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June 22, 2021

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

Re: MPSC Case No. U-20963

Dear Ms. Felice:

Attached for electronic filing in the above-referenced matter, please find the Direct Testimony and Exhibits of Dr. Laura S. Sherman and Justin R. Barnes filed on behalf of Michigan Energy Innovation Business Council and the Institute for Energy Innovation and Proof of Service. Thank you for your assistance in this matter.

Very truly yours,

VARNUM

Laura Chappelle

Laura A. Chappelle

TJL/sej
Enclosures
c. ALJ
All parties of record.
18148610.1

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

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In the matte of the application of	)	
CONSUMERS ENERGY COMPANY for	)	**Case No. U-20963**
authority to increase its rates for the	)	
generation and distribution of electricity and	)	
other relief.	)	

TESTIMONY OF DR. LAURA S. SHERMAN

ON BEHALF OF

THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL

AND

INSTITUTE FOR ENERGY INNOVATION

<u>Table of Contents</u>

I. Introduction and Qualifications

Q. State your name, business name and address.

A. My name is Dr. Laura S. Sherman and I am the President of the Michigan Energy Innovation Business Council ("Michigan EIBC") and the Institute for Energy Innovation ("IEI"), located at 115 West Allegan, Suite 710, Lansing, Michigan 48933.

Q. On whose behalf are you appearing in this case?

A. I am appearing here as an expert witness on behalf of Michigan EIBC and IEI, collectively referred to as "Michigan EIBC/IEI."

Q. Summarize your educational background.

A. I have a Ph.D. from the University of Michigan Earth and Environmental Sciences Department, conferred in May 2012. I also have a Bachelor of Science degree from Stanford University in Geological and Environmental Sciences, conferred in June 2005.

Q. Summarize your experience in the field of electric utility regulation.

A. Since April 2019, I have served as the President of Michigan EIBC and IEI. Prior to that, starting in February 2017, I was a senior consultant at 5 Lakes Energy focusing on energy policy and utility regulation and I also served as the Vice President for Policy Development for the Michigan EIBC and IEI. In these capacities, I have written testimony in many non-adjudicated dockets before the Michigan Public Service Commission ("Commission" or "MPSC"). From 2014-2016, I served as an energy policy advisor to Senator Michael Bennet (D-CO) in the U.S. Senate. In that capacity, I provided policy expertise, conducted research, developed legislation, and analyzed regulations. Prior to that, my doctoral (2007-2012) and postdoctoral (2012-2014) research was focused on the tracing of pollutants emitted during energy generation. My work experience is set forth in detail in my résumé, attached as Exhibit EIB-1 (LSS-1).

Q. Summarize your professional development coursework in the field of electric utility regulation.

A. In August 2017, I completed the EUCI course titled "Optimizing the Interconnection Process for Renewables & Storage: A National Forum for Addressing Process and Technical Issues." In December 2017, I completed the EUCI course titled "The Electric Vehicle-Utility Industry Nexus." In January 2018, I completed the EUCI course titled "Evolution of Electricity Markets: Disruptive Innovation & Economic Impacts: Highly Interactive Course Designed to Provide A Practical Overview of Evolving U.S. Power Markets."

Q. Have you testified before this Commission or as an expert in any other proceeding?

A. Yes. I previously testified as an expert witness in Case No. U-20134 (Consumers Energy Company ["Consumers Energy," "Consumers" or the "Company"] general rate case), Case No. U-20165 (Consumers Energy Integrated Resource Plan case), Case No. U-20162 (DTE Electric Company ["DTE Electric"] general rate case), Case No. U-20471 (DTE Electric Integrated Resource Plan case), Case No. 18232 (DTE Electric Renewable Energy Plan case), Case No. U-20649 (Consumers Energy Voluntary Green Pricing Program case), and consolidated Case No. 20713 (DTE Electric Voluntary Green Pricing Program case)/Case No. U-20851 (DTE Renewable Energy Plan case).

Q. Have you provided analysis in support of testimony or comments in any other utility regulatory proceeding?

A. Yes. In my roles at Michigan EIBC and IEI, from July 2017 through July 2018, I supported and reviewed filings made on behalf of the Michigan EIBC/IEI/AEE in Commission Case Nos. U-18351 and U-18352, focused on the creation of the voluntary green pricing programs. In March 2018, with input from Michigan EIBC member companies, I provided comments in Commission Case No. U-20095, focused on the Public Utility Regulatory Policies Act of 1978 ("PURPA") regulations and capacity determinations. In March and April 2018, with input from Michigan EIBC member companies, I provided comments and reply comments in Commission Case No. U-18383, focused on the development of a distributed generation tariff. In June 2018, with input from Michigan EIBC member companies, I provided comments in Commission Case No. U-18361, focused on the development of new code of conduct rules. In October 2018, with input from Michigan EIBC member companies, I provided comments in Commission Case No. U-20147 regarding the Commission Staff report on distribution system planning. Similarly, in March 2020, with input from Michigan EIBC member companies, I provided comments in Commission Case No. U-20147 regarding the updated Commission Staff draft report on distribution system planning. In June 2021, with input from Michigan EIBC member companies, I provided comments on Consumers Energy’s Draft Electric Distribution Infrastructure Investment Plan in Case No. U-20147. In November 2020, with input from Michigan EIBC member companies, I provided comments in Commission Case No. U-20905 regarding the implementation of FERC Order 872 in Michigan.

In addition to this work, I have been involved on behalf of 5 Lakes Energy and Michigan EIBC in multiple workgroup proceedings at the Commission, including those focused on electric vehicle ("EV") deployment, the distributed generation tariff, Integrated Resource Plan requirements, energy waste reduction, and distribution system planning. Over the last year, I have been involved on behalf of Michigan EIBC/IEI/AEE in the MI Power Grid workshop proceedings at the Commission including those focused on new technologies and business models, customer data access, updating the state's interconnection rules, demand response, distribution system planning, pilot programs, competitive procurement, and advanced planning.

Q. Summarize your experiences working with advanced energy companies on issues related to electric utility regulation.

A I have served as the President of Michigan EIBC and IEI since April 2019. Prior to that, from November 2017 through April 2019, I served as Vice President of Policy Development for Michigan EIBC and IEI. In these roles, I have led the trade organization's work on regulatory and legislative issues. As described above, I have participated in many workgroups at the Commission and written comments in a number of non-adjudicated cases. I also communicate formally and informally with Michigan EIBC member companies about each regulatory proceeding to understand how the advanced energy industry is affected by each proposed rule or case. Specifically, as it relates to this testimony, in my role at Michigan EIBC I have organized and led more than 10 EV convenings with a broad group of stakeholders including Michigan's investor-owned utilities, I have led interventions by Michigan EIBC/IEI in previous cases, including rate cases filed by Consumers Energy covering PowerMIDrive (including Case No. U-20134), and I have written reports on EV adoption and supportive policies on behalf of IEI.[1]

[1] Institute for Energy Innovation. December 2019. "Administrative Actions to Electrify Transportation in Michigan." Available at https://mieibc.org/reports/7496/.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of Michigan EIBC/IEI with a particular focus on Consumers Energy's proposal to continue and revise the PowerMIDrive EV pilot program.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

- Exhibit EIB-1 (LSS-1): Résumé of Dr. Laura S. Sherman
- Exhibit EIB-2 (LSS-2): Minnesota Public Utilities Commission Order in Docket No. E-999/CI-17-879, et al. Issued December 12, 2019

II. Scope of Testimony

Q. Please summarize Consumers Energy's proposal regarding the PowerMIDrive pilot project.

A. The Company presents its proposal regarding PowerMIDrive principally through the testimony of Anita J. Griffin.[2] As presented by witness Griffin, the Company is proposing:

> (1) an up to three-year extension to optimize grid benefit learnings while working toward permanent Electric Vehicle ("EV") customer programs on or before 2025;
> (2) a programmatic expansion beyond networked charging stations for residential customers to increase participation for grid benefits using direct vehicle communication and AMI technology; and
> (3) additional public charging infrastructure within the PowerMIDrive (the "pilot") at strategic locations to remove barriers to entry for EV drivers as EV adoption continues to accelerate.[3]

Witness Griffin elaborates each of these program elements in her testimony.

Q. About what aspects of the Company's PowerMIDrive proposals are you testifying?

[2] Direct testimony of Anita J. Griffin, 55:9 – 84:17.
[3] *Id.,* at 55:11-18.

A. I am supportive of each of these elements of the Company's proposal and will briefly address each. However, my testimony is primarily focused on a longer-term consideration for the Commission: the need to work toward permanent EV customer programs on or before 2025.

Q. Consumers Energy is also proposing an addition to their PowerMIFleet program in this case. Is that proposal covered by your testimony?

A. The Company is proposing a small addition to its PowerMIFleet pilot program, to add work on the electrification of its own fleet and to increase rebates offered to certain public fleet owners.[4] That proposal is responsive to the Commission's Order in U-20697 and seems reasonably tailored to the purpose. I support that proposal, including the Company's proposal to own and operate DC fast charging ("DCFC") stations at their service centers.[5] This will help ensure equitable access to public charging across the Company's territory including in rural and underserved areas. These DCFC stations will also enable the Company to charge its own electric fleet in the future.

III. Consumers Energy's PowerMIDrive Proposal

Q. Why is extension of PowerMIDrive by three years warranted?

A. Extension of the PowerMIDrive pilot program to consolidate and optimize learnings is warranted both because much of the charging infrastructure funded through PowerMIDrive is either only recently installed or yet to be installed and because the overall program experienced delays due to the COVID-19 pandemic.

Q. Why is addition of direct vehicle communication and AMI data analysis for

[4] *Id.*, at 84:18-89:2
[5] *Id.*, at 66:3-7.

residential charging a useful addition to PowerMIDrive?

A. The proposed residential charging programmatic expansion to include direct vehicle communication and use of AMI technology to obtain EV charging data is important, since only some customers who own electric vehicles are participating in the PowerMIDrive program and using communicating charging equipment.[6] Future grid management and EV charging program management will require an understanding of all charging activity.

Q. Why is additional investment in public charging infrastructure necessary within PowerMIDrive?

A. Although the previous phase of PowerMIDrive has placed some of the essential public charging facilities needed to support broad EV adoption, more public charging is needed to meet the requirements to spur wide-spread adoption of EVs.[7] The siting analysis done for the Michigan Energy and Climate Office that the Company is relying on to guide its investments is well done and is a reasonable basis for planning EV charging facilities in the near term.[8] Once this "bare-bones" network is in place, I anticipate that growing usage of charging facilities will help enable more market-based development of charging facilities, perhaps coupled with additional supportive utility tariff mechanisms. It is important that EV infrastructure lead vehicle adoption and patient utility investments are an effective manner to establish the requisite "bare bones" network.

Q. What is your concern about addressing the need to work toward permanent EV

[6] *Id*., at 59:5-62:3.
[7] *Id*., at 62:4-66:7.
[8] *Id*., at 63:9-64-2.

customer programs on or before 2025?

A. Many vehicle manufacturers have announced comprehensive electrification strategies and begun substantial investments in electric vehicle models for future release.[9] More than 60 passenger EV models will be available for purchase in the United States before the end of 2022.[10] Many of these new models are competitively priced.[11] New models that have been announced include vehicle types not previously generally available, such as pickups and utility vehicles. New models are also expected in the medium- and heavy-duty vehicle market with major manufacturers, including Volvo, Mack, Daimler, Peterbilt, and Ford promising to produce new electric vans and trucks in 2021. As a result, it is possible and even likely that EV adoption rates in Consumers Energy's service territory will exceed those included in the Company's testimony.[12] As a result, the level of EV charging site deployment planned by the Company may not satisfy demand. I support approval of the Company's proposal in this case but recommend that the Commission direct the Company to take steps in its next rate case that will transition from addressing EV charging through pilot programs to the inclusion of EV charging infrastructure in the Company's ongoing budgeting and revenue recovery as a basic utility function. The key aspect of this is that the Company be enabled to respond to evolving demand for EV charging as fluidly as it would for any other changes in customer demand, and that the business model for this be reasonably persistent and understood by market participants.

Q. What particular steps do you recommend that the Commission direct the Company

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[9]Atlas EV Hub Global Private Investments Dashboard at https://www.atlasevhub.com/tag/private-investment/
[10] Model data from the Atlas EV Hub Automakers Dashboard: https://www.atlasevhub.com/materials/state-ev-registration-data/#dashboard
[11] Average new vehicle price in 2020: https://www.cnet.com/roadshow/news/average-new-car-price-2020/
[12] Direct testimony of Anita J. Griffin, 57:1-58:7, especially Figure 5.

to take in its next rate case to transition to the inclusion of EV charging infrastructure in the Company's ongoing budgeting and revenue recovery?

A. The most important step that will enable such normalization of investments in EV charging infrastructure is to ensure that these investments are beneficial for customers who are not using EVs. In other words, it is important to ensure that the balance of incremental revenues and incremental investments and other costs associated with expanding use of EVs is beneficial for all customers, including those who do not use EVs. To that end, I recommend that the Commission direct the Company, in its next rate case and thereafter, to include an analysis of the net effects of EV adoption and charging in the Company's service territory. In a similar manner to that required by the Minnesota Public Utilities Commission in annual Transportation Electrification Plans (Exhibit EIB-2, LSS-2),[13] this analysis should include:

1) numbers of electric vehicles by class registered in the utility's service territory,
2) amounts of electricity delivered for EV charging by customer rate schedule where the charging occurs,
3) revenue from electricity delivered for EV charging by customer rate schedule where the charging occurs,
4) costs of power supply for EV charging by rate schedule,
5) gross margin from EV charging by rate schedule,
6) revenue requirements related to EV infrastructure and allocation of revenue requirements by customer rate schedule, and

[13] Minnesota Public Utilities Commission Order in Docket No. E-999/CI-17-879, *et al.*, Issued December 12, 2019. See pp. 6-7. Available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={C0D3FB6E-0000-C92C-A4C5-715C1CF495E0}&documentTitle=201912-158280-03.

7) net margin benefitting customers in each rate schedule.

The analysis described above should be provided for both historical and projected test years.

Q. Are there other steps the Commission should direct the Company to take in the next rate case in order to normalize investment in EV charging infrastructure?

A. Yes. In order to prepare the revenue and costs analysis described above and also in order to track market requirements, the Company should include explicit EV adoption rate forecasts in its sales forecast.

In addition, the Commission has previously directed Staff to convene a workgroup in 2021 to examine policies and tariffs relating to contribution in aid of construction ("CIAC").[14] My understanding is that CIAC policies have traditionally authorized utility investments in distribution and service line extensions that are limited by the amount of investment that is supported by the projected gross margin of the resulting sales. In this regard, Michigan EIBC/IEI believes that the Commission should direct the Company to extend that examination of CIAC policies to include investments in "make-ready" costs of EV charging infrastructure, but with the knowledge and understanding that while traditional line extensions only produce revenue through sales at the newly served locations, EV charging infrastructure may enable EV adoption that produces gross margin at all charging locations. This is because a customer is more likely to purchase an EV when they have access to public charging, but they will not always charge that EV at that public charger, and may instead often charge it at home, thereby paying the utility for that electricity at a different location.

[14] U-20697 Order of December 17, 2020, p 330.

Finally, the Commission should encourage the Company to propose a system of rebates for EV charging infrastructure that is not limited to a specific number of customers in a specific period of time (for example, the Commission does not and should not limit the Company to only adding a certain number of streetlights each year) but is tailored to ensure that the system of rebates together with Company investments in EV charging infrastructure provides a net benefit to non-EV customers. Further, such rebates should be targeted to either charging infrastructure that enables greater EV adoption or to equitably meeting the needs of customers in segments where there are structural barriers to EV adoption, such as but not limited to apartments with shared parking areas or public charging in low-income communities.

Q. Are there steps the Commission should direct the Company to take in this case in order to normalize investment in EV charging infrastructure?

A. Yes. A modest shift in program design will enable greater market-based participation. In the current program, Consumers Energy selects potential suppliers of EV charging equipment and implementation services through a Request for Proposals that results in a limited number of suppliers. In order to activate the market more broadly, I recommend that Consumers Energy shift to an approach where the Company establishes minimum standards for program participation and allows any vendor that can meet these standards to register as a vendor and participate in the market using Consumers Energy's customer offering for both make-ready infrastructure and rebates.

IV. Conclusions and Recommendations

Q. Please summarize your conclusions and recommendations to the Commission.

A. I recommend that the Commission:

(a.) Approve the Company's requested addition to its PowerMIFleet pilot program;

(b.) Approve the Company's proposals with respect to the PowerMIDrive pilot program, with the following additions:

1.) the Company should include an analysis of the net effects of EV adoption and charging in the Company's service territory in all electric rate cases moving forward. The analysis should provide:

i) numbers of electric vehicles by class registered in the utility's service territory,

ii) amounts of electricity delivered for EV charging by customer rate schedule where the charging occurs,

iii) revenue from electricity delivered for EV charging by customer rate schedule where the charging occurs,

iv) costs of power supply for EV charging by rate schedule,

v) gross margin from EV charging by rate schedule,

vi) revenue requirements related to EV infrastructure and allocation of revenue requirements by customer rate schedule, and

vii) net margin benefitting customers in each rate schedule.

(c.) Encourage the Company to move toward normalization investment in EV charging infrastructure in the next rate case.

Q. Does that complete your testimony?

A. Yes.

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STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

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In the matte of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and other relief.	)))))	**Case No. U-20963**

EXHIBIT OF LAURA S. SHERMAN

ON BEHALF OF

THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL

AND

INSTITUTE FOR ENERGY INNOVATION

LAURA S. SHERMAN, Ph.D.

cell: 607.592.3026
laura@mieibc.org

PROFESSIONAL EXPERIENCE:

April 2019 – present **Michigan EIBC/IEI**, Lansing, MI **President**

- Organize and lead a staff of three employees, three contractors, and multiple student interns.
- Work with and inform each organization's Board of key decisions, upcoming events, long-term strategy, etc.
- Fundraise and coordinate both organization's annual budgets.
- Represent Michigan EIBC in the media, at the legislature, with regulators, and with the state administration in collaboration with a broad coalition.
- Conduct event planning including for annual conferences, networking events, tours, and legislative networking opportunities.
- Develop regulatory and legislative policy positions to support advanced energy businesses.
- Engage with the Michigan Public Service Commission and Michigan legislature on behalf of member companies.

Oct. 2017-March 2019 **Michigan EIBC/IEI**, Lansing, MI **VP for Policy Development**

- Develop regulatory and legislative policy positions to support advanced energy businesses.
- Coordinate regulatory interventions and engagement in regulatory stakeholder processes among member companies.
- Engage with the Michigan Public Service Commission and Michigan legislature on behalf of member companies.
- Support policy initiatives focused on wind energy, solar energy, electric vehicles, storage, taxation, and corporate purchasing of renewable energy.
- Represent Michigan EIBC in the media, at the legislature, with regulators, and with the state administration in collaboration with a broad coalition.
- Conduct event planning including for annual conferences, networking events, tours, and legislative networking opportunities.

Feb. 2017-March 2019 **5 Lakes Energy**, Lansing, MI **Senior Consultant**

- Research, analysis, communication, and advocacy surrounding complex energy issues.
- Lead wind and solar siting project to address opposition to deployment in coordination with philanthropy, industry, and stakeholders across nine Midwest states.
- Focus areas include renewable energy development, community engagement, stakeholder coordination, business sustainability, and electric vehicles.
- Support newsletter, website, and social media communications.

April 2015-Dec. 2016 **U.S. Senate**, Washington, DC **Legislative Assistant/Policy Advisor**

- Policy advisor to Senator Michael Bennet (D-CO) on agriculture, energy, environment, land, and natural resource issues.
- Legislative topics included: farming and ranching, public land conservation and management, water policy, energy development, renewable energy including energy tax incentives and transmission permitting, energy efficiency, endangered species, climate change, sportsmen's issues, environmental pollution and regulations, air quality, and biofuels.

- Drafting legislation; building coalitions; negotiating policy solutions; writing speeches; staffing the Senator at hearings of the Agriculture and Finance Committees.

2014-2015 **U.S. Senate**, Washington, DC **AAAS Congressional Science Fellow**

- Competitively selected AAAS Fellow sponsored by the American Geophysical Union. Served in the Office of Senator Michael Bennet (D-CO).
- Drafting legislation; helping to facilitate political coalitions; meeting with constituents; interacting with federal agencies; delivering policy briefings and recommendations.

2012-2014 **University of Michigan**, Ann Arbor, MI **Postdoctoral Research Fellow**

- Successfully obtained competitive grant funding for novel method to track air pollution from power plants and metal smelters into rainfall across the Great Lakes region.
- In collaboration with epidemiologists, developed and utilized new methods to assess the sources and pathways of human exposure to mercury pollution.
- Published five manuscripts; presented talks and organized scientific sessions at national and international conferences.

2007-2012 **University of Michigan**, Ann Arbor, MI **Graduate Researcher**

- Competed for and received National Defense Science and Engineering Graduate Fellowship and Graham Environmental Sustainability Institute Doctoral Fellowship.
- Developed groundbreaking methods to "fingerprint" mercury pollution from coal-fired power plants and trace it into rainfall, lake sediments, and fish.
- Published eight manuscripts, was interviewed for "The Environment Report" on NPR and general-circulation science magazines, presented research at national and international conferences.
- Ph.D. dissertation received university-wide ProQuest Distinguished Dissertation Award and departmental John Dorr Graduate Academic Achievement Award.

2005-2007 **Massachusetts Institute of Technology**, Boston, MA **Research Scientist**

- Found evidence for early life on Earth in ancient rocks. Published two manuscripts.

SERVICE & LEADERSHIP:

2019-2020 **Board Member** of Advancing Women in Energy
2017-2019 **Communications Chair** for Advancing Women in Energy
2013-2014 **Supported** the Ann Arbor Energy Commission on community solar projects
2009-2014 **Peer reviewer** of more than 20 scientific manuscripts
2009 **Initiator and organizer** of new departmental seminar series, University of Michigan
2008-2010 **President** of department student organization (GeoClub), University of Michigan
2008 **Lead organizer** of Michigan Geophysical Union Poster Conference
2007-2008 **Department Steward** to Graduate Employees Union, University of Michigan

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EDUCATION:

Ph.D. 2012 Earth and Environmental Sciences, **University of Michigan** (GPA: 8.837 out of 9.0)
B.S. 2005 Geological and Environmental Science, **Stanford University** (GPA: 4.007 out of 4.33)

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John A. Tuma	Commissioner

ISSUE DATE: December 12, 2019

In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure	DOCKET NO. E-999/CI-17-879
In the Matter of Xcel Energy's Petition for Approval of a Residential Electric-Vehicle Service Pilot Program	DOCKET NO. E-002/M-17-817
In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of a Residential Electric Vehicle Charging Tariff	DOCKET NO. E-002/M-15-111
In the Matter of Otter Tail Power Company's Request for Approval of a Residential Off-Peak Electric Vehicle Service Tariff	DOCKET NO. E-017/M-15-112
In the Matter of Minnesota Power's Petition for Approval of a Residential Off-Peak Electric Vehicle Service Tariff	DOCKET NO. E-015/M-15-120

ORDER ACCEPTING FILINGS AND ESTABLISHING REQUIREMENTS FOR ADDITIONAL FILINGS

PROCEDURAL HISTORY

I. Electric Vehicle (EV) Inquiry

On December 28, 2017, the Commission opened Docket No. E-999/CI-17-879, *In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure* (the EV Inquiry), to gain a better understanding of the possible impacts of electric vehicles on the electric system, utilities, and customers; the potential extent and pace of EV adoption; and possible EV tariff options.

