May 31, 2042.

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY
PURCHASED POWER AGREEMENTS

PROJECTED 2023 RATES

Line	RENEWABLE ENERGY PLAN AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
1	River Fork Solar	Monthly Transfer Rate	None		May 31, 2042.
2	Fremont Community Digestor LLC (Anaerobic Digestor)	Monthly Transfer Rate	None		December 26, 2032.
3	WM Renewable Energy LLC, Northern Oaks Landfill Plant (Landfill Gas)	Monthly Transfer Rate	None		November 10, 2030.
4	North American Natural Resources Inc, Lennon Generating Station (Landfill Gas)	Monthly Transfer Rate	None		December 15, 2030.
5	Michigan Wind 2 (Wind)	Monthly Transfer Rate	None		December 31, 2031.
6	Harvest II Wind Farm (Wind)	Monthly Transfer Rate	None		October 31, 2032.
7	Beebe Renewable Energy, formerly Blissfield Energy (Wind)	Monthly Transfer Rate	None		December 17, 2032.
8	WM Renewable Energy LLC, Pine Tree Acres Landfill Plant (Landfill Gas)	Monthly Transfer Rate	None		February 28, 2032.
9	Heritage Stoney Corners Wind Farm I, LLC, Phase 2 (Wind)	Monthly Transfer Rate	None		December 31, 2031.
10	Heritage Stoney Corners Wind Farm I, LLC, Phase 3 (Wind)	Monthly Transfer Rate	None		December 31, 2031.
11	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**
12	Geronimo Apple Blossom Wind Farm	Monthly Transfer Rate	None		October 31, 2032.
13	Experimental Advanced Renewable Program (EARP) (Solar)	Monthly Transfer Rate	None		Individual contracts have specific termination dates. All agreements will terminate by April 30, 2023.
14	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.
15	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.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

Case No: U-21257
Exhibit No.: A-10 (JWH-4)
Page: 1 of 1
Witness: JWHahn
Date: September 2022

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

	(a)	(b)	(c)	(d)	(e)
Line		**PY 2023-24**	**PY 2024-25**	**PY 2025-26**	**PY 2026-27**
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	7,787	7,853	7,886	7,919
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	881	975	1,067	1,162
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	6,906	6,878	6,819	6,756
4	Load Diversity Factor coincident to MISO, %.	97.39%	97.39%	97.39%	97.39%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	6,726	6,699	6,641	6,580
6	Transmission Losses, %	3.60%	3.60%	3.60%	3.60%
7	Planning Reserve Margin % UCAP Basis	8.30%	7.80%	7.40%	7.40%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	7,546	7,481	7,389	7,322
9	Company Owned, In-State, Non-Intermittent, ZRC	5,665	5,676	4,370	4,359
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	17	17	17	17
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	80	266	526	595
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	15	15	15	15
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	5,778	5,974	4,928	4,986
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 3)	655.1	662.2	668.5	668.5
19	PPA, In-State, Non-Intermittent, ZRC	1,587	1,587	1,999	1,999
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	32	32	28	24
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	121	221	683	734
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	5	20	20	20
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	2	2	5	11
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	98	208	313	313
29	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	1,845	2,070	3,048	3,101
32	Total Planning Resources, ZRC (line 17 + line 18 + line 31)	8,278	8,707	8,644	8,756
33	UCAP Surplus/(Shortfall), ZRC (line 32 - line 8)	732	1,225	1,255	1,434

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, 2023	))))))	Case No. U-21257

DIRECT TESTIMONY

OF

NATHAN J. HOFFMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

Q. Please state your name and business address.

A. My name is Nathan J. Hoffman, 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 Plant Business Manager – Campbell.

Q. Please describe your educational background.

A. In 2003, I received a Bachelor of Science degree in Welding Engineering Technology from Ferris State University. In 2017, I received a Master of Business Administration with a concentration in Advanced Management Tools and Concepts from Ferris State University.

Q. Please describe your business experience.

A. In 2005, I joined Consumers Energy at the J.H. Campbell ("Campbell") Generating Complex and progressed through positions from Engineering Technical Analyst to the Plant Business Manager.

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 2023 Power Supply Cost Recovery ("PSCR") Plan year; (iii) compare the projected ROR for fossil, hydro, Ludington, and peaker units with actual ROR experienced in the five-year historical period 2017 through 2021; (iv) address availability of generating units for the five-year forecast period; (v) identify forecasted urea expenses for the 2023 PSCR Plan year, as well as the forecast period 2024 through 2027; (vi) identify forecasted aqueous ammonia expenses for the 2023 PSCR Plan year, as well as the forecast period 2024 through 2027; (vii) identify forecasted lime expenses for the 2023 PSCR Plan year, as well as the forecast period 2024 through 2027; and (viii) identify forecasted activated carbon expenses for the 2023 PSCR Plan year, as well as the forecast period 2024 through 2027.

Q. Are you sponsoring exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-11 (NJH-1)	Major Outages in the 2023 PSCR Plan;
Exhibit A-12 (NJH-2)	2023 PSCR Random Outage Rate Projections;
Exhibit A-13 (NJH-3)	2023-2027 Urea Expense;
Exhibit A-14 (NJH-4)	2023-2027 Aqueous Ammonia Expense;
Exhibit A-15 (NJH-5)	2023-2027 Lime Expense; and
Exhibit A-16 (NJH-6)	2023-2027 Activated Carbon Expense.

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

A. Yes.

<u>Major Generating Plant Outages for 2023</u>

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-11 (NJH-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-11 (NJH-1).

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

<u>Zeeland Unit 1</u>

The outage at Zeeland Unit 1 is scheduled to begin March 1, 2023 and is projected to last for 30 days – concluding March 31, 2023. The outage is necessary for the removal of the leased generator step-up transformer ("GSU") and re-installation of the owned GSU. The leased GSU was installed during the May 2022 maintenance outage.

<u>D.E. Karn ("Karn") Unit 3</u>

The outage at Karn Unit 3 is scheduled to begin March 5, 2023 and is projected to last for 41 days – concluding April 15, 2023. The outage is necessary to begin the work associated with the cooling tower rebuild - the replacement of the structural timbers, remaining stacks, and fan blades. The wooden structure is original equipment and has decayed since its installation. The cooling tower provides cooling water for the condenser. The wooden cooling tower structure supports 18 large fans that pull air through the water to drive the evaporation process to cool the water. The wooden structure also supports large water pipes that carry the cooling water to the fill. The water flow to the tower is approximately 240,000 gallons per minute. All of this weight is supported by the wooden structure as it is conveyed to the tower and cascades over the fill. Implementation of this project will provide for reliable operation of Karn Unit 3 through its retirement in 2031. During this spring outage, work will be focused on the cooling tower supports.

Campbell Unit 3

The outage at Campbell Unit 3 is scheduled to begin April 1, 2023 and is projected to last for 42 days – concluding May 13, 2023. The periodic outage is necessary for replacement of Campbell Unit 3 Lake Michigan Intake Screens, selective catalytic reduction catalyst management and other periodic maintenance which cannot be performed during plant operation.

Karn Unit 2

The outage at Karn Unit 2 is scheduled to begin May 1, 2023 and is projected to last for 30 days – concluding May 31, 2023. The periodic outage is to perform preparation activities for unit cessation on May 31, 2023.

Ludington Unit 5

The outage at Ludington Unit 5 is scheduled to begin May 15, 2023 and is projected to last for 40 days – concluding June 24, 2023. The periodic outage is to perform various periodic outage work including discharge ring inspection, generator inspections, and other routine maintenance including quarterly brush inspections and oil cooler cleaning.

Ludington Unit 6

The outage at Ludington Unit 6 is scheduled to begin May 15, 2023 and is projected to last for 40 days – concluding June 24, 2023. The periodic outage is to perform various periodic outage work including discharge ring inspections, generator inspections, and other routine maintenance including quarterly brush inspections and oil cooler cleaning.

<u>Zeeland Unit 3</u>

The outage at Zeeland Unit 3 is scheduled to begin September 22, 2023 and is projected to last for 57 days – concluding November 18, 2023. The periodic outage is to perform a gas turbine overhaul and generator field replacement based upon unit run hours.

<u>Zeeland Unit 4</u>

The outage at Zeeland Unit 4 is scheduled to begin September 22, 2023 and is projected to last for 57 days – concluding November 18, 2023. The periodic outage is to perform a gas turbine overhaul, generator field replacement, and main generator breaker replacement based upon unit run hours.

<u>Zeeland Unit 5</u>

The outage at Zeeland Unit 5 is scheduled to begin September 22, 2023 and is projected to last for 57 days – concluding November 18, 2023. The periodic outage is to perform a main generator breaker replacement and steam turbine minor overhaul based upon unit run hours.

<u>Karn Unit 3</u>

The outage at Karn Unit 3 is scheduled to begin October 1, 2023 and is projected to last for 48 days – concluding November 18, 2023. The outage is necessary for the continuation of the cooling tower rebuild – cooling tower modifications. In addition, a project to replace the entire communication, protective relaying, monitoring, and control systems to the Hampton substation will be performed, thereby affecting Karn Units 3 and 4.

<u>Karn Unit 4</u>

The outage at Karn Unit 4 is scheduled to begin October 1, 2023 and is projected to last for 48 days – concluding November 18, 2023. The outage is necessary for the replacement of the entire communication, protective relaying, monitoring, and control systems to the Hampton substation, thereby affecting Karn Units 3 and 4.

Campbell Unit 1

The outage at Campbell Unit 1 is scheduled to begin October 13, 2023 and is projected to last for 30 days – concluding November 12, 2023. The periodic outage is necessary for periodic maintenance on balance of plant of equipment which cannot be performed during plant operation.

Miscellaneous Outages

Q. Are other outages projected for 2023?

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 (2017 through 2021) and are modified to reflect current operating conditions and recent investments. This is shown in Exhibit A-12 (NJH-2). Generating units which have a projected ROR that varies from their five-year average ROR by more than 10% are described below.

Karn Unit 3

The 2023 ROR for Karn Unit 3 is projected to be 18.42% lower than the five-year average. The reduction in projected ROR is the result of recent investment in the unit to improve unit availability. The five-year average ROR was elevated due to failure of the Karn Unit 4 induced draft fan 4B (requiring Unit 3 to go offline due to the sharing of a common duct) and the COVID 19 pandemic in 2020.

Karn Unit 4

The 2023 ROR for Karn Unit 4 is projected to be 15.45% lower than the five-year average. The reduction in projected ROR is the result of recent investment in the unit to improve unit availability. The five-year average ROR was elevated, in part, due to failure of the Karn Unit 4 induced draft fan 4B in 2020.

Availability

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

A. Yes. The 2023 projected availability for each of the generating units is shown in Exhibit A-12 (NJH-2), column (b).

Oxides of Nitrogen Emission Allowances

Q. Does Consumers Energy expect to incur expenses in 2023 related to the Oxides of Nitrogen (“NO_x”) emission allowance program?

