OLSON, BZDOK & HOWARD

October 22, 2018

Ms. Kavita Kale ***Via E-Filing***
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-20134

Dear Ms. Kale:

The following is attached for paperless electronic filing:

Official Exhibits of the Michigan Environmental Council, Natural Resources Defense Council and Sierra Club (MEC-1 through MEC-45, MEC-48 and MEC-49, MEC-51 through MEC-67

Proof of Service

*****NOTE: MEC-31, 32, 33, 34, 35 and 62 are CONFIDENTIAL and only being served on those with a signed NDC on file*****

Sincerely,

Digitally signed by Tracy Jane Andrews
DN: cn=Tracy Jane Andrews, email=tjandrews@envlaw.com, c=US
Date: 2018.10.22 14:57:47 -04'00'

Tracy Jane Andrews
tjandrews@envlaw.com

xc: Parties to Case No. U-20134
James Clift, MEC
Ariana Gonzalez, NRDC
Elena Saxonhouse, Sierra Club

Douglas B. Jester

Personal Information

Contact Information:
115 W Allegan Street, Suite 710
Lansing, MI 48933
517-337-7527
djester@5lakesenergy.com

Professional experience

January 2011 – present 5 Lakes Energy

Partner

Co-owner of a consulting firm working to advance the clean energy economy in Michigan and beyond. Consulting engagements with foundations, startups, and large mature businesses have included work on public policy, business strategy, market development, technology collaboration, project finance, and export development concerning energy efficiency, smart grid, renewable generation, electric vehicle infrastructure, and utility regulation and rate design. Policy director for renewable energy ballot initiative and Michigan energy legislation advocacy. Supported startup of the Energy Innovation Business Council, a trade association of clean energy businesses. Expert witness in utility regulation cases. Developed integrated resource planning models for use in ten states' compliance with the Clean Power Plan.

February 2010 - December 2010 Michigan Department of Energy, Labor and Economic Growth

Senior Energy Policy Advisor

Advisor to the Chief Energy Officer of the State of Michigan with primary focus on institutionalizing energy efficiency and renewable energy strategies and policies and developing clean energy businesses in Michigan. Provided several policy analyses concerning utility regulation, grid-integrated storage, performance contracting, feed-in tariffs, and low-income energy efficiency and assistance. Participated in Pluggable Electric Vehicle Task Force, Smart Grid Collaborative, Michigan Prosperity Initiative, and Green Partnership Team. Managed development of social-media-based community for energy practitioners. Organized conference on Biomass Waste to Energy.

August 2008 - February 2010 Rose International

Business Development Consultant - Smart Grid

- Employed by Verizon Business' exclusive external staffing agency for the purpose of providing business and solution development consultation services to Verizon Business in the areas of Smart Grid services and transportation management services.

December 2007 - March 2010 Efficient Printers Inc

President/Co-Owner

- Co-founder and co-owner with Keith Carlson of a corporation formed for the purpose of acquiring J A Thomas Company, a sole proprietorship owned by Keith Carlson. Recognized as Sacramento County (California) 2008 Supplier of the Year and Washoe County (Nevada) Association for Retarded Citizens 2008 Employer of the Year. Business operations discontinued by asset sale to focus on associated printing software services of IT Services Corporation.

August 2007 - present IT Services Corporation

President/Owner

- Founder, co-owner, and President of a startup business intended to provide advanced IT consulting services and to acquire or develop managed services in selected niches, currently focused on developing e-commerce solutions for commercial printing with software-as-a-service.

2004 – August 2007 Automated License Systems

Chief Technology Officer

- Member of four-person executive team and member of board of directors of a privately-held corporation specializing in automated systems for the sale of hunting and fishing licenses, park campground reservations, and in automated background check systems. Executive responsible for project management, network and data center operations, software and product development. Brought company through mezzanine financing and sold it to Active Networks.

2000 - 2004 WorldCom/MCI

Director, Government Application Solutions

- Executive responsible in various combinations for line of business sales, state and local government product marketing, project management, network and data center operations, software and product development, and contact center operations for specialized government process outsourcing business. Principal lines of business were vehicle emissions testing, firearm background checks, automated hunting and fishing license systems, automated appointment scheduling, and managed application hosting services. Also responsible for managing order entry, tracking, and service support systems for numerous large federal telecommunications contracts such as the US Post Office, Federal Aviation Administration, and Navy-Marine Corps Intranet.
- Increased annual line-of-business revenue from $64 million to $93 million, improved EBITDA from approximately 2% to 27%, and retained all customers, in context of corporate scandal and bankruptcy.
- Repeatedly evaluated in top 10% of company executive management on annual performance evaluations.

1999-2000 Compuware Corporation

Senior Project Manager

- Senior project manager, on customer site with five project managers and team of approximately 80, to migrate a major dental insurer from a mainframe environment to internet-enabled client-server environment.

1995 - 1999 City of East Lansing, Michigan

Mayor and Councilmember

- Elected chief executive of the City of East Lansing, a sophisticated city of 52,000 residents with a council-manager government employing about 350 staff and with an annual budget of about $47 million. Major accomplishments included incorporation of public asset depreciation into budgets with consequent improvements in public facilities and services, complete rewrite and modernization of city charter, greatly intensified cooperation between the City of East Lansing and the East Lansing Public Schools, significant increases in recreational facilities and services, major revisions to housing code, initiation of revision of the City Master Plan, facilitation of the merger of the Capital Area Transportation Authority and Michigan State University bus systems, initiation of a major downtown redevelopment project, City government efficiency improvements, and numerous other policy initiatives. Member of Michigan Municipal League policy committee on Transportation and Environment and principal writer of league policy on these subjects (still substantially unchanged as of 2009).

1995-1999 Michigan Department of Natural Resources

Chief Information Officer

- Executive responsibility for end-user computing, data center operations, wide area network, local area network, telephony, public safety radio, videoconferencing, application development and support, Y2K readiness for Departments of Natural Resources and Environmental Quality. Directed staff of about 110. Member of MERIT Affiliates Board and of the Great Lakes Commission's Great Lakes Information Network (GLIN) Board.

1990-1995 Michigan Department of Natural Resources

Senior Fisheries Manager

- Responsible for coordinating management of Michigan's Great Lakes fisheries worth about $4 billion per year including fish stocking and sport and commercial fishing regulation decisions, fishery monitoring and research programs, information systems development, market and economic analyses, litigation, legislative analysis and negotiation. University relations. Extensive involvement in regulation of steam electric and hydroelectric power plants.
- Served as agency expert on natural resource damage assessment, for all resources and causes.
- Considerable involvement with Great Lakes Fishery Commission, including:
  - Co-chair of Strategic Great Lakes Fishery Management Plan working group

- Member of Lake Erie and Lake St. Clair Committees
- Chair, Council of Lake Committees
- Member, Sea Lamprey Control Advisory Committee
- St Clair and Detroit River Areas of Concern Planning Committees

1989-1990 American Fisheries Society

Editor, North American Journal of Fisheries Management

- Full responsibility for publication of one of the premier academic journals in natural resource management.

1984 - 1989 Michigan Department of Natural Resources

Fisheries Administrator

- Assistant to Chief of Fisheries, responsible for strategic planning, budgets, personnel management, public relations, market and economic analysis, and information systems. Department of Natural Resources representative to Governor's Cabinet Council on Economic Development. Extensive involvement in regulation of steam electric and hydroelectric power plants.

1983-present Michigan State University

Adjunct Instructor

- Irregular lecturer in various undergraduate and graduate fisheries and wildlife courses and informal graduate student research advisor in fisheries and wildlife and in parks and recreation marketing.

1977 – 1984 Michigan Department of Natural Resources

Fisheries Research Biologist

- Simulation modeling & policy analysis of Great Lakes ecosystems. Development of problem-oriented management records system and "epidemiological" approaches to managing inland fisheries.
- Modeling and valuation of impacts power plants on natural resources and recreation.

Education

1991-1995 Michigan State University

PhD Candidate, Environmental Economics

Coursework completed, dissertation not pursued due to decision to pursue different career direction.

1980-1981 University of British Columbia

Non-degree Program, Institute of Animal Resource Ecology

1974-1977 Virginia Polytechnic Institute & State University

MS Fisheries and Wildlife Sciences

MS Statistics and Operations Research

1971-1974 New Mexico State University

BIS Mathematics, Biology, and Fine Arts

Citizenship and Community Involvement

Youth Soccer Coach, East Lansing Soccer League, 1987-89

Co-organizer, East Lansing Community Unity, 1992-1993

Bailey Community Association Board, 1993-1995

East Lansing Commission on the Environment, 1993-1995

East Lansing Street Lighting Advisory Committee, 1994

Councilmember, City of East Lansing, 1995-1999

Mayor, City of East Lansing, 1995-1997

East Lansing Downtown Development Authority Board Member, 1995-1999

East Lansing Transportation Commission, 1999-2004

East Lansing Non-Profit Housing and Neighborhood Services Corporation Board Member, 2001-2004

Lansing – East Lansing Smart Zone Board of Directors, 2007-present

Council on Labor and Economic Growth, State of Michigan, by appointment of the Governor, May 2009 – May 2012

East Lansing Downtown Development Authority Board Member and Vice-Chair, 2010 – present.

East Lansing Brownfield Authority Board Member and Vice-Chair, 2010 – present.

East Lansing Downtown Management Board and Chair, 2010 – 2016

East Lansing City Center Condominium Association Board Member, 2015 – present.

Douglas Jester
Specific Energy-Related Accomplishments

Unrelated to Employment

- Member of Michigan SAVES initial Advisory Board. Michigan SAVES is a financing program for building energy efficiency measures initiated by the State of Michigan Public Service Commission and administered under contract by Public Sector Consultants. Program launched in 2010.
- Member of Michigan Green Jobs Initiative, representing the Council for Labor and Economic Growth.
- Participated in Lansing Board of Water and Light Integrated Resource Planning, leading to their recent completion of a combined cycle natural gas power plant that also provides district heating to downtown Lansing.
- In graduate school, participated in development of database and algorithms for optimal routing of major transmission lines for Virginia Electric Power Company (now part of Dominion Resources).
- Commissioner of the Lansing Board of Water and Light, representing East Lansing. December 2017 – present.

For 5 Lakes Energy

- Participant by invitation in the Michigan Public Service Commission Smart Grid Collaborative, authoring recommendations on data access, application priorities, and electric vehicle integration to the grid.
- Participant by invitation in the Michigan Public Service Commission Energy Optimization Collaborative, a regular meeting and action collaborative of parties involved in the Energy Optimization programs required of utilities by Michigan law enacted in 2008.
- Participant by invitation in Michigan Public Service Commission Solar Work Group, including presentations and written comments on value of solar, including energy, capacity, avoided health and environmental damages, hedge value, and ancillary services.
- Participant by invitation in Michigan Senate Energy and Technology Committee stakeholder work group preliminary to introduction of a comprehensive legislative package.
- Participant by invitation in Michigan Public Service Commission PURPA Avoided Cost Technical Advisory Committee.
- Participant by invitation in Michigan Public Service Commission Standby Rate Working Group.
- Participant by invitation in Michigan Public Service Commission Street Lighting Collaborative.
- Participant by invitation in State of Michigan Agency for Energy Technical Advisory Committee on Clean Power Plan implementation.
- Conceived, obtained funding, and developed open access integrated resource planning tools (State Tool for Electricity Emissions Reduction aka STEER) for State compliance with the Clean Power Plan:
    - For Energy Foundation - Michigan and Iowa
    - For Advanced Energy Economy Institute – Arkansas, Florida, Illinois, Ohio, Pennsylvania, Virginia
    - For The Solar Foundation - Georgia and North Carolina
- Presentations to Michigan Agency for Energy and the Institute for Public Utilities Michigan Forum on Strategies for Michigan to Comply with the Clean Power Plan.
- Participant in Midcontinent Independent Systems Operator stakeholder processes on behalf of Michigan Citizens Against Rate Excess and the MISO Consumer Representatives Sector, including Resource Adequacy Committee, Loss of Load Expectation Working Group, Transmission Expansion Working Group, Demand Response Working Group, Independent Load Forecasting Working Group, and Clean Power Plan Working Group.
- Expert witness before the Michigan Public Service Commission in various cases, including:

  - Case U-17473 (Consumers Energy Plant Retirement Securitization)
  - Case U-17096-R (Indiana Michigan 2013 PSCR Reconciliation)
  - Case U-17301 (Consumers Energy Renewable Energy Plan 2013 Biennial Review);
  - Case U-17302 (DTE Energy Renewable Energy Plan 2013 Biennial Review);
  - Case U-17317 (Consumers Energy 2014 PSCR Plan);
  - Case U-17319 (DTE Electric 2014 PSCR Plan);
  - Case U-17674 (WEPCO 2015 PSCR Plan);
  - Case U-17679 (Indiana-Michigan 2015 PSCR Plan);
  - Case U-17689 (DTE Electric Cost of Service and Rate Design);
  - Case U-17688 (Consumers Energy Cost of Service and Rate Design);
  - Case U-17698 (Indiana-Michigan Cost of Service and Rate Design);
  - Case U-17762 (DTE Electric Energy Optimization Plan);
  - Case U-17752 (Consumers Energy Community Solar);
  - Case U-17735 (Consumers Energy General Rates);
  - Case U-17767 (DTE General Rates);
  - Case U-17792 (Consumers Energy Renewable Energy Plan Revision);
  - Case U-17895 (UPPCO General Rates);
  - Case U-17911 (UPPCO 2016 PSCR Plan);
  - Case U-17990 (Consumers Energy General Rates); and
  - Case U-18014 (DTE General Rates);
  - Case U-17611-R (UPPCO 2015 PSCR Reconciliation);
  - Case U-18089 (Alpena Power PURPA Avoided Costs);
  - Case U-18090 (Consumers Energy PURPA Avoided Costs);
  - Case U-18091 (DTE PURPA Avoided Costs);
  - Case U-18092 (Indiana Michigan Electric Power PURPA Avoided Costs);
  - Case U-18093 (Northern States Power PURPA Avoided Costs);
  - Case U-18094 (Upper Peninsula Power Company PURPA Avoided Costs);
  - Case U-18095 (UMERC PURPA Avoided Costs);
  - Case U-18224 (UMERC Certificate of Necessity);
  - Case U-18255 (DTE General Rate Case);
  - Case U-18322 (Consumers Energy General Rate Case).
- Expert witness before the Public Utilities Commission of Nevada in
  - Case 16-07001 (NV Energy 2017-2036 Sierra Pacific Integrated Resource Plan)
- Expert witness before the Missouri Public Service Commission in
  - Case ER-2016-0179 (Ameren Missouri General Rate Case)
  - Case ER-2016-0285 (KCP&L General Rate Case)
  - Case ET-2016-0246 (Ameren Missouri EV Policy)
- Expert witness before the Kentucky Public Service Commission
  - Case 2016-00370 (Kentucky Utilities General Rate Case)
- Expert witness before the Massachusetts Department of Public Utilities in
  - Case 17-05 (Eversource General Rate Case)
  - Case 17-13 (National Grid General Rate Case)
- Coauthored “Charge without a Cause: Assessing Utility Demand Charges on Small Customers”
- Currently under contract to the Michigan Agency for Energy to develop a Roadmap for CHP Market Development in Michigan, including evaluation of various CHP technologies and applications using STEER Michigan as an integrated resource planning tool.
- Under contract to NextEnergy, authored “Alternative Energy and Distributed Generation” chapter of Smart Grid Economic Development Opportunities report to Michigan Economic Development Corporation and assisted authors of chapters on “Demand Response” and “Automated Energy Management Systems”.
- Developed presentation on “Whole System Perspective on Energy Optimization Strategy” for Michigan Energy Optimization Collaborative.
- Under contract to NextEnergy, assisted in development of industrial energy efficiency technology development strategy.

- Under contract to a multinational solar photovoltaics company, developed market strategy recommendations.
- For an automobile OEM, developed analyses of economic benefits of demand response in vehicle charging and vehicle-to-grid electricity storage solutions.
- Under contract to Pew Charitable Trusts, assisted in development of a report of best practices for electric vehicle charging infrastructure.
- Under contract to a national foundation, developed renewable energy business case for Michigan including estimates of rate impacts, employment and income effects, health effects, and greenhouse gas emissions effects.
- Assisted in Michigan market development for a solar panel manufacturer, clean energy finance company, and industrial energy management systems company.
- Under contract to Institute for Energy Innovation, organized legislative learning sessions covering a synopsis of Michigan's energy uses and supply, energy efficiency, and economic impacts of clean energy.

For Department of Energy Labor and Economic Growth

- Participant in the Michigan Public Service Commission Energy Optimization Collaborative, a regular meeting and action collaborative of parties involved in the Energy Optimization programs required of utilities by Michigan law enacted in 2008.
- Lead development of a social-media-based community for energy practitioners in Michigan at www.MichEEN.org.
- Drafted analysis and policy paper concerning customer and third-party access to utility meter data.
- Analyzed hourly electric utility load demonstrating relationship amongst time of day, daylight, and temperature on loads of residential, commercial, industrial, and public lighting customers. Analysis demonstrated the importance of heating for residential electrical loads and the effects of various energy efficiency measures on load-duration curves.
- Analyzed relationship of marginal locational prices to load, demonstrating that traditional assumptions of Integrated Resource Planning are invalid and that there are substantial current opportunities for cost-effective grid-integrated storage for the purpose of price arbitrage as opposed to traditionally considered load arbitrage.
- Developed analyses and recommendations concerning the use of feed-in tariffs in Michigan.
- Participated in Pluggable Electric Vehicle Task Force and initiated changes in State building code to accommodate installation of vehicle charging equipment.
- Organized December 2010 conference on Biomass Waste to Energy technologies and market opportunities.
- Participated in and provided support for teams working on developing Michigan businesses involved in renewable energy, storage, and smart grid supply chains.
- Developed analyses and recommendations concerning low-income energy assistance coordination with low-income energy efficiency programs and utility payment collection programs.
- Drafted State of Michigan response to a US Department of Energy request for information on offshore wind energy technology development opportunities.
- Assisted in development of draft performance contracting enabling legislation, since adopted by the State of Michigan.

For Verizon Business

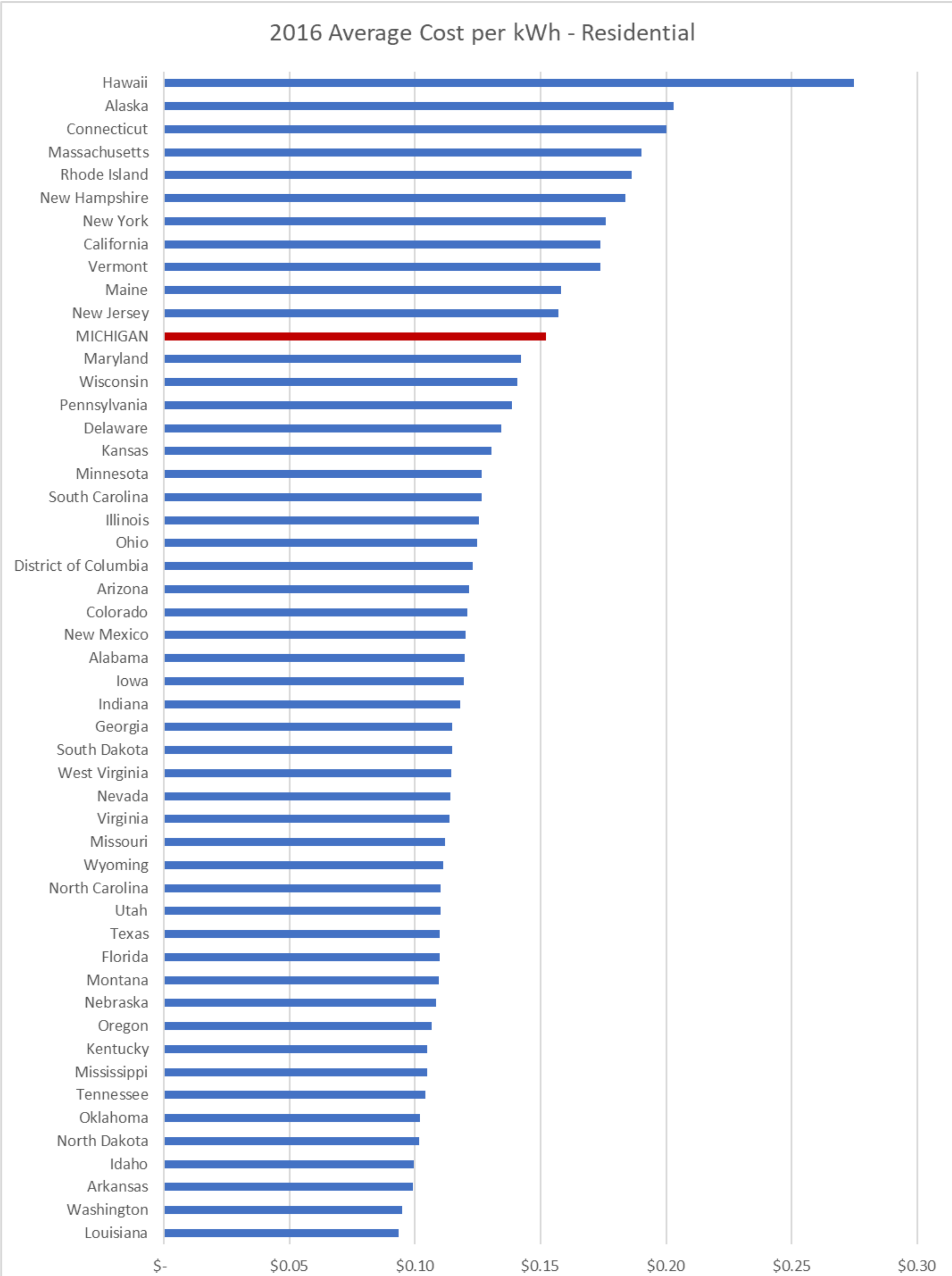
- Analyzed several potential new lines of business for potential entry by Verizon's Global Services Systems Integration business unit and recommended entry to the "Smart Grid" market. This recommendation was adopted and became a major corporate initiative.
- Provided market analysis and participation in various conferences to aid in positioning Verizon in the "Smart Grid" market. Recommendations are proprietary to Verizon.

- Led a task force to identify potential converged solutions for the “Smart Grid” market by integrating Verizon’s current products and selected partners. Established five key partnerships that are the basis for Verizon’s current “Smart Grid” product offerings.
- Participated in the “Smart Grid” architecture team sponsored by the corporate Chief Technology Officer with sub-team lead responsibilities in the areas of Software and System Integration and Network and Systems Management. This team established a reference architecture for the company’s “Smart Grid” offerings, identified necessary changes in networks and product offerings, and recommended public policy positions concerning spectrum allocation by the FCC, security standards being developed by the North American Reliability Council, and interoperability standards being developed by the National Institute of Standards and Technology.
- Developed product proposals and requirements in the areas of residential energy management, commercial building energy management, advanced metering infrastructure, power distribution monitoring and control, power outage detection and restoration, energy market integration and trading platforms, utility customer portals and notification services, utility contact center voice application enablement, and critical infrastructure physical security.
- Lead solution architecture and proposal development for six utilities with solutions encompassing customer portal, advanced metering, outage management, security assessment, distribution automation, and comprehensive “Smart Grid” implementation.
- Presented Verizon’s “Smart Grid” capabilities to seventeen utilities.
- Presented “Role of Telecommunications Carriers in Smart Grid Implementation” to 2009 Mid-America Regulatory Conference.
- Presented “Smart Grid: Transforming the Electricity Supply Chain” to the 2009 World Energy Engineering Conference.
- Participant in NASPInet work groups of the North American Energy Reliability Corporation (NERC), developing specifications for a wide-area situational awareness network to facilitate the sharing and analysis of synchrophasor data amongst utilities in order to increase transmission reliability.
- Provided technical advice to account team concerning successful proposal to provide network services and information systems support for the California ISO, which coordinates power dispatch and intercompany power sales transactions for the California market.