On February 1, 2019, the Commission issued an order in the docket, making a number of general findings about transportation electrification, as well as specific findings on the role utilities should play in promoting EVs. Among other items, the Commission directed Minnesota Power, Otter Tail Power Company (Otter Tail), and Northern States Power Company d/b/a Xcel Energy (Xcel) to make several filings, including the following:

- By June 1, 2019, annual EV reports, including EV promotional cost recovery mechanisms.[1]
- By June 30, 2019, Transportation Electrification Plans (TEPs), identifying and discussing each utility's planned EV initiatives.
- By October 31, 2019, proposals "intended to enhance the availability of or access to charging infrastructure, increase consumer awareness of EV benefits, and/or facilitate managed charging or other mechanisms that optimize the incorporation of EVs into the electric system."[2]

II. Annual EV reports

On May 31, 2019, Minnesota Power, Otter Tail, and Xcel filed their annual EV reports for existing EV tariffs and pilot programs.[3]

On June 14, 2019, the Commission issued a Notice of Comment Period regarding the annual EV reports. Initial comments were accepted until July 15, utility responses to initial comments until July 25, and all reply comments until August 5.

On July 15, 2019, the Minnesota Department of Commerce, Division of Energy Resources (the Department), filed comments recommending that the Commission accept each utility's annual EV report.

III. Transportation Electrification Plans

On June 28, 2019, Xcel and Otter Tail filed their TEPs.

On July 1, 2019, Minnesota Power filed its TEP.

On July 8, 2019, the Commission filed a Notice of Comment Period regarding the TEPs. Topics for comment included whether the Commission should accept the submitted TEPs, whether additional TEPs should be required, and if so, whether the contents should be modified. Initial comments were accepted until July 31, utility responses to initial comments until August 12, and all reply comments until August 22.

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[1] The contents of annual EV reports are established by Minn. Stat. § 216B.1614, passed in 2014, and several subsequent Commission orders, including the February 1, 2019 order. *See* Comments of the Minnesota Department of Commerce, Division of Energy Resources, Docket Nos. E-002/M-15-111, E-002/M-17-817, E-017/M-15-112, and E-015/M-15-120 (July 15, 2019).

[2] *In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure*, Docket No. E-999/CI-17-879, Order Making Findings and Requiring Filings, at 13 (February 1, 2019).

[3] Xcel filed EV reports in Docket Nos. E-002/M-15-111 (Residential Electric Vehicle Charging Tariff) and E-002/M-17-817 (Residential Electric Vehicle Service Pilot Program); Otter Tail filed an EV report in Docket No. E-017/M-15-112 (Residential Off-Peak Electric Vehicle Service Tariff); and Minnesota Power filed an EV report in Docket No. E-015/M-15-120 (Residential Off-Peak Electric Vehicle Service Tariff).

Between July 31 and August 22, the following parties filed initial and/or reply comments:

- Chargepoint, Inc.
- Greenlots (initial comments only)
- Xcel Large Industrials and Large Power Intervenors (XLI/LPI)
- Minnesota Department of Commerce, Division of Energy Resources
- Fresh Energy, Minnesota Center for Environmental Advocacy, Natural Resources Defense Council, Sierra Club, and Union of Concerned Scientists
- City of Minneapolis (initial comments only)
- Siemens
- Xcel (reply comments only)
- Otter Tail (reply comments only)
- Minnesota Power (reply comments only)
- Office of the Attorney General – Residential Utilities and Antitrust Division (OAG) (reply comments only)

IV. Additional program proposals

On July 1, 2019, Minnesota Power filed its TEP as noted above. As part of the TEP, Minnesota Power stated that it had already submitted a proposal to the Commission for a commercial EV rate pilot program and that it was exploring potential programs relating to residential EV charging.

On October 24, 2019, Otter Tail requested an extension of the October 31 deadline and proposed to file its proposals by December 12, 2019.

On October 31, 2019, Xcel filed a list of its EV programs that had been approved by or submitted to the Commission between 2015 and 2019, including its August 30 proposal to expand its residential EV service pilot to a standard offering.

V. Combined Commission meeting

On October 31, 2019, the Commission met to consider the reports filed in the various dockets.

FINDINGS AND CONCLUSIONS

I. Annual EV reports

The Commission has reviewed each utility's annual EV report and concurs with the Department that each report complies with the requirements of Commission orders and state statute. Consequently, the Commission will accept the annual reports submitted in Docket Nos. E-002/M-15-111, E-002/M-17-817, E-017/M-15-112, and E-015/M-15-120.

The Commission will establish requirements for future reports in Docket Nos. E-002/M-15-111, E-017/M-15-112, and E-015/M-15-120, as described in the ordering paragraphs. Going forward, the reporting requirements established in this order will replace the reporting requirements established in those prior orders; other existing requirements are eliminated or moved to the TEPs in order to streamline the reports and reduce redundancy. The Commission believes that these revised reporting requirements will provide valuable insights into the operation of the permanent EV tariffs while avoiding unnecessarily duplicative or burdensome filings.

II. TEPs

Most commenters recommended that the Commission accept the utilities' initial TEPs and require ongoing TEPs on either an annual or biennial basis. A majority of parties that commented on the report frequency supported annual filings; Greenlots commented that biennial filings may be sufficient in the future, but at this early stage, annual reporting would be preferable.

Several parties proposed additional reporting requirements, many of which were broadly supported by commenters, including reporting on various baseline EV system data and information on ongoing EV-related efforts. Parties were supportive of reporting requirements proposed by Commission staff, with minor modifications. Commission staff's proposal included moving certain general reporting requirements from annual EV reports to the TEPs to avoid unnecessary duplication.

Utilities noted that for some items, they may be able to provide only estimates or limited data due to technical limitations. In response, the Department suggested language that gives flexibility and directs utilities to provide an explanation when information is not available.

Certain proposed reporting requirements were contested, largely because they would be logistically or technologically difficult for utilities to implement. For example, XLI/LPI proposed reporting on total costs and benefits of the TEPs; other parties opposed this suggestion, stating variously that a comprehensive cost-benefit analysis for transportation electrification efforts would be difficult, and that it is more appropriate to undertake cost-benefit analysis in individual program dockets.

The Commission has reviewed the utilities' TEPs and finds them to be complete. The Commission will accept the utilities' initial TEPs, and will require additional TEPs to be filed annually with a deadline of June 1 to align with the existing deadline for annual EV reports. The Commission believes that timely updates are necessary in this rapidly-changing area, and that annual reports will allow the Commission to stay abreast of important developments.

The Commission will establish reporting requirements for future TEPs as described in the ordering paragraphs, including most of the items that had consensus agreement among parties and the Department's suggested language allowing for flexibility. The Commission believes that these report contents will provide a robust view of the utilities' EV-related activity while avoiding unnecessarily burdensome reporting requirements. The Commission will not require reporting on total costs and benefits of the TEPs; the Commission believes that this would be difficult and of limited value, and that it is better to leave discussion of costs and benefits to individual dockets.

III. Additional program proposals

Among other findings in its February 1, 2019 order, the Commission stated that "utilities should. . . [d]evelop and file EV-related proposals intended to encourage the adoption of EVs. . . ."[4] Specifically, the Commission directed Minnesota Power, Otter Tail, and Xcel to file such proposals, in consultation with stakeholders, by October 31, 2019.

A. Minnesota Power

Minnesota Power stated that it had already filed EV-related proposals before the February 1 order. Additionally, Minnesota Power stated that it was in the process of developing an EV program addressing residential charging, and anticipated developing a proposal for a public charging program in the future.

The Commission believes that Minnesota Power's anticipated residential charging program is in alignment with the findings set out in its February 1, 2019 order, and that timely action on this program is needed. The Commission will direct Minnesota Power to file this proposal in the first half of 2020.

B. Xcel

Xcel stated that it had already filed EV-related proposals before the February 1 order, including its August 30 proposal to expand its residential EV service pilot to a standard offering.[5]

Environmental groups and the City of Minneapolis both commented on the importance of EV charging for multi-unit dwellings (MUDs), noting that although Xcel stated in its TEP that it was developing a MUD EV proposal, it did not provide detailed information and stated only that a proposal was anticipated in the next two years. Parties variously stated that an increasing number of people were living in MUDs, particularly in the city of Minneapolis; that a lack of charging infrastructure was a major barrier for customers living in MUDs; and that utilities had the necessary experience and technology to address these issues.

The Commission agrees with commenters that EV charging for multi-unit dwellings is increasingly important, and timely advancements in this area are essential. The Commission will direct Xcel to file a pilot or program addressing EV charging in multi-unit dwellings within nine months.

C. Otter Tail

Otter Tail requested an extension until December 12, 2019, to file its EV pilot proposals, noting that it was in the process of developing a pilot program and rate structure, but that additional research was needed to ensure that the program would be feasible within its existing billing system. The Commission will grant the requested extension; the Commission anticipates that the relatively short extension will allow Otter Tail to file a well-developed, comprehensive proposal.

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[4] *In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure*, Docket No. E-999/CI-17-879, Order Making Findings and Requiring Filings, at 11 (February 1, 2019).

[5] *In the Matter of Xcel Energy's Petition for Approval of An Electric Vehicle Home Service Program*, Docket No. E-002/M-19-559.

ORDER

1. The Commission accepts the 2019 Electric Vehicle Reports filed by Minnesota Power, Otter Tail Power, and Xcel Energy in Docket Nos. E-002/M-15-111, E-017/M-15-112, and E-015/M-15-120.

2. Utilities must include the following information in future reports filed in Docket Nos. E-002/M-15-111, E-017/M-15-112, and E-015/M-15-120.

    a. The amount of energy sold per time period, and number of customers on the rate, on a monthly basis.

    b. The number of customers choosing a renewable-source option.

    c. The status of the communications costs tracker account, if applicable, including a breakdown of costs by educational and outreach initiatives; where possible, a separation of costs used to promote specific EV programs versus EV adoption in general; and a brief description of the activities for which the Company has incurred costs.

3. The Commission accepts Xcel Energy's first annual Residential EV Service Pilot report.

4. The Commission accepts Minnesota Power, Otter Tail Power, and Xcel Energy's 2019 Transportation Electrification Plans.

5. In the first half of 2020, Minnesota Power must file at least one additional EV program addressing residential charging.

6. Within nine months of the issuance of this order, Xcel Energy must file a pilot or program addressing EV charging in multi-unit dwellings.

7. Starting on June 1, 2020, the utilities must file Transportation Electrification Plans annually.

8. In each annual Transportation Electrification Plan, utilities must provide the following information and data to the greatest extent practicable. For any instance in which the utility is not able to provide the information and data, or it is not practicable to do so, the utility must (1) explain why it is unable to provide the information and data; and (2) make a reasonable effort to provide an approximation of the required information and data. If the utility is unable to provide an approximation of the required information and data, the utility must provide the reason or reasons and explain whether it will be possible to provide the required information and data in the future.

    a. Number of EVs in service territory, by type where possible (e.g. light duty, transit, medium duty, heavy duty).

    b. Number of customers and vehicles on each off peak or managed charging rate, energy consumed, and average hourly load profiles by month.

    c. Level of demand (in kilowatts) resulting from electric vehicles during each hour of the day, or if not yet available, during each time period in a utility's time-differentiated tariff, for each electric vehicle tariff offered by the utility.

d. Consumption of electricity (in kilowatt-hours) by electric vehicles during each hour of the day, or if not yet available, during each time period in a utility's time-differentiated tariff, for each electric vehicle tariff offered by the utility.

e. Number and capacity of known Level 2 Charging Stations (public, and any enrolled in a utility program).

f. Number and capacity of direct current fast charging (DCFC) stations (including breakout of DCFC installed through a utility program).

g. Any system upgrades performed to accommodate EV charging, total costs paid by utility and by customer, and average cost per upgrade. Cost should be reported separately for the following customer groups: Residential, Government Fleet, Private Fleet, and Public Charging.

h. EV adoption forecast scenarios (low, likely, high) by sector (residential, medium duty, and heavy duty).

i. EV load forecast scenarios (low, likely, high) for capacity and energy, by sector (residential, medium duty, and heavy duty).

j. A summary of the utility's ongoing transportation electrification efforts, including existing programs and projects in development over at least the next 2 years.

k. How the utility plans to facilitate:

    i. availability and awareness of public charging infrastructure, including an assessment of the private sector fast charging marketplace for the utility's service territory;

    ii. availability of residential charging options for both single family and multiple unit dwellings;

    iii. programs or tariffs in development to address flexible load or reduce metering and data costs; and

    iv. fleet electrification.

l. A summary of customer EV education initiatives. Utilities need not include specific examples of outreach materials.

m. How the utility plans to optimize EV benefits, including a discussion of how to align charging with periods of lower customer demand and higher renewable energy production and by improving grid management and overall system utilization/efficiency.

n. Summaries of any proposals or pilots, including links to full reports, submitted to other regulatory agencies or jurisdictions (for example, proposals submitted under Conservation Improvement Programs or pilots run in other states).

o. Attachments or links to the most recent reports for any ongoing EV pilots or programs.

9. The Commission delegates authority to the Executive Secretary to establish final report formatting and to clean up any inconsistencies between various existing reporting requirements in individual dockets.

10. The Commission grants Otter Tail Power an extension until December 12, 2019, to file its EV pilot proposals.

11. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf
Executive Secretary

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STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

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In the matte of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and other relief.	)))))	**Case No. U-20963**

TESTIMONY OF JUSTIN R. BARNES

ON BEHALF OF

THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL

AND

INSTITUTE FOR ENERGY INNOVATION

Table of Contents

I. Introduction

Q. Please state your name, business address, and current position.

A. My name is Justin R. Barnes. My business address is 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 27511. My current position is Director of Research with EQ Research LLC.

Q. On whose behalf are you submitting testimony?

A. I am submitting testimony on behalf of the Michigan Energy Innovation Business Council and the Institute for Energy Innovation ("Michigan EIBC/IEI").

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

A. No.

Q. Please describe your educational and occupational background.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at N.C. State University for more than five years as a Policy Analyst and Senior Policy Analyst.[1] During that time I worked on the Database of State Incentives for Renewables and Efficiency ("DSIRE") project, and several other projects related to state renewable energy and energy efficiency policy. I joined EQ Research in 2013 as a Senior Analyst and became the Director of Research in 2015. In my current position, I coordinate and contribute to EQ Research's various research projects for clients, assist in the oversight of

[1] The North Carolina Solar Center is now known as the North Carolina Clean Energy Technology Center.

EQ Research's electric industry regulatory and general rate case tracking services, and perform customized research and analyses to fulfill client requests.

Q. Please summarize your relevant experience as it relates to this proceeding.

A. I possess a detailed understanding of how regulators in other states have evaluated programs and proposals for utility ownership of customer-sited distributed energy resources ("DERs") and regulators' efforts to realize the benefits of customer-sited energy storage. This includes the benefits and drawbacks of different approaches, how they are weighed, and the overall strategies being employed. I believe that this information can provide valuable insights to the Commission.

My professional career has been spent researching and analyzing numerous aspects of federal and state energy policy, spanning more than a decade. Throughout that time, I have reviewed and evaluated trends in regulatory policy, including trends in distributed generation ("DG") policy, rate design and cost of service. For example, I have closely followed the progression of regulators' interest and investigations of DG costs and benefits and cost of service and resulting determinations for the better part of the last decade. More recently, I have closely followed evolving trends in the behind-the-meter ("BTM") energy storage market, including the development and implementation of programs that enable customers to provide grid services and obtain bill management and other benefits from customer-sited energy storage.

I have submitted testimony before utility regulatory commissions in Colorado, Georgia, Hawaii, Kentucky, New Hampshire, New Jersey, New York, North Carolina, Oklahoma, South Carolina, Texas, Utah, and Virginia, as well as to the City Council of

New Orleans,[2] on various issues related to DG and DER policy, net metering, rate design, cost of service, utility ownership of DG and other DERs, and bring-your-own-device ("BYOD") programs. These individual regulatory proceedings have involved a mix of general rate cases and other types of contested cases. My curriculum vitae is attached as Exhibit EIB-3 (JRB-1). It contains summaries of the subject matter I have addressed in each of these proceedings.

Q. Please describe the purpose of your testimony and how it is organized.

A. The purpose of my testimony is to provide an analysis of the Home Battery Pilot ("Pilot" or "Proposal") proposed by Consumers Energy Company ("Consumers" or "the Company"); describe the deficiencies in the Company's Proposal with respect the Commission's stated policy objectives; provide a summary the programs in other states for customer-sited energy storage to provide grid service benefits and delineate best practices; and propose modifications to and a framework for approving the BYOD portion of the Proposal for Commission consideration. My testimony is organized as follows:

- Section II provides an overview and high-level evaluation of the Company's Proposal, including those elements with which I agree and those with which I disagree.
- Section III contains an evaluation of the Company's Proposal from the standpoint of its consistency with relevant state and federal policies, leading to a conclusion that it is highly inconsistent with both and that the BYOD design I recommend would do far more to advance these objectives.
- Section IV specifically discusses the reasons why utility ownership of BTM energy storage is inappropriate and should not be permitted.

[2] The City Council of New Orleans regulates the rates and operations of Entergy New Orleans in a manner equivalent to state utility regulatory commissions.

- Section V provides a discussion and supporting analysis of deficiencies in the Company's Proposal, other than its proposal to own BTM energy storage at customer residences.
- Section VI provides an analysis of available "value-stacking" opportunities and how a BYOD program under the design I support offers superior value to both participant and non-participant customers.
- Section VII presents a "Straw BYOD" model program, including recommended minimum design elements, and discussion of the options and considerations for specific design elements.
- Section VIII contains my concluding recommendations for finalizing a revised BYOD program design.

Q. What are your recommendations to the Commission on the design of the Company's Home Battery Pilot?

A. I recommend that the Commission deny the Company-ownership component of the proposed Pilot. I recommend the Commission approve the BYOD component in concept but direct the Company to engage with Staff and Stakeholders via a working group process to further develop the BYOD component and offer recommendations to guide the development of those details.

Q. What are your recommendations for guidance the Commission should provide for further development of the BYOD component of the Pilot?

A. I recommend the Commission provide guidance on the program elements that the BYOD program should include and a timeline for submitting a final BYOD program recommendation for Commission approval. In summary, my recommendations for core program characteristics and the finalization of the Pilot design are as follows:

- Define the use cases and operational parameters for participating batteries in accordance with the Commission's stated policy objectives. The working group should address use cases identified by the Commission; any use case not included in the working group's final program recommendations should include an explanation as to why it should not be included at this time. Use cases not specifically identified by the Commission that the working group includes in its final recommendations should include justifications for how the use case advances the Commission's policy goals and why it should be part of the BYOD program;
- Conduct benefit cost analysis for recommended use cases to better understand potential for customer-sited storage grid service use cases to deliver cost-effective services;
- Accommodate customer use cases of battery for bill management;
- Include participation requirements that advance the utilization of customer-sited renewable energy;
- Incorporate the third-party aggregator role into program design; and
- Provide a timeline for development and implementation of DERMS platform or other DER communication protocols as necessary to effectively carry out the Pilot and support successor programs.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

- Exhibit EIB – 3 (JRB – 1): curriculum vitae of Justin Barnes

- Exhibit EIB – 4 (JRB – 2): U-20963-MEIBC-CE-449
- Exhibit EIB – 5 (JRB - 3): U-20963-MEIBC-CE-450
- Exhibit EIB – 6 (JRB – 4): Example BYOD Terms and Conditions

II. Overview Consumers Energy's Home Battery Pilot Proposal

A. Summary of the Pilot Proposal

Q. Please briefly summarize the Company's proposed Home Battery Pilot.

A. The Company proposes to install 2,000 home battery units at 1,000 homes across its service territory over a three-year period from 2022 – 2024. Each home would have two battery units with an aggregate anticipated energy capacity range of between 25 – 30 kilowatt-hours ("kWh"), and an aggregate continuous discharge rating of 10 kilowatts ("kW"). Thus, across all participants, the total energy storage capacity based on the discharge capacity rating would amount to 10 megawatts ("MW").

Customers would have the option to participate with a Company-owned battery -- the "Company-owned" option; or a customer or third-party owned battery - the "BYOD" option. Customers opting for the Company-owned option would pay $29, $39, or $49 per month, depending on the customer's enrollment tier. BYOD customers would receive an incentive of $1,050, $950, or $800 per kW of battery capacity, depending on the customer's enrollment tier. Participants in either portion of the program would be locked into a 10-year contract.

Both the Company-owned and BYOD batteries would be controlled and operated by the Company and dispatched when peak system conditions are anticipated for up to three hours per day. The customer's use of the battery under either option would be limited to grid outage events to provide back-up power to the home.[3]

Q. Did the Company perform a cost-benefit analysis for the proposed Home Battery Pilot, and if so, what are the results?

A. The Company estimates program costs of approximately $14.3 million[4] and potential benefits of $5.5 million. As detailed in Exhibit EIB-4 (JRB-2), the Company's potential benefits are based on a net present value ("NPV") analysis that estimates potential avoided costs associated with generation capacity, energy and line losses, and distribution substation upgrade deferral over a 15-year period from 2022 – 2036.[5] The bulk of the benefits are associated with generation capacity savings, which account for roughly 77% of the total NPV excluding losses.