A. Potentially. Currently the Company is not planning to incur expenses in 2023 under the current NOx emission allowance program. However, the Environmental Protection Agency (“EPA”) has proposed the “Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard”. If the rule is finalized as proposed, prior to the conclusion of the 2023 ozone season, then there is the potential for an increase of expenses in either the form of purchased NOx allowances, additional reagent for the NOx control equipment and/or a combination of the two. The Company will continue to monitor the progress of the proposed rule and evaluate the various options for compliance with the rule.

Q. Please explain why Consumers Energy does not expect to incur expenses in 2023 related to the NO_x emission allowance program.

A. The Company has installed Selective Catalytic Reduction ("SCR") units which have significantly reduced NO_x emissions and the associated need to purchase NO_x emissions allowances under the current Cross-State Air Pollution Rule ("CSAPR"). 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 EPA to be revised. In August 2011, the EPA finalized the CAIR replacement rule, known as the 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 through 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.

On April 6, 2022, the EPA proposed the "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard", also known as the Good Neighbor Plan ("GNP"). For sources in Michigan, the GNP will replace the CSAPR NOx Ozone Season Group 3 Trading starting in the 2023 ozone season control period. Unlike the other CSAPR programs, the proposed GNP will introduce several new concepts, including the following:

- Via rule, there will only be fixed allowance allocations in 2023-2024, with subsequent allocations determined via a dynamic process using ozone season data for the period two years prior to the allocation year (i.e., 2023 data would be used of the 2025 allocations).
- Under the proposed dynamic budgeting process, retired units would only continue to receive allowances for two years after they retire, as opposed to five years under the current CSAPR programs.
- Starting in 2024 for units with existing SCR controls and 2027 for other units, a new daily NOx rate limit will apply to large (>100 MW) coal-fired units. If the daily average NOx rate exceeds 0.14 lb./MMBtu for a subject unit, then emissions above that level must be offset by a 3-for-1 allowance surrender ratio. As proposed, there are no exclusions for periods of startup, shutdown, or malfunction.
- Starting with the 2024 control period, the EPA proposes to "recalibrate" the bank of allowances to ensure that the bank does not exceed 10.5% of the sum of the state emissions budgets for the control period.
- In cases where assurance levels are exceeded for a given state, the EPA is proposing additional potential penalties beyond the standard 3-for-1 allowance surrender.

Specifically, if a unit exceeds a calculated secondary limit, such a unit would be at risk of enforcement under Clean Air Act provisions.

- The timing of allocations for a given control period will also change. Under the historic CSAPR programs, existing unit allocations for control periods in 2025 and later years were to be made by July 1 of the third year before the year of the control period (i.e., by July 1, 2022 for the 2025 control period). Under the proposed GNP, allocations would be made by July 1 of the year before the control period (i.e., by July 1, 2024 for the 2025 control period). This change was made to accommodate the proposed dynamic budgeting under the GNP.

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 2023 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 2023 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 Michigan Department of Environmental Quality which pushed compliance to April 16, 2016. Consumers Energy has five coal-fired units and two oil-fired units subject to MATS.

<u>Urea Expenses</u>

Q. Are there urea expenses for which Consumers Energy is seeking recovery in 2023?

A. Yes. Exhibit A-13 (NJH-3) identifies the projected urea expenses through 2027.

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

A. In 2023, Consumers Energy projects spending $4.1 million for urea as a necessary expense of operating Campbell Units 2 and 3. In 2024, Consumers Energy expects to spend $4.3 million for urea. For the years 2025 through 2027, urea expenses are expected to be $1.4, $0.0, and $0 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. How does the projected urea expense compare to the Company's 2022 PSCR Plan case (Case No. U-21048) projections?

A. The projected expense for urea has increased for the years 2023 and 2024 and dropped in 2025. The projected increase in urea expense is primarily a direct result of an increase in the urea unit cost as a result of commodity price increases. Significant increases in natural gas pricing have led to increased urea unit price increases and projected urea expense. The cost of urea is dependent on natural gas pricing which has increased significantly in the last year. As a result, pricing has increased 51% over the last year. The projected urea unit costs for Campbell Units 2 and 3 have increased by approximately 65% and 52% respectively, including transportation, versus those reflected in the 2022 PSCR Plan case (Case No. U-21048).

The decrease in urea expense in 2025 and beyond is a result of the June 23, 2022 Order Approving Settlement Agreement in Case No. U-21090 which reflects the retirement of Campbell Units 2 and 3 on May 31, 2025. Campbell Unit 1 will also be retired but does not consume urea.

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

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

<u>Aqueous Ammonia Expenses</u>

Q. Are there Aqueous Ammonia expenses for which you are seeking recovery in 2023?

A. Yes. Exhibit A-14 (NJH-4) identifies the projected aqueous ammonia expenses for the years 2023 through 2027.

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

A. In 2023, Consumers Energy projects spending $0.8 million for aqueous ammonia as a necessary expense of operating Karn Units 1 and 2 and Zeeland Unit 2 (the Combined Cycle unit). In 2024, Consumers Energy also expects to spend $0.3 million for aqueous ammonia associated with the operation of Zeeland Unit 2 only. For each of the years 2025 through 2027, expenses are expected to be $0.3 million, respectively.

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

A. The June 7, 2019 Order in Case No. U-20165 approved a contested settlement agreement in the Company's 2018 Integrated Resource Plan ("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 Midcontinent Independent System Operator, Inc. Planning Year. As a result of the Karn Units 1 and 2 retirements, Zeeland will be the sole user of aqueous ammonia – see Exhibit A-14 (NJH-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. How does the projected aqueous ammonia expense compare to the Company's 2022 PSCR Plan case (Case No. U-21048) projections?

A. The projected aqueous ammonia expense for 2023 is down slightly from that projected for 2022 in the Company's 2022 PSCR Plan case (Case No. U-21048). This reduction is entirely due to the retirement of Karn Units 1 and 2 on May 31, 2023 as previously discussed. Overall unit expense for aqueous ammonia, which is also dependent on natural gas pricing, has increased significantly in 2022.

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.

<u>Lime Expenses</u>

Q. Are there lime expenses for which you are seeking recovery in 2023?

A. Yes. Exhibit A-15 (NJH-5) identifies the projected lime expenses for the years from 2023 through 2027.

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

A. In 2023, Consumers Energy projects spending $8.2 million for lime. In 2024, Consumers Energy expects to spend $7.8 million for lime. In the years from 2025 through 2027, lime expenses are expected to be $2.8, $0, and $0 million, respectively.

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; these units consume pebble lime. DSI was installed at Campbell Units 1 and 2 in early 2016; these units consume hydrated lime. Lime will be injected into the SDA/DSI where it will react with SO_2 and heavy metals found in the exhaust gases. When used in combination with Pulse Jet Fabric Filters ("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.

Q. How does the projected lime expense compare to the Company's 2022 PSCR Plan case (Case No. U-21048) projections?

A. The projected expense for lime reflects a slight increase for 2023 before beginning to drop in 2024 and beyond. The 2023, 2024, and 2025 projected lime expense projected in the Company's 2022 PSCR Plan case (Case No. U-21048) was \$8.0, \$7.3, and \$6.7 million respectively versus current projections of \$8.2, \$7.8, and \$2.8 million respectively. The unit costs for hydrated and pebble lime have increased approximately 14% and 12% respectively in the past year, including transportation costs.

The decrease in lime expense in 2025 and beyond is a result of the June 23, 2022 Order Approving Settlement Agreement in Case No. U-21090 which reflects the retirement of Campbell Units 1 through 3 on May 31, 2025.

<u>**Activated Carbon Expenses**</u>

Q. Are there Activated Carbon expenses for which you are seeking recovery in 2023?

A. Yes. Exhibit A-16 (NJH-6) identifies the projected activated carbon expenses for the years from 2023 through 2027.

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

A. In 2023, Consumers Energy projects spending $2.3 million for activated carbon as a necessary expense of operating Campbell Units 1 through 3 and Karn Units 1 and 2. In 2024, Consumers Energy expects to spend $2.2 million for activated carbon. In the years from 2025 through 2027, activated carbon expenses are forecasted to be $0.9, $0.0, and $0 million, respectively.

Q. How will activated carbon be used?

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

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

A. 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.

Q. How does the projected activated carbon expense compare to the Company's 2022 PSCR Plan case (Case No. U-21048) projections?

A. The projected expense for activated carbon reflects an approximate 124% increase in 2023 before dropping in 2024 and in 2025. The increase in activated carbon expense in 2023 reflects the expiration of the three-year contract which was established in 2019 through the

Commodity Chemicals Request for Proposal ("RFP") and the fact that natural gas prices, to which activated carbon prices are directly correlated, have increased approximately 300% since the contract arising from the Commodity Chemicals RFP was established. The 2023 increase is somewhat offset by the retirement of Karn Units 1 and 2 on May 31, 2023. The decrease in activated carbon expense in 2024 reflects the first full year of retirement of Karn Units 1 and 2 and the further reduction in 2025 is a result of the June 23, 2022 Order Approving Settlement Agreement in Case No. U-21090 which reflects the retirement of Campbell Units 1 through 3 on May 31, 2025.

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	)	Case No. U-21257
cost recovery plan for the 12 months	)	
ending December 31, 2023	)	
	)	

EXHIBITS

OF

NATHAN J. HOFFMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21257
Exhibit No.: A-11 (NJH-1)

Witness: NJHoffman
Date: September 2022

Major Outages in the 2023 PSCR Plan

	(a)	(b)	(c)	(d)
Line No.	**Unit**	**Days in 2023**	**Start Date**	**End Date**
1	Zeeland 1	30	3/1/2023	3/31/2023
2	Karn 3	41	3/5/2023	4/15/2023
3	Campbell 3	42	4/1/2023	5/13/2023
4	Karn 2	30	5/1/2023	5/31/2023
5	Ludington 5	40	5/15/2023	6/24/2023
6	Ludington 6	40	5/15/2023	6/24/2023
7	Zeeland 3	57	9/22/2023	11/18/2023
8	Zeeland 4	57	9/22/2023	11/18/2023
9	Zeeland 5	57	9/22/2023	11/18/2023
10	Karn 3	48	10/1/2023	11/18/2023
11	Karn 4	48	10/1/2023	11/18/2023
12	Campbell 1	30	10/13/2023	11/12/2023

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21257
Exhibit No.: A-12 (NJH-2)
Page: 1 of 1
Witness: NJHoffman
Date: September 2022