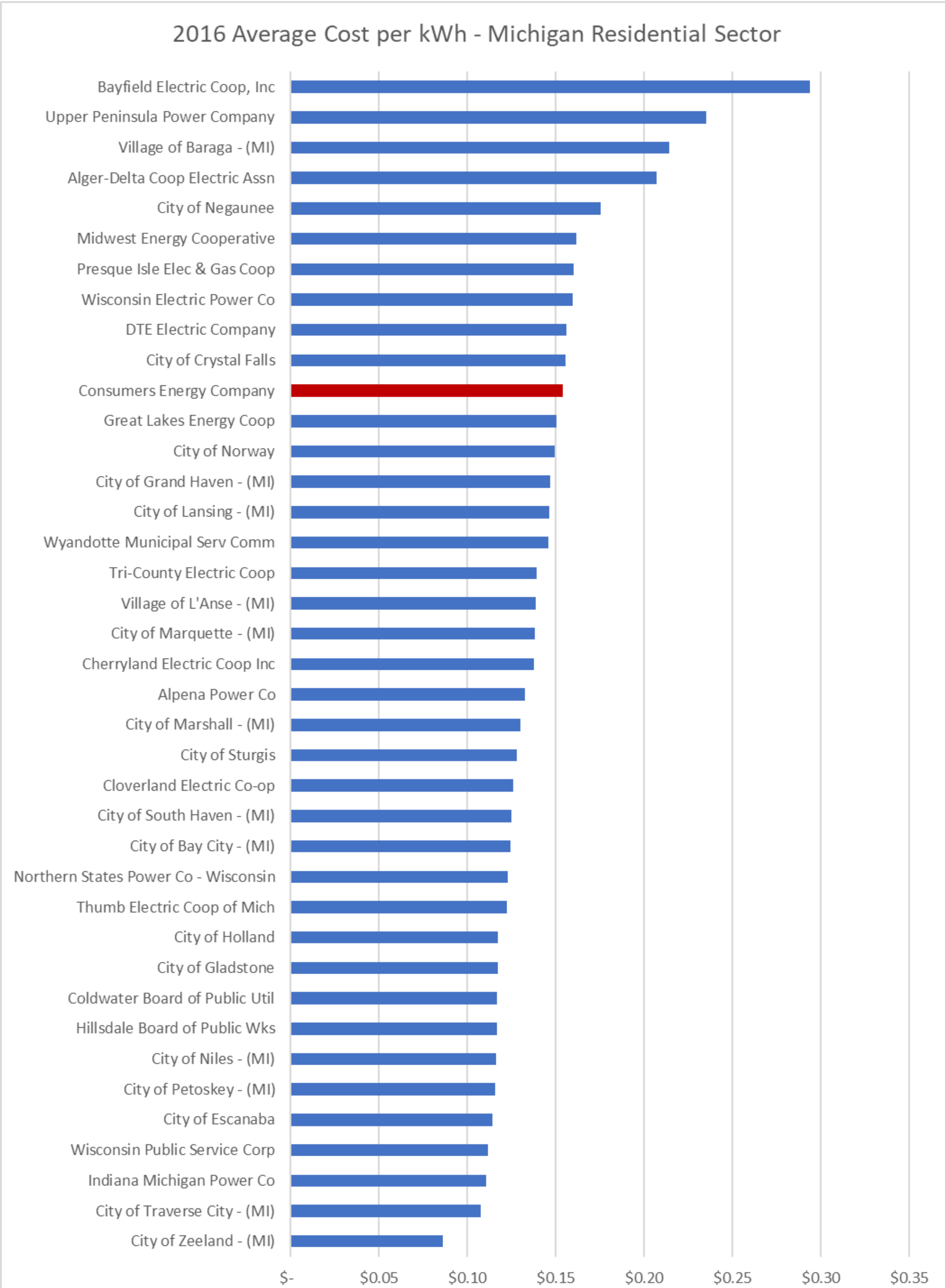
For Michigan Department of Natural Resources

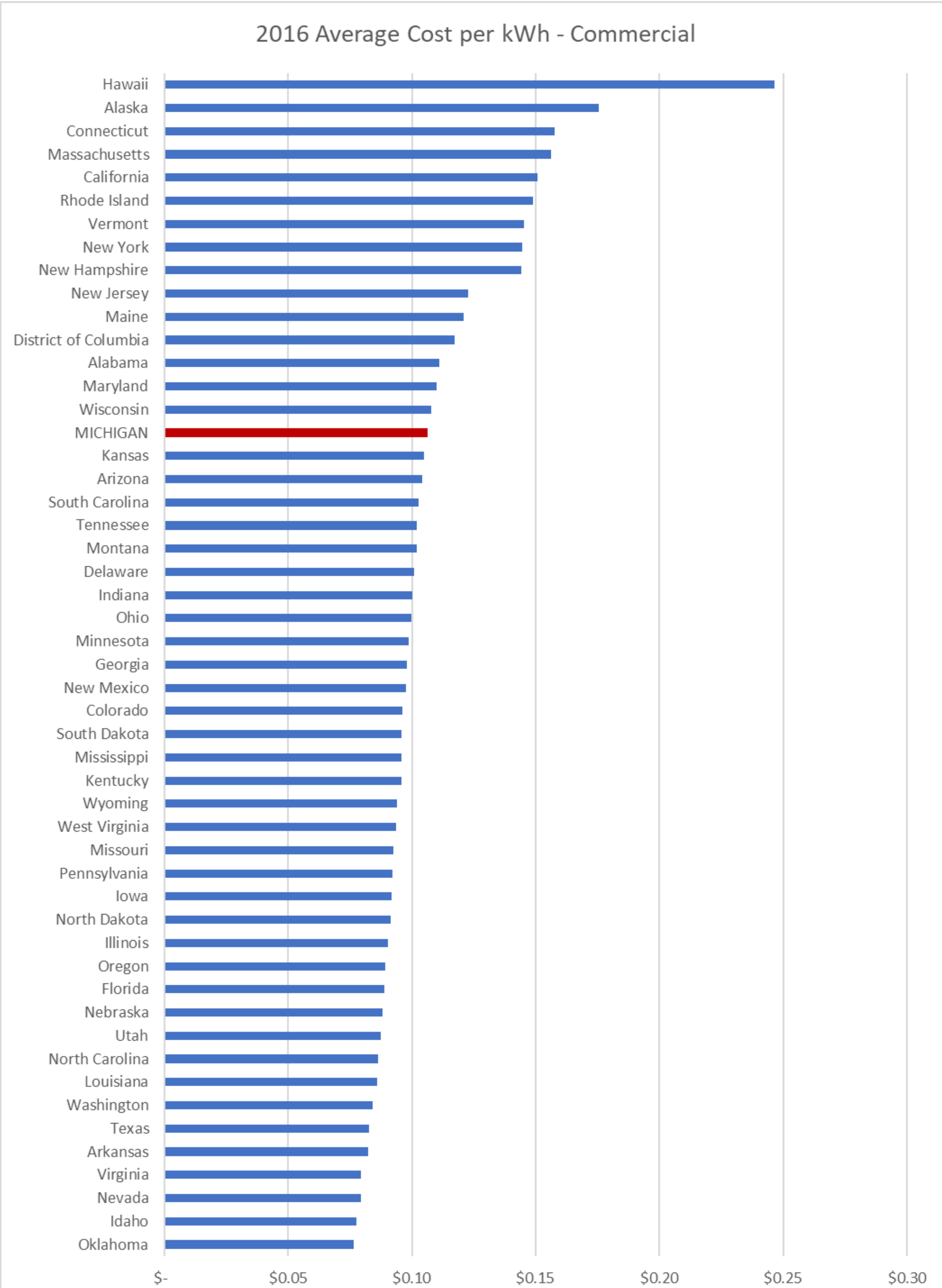
- Determined permit requirements under Section 316 of the Clean Water Act for all steam electric plants currently operating in the State of Michigan.
- Case manager and key witness for the State of Michigan in FERC, State court, and Federal court cases concerning economics and environmental impacts of the Ludington Pumped Storage Plant, which is the world’s largest pumped storage plant. A lead negotiator for the State in the ultimate settlement of this issue. The settlement was valued at $127 million in 1995 and included considerations of environmental mitigation, changes in power system dispatch rules, and damages compensation.
- Managed FERC license application reviews for the State of Michigan for all hydroelectric projects in Michigan as these came up for reissuance in 1970s and 1980s.
- Testified on behalf of the State of Michigan in contested cases before the Federal Energy Regulatory Commission concerning benefit-cost analyses and regulatory issues for four different hydroelectric dams in Michigan.
- Reviewed (as regulator) the environmental impacts and benefit-cost analyses of all major steam electric and most hydroelectric plants in the State of Michigan.
- Executive responsibility for development, maintenance, and operations of the State of Michigan’s information system for mineral (includes oil and gas) rights leasing, unitization and apportionment, and royalty collection.
- In cooperative project with Ontario Ministry of Natural Resources, participated in development of a simulation model of oil field development logistics and environmental impact on Canada’s Arctic slope for Tesoro Oil.

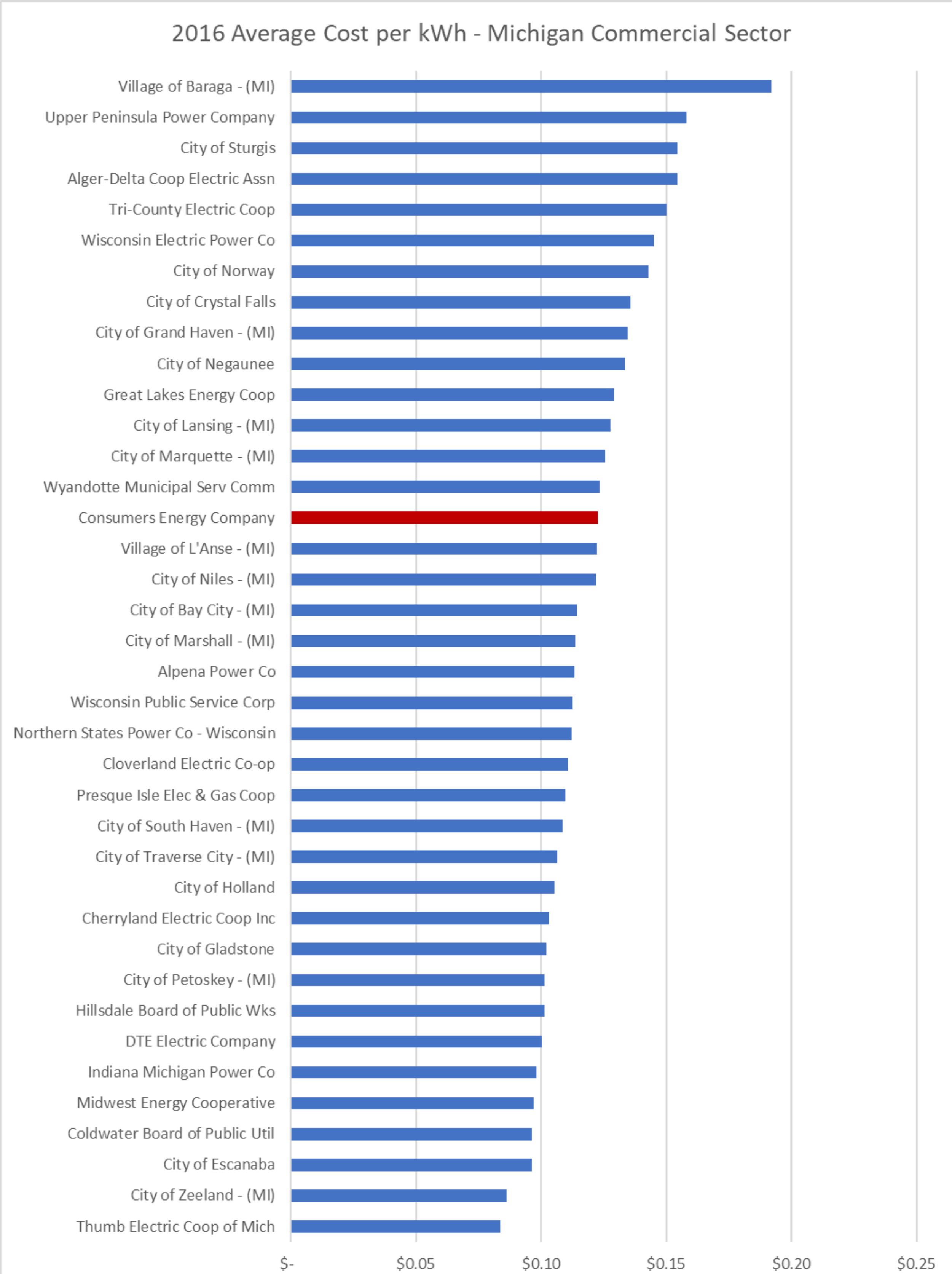
U-20134 Exhibit MEC-2
Page 1 of 15



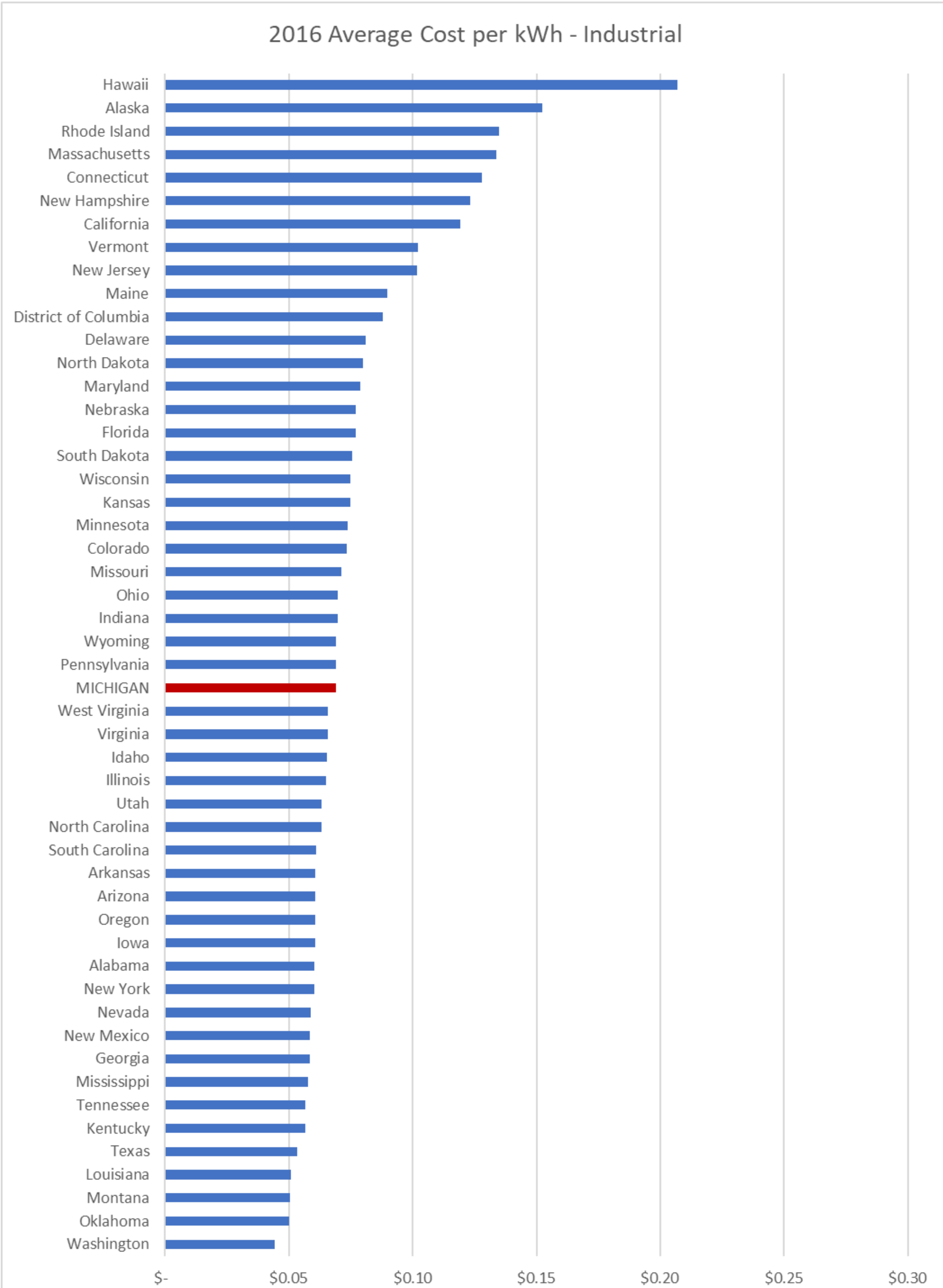
U-20134 Exhibit MEC-2
Page 2 of 15



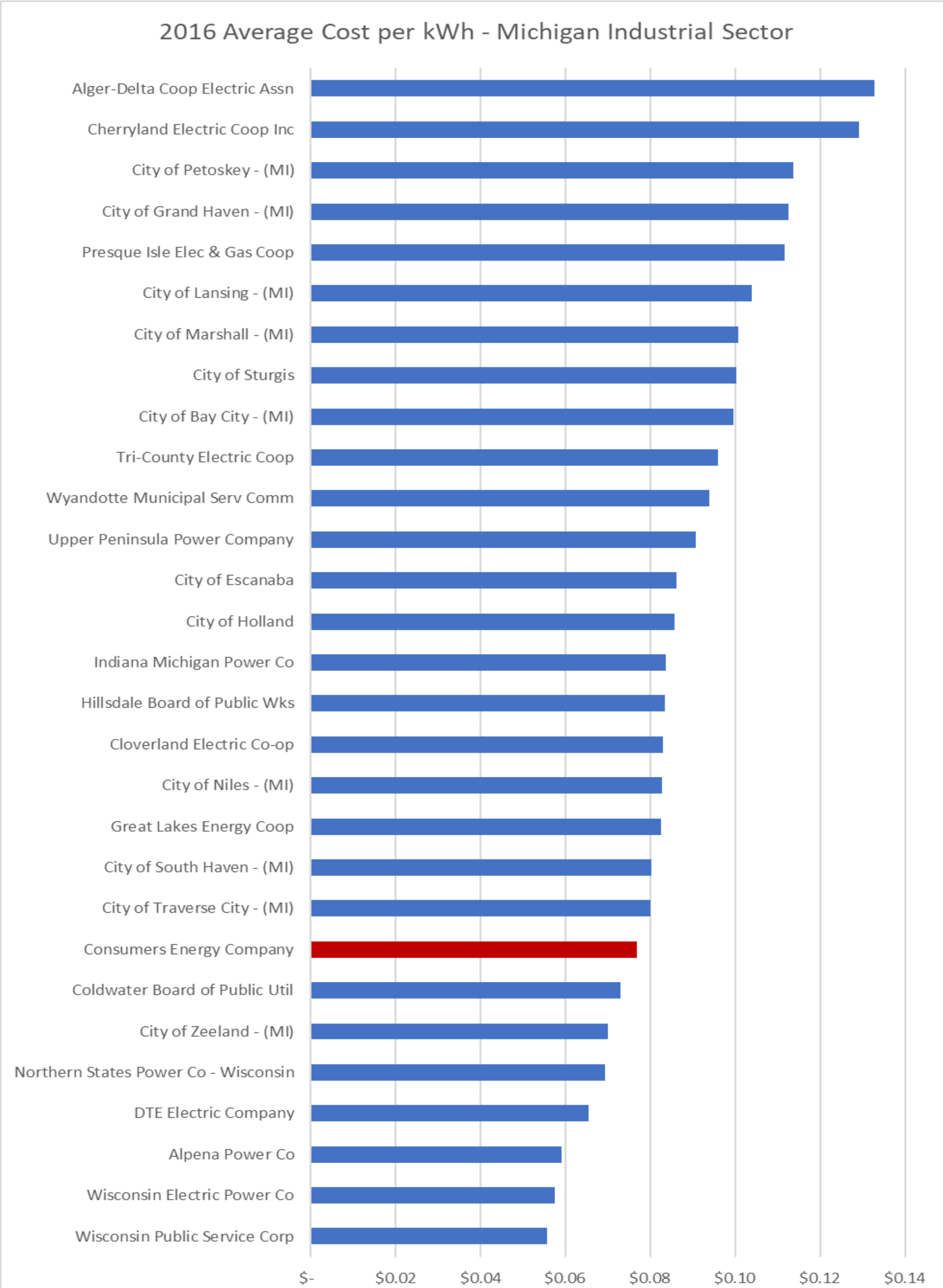

2016 Average Cost per kWh - Commercial
Hawaii
Alaska
Connecticut
Massachusetts
California
Rhode Island
Vermont
New York
New Hampshire
New Jersey
Maine
District of Columbia
Alabama
Maryland
Wisconsin
MICHIGAN
Kansas
Arizona
South Carolina
Tennessee
Montana
Delaware
Indiana
Ohio
Minnesota
Georgia
New Mexico
Colorado
South Dakota
Mississippi
Kentucky
Wyoming
West Virginia
Missouri
Pennsylvania
Iowa
North Dakota
Illinois
Oregon
Florida
Nebraska
Utah
North Carolina
Louisiana
Washington
Texas
Arkansas
Virginia
Nevada
Idaho
Oklahoma
$-
$0.05
$0.10
$0.15
$0.20
$0.25
$0.30

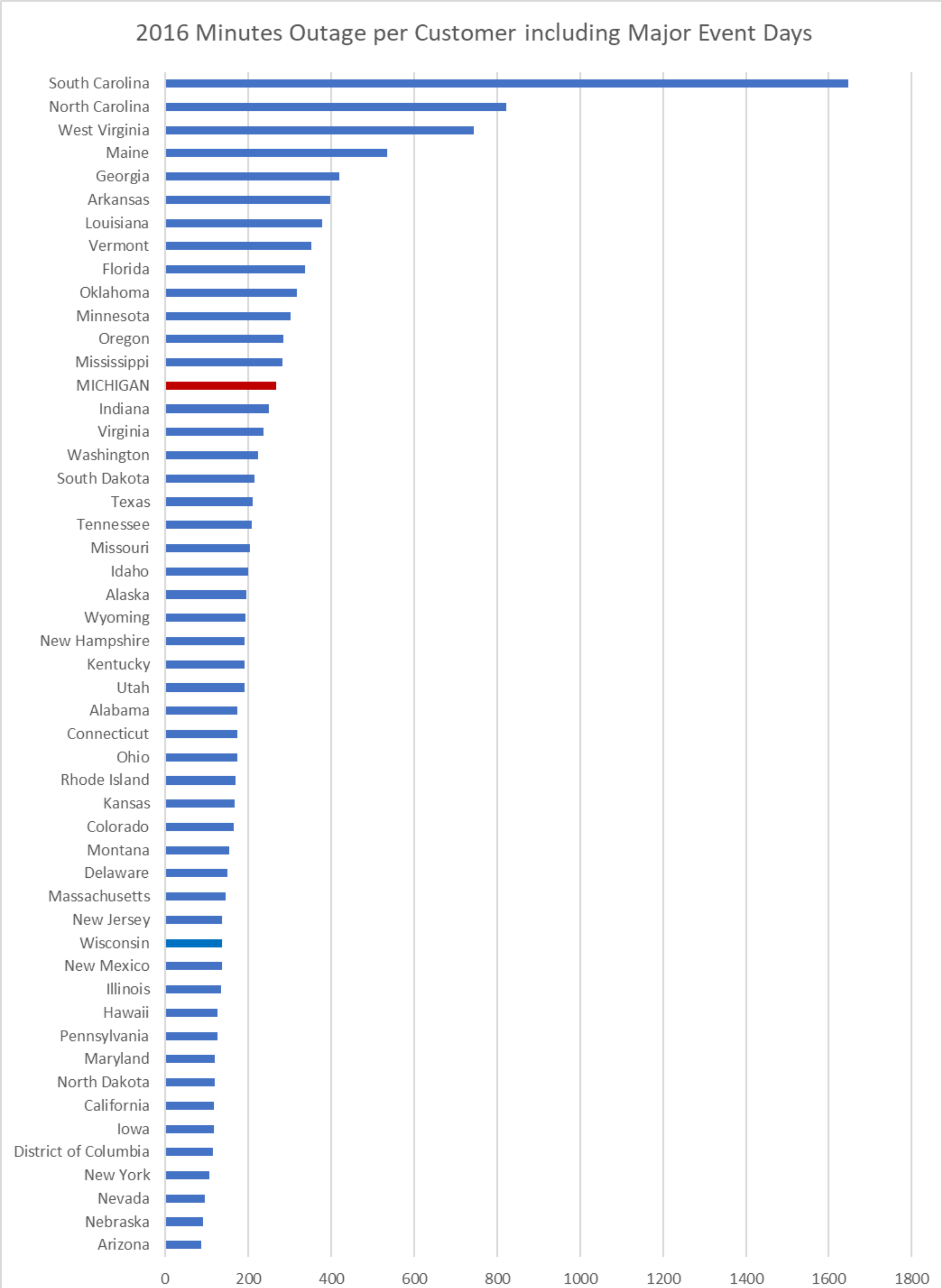

2016 Average Cost per kWh - Michigan Commercial Sector
Village of Baraga - (MI)
Upper Peninsula Power Company
City of Sturgis
Alger-Delta Coop Electric Assn
Tri-County Electric Coop
Wisconsin Electric Power Co
City of Norway
City of Crystal Falls
City of Grand Haven - (MI)
City of Negaunee
Great Lakes Energy Coop
City of Lansing - (MI)
City of Marquette - (MI)
Wyandotte Municipal Serv Comm
Consumers Energy Company
Village of L'Anse - (MI)
City of Niles - (MI)
City of Bay City - (MI)
City of Marshall - (MI)
Alpena Power Co
Wisconsin Public Service Corp
Northern States Power Co - Wisconsin
Cloverland Electric Co-op
Presque Isle Elec & Gas Coop
City of South Haven - (MI)
City of Traverse City - (MI)
City of Holland
Cherryland Electric Coop Inc
City of Gladstone
City of Petoskey - (MI)
Hillsdale Board of Public Wks
DTE Electric Company
Indiana Michigan Power Co
Midwest Energy Cooperative
Coldwater Board of Public Util
City of Escanaba
City of Zeeland - (MI)
Thumb Electric Coop of Mich
$-
$0.05
$0.10
$0.15
$0.20
$0.25