Q. What objectives does the Company seek to achieve through the Home Battery Pilot?

A. Company Witness Machi describes three goals. The primary goal is to test customer interest and "willingness to pay" for "resiliency as a service" battery offering, referring to batteries installed at the customer's home to provide back-up power in the event of a grid outage.[6] The Company also seeks to better understand residential battery storage use cases and to evaluate the similarities and differences between utility-owned and customer-owned battery fleets as tools for managing supply and demand on the grid.[7]

The Company further describes the Pilot as "co-optimizing around three foundational elements to achieve the overall vision of the Commission's MI Power Grid

[3] Direct Testimony of Priya D. Machi ("Machi Direct"), throughout.
[4] Machi Direct at 2:12.
[5] *See* Exhibit EIB-4 (JRB-2). U-20963-MEIBC-CE-449-Machi_ATT_1.xlsx in the tab labeled "1.Inputs, Outputs."
[6] Machi Direct at 2:15-16.
[7] *Ibid.* at 7:20 through 8:2.

initiative: (1) explore customer engagement with customer-sited distributed storage resources in support of the energy transition; (2) test the integration of emerging storage technologies for dually beneficial customer and utility system benefit; and (3) test optimization of grid investments and performance by evaluating distribution and generation use cases and the utility incentives and alternative regulatory approaches that would be needed to develop a scaled residential storage program.[8]

B. High Level Review of the Company's Proposal

Q. Please summarize your views in general on the Company's proposed Home Battery Pilot.

A. On a conceptual level, I support the establishment of a Home Battery Pilot based on a BYOD model, and agree with certain aspects of the Company's program design and some of its objectives. Having said that, I also have serious concerns about other design elements and program objectives, which I view as significant flaws to the proposed Home Battery Pilot overall. Consequently, while I applaud the Company's initiative in making its Proposal, I do not support the establishment of the Pilot as filed by the Company. At the most general level, my review leads me to conclude that the design of the proposed program is heavily skewed to benefit Consumers and not the Company's ratepayers. I therefore recommend considerable revisions to the Company's Proposal that will achieve greater benefits in both the near-term and long-term at lower costs for both participants and non-participants while also meeting the Commission's stated policy objectives for integrating energy storage (and other emerging DER technologies) into the grid architecture.

[8] *Ibid*. at 19:7-15.

Q. Please describe the portions of the Company's Pilot Proposal with which you agree and the reasons for your agreement.

A. There are several. First, the Company intends to use the full discharge capability of the enrolled storage systems for dispatch during peak periods, rather than limiting discharge to reducing customer load, based on a finding from its previous home battery test case that maximizing discharge beyond customer load during peak conditions is more efficient.[9] I could not agree more with this aspect of the program design. In my experience, it is frequently the case that notions of "traditional" demand response (*i.e.*, load reduction without exports) inhibits the use of battery storage to produce cost savings by capping the energy storage contribution at the level of a customer's real-time load. This results in suboptimal utilization of the storage resource by underutilizing available capacity.

Second, the Company's Proposal would allow both existing solar customers (*e.g.*, legacy net metering/DG tariff) and new solar customers to enroll in the program, and will allow those customers to charge their battery system exclusively from the on-site solar system.[10] I agree with this element for several reasons. First, it would simply be discriminatory to not allow solar customers to participate, and allowing existing battery systems (or additions to existing solar systems) offers opportunities to increase their utilization. Second, as I discuss later in my testimony, the presence of on-site solar can significantly enhance the duration of available back-up power for customers. Third, rules associated with the federal solar investment tax credit ("ITC") allow the credit to be claimed for battery storage costs, but only in its full amount if the battery is charged from on-site solar (or another qualifying renewable generation resource). The ability to claim

[9] *Ibid*. at 6:9-12.
[10] *Ibid.* at 15:1-14.

the federal ITC, currently set at 26% of installed costs, considerably enhances the customer economics of battery storage.

Finally, I agree that the overarching goal of the program should be to support the overall vision of the Commission's MI Power Grid initiative. However, to be clear, I disagree that the program as filed is actually consistent with this overall vision.

Q. Please summarize the aspects of the Company's Pilot Proposal with which you disagree and the reasons for that disagreement.

A. My points of disagreement are numerous. I regard each point of disagreement listed below as a deficiency that must be remedied in a revised program before gaining approval by the Commission. Furthermore, I urge the Commission to appreciate that while I regard each individual flaw as serious, in aggregate they are even more harmful from the standpoint of charting a path towards a durable and scalable platform for maximizing the value customer-sited energy storage on the grid (*i.e.*, the whole is greater than the sum of the parts). In many ways, the Company's Proposal reduces the value of customer-sited storage from the customer perspective and likely the overall value to non-participating ratepayers, and is so far out of step with overwhelming national trends in customer-sited battery storage programs that the Company's Proposal is more likely to sabotage long-term goals of producing a durable program at scale in the future – or at best significantly stymie such efforts. My specific disagreements with the Proposal are as follows:

1. The utility-owned portion will have a meaningful, destructive impact on the competitive market's ability to provide energy storage products and grid services, ultimately frustrate the achievement of the MI Power Grid initiative, and according to

the Company's own cost projections, be more costly on a net cost basis than the BYOD portion of the proposed program.

2. In both the Company-owned and BYOD battery portions of the proposed Pilot, limiting customer use of enrolled battery systems to providing back-up power only prevents the accrual of additional value to participating customers, and ultimately results in underutilization of participating storage resources.
3. The Company's primary research objective of evaluating customer willingness to pay for resilience is both misplaced and unnecessary.
4. The Company effectively proposes to subsidize storage-based resilience in a manner weighted towards the Company's benefit, when such a subsidy is wholly unnecessary were it to instead develop a value-based pay for performance model for the provision of grid services.
5. The proposed offering of two batteries per home is inconsistent with actual customer resiliency needs and the demonstrated preferences of customers with existing solar-paired storage systems.
6. The Company's proposal to exercise full and direct control over both the Company-owned and BYOD batteries is unjustified and fails to bring in at the early pilot stage the partnership role of third party DER aggregators to interface between the utility and customers.

III. Consistency with Relevant Policies

Q. Has the Commission provided guidance for integrating customer-sited energy storage into the grid architecture or otherwise testing pathways for BTM storage to provide grid services?

A. Yes. The MI Power Grid initiative was launched in October 2019 to maximize the benefits of the transition to clean, distributed energy resources for Michigan residents and businesses. The Commission described the MI Power Grid initiative as being driven by multiple factors influencing the electric industry, including declining costs in renewable energy technologies, carbon emission reduction goals, and strong customer preferences for renewable energy and new ways to lower their energy bills.[11] The Commission specifically noted significant year-over-year cost declines in energy storage technologies along with ability of storage to provide multiple customer and utility use case applications. Forecasting longer-term changes, the Commission noted the growing transition to electric vehicles as a transformational shift for both the electric and transportation sector.

Q. What specific objectives did the Commission establish for the MI Power Grid initiative?

A. In recognition of the market and regulatory barriers that hinder the pace and scale of unlocking the value of new technologies – particularly energy storage and other forms of DERs, the Commission established three overarching objectives for the MI Power Grid initiative to better engage utility customers, integrate new clean energy technologies and optimize grid investments for reliable and affordable electric service.

Q. Please elaborate on the Customer Engagement objective and its relevance to the instant proceeding.

A. The Commission describes the customer engagement objective as "providing residents and businesses with energy technologies, programs, and price signals that will allow customers to be more active and effective participants in the state's transition to increased clean and

[11] Case No. U-20645, Order at p. 6 (Oct. 17, 2019) ("MI Power Grid Initiative Order").

distributed energy resources."[12] In sum, the customer engagement objective focuses on enabling more customers to become more active participants in Michigan's clean energy transition. As advances in solar, storage and other distributed energy technologies have enhanced customers' ability to choose their energy source and provided new tools to help customers manage their energy bills, customers demand for these technologies continues to grow.

As the Commission noted in its Order establishing the MI Power Grid initiative, these customer-sited resources have multiple use applications that extend beyond the immediate customer benefits to the ability to provide broader ratepayer benefits. Programs that provide customers a clear value proposition and straightforward enrollment and participation opportunities to provide grid benefits that also allow them to obtain the customer benefits derived from their private capital investment will encourage greater customer participation and advance the customer engagement objective.

Q. Please elaborate on the Emerging Technologies Integration objective and its relevance to the instant proceeding.

A. The Commission describes the integrating emerging technologies objective as "ensuring timely and fair grid access and appropriate information exchange to support customer-oriented solutions and reliable system operations." Customer-sited energy storage – particularly when paired with customer-sited solar – is an increasingly valuable customer-based solution to grid needs, including demand reduction, locational support for reliability and other needs, distribution and other infrastructure upgrade deferral or avoidance, and other use cases that provide ratepayers benefits through cost-savings from reduced utility

[12] MI Power Grid Initiative Order at p. 7.

investment and other expenditures for traditional utility solutions.

Unlocking these benefits requires breaking down barriers to customer and third-party participation in areas traditionally served by the monopoly utility by creating new market participation frameworks that encourage and allow customers to enroll their storage (and potentially other DERs) into programs designed to integrate customer-sited resources into the grid architecture and operations and provide fair compensation for the services provided.

Q. Please elaborate on the Optimizing Grid Investment and Performance objective and its relevance to the instant proceeding.

A. The Commission describes the optimizing grid investments and performance objective as "integrating transmission, distribution, and resource planning to increase transparency and optimize solutions; enhancement of tools, financial incentives, and regulatory approaches to adapt to technology change and customer preferences." Customer-sited energy storage – particularly when paired with customer-sited solar – is increasingly cost-effective resource that can be leveraged to optimize grid investment and performance. However, there is an inherent financial conflict for utilities to pursue non-wires solutions and other alternatives that remove or reduce the need for utility capital investments under the traditional natural monopoly cost plus return regulatory model (*i.e.*, the capital investment bias).

The conditional assumptions under which the monopoly-centered model was established in the interest of avoiding duplicative service and providing economic efficiency do not all hold true today. Information and communications technologies, solar and other renewable generating technologies, electric storage technologies, financing and energy service models, and other aspects of the electric industry have evolved to the point where non-utility owned resources and other third-party service providers can compete on a cost and performance basis with many utility investments and services. However, their ability to do so is in large part dependent upon the existence of a market environment with a level playing field under which an incumbent monopoly is not offered competitive advantages that derive from its monopoly status rather than innovation or other competitive factors.

Optimizing grid investment and performance in the evolving electric sector requires both: (a) a recognition of the inherent capital investment bias, and (b) a rethinking of past assumptions about the roles and functions of the "monopoly utility" in Michigan when evaluating the tools, incentives and regulatory approaches necessary to adapt to technology changes and customer preferences. A critical evaluation of these assumptions and the removal - or at least mitigation - of the inherent utility capital bias against non-utility solutions to grid needs will help provide a foundation for mapping the appropriate incentives, tools and regulatory structures to optimize grid investment and performance.

Q. Has the Commission provided any additional guidance on integrating customer-sited energy storage into the grid architecture?

A. Yes. The Commission has engaged stakeholders in efforts to advance distribution investment, maintenance planning, resilience, DER integration and other matters in Case No. U-20147. In addition to other DER related guidance, the Commission's August 20, 2020 Order in that docket emphasized non-wires alternative ("NWA") as an important part of distribution planning. The Commission stated that it "approaches NWAs from a fundamental tenet of utility regulation—that major utility investments (individual projects or groups of investments) should be examined for prudency through an open process and that this should necessarily include an examination of alternatives, whether they are approaches NWAs from the prudency perspective to evaluate major utility investments whether they are "wires" or "non-wire" in nature, or a combination thereof."[13]

The Commission continued that it would like to see utilities conduct pilot studies focused on BTM technologies "to better understand how these customer-sited resources can improve the reliability, efficiency, and productivity of the distribution system." It referenced this need for such pilot studies by observing that as utilities move to advanced distribution management systems, "the potential for ancillary services beyond load reduction, such as reliability improvement, volt/var reduction, and microgrids from DERs, will also expand" and that thoroughly understanding these technologies and their impact on distribution system operations is crucial to modernizing the electric grid." Critically, the Commission stated that it views "NWAs not only as an opportunity for electric utilities to lower costs but also as an opportunity to engage, empower, and form partnerships with customers to meet carbon reduction goals economically" and directed the utilities to "work with the Staff to develop NWA pilots that expand beyond existing DR and EWR programs" but that "in the short-term, NWA projects should focus on capacity and substation projects."[14]

Q. Has the Company provided any insights into how it will implement the guidance in the Commission in the August 20, 2020 Order outside of the Proposed Pilot?

A. Yes. The Company's Initial Draft of its Electric Distribution Infrastructure Investment Plan (2021-25) ("EDIIP Initial Draft"), released April 30, 2021, provides important insights into

[13] Case No. U-20147, Order at p. 42 ("August 20, 2020 Order").
[14] *Ibid.*, p. 43.

the Company's resource planning and operating goals in response to the Commission's August 20, 2020 order. The EDIIP Initial Draft states:

> The Company is committed to providing an electric distribution system that delivers safe, reliable, and affordable electricity to customers today and in the future. To do that, the Company must address infrastructure issues in the near term while adapting to meet evolving customer expectations and technology advancements. The Company's distribution strategy is based on five customer-focused objectives:
>
> - Safety and Security: Improving overall safety and security for customers and employees;
> - Reliability: Improving system reliability under normal operating conditions and resiliency under extreme conditions;
> - System Cost: Delivering the objectives above at an optimal, long-term system cost for all customers;
> - Sustainability: Continuing to look for opportunities to explore sustainable options and reduce system waste; and
> - Control: Providing customers with the data, technology and tools to take greater control over their energy supply and consumption.[15]

Q. How would you describe the Company's proposed Pilot as it relates to the Commission's stated objectives in the MI Power Grid initiative and other guidance?

A. The Company's proposed Pilot does not advance fundamental underpinnings of the MI Power Grid Initiative. In fact, as currently proposed, the Pilot would undermine key areas the Commission is seeking to advance through the MI Power Grid initiative. The proposed Pilot also falls short of advancing the goals articulated by the Commission the August 20, 2020 Order in Case No. U-20147. Further underscoring the shortcomings of the Company's proposed Pilot, several core aspects of the proposed Pilot's design undermine the Company's five "customer-focused" objectives articulated in the EDIIP Initial Draft.

Q. Please explain how the proposed Pilot is inconsistent with the Customer Engagement objective of the MI Power Grid initiative.

[15] EDIIP Initial Draft at pp. 4-5 (Apr. 30, 2021).

A. Starting with Customer Engagement, the Company's Proposal for utility ownership and full utility control of non-utility-owned batteries, at a minimum, falls well short of advancing the simple meaning implied by the term, and arguably moves in precisely the opposite direction. By preventing customers from using enrolled battery systems except for back-up purposes (*i.e.*, preventing use for bill management or DG export arbitrage) and subjecting even that use case to potential compromise through discretionary utility dispatch, program participants are effectively relegated to being distributed battery site hosts. That hardly offers customers an opportunity "to be more active and effective participants in the state's transition to increased clean and distributed energy resources." Furthermore, even if one were to regard participation in the Pilot itself as a form of customer engagement for the purpose of generating useful research information, the Company's primary research goal of testing "customer willingness to pay" for reliability services is of highly dubious value. As I discuss in more detail later in my testimony, anything learned from this research primarily benefits Consumers in the form of ratepayer-subsidized market research, and in practice is wholly unnecessary because it asks a question for which the answer can be readily identified through analysis of current and future customer installations outside of the proposed program.

Q. How would a grid services-based BYOD model of the type you support provide greater customer engagement than what the Company has proposed?

A. A BYOD model based on a value stacking framework is a superior model to facilitate customer engagement because it is capable of providing multiple customer benefits (*i.e.*, both bill management and resiliency) along with grid service benefits that will provide a proven market framework to test meaningful grid service and other integration strategies for customer-sited storage. It would allow prospective customers, with the assistance of third-party aggregators as facilitators, to pursue energy storage and solar-paired storage in a manner that optimizes systems from the standpoint of customer needs and priorities and costs, including potential opportunity costs of committing to provide different grid services. In short, it makes customers the decision makers, not Consumers, and in that way will allow the Commission, the Company, industry and other stakeholders, and customers to gain much more meaningful insights that will inform scaling of a pilot to a full-scale sustainable customer-sited battery program.

Q. Please explain how the proposed Pilot is inconsistent with the Emerging Technologies Integration objective of the MI Power Grid initiative.

A. The pilot in no way supports "appropriate information exchange to support customer-oriented solutions and reliable system operations." The notion of full utility control does not provide for the exchange of information that could, for instance, facilitate the development of a grid service aggregator framework and related systems that are foundational to creating a true market for grid services. Likewise, in a further reflection of the lack of attention to Customer Engagement, does it support customer-oriented solutions. As I previously observed, participant customers are effectively site hosts. They have no more role in facilitating solutions to grid needs than they would otherwise.

Q. How would a grid services-based BYOD model of the type you support provide greater opportunities to advance the Emerging Technologies Integration than what the Company has proposed?

A. BTM storage and DERs more generally have historically been almost exclusively funded by non-utility investment. It is axiomatic that this characteristic will continue, if for no other reason than the volume of available private investment money is virtually limitless, whereas utility investments are necessarily constrained. Integrating emerging technologies such as customer-sited storage, therefore, requires a focus on creating platforms that mobilize privately owned and operated resources to operate in ways that are beneficial to the grid. The Commission's reference to "customer-oriented solutions" is emblematic of that necessity.

In other words, planning for a future of utility-owned and/or controlled DERs makes no sense. Grid services-based BYOD programs both take advantage of private investments that might have been made for other reasons and help foster additional private investments by improving the economics. However, BYOD grid services require a well-designed and predictable platform in order to function. A storage pilot program provides the opportunity to develop and refine this platform. In order to be effective at doing so, the platform must embrace participation of privately owned and operated DERs, most specifically by facilitating participation by third-party aggregators with expertise in owning and operating DERs, operating in a competitive market, communicating effectively with DER customers, and the many other core competencies they possess.

Q. Please explain how the proposed Pilot is inconsistent with the Optimizing Grid Investment and Performance objective of the MI Power Grid initiative.

A. The Company's proposal is rooted in utility capital investment and expanding the monopoly utility role into a market that is objectively already competitive. This capital investment bias is evident in the Company's proposal to install two batteries per home in the name of providing enhanced resilience. I provide an analysis later in my testimony demonstrating that this aspect of the program amounts to gold-plating, but as an initial matter, it is telling of the Company's motivations that it does not intend to base battery size on actual participant customer needs and has not conducted any meaningful research to identify customer preferences or needs based on available information. This is certainly indicative of an intent to "optimize solutions" or respond to "customer preferences."

Furthermore, at an even more foundational level, Consumers is clearly not seeking to maximize the cost-effective provision of grid services. Instead, the Company proposes to offer subsidies for a resilience "service" that it will itself offer and benefit from. It is hard to grasp how this could possibly be viewed as an effort to optimize grid investments. Moreover, given that Consumers is not seeking to develop a platform to support third-party aggregation, the Company's proposal would not even put it on a path to optimizing grid investment in the future, insofar as it is not designed to facilitate non-Company solutions to grid needs.

Q. How would a grid services-based BYOD model of the type you support provide greater opportunities to advance the Optimizing Grid Investment and Performance objective than what the Company has proposed?

A. The BYOD grid service model is based on two core ideas. One core idea is that payment for services can support the economics of private investments in technologies such as battery storage, supporting their increased deployment. The second core idea is that the compensation for grid services takes place in line with the value of those services, such that non-participants are at worst indifferent. In other words, grid services-based BYOD advances the deployment of cost-effective solutions to grid problems utilizing non-utility investment. It does not offer a subsidy, it bases compensation on actual delivery of services (*i.e.*, does not place ratepayer dollars at risk), and it takes advantage of other values that customers place on DERs to help support the consumer value proposition.

Q. Has the Commission provided any additional guidance on integrating customer-sited energy storage into the grid architecture?

A. Yes. In addition to other DER related guidance, the Commission's August 20, 2020 Order in that docket emphasized NWAs as an important part of distribution planning. The Commission stated that it would like to see utilities conduct pilot studies focused on BTM technologies "to better understand how these customer-sited resources can improve the reliability, efficiency, and productivity of the distribution system." The Commission further elaborated on the need for such pilot studies by observing that as utilities move to advanced distribution management systems, "the potential for ancillary services beyond load reduction, such as reliability improvement, volt/var reduction, and microgrids from DERs, will also expand" and that "[T]horoughly understanding these technologies and their impact on distribution system operations is crucial to modernizing the electric grid."[16]

Critically, the Commission stated that it views "NWAs not only as an opportunity for electric utilities to lower costs but also as an opportunity to engage, empower, and form partnerships with customers to meet carbon reduction goals economically" and directed the utilities to "work with the Staff to develop NWA pilots that expand beyond existing DR and EWR programs" but that "in the short-term, NWA projects should focus on capacity and substation projects."[17]

Q. Please explain how the proposed Pilot is inconsistent with the Commission's August 20, 2020 Order.

[16] August 20, 2020 Order, at p. 43.
[17] *Ibid*.

A. First, as I discussed in the section on utility ownership, I am concerned that the Company-owned battery portion of the Pilot will stymie key goals of NWAs – namely by preventing competition from *non-utility* solutions that would otherwise drive down costs for ratepayers. In this same vein, utility ownership stymies the innovation that competition in the grid service space would otherwise foster.

Second, certain substantive elements of the proposed Pilot undermine key goals established in the August 20, 2020 Order. For instance, the Commission specifically articulated its view that "NWAs not only as an opportunity for electric utilities to lower costs *but also as an opportunity to engage, empower, and form partnerships with customers to meet carbon reduction goals economically*."[18] As I discuss in the sections above on the MI Power Grid initiative, the Company's proposal does not provide a meaningful framework to engage, empower and form partnerships with customers to economically meet carbon reduction goals. In fact, the Company's proposal risks *increasing* carbon pollution by subsidizing non-solar storage installations that would likely grid charge during off-peak periods from baseload power supplies, which include coal-fired generation.[19]

Moreover, as I discussed above, the Company's proposal actually disenfranchises customer engagement, empowerment and partnership by essentially utilizing customer homes as host sites for utility-controlled energy storage while preventing the storage device to provide customer benefits except when there is a grid outage. This shortcoming is further highlighted by the Company's EDIIP Initial Draft, released April 30, 2021. The EDIIP Initial Draft states that the Company's distribution strategy is based on five customer-

[18] August 20, 2020 Order, at p. 43 (emphasis added).
[19] The actual specific carbon emission impacts would require an evaluation of time-varying marginal emission rates that apply to the charge and discharge cycles, taking into account the round-trip efficiency of storage devices.

focused objectives, including "providing customers with the data, technology and tools *to take greater control over their energy supply and consumption*."[20] Instead of advancing these goals, the Company's proposed Pilot actually removes storage as a technology tool to help customers take greater control over their energy supply and consumption.

Q. How would a grid services-based BYOD pay-for-performance model of the type you support provide greater opportunities to achieve the goals articulated by the Commission in the August 20, 2020 Order?