2023 PSCR Random Outage Rate Projections

Line No.	(a) Unit	(b) Availability	(c) Periodic Factor	(d) 2023 Projected ROR	(e) Actual ROR 2017-2021
1	**Campbell 1**	77.09%	8.23%	16.00%	14.54%
2	**Campbell 2**	70.27%	17.81%	14.50%	20.24%
3	**Campbell 3**	81.41%	11.51%	8.00%	9.75%
4	**Karn 1**	78.50%	0.00%	21.50%	20.30%
5	**Karn 2**	66.80%	20.00%	16.50%	16.71%
6	**Karn 3**	63.29%	24.20%	16.50%	34.92%
7	**Karn 4**	71.73%	13.06%	17.50%	32.95%
8	**Ludington 1**	89.01%	7.28%	4.00%	1.85%
9	**Ludington 2**	89.01%	7.28%	4.00%	8.52%
10	**Ludington 3**	87.81%	8.53%	4.00%	2.63%
11	**Ludington 4**	87.81%	8.53%	4.00%	6.26%
12	**Ludington 5**	80.68%	15.96%	4.00%	6.45%
13	**Ludington 6**	81.91%	14.68%	4.00%	3.77%
14	**Hydros**	88.28%	6.48%	5.60%	5.76%
15	**Zeeland CC**	77.46%	19.31%	4.00%	2.67%
16	**Zeeland 1A**	84.37%	12.11%	4.00%	1.48%
17	**Zeeland 1B**	92.74%	3.40%	4.00%	3.04%
18	**Jackson 1**	89.13%	6.67%	4.50%	5.38%
19	**Covert 1**	89.62%	9.32%	1.17%	
20	**Covert 2**	92.89%	5.47%	1.74%	
21	**Covert 3**	93.62%	5.47%	0.96%	

2023-2027 Urea Expense

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Unit**	**2023**	**2024**	**2025**	**2026**	**2027**
1	**Campbell 2**	$782,756	$745,820	$247,751	$0	$0
2	**Campbell 3**	$3,362,009	$3,580,402	$1,145,411	$0	$0
3	**Total**	$4,144,765	$4,326,222	$1,393,163	$0	$0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21257
Exhibit No.: A-14 (NJH-4)
Page: 1 of 1
Witness: NJHoffman
Date: September 2022

2023-2027 Aqueous Ammonia Expense

Line No.	(a) Unit	(b) 2023	(c) 2024	(d) 2025	(e) 2026	(f) 2027
1	**Karn 1**	$360,181	$0	$0	$0	$0
2	**Karn 2**	$148,517	$0	$0	$0	$0
3	**Zeeland**	$290,784	$317,626	$323,695	$287,522	$318,468
4	**Total**	$799,482	$317,626	$323,695	$287,522	$318,468

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21257
Exhibit No.: A-15 (NJH-5)

Witness: NJHoffman
Date: September 2022

2023-2027 Lime Expense

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Unit**	**2023**	**2024**	**2025**	**2026**	**2027**
1	**Karn 1**	$251,646	$0	$0	$0	$0
2	**Karn 2**	$249,729	$0	$0	$0	$0
3	**Campbell 1**	$1,952,405	$1,915,585	$933,926	$0	$0
4	**Campbell 2**	$2,473,551	$2,356,832	$782,907	$0	$0
5	**Campbell 3**	$3,277,918	$3,490,848	$1,116,762	$0	$0
6	**Total**	$8,205,249	$7,763,265	$2,833,595	$0	$0

2023-2027 Activated Carbon Expense

Line No.	(a) Unit	(b) 2023	(c) 2024	(d) 2025	(e) 2026	(f) 2027
1	**Campbell 1**	$967,074	$993,632	$504,290	$0	$0
2	**Campbell 2**	$459,999	$437,129	$151,159	$0	$0
3	**Campbell 3**	$737,448	$783,266	$260,845	$0	$0
4	**Karn 1**	$53,433	$0	$0	$0	$0
5	**Karn 2**	$53,025	$0	$0	$0	$0
6	**Total**	$2,270,980	$2,214,026	$916,294	$0	$0

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	)	Case No. U-21257
cost recovery plan for the 12 months	)	
ending December 31, 2023	)	
	)	

DIRECT TESTIMONY

OF

KEVIN C. LOTT, PE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

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 Supply 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 what is now called the Electric Supply organization 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 Campbell and Karn generating plant sites 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 Karn Units 3 and 4; and natural gas for Zeeland, Jackson, Karn Units 3 and 4, and Covert 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 Power Supply Cost Recovery ("PSCR") Plan regarding projected as-burned costs and volumes of coal, oil, and natural gas used for electric generation in 2019;
- MPSC Case No. U-20525 (direct and rebuttal), the Company's 2020 PSCR Plan regarding projected as-burned costs and volumes of coal, oil, and natural gas used for electric generation in 2020;
- MPSC Case No. U-20802 (direct), the Company's 2021 PSCR Plan regarding projected as-burned costs and volumes of coal, oil, and natural gas used for electric generation in 2021; and
- MPSC Case No. U-21048 (direct), the Company's 2022 PSCR Plan regarding projected as-burned costs and volumes of coal, oil, and natural gas used for electric generation in 2022.

<u>PURPOSE OF TESTIMONY</u>

Q. What is the purpose of your testimony?

A. I am sponsoring 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 testimony?

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

Exhibit A-17 (KCL-1) – Projected As-Burned Coal Costs – 2023;

Exhibit A-18 (KCL-2) – Projected As-Burned Coal Costs (2024 – 2027);

Exhibit A-19 (KCL-3) – Projected As-Burned Oil & Gas Costs – 2023; and

Exhibit A-20 (KCL-4) – Projected As-Burned Oil & Gas Costs (2024 – 2027).

AS-BURNED COAL COSTS

Q. Please explain Exhibit A-17 (KCL-1).

A. Exhibit A-17 (KCL-1) summarizes the projected as-burned coal costs and tonnage at each of the Company's coal-fired generating plants for the year 2023. 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 PSCR and economic dispatch purposes. In economic dispatch, only the variable expense relating to coal is included, and is represented by spot coal that will be purchased at the next opportunity, 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 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 dust inhibitors to ensure compliance with railroad operating rules and tariffs; applicable harbor maintenance fees; as well as the cost of transporting the coal to the plant.

<u>COAL PRICE DETERMINATION</u>

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.

<u>COAL TRANSPORTATION CONTRACTS</u>

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 2023, the Company expects to have in effect three contracts that will provide for the shipment of coal on railroads. The Company has not entered into contracts for lake vessel shipments for 2023 due to the planned plant closure of Karn Units 1 and 2 by May 31, 2023 and will rely solely on rail deliveries to deliver coal to the Karn site after 2022 and until cessation of operations.

COAL TRANSPORTATION RATE DETERMINATION

Q. What process was used to determine freight rates?

A. Freight rates were determined by contract pricing, including forecasted periodic adjustments per the terms of each respective contract. 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 2023?

A. As described in Company witness Joshua W. Hahn's testimony, a computer model is used to determine production estimates (*i.e.*, MWh production and hence MMBtu coal burn requirements to support that production) for each generating unit. In addition to 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 2023 and do you expect to purchase more?

A. The Company presently has approximately 4.1 million tons of coal committed for 2023 from the multiyear or annual purchases shown in Company witness Rissman's Exhibit

A-22 (AKR-1). Currently, the Company does not anticipate purchasing any additional coal in 2022 for 2023 delivery.

SPOT COAL PURCHASES

Q. How much coal do you expect to purchase on a spot basis during 2023?

A. Approximately 1.9 million tons of coal are projected to be purchased on a spot basis in 2023.

2024 – 2027 PROJECTED AS-BURNED COAL COSTS

Q. Please explain Exhibit A-18 (KCL-2).

A. Exhibit A-18 (KCL-2) summarizes the projected as-burned coal costs and tonnage at each of the Company's coal-fired generating plants for the years 2024 – 2027. The total cost includes primary fuel, auxiliary fuel, freeze protection and dust inhibiting treatments, and state air emission fees.

Q. How were the projected as-burned coal costs for the years 2024 – 2027 determined?

A. In a manner similar to 2023, with adjustments made to existing supply and transportation contract prices based on the forecasted performance of the indices to which a given contract's pricing is tied, as necessary per the terms of the individual contracts. The fixed prices from those contracts with fixed price components were included without escalation. Forecasted commodity prices provided by Company witness Rissman and transportation costs, as described above, were utilized for open position (unsecured) tonnage.

Q. Are any new contracts anticipated for the 2024 – 2027 time period?

A. Yes. It is anticipated that the Company will be entering into new supply and transportation contracts as needed to replace those contracts which will expire during

2024 – 2027 time period. The pricing for any new coal supply is provided by Company witness Rissman and modeled accordingly. The pricing for any future transportation contracts is modeled in the same manner as existing contracts.

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

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

A. I am supplying the oil and gas fuel cost projections for the Company's oil-fired and gas-fired generating units, which are Karn Units 3 and 4, the Zeeland plant, and the Jackson plant. In addition, I am supplying the gas fuel cost projections for the Covert Plant, which is planned to be acquired by June 1, 2023 which occurs during this forecast period by the Company per the settlement agreement in the most recent Integrated Resource Plan ("IRP"), which was approved by the Commission (Case No. U-21090) on June 23, 2022.

Q. Please explain Exhibit A-19 (KCL-3).

A. Exhibit A-19 (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 2023.

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 2024 – 2027?

A. Yes, these annual cost projections are shown in Exhibit A-20 (KCL-4).

Q. How were your oil and natural gas projections determined for the years 2024 – 2027?

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 2023.

Q. Does this complete your prepared 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, 2023	))))))	Case No. U-21257

EXHIBITS

OF

KEVIN C. LOTT, PE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21257
Exhibit No.: A-17 (KCL-1)

Witness: KCLott
Date: September 2022

Projected As-Burned Coal Costs - 2023

Line	**(a)** Plant	**(b)** Burn Volume (Tons)	**(c)** Burn Dollars
1	JHCampbell 1-2	2,118,878	$ 100,109,416
2	JHCampbell 3 (CE Owned Portion)	3,055,291	$ 143,827,620
3	DEKarn 1-2	659,385	$ 31,878,467
4	Total	5,833,555	$ 275,815,503

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21257
Exhibit No.: A-18 (KCL-2)
Page: 1 of 1
Witness: KCLott
Date: September 2022

Projected As-Burned Coal Costs
2024 - 2027

Line	(a)	(b)	(c)	(d)	(e)	(f)
	Burn Volume (Tons)					
	Plant		2024	2025	2026	2027
1	JHCampbell 1-2		1,998,514	792,331	0	0
2	JHCampbell 3 (CE Owned Portion)		3,176,461	989,615	0	0
3	DEKarn 1-2		0	0	0	0
4		Total Burn Tonnage	5,174,975	1,781,946	0	0
	Burn Dollars					
	Plant		2024	2025	2026	2027
5	JHCampbell 1-2		$ 96,130,611	$ 39,229,057	$ -	$ -
6	JHCampbell 3 (CE Owned Portion)		$ 152,837,966	$ 48,859,178	$ -	$ -
7	DEKarn 1-2		$ -	$ -	$ -	$ -
8		Total Primary Fuel	$ 248,968,577	$ 88,088,235	$ -	$ -
9		Total Primary Fuel	$ 248,968,577	$ 88,088,235	$ -	$ -
10		Total Auxilliary Fuel	$ 3,053,366	$ 1,291,319	$ -	$ -
11		Total Freeze/Dust Treatment	$ 1,276,564	$ 511,260	$ -	$ -
12		State Air Emission Fees	$ 428,114	$ 428,114	$ 300,736	$ 300,736
13		Total Coal Burn Cost	$ 253,726,621	$ 90,318,929	$ 300,736	$ 300,736