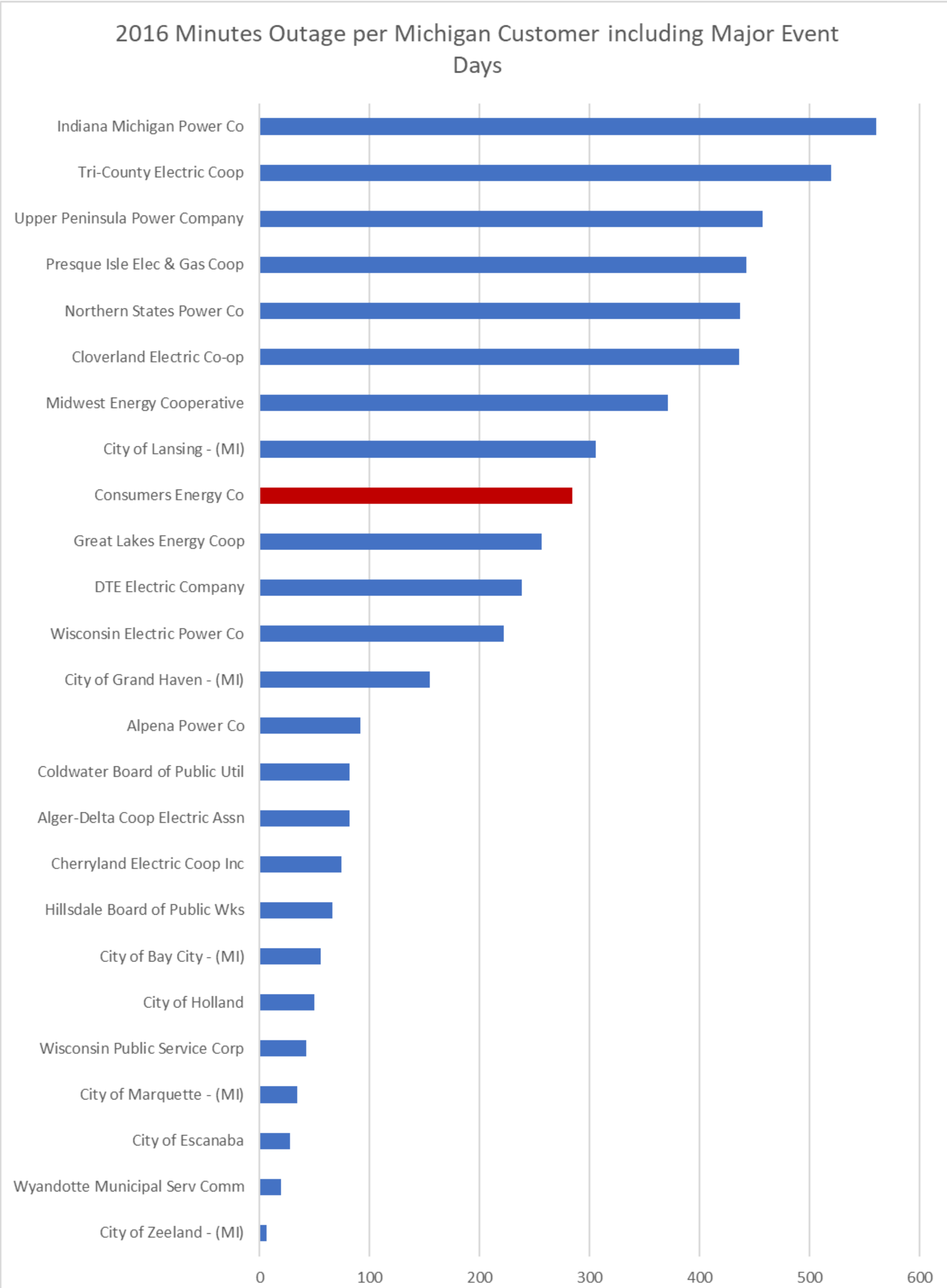
U-20134 Exhibit MEC-2
Page 5 of 15



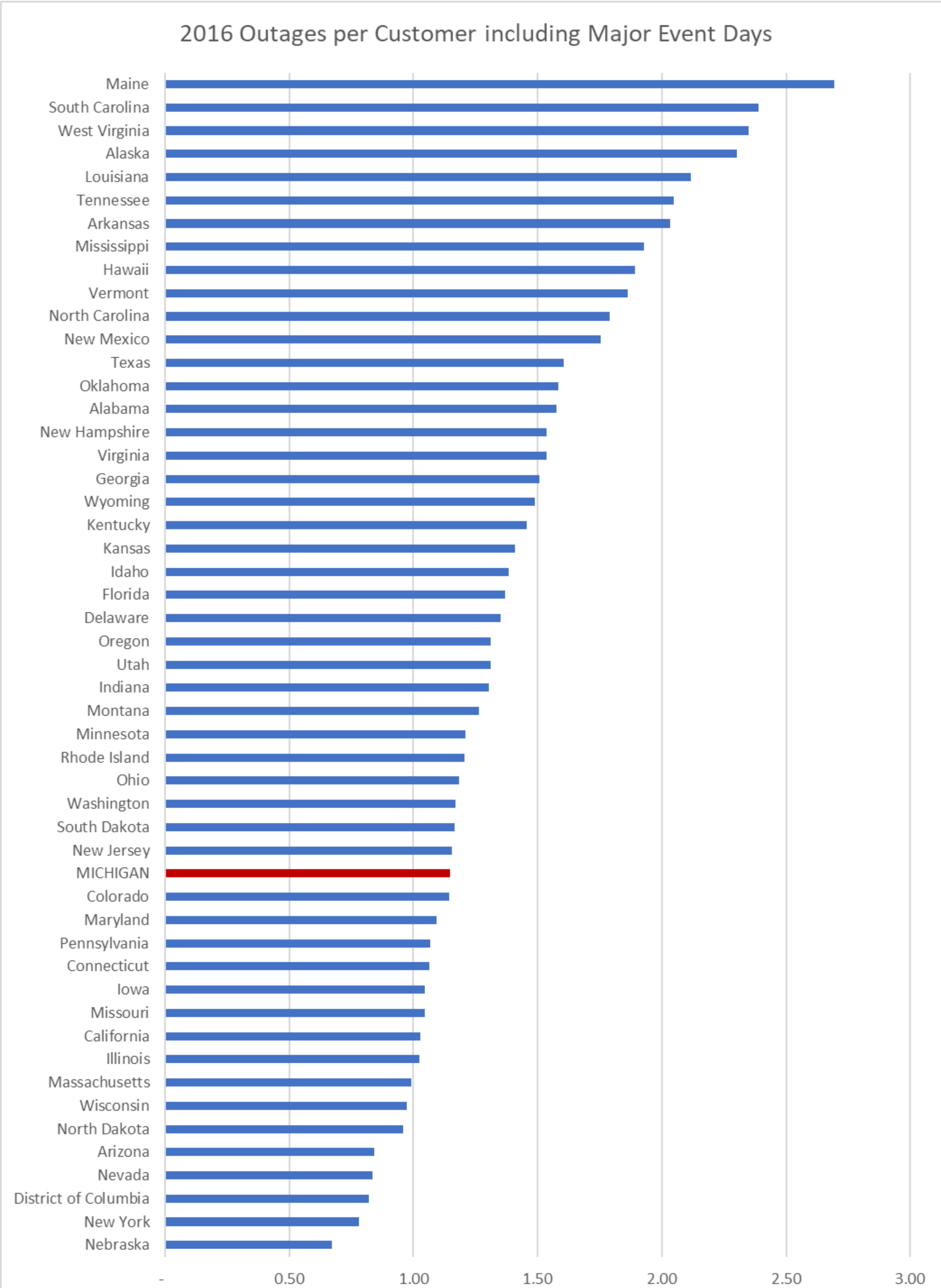
U-20134 Exhibit MEC-2
Page 6 of 15

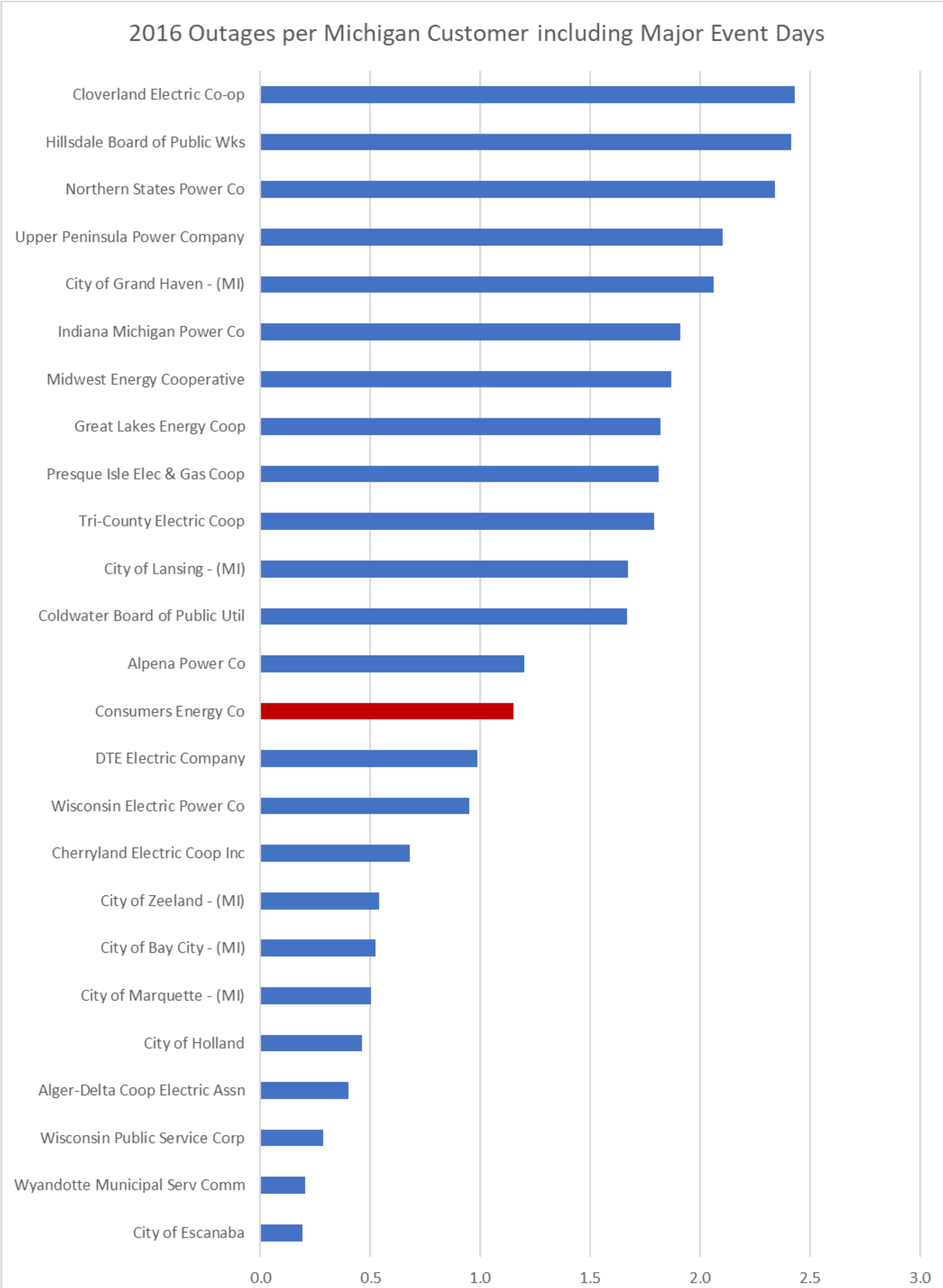


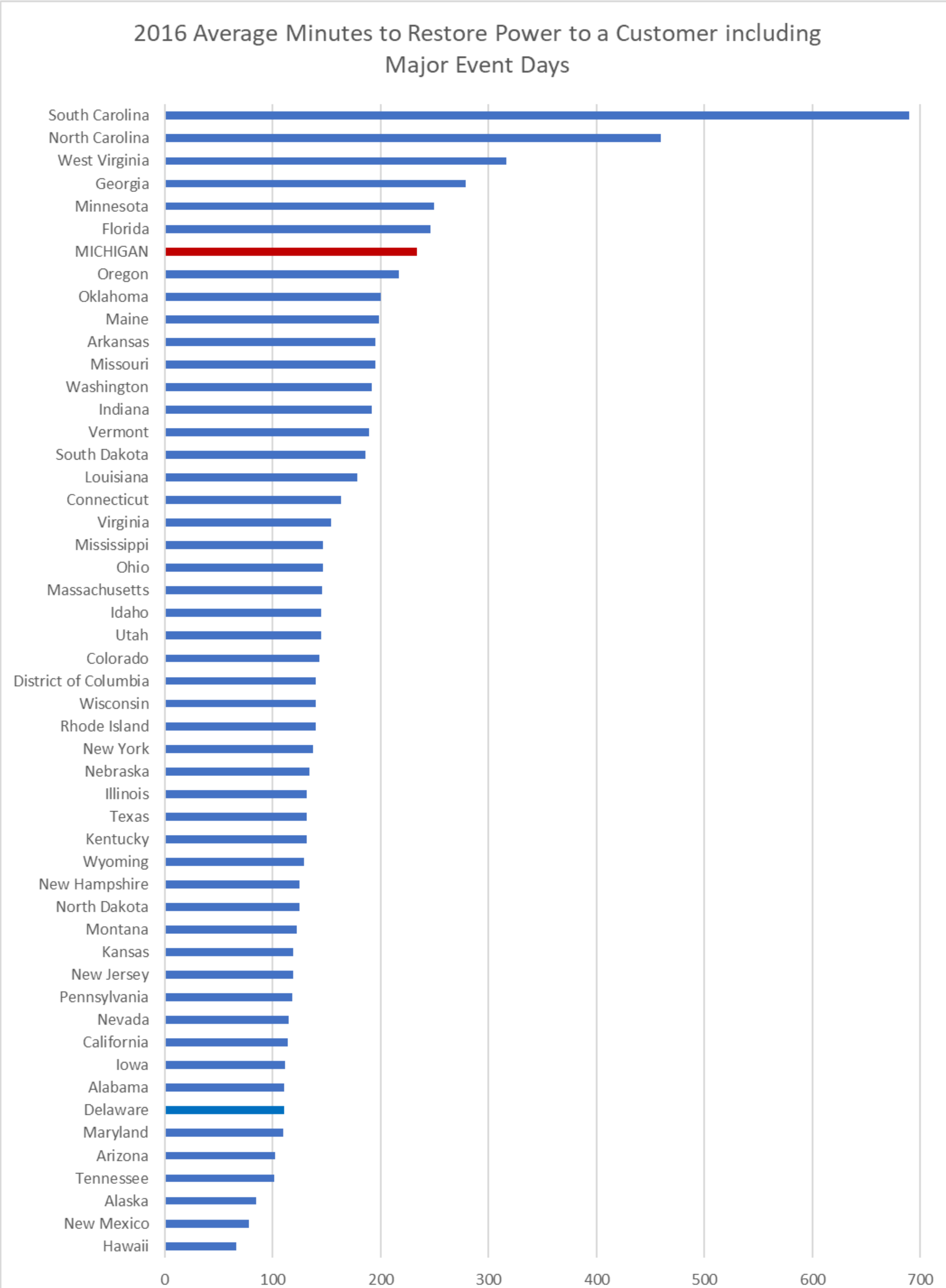

2016 Minutes Outage per Customer including Major Event Days
South Carolina
North Carolina
West Virginia
Maine
Georgia
Arkansas
Louisiana
Vermont
Florida
Oklahoma
Minnesota
Oregon
Mississippi
MICHIGAN
Indiana
Virginia
Washington
South Dakota
Texas
Tennessee
Missouri
Idaho
Alaska
Wyoming
New Hampshire
Kentucky
Utah
Alabama
Connecticut
Ohio
Rhode Island
Kansas
Colorado
Montana
Delaware
Massachusetts
New Jersey
Wisconsin
New Mexico
Illinois
Hawaii
Pennsylvania
Maryland
North Dakota
California
Iowa
District of Columbia
New York
Nevada
Nebraska
Arizona
0
200
400
600
800
1000
1200
1400
1600
1800


2016 Minutes Outage per Michigan Customer including Major Event Days
Indiana Michigan Power Co
Tri-County Electric Coop
Upper Peninsula Power Company
Presque Isle Elec & Gas Coop
Northern States Power Co
Cloverland Electric Co-op
Midwest Energy Cooperative
City of Lansing - (MI)
Consumers Energy Co
Great Lakes Energy Coop
DTE Electric Company
Wisconsin Electric Power Co
City of Grand Haven - (MI)
Alpena Power Co
Coldwater Board of Public Util
Alger-Delta Coop Electric Assn
Cherryland Electric Coop Inc
Hillsdale Board of Public Wks
City of Bay City - (MI)
City of Holland
Wisconsin Public Service Corp
City of Marquette - (MI)
City of Escanaba
Wyandotte Municipal Serv Comm
City of Zeeland - (MI)
0
100
200
300
400
500
600

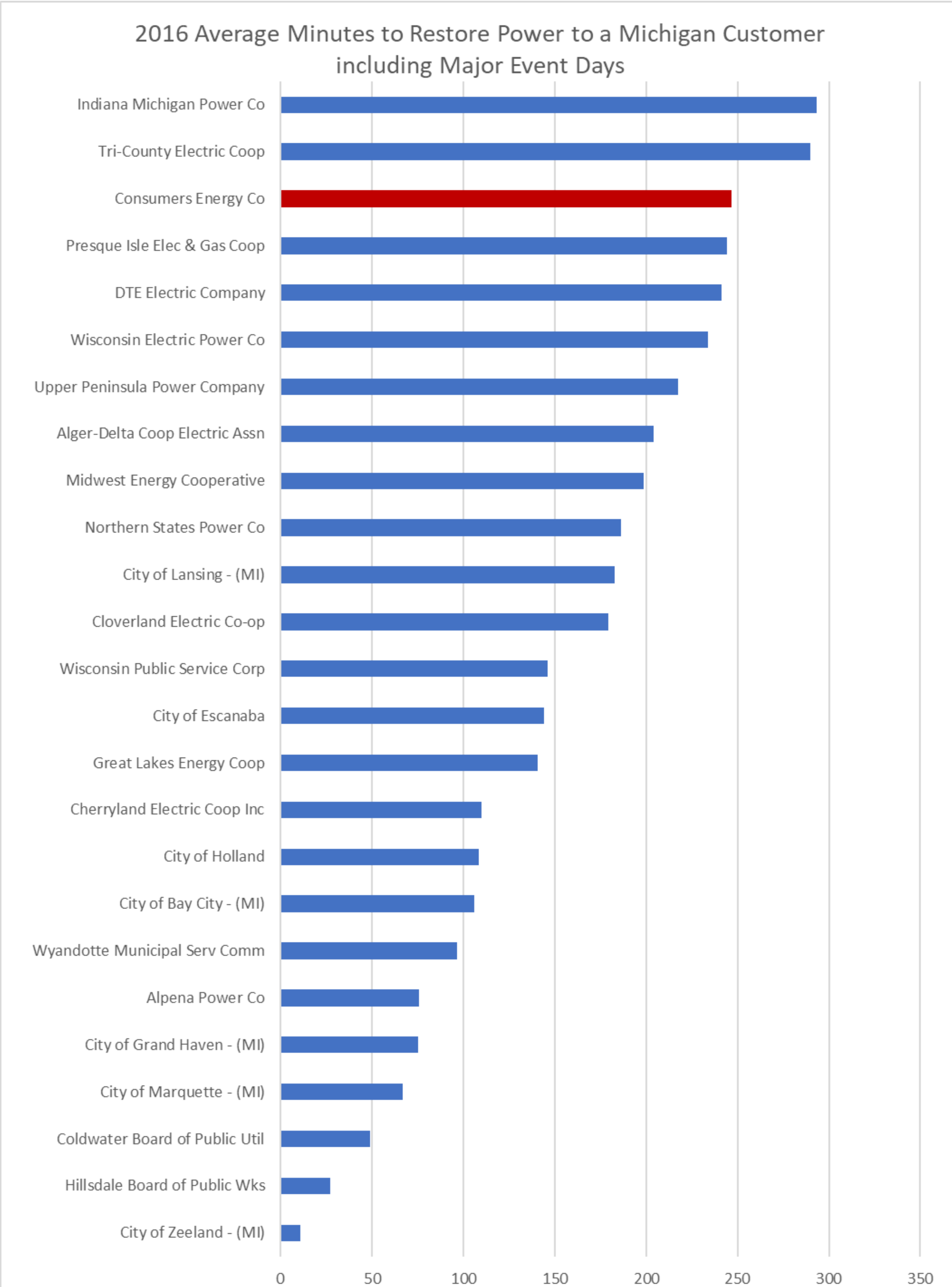
U-20134 Exhibit MEC-2
Page 9 of 15



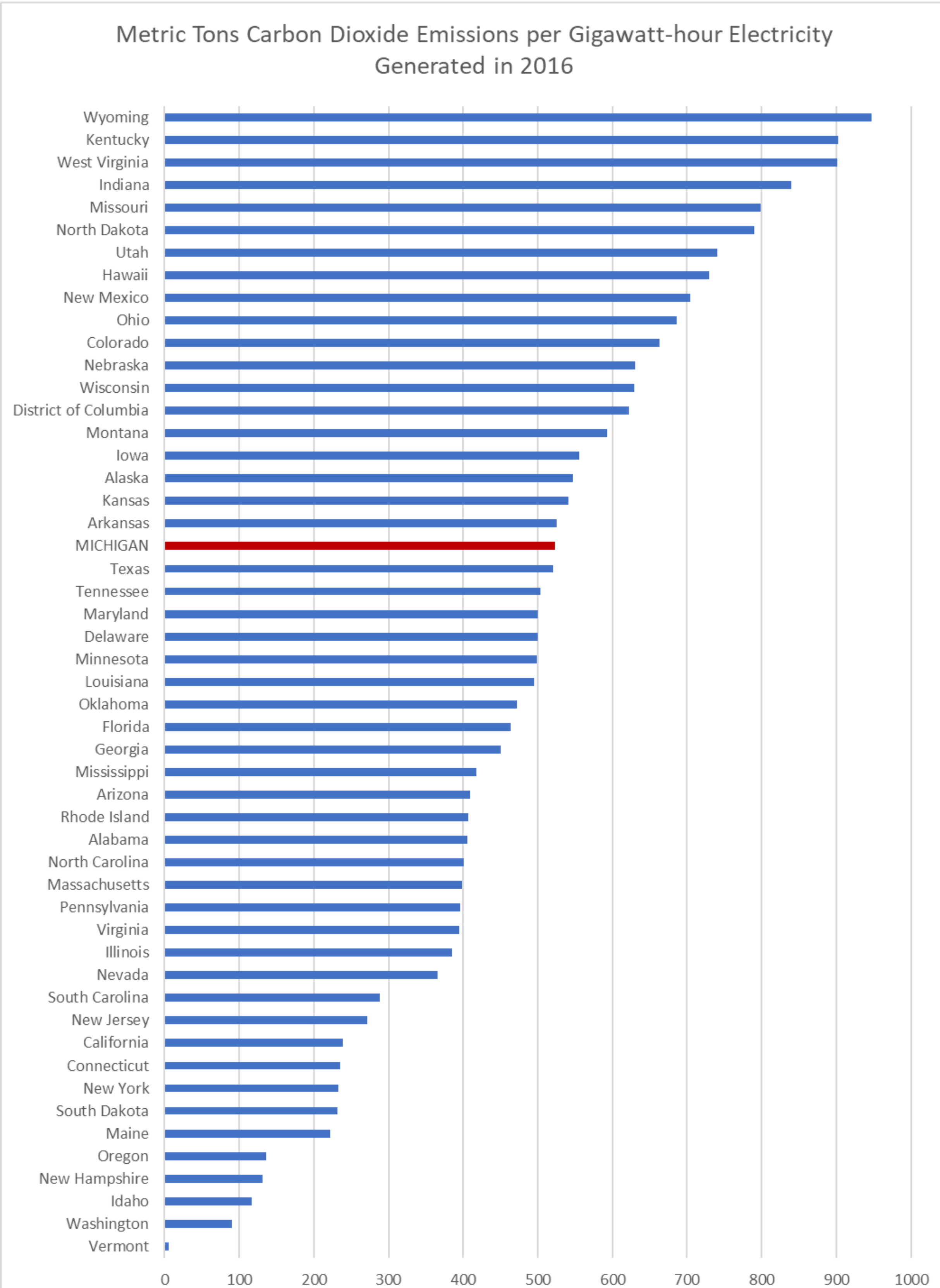

2016 Outages per Michigan Customer including Major Event Days
Cloverland Electric Co-op
Hillsdale Board of Public Wks
Northern States Power Co
Upper Peninsula Power Company
City of Grand Haven - (MI)
Indiana Michigan Power Co
Midwest Energy Cooperative
Great Lakes Energy Coop
Presque Isle Elec & Gas Coop
Tri-County Electric Coop
City of Lansing - (MI)
Coldwater Board of Public Util
Alpena Power Co
Consumers Energy Co
DTE Electric Company
Wisconsin Electric Power Co
Cherryland Electric Coop Inc
City of Zeeland - (MI)
City of Bay City - (MI)
City of Marquette - (MI)
City of Holland
Alger-Delta Coop Electric Assn
Wisconsin Public Service Corp
Wyandotte Municipal Serv Comm
City of Escanaba
0.0
0.5
1.0
1.5
2.0
2.5
3.0