A. For the reasons described above, a BYOD model would provide greater opportunity to advance the MI Power Grid initiative objectives as well as the Commission's distribution planning and NWA goals. I would also note that the Company's Proposal does not include any location-based use cases that would be typical in an NWA pilot. I find this concerning and it highlights an important shortcoming in the Company's Proposal - that the use-cases are not sufficiently developed to warrant approval of the Pilot as currently proposed. Further development of location-based use cases, as I discuss in Section VII and advancing these use cases through a BYOD model has a greater chance of achieving engaging, empowering and fostering customer partnerships to deliver cost-effective carbon reduction and lower cost service for all ratepayers. Moreover, the BYOD model I support is objectively far better suited to advancing the customer-focused goals articulated by the Company than the Company's own proposal.

Q. Are there federal policy considerations that the Commission should take into account when evaluating the proposed Pilot?

[20] EDIIP Initial Draft at pp. 4-5 (Apr. 30, 2021).

A. Yes. Federal Energy Regulatory Commission ("FERC") Order 2222 ("Order 2222"), issued September 17, 2020, removed key barriers to participation in organized regional wholesale markets for energy storage and other types of DERs by allowing these resources to participate wholesale energy, capacity and ancillary service markets. While FERC Order 841 allowed energy storage resources to participate in wholesale markets as a demand response resource – which limited the scope of storage resource's participation to reducing customer load, Order 2222 provides the pathways for energy storage - and other DERs – to provide additional grid services.

Additionally, Order 2222 allows energy storage and other DERs to participate in the ISO/RTO markets through "DER Aggregators." The Order defines a DER Aggregator as "the entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy and/or ancillary service markets of the regional transmission organization and/or independent system operators."[21]

Q. Why is Order 2222 relevant to the Company's proposed Pilot?

A. For one, Order 2222 acknowledges that energy storage can provide value beyond customer load reduction at the meter. As such, Order 2222 seeks to remove barriers to participation of storage resources by expanding the wholesale markets these resources are eligible to participate in by allowing for exports. Second, Order 2222 allows resources to participate in both retail and wholesale markets. This further expands the "value stack" – which I discuss further in Section VI of my testimony – to wholesale market value in addition to the customer and distribution level value. Third, Order 2222 allows resources to participate

[21] Order 2222 at p. 93.

through third-party DER Aggregators based on a participation model that accommodates the physical and operational characteristics of the aggregation.[22]

These participation characteristics are critical considerations for the Commission because they define the wholesale market framework through which customers with energy storage will be able to participate. Because these are the very same customers that the Company is targeting through its proposed Pilot, it is critical that the participation models are aligned with both wholesale and retail use cases. This has several implications for the Company's Proposal.

Q. Please describe these implications.

A. First, it is critical to provide further definition around the grid-service use cases the Company proposes test through the Pilot. Second, it underscores the scalability, flexibility, and ratepayer risk mitigation advantages of the BYOD pay-for-performance model. Third, it highlights the shortsightedness and self-serving nature of the Company's proposal for "utility control" over both the proposed Company-owned and BYOD batteries, as this feature directly conflicts with the third-party DER aggregator participation model in Order 2222.

The divergence between the market participation models of Order 2222 and the Company's proposed Pilot are significant. FERC Order 2222 provides important guidance about the market structures that a Pilot program should seek to gain greater understandings of how to maximize value between the retail and wholesale market opportunities while avoiding double compensation issues. The BYOD pay-for-performance model I recommend offers a straightforward mechanism for the Commission to gain these learnings

[22] Order 2222 at p. 102.

and advance other policy objectives, such as those articulated in the MI Power Grid initiative and others, as discussed above.

IV. The Utility-Owned Portion of the Storage Pilot is Inappropriate

Q. Please summarize your concerns with the proposed Company-owned battery aspect of the Pilot.

A. I have a number of concerns. First, utility ownership of customer-sited BTM batteries inappropriately inserts the rate-regulated monopoly utility into the growing competitive market for residential energy storage. The prospect of utility ownership in this nascent, yet growing competitive market raises numerous concerns around the ability of the utility to exercise its monopoly power to gain unfair competitive advantages over non-rate regulated competitive market provider. My concerns in this respect are not unique. As I discuss in this section of my testimony, such reservations are shared by regulators, including the Commission.

I am also not aware of any state laws or regulations allowing the Company's regulated arm to own and operate BTM energy storage in the competitive market space. Further underscoring this second concern is that the Commission has expressed reservations regarding utility ownership of BTM DERs (in the context of utility-owned customer-sited solar) and has sought additional input from stakeholders on the question of whether and under what circumstances utility ownership of customer-sited BTM resources should be permitted, if at all.[23] Allowing Company-ownership at this juncture would undercut the deliberative process that is already underway.

[23] Case No. U-20649, Order at pp. 55-56 ("Sept. 24, 2020 Order").

Q. Please elaborate on what you view as the Commission's "reservations" with respect to utility ownership of BTM DERs.

A. The Commission very recently explicitly addressed the issue of utility ownership of BTM solar assets in rejecting the Company's proposed bring-your-our-own brightfield ("BYOBF") pilot in Case No. U. 20649. The Company proposed the BYOBF pilot as an option within the voluntary green pricing program for customers with a minimum 1 MW aggregate load to pay the cost of and utilize energy from a Company-owned solar system installed on the participating customer's premises. The Commission's rejection of the proposal was based on, among other reasons, its finding that the implications of putting BTM assets into rate base were not sufficiently explained or justified and that a more thorough consideration of the utility's role in serving a growing, competitive BTM DER market was necessary.[24]

Q. How should the Commission's decision and guidance on the BYOBF proposal inform the Commission's assessment of the Home Battery Pilot proposal?

A. The Commission's rejection of the Company's BYOBF proposal set a high bar for utilities seeking to participate in the competitive market to develop BTM resources, requiring sufficient explanation and justification for such proposals. A similar level scrutiny of the Company's proposal is warranted in this case.

Q. Has the Commission reached consensus or conclusion on parameters for if or when utility ownership of customer sited BTM assets would be appropriate?

A. No, following the Commission's rejection of the Company's BYOBF proposal, it launched the New Technologies and Business Models working group as part of Phase II of the MI

[24] *Ibid*.

Power Grid initiative. The Commission tasked the group to explore and provide recommendations "on models for modern grid operations with increased DERs including consideration of the evolving role of the utility, the potential for the utility to serve as a distribution system operator, potential utility ownership of BTM or other customer-sited resources, regulatory models being pursued in other jurisdictions, and lessons learned from the workgroup's investigation of specific technologies, configurations, and ownership structures."[25] The New Technologies and Business Models workgroup has not yet concluded and Staff is scheduled to issue a final report on September 1, 2021.

Q. Please explain why utility ownership of BTM storage is of concern.

A. The Company's Proposal to own customer-sited BTM storage raises public interest antitrust concerns given the ability of a rate regulated monopoly utility to exercise unfair competitive advantages over non-rate regulated competitive market participants. The Proposal also raises fundamental questions about the future of the DER marketplace in Michigan, the appropriate role of rate regulated electric utilities in facilitating the deployment of clean energy technologies, and how to best achieve public policy goals.

Approving the Company's proposal would create a market structure in which the rate-regulated monopoly utility is allowed to compete against non-rate regulated market participants to offer energy storage products that are currently offered in the competitive market. Because of the Company's status as a monopoly utility, it would have multiple competitive advantages over non-utility entities simply by virtue of its status as a monopoly utility, including:

- The ability to earn a guaranteed rate of return on its investments;

[25] Case No. U-20898, Order at p. 11 ("Oct. 29, 2020 Order").

- The ability to include the cost of DER systems in its rate base and spread those costs among its ratepayers;
- Access to lower cost capital due to its status as a rate regulated utility;
- Prejudicial marketing opportunities through a captive customer base;
- Exclusive access to certain consumer data;
- Informed interconnection opportunities; and
- Information regarding the system's capacity to host DER without infrastructure upgrades.

Q. What risks does this pose to ratepayers?

A. Utility ownership of BTM storage unnecessarily puts ratepayer dollars at risk and potentially increases the ratepayer costs as compared to providing the same services through competitive market providers. Under the Company's Proposal – based on the Company's own analysis – because the program costs far exceed the estimated benefits, and the resiliency benefits would accrue only to the participating customers, non-participating ratepayers would be subsidizing a high-cost utility program.

Moreover, extending the utility monopoly into the BTM storage market and emerging grid services market under a program design that pits the regulated utility against competitive market providers is recipe for undermining the competitive industry and is antithetical to the goals of encouraging non-utility investment in energy storage and animating competitive grid service markets. If approved, the Pilot would open the door to the Company further exercising its monopoly power against private entities in competitive markets, giving the Company an unfair advantage in competition against non-rate regulated market participants.

Q. Does the Company sufficiently justify why it is pursuing a utility-owned storage component for the Home Battery Pilot?

A. No. Company Witness Machi describes the proposed Pilot as critical to meeting policy goals articulated by the Commission and the Company's desire to test different ownership models, but does not justify why the utility ownership component is necessary to meet these goals or provide any statutory or Commission authority to support the Company ownership model. Moreover, the Company has not provided any compelling justifications for how its "test" of "willingness to pay" for resiliency will close the gap between the projected costs and anticipated benefits. Approving such a program would usher in anti-competitive utility behavior that would have a chilling effect on the BTM storage market in Michigan and set a dangerous precedent with respect to how the Commission may evaluate proposals for BTM energy storage programs from the Company and other utilities.

Q. Company Witness Machi contends that the Pilot meets the Commission's desire to test non-wires solutions. Is it common for utility ownership of energy storage (or other DERs) to extend to NWA projects?

A. No. The general idea behind NWA projects is that DERs may be a more cost-effective solution than traditional utility investments to meet some system needs. It follows from this premise that in some cases more cost-effective competitive solutions are possible for needs that have traditionally been met by monopoly providers. As such, the NWA framework is based in large part on leveraging non-utility, competitive provider solutions to meet needs that have traditionally been met by monopoly providers where the competitive solutions are more cost effective.

Implicit within the NWA construct is that utilities and non-utilities are competing, within their respective areas of core competency (*i.e.*, non-utility owned DERs vs. utility capital investments in distribution infrastructure), to provide the most cost-effective solution to a particular grid need. Non-utility energy storage owners are fully capable of operating storage systems in line with system needs when provided the market construct and appropriate compensation for doing so. Where a non-utility owned non-wires solution is more cost-effective than the traditional utility "wires" solution, a cost-effective "NWA solution" is revealed.

Importantly, while some utility solutions may not be wires-based (*e.g.*, a battery at a substation), the NWA concept is not defined by the resource in as much as it is defined by the introduction of competition into the process. Substituting one utility investment for another as a "NWA" without consideration of competing solutions, including consideration of the core competencies of providers offering solutions is inconsistent with the purpose of NWAs.

Q. Do you have any other concerns about the Company's proposal for a utility ownership component within the Pilot?

A. In addition to the concerns discussed above, including regulated monopolies participating in non-regulated/competitive markets, the utility-ownership option proposed by the Company is effectively a "self-subsidization" of utility market research with ratepayer funds. I discuss this issue further later in my testimony in the context of my analysis of the Company's primary objective of testing willingness to pay for energy storage-based resilience.

Q. Has utility ownership of customer-sited energy storage been permitted by regulators in other states?

A. I am aware of only two instances where utility ownership of customer-sited (*i.e.*, BTM) energy storage has been permitted at a level similar to what the Company proposes – the Green Mountain Power ("GMP") Tesla Powerwall program in Vermont and the Liberty Utilities program in New Hampshire. In both instances, the Commissions have approved BYOD battery programs in addition to the utility-owned programs.

Q. How would you describe the two programs that adopted a utility ownership model in Vermont and New Hampshire as compared to the national landscape for programs for customer sited BTM batteries to provide grid services?

These programs are the exception to the rule. As illustrated in Table 1, multiple states have adopted BYOD programs for customer and third-party owned energy storage systems to deliver grid service benefits.[26]

Table 1

State	Utility	Program	Compensation	Use Case
Arizona[27]	APS	Distribution Demand Side Aggregation Tariff	TBD – under development.	Capacity, demand reduction, load shifting, locational value, voltage support, ancillary and other grid services.
California[28]	PG&E, SCE, SDG&E	Distribution Deferral Tariff, Partnership Pilot	85% of deferral value of the planned investment.	Distribution deferral
Connecticut[29]	Eversource	Connected Solutions – Demand Response	$225/kW-summer & $50/kW-winter (avg. per peak event), locked in for five years.	System peak reduction
Connecticut[30]	United Illuminating	ConnectSun	$0.05/kWh from June – Sept. on-peak energy, locked in for	Distribution deferral

[26] Exhibit EIB – 6 (JRB – 4) contains a version of Table 1 with citations.
[27] Arizona Corp. Comm'n, Docket No. E-01345A-I9-0148, Decision No. 77762 (Oct. 2, 2020); Decision No. 77855 (Dec. 31, 2020) *available at* https://edocket.azcc.gov/search/docket-search/item-detail/22809.
[28] Cal. Pub. Utils Comm'n, Rulemaking 14-10-003, Decision 21-02-006 (Feb. 11, 2021) *available at* https://docs.cpuc.ca.gov/DecisionsSearchForm.aspx.
[29] Eversource Connecticut, ConnectedSolutions Demand Response Program, *available at* https://www.eversource.com/content/ct-c/residential/save-money-energy/manage-energy-costs-usage/demand-response/battery-storage-demand-response.
[30] Energize Connecticut, ConnectSun, *available at* https://www.energizect.com/connectsun-home/you-home.

			five years, plus $500 rebate for additional metering.	
Hawaii[31]	Hawaiian Electric Companies	Emergency Demand Response Program, Scheduled Dispatch Program Rider	$850/kW for first 15 MW, $750 kW for next 15 MW of and $500 / kW for next 20 MW of enrolled capacity.	Load shift system peak reduction
Massachusetts[32]	National Grid, Eversource	Connected Solutions – Targeted Seasonal	$225/kW-summer & $50/kW-winter (avg. per peak event), locked in for five years.	System peak reduction
New Hampshire[33]	Liberty Utilities	Residential Battery Storage Pilot	Phase 2 (BYOD): TBD, following completion of Phase 1 (Utility-Owned) pilot. Under utility-owned Pilot customers receive arbitrage value via new TOU rate.	System peak reduction
New Hampshire[34]	Eversource	Connected Solutions Demand Response	$225 / kW - summer & $50/kW-winter (avg. per peak event)	System peak reduction
New York[35]	PSEG Long Island	Dynamic Load Management Tariff	$/kW-month capacity reservation payment (May – September), differentiated by location. 10-year rate lock-in for energy storage systems. Minor $/kWh payment during events.	Commercial System Relief Program (CSRP): System-wide distribution deferral Distribution Load Relief Program (DLRP): Local distribution network reliability emergencies
New York[36]	Consolidated Edison NY	Commercial Demand Response Programs	$/kW-month capacity reservation payment (May – September) differentiated by location & number of event calls	CSRP: System-wide distribution deferral

[31] Hawaii Pub. Serv. Comm'n Docket No. 2019-0323, Decision and Order No. 37816 (June 8, 2021) *available at* https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A21F08B30537B01373.
[32] MassSave, Program Materials ConnectedSolutions for Small Scale Batteries, https://www.masssave.com/-/media/Files/PDFs/Save/Residential/connectedsolution-batteries/Program-Materials-for-ConnectedSolutions-for-Small-Scale-Batteries.pdf?la=en&hash=90F93C9BC4BFBD8D6160CCAA5E594A64B6C8B29B.
[33] New Hampshire Pub. Utils Comm'n, Docket No. DE 17-189, Order No. 26,209 (Jan. 17, 2019). New Hampshire is also pursuing the development of a statewide BYOD program via its 2021-2023 energy efficiency and demand response program development process. *See* NH PUC Docket No. DE 20-092, *available at* https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-092.html.
[34] Eversource New Hampshire, ConnectedSolutions Demand Response Program https://www.eversource.com/content/nh/residential/save-money-energy/manage-energy-costs-usage/demand-response/battery-storage-demand-response.
[35] PSE&G Long Island, Program Guidelines and Operational Procedures For Dynamic Load Management Tariff Programs (Eff. June 2019) *available at* https://www.psegliny.com/businessandcontractorservices/businessandcommercialsavings/-/media/F9B52424E0FF48FBBD8AC4E336EDBE24.ashx.
[36] Consolidated Edison New York. Schedule for Electric Delivery Service, Rider T, *available at* https://www.coned.com/-/media/files/coned/documents/save-energy-money/rebates-incentives-tax-credits/smart-usage-rewards/rider-t.pdf.

			per peak season. Rates may change annually. Minor $/kWh payment during events.	DLRP: Local distribution network reliability emergencies
Rhode Island[37]	National Grid	Connected Solutions – Targeted Seasonal	$400/kW-summer season (avg. per peak event), locked in for five years.	System peak reduction
Vermont[38]	Green Mountain Power	Bring Your Own Device	Up-front payment of $850/kW for 3-hour storage discharge capability or $950/kW for 4-hour discharge capability (10% event performance tolerance subject to clawback), plus $850 for systems installed under solar self-consumption option. Adder of $100/kW for standalone systems and additions to existing solar in certain locations. 10-year program commitment.	System peak reduction, solar production / load shifting.

With respect to the question of utility ownership, the Liberty Utilities New Hampshire program is distinct because, in contrast to Michigan statutes, New Hampshire statutes explicitly authorize utilities to own and develop DERs.[39] Moreover, while Liberty Utilities' utility ownership component of its pilot was ultimately approved as a "Phase I" program, it was conditioned on the utility developing a BYOD option as a "Phase II" program. Unfortunately, Phase I has been plagued with substantial delays in procuring the batteries, cost overruns, and other hurdles that have to date prevented the Phase II program from launching. I also note that the other major utility in New Hampshire, Eversource, has not pursued a utility ownership model, despite having explicit statutory authority to do so. Instead Eversource has proposed (pending final approval) a BYOD program similar to the BYOD programs it offers in Massachusetts and Connecticut.

[37] National Grid Rhode Island Program Materials for Connected Solutions for Small Scale Batteries, *available at* https://www.nationalgridus.com/media/pdfs/resi-ways-to-save/ri_program_materials_for_connectedsolutions_for_small_scale_batteries__may_2021.pdf.
[38] Green Mountain Power, BYOD – Terms and Conditions *available at* https://greenmountainpower.com/bring-your-own-device/battery-systems/.
[39] New Hampshire Statutes § 374-G.

With respect to the GMP Tesla Powerwall program, this was the first program in the country that attempted to use customer-sited batteries to provide grid services – in that case for peak demand reduction. GMP was a "first mover," testing the fundamental and brand new concept of *whether* customer-sited batteries could be successfully operated in a coordinated manner to deliver grid and ratepayer benefits. GMP deserves credit for demonstrating "proof of concept," but it is important to note that the utility ownership aspect of its initial program was a characteristic of its novel nature. There is no need for a duplicative demonstration of "proof of concept" in Michigan. Moreover, while Vermont regulators have allowed GMP to continue to offer its Tesla Powerwall program, regulators have required GMP to also offer a BYOD program, which launched in 2020.

Further underscoring that the GMP and Liberty programs are outliers for specific reasons that do not exist in Michigan, Table 1 illustrates the other grid services programs for residential battery storage that have been implemented across the country, or are in the process of being developed and implemented, use some version of the non-utility ownership BYOD model that I support.

Q. Do you have any recommendation for how the Commission should evaluate the Company's proposal for utility ownership of customer sited BTM storage?

A. The Commission's decisions on this question will have long-lasting impacts on the storage industry as well as the broader competitive DER market in Michigan and I commend the Commission for establishing a forum through which to explore the question of utility ownership of BTM storage resources and gain input from stakeholders through the MI Power Grid Initiative. I appreciate that the Commission has many considerations to balance in making these policy decisions. My recommendation to the Commission is that it: (a) establish a general or default rule prohibiting utility ownership, and (b) provide clear guidance regarding any instances for when utility ownership would be appropriate.

Q. Please explain your rationale for this recommendation.

A. A general prohibition coupled with clear guidance for exceptions to the general prohibition would apply will provide the best framework to achieve the long-term vision for Michigan's energy future as articulated by the Commission, Governor Whitmer, and other policy makers. The MI Power Grid initiative establishes forward looking policy objectives centered on customer engagement, integrating innovative technologies, and optimizing grid investments and grid performance. Utilities have a critical role in advancing these goals; however, it is clear that climate, clean energy and other pressing public policy considerations, evolving customer preferences, technological advances, and the ability for non-utility market participants to deliver energy products and services to satisfy customer preferences are fundamentally changing the electric sector landscape.

To fully realize the potential of these evolving market forces to serve Michigan's public policy and customer focused objectives, it is essential that the competitive DER market be allowed to mature without interference and unfair competition from monopoly utilities. This requires balancing the need to: (a) create market structures that facilitate the integration of DERs into the grid architecture, and (b) remove barriers that prevent competitive market participants from delivering products and services to customers, while recognizing when the market fails to address a particular need and devising solutions with appropriate care.

Q. Can you provide any examples that the Commission could draw from as it seeks to achieve a good "balance" of competing objectives?

A. Regulators in other states who are similarly grappling with these challenges offer a helpful touchstone for the Commission as it navigates these important policy considerations in Michigan. The framework adopted by the New York Public Service Commission ("NYPSC") for when utility ownership of DERs is allowed, described in further detail below, provides clear policy prescriptions regarding utility ownership that I believe align with the goals articulated in the MI Power Grid Initiative and elsewhere by the Commission, Governor Whitmer and other policy makers in Michigan.

Q. Please describe the New York rule regarding utility ownership BTM storage.

A. The NYPSC established a general rule that "utility ownership of DERs will not be allowed unless markets have had an opportunity to provide a service and have failed to do so in a cost-effective manner."[40] It then described exceptions to this general rule as follows:

1. Procurement of DERs has been solicited to meet a system need, and a utility has demonstrated that competitive alternatives proposed by non-utility parties are clearly inadequate or more costly than a traditional utility infrastructure alternative;
2. A project consists of energy storage integrated into distribution system architecture [referring to systems on utility property];
3. A project will enable low- or moderate-income residential customers to benefit from DERs where markets are not likely to satisfy the need; and
4. A project is being sponsored for demonstration purposes.