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21257
Exhibit No.: A-19 (KCL-3)
Page: 1 of 1
Witness: KCLott
Date: September 2022

Projected As-Burned Oil & Gas Costs - 2023

Line	(a) Plant	(b) Burn Volume (MCF/BBLS)	(c) Burn Dollars
1	Zeeland Generating Station	29,885,011	$ 214,622,528
2	Jackson Plant	19,540,866	$ 149,812,517
3	DEKarn 3-4 - Oil	0	$ -
4	DEKarn 3-4 - Gas	0	$ 5,566,679
5	Covert Generating Station	36,126,033	$ 224,998,238
6	Total		$ 594,999,961

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Projected As-Burned Oil & Gas Costs
2024 - 2027

Line	(a)	(b)	(c)	(d)	(e)	(f)
	Burn Volume (MCF/BBLS)					
	Plant		2024	2025	2026	2027
1	Zeeland Generating Station		31,879,539	32,419,281	29,389,586	37,139,179
2	Jackson Plant		22,822,392	10,514,057	7,109,885	7,672,335
3	DEKarn 3-4 - Oil		2,307	0	0	0
4	DEKarn 3-4 - Gas		34,676	0	0	0
5	Covert Generating Station		65,704,942	65,828,155	65,848,210	65,908,134
	Burn Dollars					
	Plant		2024	2025	2026	2027
7	Zeeland Generating Station		$ 171,749,089	$ 161,524,104	$ 143,827,694	$ 180,470,062
8	Jackson Plant		$ 127,675,929	$ 57,239,959	$ 39,917,450	$ 42,145,075
9	DEKarn 3-4 - Oil		$ 218,169	$ -	$ -	$ -
10	DEKarn 3-4 - Gas		$ 5,765,261	$ 5,566,679	$ 5,566,679	$ 5,566,679
11	Covert Generating Station		$ 352,389,080	$ 326,644,219	$ 319,630,377	$ 319,411,433
		Total Primary Fuel	$ 657,797,527	$ 550,974,961	$ 508,942,199	$ 547,593,249
12		Total Primary Fuel	$ 657,797,527	$ 550,974,961	$ 508,942,199	$ 547,593,249
13		Total Auxilliary Fuel	$ 18,836,214	$ 15,589,704	$ 14,274,091	$ 15,321,558
14		State Air Emission Fees	$ 78,882	$ 78,882	$ 78,882	$ 78,882
15		Total Oil & Gas Burn Cost	$ 676,712,623	$ 566,643,547	$ 523,295,172	$ 562,993,689

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	)	Case No. U-21257
cost recovery plan for the 12 months	)	
ending December 31, 2023	)	
	)	

DIRECT TESTIMONY

OF

STEPHEN J. NADEAU

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

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 the Fossil Fuel Supply organization.

<u>QUALIFICATIONS</u>

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 Section of what is now the Electric Supply Operations Department 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);
- Case No. U-20219 (2019 PSCR Plan);
- Case No. U-20220 (2019 PSCR Reconciliation);
- Case No. U-20525 (2020 PSCR Plan);
- Case No. U-20526 (2020 PSCR Reconciliation);
- Case No. U-20802 (2021 PSCR Plan);
- Case No. U-20803 (2021 PSCR Reconciliation); and
- Case No. U-21048 (2022 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. Yes. I am sponsoring Exhibit A-21 (SJN-1), 2023 Forecasted Natural Gas Prices and 2022 Comparison of Forecasted vs. Actual Natural Gas Prices.

PRICE PROJECTIONS

Q. What is the basis of the Company's oil and gas commodity price forecasts?

A. These forecasts were based on NYMEX monthly futures price information and were indicative of future market prices for oil and gas at the time they were prepared.

Q. What are your underlying assumptions for your price projections for 2023?

A. The price of No. 6 and No. 2 oil is based on crude oil projections and our approximation of the relationship between crude oil and No. 6 and No. 2 oil. The price of natural gas for D.E. Karn ("Karn") Units 3 and 4 is based on the market gas prices (monthly New York Mercantile Exchange ("NYMEX") Henry Hub) to which the cost of transportation was added. The prices of natural gas for the Zeeland, Jackson, and Covert plants are based on gas market prices (monthly NYMEX Henry Hub) which were adjusted to the proper gas index and in accordance with the gas management services ("GMS") contracts the Company has for each gas generating plant. Also included in the price projections are the demand charges associated with the use of the associated lateral pipelines.

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

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

Q. How does the Company determine its projection for the citygates used for index pricing?

A. The Company determines historical relationships between the respective citygate 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 citygate price as shown in Exhibit A-21 (SJN-1).

Q. Has the Company changed the methodology it employs to develop natural gas and oil price forecasts?

A. No. The Company has maintained the same methodology it has historically employed to develop its natural gas and oil price forecasts.

Q. How have the forecasted natural gas prices changed from the Company's 2022 PSCR Plan projections?

A. The forecasted natural gas prices at the onset of 2023 are significantly higher than those projected in the Company's 2022 PSCR Plan case, Case No. U-21048. Specifically, the average Henry Hub forecasted natural gas price for 2023 in the 2022 PSCR Plan case was $3.09 while the average Henry Hub forecasted price for 2023 in this 2023 PSCR Plan case is $6.66, which equates to a 116% increase in price as shown on Exhibit A-21 (SJN-1), column (n), lines 2 and 3.

Q. What factors have impacted the Company's 2023 PSCR Plan forecasts?

A. The Company's 2022 PSCR Plan filed in September 2021 expected weather conditions to normalize in 2022 and COVID-19 pandemic-related drivers to begin to trend positively including increased producer investment as budgets were reset amidst higher structural demand, supportive oil prices, and decreased pandemic uncertainty. The increased investment was expected to decrease natural gas prices throughout 2022 toward long-term forecasts. The U.S. Energy Information Administration ("EIA") and IHS October 2021 short-term forecasts projected 2022 end-of-year market prices at $3.50/MMBtu and $3.79/MMBtu, respectively.

While producer investment has resulted in significant year-over-year rig count increases despite inflation, supply chain issues, labor shortages, and production volume increases to date still lag year-over-year demand gains. Liquid Natural Gas ("LNG") exports remain near available capacity as Europe looks to replace Russian supply. Russian sanctions have increased global demand for LNG and thermal coal, thus increasing U.S. domestic spot natural gas and coal prices amidst already low domestic inventories. Significantly higher domestic coal prices, rail labor shortages causing coal delivery challenges, and coal generation retirements have limited gas-to-coal switching, increasing year-to-date power generation natural gas demand. Year-to-date weather has supported increased residential and commercial electric loads, thus impeding natural gas storage injections at the national level and keeping inventory levels below normal. This has kept upward pressure on forward natural gas prices. Higher natural gas prices have thus far not deterred industrial demands, which have also increased moderately year over year despite the June 2022 NYMEX natural gas contract settling at nearly three times the June 2021 contract.

Based on the above fundamentals and the EIA's June short-term forecast, the Company expects to incur significantly higher natural gas costs in 2023 than was forecasted in the 2022 PSCR Plan as shown in Exhibit A-21 (SJN-1).

Q. How have these factors impacted the Company's costs for natural gas in 2022?

A. These factors have forced natural gas prices higher in 2022, especially during the summer months as shown on Exhibit A-21 (SJN-1), line 13, columns (f) through (i). Therefore, the Company's costs for natural gas in 2022 have been much higher than were forecasted in the 2022 PSCR Plan case, Case No. U-21048. Specifically, the average forecasted Henry Hub price in the 2022 PSCR Plan case for the first eight months of 2022 was $3.79 while the average actual Henry Hub price for the first eight months of 2022 is $6.53, a 72% increase in price which is shown on Exhibit A-21 (SJN-1), column (n), lines 12 and 13. This has led to a significant under recovery of actual 2022 PSCR costs compared to the plan.

Q. What is the basis for your projection that natural gas prices will remain higher through 2023?

A. It is anticipated that natural gas inventories will be lower heading into the 2022-2023 heating season 1.) because of the increased demand for natural gas used in electric generation in 2022, which will have the effect of holding prices higher over the winter period; 2.) because operators did not inject as much gas into storage due to the commodity's high price; and 3.) because of increased demand for LNG exports to Europe. Natural gas prices are expected to ease down starting around April 2023 due to increased domestic natural gas production, decreasing LNG exports, and increased injections of natural gas into storage. Current projections, however, suggest natural gas prices will remain significantly higher during 2023 than what was projected approximately one year ago for 2023.

<u>OIL AND NATURAL GAS PROCUREMENT</u>

Q. What types of fuels are burned at the Company's currently owned 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. 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 longer term contracts 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 operated as baseload units due to their expensive startup and shutdown costs, natural gas fired units have much more flexibility to follow the electric demand and the market price of power and are typically operated as intermediate or peaking units. Therefore, 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 natural gas. Contracting for volumes of natural gas which cannot be consumed but are required to be taken can result in increased costs for customers as a result of paying for storage, paying contract penalties, or selling excess quantities at a loss. 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 periodically performs a Request for Proposal ("RFP") for gas management services, thus making sure the most competitive, viable supplier of these services is utilized. Also, the Company utilizes the provisions contained in its gas transportation agreements and GMS agreements to minimize its natural gas related costs. For Karn, this includes monitoring gas usage and market prices during the month and competitively bidding purchases to minimize cost and 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 for Karn Units 3 and 4 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 for a portion of its needs on a seasonal basis.

ZEELAND, JACKSON, AND KARN PLANTS

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. The Zeeland Plant is connected through a lateral pipeline owned and operated by SEMCO Energy Gas Company ("SEMCO").

Q. What does Consumers Energy do to assure a reliable and economic supply of fuel for the Zeeland Plant?

A. Consumers Energy entered into a competitively bid, third-party contract to act as a GMS 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 (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 that will be provided for under this GMS 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 current contract with SEMCO was extended this year and now covers the period 2023 through 2027.

Q. How will the GMS contract work?

A. In addition to procuring the gas commodity and transportation service, the Agent will be 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 will also be responsible for purchasing gas as directed by the Company in both the day-ahead gas market and the intraday market as MISO accepts offers from the Zeeland Plant in the MISO energy market. In addition, the Agent will provide services to balance gas nomination against dispatch requests from MISO. The pricing of the GMS contract will be based on published indices.

Q. Will 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 will be 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 to the natural gas utility side of the Company 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. Do you believe the demand charges for the Jackson lateral pipeline to be reasonable and prudent?