2016 Average Minutes to Restore Power to a Customer including Major Event Days
South Carolina
North Carolina
West Virginia
Georgia
Minnesota
Florida
MICHIGAN
Oregon
Oklahoma
Maine
Arkansas
Missouri
Washington
Indiana
Vermont
South Dakota
Louisiana
Connecticut
Virginia
Mississippi
Ohio
Massachusetts
Idaho
Utah
Colorado
District of Columbia
Wisconsin
Rhode Island
New York
Nebraska
Illinois
Texas
Kentucky
Wyoming
New Hampshire
North Dakota
Montana
Kansas
New Jersey
Pennsylvania
Nevada
California
Iowa
Alabama
Delaware
Maryland
Arizona
Tennessee
Alaska
New Mexico
Hawaii
0
100
200
300
400
500
600
700

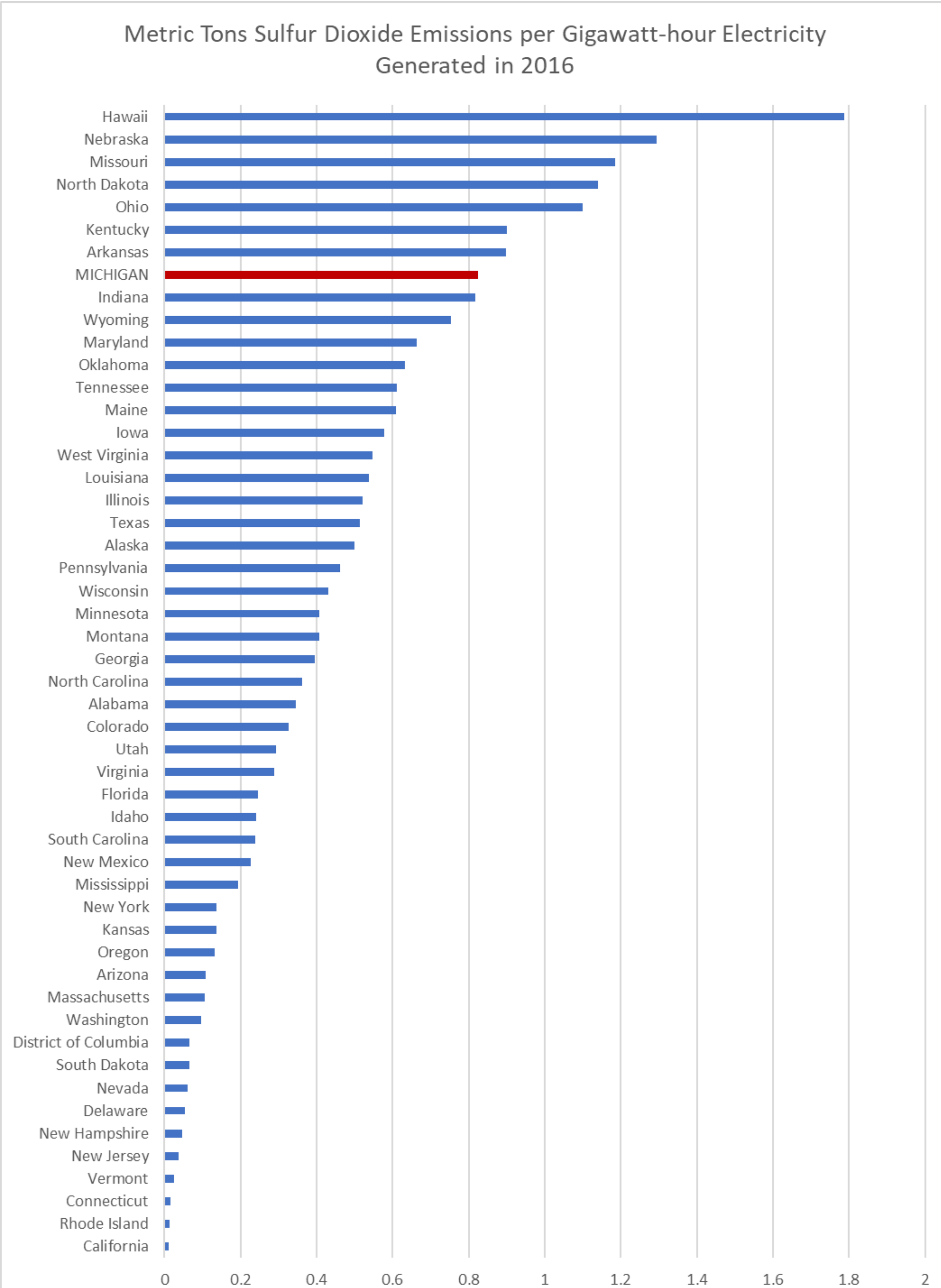
U-20134 Exhibit MEC-2
Page 12 of 15



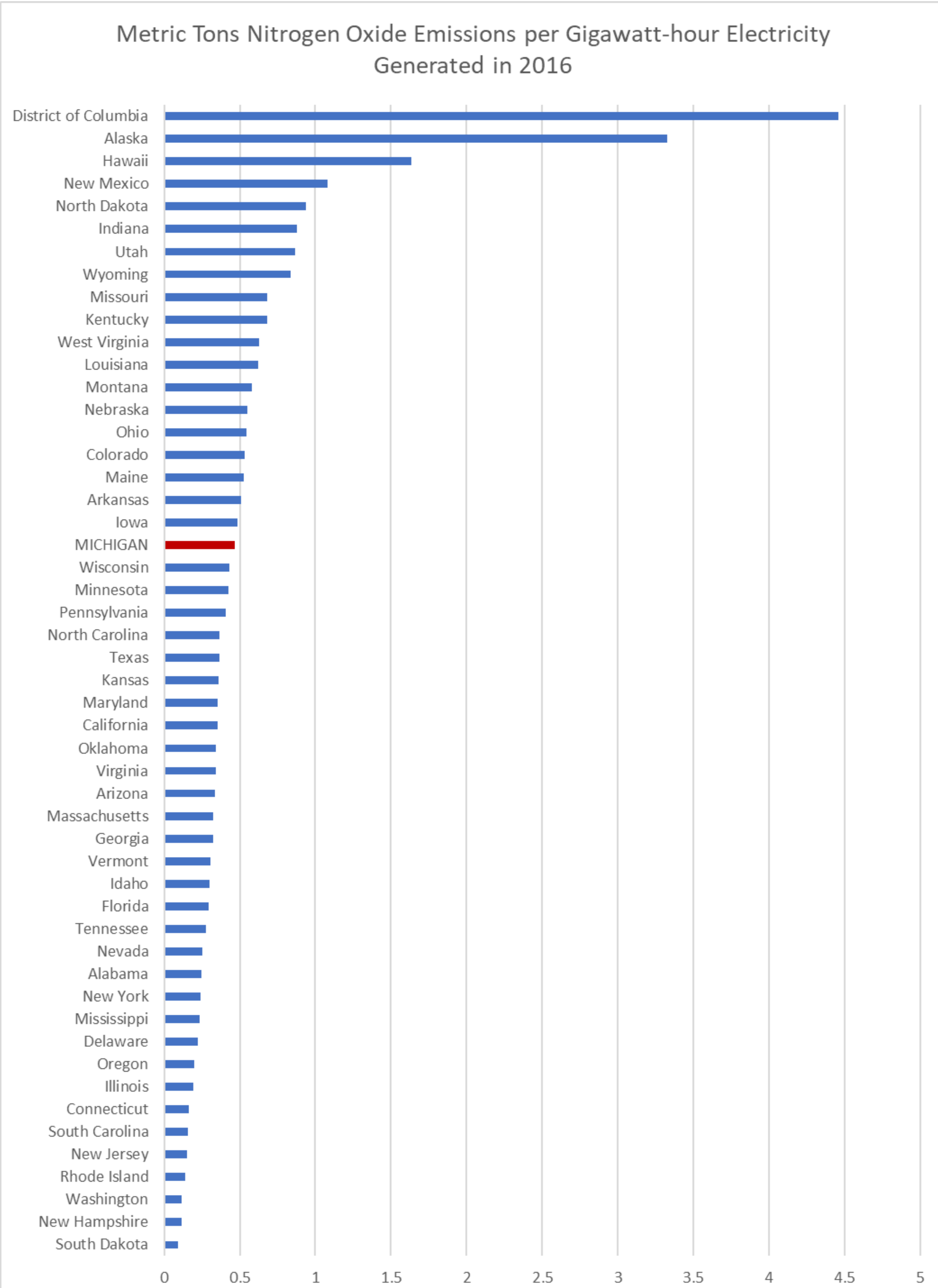
U-20134 Exhibit MEC-2
Page 13 of 15



U-20134 Exhibit MEC-2
Page 14 of 15



U-20134 Exhibit MEC-2
Page 15 of 15



20134-MEC-CE-150

Question:

1. Provide a copy of the Company's annual report pursuant to Administrative Rule 460.732 for calendar year 2017.

Response:

Attached, please find Consumers Energy's 2017 Annual Report.

(NOTE: Attached are numbered documents 13400250 through 13400262.)

Provided by Counsel, July 2018

Consumers Energy
Count on Us

A CMS Energy Company

General Offices:
One Energy Plaza Tel: (517) 788-0550
Jackson, MI 49201 Fax: (517) 768-3644

*Washington Office:
1730 Rhode Island Ave. N.W. Tel: (202) 778-3340
Suite 1007
Washington, DC 20036 Fax: (202) 778-3355

Writer's Direct Dial Number: (517) 788-2112
Writer's E-mail Address: anne.uitvlugt@cmsenergy.com

March 14, 2018

Ms. Kavita Kale
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

Re: MPSC Case No. U-12270 – In the matter, on the Commission's own motion, of the investigation into methods to improve the reliability of electric service in Michigan.

Dear Ms. Kale:

Pursuant to the Commission's December 20, 2001 Order in Case No. U-12270, enclosed for electronic filing in the above-captioned case, please find **Consumers Energy Company's January 1, 2017 Through December 31, 2017 Report To The Michigan Public Service Commission Regarding Electric Distribution System Performance Standards.**

This is a paperless filing and is therefore being filed only in PDF. I have enclosed a Proof of Service showing electronic and hard copy service upon the parties.

Sincerely,

Anne M. Uitvlugt

Digitally signed by
Anne M. Uitvlugt
Date: 2018.03.14
14:06:13 -04'00'

Anne M. Uitvlugt

cc: Parties per Attachment 1 to Proof of Service

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion,) of the investigation into methods to improve the) reliability of electric service in Michigan))	Case No. U-12270

CONSUMERS ENERGY COMPANY'S JANUARY 1, 2017 THROUGH DECEMBER 31, 2017 REPORT TO THE MICHIGAN PUBLIC SERVICE COMMISSION REGARDING ELECTRIC DISTRIBUTION SYSTEM PERFORMANCE STANDARDS

I. BACKGROUND

On November 25, 2003, the Michigan Public Service Commission ("MPSC" or the "Commission") issued an Order Approving Administrative Rules in Case No. U-12270, in which it directed all electric utilities under its jurisdiction to begin collecting data as of January 1, 2004, relative to Service Quality and Reliability Standards for Electric Distribution Systems. Part 3 of the Standards (Records and Reports) requires that electric utilities file an annual report containing the utilities' actual performance against these 11 standards and other related data. This report contains Consumers Energy Company's ("Consumers Energy" or the "Company") January 1, 2017 through December 31, 2017 results and compliance status per those requirements.

II. SUMMARY OF PERFORMANCE

Consumers Energy met 10 of the 11 Performance Standards for the time period of January 1, 2017 through December 31, 2017. Our actual performance relative to R 460.732, Rule 32, subparts (a) through (j) and (l) through (n), is summarized below.

Distribution Performance Standards Results
For The Calendar Year 2017

	Standard Definition	Standard	Actual Performance	In Compliance
(a)	Call Blockage Factor % of customer phone calls that are blocked	< 5%	0.04%	**YES**
(b)	Complaint Response Factor % of complaints responded to within 3 business days	> 90%	94.1%	**YES**
(c)	Average Customer Call Answer Time Average time to answer a customer call	< 90 sec	24 sec	**YES**
(d)	Meter Reading Factor % of meters read within approved period	> 85%	99.4%	**YES**
(e)	New Service Installation Factor % of services installed within 15 business days	> 90%	92.5%	**YES**
(f)	Wire down Relief Factor % of police/fire-guarded wire downs relieved in 4 hours or less within Major Metropolitan Statistical Area ("MMSA")	> 90%	86.7%	**NO**
	% of police/fire-guarded wire downs relieved in 6 hours or less outside MMSA	> 90%	93.2%	**YES**
(g)	Service Restoration Factor for All Conditions % of customers restored in 36 hours or less	> 90%	95.6%	**YES**
(h)	Service Restoration Factor for Normal Conditions % of customers restored in 8 hours or less	> 90%	90.8%	**YES**
(i)	Service Restoration Factor for Catastrophic Conditions % of customers restored in 60 hours or less	> 90%	93.1%	**YES**
(j)	Same-circuit Repetitive Interruption Factor % of customers with 5 or more interruptions in a 12-month period.	< 5%	4.2%	**YES**

It should be noted that performance improved over 2016 results for four standards:

- Complaint Response Factor;
- Average Customer Call Answer Time;

- Meter Reading Factor; and
- Service Restoration Factor for Normal Conditions restored in 8 hours or less.

III. CUSTOMER CREDITS

Customer credits paid during 2017 are summarized in the following table per R 460.732, subparts (l) through (n):

(l) Catastrophic Outage Credits Paid

Customer Class	Total Number	Total Dollar Amount
Residential	106	$ 2,650.00
Commercial	2	$ 1.34
Industrial	0	$ 0.00
Total Catastrophic	108	$ 2,651.34

(m) Normal Outage Credits Paid

Customer Class	Total Number	Total Dollar Amount
Residential	186	$ 4,650.00
Commercial	11	$ 7.83
Industrial	0	$ 0.00
Total Normal	197	$ 4,657.83

(n) Repetitive Outage Credits Paid

Customer Class	Total Number	Total Dollar Amount
Residential	19	$ 475.00
Commercial	1	$ 1.33
Industrial	0	$ 0.00
Total Repetitive	20	$ 476.33
Company Total	325	$ 7,785.50

By comparison, customer credits paid in 2016 totaled $9,856.69. There is a small decrease in outage credits in 2017 even though there were two catastrophic storms in comparison to zero catastrophic storms in 2016. Consumers Energy continues to communicate the Outage Credit Program to customers each year through mailer inserts in bill statements.

IV. CATASTROPHIC STORMS

A description of all catastrophic conditions per R 760.732, subpart (k), is summarized below.

"Catastrophic conditions," as defined in the MPSC Performance Standards, means either severe weather conditions that result in service interruptions for 10% or more of a utility's customers, or events of sufficient magnitude that result in issuance of an official state of emergency declaration by the local, state, or federal government.

During 2017, two catastrophic storms occurred on the Consumers Energy system, compared with zero events in 2016. On March 7, a strong wind event occurred in mostly western and northern Michigan largely associated with showers and thunderstorms along and ahead of the cold front. On the evening of March 7, a secondary period of strong wind gusts occurred as a result of showers helping mix strong winds to the surface. On March 8, a widespread damaging wind event occurred across all of Lower Michigan with straight line gusts in excess of 50 to 65 miles per hour lasting over 6 hours during that day. The overall event lasted for over 30 hours across the entire state with the severe weather near tropical storm strength. This resulted in approximately 358,000 customers being interrupted, 5,900 wire down hazards, and 790 broken poles with the hardest hit areas of Allegan, Barry, Calhoun, Genesee, Ionia, Jackson, Kalamazoo, Kent, Lenawee, and Saginaw counties. The storm was ranked as the 15th most customer outages in the Company's 130-year history and was an all-time combined record for Michigan residents. For a more detailed write up of this catastrophic storm and the Company's response, refer to Case No. U-18346. Consumers Energy was recognized by the Edison Electric Institute for safe and quick response to this catastrophic storm by receiving the Emergency Recovery Award.

On the afternoon of July 6, a trough developed across northern Michigan helping trigger an initial round of severe thunderstorms affecting the Consumers Energy service territory and lasting into the morning hours of July 7. This event contained multiple waves of storms with the most widespread impacts occurring during the overnight hours in a band stretching from Grand Haven to Eaton Rapids. This resulted in approximately 182,000 customers being interrupted with over 2,500 wire down hazards and 140 broken poles. The service restoration factor for catastrophic conditions was met with the final value of 93.1% for both 2017 events.

The tabulated data for these events is shown below.

Event Dates	Number of Interruptions	Total Customers Interrupted
March 7-13	6,245	357,695
July 6-10	2,565	181,620

V. GENERAL WEATHER CONDITIONS

In 2017, the frequency and magnitude of weather events impacting the Company's service territory was mixed. When compared to 2016, the number of severe thunderstorm and tornado warnings issued by the Detroit, Grand Rapids, and Gaylord weather forecast offices decreased by 18%. The number of cloud-to-ground lightning strikes recorded across the Lower Peninsula decreased by 7%. But, the number of hourly surface observations of freezing precipitation increased by 43%. When compared to the averages over the preceding five years, the number of warnings, strikes, and freezing precipitation observations in 2017 were down by 44%, 7%, and 35%, respectively.

However, on March 8, 2017, a large storm with a low pressure typical of a category 2 hurricane passed through southern Canada. The system brought high winds to Michigan, with multiple locations reporting gusts in excess of 60 mph. The gusts were not associated with a line of intense thunderstorms and, unlike a line of storms, strong winds covered the entire Lower Peninsula and were sustained over a period of several hours.

On July 7, 2017, a severe storm system moved through the southwest part of the state, impacting an area nearly 100 miles long by 30 miles wide. Counties with the greatest storm impact were Muskegon, Ottawa, Kent, Allegan, Barry, and Eaton.

Comparing 2016 to 2017, the number of customers requiring restoration increased from 2,079,416 to 2,372,256, an increase of 14%, which was heavily influenced by the two catastrophic events in 2017. 539,315 customers were attributed to the two catastrophic events discussed above. These customers represent approximately 23% of the 2,372,256 customers requiring restoration in 2017. The number of total wire downs increased from 21,399 to 27,157, an increase of 21%.

VI. 2017 – WIRE DOWN RELIEF FACTOR (OUTSIDE AND INSIDE MMSA) – SUCCESS AND FUTURE OPPORTUNITY

Public safety is Consumers Energy's number one priority, and success in this area can be attributed to continuous standardization and improvement in the wire down process. In 2017, Consumers Energy was successful in meeting the standard of above 90% for Wire Down Relief Factor (% of police/fire-guarded wire downs relieved in six hours or less outside MMSA) with a 93.2% response, even with two catastrophic storm events.

Unfortunately, the Company did not meet the same standard of above 90% for Wire Down Relief Factor (% of police/fire-guarded wire downs relieved in four hours or less inside MMSA), finishing the year with 86.7%. The catastrophic event of March adversely impacted response percentage, by removing results for wire downs incurred during that storm, the year-end results increase to 93.6%, which would have met the standard.

Consumers Energy's storm process continues to place its highest priority on responding to wire down calls during emergencies. During peak volumes of interruption and wire down calls, our priority is to protect the public and employees – safety is paramount. As specified in R460.732, Rule 32, subpart (f), Consumers Energy is submitting the following plan to bring Wire Down Relief Factor (% of police/fire-guarded wire downs relieved in four hours or less inside MMSA) performance above standard:

- Complete end-to-end wire down process mapping to identify gaps and resolve high impact items;
- Develop key performance indicator tree to understand the longest time component of the wire down process;
- Conduct daily operating review for wire down metrics, understand causes for missed jobs, and conduct problem solving to improve performance;
- Continue certification process to ensure sufficiently trained levels of office and field resources;
- As part of the certification process, equip all certified wire down resources with material kits, which are necessary for performing duties in the field;
- Enhance existing wire down resource management system to provide wire down resource deficiency calculation during restoration events;
- Enhance pre-planning efforts by developing storm and resource models based on weather impact; and
- Operationalize Wire Down Task Force processes, following the Incident Command System methodology.

VII. IMPROVED PERFORMANCE FOR 2017 – SERVICE RESTORATION FACTOR FOR NORMAL CONDITIONS

For 2017, the Service Restoration Factor for Normal Conditions (% of customers restored in eight hours or less) was 90.8%, which was above the 2016 performance of 88.4%, as well as the standard of 90%. Even though the standard was met in 2017, Consumers Energy continues to improve service restoration processes with the following tactics:

- Establishing a cross-functional task force consisting of line workers, dispatchers, schedulers, engineers, and restoration management employees to focus on service restoration improvements;

- Investigating equipment that can be used to temporarily restore power to customers during underground cable fault outages, while the crews work on permanent repairs;

- Evaluating temporary repair solutions for broken poles to restore power to customers while Miss Dig marks the premise and crews deliver a pole for replacement;

- Parallel dispatching Electric Service Workers and Line Crews to large customer outages to perform patrol faster and proactively identify material needs onsite;

- Establish troubleshooting training for Electric Service Workers to teach best practices;

- Continuing to improve the load transfer process to sectionalize and restore customers where transfer capability exists;

- Completing targeted investments in electric system infrastructure upgrades and line clearing to minimize the potential for outages during storms;

- Leveraging Distribution Supervisory Control and Data Acquisition remote operations and enhancing infrastructure resilience by installing Distribution Automation;

- Improving electric geographic information system to maximize benefits of outage analysis within the Outage Management System;

- Leveraging smart meter integration with Outage Management System to provide more data inputs for prediction of outage locations;

- Implementing Incident Command System at the local level and expanding resource pool beyond traditional operational areas;

- Pre-planning, pre-staging, and mobilizing personnel prior to weather events especially during non-business hours and weekends;

- Continuing to conduct real-time reviews, restoration process assessments, coaching, and restoration tabletop exercises; and

- Continuing daily, weekly, and monthly operating reviews to focus on outage duration metrics in operational areas.