Of significance with respect to exception (4) is that the NYPSC observed that "partnerships with utilities and third parties can accelerate market understanding and the

[40] NYPSC. Docket No. 14-M-0101. Order Adopting a Regulatory Policy Framework and Implementation Plan. February 26, 2015. p. 70 ("REV Track 1 Order").

development of sustainable business models."[41] In other words, the demonstration project exception is intended to support the scaling of DERs through early stage utility and third-party partnerships and was limited to the greater of 0.5% of a utility's revenue requirement or $10 million.[42]

The NYPSC later reaffirmed the general prohibition against utility ownership of DERs in the specific context of articulating its overarching policy for energy storage deployment. It specified that "[f]or BTM energy storage, the Commission finds no compelling reason to modify its stated preference for third-parties to develop these projects" and further clarifying that "[e]ven in the case of electric grid-connected energy storage, utility ownership will be limited to compensating for failures in the marketplace and other specifically delineated situations."[43]

The importance of delineating a clear policy on this issue cannot be overstated. As the NYPSC observed "markets will thrive best where there is both the perception and the reality of a level playing field, and that is best accomplished by restricting the ability of utilities to participate."[44] The energy storage market is an emerging industry in Michigan, but one with great potential to deliver durable, long-term benefits for all Michiganders. To unleash this potential, it is critical to provide a level playing field free from the overwhelming competitive disadvantages that would ensue if utility ownership of BTM energy storage resources – such as is proposed by the Company – were allowed.

[41] REV Track 1 Order at p. 116.
[42] REV Track 1 Order at p. 116.
[43] Case 18-E-0130, Order Establishing Energy Storage Goal and Deployment Policy at p. 53 (Dec. 13, 2018 "Energy Storage Order").
[44] REV Track 1 Order at pp. 67-68.

Q. Please summarize your recommendations as they pertain to the company's proposal for a utility ownership component in the Pilot.

A. I recommend that the Commission reject the utility ownership component. Consistent with my recommendations above, utility ownership of BTM energy storage should be limited to those instances where there is a demonstrated failure by the competitive market to provide the product or service that the utility seeks to provide. In this instance, the competitive market currently provides energy storage products to residential customers. Accordingly, there is no market failure for which a utility ownership regime is needed to remedy.

Q. If the Commission rejected the utility ownership component of the Pilot, would this resolve your concerns with the Company's Proposal?

A. No. In addition to the utility ownership aspect of the Proposal discussed above, I have additional concerns with the proposed BYOD aspect of the Pilot. I addressed the Proposal's compatibility with overarching policy objectives in the prior section of my testimony and address the further issues that I have identified in the next section.

V. Additional Deficiencies in the Company's Storage Pilot Proposal

Q. Please summarize the deficiencies that you have identified in the design of the Company's proposed Home Battery Pilot program.

A. Apart from the question of whether it is appropriate for the Company to own customer-sited energy storage, which I have already addressed elsewhere, the deficiencies include problems with the basic program structure, the Company's research objectives, the specifics of the product offering, and overall design of the Company's proposed BYOD program. In summary the issues I have identified are as follows:

1. The Company's core objective of testing "willingness to pay" for battery storage-based resilience is misplaced and inappropriate because willingness to pay is irrelevant to cost-effectiveness.
2. The proposed "incentive" design will offer a considerable subsidy to participants at the expense of non-participants, in particular for the utility-owned portion to the detriment of the competitive market provided BYOD portion, and in doing so fail to establish a durable model to support the deployment and integration of customer-sited energy storage to provide customer and rate payer benefits at scale.
3. The Company's proposal that each participant receive two batteries is inconsistent with the value structure of resiliency and a reasonable assessment of customer needs for resiliency.
4. The Company's proposal to exercise full and direct control over both the Company-owned and BYOD batteries is unjustified and fails to bring in at the early Pilot stage the partnership role of third party DER aggregators to interface between the utility and customers.

A. Testing Customer "Willingness to Pay" Asks the Wrong Question

Q. Why does the Company propose to test "willingness to pay"?

A. Company Witness Machi describes the "willingness to pay" test as necessary to demonstrate cost-effectiveness in a future business case "to ensure that the amount participating customers pay for resiliency, plus the savings associated with capacity, energy, distribution deferral, and other use cases of storage, are equal to or greater than the program cost."[45]

Q. Is this a common means by which to determine program cost-effectiveness and base?

A. No. I am not aware of any instances where a customer "willingness to pay" approach was used to determine cost-effectiveness of customer-sited batteries to provide grid services, let alone provide the basis for a scalable battery storage program. Customer "willingness to pay" is entirely irrelevant to the value of the grid services that the customer's battery can provide to the grid – and by extension, non-participating ratepayers – once a viable pathway is available for customer sited batteries to provide energy, capacity or ancillary grid services. It has no place in generally accepted standards for cost-effectiveness evaluations apart from the Participant Cost Test ("PCT") which, as the name implies, only considers costs and benefits to participants rather than the utility, non-participant ratepayers, or society as a whole.[46]

Q. In what ways might willingness to pay be relevant as a research question from the standpoint of battery storage deployment?

A. In practice, the primary use case for willingness to pay for battery storage-based resilience is the definition of price points that provide market intelligence to providers, or insights into the setting of *incentives* designed to spur adoption. To be clear, a payment in exchange for a commitment to provide valuable grid services should not be viewed as an *incentive*. Incentives are utilized to address market failures that inhibit adoption of measures that are

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[45]Machi Direct at 8:5-8.

[46] *See*, for example, the California Public Utility Commission Standard Practice Manual for Economic Analysis of Demand-Site Programs and Projects, October 2001. Available at: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf

otherwise cost-effective, or that are desirable for other reasons (*e.g.*, more general public policy or achievement of deployment targets). Accordingly, from a public policy standpoint, willingness to pay is secondary to the question of whether market forces themselves will accomplish the associated policy objective, as driven by the value that customers may realize from the adoption of a given measure.

Seen from this perspective, the Company's focus on willingness to pay is both misplaced and self-serving. It is misplaced because any "market failure" that may be present can be remedied by the Company actually developing programs that provide the market framework necessary to remove customer barriers to participation and provide participants compensation aligned with the value of the service being provided. The development of such market mechanisms is within the control of the Company and the Commission. The proposal is self-serving to the Company because, in effect, the Company is proposing to conduct ratepayer subsidized market research in support of its stated objective of potentially providing resiliency services more broadly as part of a future business case.[47]

Q. Is there evidence that energy storage deployment is already occurring in the Company's service territory based on the competitive market and value to customers that already exists?

A. Yes. Customers across the Company's service territory are adopting energy storage and often pair it with solar to provide cost savings, back-up power, and other customer benefits. The Company's own Annual Net Metering and DG Report for 2020[48] shows that 145

[47] *See* Machi Direct at 8:3-29; 9:1-2.
[48] *Consumers Energy Company's Annual Net Metering Report for 2020*, Case No. U-15787, dated March 31, 2021 ("Consumers 2020 Annual NM/DG Report"). https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000MLTHwAAP

residential or small customers (systems below 20 kW) installed energy storage with their solar system in 2020, which represents about 10.7% of residential solar net metered customers in 2020.[49] The attachment rates of batteries paired with solar clearly demonstrates customer interest and actual investment in customer-sited battery storage; which demonstrates that Michigan residents are willing to pay for energy storage.

Q. If the Commission were interested in developing information on customer willingness to pay for battery storage resilience, how do you suggest it seek to develop this information?

A. Willingness to pay for back-up power is essentially the difference between what a customer pays for a battery storage device and the tangible monetary value that the customer receives as a result of that investment - such as value generated through export arbitrage under the Company's DG tariff and other payments received – such as from the provision of grid services under a BYOD program. At present, Michigan customers do not currently have a market participation pathway to receive compensation for providing grid services. As such, "customer willingness to pay" could be readily inferred by surveying customers on the amount they paid for their storage device, and the direct monetary value they can realize in the form of export arbitrage savings and any payments they receive in the future for grid services. In short, there is simply no need to spend time and money on a pilot to study a customer's "willingness to pay" for a back-up battery.

Q. What would be a more appropriate objective for an energy storage pilot program?

A. A scalable and sustainable battery storage program should be built on the value the program can provide to ratepayers at large. In other words, a program is "cost-effective" when the

[49] 2020 is the first year the Company began reporting energy storage adoption in Consumers' Annual 2020 NM/DG Report.

avoided cost savings achieved from the battery program are sufficient to pay participating customers for services performed, cover the utility's administrative costs, and provide ratepayer savings as compared to the "business as usual" scenario. Instead of testing customers "willingness to pay" for a "resiliency as a service" product, the Company should be evaluating grid value of specified use cases and basing payments for these services on the savings (or avoided costs) that the battery program achieves in delivering value to all ratepayers. A pilot program that tests the use cases to determine the batteries performance and gather data on costs and benefits of the program, developing learnings on utility roles in event forecasting, dispatch signals and communication protocols with DER aggregator and other third party providers, monitoring and verification methods for determining participating battery performance, and other operational parameters for testing different use cases would provide valuable and actionable information to move from a pilot to a full scale battery program.

Q. Do you have any further observations on the reasonableness of the Company's focus on customers' willingness to pay for enhanced resiliency?

A. Yes. Underlying the purported need for a home resiliency program is overall poor grid reliability. In proposing to offer enhanced reliability for a price (albeit a heavily subsidized one in the current proposal) the Company seems to be attempting to translate its failure to provide service that all customers expect their utility to provide at a level consistent with customer expectations, into a profit center. From this vantage point, the results are that:

1. Participant customers pay more at an individual level for a "resiliency" service that they should already be receiving from the Company based on its obligation to deliver

reliable electric service, while also paying for Company expenditures to improve overall grid reliability.

2. Non-participant customers pay for expenses associated with more general reliability improvement measures, while also paying a substantial subsidy to enhance the resilience of the participants in the Company's proposed Pilot.

The only clear winner is the Company, who not only earns profits on the utility-owned assets enrolled in the pilot, but also generates market intelligence on a new business model it wished to pursue at no cost to itself. In short, the proposal is inequitable, wasteful, and does nothing to improve the broader reliability issues that the Company purports to solve through the "customer willingness to pay" for the "resiliency as a service" offering that the Company is already obligated to deliver to customers through reliable electric service.

B. The Company's Proposal is Not Cost-Effective

Q. Please summarize the breakdown of costs and benefits associated with the Company's Proposal?

A. According to the payment (for Company-owned batteries) and incentive (for BYOD batteries) structure the Company proposes, and the results of the Company's grid benefits analysis, the program is not cost-effective. The costs for the program total $14.3 million while the Company's assessment of grid service benefits produces a net present value of only $5.55 million.[50] Assuming the same 50/50 breakdown between utility-owned and customer-owned systems on which the $14.3 million estimate is based, additional revenue from the utility-owned portion would total $2.49 million over ten years. The net cost would

[50] *See* U20963-MEIBC-CE-449-Machi_ATT_1.xlsx in the tab labeled "1.Inputs, Outputs."

therefore be approximately $6.26 million. Regardless of the breakdown between customers electing the BYOD option or utility-owned option, the benefits are significantly less than the costs.

Q. Are the utility-owned portion and the BYOD customer-owned portion equivalent from the standpoint of cost-effectiveness?

A. No. The BYOD portion of the program is less costly than the utility-owned portion of the program but produces equivalent benefits. If one assumes that utility-owned and non-utility-owned batteries each account for 50% of the program benefit, each portion is responsible for $2.775 million in benefits. The utility owned portion costs $9 million in total,[51] which is offset by those benefits and roughly $2.49 million in revenue from customer payments, leaving a gap of $3.735 million.

The BYOD portion of the program costs $5.3 million in total,[52] which is offset by $2.775 million in benefits. This produces a cost-benefit gap of $2.49 million, considerably less than the cost-benefit gap associated with the utility-owned portion of the program. Yet, under the Company's proposal each portion of the program would provide and identical service to participant customers and provide identical grid service benefits.

Q. What are the implications of adopting the Company's proposed program design in light of its underwhelming cost-effectiveness profile?

A. There are at least two significant adverse implications, which also relate in large part to other aspects of the Company's Proposal. First, the Company will be considerably subsidizing participants at the expense of non-participants and doing so in a completely untargeted manner (*i.e.*, without an evaluation of customer needs, locational needs, or other

[51] Machi Direct at 22:4-5.
[52] *Ibid.* at 22:5-7.

potential justifications). This aspect is particularly troubling because: (a) for the utility-owned portion, the Company is proposing to subsidize a service that it will itself offer, and (b) the stated research objective of evaluating customer willingness to pay for battery storage resilience amounts to ratepayer funding of market research from which the Company is the clearest beneficiary.

Second, the program design is not supportive of the establishment of a durable and scalable energy storage grid services platform that maximizes the value of battery storage to individual participant customers, non-participants, and the grid as a whole. The Company's proposed dispatch model for the provision of grid services is vague at best and fails to engage the competitive market in the provision of grid services from battery storage. As a result, the program is not designed to, and will not otherwise achieve, policy goals that may merit some flexibility with respect to consideration of cost-effectiveness.

Q. Could an expansion of the grid services provided by enrolled battery storage systems improve the cost-effectiveness profile?

A. Yes, but the Company has certainly not articulated in any meaningful way how it will seek to evaluate the inclusion of additional grid services, let alone implement such an addition.

Q. How would you respond to the idea that subsidization could be reduced, and cost-effectiveness improved if the proposed customer incentive was reduced?

A. Reducing the incentive, whether through a reduction in the BYOD payment or an increase in the service rate for utility-owned batteries, would of course improve the cost-effectiveness profile. However, in order to equalize costs and benefits, the reduction would have to be dramatic. As I previously noted, the cost-benefit gap for the utility-owned portion of the program is $3.735 million. Accordingly, in order to reach parity, customer payments must increase by $3.735 million, from $2.49 million to a total of $6.225 million. In order to produce that amount of revenue the monthly payment would have to increase to roughly $104/month, well beyond the cost the Company estimates for the average price of a natural gas home generator of $60/month.[53] This simple math highlights the basic structural flaw in the Company's proposal to only allow the use of the battery by the customer to provide back-up power. By prohibiting the customer from deriving value from the battery from additional use cases - *i.e.*, realize the "value-stacking" potential of the battery – the battery system is prohibitively expensive relative to other options. I discuss the application of value-stacking and how it can improve customer economics later in my testimony.

C. Two Batteries per Home is Unnecessary to Provide High Value Resilience

Q. Why does the Company propose to install two batteries per participant home rather than one battery?

A. The Company states that it anticipates that its offering will provide 25 – 30 kWh of backup power.[54] This level of energy storage capacity typically requires more than one battery, based on the specifications of standard battery packages on the market today. For instance, an individual Tesla Powerwall has a 5 kW maximum discharge rating and can store 13.5 kWh of usable energy. Thus offering 25 – 30 kWh of energy storage capacity requires two Tesla Powerwalls, which in aggregate amount to a 10 kW / 27 kWh storage system.

[53] Machi Direct at 8:14.
[54] *Ibid.* at 8:22-23.

As shown in Exhibit EIB-5 (JRB-3), the Company states that it selected this amount of energy storage capacity on the basis that a program offered by GMP in Vermont provided two Tesla Powerwalls per home, and that its 50-unit test project suggested that "a larger, more meaningful home battery backup length should be a key design attribute for the Home Battery Pilot offering, as the 50-unit test batteries were smaller and in some cases did not provide the level of backup power to meet customer needs."[55]

Q. Did the Company identify the nature of "customer needs" for back-up power?

A. Not explicitly, but it did offer the observation that 25 – 30 kWh of energy storage capacity would be sufficient to provide 8 – 15 hours of backup power for a typical residential customer, which could be extended if a customer modifies their behavior.[56]

Q. Is this estimate of backup duration accurate in your view?

A. While it is not clear to me precisely how the Company generated this duration estimate, and individual customer loads will certainly vary, my own analysis of the back-up power duration offered by a single 5 kW / 13.5 kWh battery system under a worst-case scenario indicates that for a 25 – 30 kWh battery system, the 8 – 15 hour duration range is a significant underestimate. I present this analysis later in this section of my testimony.

Q. Does any available data indicate that customers prefer a larger-sized battery system?

A. No. To the contrary, with the caveat that this available data that I am aware of is limited to customers with DG-paired storage, the revealed preferences of the vast majority of customers who have installed battery storage indicate that they prefer a smaller battery. The Company's 2020 Net Metering and DG Report indicates that as of the end of 2020, a total of 147 battery-paired DG systems were present in its service territory. For the 142 of

[55] Exhibit EIB-5 (JRB-3). U-20963-MEIBC-CE-450.
[56] Machi Direct at 8:23 to 9:2.

these systems, the data includes the storage discharge capacity rating. Of those 142 systems, 128 are listed as having a discharge rating of 5 kW or less, which count 127 systems rated at 5 kW and one rated at 4.1 kW. Only a single system is rated at 10 kW, and the remainder fall in between 5 kW and 10 kW.[57] While the energy storage capability in kWh is not provided in the dataset, given typical battery packages it is reasonable to conclude that the battery systems rated at 5 kW or less, which constitute 90% of systems, are single batteries capable of storing 10 – 15 kWh. DTE's 2020 Net Metering and DG Report shows a nearly identical pattern, with 88% of installed battery systems rated at 5 kW or less.[58]

Q. Would you anticipate that this same revealed preference would exist for energy storage only customers?

A. That is a difficult question to answer, and preferences certainly could differ because as I discuss later in my testimony, the presence of on-site generation considerably enhances the duration of back-up power available to a customer. Having said that, the Commission should appreciate that DG-paired BTM battery storage is far more common than standalone BTM battery storage for at least two reasons.

One reason is that DG pairing is more cost-effective for customers because: (a) it allows the federal ITC to be claimed if the storage is charged from on-site DG, and (b) the net incremental costs of battery storage can be lower when paired with DG when both can share common equipment (*e.g.*, a shared inverter). Second, customers whose primary

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[57] Consumers' 2020 Annual NM/DG Report,

[58] *DTE Electric Company 2020 Annual Net Metering / Distributed Generation Report*, dated March 31, 2021, Case No. U-15787. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000MKx0pAAD

motivation is having back-up power during outages, rather than also desiring to use clean energy, may find fossil-fueled back-up generation more attractive than battery storage for cost and available duration reasons.

Q. Why would a customer elect to install a smaller single battery system as opposed to a larger two battery system?

A. It is essentially a question of cost versus value. A two battery system costs significantly more than a single battery system but does not provide incremental value that is worth the additional cost. Stated another way, for most customers the incremental storage capability has diminishing returns. This is true from both the standpoint of backup power availability and the monetary value that a customer can generate for themselves by avoiding exports under the Company's DG tariff.

Q. Please explain why the Company's proposal to install two battery storage units at each home is unsound from the standpoint of the value of resilience.

A. A two battery system under the assumptions used by the Company results in each participant customer having 27 kWh of available battery storage energy that may be used to provide back-up power. This amount of available stored energy is in excess of what is needed to address customer resiliency needs under most circumstances. As a result, in most cases the second battery is an added and unnecessary cost from the standpoint of providing basic resilience, which should focus on high value critical needs. It amounts to gold-plating, resulting in the incurrence of costs well beyond the point of diminishing returns.

Q. Please explain how you arrived at the conclusion that a single battery is sufficient to address customer resiliency needs under most circumstances.

A. In brief, I evaluated the Company's data on historic outage duration and how that compares to the duration of back-up power that a solar-paired 13.5 kWh storage device could offer based on an average residential customer load profile. Two critical conclusions emerged from this analysis. First, solar-paired storage offers a significant increase in resilience as measured by the duration of available back-up power than battery storage alone because solar makes its own contribution to on-site needs. Second, even considering outage duration averages that include major event days ("MEDs"), battery degradation, and high customer loads, a 13.5 kWh battery is sufficient to meet customer energy needs provided the customer reduces their consumption during an outage to critical loads.

Q. Can you elaborate on your resiliency analysis and the results?

A. Of course. I first reviewed the Company's annual Customer Average Interruption Duration Index ("CAIDI") metric including MEDs, from 2013-2019.[59] For reference, CAIDI represents the average time to restore power during an outage. Table 2 shows the annual amounts, averaging roughly 7.1 hours with a maximum of 11.5 hours during 2019. The 2019 number could be considered a worst-case scenario.

Table 2

Year	CAIDI Hours
2013	9.2
2014	5.7
2015	6.2
2016	4.1
2017	7.7
2018	5.2
2019	11.5
Average	**7.1**

[59] Sourced from Energy Information Agency ("EIA") Form 861 data in the Reliability data table. Individual annual files are available for download at: https://www.eia.gov/electricity/data/eia861/

I then calculated maximum consecutive 24-hour and 12-hour loads using an average residential customer load profile for both a solar customer and a non-solar customer.[60] The solar customer comparison uses net hourly loads including the contribution from solar rather than total customer load as indicated by the profile.[61] The maximum 24-hour and 12-hour consecutive hourly loads are the maximum loads for any individual period of 24 or 12 consecutive hours during an entire year. Their use reflects the "high load" assumption I previously referred to, as they assume an outage occurs when customer energy needs are at their highest. Both maximums correspond to hours associated with a particularly hot day in July 2019.[62]

Finally, to further reflect a worst-case scenario, I assumed that an outage occurs in the 10th year of the battery lifetime under a 3% annual degradation assumption. Under this assumption, a 13.5 kWh battery would only be able to store 70% of its initial energy capacity rating, or 9.45 kWh. Table 3 shows the results of my analysis using a 24-hour maximum consecutive hour load and Table 4 shows the results for the 12-hour maximum consecutive hour load.

Table 3

24 Consecutive Hours	**Load (kWh)**	**Average Hourly (kWh)**	**Duration (Hrs), 100% Load**	**Duration (Hrs), 75% Load**	**Duration (Hrs), 50% Load**
Maximum Solar Net Load	28.6	1.19	7.9	10.6	15.9

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[60] The profile used for this projection is sourced from actual 2019 residential class usage data in Standard Filing Requirement Attachment 56 and 57. The individual customer load shape was developed by scaling the total class usage from this data to average annual customer usage used by the Company for rate design purposes. Because the load shape reflects actual hourly loads, it accounts for infrequent events that may produce unusually high energy usage. This is relevant for the calculation of maximum consecutive hourly loads used in this analysis, which reflect a spike in energy usage during a July 2019 heat event.

[61] The solar contribution reflects a 100% annual load offset using default assumptions from PVWatts for a Lansing Michigan location, which reflects a 6.1 kW PV system that produces 7,737 kWh annually.

[62] The time period for each of the four separate maximums (solar and non-solar and 12 and 24 hours) encompasses different sets of hours that all start on July 19 and end on July 20.