A. Yes. The natural gas transportation agreement for the Jackson plant was initially negotiated and executed as an arm's length transaction between the Company's natural gas utility and a third party under the rules and regulations of Michigan's Act 9 of 1929. The agreement was not negotiated between Company affiliates. As the original parties to the agreement were unaffiliated, there was no reason for the Company's natural gas utility to undercharge for the pipeline and natural gas service and there was also no reason for the former plant owner to overpay for the pipeline and natural gas service. When the Company's electric utility later acquired the Jackson Plant from the prior plant owner, the Company's electric utility assumed the prior plant owner's role and obligations under the natural gas transportation agreement. This is analogous to what the Company did when it purchased the Zeeland Plant.

The Commission initially approved recovery of the costs related to the Company's ownership of the Jackson Plant in the Company's 2014-2015 electric rate case, Case No. U-17335. See MPSC Case No. U-17335, November 19, 2015 Order, page 96. Since the Commission issued its November 19, 2015 Order finding the Jackson Plant capital and Operations and Maintenance costs to be reasonable and prudent for cost recovery purposes, the Company has routinely included the demand charges, as paid by the Company's electric utility to the Company's natural gas utility under the Jackson Plant natural gas transportation agreement, and those charges have been routinely approved for recovery by the Commission as reasonably and prudently incurred power supply costs.

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

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

Q. What is the source of fuel for Karn Units 3 and 4?

A. Karn Units 3 and 4 burn natural gas from two pipelines: one source is through a lateral pipeline owned by DCP Midstream that is connected to DTE's gas pipeline system in the Alpena, MI area, and the other source is through a direct connection to the Company's natural gas distribution system. In addition, the units can also burn No. 6 fuel oil.

Q. How does the Company expect to manage gas and oil purchasing and transportation for Karn Units 3 and 4?

A. The No. 6 fuel oil burned at Karn Units 3 and 4 will be purchased on an as-needed, spot market basis. The gas for Karn Units 3 and 4 delivered via the Company distribution system will be purchased on a spot market basis, while the gas delivered via the DCP lateral from DTE's system will be purchased under a GMS contract with spot pricing terms.

Q. Does the Company currently use an Agent to manage supplies to Jackson, Zeeland, and Karn?

A. Yes, the Company has historically found it prudent to utilize a GMS Agent for these services.

Q. When do the current GMS agreements for these plants expire?

A. For Zeeland and Jackson, they expire on October 31, 2024. For Karn, it expires on May 31, 2023; however this will likely be extended through October 31, 2024 to line up with the expiration of the Zeeland and Jackson plant GMS agreements. New RFPs will be issued for future years.

Q. Does the method for managing the gas supplies for the Jackson, Zeeland, and Karn plants using an Agent 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.

<u>COVERT PLANT</u>

Q. Are there any major changes to gas generation assets in 2023?

A. Yes. The Company will assume ownership of the Covert Generating Facility ("Covert Plant") on June 1, 2023 from New Covert Generating Company, LLC consistent with the Company's 2021 Integrated Resource Plan Proposed Course of Action. The Covert Plant, which entered commercial operations in 2004, is a natural gas fired generating facility located in Covert Township, Van Buren County, MI with a nameplate capacity of 1,176 MW.

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

A. The Covert Plant is directly connected to the ANR natural gas interstate pipeline system.

Q. How does the Company plan to supply natural gas to this facility?

A. At the time the Company assumes ownership and takes over operation of the Covert Plant, the Company will assume from the prior owners of the Covert Plant, an existing gas management services agreement it has with a GMS agent. At such time that agreement expires, the Company anticipates it will continue to use a GMS agent as it does for the Zeeland Plant. The Covert Plant is served off the same ANR pipeline as the Zeeland Plant, and because of the similarity in location, nature, and operation between the two plants, the Company believes it will be prudent to utilize a GMS agent for the same reasons the Company has elected to use one for the Zeeland Plant.

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, 2023	))))))	Case No. U-21257

EXHIBIT

OF

STEPHEN J. NADEAU

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21257
Exhibit No.: A-21 (SJN-1)

Witness: SJNadeau
Date: September 2022

2023 Forecasted Natural Gas Prices and 2022 Comparison of Forecasted vs. Actual Natural Gas Prices

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	2023 Forecasted Prices													
1	**Month**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Average**
2	2022 Plan Henry Hub Forecast	$3.73	$3.64	$3.37	$2.88	$2.81	$2.85	$2.89	$2.90	$2.89	$2.91	$3.00	$3.18	$3.09
3	2023 Plan Henry Hub Forecast	$9.59	$9.15	$7.71	$5.95	$5.77	$5.82	$5.87	$5.88	$5.86	$5.91	$6.07	$6.30	$6.66
4	CE-Henry Hub Basis	($0.29)	($0.29)	($0.29)	($0.19)	($0.19)	($0.20)	($0.20)	($0.20)	($0.19)	($0.19)	($0.19)	($0.29)	($0.22)
5	Consumers Citygate	$9.30	$8.87	$7.42	$5.76	$5.58	$5.62	$5.67	$5.68	$5.67	$5.72	$5.88	$6.01	$6.43
6	Michcon-Henry Hub Basis	($0.36)	($0.36)	($0.36)	($0.19)	($0.19)	($0.19)	($0.19)	($0.19)	($0.19)	($0.19)	($0.19)	($0.36)	($0.25)
7	Michcon Citygate	$9.23	$8.79	$7.34	$5.75	$5.57	$5.63	$5.68	$5.69	$5.67	$5.72	$5.87	$5.94	$6.41
8	Dawn-Henry Hub Basis	($0.34)	($0.34)	($0.34)	($0.20)	($0.20)	($0.21)	($0.21)	($0.21)	($0.20)	($0.20)	($0.20)	($0.34)	($0.25)
9	Dawn Ontario	$9.26	$8.82	$7.37	$5.75	$5.57	$5.61	$5.66	$5.67	$5.66	$5.71	$5.87	$5.96	$6.41
10	**2022 Forecast vs. Actual**													
11	**Month**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Average[1]**
12	2022 Plan Henry Hub Forecast	$4.57	$4.48	$4.14	$3.47	$3.38	$3.41	$3.44	$3.44	$3.43	$3.46	$3.52	$3.65	$3.79
13	2022 Henry Hub Actuals	$4.30	$4.75	$4.85	$6.53	$8.07	$7.79	$7.20	$8.78					$6.53

[1] represents an eight month average of January - August.

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	)	Case No. U-21257
cost recovery plan for the 12 months	)	
ending December 31, 2023	)	
	)	

DIRECT TESTIMONY

OF

ANGELA K. RISSMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

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 the Fossil Fuel Supply Section of the Electric Supply Operations Department.

<u>QUALIFICATIONS</u>

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 Supply Operations Department, and specifically began work in the Fossil Fuel Supply Section 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 fuel used at the Company's electric generating plants; negotiating and managing associated fossil fuel 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 MPSC?

A. Yes. I provided testimony in:

- MPSC Case No. U-18142 - 2017 Power Supply Cost Recovery ("PSCR") Plan;
- MPSC Case No. U-20068 - 2017 PSCR Reconciliation;
- MPSC Case No. U-18402 - 2018 PSCR Plan;
- MPSC Case No. U-20202 - 2018 PSCR Reconciliation;
- MPSC Case No. U-20219 - 2019 PSCR Plan;
- MPSC Case No. U-20220 - 2019 PSCR Reconciliation;
- MPSC Case No. U-20525 - 2020 PSCR Plan;
- MPSC Case No. U-20526 - 2020 PSCR Reconciliation;
- MPSC Case No. U-20802 - 2021 PSCR Plan;
- MPSC Case No. U-20803 – 2021 PSCR Reconciliation; and
- MPSC Case No. U-21048 – 2022 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 2023-2027 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-22 (AKR-1) 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 Fossil Fuel Supply Section endeavors to secure coal supplies in quantity and quality sufficient to meet the needs of the Company's coal-fired generating units in a cost effective manner. Coal from different regions is evaluated and purchased based on total delivered 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 up to 20% to 25% secured for the third calendar year.

Q. Have there been any changes to your coal purchase strategy for 2023 from the previous PSCR filings?

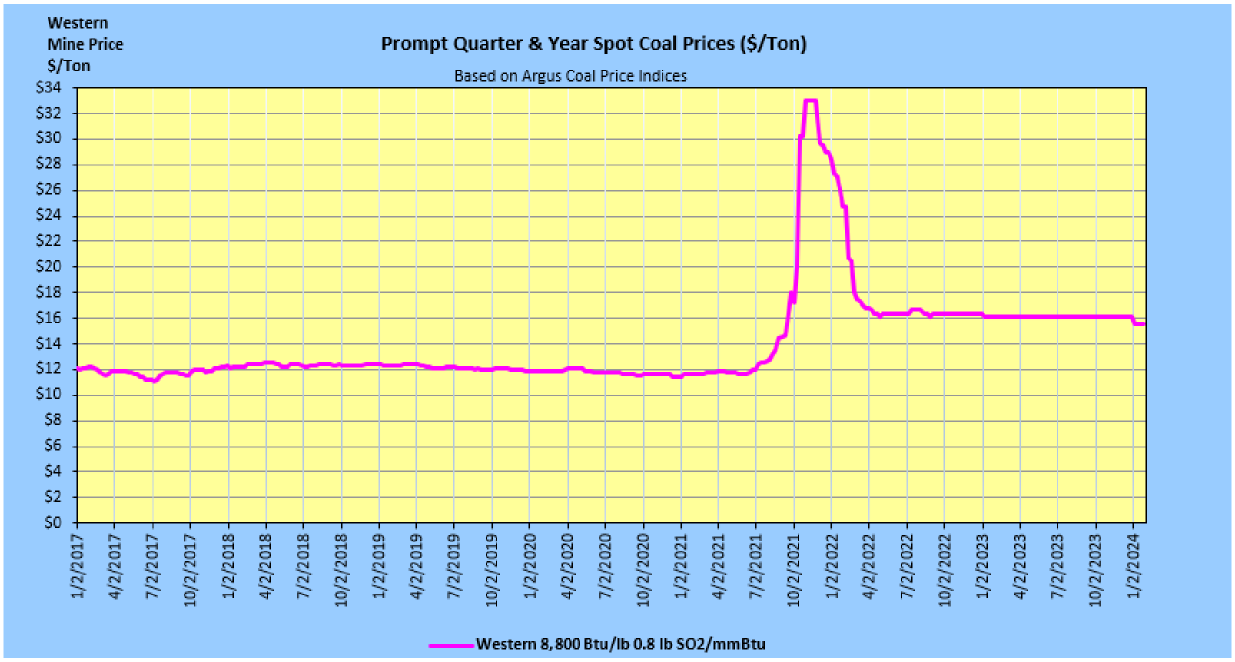
A. No. The Company is continuing to layer coal purchases in order to maintain a diverse, flexible portfolio of contracts responsive to changing market conditions.

Q. Has there been any notable differences in the price of spot coal projected in this case compared to the price projected in the 2022 PSCR Plan case?

A. Yes. In the 2022 PSCR plan, the projected spot price of western sub-bituminous coal for 2023 was $12.50/Ton. In this case, the 2023 projected spot price for western sub-bituminous coal, is $16.44/Ton.