Continued application of these tactics is expected to improve performance for Service Restoration Factor for Normal Conditions.

VIII. CONCLUSION

As mentioned in previous reports, Consumers Energy has established reliability and response improvement teams, conducts after-action reviews following major restoration events, and applies best practices (identified both internally and externally from other utilities) to continuously improve restoration capabilities. This overall approach contributed to the success in most reliability-related Performance Standards for 2017. These activities will continue as the Company strives to provide more reliable electric service to better serve our customers.

Respectfully submitted,

Dated: March 14, 2018 CONSUMERS ENERGY COMPANY

20134-MEC-CE-151
Page 1 of 2

Question:

2. Identify each occasion in 2017 on which the Company experienced catastrophic conditions as defined in Administrative Rule 460.702 (f), and for each provide:

   a. The number of customers by class to whom service was not restored within 120 hours after the interruption occurred;
   b. The number of customers by class to whom service was not restored within 120 hours after the interruption occurred and who notified the Company of the interruption;
   c. The number of customers by class to whom the Company made payments pursuant to Administrative Rule 460.744;
   d. The amount bill-credited by class pursuant to Administrative Rule 460.744;
   e. The amount that the Company would have been required to bill- credit by class if all customers experiencing service interruption that was not restored within 120 hours after the interruption occurred had notified the Company of the interruption and received credit.

Response:

Please see **Table 1** below, which provides the data requested in question 20134-MEC-CE-151**,** parts (a) and (b). See **Table 2** for parts (c), (d) and (e).

Table 1

Catastrophic Event Customers Out GT 120 Hours

EVENT	ACCT	# CUSTS	# CALLED
3/7/2017-3/13/2017	COMMERCIAL	42	4
3/7/2017-3/13/2017	RESIDENTIAL	346	162
3/7/2017-3/13/2017	INDUSTRIAL	0	0
7/6/2017-7/10/2017	COMMERCIAL	0	0
7/6/2017-7/10/2017	RESIDENTIAL	0	0
7/6/2017-7/10/2017	INDUSTRIAL	0	0

Table 2

2017 Catastrophic Outage Credits Paid				
	Actual		Qualified Customers	
Customer Class	Total Number	Total Dollar Amount	Total Number	Total Dollar Amount
Residential	106	$2,650.00	346	8,650.00
Commercial	2	$1.34	42	31.50
Industrial	0	$0.00	0	-
Total Catastrophic	**108**	**$2,651.34**	**388**	**$ 8,681.50**

Note: Commercial and Industrial customer totals in **Table 2** are estimates as the amount per claim is based on a percentage of the fixed portion of their bill and varies from customer to customer.

Andrew J. Bordine
July 19, 2018

LVD Engineering

20134-MEC-CE-152
Page 1 of 2

Question:

3. For calendar year 2017, provide:

a. The number of customer outages (in which each combination of customer and event shall be separately counted) in normal conditions as defined in Administrative Rule 460.702 (r) by class to whom service was not restored within 16 hours after the interruption occurred;
b. The number of customer outages in normal conditions as defined in Administrative Rule 460.702 (r) by class in which service was not restored within 16 hours after the interruption occurred and for which the customer notified the Company of the interruption;
c. The number of bill credits by class issued by the Company pursuant to Administrative Rule 460.745;
d. The amount bill-credited by class pursuant to Administrative Rule 460.745;
e. The amount that the Company would have been required to bill- credit by class if all customers experiencing service interruption during normal conditions that was not restored within 16 hours after the interruption occurred had notified the Company of the interruption and received credit.

Response:

Please see **Table 1** below, which provides the data requested in question 20134-MEC-CE-152**,** parts (a) and (b). See **Table 2** for parts (c), (d) and (e).

Table 1

Normal Event Customers Out GT 16 Hours

ACCT	# CUSTS	# CALLS
COMMERCIAL	4,693	432
RESIDENTIAL	43,313	10,088
INDUSTRIAL	13	3

20134-MEC-CE-152
Page 2 of 2

Table 2

2017 Normal Outage Credits Paid			Qualified Customers	
Customer Class	Total Number	Total Dollar Amount	Total Number	Total Dollar Amount
Residential	186	$4,650.00	43,313	1,082,825.00
Commercial	11	$7.83	4,693	3,519.75
Industrial	0	$0.00	13	9.75
Total Normal	**197**	**$4,657.83**	**48,019**	**$ 1,086,354.50**

Note: Commercial and Industrial customer totals in **Table 2** are estimates as the amount per claim is based on a percentage of the fixed portion of their bill and varies from customer to customer.

Andrew J. Bordine
July 19, 2018

LVD Engineering

20134-MEC-CE-153
Page 1 of 2

Question:

4. For calendar year 2017, provide:

a. The number of customers by class that experienced more than 7 interruptions due to a same-circuit repetitive interruption in a trailing 12-month period that ended in 2017.
b. The number of customers by class that experienced and notified the Company of more than 7 interruptions due to a same-circuit repetitive interruption in a trailing 12-month period that ended in 2017.
c. The number of bill credits by class issued by the Company pursuant to Administrative Rule 460.746;
d. The amount bill-credited by class pursuant to Administrative Rule 460.746;
e. The amount that the Company would have been required to bill- credit by class if all customers experiencing more than 7 interruptions due to a same-circuit repetitive interruption in a trailing 12-month period that ended in 2017 had notified the Company of the interruption and received credit.

Response:

Please see **Table 1** below, which provides the data requested in question 20134-MEC-CE-153**,** parts (a) and (b). See **Table 2** for parts (c), (d) and (e).

Table 1

Customers Experiencing 7 or more Outages in 2017

TYPE OF ACCOUNT	# Customers GT 7
COMMERCIAL	2,302
INDUSTRIAL	6
RESIDENTIAL	20,858

20134-MEC-CE-153
Page 2 of 2

Table 2

2017 Repetitive Outage Credits Paid			Qualified Customers	
Customer Class	Total Number	Total Dollar Amount	Total Number	Total Dollar Amount
Residential	19	$475.00	20,858	521,450.00
Commercial	1	$1.33	2,302	1,726.50
Industrial	0	$0.00	6	4.50
Total Repetitive	**20**	**$476.33**	**23,166**	**$ 523,181.00**

Note: Commercial and Industrial customer totals in **Table 2** are estimates as the amount per claim is based on a percentage of the fixed portion of their bill and varies from customer to customer.

Andrew J. Bordine
July 19, 2018

LVD Engineering

Projected 12-Month Period Ending Dec 31, 2019
Difference between Version 2 and Version 1
of Consumers Energy's Cost of Service Study
(thousands of dollars)

Summary
RETURN

Line No.	(a) Description	(b)	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Total Rate Base		-	2,370	242,345	(89,120)	(153,850)	3,862	(867)	(2,370)
			-	-	-	-	-	-	-	-
2	Total Rate Revenue		-	-	-	-	-	-	-	-
3	Total Revenue Credits		-	(659)	1,896	(307)	(2,331)	84	(1)	659
4	Total Revenue		-	(659)	1,896	(307)	(2,331)	84	(1)	659
			-	-	-	-	-	-	-	-
5	Expenses:		-	-	-	-	-	-	-	-
6	Fuel and P&I Expense		-	366	14,066	2,553	(17,083)	799	31	(366)
7	Transmission Expense		-	168	3,023	1,113	(3,912)	(63)	6	(168)
8	Other O & M Expense		-	89	9,110	(3,391)	(5,748)	142	(25)	(89)
9	Depreciation & Amortization Expense		-	179	14,713	(4,406)	(10,424)	331	(34)	(179)
10	Other Taxes		-	(34)	1,632	(958)	(701)	11	(18)	34
11	Federal Income Taxes		-	(216)	(6,160)	725	5,385	(172)	6	216
12	Total Expenses		-	551	36,384	(4,365)	(32,482)	1,048	(33)	(551)
			-	-	-	-	-	-	-	-
13	Net Operating Income		-	(1,211)	(34,488)	4,058	30,151	(964)	33	1,211
14	Other Income Adjustments		-	3	170	(20)	(153)	6	(1)	(3)
15	Adjusted Net Operating Income		-	(1,208)	(34,318)	4,038	29,999	(958)	32	1,208
			-	-	-	-	-	-	0	-
16	Rate of Return on Rate Base		0.00%	-0.01%	-0.93%	0.32%	1.65%	-0.96%	5.43%	2.45%
			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
17	Index of Return (Jurisdictional)		-	-	(15)	6	28	(16)	93	-
			-	-	-	-	-	-	-	-
18	Return on Rate Base @ 6.33%		-	150	15,348	(5,644)	(9,743)	245	(55)	(150)
			-	-	-	-	-	-	-	-
19	Income Deficiency (Sufficiency)		(0)	1,358	49,666	(9,682)	(39,742)	1,203	(87)	(1,358)
			-	-	-	-	-	-	-	-
20	Revenue Deficiency (Sufficiency)		(0)	1,819	66,506	(12,965)	(53,217)	1,611	(116)	(1,819)
			-	-	-	-	-	-	-	-
20b	Additional Rev Requirement		-	(0)	0	(0)	(0)	0	(0)	0
20c	Total Revenue Deficiency (Sufficiency)		(0)	1,819	66,506	(12,965)	(53,217)	1,611	(116)	(1,819)
			-	-	-	-	-	-	-	-
21	Revenue Requirement/Total Cost of Service		-	1,159	68,402	(13,272)	(55,548)	1,694	(117)	(1,159)
22	Less: Revenue Credits		-	(659)	1,896	(307)	(2,331)	84	(1)	659
23	Proposed Rate Design Revenue		-	1,819	66,506	(12,965)	(53,217)	1,611	(116)	(1,819)
			-	-	-	-	-	-	-	-
24	Production: Net Capacity Cost		0	595	13,337	2,282	(14,979)	(81)	36	(595)
25	Production: Capacity Related Cost Offset		-	377	21,198	4,073	(27,054)	2,103	57	(377)
26	Production: Non-Capacity Related Cost		0	828	1,873	1,035	(1,900)	(176)	(4)	(827)
27	Distribution: Demand Related Cost		(6)	13	18,573	(12,842)	(5,284)	(232)	(201)	(19)
28	Distribution: Customer Related Cost		5	6	11,525	(7,513)	(4,000)	(2)	(4)	(0)
			-	-	-	-	-	-	-	-
29	Full Service MWH Sales		-	-	-	-	-	-	-	-
30	ROA MWH Sales		-	-	-	-	-	-	-	-
31	MWH Sales		-	-	-	-	-	-	-	-
32	Customers		-	-	-	-	-	-	-	-

20134-MEC-CE-50

Question:

2. Reference the testimony of Laura M. Collins, page 10, line 19 through page 11, line 22. Did the Company revise or modify the Class Cost of Service Study to reflect the effects of the behavior of residential customers in response to a change in rate design on which Ms. Collins based rate design? If so, provide the modified or revised cost of service allocators for both Cost of Service Studies presented by Witness Aponte.

Response:

No, the Company did not modify the Cost of Service Study to reflect customer behavior changes. The Company reflected the change in behavior by shifting sales in rate design.

Laura Collins

Laura M. Collins
June 27, 2018

Rates and Regulation Department

20134-MEC-CE-64

Question:

16. Reference the testimony of Michael Delaney, page 7, line 15 to page 8, line 2. Mr. Delaney identifies an electric vehicle charging "infrastructure gap" in the State of Michigan that "needs to be addressed…."

a. Please state whether the Company intends for its Pilot Foundational Infrastructure Program to fulfill a percentage of the electric vehicle charging "infrastructure gap" in Michigan.

i. If yes, please state what percent of the infrastructure gap the company intends for its Pilot Foundational Infrastructure Program to fulfill, and describe in detail how the Company settled on that percentage. Please explain your response and provide supporting documentation.

ii. If not, please explain why not.

Response:

a. No, the goal of the program was not to fulfill a percentage of the gap in Michigan.

i. N/A

ii. The program size was derived through cost benefit analysis, demonstrating overall benefit to Consumers Energy's electric customers while allowing the pilot to be large enough to capture detailed learnings of the market. As there are currently an estimated 467 public Level 2 chargers and 16 DCFCs (excluding Tesla) in Michigan (page 7, line 19 of my direct testimony), the Program is projected to increase the number of chargers available to the public by 43% for L2 chargers, and by 150% for DCFC chargers.

Michael Delaney
June 29, 2018

Corporate Strategy

Forecasted Electric Vehicle Adoption and Charging Infrastructure Gap Analysis in the Consumers Energy Service Territory

Timothy Arvan and Charles Griffith,
Climate and Energy Program, Ecology Center

August, 2018

Introduction:

The following memorandum will address Consumers Energy Company's plan to support the adoption of electric vehicles (EVs) within its service territory through the near-term sponsorship of charging infrastructure construction, as presented in testimony (Case No. U-20134) before the Michigan Public Service Commission in May of 2018. In Section 1C lines 10-20 of that testimony--delivered by Michael J. Delaney, Executive Director for Corporate Strategy at Consumers Energy--a section addressing barriers to EV penetration of the broader vehicle market identifies Michigan's deficit of charging stations relative to the number of electric vehicles on its roads as a primary contributor of range anxiety. In this way, Consumers Energy acknowledges its facilitation of EV charging capacity as essential to market potential of EVs within its service territory.

As a response to CEC's proposal to fund the installation of new charging infrastructure in its service area, the Ecology Center has prepared the following summary of methods and results from its study forecasting near-term electric vehicle charging infrastructure demand in Consumers Energy Company's (CEC) service territory. As electric vehicle sales continue to grow rapidly in Michigan, it will be necessary for major utilities and other stakeholders to invest in EV charging infrastructure in order to ensure access to charging and manage its interaction with the grid. At present, the provision of public EV charging capacity is known to lag significantly behind statewide EV demand. The following material endeavors to quantify this so-called infrastructure gap as faced by Michigan drivers across Consumers Energy territory. These quantitative findings are then applied in the analysis of public and workplace charging aspects of CEC's recently proposed $7.5 million three-year EV plan.

Scenario Selection:

The Ecology Center employed the online modeling tool known as the Electric Vehicle Infrastructure Projection Tool Lite (EVI Pro) created by the National Renewable Energy Laboratory (NREL) to examine various scenarios of forecasted charging demand in CEC territory. Three broad categories of scenarios were tested to determine required infrastructure in the form of (a) level 2 public workplace stations (b) level 2 public charging stations and (c) direct current fast chargers; scenarios are outlined as follows:

1. Conservative Growth Scenario:
Adapted from numbers provided in CEC testimony regarding the company's plan to support construction of charging infrastructure over the next three years, the conservative scenario assumes 4,000 EVs currently on the roads in CEC territory, a quantity forecasted to double to 8,000 over the three year scenario timeframe. This amounts to a compound annual growth rate of the EV market at 26 percent.

2. High-Growth Rate Case:
Various estimates of growth in the EV market (including studied by Bloomberg New Energy Finance and M.J. Bradley and Associates) have predicted compound annual growth rates significantly higher than the conservative scenario--ranging from 29-36 percent through 2030. To account for these relatively more aggressive forecasts the high-growth rate case assumes 33% growth of the EV market; the 4,000 EVs in CEC territory are therefore assumed to expand to a fleet of 9,411 over a three year time interval.

3. Extended Timeframe Case:
The third scenario category takes the conservative scenario and extrapolates the projection over a six year time interval, as current trends in the EV market are likely indicative of long-term changes in consumers' vehicle preferences. The extended timeframe case therefore assumes the CEC EV fleet to expand from 4,000 to 16,000 EVs over six years.

Methodology:

For each of the three cases, EVI-Pro infrastructure analysis was conducted under a variety of conditions. Firstly, an analysis of Michigan EV registrations by make and model in each county yielded a ratio of plug-in to battery hybrid EVs over various driving ranges in CEC service territory. The calculated ratio of PHEV/BEV fleet composition was used as an input to the EVI-Pro model and is as follows:

Fig. 1 Consumers Energy Service Territory EV Fleet Composition:

To complement the CEC PHEV/BEV ratio projections, an additional set of analysis was conducted on a high-BEV ratio, as recent trends in Michigan EV sales reveal a gradual increase in the number of BEVs sold relative to PHEVs--although PHEVs continue to dominate the market in raw magnitude of vehicles. The high-BEV scenario, therefore, is likely representative of the future market composition of Michigan's EV fleet, and is quantified as follows:

Fig. 2 Future Expected (High-BEV) Michigan EV Fleet Composition:

PHEV 20mi	PHEV 50mi	BEV 100mi	BEV 250mi
20%	30%	25%	25%

Finally, the Ecology Center tested each scenario at a range of levels for access to residential charging. While a majority of electric vehicle owners are likely able to charge at their place of residence, the exact percentage of EV owners dependent on public charging is spatially variable. Ecology Center ran the EVI-Pro projections assuming 50%, 70%, 85%, and 100% access to residential changing infrastructure.

Note: CEC has stated that 70-85% of its EV drivers charge at home, so these estimates are likely most accurate for the service territory, while 50% and 100% indicate more extreme cases. In the summary data tables to follow, projections based on 70% residential charging access are presents, as Ecology Center has determined this to be the most moderate, reasonable, and likely of its estimates. Complete scenario analysis and corresponding infrastructure projections are available *here*.

The Ecology Center additionally ran each scenario category under conditions of partial and full support for plug in hybrid electric vehicles. Partial support entails that the average PHEV driver will occasionally rely on gasoline, whereas full support for PHEVs estimates charging infrastructure such that PHEV drivers can reply exclusively on electricity. In the data to follow, only EVSE estimates associated with partial PHEV support are shown, as full PHEV support would entail exponentially higher quantities of infrastructure than likely feasible at this time. Please refer to the complete scenario spreadsheet for full PHEV support projections.

Quantification of Existing Service Territory Infrastructure:
To determine the charging infrastructure gap (which is equivalent to the demand for new, additional chargers), it was necessary for the Ecology Center to subtract the existing volume of L2 and DCFC stations in CEC territory from the total recommended number of chargers suggested by EVI-Pro modeling. To understand levels of existing infrastructure, the Ecology Center relied on the U.S. Department of Energy's Alternative Fuels Data Center Station Locator, which provides estimates of L2 and DCFC station counts in major urban areas across each state. In the case of CEC, the Ecology Center aggregated the Station Locator infrastructure estimates across all the urban regions in CEC territory. This calculation is performed in the following table:

Fig. 3 Existing Charging Infrastructure in Consumers Energy Service Territory by Urban Area:

Michigan Region	***Existing L2 Plugs***	***Existing DCFC Plugs***
Battle Creek	1	0
Bay City	1	8
Benton Harbor	13	8
Flint	7	0
Grand Rapids	77	10
Holland	52	0
Jackson	5	0
Kalamazoo	35	0

Midland	0	0
Muskegon	18	0
CEC Service Territory Total	**209**	**26**

A. Results and Findings--Conservative Growth Scenario:

For the low growth rate scenario, at 70% access to residential charging and the current CEC vehicle mix, EVI-Pro predicts a deficit of 554 level 2 workplace chargers, 324 level 2 public chargers, and 37 DCFC chargers over three years. At a high-BEV vehicle mix and 70% residential access, the conservative scenario yields the need for 434 workplace level 2 chargers, 203 public level 2 chargers, and 97 DCFCs.

Fig 4. Conservative Scenario EVSE Gap → *table entries reflect demand for new, additional stations*
Gap = (Total Recommended Infrastructure) - (209 Existing Level 2)* - (26 Existing DCFC)

Conditions	***Workplace L2***	***Public L2***	***DCFC***
-*Current CEC vehicle mix* -70% access to home charging -Partial PHEV support	554	324	37
-*High-BEV vehicle mix* -70% access to home charging -Partial PHEV support	434	203	97

* Because the EVI-Pro model differentiates between workplace and public L2 chargers, the subtraction of existing stations from the total recommended quantity was divided proportionally between workplace and public categories in calculating the infrastructure gap.

B. Results and Findings--High Growth Rate Scenario:

Under the high growth rate scenario at 70% access to residential charging, EVI-Pro predicts a deficit of 664 L2 workplace chargers, 371 L2 public chargers, and 47 DCFCs for current CEC vehicle mix, or 524 L2 workplace, 280 L2 public, and 111 DCFC chargers with a high-BEV vehicle mix.

High Growth Scenario EVSE Gap → *table entries reflect demand for new, additional stations*
Gap = (Total Recommended Infrastructure) - (209 Existing Level 2) - (26 Existing DCFC)

Conditions	***Workplace L2***	***Public L2***	***DCFC***

-*Current CEC vehicle mix* -70% access to home charging -Partial PHEV support	664	371	47
-*High-BEV vehicle mix* -70% access to home charging -Partial PHEV support	524	280	111

C. Results and Findings--Extended Timeframe Scenario:

Finally, over an extended time scenario of six years at the conservative growth rate, a monumental 1196 L2 workplace, 692 L2 public, and 86 DCFC chargers would be required to meet demand at the current CEC vehicle mix and 70% access to at-home charging. Under a high-BEV scenario at 70% access, infrastructural demand is predicted to be 959 L2 workplace, 541 L2 public, and 146 DCFC chargers.

Fig 6. Extended Time Scenario EVSE Gap → *table entries reflect demand for new, additional stations*
Gap = (Total Recommended Infrastructure) - (209 Existing Level 2)* - (26 Existing DCFC)

Conditions	***Workplace L2***	***Public L2***	***DCFC***
-*Current CEC vehicle mix* -70% access to home charging -Partial PHEV support	1196	692	86
-*High-BEV vehicle mix* -70% access to home charging -Partial PHEV support	959	541	146

Data Analysis and Consumers Energy's EV Plan:

In framing the context for Consumers Energy's proposal to promote EV adoption, Executive Director for Corporate Strategy Delaney testified the following:

> *"Limited availability and geographic distance between chargers, lack of EV understanding, and desire for a vehicle with a significantly higher range than average daily mileage all lead to range anxiety. Range anxiety can be partially alleviated by installing charging infrastructure and educating customers about charging capabilities and their own driving needs. Michigan has a gap in charging infrastructure that must be addressed in order to relieve range anxiety. National Renewable Energy Laboratory suggests in a September 2017 report that there should be 73 Level 2 public chargers and 4 Direct Current Fast Chargers (DCFC) for every 1,000 EVs on the road.*

> *Currently, there are approximately 15,000 EVs on the road in Michigan which would equate to the need for 1,095 public chargers and 60 DCFCs; however, currently there are only 467 public chargers and 16 DCFCs (excluding Tesla).”*

The above quantification of the statewide infrastructure gap as expressed in Director Delaney’s testimony informs specific provisions of the company’s strategic three-year EV plan, which as a whole seeks to promote EV adoption through economic, infrastructural, educational, and technical channels. Focusing on the plan’s components targeting the strengthening of EVSE capacity, CEC has pledged to fund the construction of up to 200 Level 2 charger in public, workplace, and multi-dwelling units throughout its service area (at a cost of $1 million over three years). Additionally, the company has allotted funding for 24 DCFC chargers over the same time frame, at a cost of $1.7 million.

CEC’s analysis of the gap finds the state deficient of 628 L2 chargers and 44 DCFCs, and relies on National Renewable Energy Laboratory (NREL) conversion factors suggesting “73 Level 2 public chargers and 4 Direct Current Fast Chargers for every 1,000 EVs on the road.” When applying this factor to the total number of EV sales across the state, CEC determined total Michigan EVSE demand and then subtracted the number of known existing stations in the state. This method, however, does not specifically aim to conceptualize the gap within CEC territory. As much of the state’s existing charging infrastructure is located in heavily populated areas of Washtenaw and Wayne counties (not serviced by CEC), a more precise estimate of the gap is needed for the region of the state to which the CEC plan applies.