Maximum Total Load	38.6	1.61	5.9	7.8	11.8
Added Solar Resilience Value (Ref Day)			35.1%		
Added Solar Resilience Value (Avg Day)			323.6%		

Table 4					
12 Consecutive Hours	**Load (kWh)**	**Average Hourly (kWh)**	**Duration (Hrs), 100% Load**	**Duration (Hrs), 75% Load**	**Duration (Hrs), 50% Load**
Maximum Solar Net Load	19.3	1.61	5.9	7.8	11.7
Maximum Total Load	23.3	1.94	4.9	6.5	9.7
Added Solar Resilience Value (Ref Day)			20.7%		
Added Solar Resilience Value (Avg Day)			114.6%		

As illustrated in Table 4, even in a worst-case scenario reflecting anomalously high energy needs at the time of an outage and an aged battery, the solar-paired battery is still sufficient to provide 11.7 hours of back-up power if the customer reduces their energy consumption by 50%. This duration is comparable to the average duration of interruption including MEDs during 2019, the worst year in recent history for the Company in terms of this reliability metric.

Q. Please further explain the additional solar resilience values you identify in Tables 3 and 4 and how the Commission should view it.

A. As I previously mentioned, when an outage encompasses any daylight hours, solar provides additional power that supplements the energy stored in the battery. The percentages listed in Tables 3 and 4 indicate how much the duration of available power is enhanced by the presence of on-site solar. The rows identified with "Ref Day" refer to the added value implied based on modeled solar production for the specific set of hours encompassed by the maximum load periods. The rows identified with "Avg Day" use modeled production for the same set of hours on an average July day. I included the Avg Day comparison because a characteristic of solar production data I used likely considerably understates the added solar resilience value by a considerable amount.

This understatement arises because the PVWatts solar production profile is based on a typical meteorological year ("TMY") whereas the load data is based on actual 2019 customer usage. As a consequence, the TMY data shows variations in production that are disconnected from actual weather conditions on an hourly and daily basis for a single year. Basically, some calendar days in the historical record have had more cloud cover than others, which shows up as lower solar production using TMY data even if the same date for a particular year had different weather. The Ref Day examples coincide with periods of unusually low solar production based on TMY data, but in reality, those periods likely actually featured better solar production because they coincide with unusually hot days during mid-July 2019, which on average would tend to be sunnier days.

Q. Please explain why the added solar resilience value based on a 12 consecutive hour maximum load is lower than the amount indicated for a 24 consecutive hour period?

A. There are two reasons. The 12 consecutive hour maximum load net of solar encompasses a period from 3 PM – 3 AM. First, since that time period includes a considerable number of low or no daylight hours solar is not able to contribute as much to meeting a customer's load. In general, any assessment of 12 consecutive hour maximum load net of on-site solar is likely to produce such a result for the simple reason that 12 consecutive hours can in theory encompass minimal daylight hours for the entire duration (*i.e.*, 6 PM – 6 AM). My particular assessment does not produce this result because it also considers customer loads, which tend to decrease overnight even considering nighttime air conditioning use.

The second reason is the TMY is the TMY/actual date disconnect I previously described. Using a TMY profile, that 12-hour period produces solar generation of 1.5 kWh, the second lowest amount or solar production for any day during the entire month for that time period. However, the average for that hourly time frame on a typical July day is 10 kWh. If solar production were assumed to average the monthly average, the average hourly load would have been 0.906 kWh. The duration of the battery even at 100% of implied customer load would have been 10.4 hours, which produces the added solar resilience value in the Avg Day case of 114.6% (*i.e.*, 10.4 hours vs. 4.9 hours without solar).

Q. What amount of back-up duration could be expected from a single battery under less extreme circumstances, where an outage does not coincide with unusually high electricity consumption?

A. Table 5 shows average hourly consumption based on the same load profile by month alongside the back-up duration provided by an aged battery in Year 10 of its lifetime. The duration assumes *no reduction* in consumption during an outage and *no contribution* from on-site solar generation to meeting on-site needs. In practice, solar production during July - the highest load month - from the hypothetical on-site solar system would average 1.22 kWh/hour, more than offsetting monthly on-site energy needs.

Table 5

Month	Hourly Average Use (kWh)	Battery Duration (Hr), Year 10
1	0.97	9.72
2	0.93	10.12
3	0.85	11.09
4	0.74	12.75
5	0.71	13.35
6	0.84	11.26

7	1.21	7.82
8	0.98	9.68
9	0.81	11.63
10	0.75	12.62
11	0.87	10.84
12	0.93	10.16

Q. Is it reasonable for customers to be expected to modify their energy usage behaviors during outage events in order to preserve scarce battery energy availability?

A. Yes, the concept of resiliency should be viewed from the standpoint of meeting a customer’s basic energy needs. Those basic energy needs may vary from customer to customer, but generally center on the protection of life and property (*i.e.*, critical loads) while many other typical loads are matters of convenience (*i.e.*, flexible or discretionary). The value of resiliency is high for critical loads, and minimal to non-existent for discretionary or flexible end uses. While some customers may place a value on the ability to operate on a business as usual basis during an outage, their ability to do so should not be a consideration in policy decisions.

Q. What sorts of end uses might fall within the definition of a “critical load”?

A. I would not say that there is a common agreed upon definition, but the most basic definition of a critical load would include end uses such as life-sustaining medical equipment and refrigeration of temperature-sensitive medicines. Beyond that very narrow definition are loads such as minimal space conditioning (including fans for gas heating), refrigeration more generally, well pumps, water heating, basic lighting, and the ability to charge technology devices (*e.g.*, phones, computers).

In practice, the concept of nature of critical loads is best viewed as a spectrum (*e.g.*, is computer charging a necessity?) and there are variations even within those general categories. For instance, maintaining a comfortable temperature in a home requires one thermostat setting, but protection of health and safety allows for a larger potential range. Regardless, critical loads are not synonymous with typical average loads.

Q. Is it possible that a greater amount of energy storage capacity may be needed by some customers under some circumstances?

A. Of course. It is certainly plausible that any individual outage could last longer than the CAIDI benchmark I used in my analysis, and that an individual customer's truly critical energy needs could differ from the averages. However, it is equally plausible that customers faced with longer outages could adapt to those circumstances by conserving electricity, and that on-site energy needs I used in my analysis overstate even a worst-case scenario. Ultimately, customers that desire larger capacity batteries should be permitted to deploy them, but there is no justification for subsidizing those systems in the name of resilience as the Company proposes to do.

Q. Please summarize your conclusions from the analysis you conducted of customer resiliency needs.

A. Two conclusions can be readily reached from my analysis. One, a single battery is all that is needed to create high value resilience for customers under most circumstances. Two, pairing a battery with on-site solar provides meaningful additional resilience value, to the point where in many scenarios the duration of available back-up power would be increased beyond the incremental duration provided by a second battery. This suggests that if resiliency is a program objective, the Company should focus on solar-paired storage rather than standalone storage installations.

VI. Framework and Opportunities for Value-Stacking

Q. What sort of "value-stack" could be utilized in the case of battery storage systems installed in the Company's service territory?

A. Currently, the most readily identifiable use case for battery storage, beyond the provision of back-up power, is the opportunity for "export arbitrage" by solar customers driven by the character of the Company's DG Program tariff, which devalues exports to the grid relative to consumption of DG electricity on-site. Under a "pay-for-performance" grid services BYOD model, the value of export arbitrage can be "stacked" with the payment for the provision of grid services. The resiliency value the customer also receives is not easily translated into monetary terms, but it is another part of the value stack to the customer.

Q. Does the Company's proposal allow for value-stacking?

A. No. Customer use of the battery is limited to back-up power. Participant customers are not permitted to use pilot program storage devices to produce direct savings for themselves in any form (*e.g.*, TOU rate arbitrage, export arbitrage for solar-paired systems).

Q. Please explain how export arbitrage can generate value for a DG customer.

A. At present, the arbitrage value amounts to 7.2-8.5 cents/kWh of customer-generated electricity that would otherwise be exported depending on the time period during which an export would occur. Table 6 illustrates the value of export arbitrage by comparing the retail rate under the Company's Residential Summer On-Peak Basic Rate ("Rate RSP")[63] to the export value for Rate RSP.[64] The Difference column represents the value to the customer of storing electricity that would otherwise be exported and using it for direct self-

[63] Consumers Energy Tariff, Sheet No. D-14.00.
[64] *Ibid.* Sheet No. C-64.30

consumption during the same pricing period (*i.e.*, reducing inflows from the grid priced at the retail rate).

Table 6			
Pricing Period	**Rate RSP Inflow ($/kWh)**	**Rate RSP Outflow ($/kWh)**	**Difference ($/kWh)**
Summer Peak	$0.2055	$0.1197	-$0.0858
Summer Off-Peak	$0.1565	$0.0805	-$0.0760
Winter	$0.1563	$0.0848	-$0.0715

While Table 6 presents rate differences in relation to the pricing period of the export, there may be additional value that can be gained through time-based arbitrage during the summer months, where electricity that would be exported during off-peak periods may be used to offset net consumption during the on-peak periods. How much value exists for enhanced time-based arbitrage depends on whether a customer has available storage capacity for off-peak outflows and on-peak use in excess of DG generation against which to use the stored electricity. This opportunity does not exist during the winter months because there is only a single winter pricing period.

Q. Have you estimated how much value export arbitrage can offer to a DG customer?

A. Yes. Based on a standard residential load shape and an on-site DG system that provides a 100% offset of annual on-site needs, a hypothetical 5 kW/13.5 kWh battery storage system could produce cost savings of roughly $192/year at current rates.[65] There are a number of factors that could affect this estimate (*e.g.*, individual customer load profile, system production, rate changes, TOU arbitrage optimization, etc.) but approximately $200/year should be a good average estimate. This translates to value of $400/kW of discharge

[65] Assumes a 92.5% roundtrip efficiency of the battery, degradation of energy storage capacity of 3% annually (*i.e.*, to 70% of the initial storage capacity in Year 10).

capacity (*i.e.*, $200 annually over 10 years divided by 5 kW). I note that this amount is lower than the theoretical maximum value that would be present if all electricity that would otherwise be exported is instead stored for self-consumption because the battery storage capacity is a limiting factor. During extended periods that produce large amounts of excess generation, the battery becomes fully charged and cannot store additional electricity. That excess continues to be exported.

Q. How does having a larger battery storage capacity affect the value a customer can redeem from export arbitrage?

A. Having a larger battery storage capacity would offer a small enhancement in value, but likely not sufficient additional value to justify the additional cost if value is confined to that use case alone. The reason that the additional value of a larger capacity battery is small is that the incremental storage capacity is small in relation to production from the DG system and the patterns of excess production, so battery storage capacity continues to be a prominent limiting factor.

For instance, I have modeled total hourly exports of 593 kWh and total net monthly use of -336 kWh during May. Since the incremental storage capacity is only 13.5 kWh, during a month like May with significant net excess a larger battery is full nearly as often as a smaller battery. In my modeling a 27 kWh battery produces annual export arbitrage value of $216/year, only roughly 13% more than a 13.5 kWh battery.

Q. Assuming a 13.5 kWh battery capacity, how could a grid services BYOD framework enhance the value of the battery to the customer and potential customer adoption of battery storage?

A. As I previously noted, the Company's benefit analysis produces a net present value ("NPV") of $555/kW.[66] Assuming Company's NPV for the sake of this analysis, if this amount were layered on top of the arbitrage value I estimated at roughly $400/kW, the customer value of arbitrage combined with payment for the provision of grid services is $955/kW. This amount is higher than the "BYOD Incentive" the Company proposes for the second and third tiers of the program ($925/kW and $800/kW respectively), thus a hypothetical customer would be better off pursuing arbitrage alongside providing grid services under the BYOD grid service model rather than electing a BYOD incentive under the model the Company proposes. One would expect that such additional customer value would spur incremental deployment relative to the Company's proposal.

Furthermore, as I have previously discussed, the pay-for-performance BYOD grid services model provides a payment for services, not an incentive or subsidy. As a consequence, it is preferable for non-participant customers because it does not simply subsidize customer-specific resilience as the Company proposes to do. Instead, it offers a durable foundation for storage deployment that benefits non-participants and can be expected to produce greater overall deployment of battery storage in the long run. Such a foundation, in the form of a scalable grid services platform, has further value in itself, as it could be used to also support advanced grid service applications for additional DER technologies, such as electric vehicles.

Q. Is it correct that a two battery per home system that the Company proposes would change the relative value of value-stacking versus the Company's proposed BYOD incentive?

[66] *See* U20963-MEIBC-CE-449-Machi_ATT_1.xlsx in the tab labeled "1.Inputs, Outputs."

A. Yes. A two battery system produces more "value" for a participant customer under the Company's BYOD incentive than a value stacking approach, but that is simply because it is being more heavily subsidized. By way of explanation, consider the first tier of the Company's proposed BYOD incentive, which offers $1,050/kW. A 5 kW battery receives an incentive of $5,250 while a 10 kW battery receives an incentive of $10,500. The 10-year NPV of benefits is battery is $2,775 for the 5 kW battery and $5,550 for the 10 kW battery. Therefore, the 5 kW battery receives a $2,475 subsidy and the 10 kW battery receives a $4,950 subsidy. Since the value of export arbitrage does not have a 1:1 relationship with energy storage capacity, the difference in the amount of the subsidy is greater than the incremental export arbitrage value for the customer under a value-stacking regime.

Q. Does this suggest that the Company's proposal is better than value-stacking approach for supporting BTM storage deployment?

A. Absolutely not. It is an apples-to-oranges comparison. Clearly, providing a subsidy in excess of the grid service value is likely to produce greater uptake, but there are costs to that. One cost is the incremental monetary cost. Another cost is underutilization of the incremental capacity in terms of providing high value resilience. As I discussed previously, a single battery should be sufficient to meet customers' resiliency needs under most circumstances. Beyond that, there is diminishing value as the excess will be unutilized, or utilized only to support lower value customer convenience rather than need.

For this reason, if the Commission uses customer uptake potential as a factor in evaluating the merits of the Company's resiliency-focused proposal versus a grid-service value-stacking approach, it should do so in the context of a single battery system.

Furthermore, as I have previously discussed at length, grid services-based BYOD is a payment for services delivered based on the value delivered to ratepayers at large, whereas the Company proposes a subsidy, and a highly oversized one at that relative to true customer resiliency needs.

Q. Please summarize your conclusions from the value-stacking analysis you have presented.

A. A BYOD Pilot based on value-stacking could offer equivalent or greater value to participant customers to what the Company has proposed without any need for an incentive or subsidy funded by non-participant ratepayers. Assuming rationality on the part of prospective customers, storage deployment under a value-stacking approach would be incrementally higher.

VII. Straw BYOD Program Design

A. Basic BYOD Program Design

Q. Please explain what you mean by a "Straw BYOD Program Design."

A. The "Straw BYOD Program Design" represents a model BYOD program structure. This contains certain minimum program characteristics that a BYOD program in Michigan should have based on my review of BYOD programs in other jurisdictions. I refer to this as a "straw" design because further refinement would be necessary to flesh out additional details such as specific compensation rates, operational protocols, and other processes. The Company should be directed to work with stakeholders to finalize a program design based on a BYOD model approved by the Commission in this proceeding.

Q. Please briefly summarize the overarching structure of a BYOD program.

A. Generally speaking, BYOD refers to a program design that allows the procurement of grid services (*e.g.*, peak load reduction) in exchange for compensation under standard terms and conditions from eligible non-utility owned devices (*e.g.*, battery storage). Most often the term has been applied to programs centered on energy storage, but BYOD has also been used in the context of thermostats with remote-control capability. The terms, conditions, and device qualifications reflect the service being procured pursuant to an identified need. Many variations can arise from this basic framework, but ultimately BYOD targets a "plug and play" grid services procurement model where a customer with a storage asset can enroll in a utility program to provide a particular grid service pursuant to a standard offer price set in the grid service program tariff.

Another element key to a well-designed BYOD program is structuring participating customer compensation under a "pay-for-performance" mechanism. This ensures that participating customers compensation is based on the enrolled device actually providing the grid service it enrolled in the program to provide. The pay-for-performance design ensures that ratepayers are held harmless if a customers' device does not perform (*i.e.*, the customer does not receive payment if the storage system does not perform or does not perform correctly) during any particular grid event. Pay-for-performance mechanisms can be designed in multiple ways, including reservation payments to encourage enrollment coupled with the payments tied to the device's performance during an event.

One further key characteristic of a BYOD program is the role that resource aggregation and third-party aggregators play. BYOD targets the coordinated operation of many individual resources towards serving a defined need. Resource aggregators supply this requisite coordination and are therefore critical to the success of a program. Aggregation also streamlines the transactional and administrative aspects of the program and offers additional flexibility with respect to participation and meeting program commitments.

Q. Please summarize how the BYOD model can be applied to customer-sited energy storage to provide grid services in the Company's service territory.

A. To a large degree, the operational model is not much different than how the Company proposes to utilize battery storage systems enrolled in its proposed Pilot. The primary differences are that: (a) customers receive a payment for committed and delivered grid services in accordance with their value, rather than an incentive, and (b) the utility does not control battery dispatch, which instead resides with the system owner or operator (*e.g.*, a third-party aggregator).

Accordingly, by enrolling in the program, the energy storage system owner is committing to providing a specific amount of flexible capacity that can be drawn on to meet the system need. The actual compensation mechanism can take multiple forms. For instance, compensation could take the form of an up-front payment accompanied by a commitment term, ongoing payments over time, or a combination of the two. The program administrator (*e.g.*, the utility) is responsible for providing the dispatch signal with appropriate notice to the third-party aggregator, or possibly directly to the participating customer. This type of protocol is similar to the system used in more generalized DR programs and as part critical peak pricing or peak credit programs.

Like these types of programs, a BYOD program will typically contain provisions that limit the timing of called events to certain hours and may limit the duration and number of called events over a specified time period. For instance, participants might be required to dispatch the storage device for three hours at a time and no more than five times a month. The dispatch protocols and requirements correspond to the grid need targeted by the program and could feature multiple options (*e.g.*, a two-hour and three-hour duration option, enhanced compensation for shorter periods of notice, etc.).

Q. How would such a program function in concert with the legacy net metering or DG programs?

A. Neither program would directly affect a customer's ability to participate in a BYOD grid services program. The customer would retain full use of their battery for whatever purpose they choose (*e.g.*, export arbitrage), except when required to respond to a dispatch signal. By committing to provide capacity to the program, they are essentially making their own use of the battery secondary to grid service priorities when a dispatch event is called.

Again, to be clear, the storage systems are not controlled directly by the utility. Performance is ensured in a market-based fashion by tethering compensation to delivery on commitments. Under the aggregation model, the aggregator is effectively committing to provide a certain volume of services from devices that they control under an arrangement with the customer. This means that dispatch of individual systems within an aggregator's portfolio could differ from event to event as long as the aggregator meets its total commitment.

Q. What specific program characteristics do you recommend for a Consumers' BYOD program for customer-sited energy storage?

A. I recommend the following minimum design elements, several of which I discuss in more detail in following sections:

1. The program should be based on a pay-for-performance model.
2. Customers with solar-paired storage should be permitted to participate on terms identical to customers without paired solar.
3. Storage owners should be permitted to aggregate multiple devices that they own into a single "resource."
4. Performance should be evaluated at the level of the aggregated resource (if applicable), rather than the individual storage system level.
5. Performance should be measured directly at the storage device using inverter data, rather than using a baseline load methodology or additional non-integrated metering.
6. Storage owners should be permitted to have their energy storage system controlled remotely by another entity (*e.g.*, a third-party owner, third-party DER aggregator or the program administrator).
7. Compensation rates should be based on long-term costs avoided by dispatch of the enrolled device, assignable to the system owner.
8. Storage owners should be permitted to lock-in the participation compensation for ten years.

Q. What types of "grid services" do you envision being part of a BYOD program?

A. The simplest application of BYOD has historically been for targeting system-wide peak capacity costs. This model is simple insofar as it can be applied across an entire service territory and may involve less frequent dispatch over more readily predictable time frames than dispatch to mitigate more localized distribution capacity issues. As I previously noted, the Company's benefits analysis for its proposed program is weighted heavily toward this use case.

Having said that, a BYOD program can also target distribution deferral on a system-wide basis and in designated local areas. For instance, the PSEG-LI and Consolidated Edison New York DLM programs I previously noted in Table 1 are broken into two program segments: the Commercial System Relief Program ("CSRP") and the Distribution Load Relief Program ("DLRP"). CSRP events are called in response to system-wide peak demand, providing peak shaving throughout the service area, and higher compensation rates apply for load reductions on certain networks. DLRP events are called on a network-specific basis to address more isolated reliability needs, also with price differentiation based on location. A given customer can participate in both at the same time.[67, 68] Beyond distribution deferral, as the Company contemplates, additional services such as voltage and frequency support could potentially be layered into the program.[69]

Q. Is it necessary that an initial version of a BYOD program seek to provide all of these possible services?

A. No. Although it would be ideal to design a program that fully addresses all potential grid services that could be provided by BTM energy storage, seeking to do so threatens to make perfect the enemy of the good. The deployment of a relatively simple model that can serve as a foundation for a more comprehensive program while still providing immediate benefits to both participants and non-participants makes far more sense.

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[67] Consolidated Edison New York. Schedule for Electric Delivery Service, Rider T, available at: https://www.coned.com/_external/cerates/documents/elecPSC10/electric-tariff.pdf

[68] Long Island Power Authority. Tariff for Electric Service, Section XIII: Dynamic Load Management and accompanying Commercial System Relief Program and Distribution Load Relief Program Payment Statements, available at: https://www.lipower.org/about-us/tariff/

[69] *See* Machi Direct at 11 in the table discussing potential use cases and evaluation methods.

Q. What would be a reasonable starting point for such an initial BYOD program?

A. A program targeting generation capacity cost savings is likely the lowest hanging fruit. Targeting capacity cost savings with a BYOD program would only require a modest difference in approach. In a BYOD program, instead of dispatching the utility-controlled storage systems directly during peak events, Consumers would instead provide notice and dispatch instructions to the non-utility storage owner participants and aggregators. Post-event performance verification would validate to what degree the participating systems met their program commitments and the amount of pay for performance compensation due. Nothing would prevent additional services and compensation structures from being added over time as opt-ins for existing participants and new participants.

Q. Are there other already operating BYOD programs that target Generation Capacity Cost savings?

A. Yes. As I previously showed in Table 1, most of the currently operating programs are focused on generating capacity cost savings. Furthermore, even though New York DLM programs target distribution deferral, the approach to calling peak events is more or less identical to what is necessary to target generation capacity savings. There is no reason that any one of these examples could not be replicated in a Consumers program. In other words, this particular wheel has already been invented.