Q. Why did the $/ton coal prices change so much between the two cases?

A. In the 4th quarter of 2021, after the 2022 PSCR Plan case was filed, there was an increase in natural gas prices which resulted in an increased coal demand for electric generation. The coal supply chain could not respond fast enough to this sudden increase in coal demand and coal prices spiked to unprecedented levels. The inability of the coal supply chain to respond was at least partially attributed to coal and railroad staffing constraints associated with COVID-19. As shown in the table below, the prices increased during the 4th quarter of 2021 where western sub-bituminous coal reached an all-time high of $33.00/Ton.



Q. How do the higher natural gas costs described by Company witness Stephen J. Nadeau impact the current projections for western sub-bituminous coal?

A. Higher prices of natural gas forecasted during the 2022 PSCR plan period have contributed to western sub-bituminous coal prices stabilizing in the $16/Ton range, as seen in the chart above. We do not expect to see a decrease in coal prices until natural gas prices drop to below $4/MMBtu.

Q. What impact do these higher coal prices have on the cost of coal forecasted in this plan for 2023 compared to the cost filed in the 2022 PSCR plan for 2023?

A. At the time the 2022 PSCR Plan was filed and in accordance with the Company's layered coal procurement strategy, approximately 40% of the of the coal commitments for 2023 had been procured at an average cost of $12.77/Ton. Since that time and during 2022, the Company has procured additional coal and at the time of this filing has procured approximately 70% of its coal total requirements for 2023 at an average cost of $14.63/Ton.

The remaining coal requirements are expected to be purchased at an average price of $16.44/Ton.

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 limitations as set forth in the consent decree have been incorporated into our Renewable Operating Permits for each site. These restrictions dictate the quality of coal that can be purchased. In order to comply with the permit limitations, the Company will purchase only western and/or low sulfur eastern coal.

These federally enforceable limits were, by operation of the Consent Decree, incorporated into the Renewable Operating Permit ("ROP" also known as a Title V permit or air permit as issued by the State) with the Michigan Department of Environmental Quality, now known as the Michigan Department of Environment, Great Lakes, and Energy on June 16, 2016 for D.E. Karn and December 21, 2017 for J.H. Campbell.

COAL PURCHASE CONTRACTS

Q. Please describe Exhibit A-22 (AKR-1).

A. Exhibit A-22 (AKR-1) shows all current and expected coal contracts providing for delivery for the 2023-2027 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 western bituminous coal (originating typically from Colorado) or western sub-bituminous 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. Are there any differences in coal supply in this case compared to previous PSCR cases?

A. Yes. Whereas previously, the Company modeled and forecasted burn for eastern coal, the company now has adjusted its modeling to replace eastern coal with western bituminous coal. Burning western bituminous coal at JHC2 allows the unit to achieve maximum capacity for longer periods of time without exceeding environmental limitations.

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 2023?

A. Yes. We anticipate purchasing spot coal during 2023 for delivery in 2023.

Q. Do you anticipate entering into any additional coal supply contracts from which tonnage would be received in the 2024-2027 time period?

A. Yes. It is anticipated that the Company will be entering into new coal contracts to provide a secure supply of coal through 2025, when the plants are scheduled to retire. The Company will follow the coal procurement strategy previously discussed.

COAL PRICE DETERMINATION 2023 - 2027

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[1]:

[1] The sources for this data incude Argus Coal Daily and internal fossil fuel supply department model projections.

YEAR	WESTERN SUB-BITUMINOUS ($/Ton)	WESTERN BITUMINOUS ($/Ton)
2023	$16.44	$145.00
2024	$16.15	$76.00
2025	$16.78	$79.53

Q. Does this complete your prepared 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	)	Case No. U-21257
cost recovery plan for the 12 months	)	
ending December 31, 2023	)	
	)	

EXHIBIT

OF

ANGELA K. RISSMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21257
Exhibit No.: A-22 (AKR-1)
Page: 1 of 1
Witness: AKRissman
Date: September 2022

2023 - 2025 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	363	Western	9/24/2021	1/1/2022	12/31/2023	1,187,160	$11.785
2	365	Western	11/23/2021	1/1/2022	12/31/2023	1,187,160	$13.757
3	372	Western	12/14/2021	1/1/2023	12/31/2023	364,135	$16.917
4	378	Western	3/9/2022	7/1/2022	12/31/2023	193,440	$14.930
5	383	Western	7/6/2022	1/1/2023	12/31/2024	382,200	$15.600
6	386	Western	*	10/1/2022	12/31/2023	705,120	$14.800
7		2023 UNCOMMITTED AS OF 2023 PSCR PLAN CASE				1,894,818	
8					**2023 Total**	**5,914,034**	
9	383	Western	7/6/2022	1/1/2023	12/31/2024	756,600	$15.800
10		2024 UNCOMMITTED AS OF 2023 PSCR PLAN CASE				4,544,698	
11					**2024 Total**	**5,301,298**	

* = 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, 2023	))))))	Case No. U-21257

DIRECT TESTIMONY

OF

ANDREW G. VOLANSKY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

Q. Please state your name and business address.

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

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

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

Q. Please state your educational background.

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

Q. Please describe your business experience.

A. After receiving my accounting degree in 2001, I worked as a staff auditor at Arthur Andersen LLP (2001-2002) 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. My responsibilities include assisting 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 Filing;

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

Case No. U-20525 – 2020 PSCR Plan Case;

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

Case No. U-20802 – 2021 PSCR Plan Case; and

Case No. U-21048 – 2022 PSCR Plan Case.

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

A. The purpose of my testimony is to present the calculation of the 2023 PSCR Factor.

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

A. Yes, I am sponsoring the following exhibits:

Exhibit A-23 (AGV-1)	Calculation of 2023 PSCR Factor; and
Exhibit A-24 (AGV-2)	Forecasted 2022 PSCR Under-Recovery.

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

A. Yes.

Q. Please describe Exhibit A-23 (AGV-1).

A. Exhibit A-23 (AGV-1) shows the calculation of the 2023 PSCR Factor. The 2023 PSCR Factor is calculated by adding line 1, Total Power Supply Cost less Long Term Industrial Load Retention Rate ("LTILRR") Payments provided by Company witness

Joshua W. Hahn to line 2, the projected 2022 under recovery as shown in Exhibit A-24 (AGV-2), to determine line 3, 2023 PSCR Factor Costs. The 2023 PSCR Factor Costs is divided by line 4, Total System Requirements less LTILRR (measured in units of kilowatt hours ("kWh")), provided by Company witness Eugene M. Breuring, to determine the average cost per kWh of requirements on line 5. From this quotient is subtracted the Base Recovery Factor (shown on line 6) collected through the standard tariffs as approved by the Commission. This remaining cost per kWh amount of $0.02506, set forth on line 7, is multiplied by the Line and Transformation Loss Factor on line 8 to determine the 2023 per kWh PSCR Factor of $0.02700 at sales, shown on line 9.

Q. Please describe the Exhibit A-24 (AGV-2).

A. Exhibit A-24 (AGV-2) shows the calculation of the forecasted 2022 under-recovery. Lines 1 through 42 show the Total PSCR Costs and Revenues and the components that comprise the totals. Lines 43 through 50 show the Total Under-Recovery and corresponding interest. Columns C through J show actual amounts from January through August 2022 and Columns K through N show forecasted amounts for the remainder of the year. Line 50 Column O shows the total forecasted 2022 under-recovery of $449,076,328.

Q. Is the Company looking for approval of 2022 PSCR cost and 2022 projected under-recovery?

A. No. In this plan case we are asking for the ability to collect the 2022 projected under-recovery amount in 2023. Actual approval of 2022 PSCR costs will be requested in the 2022 reconciliation case.

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 9.90%.

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, 2023	))))))	Case No. U-21257

EXHIBITS

OF

ANDREW G. VOLANSKY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21257
Exhibit No.: A-23 (AGV-1)
Page: 1 of 1
Witness: AGVolansky
Date: September 2022

Consumers Energy Company

Calculation of 2023 PSCR Factor

Line			
1	Total Power Supply Costs less LTILRR Payments[1]	$	2,228,299,329
2	Projected 2022 Under Recovery[2]	$	449,076,328
3	2023 PSCR Factor Costs (Line 1 + Line 2)	$	2,677,375,657
4	Total System Requirements less LTILRR in kWh[3]		33,150,055,000
	Jurisdictional Factor Calculation		
5	Average Cost at Requirements (Line 3 / Line 4)	$	0.08076
6	Less: Base Recovery Factor[4]	$	0.05570
7	Remaining Cost per kWh (Line 5 - Line 6)	$	0.02506
8	Line & Transformation Loss Factor[4]		1.07735
9	2023 PSCR Factor at Sales (Line 7 x Line 8)	$	0.02700

Sources: [1]Exhibit A-7 (JWH-1), Page 1, Line 42
[2]Exhibit A-24 (AGV-2), Page 1, Line 35
[3]WP-EMB-1
[4]Per Rule C-8, Section B(1) of Company Tariffs