Additionally, the NREL conversion factor of stations per 1000 EVs employed by CEC is specific to rural areas. And while CEC service territory may be mostly rural, separate conversion factors exist for “town” and “urban” areas--an assumption built into NREL’s more recent EVI-Pro software and the Ecology Center’s analysis.

Finally, gap quantification using EVI-Pro accounts for further contributing factors--including the percentage of residents with access to home charging, the degree to which plug-in hybrid drivers would be supported by the EVSE network, and the specific mix of PHEV/BEV types in the regional EV fleet; each of these parameters can have drastic consequences for total infrastructural demand, and CEC’s internal analysis makes no mention of these elements. For these reasons, the Ecology Center is confident that its study of the gap more accurately reflects additional station demand over the next three to six years--at levels significantly higher than CEC has found.

While CEC’s contributions will undoubtedly constitute a drastic improvement to the EVSE network in its territory, it is necessary to consider the degree to which the company’s proposal will tangibly alleviate the strain imposed by growing charging demand in its service territory. For example, taking the Ecology Center’s conservative three-year gap estimate at the future expected (high-BEV) vehicle mix, a CEC territory gap of 637 L2 chargers would be just 31% satisfied by CEC’s plan, and a gap of 97 DCFCs would be 25% satisfied. Over a six year timeframe at the same conservative growth rate, a CEC territory gap of 1500 L2 plugs and 146 DCFCS would be just 13% and 16% filled, respectively, by the plan. (See Fig. 7)

Summary of L2 Infrastructure Gaps and Gap Mitigation Levels in Consumers Energy's Territory by Scenario:

Scenario Type	***Forecasted Deficit of L2 Chargers***	***Percent of Gap Filled by CEC's 200 Proposed New L2s***
Conservative Growth over 3 years	530	37.7%
High Growth over 3 years	588	34.0%
Conservative Growth over 6 years	1121	17.8%
High Growth over 6 years	1347	14.8%

Summary of DCFC Infrastructure Gaps Gap Mitigation Levels in Consumers Energy's Territory by Scenario:

Scenario Type	***Forecasted Deficit of DCFC Chargers***	***Percent of Gap Filled by CEC's 24 Proposed New DCFCs***
Conservative Growth over 3 years	27	89.9%
High Growth over 3 years	44	54.5%
Conservative Growth over 6 years	76	31.6%
High Growth over 6 years	165	14.5%

There are a variety of reasons for which CEC may not desire to fill 100% of the EVSE gap. For instance. On the other hand, without investment from CEC there have been woeful investments in EV infrastructure to date. Thus, while CEC may wish to strategically alleviate only a portion of the range anxiety its EV-drivers face, the Ecology Center encourages CEC to maximize its contributions and carefully consider the long-term expected growth of the EV market. Given the exponential projected EV sales in the coming decade, it appears CEC's proposal will need multi-phase deployment if it is to remain a relevant mitigator of range anxiety in the future.

Conclusions:

The Ecology Center commends CEC for its commitment to development of the EV market, as the utility's proposal will function to improve public health and environmental outcomes for residents of its service territory, as well as sustain a major sector of Michigan's economy. CEC's proposed contributions toward

EV charging infrastructure will inevitably reduce range anxiety significantly, serving to propel a widespread transition to an EV-centric vehicle fleet in Michigan.

EVI-Pro modeling reveals over a range of potential scenarios that the near-term EV charging infrastructure gap in Consumers Energy service territory will be significant, and higher than originally forecasted by CEC. A variety of factors contribute to the differential between CEC's projection of the gap and the calculations herein, including the Ecology Center's incorporation of (1) precise levels of access to residential charging opportunities, (2) a high-BEV vehicle mix predictive of future Michigan EV sales trends, (3) a more thorough analysis of future market growth rates, and (4) more precise modeling software specific to the CEC service territory, rather than the state as a whole. In total, these factors inform the Ecology Center's confidence in its gap calculations and provide the basis on which it suggests the deployment of gap mitigation actions more aggressive than originally proposed by CEC. Finally, the Ecology Center's projections over an extended time horizon reveal that a long-term EVSE plan will be necessary to avoid falling behind expected exponential market growth; in its current form, CEC's proposal will only alleviate range anxiety over a brief, near-term window.

The Ecology Center recommends that its projections be taken into consideration in revised CEC plans to provide optimal service to its growing pool of EV-driving customers.

CHRISTOPHER R. VILLARREAL

9492 Olympia Drive Eden Prairie, MN 55347 *(415) 680-4224*
email: chris@pluggedinstrategies.com

EMPLOYMENT

PRESIDENT — APRIL 2017-CURRENT
Plugged In Strategies — *Eden Prairie, MN*

- Provide regulatory and policy analysis and consulting services related to evolution of electricity grid, emerging customer and grid-connected technologies, and regulatory strategies
- Provide facilitation and moderation services for groups, workshops, and working groups
- Provide research and analysis services regarding utility and regulatory matters and structures
- Provide additional expert analysis on matters affecting electricity and regulatory structures, including topics such as data privacy, data access, rate design, internet of things, advanced technologies, and convergence of technology, industries, and markets.

DIRECTOR OF POLICY — MAY 2015- APRIL 2017
Minnesota Public Utilities Commission — *Saint Paul, MN*

- Maintained high profile inside and outside the state representing the Commission on electricity matters
- Assisted Commissioners with policy analysis to support decision-making options
- Provided policy analysis to support development of record in proceedings
- Provided subject matter expertise on specific topics, including rate design, energy storage, grid modernization, data privacy, data access, interconnection, and security
- Organized workshops, including preparing agendas, inviting speakers, and moderating public panels
- Engaged and interact with several national organizations, including National Association of Regulatory Utility Commissioners, Department of Energy, Federal Energy Regulatory Commission, National Institute of Standards and Technologies, North American Energy Standards Board, and Smart Grid Consumer Collaborative
- Regularly spoke and participated in panels, conferences, webinars, and other international, national, and state conferences on behalf of the Minnesota Public Utilities Commission
- Engaged and worked with several state-level projects, including e21 Initiative and 2025 Energy Action Plan
- Participated in actions related to Midcontinent Independent System Operator product development, including demand response and energy storage
- Chaired NARUC Staff Subcommittee on Rate Design, and managed development of Distributed Energy Resources Rate Design and Compensation manual, which included meeting specific deadlines, organize and manage a group of seven staff from around the country to develop, draft, and finalize manual on time
- Maintained an awareness and understanding of electricity policy developments across the country, including at national and state level; provide an analysis of these developments for Commissioners

SENIOR REGULATORY ANALYST — MARCH 2006- APRIL 2015
California Public Utilities Commission — *San Francisco, CA*

Major Accomplishments:
- Staff lead on Commission Smart Grid rulemaking: responsible for coordinating Staff work on rulemaking, working with ALJ and Assigned Commissioner's Office, organizing and facilitating workshops on a number of Smart Grid-related topics, including cybersecurity, privacy, customer data access and other customer issues, and ensuring proceeding met legislatively mandated time-frame.
- Prepared initial Orders Instituting Rulemaking on energy storage, rate design reform, and Smart Grid, and assisted in completion of final Commission decisions on Smart Grid, rate design, customer access to data, and privacy.
- Named as a Top 50 Smart Grid Pioneers for 2013 by Smart Grid Today.

- Managed and facilitated Commission workshops on emerging topics, such as privacy, cybersecurity, energy storage, and customer data access.

- Provided lead and support analysis on many electricity issues affecting customers, market participants, and utilities, including dynamic pricing, demand response, energy efficiency, rate design, electric energy storage, direct access and retail/wholesale integration.
- Responsible for monitoring activities, preparing analyses of policies, and preparing and submitting comments related to specific subject areas before FERC, U.S. Congress, California State Legislature, CEC, DOE, NIST, and Office of Science and Technology Policy.
- Participated in standard making process, and prepared and submitted comments to FERC, NIST, and NAESB. Chair of NAESB Energy Services Provider Interface Task Force, and a member of NAESB Executive Committee.
- Lead author and contributor on White Papers related to several emerging topics, such as Pre-Pay, cybersecurity, and microgrids.
- Presented at conferences on updates and summaries of Commission position on Smart Grid issues, such as customer education, privacy, cybersecurity, customer access to usage, rate design and tariffs, and general regulatory policy.

PARALEGAL — NOVEMBER 2005-FEBRUARY 2006
Patton Boggs — *Washington, D.C.*

- Performed research at FERC, other Federal agencies, Congressional legislative history, and various state agencies.
- Cite-check, proofread, and shepardize pleadings filed at FERC and various U.S. Courts of Appeals.
- Organized and maintained discovery files.

PARALEGAL — JULY 2004- OCTOBER 2005
McCarthy, Sweeney & Harkaway — *Washington, D.C.*

- Performed research for FERC, other Federal agencies, U.S. Congress, state legislatures and state regulatory agencies.
- Obtained and summarized pleadings filed at FERC and courts for clients and attorneys.
- Performed energy-related research (*e.g.*, monitor Energy news, obtain FERC and U.S. Court cases and opinions) and maintained extensive knowledge of many energy issues (*e.g.*, RTOs, deregulation/competition, and California/Pacific Northwest refund proceedings at FERC and U.S. Courts).
- Prepared testimony and discovery-related materials for hearing before FERC Administrative Law Judge, and provided proofreading, cite-checking, and shepardizing assistance for documents filed at FERC, U.S. Supreme Court, U.S. Court of Appeals and U.S. District Courts.
- Prepared briefs and appendices, and maintained and organized case files for proceedings before FERC and U.S. Court of Appeals.
- Monitored energy-related legislation and hearings before U.S. Congress and state legislatures, as well as energy-related activities at state PUC levels (*e.g.*, electric competition/deregulation activities).

PARALEGAL — MARCH 2003- JUNE 2004
Duane Morris, LLP — *Washington, D.C.*

- Performed research at FERC and other Federal agencies. Monitored FERC meetings and prepared summaries of meeting for attorneys and clients.
- Obtained and summarized pleadings filed at FERC and courts for clients and attorneys.
- Performed energy-related research (*e.g.*, monitor Energy news, obtain FERC and U.S. Court cases and opinions) and maintained knowledge base on many energy issues (*e.g.*, RTOs, deregulation/competition, and California/Pacific Northwest refund proceedings at FERC and U.S. Courts).
- Prepared testimony and discovery-related materials for hearing before FERC Administrative Law Judge, and provided proofreading, cite-checking, and shepardizing assistance for documents filed at FERC, U.S. Supreme Court, U.S. Court of Appeals, and U.S. District Courts.
- Monitored energy-related legislation and hearings before U.S. Congress and state legislatures, as well as energy-related activities at state PUC levels (*e.g.*, electric competition/deregulation activities).

LEGAL ASSISTANT APRIL 2001-MARCH 2003
McGuireWoods LLP *Washington, D.C.*

- Performed research at FERC and other Federal agencies. Monitored FERC meetings and prepared summaries of meeting for attorneys and clients.
- Performed energy-related research (*e.g.*, monitor energy news, obtain FERC and U.S. Court cases and opinions) and responsible for monitoring energy issues for attorneys (*e.g.*, RTOs, deregulation/competition, generation interconnection, and California/Pacific Northwest refund proceedings at FERC and U.S. Courts).
- Prepared testimony and discovery-related materials for hearing before FERC Administrative Law Judge, and provided proofreading, cite-checking, and shepardizing assistance for documents filed at FERC, U.S. Supreme Court, U.S. Court of Appeals for D.C. Circuit and 9th Circuit, and U.S. District Court for D.C.
- Monitored energy-related legislation and hearings before U.S. Congress and state legislatures, as well as energy-related activities at state PUC levels (*e.g.*, electric competition/deregulation activities).

ENERGY SPECIALIST MARCH 1998- APRIL 2001
Verner, Liipfert, Bernhard, McPherson, & Hand *Washington, D.C.*

- Performed research at FERC, SEC, Library of Congress, U.S. Congress, NRC, Department of Interior, National Archives, EPA, U.S. Supreme Court, U.S. Court of Appeals for D.C. Circuit, U.S. District Court for D.C., and other state agencies.
- Performed and monitored energy and environmental-related research.
- Made filings at FERC, U.S. Court of Appeals for D.C. Circuit, U.S. District Court for D.C., and SEC.
- Provided proofreading assistance, including cite-checking and shepardizing of documents.
- Attended U.S. Congress hearings on Energy issues and summarized for attorneys.
- Organized and maintained Energy Group library and trade press.
- Supervised Energy Group Summer intern.

EDUCATION

BACHELOR OF ARTS IN HISTORY 1993-1997
Baylor University Waco, Texas

ASSOCIATIONS

- Board of Directors, Emeritus, North American Energy Standard Board
- Executive Committee, Retail Markets Quadrant, North American Energy Standards Board
- Board of Directors, Emeritus, Smart Grid Consumer Collaborative
- Chair, Staff Subcommittee on Rate Design, National Association of Regulatory Utility Commissioners (November 2015-April 2017)
- Co-Chair, Business and Policy Domain Expert Working Group, Smart Grid Interoperability Panel
- Associate Member, GridWise Architecture Committee
- Planning Commission, City of Eden Prairie, MN

PUBLICATIONS

- *Distributed Energy Resources Rate Design and Compensation Manual*, National Association of Regulatory Utility Commissioners, Staff Subcommittee on Rate Design (November 10, 2016). http://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

- *Microgrids: A Regulatory Perspective*, California Public Utilities Commission, Policy and

Planning Division (April 14, 2014).
http://www.cpuc.ca.gov/NR/rdonlyres/01ECA296-5E7F-4C23-8570-1EFF2DC0F278/0/PPDMicrogridPaper414.pdf

- *Utility Investment Valuation Strategies: A Case for Adopting Real Options Valuation*, California Public Utilities Commission, Policy and Planning Division (October 3, 2013).
http://www.cpuc.ca.gov/NR/rdonlyres/D5C63A2B-40F2-468D-964A-F265B90346B1/0/Final2RRM.pdf

- *Cybersecurity and the Evolving Role of State Regulation: How it Impacts the California Public Utilities Commission*, California Public Utilities Commission, Grid Planning and Reliability/Policy and Planning Policy Paper (September 19, 2012).
http://www.cpuc.ca.gov/NR/rdonlyres/D77BA276-E88A-4C82-AFD2-FC3D3C76A9FC/0/TheEvolvingRoleofStateRegulationinCybersecurity9252012FINAL.pdf

- *A Review of Pre-Pay Programs for Electricity Service*, California Public Utilities Commission, Policy and Planning Division Policy Paper (July 26, 2012).
http://www.cpuc.ca.gov/NR/rdonlyres/152ED1D4-DD85-4D6F-984B-B84847933A18/0/Prepaypolicypaper0712.pdf

- *Electric Energy Storage: An Assessment of Potential Barriers and Opportunities*, California Public Utilities Commission, Policy and Planning Division (July 9, 2010).
http://www.cpuc.ca.gov/NR/rdonlyres/71859AF5-2D26-4262-BF52-62DE85C0E942/0/CPUCStorageWhitePaper7910.pdf

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their five-year distribution investment and maintenance plans and for other related, uncontested matters.	Case No. U-20147

COMMENTS BY NATURAL RESOURCES DEFENSE COUNCIL AND PLUGGED IN STRATEGIES ON FIVE-YEAR DISTRIBUTION PLANS SUBMITTED BY DTE ELECTRIC COMPANY AND CONSUMERS ENERGY COMPANY

Table of Contents

The Natural Resources Defense Council and Plugged In Strategies (collectively, NRDC) hereby submit comments on the five year distribution plans submitted by DTE Electric Company (DTE) and Consumers Energy Company (Consumers) as directed by the Michigan Public Service Commission (Commission). NRDC thanks the Commission for its foresight and recognition of the substantial role that the distribution system will play in the evolution of the electricity system currently underway in Michigan. The growth of distributed energy resources (DERs) such as solar, storage, electric vehicles, and utilization of energy efficiency and demand response presents tremendous opportunities to meet the future energy needs of Michigan's consumers. Thus, the Commission has rightly recognized that a more robust distribution planning process is necessary in order to meet growing consumer demands, replace aging infrastructure, enhance reliability and resilience, enable greater system efficiency, and maintain affordability for all customers.

I. Background

NRDC is a non-profit environmental organization headquartered in New York City, with offices in Chicago; Washington, D.C.; San Francisco; Los Angeles; New Delhi, India; Bozeman, Montana; and Beijing, China. NRDC advocates on behalf of more than three million members and online activists with the expertise of more than 500 scientists, lawyers, and policy advocates to safeguard the air we breathe, the water we drink, and the places we treasure. NRDC has over 12,300 members who live, use electricity, and pay electric bills in Michigan.

Plugged In Strategies is a Minnesota based consulting group that provides regulatory and policy support and strategy in the area of grid modernization, distribution system planning, and distributed energy resources.

II. Procedural History

In early 2017, the Commission issued orders directing DTE and Consumers to develop a draft five-year distribution plan that was to be submitted to Commission Staff during that summer. The draft plans were to contain five components:

1. A detailed description of distribution system conditions, including age of equipment
2. System goals and related reliability metrics
3. Expected needs of customers using the distribution system
4. Maintenance and upgrade plans
5. Cost/benefit analyses

As noted by the Commission, the purpose of these filings is "to be able to properly evaluate significant and necessary investments to the utilities' aging electric distribution systems to ensure that such systems are safe, reliable, and resilient long into the future, as opposed to merely evaluating such costs over a 12-month snapshot of time."[1] DTE and Consumers submitted their draft five-year plans in June and August 2017, respectively. Stakeholder comments on the draft plans were submitted to the Commission in September 2017.

On October 11, 2017, the Commission issued an order providing additional details on the objectives and purpose of the five-year distribution plans. The Commission is focused on four objectives[2]:

1) Safety;

[1] *In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their five-year distribution investment and maintenance plans and for other related, uncontested matters*, Order Opening Docket, Case No. U-20147 at 1 (April 12, 2018) (April 12 Order).

[2] *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, et al.*, Order, Case No. U-17990, *et al.*, at 10-12 (October 11, 2017) (October 11 Order).

2) Reliability and Resiliency;
3) Cost Effectiveness and Affordability; and
4) Accessibility;

With these objectives in mind, the Commission also noted the evolving nature of the electricity system into a two-way distribution grid, changing expectations and preferences from consumers, and a more complex grid that includes greater uncertainty around customer demands. Recognizing these changes as well as the need to replace aging infrastructure, the Commission stated, "that there is benefit to having a formal distribution planning process that evolves over time and is intended to take a longer term look at changing system and customer needs and innovative solutions that can be leveraged to address these needs in a safe, reliable, and affordable manner."[3] The Commission identified several benefits to a more formal and open distribution planning process, including:

1) Better understanding of the long-term goals and objectives underlying utility investment plans and how the execution of these plans can meet these goals and objectives in an affordable manner;
2) Providing transparency around the need for, scope of, and expected outcomes resulting from specific investment strategies may facilitate ratemaking processes;
3) Facilitation of economic development activities by identifying suitable locations to accommodate growth and areas where reinforcements are needed;
4) Enabling the Staff and stakeholders to weigh in on planning assumptions, particularly those that address factors outside the utility's control, such as rooftop solar and electric vehicle adoption; and

[3] *Id.* at 14.

5) Ensuring that Michigan is making “no regrets” investment decisions in the long term.[4]

Additionally, the Commission noted that a key component of this initiative is to ascertain the health of the existing distribution system with a focus on the “near-term safety and reliability of the distribution grid,”[5] and that “a focus on safety and reliability improvements in the near term will also provide a foundation for a stronger electric system that can adapt to changing technologies and customer patterns over time.”[6] The Commission directed DTE and Consumers to submit their five year distributions plans by January 31, 2018.[7] In those filings, the Commission identified four priorities for the five year distribution plans:

1) Defining the scope of work, capital, and O&M investments needed to address aging infrastructure and the risk assessments that drive the prioritization of these investments;
2) Identifying known safety concerns on the system and work necessary to address these concerns;
3) System maintenance and investment strategies that improve resiliency and mitigate the financial effects and safety issues associated with inclement weather, and
4) Company objectives and associated performance metrics relevant to utility near-term investment and maintenance plans.[8]

On April 12, 2018, the Commission issued an order seeking comments on the distribution plans submitted by DTE and Consumers. The Commission stated that the comments should focus “on the existing distribution plans filed by DTE Electric and Consumers and how the information

[4] *Id.* at 15.

[5] *Id.* at 16.

[6] *Id.* at 17.

[7] Consumers received an extension to file its plan until March 1, 2018.

[8] October 11 Order at 16.

can help inform ratemaking and other regulatory processes, including consideration of performance-based metrics."[9] The Commission also directed Commission Staff to hold a workshop following the submission of comments, with a report due to the Commission by September 1, 2018.

The Commission also stated its intent to request additional comments on the September 2018 report and to convene stakeholder groups to discuss future iterations of the utilities' distribution plans.[10]

III. Discussion

Both Consumers and DTE should be commended for their efforts in developing these initial distribution planning documents. Both filings provide significant details about the structure, architecture, and operations of the utilities' distribution systems (including areas where reliability is less than optimal), the varying nature of voltages and service quality, and the need for better understanding of outages, where they are occurring, and how to respond to these challenges cost-effectively. As directed by the Commission, both utilities focused on near-term distribution needs. DTE addressed the aging nature of its distribution system, and the need to rebuild large swaths of its service territory. Consumers focused on the reliability of its system, noting discrepancies in rural reliability performance across its territory while balancing the cost-effectiveness of urban versus rural investments on its customer base.

Crafting a distribution plan in the face of a range of service challenges is no small task. However, while the utility filings address the Commission's immediate goal of identifying short-term needs for the distribution system, both filings would benefit from improved discussion of: (1)

[9] April 12 Order at 3.

[10] *Id.*

a robust and transparent distribution planning process; (2) how greater intelligence and data can be used to better plan and optimize the distribution system, as well as integration across utility operations; and (3) how DERs[11] could be used to avoid, minimize, or defer more costly distribution investments.

As described below, DTE and Consumers' five year plans respond to the immediate (and understandable) goals of assessing short-term reliability and aging infrastructure needs, but they do not adequately set the stage for the substantial changes that will also soon be necessary for Michigan's electricity system to accommodate the growth of DERs. While discussed in passing and in varying level of detail by DTE and Consumers, NRDC believes that the five years plans should at a minimum touch upon (and with a more prominent emphasis in the upcoming workshops) the following topics:

- Hosting Capacity;
- Interconnection studies, processes, and standards;
- Data Access;
- Non-Wires Alternatives; and
- Demand Forecasting due to impacts from DERs.

These topics should be considered as fundamental components of a more robust and transparent distribution planning process, and they can be addressed on a parallel timeline with any necessary infrastructure investments identified in this inquiry. While adoption levels for solar, storage, and electric vehicles are in early stages in Michigan, the time is nonetheless opportune for Michigan to begin laying out a vision and foundation for an electricity system that can plan for, take account of, and use DERs to meet the goals of the state.

[11] NRDC defines DERs to include solar, energy storage, microgrids, energy efficiency, demand response, and electric vehicles.

1. Distribution System Planning and System Optimization

To assist the Commission in developing and evaluating a distribution system planning process, NRDC outlines below a two-part pathway consisting of inquiries/analyses that can be conducted in the near-term, as well as those on longer timelines. This framework offers a range of topics and examples for the Commission's consideration, derived from regulatory commission and expert guidance from around the country. NRDC also identifies where the utilities' five-year plans reflect (or do not reflect) this framework.

a. A Framework for Integrated Distribution Planning

NRDC directs the Commission to a guidance document prepared by the Department of Energy for the Minnesota Public Utilities Commission,[12] as well as the NARUC Distributed Energy Resources Rate Design and Compensation manual.[13] Both provide examples of the *need* for, the *organization* of, and the types of *information and data* necessary to commence an inquiry on distribution system planning.