B. Pay for Performance Model

Q. Please describe specifically what you mean by a "pay-for-performance model".

A. In basic terms, I used the term "pay-for-performance" to refer to a design that awards payments based on the ratio of what a device owner committed to do versus what they actually delivered. In a basic example, an energy storage owner may commit to providing

5 kW of storage discharge over a four-hour window whenever a peak is predicted to occur. In return, the storage owner receives an annual payment of $100/kW (a $500 payment). However, if the storage owner only delivers 4 kW on average during a year, the payment is reduced to $400 in total. At the level of an aggregator, the commitment might be 500 kW from 100 aggregated systems, but the compensation system would function in the same manner.

Q. Does the payment transaction model necessarily need to provide compensation over time as the services are delivered?

A. No. There are multiple ways to execute a pay-for-performance arrangement that do not rely exclusively on payment for services as they are delivered that do not compromise the model. For instance, up-front payments can be implemented with a defined commitment period, performance tolerance requirement, and claw back mechanism that can collectively effectuate pay for performance. This is the structure used in GMP Vermont's BYOD program, which uses a 10% performance tolerance and requires repayment of a pro-rated portion of the up-front payment if an enrolled storage device exits the program. The Company's proposal is similar to this structure insofar as it requires a 10-year customer commitment but differs in that the Company does not place a performance requirement on itself.

Another option is to provide a portion of the total expected payment over the commitment term (*e.g.*, 50%) as an up-front payment and provide the remainder over time as the service is delivered. The portion of the compensation that accrues over time can be used to reflect actual performance and function as a true-up for the up-front payment (*i.e.*, deductions for underperformance).

Q. Are there merits to providing a portion or all of the compensation as an up-front payment relative to an ongoing performance payment?

A. Yes. First, up-front payments are simpler to administer than ongoing performance payments. Second, the effective reduction in up-front costs lowers the amount of costs that may need to be financed, producing lower financing costs for the system owner.

Q. How would the service commitment required of the energy storage owner be established?

A. The nature of the grid service need defines the capacity commitment that is required, such as the duration, feasible notice, and time windows when an event may be called. The energy storage owner determines the amount of capacity they are able and willing to commit and the system is operated to meet that commitment. For instance, an energy storage device might be committed for only a portion of its maximum discharge rating due to the duration of the commitment window, the timing of potential events, the customer's desire to reserve a certain amount of discharge capacity for their own use (*i.e.*, backup power), and other reasons. Providing customers with the flexibility to select from a menu of discharge service commitment options (similar to GMP's BYOD program) allows the customer to work with the DER system owner and/or aggregator to balance the customer's needs with program participation requirements.

C. Device Aggregation

Q. Please explain what you mean by "device aggregation."

A. The program should allow for multiple energy storage systems to be operated as a collective aggregated resource. This includes allowing customer-owned systems to enroll in the program through an aggregator. The aggregated resource is viewed within the program as a single unit for the purposes of compensation and performance measurement.

Q. Why is it important that the program permit aggregation?

A. Aggregation has several benefits. First, it simplifies and consolidates the transactions involved between the program administrator and energy storage owner participants (*e.g.*, dispatch communication, device management, payments, performance verification, and others). This is particularly attractive in the context of systems owned and operated by third-parties on customer sites, where the system owner is responsible for managing program participation and the operation of the device.

Second, aggregation for the purpose of performance commitments and measurements provides third party energy storage owners flexibility to determine the level of commitment they can offer and how they manage individual units in order to meet that commitment. For instance, an aggregation owner that owns 50 participating units may want to assume that one or more units may not be operating during any given called event. De-rating every individual unit to reflect that assumption could strand potentially available capacity. An aggregated portfolio allows other units in the portfolio to make up for a potential shortfall in availability from other units.

Third, aggregation of DERs is a core component to the evolution of a more decentralized and resilient grid. That is the long-term vision embodied within FERC Order No. 2222 and implicit within many aspects of the MI Power Grid initiative and the Commission's August 20, 2020 Order in Case No. U-20147 providing guidance on advanced distribution planning and DER integration.

Q. Why is it appropriate to evaluate performance at the aggregated resource level?

A. The framework for performance measurement should be aligned with the framework for commitments. Furthermore, the value of the service itself does not depend on which specific units fill a commitment, it only matters that the aggregate commitment is achieved.

Q. What additional parameters need to be determined to facilitate a resource aggregation framework?

A. Three primary issues must be resolved. First, whether there is a minimum size for aggregations, and if so, what that minimum is. To simplify program administration, it could be beneficial to limit the program to resources or aggregations of a minimum size (*e.g.*, 50 kW). Second, the process through which aggregate commitments can be updated to reflect changes in the composition of an aggregate resource, or updates for other reasons, must be determined. Third, protocols must be developed to facilitate aggregation where resources are enrolled in multiple program segments, such as a system level program and one could be more localized. That is, an aggregation of resources could contain some facilities enrolled to provide a system-wide service (*e.g.,* peak load reduction) while a subset of that group also provides another service with geographic limitations (*e.g.*, distribution deferral). The aggregation framework should be designed to accommodate such a "multi-use" scenario.

D. Performance Measurement

Q. Please explain the distinction between performance measurement and performance evaluation.

A. Performance measurement refers to the means through which performance data is collected. Performance evaluation refers to how that data is used for the purpose of determining payments owed for services and compliance with program rules. Measurement must take place at the individual device level, but as I noted in the prior sub-section of my testimony, evaluation should take place at the aggregated portfolio level for aggregations of resources.

Q. Please explain your recommendation that performance be measured at the energy storage device level.

A. Direct measurement is the most accurate way to determine how well dispatch of the energy storage device matches the dispatch instruction. The use of a baseline load methodology introduces the additional complication of devising appropriate baselines, and by its very nature represents only an approximation of the response to dispatch instructions. Furthermore, executing a baseline load methodology might require additional interval metering that would either deplete the value of participation (if charged to storage owners) or the cost-effectiveness of the program (if recovered from non-participants).

Q. Does direct measurement of the energy storage device require additional interval metering?

A. No. Direct measurement of the energy storage device can be accomplished using inverter measurements. Modern inverters are capable of recording interval discharge data sufficient for validating performance with high accuracy. Additional metering of the storage device is not necessary.

Q. Are you recommending any specific measures to address underperformance?

A. Not at this time. The pay-for-performance model addresses the primary concern that a resource owner would be compensated for underperformance – *i.e.*, receive payment even if the device did not perform the service it was called upon to provide. Beyond that, there is the possibility that persistent underperformance could compromise the use case underlying the arrangement. This could be the case where a minimum need exists, such as with deferral of a specific distribution investment. Under these circumstances, additional performance assurance requirements could be considered. For instance, a resource or aggregation of resources might be de-rated for future periods until the performance issue is cured (*i.e.*, limiting maximum payments), or repeated uncured underperformance could result in removal from the program.[70]

While potential punitive measures may be worth considering, I caution against their immediate deployment in the early stages of a new program due to the potential negative effects they could have on participation. The need for such measures should be assessed based on initial program performance; and in the event that such measures are established, participants should have reasonable opportunities to cure underperformance before being assessed any penalties.

Q. Has non-performance been a significant issue in existing BYOD programs?

A. Generally speaking, no. Although not all of the programs have long operational histories to draw from. The longest running programs are the multiple versions of the GMP Vermont residential battery storage program, and the New York DLM programs, though the New York DLM programs are more generalized DR programs that are not limited to battery storage. The simple fact that these programs have persisted and even been expanded over time is indicative that regulators are comfortable with the historic performance and believe the programs have value.

[70] To the extent that any forward compensation for services has been provided as an up-front payment, removal from the program would need trigger a claw back mechanism for a pro-rated amount of the up-front payment to effectuate a pay for performance model.

As a specific example, Consolidated Edison's 2019 DLM program report cites a performance factor (the ratio capacity pledged to capacity delivered) of 83% in 2019 and 85% in 2018 for CSRP planned events.[71] A planned event refers to an event called with at least 21 hours of notice. It is also worth noting that the recent approval of the Daily Dispatch BYOD programs in Massachusetts hinged on the successful completion of limited pilots during Summer 2019. According to the Order approving the programs, by the end of the its residential pilot National Grid reached a 93% performance level while participants (limited to non-residential customers) in the Eversource pilot met 91% of their committed dispatch levels.[72]

Q. Do you have any other observations on the issue of non-performance that the Commission should be aware of?

A. Yes. It is notable that the Daily Dispatch pilot programs in Massachusetts were "first generation" programs. The fact that they produced high quality results nearly immediately indicates that it is simply not that difficult to deploy a successful BYOD program. While this might initially seem surprising, it is less so if one considers that the BYOD model is both conceptually and operationally simple, and modern energy storage systems have the control functionality necessary to produce reliable responses.

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[71] New York Public Service Commission. Case No. 09-E-0115. Consolidated Edison Company of New York, Inc. Report on Program Performance and Cost Effectiveness of Demand Response Programs – 2019. November 15, 2019, available at: https://tinyurl.com/rcr75qe

[72] Massachusetts Department of Public Utilities. Docket Nos. 20-33, 20-34, 20-35, and 20-36. Order dated July 28, 2020 at p. 6, available at: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12489986

E. Compensation Rates

Q. How should the amount of capacity reservation payments be determined?

A. At a high level, the payments should be based on avoided costs, such as the projected generation capacity cost savings or the marginal cost of deferred or eliminated distribution investments. A compensation structure based on marginal cost savings, coupled with a pay for performance only design, ensures that other ratepayers do not experience higher costs as a result of the program. The direct translation of avoided costs into compensation rates could be structured to reduce ratepayer risk, allow benefits sharing, and reflect program costs.

Q. Please elaborate on potential adjustments to a direct passthrough of avoided costs for participant compensation.

A. While a pay-for-performance model addresses performance risk to non-participants, it does not address the risk that event calls may not perfectly align with cost avoidance (*i.e.*, forecast error).[73] For instance, it could be that dispatches targeting generation capacity cost reductions miss one or more hours that contribute to the incurrence of costs. To address this, compensation could be pro-rated to assume that event calls will not be 100% effective. For instance, in its initial utility-owned customer-sited storage pilot, GMP in Vermont assumed that systems would only be 75% effective at reducing transmission charges.[74] A later version of the program using a BYOD model assumes that the systems will be effective at reducing 8 out of 12 monthly peaks.[75] The avoided costs calculation based on these assumptions is then translated into a fixed minimum participation payment based on

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[73] One virtue of a daily dispatch model is that mitigates potential issues with forecast error.
[74] GMP Innovative Pilot Filing. December 2, 2015. Available at: https://greenmountainpower.com/wp-content/uploads/2017/01/Hudson-12.02.2015-Tesla-Pilot-Filing.pdf
[75] GMP Letter to the VTPSB, dated February 23, 2018.

the power made available to the utility. Similarly, the Company's benefits analysis effectively assumes a 75% effectiveness ratio by assuming a capacity value set at 75% of the Cost of New Entry ("CONE").[76]

Separately, a direct pass-through of total avoided costs in the form of compensation to participants does not produce savings for non-participants. In other words, the cost of the service is provided by one resource, but at the same cost of the alternative resource, thereby providing zero net-savings (*i.e.*, zero net -benefit). A benefits/sharing ratio could reserve a portion of projected avoided costs (*e.g.*, 10%) for non-participant ratepayers.

Q. Do you recommend that the Commission incorporate adjustments of this type into the BYOD compensation design?

A. Not necessarily in the initial version of the program. The initial version of the program should target participation as the highest priority goal in order to validate program operation. Lowering the compensation rate with these types of adjustments could dampen participation and detract from the ultimate success of the program. Such adjustments would be worth considering in the future though once a successful framework has been established.

Q. Please explain your recommendation that customers be permitted to lock-in compensation rates for ten years.

A. Ten years is typically cited as the minimum useful life of lithium-ion based battery storage systems based on product warranties, though I note that in the instant proceeding, Company assumes a useful life of 15 years for calculating cost savings benefits.[77] A fixed or minimum compensation lock-in feature is an important financing consideration due to the

[76] *See* U20963-MEIBC-CE-449-Machi_ATT_1.xlsx in the tab labeled "1.Inputs, Outputs".
[77] *Ibid.*

high upfront costs of energy storage systems. A fixed rate payment is functionally similar to how costs would be incurred if an energy storage system was owned by Consumers and included in its rate base. The 10-year lock in is used in other utility programs as well. The PSEG-LI DLM program allows a 10-year rate lock-in for energy storage systems and the GMP Vermont BYOD program effectively does so through its up-front payment model and 10-year commitment term.

Q. Would a minimum locked-in rate create risks to non-participating ratepayers, for instance, if cost savings are lower than expected?

A. It would, though the design I propose can incorporate several discretionary elements to mitigate non-participant risk. First, assumptions of: (a) less than 100% effectiveness, and (b) a non-participant sharing ratio, could provide a margin for error in cost projections, creating an insulating effect. In addition, it is important to acknowledge that non-participating customers would also retain the upside if cost savings turned out to be higher than expected. In my view this is a reasonable balance of risk, and a better deal than ratepayers receive under the Company's proposal because pay for performance ensures that ratepayers are not saddled with large capital investment costs and the attendant performance-related risk.

Q. How would compensation for services be distributed to participant energy storage owners?

A. Payment for services would be assigned to the energy storage owner, which could be an individual customer participant or a third-party owner and operator. Individual participants should be permitted to assign their payment to another entity through private contractual agreements between those entities, such as a third-party operator (*i.e.*, DER aggregator) that does not own the energy storage system.

VIII. Concluding Recommendations and Next Steps

Q. What are your recommendations to the Commission on the Company's proposed Home Battery Pilot?

A. I recommend that the Commission adopt a conceptual BYOD framework based on minimum program characteristics I identify in the Straw BYOD Design and deny the Company's proposed utility-ownership component. I further recommend the Commission direct the Company to:

1. Direct the Company to consult with Staff, industry and other interested stakeholders to further develop the remaining program details including consideration of the design characteristics I identify in my testimony, and such additional guidance as the Commission deems appropriate; and
2. Submit a revised BYOD Pilot for Commission approval in its next general rate case filing.

Q. What characteristics should the Commission adopt for the conceptual BYOD framework for inclusion in the revised BYOD Pilot proposal?

A. As I describe in my testimony on the conceptual BYOD framework, the BYOD Pilot should – at a conceptual level - be designed to provide a platform for residential customers to enroll in programs that provide a pathway for battery systems to provide grid services and receive compensation for the provision of those services in addition to continuing to provide tangible customer benefits, including bill management and home resilience. As I discuss in my testimony, unlocking this "value stack" of customer and grid service benefits provides greater financial certainty to customers and third-party developers about the value proposition of the investment in storage. Greater certainty in turn supports increased private investment in storage resources need to help meet the fundamental goals articulated in the MI Power Grid initiative of increasing customer engagement, integrating emerging technologies, and optimizing grid investments and performance.

To effectuate these goals, at a minimum the revised BYOD Pilot to be filed by the Company in their next rate case should include: (a) a full set of proposed program terms and conditions, such as those attached as Exhibit EIB - 6 (JRB - 4); (b) justifications for all substantive program terms and conditions, including but not limited to compensation rates, performance measurement protocols, and all program processes; (c) a detailed description of the Company's consultation efforts that includes participant lists, summaries of individual meetings or consultations held and materials from those events; (d) a list of consensus and non-consensus issues tethered to the proposed terms and conditions; and (e) an implementation plan that includes a program timeline and a marketing plan that includes plans for how the Company will work with industry on co-marketing.

I further recommend the Commission adopt the following guidance to the Company for finalizing the program design:

- Through a collaborative process with Staff and stakeholders, the Company shall identify specific residential energy storage use cases and operational parameters for participating batteries that advance the Commission's stated policy objectives, including a customer-use case for bill management;
- Through a collaborative process with Staff and Stakeholders, the Company shall provide preliminary estimates of potential ratepayer savings and other benefits

anticipated to result from the implementation of the identified use cases; along with estimated costs of operating the Pilot. These estimates should inform the working group's recommendation for the initial use cases to be tested under the BYOD Pilot, which will ultimately be implemented to determine the potential cost-effectiveness for a full-scale program;

- The program design shall include participation/operational parameters that advance the utilization of customer-sited renewable energy;
- The program design must allow customers to stack the value of their storage system across programs and use cases (*e.g.*, customers may participate in the Pilot, utilize their battery for bill management, and participate in other additional storage programs);
- The program design must allow participation by third-party aggregators and incorporate their role within the structure in a manner that fully supports and facilitates their participation; and
- The revised BYOD Pilot proposal must provide a timeline for development and implementation of DERMS platform or other DER communication protocols as necessary to effectively conduct the Pilot and support successor program.

The Commission may wish to specify further requirements to ensure that it receives a high-quality program design that fully addresses any particular concerns it has, such as interim progress reporting and/or additional program operational characteristics. I generally support the inclusion of greater rather than lesser detail in any Commission directives surrounding the development of a final program design.

Q. Does this conclude your testimony?

A. Yes.

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STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

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In the matte of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and other relief.	)))))	**Case No. U-20963**

EXHIBITS OF JUSTIN R. BARNES

ON BEHALF OF

THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL

AND

INSTITUTE FOR ENERGY INNOVATION

JUSTIN R. BARNES

(919) 825-3342, jbarnes@eq-research.com

EDUCATION

Michigan Technological University Houghton, Michigan
Master of Science, Environmental Policy, August 2006
Graduate-level work in Energy Policy.

University of Oklahoma Norman, Oklahoma
Bachelor of Science, Geography, December 2003
Area of concentration in Physical Geography.

RELEVANT EXPERIENCE

Director of Research, July 2015 – present
Senior Analyst & Research Manager, March 2013 – July 2015
EQ Research, LLC and Keyes, Fox & Wiedman, LLP Cary, North Carolina

- Oversee state legislative, regulatory policy, and general rate case tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting. Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage.
- Oversee and perform policy research and analysis to fulfill client requests, and for internal and published reports, focused primarily on drivers of distributed energy resource (DER) markets and policies.
- Provide expert witness testimony on topics including cost of service, rate design, distributed energy resource (DER) value, and DER policy including incentive program design, rate design issues, and competitive impacts of utility ownership of DERs.
- Managed the development of a solar power purchase agreement (PPA) toolkit for local governments, a comprehensive legal and policy resource for local governments interested in purchasing solar energy, and the planning and delivery of associated outreach efforts.

Senior Policy Analyst, January 2012 – May 2013;
Policy Analyst, September 2007 – December 2011
North Carolina Solar Center, N.C. State University Raleigh, North Carolina

- Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States.
- Managed state-level regulatory tracking for private wind and solar companies.
- Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets.
- Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort.
- Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis.
- Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies.

- Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits.
- Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

SELECTED ARTICLES and PUBLICATIONS

- EQ Research and Synapse Energy Economics for Delaware Riverkeeper Network. *Envisioning Pennsylvania's Energy Future*. 2016.
- Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?*. September 2015. Published by EQ Research, LLC.
- Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments*. July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts*. December 2013. Article in Solar Today.
- Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues*. July 2013. For the U.S. DOE SunShot Solar Outreach Partnership.
- Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communities: Gaston County, North Carolina*; and *Solar in Small Communities: Columbia, Missouri*. 2013. Case Studies for the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards Live On*. 2013. For Keyes, Fox & Wiedman.
- Barnes, J. *Why Tradable SRECs are Ruining Distributed Solar*. 2012. Guest Post in Greentech Media Solar.
- Barnes, J., multiple co-authors. *State Solar Incentives and Policy Trends*. Annually for five years, 2008-2012. For the Interstate Renewable Energy Council, Inc.
- Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.
- Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets*. 2011. American Solar Energy Society Conference Proceedings.
- Barnes, J. *SREC Markets: The Murky Side of Solar*. 2011. Article in State and Local Energy Report.
- Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues*. 2010. For the Interstate Renewable Energy Council, Inc.

TESTIMONY & OTHER REGULATORY ASSISTANCE

Colorado Public Utilities Commission. Proceeding No. 20AL-0432E. March 2021. On behalf of the Colorado Solar and Storage Association and the Solar Energy Industries Association. Public Service Company of Colorado (Xcel Energy Colorado) general rate case. Provided analysis and recommendations on several non-residential rate design issues, including the utility's practice of switching small commercial customers to demand rates, relaxing the demand threshold at which commercial customers are subject to demand rates, the utility's proposal for modifying time-varying pricing windows, and the establishment of a pilot time-of-use rate for Secondary General (SG) commercial customers intended to remedy the misalignment between the SG non-coincident demand rate design and cost causation and set a foundation for a default time-varying rate option for SG class customers.

Kentucky Public Service Commission. Docket Nos. 2020-00349 and 2020-00350. March 2021. On behalf of the Kentucky Solar Energy Industries Association. Kentucky Utilities and Louisville Gas and Electric general rate case applications. Provided an analysis of the utilities' current tariffs governing purchases from qualifying facilities and recommended changes to align them with state regulations, recent precedent, and accepted methodologies of energy and capacity pricing.

South Carolina Public Service Commission. Docket Nos. 2020-264-E and 2020-265-E. February 2021. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a Solar Choice tariff for customers of Duke Energy Carolinas and Duke Energy Progress. Provided testimony in support of a stipulated settlement discussing the critical role that a proposed smart thermostat rebate and enabling technologies more generally play in the successfully meeting the legislative objectives for Solar Choice tariffs.

South Carolina Public Service Commission. Docket No. 2020-229-E. January 2021. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a Solar Choice tariff for customers of Dominion Energy South Carolina. Provided an analysis of the proposed Solar Choice tariff from the standpoint of NEM successor best practices, alignment with the enabling statute, and cost of service basis. Offered an alternative Solar Choice tariff proposal based on this analysis. Surrebuttal testimony provided an evaluation of solar customer cost of service correcting erroneous assumptions used by the Office of Regulatory Staff in its direct testimony.

Virginia State Corporation Commission. Docket No. PUR-2020-00134. January 2021. On behalf of the Behind the Meter Solar Alliance. Docket for Dominion Virginia's 2020 RPS Plan. Offered testimony supporting the designation of small-scale resource carve-out eligibility being limited to behind the meter resources, based on the underlying Virginia statute and other public policy reasons.

South Carolina Public Service Commission. Docket No. 2019-182-E. October 2020. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a cost-benefit analysis methodology and protocols for net metering and DERs. Provided discussion of historic regulatory use of DG cost-benefit and cost of service studies, how results should be viewed, and a discussion of the role of economic benefits and resiliency in DER cost-benefit analyses.

Kentucky Public Service Commission. Docket No. 2020-00174. October 2020. On behalf of the Kentucky Solar Industries Association. Kentucky Power general rate case. Provided an evaluation and critique of the cost of service support for, and design of, Kentucky Power's proposed net metering successor tariff and offered recommendations for developing cost-based DER rate designs. Also recommended changes to the utility's QF tariff and calculation of capacity costs.