CONSUMERS ENERGY COMPANY
FORECASTED 2022 PSCR UNDER-RECOVERY
TWELVE MONTH PERIOD ENDED DECEMBER 31, 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Line	Description	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	TOTAL
		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	forecast	forecast	forecast	forecast	
	Costs													
1	Total Recoverable PSCR Costs	179,362,107	169,371,363	177,567,922	166,036,527	185,132,034	227,524,051	249,372,900	280,290,534	206,319,408	189,474,873	187,895,936	206,215,297	2,424,562,951
	Sales (kWh)													
	Residential													
2	Cycle Billed	1,163,406,000	1,155,544,000	1,126,427,000	974,912,000	922,522,000	988,241,000	1,268,057,000	1,317,857,000	1,060,348,000	903,241,000	916,766,000	1,066,481,000	12,863,802,000
3	Current Month Unbilled	807,260,520	711,848,799	614,374,671	554,037,802	600,270,403	771,844,234	859,120,375	808,589,533	632,544,533	590,332,533	620,970,533	726,882,533	8,298,076,469
4	Prior Month Unbilled	(732,998,472)	(807,260,520)	(711,848,799)	(614,374,671)	(554,037,802)	(600,270,403)	(771,844,234)	(859,120,375)	(808,589,533)	(632,544,533)	(590,332,533)	(620,970,533)	(8,304,192,408)
5	Total Residential	1,237,668,048	1,060,132,279	1,028,952,872	914,575,131	968,754,601	1,159,814,831	1,355,333,141	1,267,326,158	884,303,000	861,029,000	947,404,000	1,172,393,000	12,857,686,061
	Commercial & Industrial													
6	Cycle Billed (less GSG-2)	1,401,780,496	1,430,980,042	1,482,873,438	1,418,707,098	1,401,010,924	1,489,452,113	1,613,941,056	1,668,527,454	1,592,636,840	1,484,643,260	1,457,950,350	1,442,571,800	17,885,074,871
7	Current Month Unbilled	1,339,114,146	1,288,453,712	1,324,735,621	1,262,993,856	1,305,836,436	1,427,585,728	1,492,259,112	1,532,178,637	1,463,097,637	1,502,994,637	1,510,042,637	1,466,404,637	16,915,696,796
8	Prior Month Unbilled	(1,197,953,350)	(1,339,114,146)	(1,288,453,712)	(1,324,735,621)	(1,262,993,856)	(1,305,836,436)	(1,427,585,728)	(1,492,259,112)	(1,532,178,637)	(1,463,097,637)	(1,502,994,637)	(1,510,042,637)	(16,647,245,509)
9	Total Commercial & Industrial	1,542,941,292	1,380,319,608	1,519,155,347	1,356,965,333	1,443,853,504	1,611,201,405	1,678,614,440	1,708,446,979	1,523,555,840	1,524,540,260	1,464,998,350	1,398,933,800	18,153,526,158
10	Total Residential and C&I Sales	2,780,609,340	2,440,451,887	2,548,108,219	2,271,540,464	2,412,608,105	2,771,016,236	3,033,947,581	2,975,773,137	2,407,858,840	2,385,569,260	2,412,402,350	2,571,326,800	31,011,212,219
11	Base Recovery Factor ($)	0.06000	0.06000	0.06000	0.06000	0.06000	0.06000	0.06000	0.06000	0.06000	0.06000	0.06000	0.06000	
12	Max PSCR Factor	0.00177	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	
13	PSCR Factor ($)	0.00177	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	
14	CM Unbilled PSCR Factor	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	0.00176	0.02630	
	Revenues ($)													
	Base Recovery													
15	Residential	74,305,195	63,608,792	61,737,172	54,874,508	58,125,276	69,588,890	81,319,988	76,039,569	53,058,180	51,661,740	56,844,240	70,343,580	771,507,131
16	Commercial & Industrial	92,522,793	82,815,348	91,149,321	81,417,920	86,631,210	96,672,084	100,716,866	102,506,819	91,413,350	91,472,416	87,899,901	83,936,028	1,089,154,056
	PSCR Recovery													
	Residential													
17	Cycle Billed	2,059,229	2,033,757	1,982,512	1,715,845	1,623,639	1,739,304	2,231,780	2,319,428	1,866,212	1,589,704	1,613,508	1,877,007	22,651,926
18	Current Month Unbilled	1,420,779	1,252,854	1,081,299	975,107	1,056,476	1,358,446	1,512,052	1,423,118	1,113,278	1,038,985	1,092,908	19,113,629	32,438,931
19	Prior Month Unbilled	(1,297,407)	(1,420,779)	(1,252,854)	(1,081,299)	(975,107)	(1,056,476)	(1,358,446)	(1,512,052)	(1,423,118)	(1,113,278)	(1,038,985)	(1,092,908)	(14,622,709)
20	Total Residential	2,182,600	1,865,833	1,810,957	1,609,652	1,705,008	2,041,274	2,385,386	2,230,494	1,556,373	1,515,411	1,667,431	19,897,728	40,468,148
	Commercial & Industrial													
21	Cycle Billed	2,481,151	2,518,525	2,609,857	2,496,924	2,465,779	2,621,436	2,840,536	2,936,608	2,803,041	2,612,972	2,565,993	2,538,926	31,491,750
22	Current Month Unbilled	2,356,841	2,267,679	2,331,535	2,222,869	2,298,272	2,512,551	2,626,376	2,696,634	2,575,052	2,645,271	2,657,675	38,559,621	65,750,375
23	Prior Month Unbilled	(2,120,377)	(2,356,841)	(2,267,679)	(2,331,535)	(2,222,869)	(2,298,272)	(2,512,551)	(2,626,376)	(2,696,634)	(2,575,052)	(2,645,271)	(2,657,675)	(29,311,132)
24	Total Commercial & Industrial	2,717,615	2,429,363	2,673,713	2,388,259	2,541,182	2,835,714	2,954,361	3,006,867	2,681,458	2,683,191	2,578,397	38,440,872	67,930,993
25	Total PSCR Recovery	4,900,215	4,295,195	4,484,670	3,997,911	4,246,190	4,876,989	5,339,748	5,237,361	4,237,832	4,198,602	4,245,828	58,338,600	108,399,140
		0												
26	Total Costs	179,362,107	169,371,363	177,567,922	166,036,527	185,132,034	227,524,051	249,372,900	280,290,534	206,319,408	189,474,873	187,895,936	206,215,297	2,424,562,951
27	Total Revenues	171,728,203	150,719,335	157,371,164	140,290,339	149,002,677	171,137,963	187,376,603	183,783,749	148,709,362	147,332,757	148,989,969	212,618,208	1,969,060,328
28	Prior Year Over/Under Recovery	10,201,698												10,201,698
29	Over (Under) Recovery	(7,633,904)	(18,652,028)	(20,196,758)	(25,746,188)	(36,129,358)	(56,386,088)	(61,996,297)	(96,506,785)	(57,610,046)	(42,142,115)	(38,905,967)	6,402,911	(445,300,925)
30	1/2 Current Month	(3,816,952)	(9,326,014)	(10,098,379)	(12,873,094)	(18,064,679)	(28,193,044)	(30,998,149)	(48,253,392)	(28,805,023)	(21,071,058)	(19,452,983)	3,201,455	(227,751,312)
31	Year to Date Recovery	10,201,698	2,567,794	(16,084,235)	(36,280,992)	(62,027,180)	(98,156,538)	(154,542,626)	(216,538,923)	(313,045,708)	(370,655,754)	(412,797,869)	(451,703,836)	(2,119,064,171)
32	Average Balance	6,384,746	(6,758,220)	(26,182,613)	(49,154,086)	(80,091,859)	(126,349,582)	(185,540,775)	(264,792,316)	(341,850,731)	(391,726,812)	(432,250,853)	(448,502,381)	(2,346,815,482)
33	Interest Rate	9.90%	0.01%	0.05%	0.29%	0.50%	0.89%	1.71%	2.19%	2.19%	2.19%	2.19%	2.19%	
34	Monthly Interest	52,674	(35)	(1,050)	(12,071)	(33,482)	(93,597)	(264,425)	(482,403)	(622,789)	(713,654)	(787,482)	(817,089)	(3,775,403)
35	Total Over (Under) Recovery	2,620,468	(18,652,063)	(20,197,808)	(25,758,259)	(36,162,839)	(56,479,685)	(62,260,722)	(96,989,188)	(58,232,835)	(42,855,770)	(39,693,449)	5,585,822	(449,076,328)

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, 2023	))))))	Case No. U-21257

DIRECT TESTIMONY

OF

EMILY M. WALAINIS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

Q. Please state your name and business address.

A. My name is Emily M. Walainis, 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 Manager of Supply Contracts in the Contracts and Settlements Section of the of the Electric Supply Operations Department.

<u>QUALIFICATIONS</u>

Q. Please describe your educational background and business experience.

A. I received a bachelor's degree in finance from Michigan State University and a Master of Business Administration degree from the University of Michigan.

Prior to joining Consumers Energy, I worked as an investment banking analyst at Wells Fargo from 2008 to 2011. In this role, I built comprehensive financial models, completed due diligence and credit analysis, and developed offering memoranda and investor presentations to support the origination and execution of syndicated leveraged loans and high yield bonds. From 2011 to 2015, I worked as a financial analyst at Atlas Energy L.P., an oil and gas exploration and production company. In this position, I was the liaison between the decentralized corporate accounting team and operational groups and performed quantitative and qualitative analysis for financial, operational, and combined projects.

I joined Consumers Energy in 2016 as a senior financial analyst in the Enterprise Risk department. In this role, I facilitated the enterprise risk management program, which consisted of working with risk owners across corporate and operational groups, to identify, analyze, and present risks to senior management. From 2017 to 2021, I was a senior associate in the Corporate Strategy department where I was responsible for managing the gas, electric, and retail businesses and supporting organizations strategy development. I also worked on the electric vehicle strategy and supported electric vehicle pilot program testimony and exhibits to ensure electric vehicles are successfully integrated into the electric grid for the benefit of all customers.

I started in my current role at Consumers Energy as the Manager of Supply Contracts in the Electric Grid Integration Contract and Settlements department in 2021. I am responsible for implementing the Company's Clean Energy Plan including: 1) the development of annual competitive solicitations for the procurement of wholesale electric generation; 2) negotiations and development of power purchase agreements; and 3) implementation and compliance with the Public Utility Regulatory Policies Act of 1978 ("PURPA"). I am also responsible for managing the: 1) Renewable Energy Plan ("RE Plan"); 2) Experimental Advanced Renewable Program; 3) Renewable Energy Credit administration and compliance; and 4) procurement of supply for the Company's Voluntary Green Pricing ("VGP") Programs.

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-21009 (direct), the Company's 2020 Renewable Energy Cost Reconciliation case, regarding the actual and expected expenses incurred to implement the Company's approved RE Plan in 2020, the billed surcharge revenues, and a discussion on the Company's Regulatory Liability Balance projection;

- Case No. U-21131 (direct), the Company's petition for approval of criteria for the formation of a Legally Enforceable Obligation under PURPA;

- Case No. U-21048 (direct), the Company's 2022 Power Supply Cost Recovery Plan ("PSCR") case, regarding Power Purchase Agreement ("PPA") resources, the Company's Blackstart Resource Agreement, treatment of Midcontinent Independent System Operator, Inc. ("MISO") revenue and expenses, expenses associated with the Company's Renewable Resource Program ("RRP"), and the treatment of forward commodity sales contracts associated with the Company's 2021 Integrated Resource Plan ("IRP") gas plant acquisitions;

- Case No. U-20604 (direct), the Company's requests for approval of new PPAs based on the Company's avoided costs;

- Case No. U-20803 (direct), the Company's 2021 PSCR Plan Reconciliation case, regarding the Independent Administrator expense associated with the Company's annual IRP competitive solicitations, the allocation of costs to the Renewable Resource Fund, PPAs executed, terminated, or otherwise modified in 2021, reverse capacity auction costs, and the Financial Compensation Mechanism forecast;

- Case No. U-21134 (rebuttal), the Company's request for approval of VGP Programs, regarding the Company's competitive bidding processes and IRP capacity; and

- Case No. U-21197 (direct), the Company's 2021 Renewable Energy Cost Reconciliation case, regarding the actual and expected expenses incurred to implement the Company's approved RE Plan in 2021, the billed surcharge revenues, and a discussion on the Company's Regulatory Liability Balance projection.

<u>PURPOSE OF DIRECT TESTIMONY</u>

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 Midcontinent Independent System Operator, Inc. ("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. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibit:

Exhibit A-25 (EMW-1)	New and Amended PPAs not Previously Included in the Company's PSCR Plan.

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

A. Yes.

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

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 several 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;
- New Solar Facilities; and
- One-Time Solicitation Resources.