In 2015, the Minnesota Public Utilities Commission initiated a proceeding to consider grid modernization policies and initiatives for its regulated utilities with a focus on distribution system planning. On behalf of the Minnesota PUC, the Department of Energy supported a white paper to assist the PUC in its consideration of what an integrated distribution system initiative may look like. Figure 1 below illustrates the components of such an initiative.[14]

[12] "Integrated Distribution Planning," ICF International, primary author Paul DeMartini, prepared for the Minnesota Public Utilities Commission (August 2016) (https://www.energy.gov/sites/prod/files/2016/09/f33/DOE%20MPUC%20Integrated%20Distribution%20Planning%208312016.pdf) (IDP Report).

[13] "Distributed Energy Resources Rate Design and Compensation: A Manual Prepared by the NARUC Staff Subcommittee on Rate Design," National Association of Regulatory Utility Commissioners (November 2016) (https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0) (NARUC DER Manual).

[14] IDP Report at 5.

Figure 1: Integrated Distribution Planning

The left side of Figure 1 identifies the near-term components of a more integrated vision for distribution planning. Note that in this approach (as opposed to more traditional planning), distribution planning encompasses more than just engineering analyses: it also includes forecasting and modeling; transmission planning; and integration of other activities such as data generated via the utility's interconnection study process and any hosting capacity analyses that the utility has undertaken. NRDC acknowledges that utilities are already doing some form of distribution system planning, which in the case of DTE and Consumers is primarily focused in their five-year plans on aging infrastructure and new demand. What is missing from these plans, however, are the distribution engineering analyses and interconnection process components reflected in Figure 1. Incorporating these elements into distribution planning would enable the state to build a stronger foundation for accommodating DERs in the coming years and ensuring that their benefits accrue to the distribution system and to consumers.

The right side of Figure 1 identifies the longer-term components of integrated distribution planning. This illustrates how the more traditional utility planning elements can be used to support future initiatives, including any potential valuation, utilization, or procurement of DERs, and how these efforts result in a distribution system investment roadmap—which, while likely to have some commonality with the five year plans, affords greater insight into the distribution system, including adoption levels of DERs and their contributions to the system. Further, the "Value of DER" box can be thought of as future integration of DERs in utility resource procurement, which includes more detailed locational net benefits analysis, or the establishment of locational distribution marginal pricing. In that longer-term scenario, the utility would be procuring and dispatching DERs at the distribution level akin to how they currently dispatch wholesale resources at the generation level.[15]

To be sure, the Commission may need additional information to determine whether DTE and Consumers have the existing capabilities to undergo a more robust and integrated distribution system planning effort. The NARUC DER Manual provides an initial set of questions and types of data that a Commission may want to consider as it analyzes the needs of a distribution utility and the role that DERs can play to meet system needs or be used as an alternative to planned capital investments.[16] Further, the NARUC DER Manual notes the important role of regulatory commissions (and utilities) in monitoring and planning for the changes occurring across a service territory.[17] Michigan is in the early stages of adoption levels of resources like energy storage and rooftop solar; nonetheless, embracing a more integrated distribution planning process now would provide the Commission with an opportunity to start planning for a higher DER future. By opening

[15] *See also* NARUC DER Manual at 132-142 (discussing valuation methodologies). Consideration of this topic may include additional options including the creation of a distribution system operator, a distribution system platform provider, or another similar type of entity. For additional information, *see*, "Evolution of the Distribution System & the Potential for Distribution-level Markets: A Primer for State Utility Regulators," Sharon Thomas, NARUC (January 2018) (https://www.naruc.org/default/assets/File/201801%20Evolution%20of%20the%20Distribution%20System.pdf).

[16] *Id.* at 143-155.

[17] *Id.* at 59-63.

this proceeding, the Commission clearly envisions putting appropriate policies into place before DER penetration levels reach an inflection point and get out ahead of policy.

a. Planning for and Identification of New Investments and Locations

To best plan for current and future utility investments, it is important to take an inventory of the existing utility capabilities. Both DTE and Consumers extensively detail the physical components of their systems in their five-year plans. However, little insight is offered into the technical (types of infrastructure), systems (SCADA and ADMS), or network (communication) aspects of their distribution systems. It appears from DTE's discussion of its communications and sensor networks that its systems are not being integrated. For example, DTE notes that many of its operational applications, such as AMI, outage management, and SCADA are not currently integrated.[18] Furthermore, DTE notes that its system has significant data gaps between operations.[19] DTE's planned ADMS system requires an integrated network to allow the full range of benefits to be obtained, and, as such, is not integrated with its other systems. Nor does it appear that DTE is using a common network model for the variety of its systems.[20] While DTE notes that it is intending to undertake a study to better integrate its various operations systems, little else is discussed about potential communication or systems architectures. As DTE notes, integration of these data sources is vital to the success of the reliability and operation of its system.[21] Additional detail is needed on DTE's system integration plan for its operations; such detail is important in not

[18] DTE 5 Year Distribution Plan at 130.

[19] *Id.*

[20] *Id.* at 130-132.

[21] *Id.* at 139.

just looking at replacing aging infrastructure, but also analyzing existing weaknesses within the utility systems.

We also recommend that the five-year distribution plans identify what level of hosting capacity analyses the utilities are currently doing, and that these analyses be a focal point of plans and the workshop this summer. Hosting capacity is defined as the amount of DERs (in particular, solar PV) that can be accommodated on a given point in the distribution system without impacting power quality or reliability under existing control and infrastructure configurations.[22] In essence, a given point in the distribution system has a certain amount of available capacity at any given time to accommodate additional generation, such as solar. Hosting capacity analyses identify that threshold of available capacity. They provide valuable information to determine not only the capabilities of the distribution system, but also to identify optimal locations for solar, as well as to identify areas where non-wires alternatives may be deployed to defer or replace more costly capital investments. Solar can also be paired with other technologies, such as storage or greater use of energy efficiency or demand response, to enhance hosting capacity that is lacking at that point in the system. We recommend requiring DTE and Consumers to run hosting capacity analyses and make the results public; or explain why such analyses cannot be run.

2. Using Data to Better Plan and Optimize the Distribution System

a. Access to AMI Data

A common theme through both five-year plans is the need to better understand customer energy use via forecasting and load modeling. As the Commission notes in its October 11 Order, the nature of electricity delivery is changing and moving from a one-way to a two-way power flow. In other words, if customers are now able to generate a portion of their own demand, and, at certain

[22] "Distribution Feeder Hosting Capacity: What Matters When Planning for DER?," Electric Power Research Institute at 2 (April 2015).

times, are able to send excess electricity back onto the distribution grid, then the grid must be engineered to allow for two-way power flows. At the same time, customers' usage profiles are changing. With the completion (or near completion) of AMI installation in Michigan, DTE and Consumers have a substantial amount of information available to them to better understand customer demand, and to do better forecasting and modeling of customer demand. However, the utilities' five-year plans do not discuss how they plan to use this information to better run and manage their distribution systems. Customers paid for these investments and should thus expect that the utilities make the most out of them, including to use advanced meter-generated data to more efficiently plan their system.

In addition, only DTE mentions (and it is largely done in passing), the ability of customers to access their usage information and share that data with a third party. Creating a common process, based on open standards, for all customers to access their usage data should be a consideration in this discussion. Customer access to their information, and having the ability to provide that information to a third party, can assist in understanding the impacts of customer investments in energy efficiency or in understanding the cost-benefit of investing in (for example)_rooftop solar. According to DTE's filing, AMI information is only available to customers via a DTE app; it is unclear to which standard this app adheres, or whether third party apps are able to participate or access customer data from DTE. Limiting access to customer usage data greatly inhibits customers from fully realizing the benefits of the AMI investment, does not utilize open standards (such as Green Button[23]), and limits customer choice. Consumers' filing

[23] The Green Button Initiative is a standards-based process by which customer data is shared with a customer-authorized third party. Green Button is based on REQ.21, the Energy Services Provider Interface standard developed by the North American Energy Standards Board (NAESB). For purposes of this discussion, NRDC is referencing Green Button Share My Data whereby a data custodian, *i.e.*, a utility, shares customer data with a customer-authorized third party via a utility interface. Green Button has been adopted as the data sharing standard by the following states: California, Colorado, Illinois, New York, and Texas.

entirely fails to mention utilization of AMI data or allowing customers to access information for their own purposes.

Data can also assist in better demand forecasting. Forecasting is an important part of the planning process as it identifies the future expectations of usage, as well as to more accurately forecast any future load growth. Other sources of this information can come from enhanced monitoring of the distribution system via SCADA or other technologies. Importantly, demand forecasting is also used to determine future resource and investment needs. It is unclear to what extent DTE or Consumers are using this new information as an input into their demand forecasts, as well as to what extent this data is being used in infrastructure planning.

b. Interoperability of Utility Systems

Finally, a robust distribution system planning exercise should collect information about the capabilities of the distribution system, as well as seek to integrate utility systems that may have traditionally been siloed. This information can be used to better understand the distribution system and identify areas where internal planning siloes can be broken down to facilitate more efficient utilization of assets and better planning. For example, as described in the Department of Energy Modern Distribution Grid Decision Guide Volume 3, a utility could utilize an architecture based on a common communications network that its various applications could access.[24]

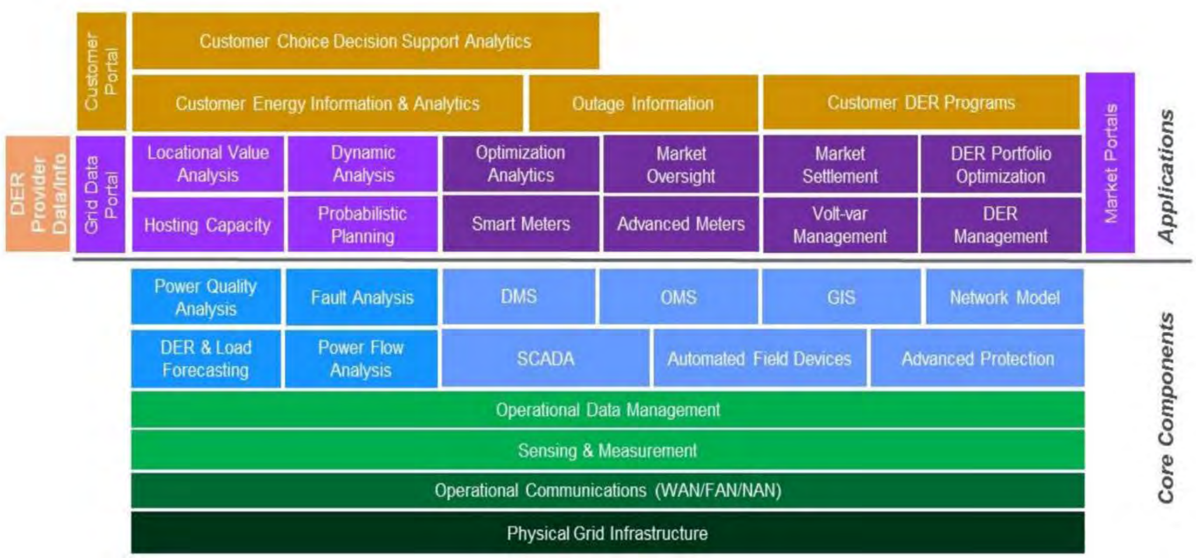
The image below shows an example of an architecture that identifies the core components of a utility system and applications of service that can be layered on to that core.[25] This is just a representative example; but, nevertheless, it shows how certain components of a utility can be "flattened" to horizontally support the entirety of a utilities' operations rather than remaining in

[24] Modern Distribution Grid, Decision Guide, Volume 3, U.S. Department of Energy at 26 (June 28, 2017) (Modern Distribution Grid).

[25] *Id.* at 26.

vertical siloes; flattening the utility becomes more important with the growth of DERs and the various components and applications of the utility need to become better integrated across the utility. The application layer can be tailored to the specifics of the utility, as some may be better served by the market.

Figure 8: Next Generation Distribution System Platform & Applications



In this instance, rather than building separate communications networks for a utility's SCADA system, Outage Management System, AMI system, ADMS system, *etc.*, a utility could create one common communications network that all applications could access. By layering these common components, each application would have access to the same data, and also be able to better share information between applications. With this common platform for utility data and communications, a utility could better coordinate within its operations to yield more efficient actions.

As the Commission has noted, "Open and effective planning processes will also facilitate economic development activities by identifying suitable locations to accommodate growth and areas where reinforcements are needed."[26] The planning process must inform other utility processes and vice versa; a robust, comprehensive, and transparent process is vital to meet this Commission goal. Even considering the limited focus of the five year plans, the filings provide limited insight into current utility planning processes and how the utilities are using information to facilitate economic development for its customers.

Further, integration of systems allows for utility systems and networks to run more efficiently and enhances interoperability across the utility network.[27] Interoperability provides the ability of multiple vendors to build to a common data model based on open standards; and breaks the reliance on a black box or closed vendor procurement. By utilizing open standards and supporting interoperability, the utility can more cost-effectively meets its technical system and network needs without compromising performance. If systems are not interoperable, on the other hand, a utility system can incur additional costs to build their own solution, or, worse, keep systems entirely separated from each other at potentially substantial cost and risk to customers. The Commission should ensure that interoperability and systems integration form a foundational component of any distribution plan, regardless of whether it is the communications network to support vegetation management or a utility plan to implement a Distributed Energy Management System (DERMs).[28]

Lastly, integration of systems will assist in meeting customer needs as they seek to interconnect or integrate directly with the utility. For example, if the utility's interconnection

[26] October 11 Order at 15.

[27] For greater discussion on interoperability, see "GridWise Interoperability Context-Setting Framework," GridWise Architecture Council (March 2008) (https://www.gridwiseac.org/pdfs/interopframework_v1_1.pdf), and "NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 3.0," National Institute of Standards and Technology (September 2014) (https://www.nist.gov/sites/default/files/documents/smartgrid/NIST-SP-1108r3.pdf).

[28] A word search of the respective filings yields zero results for the word "interoperability."

process is not sufficiently integrated with utility planning, hosting capacity, or demand forecasting groups, then these groups will work independently of each other, using incomplete information, and operating under a variety of assumptions. This could result in overbuilding or construction of unnecessary facilities, inefficient operation of the distribution system, and higher costs to customers.

As discussed above, both DTE and Consumers' five-year plan filings provide a significant amount of detail regarding the current architecture of the distribution system. NRDC suggests that combining consideration of long-term architecture and organization of the utility, with adherence to open standards and a focus on interoperability, may assist in better organization of the distribution utility systems and operations, enhance the efficiency of the utility, and result in better integration and utilization of DERs and utility assets.

3. Better Utilization of DERs and Identification of Non-Wires Alternatives

In its October 11 Order, the Commission notes that the distribution system is complex, and that in the near-term, a focus on safety and reliability is of paramount importance. The Commission, however, subsequently states that in the longer term, "continuously evolving technology and customer expectations will require a more comprehensive approach to developing a "no regrets" distribution plan."[29] NRDC shares this goal: identifying necessary and no-regrets investments in the distribution system. We caution, however, against looking at DERs as simply longer-term priorities to address at some future date—there are ample opportunities *now* to start the process of better utilizing DERs, particularly in the context of non-wires alternatives. The current five year plans include billions of dollars of proposed capital investments on the

[29] October 11 Order at 17.

distribution grid. [30] NRDC recommends that non-wires alternatives be considered as the Commission evaluates those investments, as well as for a broader DER inquiry in the workshops this summer. To the extent the five-year plans are intended to "also provide a foundation for a stronger electric system that can adapt to changing technologies and customer patterns over time," they are significantly lacking in alternative considerations that would enable that stronger system.[31]

While the Commission has specifically expressed an interest in non-wires alternatives, neither utility's five year plan filings focuses on the role that DERs can play in meeting their service obligations.[32] Consumers, for example, goes into great detail regarding the reliability of its system, especially for its more rural areas. Additionally, Consumers identifies many infrastructure upgrades necessary to address DER growth and utilization. Nevertheless, while NRDC is working with Consumers on a non-wires alternative pilot,[33] the Company neglects to identify any *additional* areas where a non-wires alternative option could be considered. Finally, Consumers identifies three specific investment types to support their reliability goals, "traditional infrastructure investment, grid modernization investment, and operational improvements."[34] Notably absent from that list is consideration of non-wires alternatives to meet reliability goals.

Additionally, DTE, while noting that non-wires alternatives could play a role in the future, inexplicably discusses DER technologies and non-wires alternatives independently of each other

[30] DTE notes that O&M costs (other than tree trimming and preventative maintenance) were largely excluded entirely from the focus of their filing. DTE 5 Year Plan at 5.

[31] October 11 Order at 17.

[32] *Id.* at 17.

[33] Consumers 5 Year Distribution Plan at 69.

[34] *Id.* at 90.

rather than in conjunction. For example, demand response, which by itself provides a distinct set of benefits, when paired with storage can provide higher combined benefits and a more reliable and durable response than either approach alone.

In addition, DTE appears to place little value in non-wires alternatives, despite countervailing evidence. In Section 5.1.4 of its five year plan the utility lists the variety of individual DER activities related to non-wires alternatives. It notes it conducted a study of the potential for energy efficiency to cost-effectively defer distribution system capital investments in a specific geographic area; and concluded that such an alternative would not have been "a cost-effective solution to defer capital investment for the selected substations used in this study."[35] However, this statement is highly misleading as the referenced study is riddled with methodological problems. For example, when assessing the cost-effectiveness of efficiency investments, the study compared the full cost of efficiency to just the benefit of deferring the distribution system investment; it completely ignored the avoided energy costs, avoided capacity costs and other electric system benefits that the efficiency investments would also provide. It is worth noting that the study actually found it possible to defer capital investments through increased efficiency investments in one of the substation areas analyzed. As shown in the testimony of NRDC witness Chris Neme in DTE's last energy waste reduction plan case, when the flaws in DTE's cost-effectiveness analysis are corrected (*i.e.*, when the total cost of efficiency is compared to its total benefits), non-wires alternatives are extremely cost-effective, with a benefit-cost ratio of greater than 5 to 1 (rather than the 0.7 to 1 estimated by DTE when including only the distribution investment deferral benefit).[36] This result is very consistent with a number of electric

[35] DTE 5 Year Distribution Plan at 100.

[36] Case No. U-18262, Corrected Direct Testimony of Chris Neme, 2 TR 298.

utility projects across the country which have also found geotargeted efficiency, either alone or in combination with demand response, distributed generation and/or other distributed resources, to be very cost-effective.[37]

It is further worth noting that DTE, NRDC, and Staff entered into a settlement agreement in that energy waste reduction docket with the express goal of jointly developing and supporting DTE's deployment of one or more energy efficiency non-wires alternative pilot projects.[38] Those projects will, for the first time in DTE's service territory, actually field test what geotargeting of efficiency can accomplish. The parties will also collectively work together to develop a methodological framework for properly assessing the cost-effectiveness of efficiency as a non-wires alternative strategy. That work is just beginning; but given both the potential suggested by DTE's study (once its methodological problems are corrected) and experience in other jurisdictions, NRDC is optimistic that geographically-targeted energy efficiency programs will be shown to be able to provide significant and very cost-effective reductions to capital investments required for DTE's distribution system.

In addition, in its discussion of distributed solar generation in the five year plan, DTE lists the many operational challenges and potential issues with integrating greater amounts of DG, yet never mentions the potential of advanced inverters or solar plus storage options as solutions to these operational challenges.[39] Similarly, in its discussion on battery storage potential, DTE notes that storage is not conducive for its immediate focus on substations over 3 MVA and states that

[37] "Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments," Chris Neme and Jim Grevatt, Northeast Energy Efficiency Partnerships (January 9, 2015), available at http://www.neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf.

[38] Case No. U-18262, Order Approving Settlement Agreement, Attachment E (April 13, 2018).

[39] DTE 5 Year Distribution Plan at 102.

storage does not provide "benefits such as improved reliability, enhanced operational flexibility, and reduced risk associated with aging infrastructure."[40] NRDC is unclear how battery storage systems would not assist with reliability, flexibility, and providing support for aging infrastructure. The NARUC DER Manual references a set of benefits identified by the Rocky Mountain Institute, and that list includes several services, such as frequency regulation, congestion relief, resource adequacy, and transmission and distribution deferral which all appear to satisfy DTE's concerns.[41]

Indeed, where multiple DERs are "stacked" with one another, non-wires alternatives truly become capable of standing in place of new capital investments in infrastructure. However, utilities must give them an opportunity to succeed. The Commission has placed an emphasis on reliability and resilience in this process; enhancing reliability and resilience is not limited solely to utility investments in infrastructure or better vegetation management, but should also include better utilization of both existing utility programs and new technologies, such as storage, energy efficiency, demand response, and distributed generation.[42] Non-wires alternatives can enhance the value of DERs to the benefit of the end-use customer, but also to the benefit of customers overall via avoidance or deferral of large infrastructure projects.

Finally, a foundational component of planning for the growth of DERs is the consideration of whether the current interconnection rules and processes are up to date in relation to the technological progress taking place across the industry. To that end, NRDC agrees with

[40] *Id.* at 103.

[41] NARUC DER Manual at 138.

[42] While NRDC recognizes these filings are focused on distribution investments, NRDC also points out the role that appropriate rate design and compensation will play in the adoption and use of DER. Neither DTE nor Consumers provide many details regarding the role or potential transition to time of use rates, or how rate design can also be used to elicit changes to customer behavior by shifting usage to lower cost time periods and avoid system peaks.

Consumers on the need to update Michigan's interconnection rules and processes.[43] With the revisions to IEEE 1547 in place, the state's interconnection rules need to be updated to reflect the capabilities of advanced inverters to provide additional services for the grid, including voltage ride-through and the capability for islanding in the case of an outage. In addition to advanced inverter changes, the Michigan interconnection rules lack effective queue management practices and a fast track screen.[44] These are substantial changes to the previous version of the interconnection rules and processes which will enhance the value of solar to the grid and lower barriers to integration of these resources onto the grid.

IV. The Commission's Planning Process

The Commission anticipates this to be the first of a biennial planning process. As such, the five year plans are critical foundational documents that will set the tone and focus for Michigan's distribution planning vision, for years to come. It is thus critical that the plans be robust, provide a sufficient amount of information, and accurately reflect the current state of the distribution system and utility activities such that the Commission can confidently rely upon them in future phases.

NRDC agrees with the Commission that safety, reliability, and resilience are important topics of focus for these initial filings. However, it would be a missed opportunity to not articulate at this stage more advanced expectations for the next iteration of planning. Specifically, the current five-year plans lack consideration of:

(1) An overarching framework for a robust and transparent distribution planning process;

[43] Consumers 5 Year Plan at 62.

[44] For more information, *see* "Model Interconnection Procedures," Interstate Renewable Energy Council (2013); "Priority Considerations for Interconnection Standards: A Quick Reference Guide for Regulators," Interstate Renewable Energy Council (2017).

(2) Utilization of existing data to support planning and measurements, as well as integration across utility operations; and

(3) Better utilization and planning for DERs, including consideration of non-wires alternatives, and interconnection and hosting capacity analyses.

Allowing the current plans to move forward without at least an acknowledgment of the broader integrated planning needs and the role of DERs for the system (particularly as non-wires alternatives to infrastructure upgrades), will essentially "bake in" a series of investments borne by customers that may have been unnecessary or could have been mitigated. This is a foundational area that commissions around the country have—and are—wrestling with in their respective proceedings.

Given the above, the Commission should identify the as-filed utility plans as initial and informational regarding the physical aspect of the utility distribution systems. Some areas of the distribution system will need to be upgraded with physical assets, some investments may be capable of deferral with better use of DERs, and some investments may be necessary to enable other critical policies (such as utilization of advanced inverters, integration of DERs, or moving towards a transactive energy system). As illustrated by the Minnesota IDP Report (discussed above), a holistic distribution system planning process takes into account not only existing distribution planning and needs assessments, but uses information gathered from hosting capacity analyses and interconnection processes. At the root of each is the availability and use of data, be it customer usage data, DER data, or grid data. Additionally, the planning process makes use of forecasts and modeling information, and those forecasts must also make use of data coming from the distribution system. By including and valuing the contributions from customers, the utility can have a more informative assessment and determine whether infrastructure investments are the most efficient and effective option.