New Jersey Board of Public Utilities. Docket No. EO18101111. September 2020. On behalf of Sunrun, Inc. Public Service Gas and Electric energy storage deployment plan proposal. Offered alternative proposal for a program utilizing non-utility owned energy storage assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

Virginia State Corporation Commission. Docket No. PUR-2020-00015. July 2020. On behalf of Appalachian Voices. Appalachian Power Company general rate case. Analysis of the cost basis for the residential customer charge, the Company's winter declining block rate proposal, and a proposed Coal Asset Retirement Rider (Rider CAR) providing for advance collection of anticipated accelerated depreciation of coal generation assets. Provided an alternative residential customer charge recommendation and an alternative rates proposal for addressing winter bill volatility for electric heating customers.

North Carolina Utilities Commission. Docket No. E-2 Sub 1219. April 2020. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case. Provided analysis of available rate options for electric vehicle charging and recommended the adoption of residential and non-residential EV-specific rate options and appropriate design characteristics for those rate options.

North Carolina Utilities Commission. Docket No. E-7 Sub 1214. January 2020. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case. Provided analysis of available rate options for electric vehicle charging and recommended the adoption of residential and non-residential EV-specific rate options and appropriate design characteristics for those rate options.

Virginia State Corporation Commission. Docket No. PUR-2019-00060. November 2019. On behalf of Appalachian Voices. Old Dominion Power Company general rate case application. Analysis of the cost basis for the residential customer charge, proposal to change the residential customer charge from a monthly charge to a daily charge, and design of proposed customer green power program and utility owned commercial behind the meter solar proposal. Proposed modified optional rate structure for mid- to large-size non-residential customers with on-site solar and/or low load factors.

Georgia Public Service Commission. Docket No. 42516. October 2019. On behalf of Georgia Interfaith Power and Light, Southface Energy Institute, and Vote Solar. Georgia Power Company general rate case application. Analysis of the cost basis for the residential customer charge, the validity of the utility's minimum-intercept study, and a proposal to change the residential customer charge from a monthly charge to a daily charge.

Hawaii Public Utilities Commission. Docket No. 2018-0368. July 2019. On behalf of the Hawaii PV Coalition. Hawaii Electric Light Company (HELCO) general rate case application. Provided analysis of HELCO's proposed changes to its decoupling rider to make the decoupling charge non-bypassable and the alignment of the proposed modifications with state policy goals and the policy rationale for decoupling.

Virginia State Corporation Commission. Docket No. PUR-2019-00067. July 2019.* On behalf of the Southern Environmental Law Center. Appalachian Power Company residential electric vehicle (EV) rate proposal. Provided review and analysis of the proposal and developed comments discussing principles of time-of-use (TOU) rate design and proposing modifications to the Company's proposal to support greater equity among rural ratepayers and greater rate enrollment. ***This work involved comment preparation rather than testimony.**

New York Public Service Commission. Case No. 19-E-0065. May 2019. On behalf of The Alliance for Solar Choice. Consolidated Edison (ConEd) general rate case application. Provided review and analysis of the competitive impacts and alignment with state policy of ConEd's energy storage, distributed energy resource management system, and earnings adjustment mechanism (EAM) proposals. Proposed model for improving the utilization of customer-sited storage in existing demand response programs and an alternative EAM supportive of utilization of third party-owned battery storage.

South Carolina Public Service Commission. Docket No. 2018-318-E. March 2019. On behalf of Vote Solar. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

South Carolina Public Service Commission. Docket No. 2018-319-E. February 2019. On behalf of Vote Solar. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

New Orleans City Council. Docket No. UD-18-07. February 2019. On behalf of the Alliance for Affordable Energy. Entergy New Orleans general rate case application. Analysis of the cost basis for the residential customer charge, rate design for AMI, DSM and Grid Modernization Riders, and DSM program performance incentive proposal. Developed recommendations for the residential customer charge, rider rate design, and a revised DSM performance incentive mechanism.

New Hampshire Public Utilities Commission. Docket No. DE 17-189. May 2018. On behalf of Sunrun Inc. Review of Liberty Utilities application for approval of customer-sited battery storage program, analysis of time-of-use rate design, program cost-benefit analysis, cost-effectiveness of utility-owned vs. non-utility owned storage assets. Developed a proposal for an alternative program utilizing non-utility owned assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

North Carolina Utilities Commission. Docket No. E-7 Sub 1146. January 2018. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

Ohio Public Utilities Commission. Docket No. 17-1263-EL-SSO. November 2017*. On behalf of the Ohio Environmental Council. ***Testimony prepared but not filed due to settlement in related case.** Duke Energy Ohio proposal to reduce compensation to net metering customers. Provided analysis of capacity value of solar net metering resources in the PJM market and distribution of that value to customers. Also analyzed the cost basis of the utility proposal for recovery of net metering credit costs, focused on PJM settlement protocols and how the value of DG customer exports is distributed among ratepayers, load-serving entities, and distribution utilities based on load settlement practices.

North Carolina Utilities Commission, Docket No. E-2 Sub 1142. October 2017. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and advanced metering infrastructure deployment plans and cost-benefit analysis.

Public Utility Commission of Texas, Control No. 46831. June 2017. On behalf of the Energy Freedom Coalition of America. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate DG rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits, and alignment of demand ratchets with cost causation principles and state policy goals, focused on impacts on customer-sited storage.

Utah Public Service Commission, Docket No. 14-035-114. June 2017. On behalf of Utah Clean Energy. Rocky Mountain Power application for separate distributed generation (DG) rate class. Provided analysis of grandfathering of existing DG customers and best practices for review of DG customer rates and DG value. Developed proposal for addressing revisions to DG customer rates in the future.

Colorado Public Utilities Commission, Proceeding No. 16A-0055E. May 2016. On behalf of the Energy Freedom Coalition of America. Public Service Company of Colorado application for solar energy purchase program. Analysis of program design from the perspective of customer demand and needs, and potential competitive impacts. Proposed alternative program design.

Public Utility Commission of Texas, Control No. 44941. December 2015. On behalf of Sunrun, Inc. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits.

Oklahoma Corporation Commission, Cause No. PUD 201500274. November 2015. On behalf of the Alliance for Solar Choice. Analysis of Oklahoma Gas & Electric proposal to place distributed generation customers on separate rates, rate impacts, cost basis of proposal, and alignment with rate design principles.

South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015. On behalf of The Alliance for Solar Choice. South Carolina Electric & Gas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Carolinas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Progress application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014. On behalf of The Alliance for Solar Choice. Generic investigation of distributed energy policy. Distributed energy best practices, including net metering and rate design for distributed energy customers.

AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Masters Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

Question:

38. Page 8, lines 5-9. Witness Machi states that "In order to demonstrate cost-effectiveness in a future business case, the Company needs to ensure that the amount participating customers pay for resiliency, plus the savings associated with capacity, energy, distribution deferral, and other use cases of storage, are equal to or greater than the program cost. To date, the Company has only a few data points and limited market data upon which to base the appropriate pricing for a resiliency service."
a. Please explain how the Company's willingness to pay for resiliency service methodology will provide more reliable information about the ability of customer-sited energy storage to provide cost-effective grid services (e.g., the savings associated with capacity, energy, distribution deferral, and other use cases of storage, are equal to or greater than the program cost).
b. Please describe any other pilots - involving batteries or not - where the primary or secondary goal was testing customer willingness to pay for a service or device.
c. Please indicate whether the Company has conducted any analyses of the use of increased customer-sited battery storage to produce the types of savings described - whether based on the initial data obtained from the 50-battery test, or otherwise.
i. If not, please explain why the Company has not attempted to model potential gross savings (e.g. limited to the benefit side of a benefit / cost analysis).
ii. If yes, please provide a detailed narrative description of the results of such analyses and all supporting calculations and workpapers and clearly specify all supporting assumptions.

Response:

a. The two items referenced (willingness to pay for a resiliency service and utility avoided costs) are variables unrelated to each other; however, the Home Battery Pilot will help the Company to understand both items better. As I described in my Direct Testimony, the Company is examining whether across the grid, the amount that customers are willing to pay for resiliency, plus the avoided costs to the utility, are greater than or equal to the cost of the program at scale.

b. I am not aware of any other such pilots conducted by the Company that test customer willingness to pay for a product or service.

c. The Company has developed some initial estimates of potential avoided costs associated with generation capacity, energy and line losses, and distribution substation upgrade deferral. However, the avoided cost estimates are expected to change as we evaluate these use cases through the Home Battery Pilot. The preliminary avoided cost estimates are provided in "U20963-MEIBC-CE-449-Machi_ATT_1". The overall results of the analysis are provided in the "1. Inputs, Outputs" tab, column H, lines 3 through 7.

Priya D. Machi
April 28, 2020

Strategic Projects

U20963-MEIBC-CE-450

Question:

39. Page 8, lines 22-23. Witness Machi states that "the Company anticipates the offering will be in the range of 25 to 30 kWh of backup power." Please explain how the Company determined a target range of "25 - 30 kWh" of backup power capacity.

Response:

Several factors were considered in the Company's determination of a 25 – 30 kWh target backup power range. First, the Company reviewed Green Mountain Power's utility-owned offering and this range is consistent with two Tesla Powerwall batteries for a single home, as offered by Green Mountain Power. The Company then expanded the target range to ensure that the Request for Proposal bids would be technology neutral and would reasonably incorporate interested bidders. Additionally, the Company learned from the 50-unit test that a larger, more meaningful home battery backup length should be a key design attribute for the Home Battery Pilot offering, as the 50-unit test batteries were smaller and in some cases did not provide the level of backup power to meet customer needs.

Priya D. Machi
April 28, 2021

Strategic Projects

GREEN MOUNTAIN POWER CORPORATION
Bring Your Own Device ("BYOD") Terms & Conditions

Below are important terms that you must understand and agree to in order to participate in the BYOD program. Application of these terms is dependent on the BYOD program that you have selected below, either the One-Time Upfront Incentive – Battery (Back Up Only) or One-time Upfront Incentive – Battery (Self-Consumption).

Customer: (printed) ____(the "Customer" or "You")

Email Address:____
Phone Number:________________________

GMP Account Number: ___________________________
Name of Installer___________________________

Address for Installation:
____("Home")

____
("Equipment"). See Attachment for compatible list of equipment.

_________("Back Up Only") OR ________ ("Self-Consumption")

Device Manufacturer: ______________________
Device Serial #: ____

Power Limit and Capacity Available to GMP: ___2kW ___2.5kW ___3kW ___3.5kW
___4kW ___4.5kW ___5kW ___5.5kW ___6kW ___6.5kW ___7kW ___7.5kW
___8kW ___8.5kW ___9kW ___9.5kW ___10kW

___3 hour capacity ___4 hour capacity

BYOD Incentive To Be Sent To: ___Customer ___Installer

1. **Acknowledgment of Access to Equipment, Internet Access, and Customer data**: You agree that the Equipment: (i) has a working and reliable internet access in Customer's home that is positioned to communicate reliably with the Equipment; (ii) has a user account for the Equipment where applicable; (iii) has other system elements that may be specified as required by the Manufacturer of any of the equipment (i.e. smart phone apps); and (iv) **BECAUSE THE BATTERY EQUIPMENT CAN BE DEPLETED AT ANY TIME, YOU SHOULD NOT RELY EXCLUSIVELY ON THE BATTERY EQUIPMENT TO POWER LIFE-SUPPORTING EQUIPMENT**. You agree that GMP may access the Equipment remotely for load management purposes as state herein, and to monitor energy usage discharge and performance. It is your responsibility to ensure that you have all required system elements and that such elements are compatible and properly configured. You are responsible for all fees charged by your Internet service provider ("ISP") in connection with participation. You also acknowledge responsibility for compliance with all applicable agreements, terms of use/service, and other policies of your Equipment Manufacturer/Installer and your ISP.

____

Customer Initials

2. **Equipment & Access Disruption Fee:** In the event that Equipment fails to operate or GMP is unable to communicate with the Equipment and communication or access is not restored as necessary within 30 days' after notice from GMP, for each One Time Up Front Incentive – Battery (Back Up Only) previously received, you will incur a charge of $12.70 per kW per month, until access is restored, or this Agreement is terminated in accordance with Paragraph 6.

3. **Equipment Performance**: If Equipment fails to perform within +/- 10% of the enrolled capacity noted above or to perform in self-consumption mode as required, you will have 30 days to resolve the issue and to have GMP test and verify that performance has been restored. If performance is not restored within 30 days, GMP may elect to terminate your participation in the BYOD program as provided in Paragraph 6.

4. **Control of Equipment During Peak Event and Data Access:** Unless you have selected the self-consumption option, You acknowledge that GMP will control the Equipment in your home as necessary and agree that GMP may access and control your Equipment during Peak Events as required. A "Peak Event" is defined as a period of time in which GMP will make necessary changes to the Equipment. Peak Events are anticipated to occur an average of 5 to 8 times per month for an average of 3 to 6 hours at a time. Customers will be sent notification of a Peak Event, via electronic method, at least 4 hours in advance.

As part of this Pilot, You consent to GMP and/or GMP third party vendor access and use of certain customer data and information, including energy usage and consumption data, as well as personally identifiable information. By signing up to participate in the BYOD Program, you consent to this information being accessed and provided to or by GMP and/or GMP third party vendors. This information will be used to assist in programming, reporting, monitoring, and controlling the Equipment, as well as other uses consistent with GMP's Privacy Policy (available upon request), and as provided in applicable third-party vendor terms and conditions. GMP control of Equipment enrolled in BYOD self-consumption option is not necessary or required, but the enrolled system must be connected to GMP and data made available as stated herein.

You consent to the terms and conditions expressed in Equipment monitoring platform(s) and web-based management services that GMP utilizes to enable control and access of Equipment, to view performance data, and otherwise enable required third party vendors or products, which may be amended or revised from time to time, and shall be posted and maintained on GMP's website at www.greenmountainpower.com. You expressly authorize GMP to use any interface necessary to facilitate vendor programming and communication with Equipment, to access data generated by your Equipment, and to issue commands for the operational control and management of the Equipment consistent with this Agreement, including without limitation charging and/or dispatching energy and storage resources. You agree not to terminate applicable software licenses, interface or engagement, or to request that the Equipment be disconnected from vendor programming or interface during the Term of this Agreement. **Acknowledgment of Customer:** You acknowledge and agree that GMP may control the operation, charge and discharge of the Equipment installed in your home as necessary, and that only the energy in the Equipment at the time of a grid outage will be available to you for backup power services. Other Equipment benefits and services, such as self-consumption (except for customers who elect self-consumption as discussed in Paragraph 9 of this agreement), load shifting for utility bill management, and other potential future services and benefits will not be available to you. You acknowledge that you remain responsible for maintenance, repair and replacement of the Equipment.

You acknowledge and understand that if your Equipment requires that it be recharged only by solar power for any reason, whether for operational, financial or other benefits or reasons, this may impact or delay the Equipment's return to a fully charged status and availability for the BYOD program commitments or back up power.

System outages, Equipment failure, or other circumstances outside GMP's control may impact or delay the charging status and availability of your Equipment. GMP cannot guarantee that your Equipment will be charged, fully charged, or available to you during all system outages; however, the BYOD program is designed so that GMP will minimize use of your Equipment during or prior to a weather event that is expected to cause system outages.

BECAUSE THE BATTERY EQUIPMENT CAN BE DEPLETED AT ANY TIME, YOU SHOULD NOT RELY EXCLUSIVELY ON THE BATTERY EQUIPMENT TO POWER LIFE-SUPPORTING EQUIPMENT.

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Customer Initials

5. **Enrollment & Term:** This Agreement shall commence upon your enrollment and shall continue for a period of ten years (the "Initial Term"), renewing annually after the Initial Term.

6. **Termination:** Either party may terminate this Agreement by providing the other party 30 days' written notice of termination. Upon early termination by Customer, Customer will owe GMP a pro-rated one-time payment based on the calculation below, payable within 30 days of invoice:

   Number of months remaining in the Initial Term / total months in Initial Term * *per kW* incentive or per incentive given = Total amount *per kW* owed to GMP (Back up Only Incentive) or Total amount (no KW multiplier) owed to GMP (Self-Consumption Incentive).

   Examples:
   Back up Only Incentive: If 48 of the 120 months remain in the Term, Customer will owe 48/120 * $850 = $340 ***per kW***, or in the case of the higher incentive: 48/120 * $950 = $380 per kW. Installations in a GMP- constrained area as shown on GMP's website receiving an additional $100 incentive would be calculated as follows: 48/120*$950=$380 per kW or in the case of the higher incentive 48/120*1050=$420 per kW.

   Self-Consumption Incentive: If 48 of the 120 months remain in the Term, Customer will owe 48/120 * $850 = $340. Installations in a GMP- constrained area as shown on GMP's website receiving an additional $100 incentive would be calculated as follows: 48/120*$950=$380.00.

7. **Change in Home Ownership:** You acknowledge that you are required to own the premises where the Equipment is installed. By signing below, you represent that you own the premises where the Equipment is installed.

You agree to provide GMP with 30 days advance notice of a sale of the home where the Equipment is installed. In the event of a sale, you may choose to terminate this Agreement in accordance with Paragraph 6 or if the parties agree, the new owner may assume this Agreement in writing. You are responsible for providing GMP with an executed assignment and assumption agreement, in a form provided by or acceptable to GMP for our records. Assignments that attempt to relieve you from responsibility for sums incurred prior to the sale are not permitted. Sale or transfer of the Equipment to a third party who has not assumed this agreement shall constitute automatic termination of this Agreement, and in that case, You acknowledge that you will be billed for any up-front incentive on a pro-rata basis consistent with Paragraph 6.

8. **Equipment Incentive Terms:**

Backup Only Option: Customers have the option to provide GMP with a three-hour resource or a four-hour resource, which will dictate the amount of the one-time upfront incentive provided GMP. You acknowledge that the one-time incentive for Equipment used for back up and are not paired with self-consumption is calculated at $850 per kW (up to 10 kW) that is available for a minimum duration of 3 hours at the full chosen capacity rating or $950 per kw (up to 10kW) that is available for a minimum duration of 4 hours at the full chosen capacity rating. An additional $100 per kW (up to 10 kW) incentive payment will apply to Equipment installed as a stand-alone system or paired with a pre-existing solar array in a constrained area of GMP's grid as defined by the red, orange, and yellow sections on GMP's solar map at the time of sign up.

Self Consumption Option: You acknowledge that if you elect the one-time incentive for Equipment used for self-consumption, your household is required to self-supply from the Equipment for the duration of each Peak Event, and that the one-time incentive payment for Equipment paired with self-consumption is $850.00. An additional $100 incentive payment will apply to Equipment installed as a stand-alone system or paired with a pre-existing solar array in a constrained area of GMP's grid as defined by the red, orange, and yellow sections of GMP's solar map at the time of sign up. You agree to program your Equipment to perform in self-consumption mode consistent with this agreement for the Term, and to notify GMP if your Equipment is no longer being used in self-consumption mode. If requested, you agree to provide GMP with verification that your Equipment is being used in self-consumption mode in accordance with this agreement. If GMP determines that it is not being used in self-consumption mode, or that household grid consumption is not being reduced as expected during Peak Events, GMP shall have the option to terminate this Agreement in accordance with Paragraph 6.

The amount of the upfront incentive payment due will be confirmed by GMP once the Equipment completes a verification process to determine full functionality within GMP's energy platform.

Customers who receive the added incentive for being located in a constrained area of the GMP grid, agree to ensure that the Equipment is charging via solar between the hours of 10am and 2pm daily. GMP will review Charging patterns for any customers who receive the added incentive, and reserves the right to collect the added incentive amount if customer does not comply with this requirement.

Upfront incentives will be mailed out in the form of a check within approximately 2 weeks of GMP confirming the functionality of the installed system.

9. **Fees:** BYOD program fees are due and will be included on your GMP utility bill. Fees are non-by passable and include a monthly integration and communication fee of $3.97 (which covers the costs of software integration), additional manufacturer or network fees and charges if applicable (see next paragraph), access disruption fee of $12.70 per kW per month, if applicable, and any prorated return of incentive in the event of early termination.

10. If you enroll Equipment that requires additional manufacturer or network fees or charges, you will be responsible for those additional charges, which will be passed through by GMP to you. A list of those fees and charges is maintained on GMP's website here www.greenmountainpower.com.

11. **Liability:** To the fullest extent allowed by law, GMP shall not be liable for any direct, indirect, special or consequential damages to any persons or property resulting from or arising out of any use, repair, delay in repairing, replacement of, or modification to the Equipment.

12. **Indemnification**. You shall indemnify and hold harmless GMP for any injury or damage to any persons or property arising from GMP's access and use of the Equipment, or caused by any breach of this Agreement by you, your negligence or that of your household members, agents, servants, employees, tenants, licensees, invitees, tenant's invitees, or independent contractors.
13. **Notice** You must send any Notice required under this Agreement to EICFrontline@greenmountainpower.com.

14. **Governing Law**. This Agreement shall be governed by the laws of the State of Vermont. Except for the privacy policies referenced in Paragraph 4, and applicable Public Utility Commission Tariffs, this Agreement is the entire agreement between GMP and Customer pertaining to the Bring Your Own Device Program and supersedes any and all prior agreements, understandings, representations, and statements between the parties, whether oral or written. Any change to the terms of this Agreement must be in a writing signed by Customer and GMP. The parties agree that any dispute arising out of this Agreement

shall be brought either before the Vermont Public Utility Commission or before a State or Federal court in the State of Vermont.

15. **Miscellaneous.** Equipment eligibility is at the sole discretion of GMP. Equipment that is enrolled in other GMP tariff or incentive programs is not eligible.

By signing this Agreement, I agree that I have read and understand the above terms.

GMP Customer Signature:

____
Name: _________________________________
Date:___________________________________

Compatible Equipment

Tesla Powerwall 2.0

Sonnenbatterie

Pika Energy Systems

SolarEdge StorEdge Compatible Systems

Sunverge Batteries

See GMP website for updates www.greenmountainpower.com

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the Matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief. ______________________________________	))))))	**Case No. U-20963**

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF INGHAM)

Sarah E. Jackinchuk, the undersigned, being first duly sworn, deposes and says that she is a Legal Assistant at Varnum LLP and that on the 22nd day of June, 2021 she served a copy of the Direct Testimony and Exhibits of Dr. Laura S. Sherman and Justin R. Barnes filed on behalf of Michigan Energy Innovation Business Council and the Institute for Energy Innovation., upon those individuals listed on the attached Service List via email.

Sarah Jackinchuk

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____
Sarah E. Jackinchuk

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