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. The Company has several contracts in place with facilities that have, or are expected to, meet the requirements of Qualifying Facilities ("QFs")[1], in accordance with PURPA, that will terminate during the time period from 2023 to 2027, 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 Case No. U-20615. The Settlement Agreement has resulted in the execution of 414 MW of new PPAs with PURPA QFs at the reduced avoided cost rates established in Case No. U-18090. The Settlement also allowed for the substitution of these 414 MW of projects by developers. Presently, out of the 414 MW, 132 MW of replacement contracts are pending execution.

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 and June 23, 2022, the Commission's Orders in Case Nos. U-20165 and U-21090 approved the Settlement agreements in the Company's IRP. The IRPs include 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 the Settlement agreements, the Company expects that 50% of the new solar assets will be sourced

[1] Either a qualifying small power production facility or a qualifying cogeneration facility that meets certain size, fuel, and/or efficiency standards.

through PPAs and the other 50% will be Company-owned solar projects. PURPA QFs of any technology up to the Company's must purchase obligation under PURPA 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 rate included in the recently executed PPA with Heartwood Solar, LLC and Confluence Solar, LLC. Therefore, the Company has forecast expenses for the new IRP solar PPAs at the Heartwood Solar, LLC and Confluence Solar, LLC rate, however, the actual rates will be determined in the annual competitive solicitations.

Q. Please explain the IRP competitive solicitations.

A. The details for administering the competitive solicitations are included in the IRP Settlement agreements in Case Nos. U-20165 and U-21090. The Company utilizes an Independent Administrator to conduct the solicitations, complete the proposal evaluations, and provide a blind ranking of projects to the Company for selection. The Company has included the costs associated with the service agreement with the Independent Administrator in this PSCR Plan case on Exhibit A-7 (JWH-1), page 1, line 32.

Q. Are there any additional contracts for energy and capacity included in this PSCR Plan case that were not previously included in the 2022 PSCR Plan?

A. Yes. The contracts that were not previously included in the 2022 PSCR Plan are listed in Exhibit A-25 (EMW-1). Column (c) shows the fuel source of the PPA. Column (a) details the plant that is supplying energy and capacity for the PPA. Columns (d) and (e) list the MPSC case number associated with the Company's application for approval of each PPA and the date of the MPSC Order approving the application, respectively.

Additionally, the Company has amended several PPAs since the filing of the 2022 PSCR Plan. These amendments are also shown in Exhibit A-25 (EMW-1) and are denoted in column (b).

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

A. On June 23, 2022, the Commission's Order in Case No. U-21090 approved the Settlement Agreement in the Company's IRP. In accordance with this Settlement Agreement, the Company expects to source 500 Zonal Resource Credits ("ZRCs") through PPAs for dispatchable, non-intermittent generation and 200 ZRCs through PPAs for intermittent resources and dispatchable, non-intermittent clean resources (including storage) through a competitive solicitation process. The Company estimates that the rates paid under the new PPAs for the 500 ZRCs will be similar to the rates for Jackson Generating Station and the rates paid under the new PPAs for the 200 ZRCs will be similar to the rates included in the recently executed PPA with Heartwood Solar, LLC and Confluence Solar, LLC. Therefore, the Company has forecast expenses for the new One-Time Solicitation PPAs at the Jackson Generating Station and Heartwood Solar, LLC and Confluence Solar, LLC rates, however, the actual rates will be determined in the One-Time Solicitation.

Q. Please explain the Company's One-Time Solicitation.

A. The details for administering the One-Time solicitation are included in the Commission's June 23, 2022 Order in Case No. U-21090. The IRP includes the addition of new PPA resources to the Company's portfolio of supply assets to be acquired through a competitive solicitation process. The Company utilizes an Independent Administrator to conduct the solicitation, complete the proposal evaluations, and provide a recommendation 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 on Exhibit A-7 (JWH-1), page 1, line 32.

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 2023?

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 costs associated with Black Start Service is in this PSCR Plan case on Exhibit A-1 (DSA-1), page 1, line 27.

TERMINATION OF COMMISSION-APPROVED PPAS

Q. Does the Company have any PPAs, previously approved by the Commission, that have terminated or will terminate in 2023?

A. Yes. In addition to the PPAs previously discussed in my testimony, the following PPA will, or is expected to be, terminate(d) by the end of 2023:

- The Agreement with STS Hydropower, LLC for the output of the Ada Hydro Plant will terminate on May 31, 2023.

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

A. Under PURPA, as well as the Federal Energy Regulatory Commission ("FERC") Orders implementing PURPA and the 2021 IRP Settlement Agreement in Case No. U-21090, the Company is obligated to buy the energy and, if applicable, capacity (i.e., the Company's avoided cost) through PURPA contracts with small power production (i.e., renewable) QFs up to 5 MW in size and co-generation facilities up to 20 MW in size.

Q. Who has the authority to determine when there is a must-purchase obligation with QFs?

A. The MPSC has the authority to determine when the Company must purchase from QFs and the price the Company must pay for energy and, if applicable, 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 23, 2022 Order Approving Settlement Agreement in Case No. U-21090 approved the Company's IRP Settlement Agreement, which maintains that current existing QFs with a full avoided cost PURPA-based PPA with the Company, as of January 1, 2019, shall receive new PPAs based on the Company's full avoided cost rates at the time of PPA expiration, regardless of whether the capacity is needed.[2] 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-

[2] The Case No. U-21090 IRP Settlement Agreement defines "QF" as "Qualifying Facilities which the Company has a legal obligation to purchase from under PURPA."

based PPAs expire. The Commission's June 23, 2022 Order Approving Settlement Agreement in Case No. U-21090 also maintains that QFs 150 kW and below are eligible to receive full avoided cost rates regardless of the Company's capacity needs. When the Company does not have a PURPA capacity need, QFs above 150 kW, that the Company has a legal obligation to purchase from under PURPA, are eligible to receive the Company's energy-only avoided cost rates.

MISO ENERGY MARKETS

Q. Regarding 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 2023?

A. Yes. All 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 2023 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 2023 PSCR Reconciliation case. In this filing, MISO revenues and expenditures are forecast and presented in the direct testimony and exhibits of Company witnesses Daniel S. 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 contribution 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.

<u>RE PLAN</u>

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, U-18345, U-18393, U-18231, and U-20984.

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

A. As discussed in Case No. U-20984, 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.

SUMMARY

Q. Please summarize your direct testimony.

A. My direct testimony explains: (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 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	)	Case No. U-21257
cost recovery plan for the 12 months	)	
ending December 31, 2023	)	
	)	

EXHIBIT

OF

EMILY M. WALAINIS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2022

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
New and Amended PPAs not Previously Included in the Company's PSCR

Case No.: U-21257
Exhibit No.: A-25 (EMW-1)
Page: 1 of 1
Witness: EMWalainis
Date: September 2022

line	(a) Counterparty	(b) New PPA/Amendment	(c) Fuel	(d) MPSC Case No.	(e) MPSC Approval Date
1	**DOW Silicones Corporation**	New PPA	Solar PV	U-20604	11/4/2021
2	**South Christian High School**	New PPA	Solar PV	U-20604	11/18/2021
3	**Cereal City Solar, LLC**	New PPA	Solar PV	U-20165	11/18/2021
4	**Jackson County Solar, LLC**	New PPA	Solar PV	U-20165	11/18/2021
5	**Cement City Solar, LLC**	Amendment	Solar PV	U-20604	1/20/2022
6	**Letts Creek Solar, LLC**	Amendment	Solar PV	U-20604	1/20/2022
7	**Pullman Solar, LLC**	Amendment	Solar PV	U-20604	1/20/2022
8	**Thorn Lake Solar, LLC**	Amendment	Solar PV	U-20604	1/20/2022
9	**Michigan Apple Packers Cooperative, Inc.**	New PPA	Solar PV	U-20604	1/20/2022
10	**STS Hydropower, LLC (Morrow)**	New PPA	Hydro	U-20833	4/25/2022
11	**NextSun Energy LLC (Lake City Solar)**	Amendment	Solar PV	U-20604	Pending
12	**NextSun Energy LLC (Morey Road Solar)**	Amendment	Solar PV	U-20604	Pending
13	**NextSun Energy LLC (Surrey Road Solar)**	Amendment	Solar PV	U-20604	Pending
14	**STS Hydropower LLC (Ada Hydro Plant)**	New PPA	Hydro	U-18425	Pending
15	**Blue Elk Solar I, LLC**	Amendment	Solar PV	U-20604	Pending
16	**Blue Elk Solar II, LLC**	New PPA	Solar PV	U-20604	Pending
17	**Confluence Solar Power, LLC**	New PPA	Solar PV	U-20165	Pending
18	**Heartwood Solar, LLC**	New PPA	Solar PV	U-20165	Pending
19	**Byrne Solar, LLC**	Amendment	Solar PV	U-20604	Pending
20	**Lightfoot Solar, LLC**	Amendment	Solar PV	U-20604	Pending
21	**Shipsterns Solar, LLC**	Amendment	Solar PV	U-20604	Pending
22	**Willford Solar, LLC**	Amendment	Solar PV	U-20604	Pending
23	**Allegheny Solar, LLC**	Amendment	Solar PV	U-20604	Pending
24	**Aluminum Solar, LLC**	Amendment	Solar PV	U-20604	Pending
25	**Hogan Solar**	Amendment	Solar PV	U-20604	Pending
26	**Johnsfield Solar, LLC**	Amendment	Solar PV	U-20604	Pending
27	**Surbrook Solar LLC**	Amendment	Solar PV	U-20604	Pending
28	**Topanga Solar, LLC**	Amendment	Solar PV	U-20604	Pending
29	**Addle Solar, LLC**	New PPA	Solar PV	U-20604	Pending
30	**Copenhagen Solar, LLC**	New PPA	Solar PV	U-20604	Pending
31	**Holly Solar, LLC**	New PPA	Solar PV	U-20604	Pending
32	**Olivier Solar, LLC**	New PPA	Solar PV	U-20604	Pending
33	**Puck Solar, LLC**	New PPA	Solar PV	U-20604	Pending
34	**Shoreline Solar, LLC**	New PPA	Solar PV	U-20604	Pending
35	**Sunbelievable Solar, LLC**	New PPA	Solar PV	U-20604	Pending

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, 2023	))))))	Case No. U-21257

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, 2022, she served an electronic copy of **Consumers Energy Company's Application with Supporting Testimony and Exhibits of Consumers Energy Company Witnesses Daniel S. Alfred, Eugène M.J.A. Breuring, Joshua W. Hahn, Nathan J. Hoffman, Kevin C. Lott, Stephen J. Nadeau, Angela K. Rissman, Andrew G. Volansky, and Emily M. Walainis** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Crystal L. Chacon

Crystal L. Chacon

Subscribed and sworn to before me this 30th day of September, 2022.

Jennifer Joy Yocum

Jennifer Joy Yocum, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 12/17/24
Acting in the County of Jackson

ATTACHMENT 1 TO CASE NO. U-21257
Parties to Case Nos. U-20525, U-20802, U-20697, and U-20963

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ATTACHMENT 1 TO CASE NO. U-21257
Parties to Case Nos. U-20525, U-20802, U-20697, and U-20963

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