V. Summary of Recommendations

The focus of the five-year plans, both current and future, should be around the customer—be it enabling greater customer choice, enhancing customer reliability, improving service quality, or focusing on the greatest amount of customer value creation. A significant question remains whether the plans as drafted are adequately focused on customers as opposed to large capital projects. NRDC acknowledges the need for capital investments in the system to ensure reliability, but we recommend more targeted discussions in utility expenditure proposals to utilize DERs and non-wires alternatives.

In order to effectively meet the goals of the Commission and move towards a more organized approach to distribution system planning, NRDC recommends further that the Commission hold additional workshops and working groups to identify areas of improvement in the utility distribution plans with a focus on developing a transparent distribution system planning process, as discussed in these comments. Additionally, the Commission should direct DTE and Consumers to provide additional details and identify areas across their systems where DERs could be used to avoid or defer distribution or transmission investments, including preparing and making public the results of hosting capacity analyses. NRDC also recommends a discussion on the status of Michigan's existing interconnection rules and processes, especially considering the completion of IEEE 1547.[45] Lastly, greater availability of data, both customer and grid, is vital to ensure the utilities have sufficient insight into their systems to make informed investment decisions, and that

[45] NRDC notes that it may be appropriate for the creation of a working group to go through the technical standards associated with updating the interconnection requirements.

customers, third parties, and the market can make use of that data to determine appropriate customer investments, where on the grid DERs can provide benefits, and where to invest in new technology. Without access to this data, it becomes increasingly difficult to efficiently and effectively plan and optimize the utility system.

NRDC thanks the Commission for initiation of this very important discussion for the customers of these utilities. Ensuring a high level of reliability and service quality supports the economy of Michigan, and a high quality of life for its residents. NRDC looks forward to working with the Commission and Staff as this inquiry continues and anticipates participating in the upcoming workshop on these plans. The five year plans submitted by DTE and Consumers are a good first step in the process, but much works remains to meet the stated goals of this Commission.

Respectfully Submitted,

Date: May 14, 2018 By:________________________________

Ariana Gonzalez
Natural Resources Defense Council

Date: May 14, 2018 By:________________________________

Christopher Villarreal
Plugged In Strategies

Date: May 14, 2018 By:________________________________

Christopher M. Bzdok
Attorney for NRDC

20134-MEC-CE-58

Question:

10. Reference the testimony of James R. Anderson, page 56, Figure 10. Regarding the line labeled "Load Carrying Capabilities and Voltage Support", provide any and all evaluations made by or for the Company of "non-wires alternatives" to the 7 projects identified in this line, including focused energy efficiency programming, localized demand response, distribution-connected generation, customer-hosted generation, and battery storage.

Response:

The Company did not perform any evaluations of "non-wires alternatives" for any of the seven "Load Carrying Capabilities and Voltage Support" projects identified on page 56, Figure 10, of my testimony.

James R. Anderson

James R. Anderson
June 27, 2018

Electric Transmission and HVD Engineering

20134-MEC-CE-59

Question:

11. Reference the testimony of James R. Anderson, page 59, Figure 111. Regarding the investments identified in this Figure, provide any and all evaluations made by or for the Company of "non-wires alternatives" to the 12 projects identified in this Figure, including focused energy efficiency programming, localized demand response, distribution-connected generation, customer-hosted generation, and battery storage.

Response:

There were no "non-wires alternatives" evaluated for the 2019 LVD Substation Capacity projects identified on page 59, Figure 11, of my testimony.

James R. Anderson
June 27, 2018

Electric Transmission and HVD Engineering

Question:

7. Reference testimony of Andrew J. Bordine, page 16 lines 1-12. Please explain how the Company has heretofore considered non-wires alternatives, how the Company "is more fully integrating its processes to consider non-wires solutions", and provide examples of the Company's adoption of non-wires alternatives to address distribution system needs.

Response:

Various forms of non-wires alternatives (NWA) are already an integral part of the electric supply planning process, and are becoming increasingly feasible as both supply and distribution capacity solutions due to technology advancements and cost reductions over time. Today, energy efficiency and demand response programs are already part of the Company's annual load monitoring and forecasting process, and are assessed as economic demand-side solutions within our electric supply resource planning process. More recently, as our supply and distribution planning functions are becoming more integrated, we are maturing capabilities in considering the full suite of NWA solutions to avoid or defer traditional distribution investments. At this point in time, we are still in the early stages of adopting NWA as distribution system planning solutions, but are doing so in a thoughtful and intentional way.

For example, as described in the Company's Electric Distribution Infrastructure Investment Plan (Exhibit A-111 (TJS-1)), the Company is piloting an energy efficiency project at the Swartz Creek substation to test the viability of deferring a potential capacity upgrade. While we are focused on one specific location at this time, we will investigate the possibility of expansion in the future. The Company also has two battery energy storage systems (BESS) installations in 2018 that will be used to further test and learn of BESS applications as solutions to address distribution system needs, as well as how to optimize NWA integration into the system. It is through these types of early deployments that we will continue to grow our capabilities using non-wires alternatives as effective grid planning solutions and plan for future, larger-scale applications.

Lastly, the Company is evolving its planning framework and developing a more customer-driven data analytics approach that will allow us to better prioritize and select investments based on multi-dimensional criteria to align with our distribution planning objectives of safety, reliability, system cost, control, and sustainability. In particular, this planning framework will enhance our current planning approach by incorporating a broader lens to more proactively consider less traditional solutions such as non-wires alternatives. This planning framework is still in development and not yet at full-scale implementation internally. As we continue to evolve over time, we will be able to enable more algorithm-based and automated decision making to help guide our investment spending. Overall, a key part of enabling greater integration of NWA and distributed energy resources will be our continued investment in not just traditional infrastructure investments but also investments to advance our grid capabilities such as telecommunications, grid devices, and advanced applications.

Andrew J. Bordine
July 16, 2018

LVD Engineering

20134-MEC-CE-157

Question:

8. Reference testimony of Andrew J. Bordine, page 16 lines 1-12. Has the Company published information to interested parties about locations in which the Company would obtain distribution system benefits from non-wires alternatives or included such information in any request for proposals for energy efficiency programs, demand response programs, distributed generation, or electricity storage? Has the Company offered to pay avoided distribution system costs to any PURPA qualifying facility where such non-wires alternatives would have value to the Company's distribution system?

Response:

Objection by Counsel: Consumers Energy objects to the request to the extent it seeks information outside the scope of the proceeding, seeks irrelevant information or documents, and because the request is unlikely to lead to the discovery of admissible evidence. Subject to that objection, and without waiving it, the Company provides the following response:

No, the Company has not published information about locations in which the Company would obtain distribution system benefits from non-wires alternatives or included such information in any request for proposals for energy efficiency programs, demand response programs, distributed generation, or electricity storage.

Andrew J. Bordine
July 16, 2018

LVD Engineering

Question:

2. Reference the testimony of James R. Anderson, page 28, lines 2-16.

   a. Does Consumers Energy utilize any load forecast data in its prioritization process?

   b. Does Consumers model expected DER adoption rates which may impact utility assumptions?

   c. Does Consumers consider how to use DER as an input into its planning process and if DER can be used to avoid or defer an investment?

   d. For each response, please explain and provide all supporting documentation.

Response:

a. The Company uses load forecast data as applicable, such as in system capacity planning. Page 28, line 2 through 16, of my direct testimony, referenced in this interrogatory, address LVD Substations Reliability. Inputs utilized to identify specific areas and help prioiritze reliability projects are discussed on page 28, lines 3 and 4, of my direct testimony. Load forecast data is not listed as it is generally not an input for reliability considerations and solutions. Load forecast data could be considered in the analysis for reliability improvement purposes if, for example, a new substation is considered as a supplement to an LVD Lines reliability solution, as such a new substation would be studied utlilizing load forecast data. This example is described page 28, lines 8 through 16 of my direct testimony.

b. There were no DER adoption rates modeled as part of the LVD Substation Reliability analysis for 2019. As discussed in Exhibit A-111 (TJS-1), pages 62 through 66, the Company is committed to expanding its ability to consider DERs and other non-wires alternatives (NWAs) as planning solutions. Various forms of NWA are already an integral part of the electric supply planning process, and are becoming increasingly feasible as both supply and distribution capacity solutions, due to technological advances and cost reductions over time. Today, energy efficiency and demand response programs are already part of the Company’s annual load monitoring and forecasting process, and are assessed as economic demand-side solutions within the Company’s electric supply resource planning process. As the Company’s supply and distribution planning functions become more integrated, the Company will develop the ability to consider the full suite of NWA solutions to avoid or defer traditional distribution investments, as discussed above. However, the Company is still in the early stages of developing the ability to consider NWAs as distribution system planning solutions, and NWAs (including DERs) were therefore not a consideration for the referenced portions of my direct testimony.

c. DER was not considered in the planning process to avoid or defer LVD Substation Reliability investments for 2019, as described in section b above.

d. No supporting documentation exists.

James R. Anderson

James R. Anderson
July 19, 2018

Electric Transmission and HVD Engineering

20134-MEC-CE-171

Question:

3. Reference the testimony of James R. Anderson, page 30, lines 20-22, page 41, lines 20-22, page 53, lines 14-20, page 54, line 3-6, page 58, lines 18-21, page 59, line 9-page 62, line 5, page 76, lines 3-6, page 92, lines 5-7. Has Consumers Energy identified any substations that may be a target for non-wires alternatives pilot? How are DER and potential nonwires alternatives considered among the identified categories? Please explain and provide all supporting documentation.

Response:

As described in Exhibit A-111 (TJS-1), the Company's Electric Distribution Infrastructure Investment Plan, beginning on page 69, the Company is piloting an energy efficiency project at the Swartz Creek substation to test the viability of deferring a potential capacity upgrade. While the Company is focused on one specific location at this time, the Company will investigate the possibility of expansion in the future. Additionally, as discussed in Exhibit A-111 (TJS-1), pages 62 through 66, the Company is also developing two battery energy storage systems ("BESS") installations in 2018 that will be used to further test and study BESS applications as solutions to address distribution system needs, as well as how to optimize non-wires alternatives ("NWA") integration into the system. It is through these types of early deployments that the Company will continue to develop its abilities to use NWAs as effective grid planning solutions and to plan for future, larger-scale applications.

Various forms of NWA are already an integral part of the electric supply planning process, and are becoming increasingly feasible as both supply and distribution capacity solutions due to technology advancements and cost reductions over time. Today, energy efficiency and demand response programs are already part of the Company's annual load monitoring and forecasting process, and are assessed as economic demand-side solutions within the Company's electric supply resource planning process. As the Company's supply and distribution planning functions become more integrated, the Company will develop the ability to consider the full suite of NWA solutions to avoid or defer traditional distribution investments, as discussed above. However, the Company is still in the early stages of developing the ability to consider NWAs as distribution system planning solutions, and NWAs were therefore not a consideration for the referenced portions of my direct testimony.

James R. Anderson
July 19, 2018

Electric Transmission and HVD Engineering

20134-MEC-CE-196

Question:

28. Reference the testimony of Timothy J. Sparks, page 5, lines 18-21. Please describe and provide supporting documentation for each example or instance where Demand Response (DR) or Energy Efficiency (EE) were used to defer any HVD or LVD capital projects in the EDIIP. Please describe how DR and EE were used and modeled when considering the EDIIP strategy. Please identify the utility objectives that are met by DR and EE. Please explain your responses.

Response:

The Company's Energy Efficiency (EE) and Demand Response (DR) programs are currently designed to help customers reduce energy waste and shift/reduce load during system peak hours, which defers and/or eliminates the need for additional supply-side resources. EE and DR programs can potentially defer and/or eliminate the need for HVD or LVD capital projects. The Company recognizes that both types of demand-side management resources are important to consider when developing its longer-term electric supply and distribution planning strategies as evidenced in both the Company's EDIIP (Exhibit A-111 (TJS-1)) and recently filed 2018 Integrated Resource Plan (MPSC Case No. U-20165).

Presently, the Company has one EE and DR project that targets deferral of specific HVD or LVD capital investments. That project is located in the Swartz Creek area. Please refer to Exhibit A-111 (TJS-1), page 69 for more detail.

In developing the Company's EDIIP, DR and EE were not explicitly modeled. The Company's long-term vision for the electric distribution system centers on five primary customer-driven objectives: Safety and Security; System Cost; Reliability; Sustainability; and Control. As presented in Sections II.B and II.C of the EDIIP, the advance and growth in EE and DR are key to achieving our objectives on Sustainability and Control by reducing waste in the electric system, improving the Company's carbon footprint, and enabling greater customer control in energy consumption. Accordingly, the Company's EDIIP presents metrics and performance targets for measuring progress in both EE and DR over the next five years. With regards to LVD and HVD capital planning, absent these programs, the Company's electric distribution average and peak loads would be higher – potentially requiring additional infrastructure investment over time. Although the Company currently has only one project where EE and DR programs are being utilized to target deferral of electric distribution capital expenditure, it is anticipated and expected that more non-wires alternatives will become more significant options that will be deployed instead of traditional infrastructure projects.

Electric Grid Integration

Timothy J. Sparks
July 19, 2018

<u>Question:</u>

4. Reference the testimony of James R. Anderson, p. 58, line 10.

   a. When forecasting peak load conditions for each substation, for how many years into the future are such forecasts developed?

   b. When developing such peak load forecasts for each substation, how does Consumers Energy account for expectations regarding energy efficiency investments made by customers served by the substations, particularly efficiency investments driven by the Company's Energy Waste Reduction (EWR) programs? Does it disaggregate the estimated system-wide energy savings forecast for EWR programs to savings that could or should be expected at each substation – given the mix of EWR programs offered system-wide, the different kinds of customers that participate in each program, the mix of customers served by each substation, the season and time of day during which each substation experiences peak demand, the load shapes of the savings provided by different EWR programs, etc.? If so, please explain how this is done.

<u>Response:</u>

a. 10 year load forecasts are typically used for LVD substation peak load forecasting. On occasion a longer forecast period of up to 20 years is analyzed.

b. Please see discovery response 20134-MEC-CE-196. As explained in that response, energy efficiency was not explicitly modeled in the development of the Company's distribution plan, other than as it relates to the Company's Swartz Creek pilot, which is using targeted energy efficiency to defer capital investments. As further explained in discovery response 20134-MEC-CE-196, if the Company's energy efficiency programs did not exist, then average and peak loads on the Company's distribution would generally be higher, potentially requiring additional capital investment over time.

   Additionally, please see discovery response 20134-MEC-CE-171. As stated in that response, "Various forms of NWA are already an integral part of the electric supply planning process, and are becoming increasingly feasible as both supply and distribution capacity solutions due to technology advancements and cost reductions over time. Today, energy efficiency and demand response programs are already part of the Company's annual load monitoring and forecasting process, and are assessed as economic demand-side solutions within the Company's electric supply resource planning process. As the Company's supply and distribution planning functions become more integrated, the Company will develop the ability to consider the full suite of NWA solutions to avoid or defer traditional distribution investments, as discussed above. However, the Company is still in the early stages of developing the ability to consider NWAs as distribution system planning solutions, and NWAs were therefore not a consideration for the referenced portions of my direct testimony." Since the Company is still in the early stages of developing the ability to consider these investments and programs, they were not generally considered for the LVD substation capacity projects referred to on page 58 of my direct testimony.

James R. Anderson

James R. Anderson
August 20, 2018

Electric Transmission and HVD Engineering

20134-MEC-CE-452

Question:

6. Reference the testimony of James R. Anderson, p. 58, lines 18-21. All four of the "alternatives typically considered" to resolve an LVD substation capacity situation are supply-side alternatives. Does Consumers ever consider demand-side alternatives, such as increasing energy efficiency investments by customers served by the substation, deploying demand response resources in homes and businesses served by the substation and/or increasing localized investment and/or deployment of distributed generation? If so, please explain how these demand-side alternatives are considered, how their relative merits are compared to the supply-side alternatives listed and the conditions under which they are preferred? If not, why not?

Response:

As explained in discovery response MEC-CE-170b in this case, the Company already includes energy efficiency and demand response programs as part of its load monitoring and forecasting process, and the Company assesses such demand-side solutions as part of its electric supply resource planning process. As the Company's supply and distribution planning functions become more integrated, the Company will develop the ability to consider a full suite of non-wires alternatives, including the demand-side alternatives outlined in this interrogatory, to avoid or defer traditional distribution investment. However, the Company is still in the early stages of developing the ability to consider these alternatives, so they were not generally considered for the LVD substation capacity projects referred to on page 58, lines 18 through 21 of my direct testimony.

However, as explained in discovery response MEC-CE-171 in this case, the Company is using its energy efficiency pilot project at Swartz Creek to test the viability, at one particular location, of using demand-side alternatives to defer a capacity upgrade. As explained in discovery response MEC-CE-171, the Company will use this kind of early deployment to develop the ability to more broadly consider demand-side alternatives in the future.

James R. Anderson
James R. Anderson
August 20, 2018

Electric Transmission and HVD Engineering

Question:

8. Reference the testimony of Andrew J. Bordine, p. 16, lines 9-12. Mr. Bordine states that the Company "…is more fully integrating its processes to consider non-wires solutions as well as traditional infrastructure investments."

a. Please explain in detail what the Company is doing to "integrate its processes" in order to consider non-wires solutions.

b. When will the Company's systems be sufficiently "integrated" to enable routine consideration of non-wires solutions?

c. When does the Company expect to begin routinely considering non-wires solutions?

d. What are there any obstacles to routinely considering non-wires solutions today? How is the Company planning to address them? Over what time frame? Please provide documentation supporting your response.

Response:

a. As explained in my response to 20134-MEC-CE-156, energy efficiency and demand response programs are already integrated in the Company's electric supply resource planning. With regards to integration with distribution planning, the Company is still in the early stages of developing the ability to consider these alternatives. However, the Company believes non-wires alternatives (NWA) and distributed energy resources will indeed be critical parts of the future distribution network. Accordingly, the Company is moving in that direction through a very thoughtful and intentional approach including targeted pilots and evolution of its distribution system planning processes.

The NWA pilot project mentioned in my response to 20134-MEC-CE-156 is the first step in integrating our processes by evaluating non-traditional, demand-side solutions to potentially defer or avoid a traditional distribution investment (substation transformer capacity upgrade). Through this pilot, the Company will be able to test, learn and adapt to determine the feasibility of NWA as distribution system solutions. This will, in turn, help the Company more broadly develop the appropriate framework and suitability criteria for future NWA projects.

In parallel to this, since late 2017, the Company has been working to enhance its distribution planning process through increased use of multi-dimensional data to prioritize needs across the system and solve for a broader set of customer-centric objectives. As part of this, the Company is building in more structured processes and algorithm-based decision-making to enhance prioritization around Sustainability and Control objectives. This will, in turn, guide more proactive and intentional action towards considering NWA more routinely as grid solutions. This evolution in the Company's distribution planning process is still in early design and has not been fully rolled out or implemented across the broader organization. This change requires advancements in people, process and technology.

Lastly, through both of the aforementioned efforts (pilots and enhancements to distribution planning processes), the Engineering and Customer organizations are continuously increasing collaboration to drive more integrated decision-making and outcomes.

b. Not unlike many other utilities across the industry, the Company's distribution planning process is in a state of evolution, and as explained in sub-part (a), the Company is continuing to advance its integration of NWA as grid solutions through a multi-prong approach. Part of the pace will be set by the learnings from its NWA pilot program, and accordingly, does not have a specific expected date when full integration will be achieved.

c. Please see my response to sub-part (b) above.

d. The major obstacles to routinely considering non-wires solutions today are determining the appropriate suitability criteria and feasibility of NWA to defer or avoid traditional distribution investments and maturity and experience around this capability. In addition, redesign of current planning processes is required, with implications on people and technology. As described in my response to sub-part (a), the Company has efforts underway to address these obstacles, largely during the 2017-2019 time frame. Please refer to Exhibit A-111 (TJS-1), the Company's Electric Distribution Infrastructure Investment Plan as supporting documentation. Also, please see Attachment 1 of this response which is a recently shared presentation made by Consumers Energy at the MPSC Distribution System Planning Technical Conference held on August 7, 2018. During this presentation, the Company shared information regarding both efforts underway described in sub-part (a).

Attachments
1. Attachment 1 – "20134-MEC-CE-454 Attachment 1 – CE EDIIP Presentation.pdf"

Andrew J. Bordine
August 20, 2018

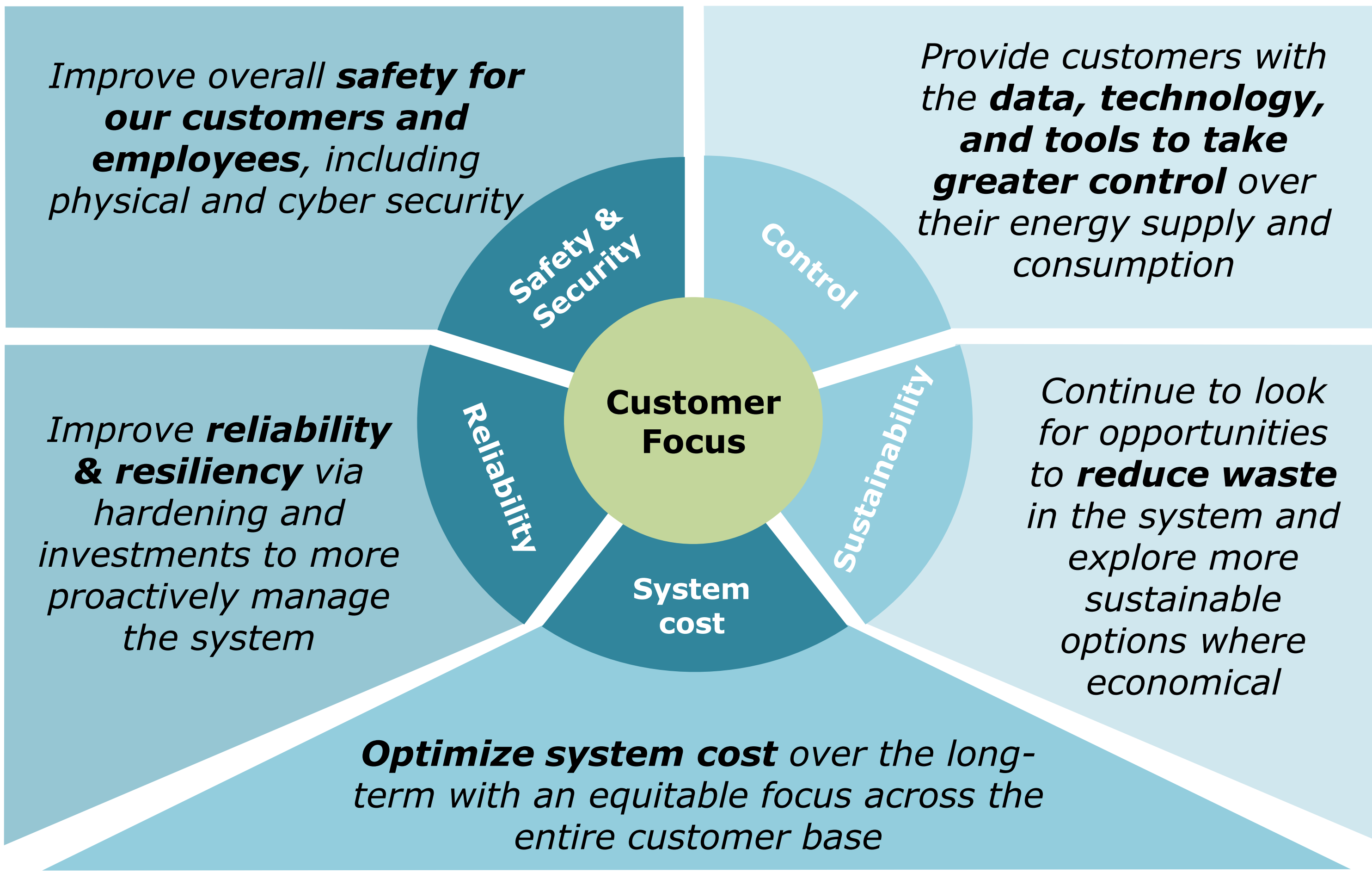
LVD Engineering

Consumers Energy Electric Distribution Infrastructure Investment Plan (EDIIP)

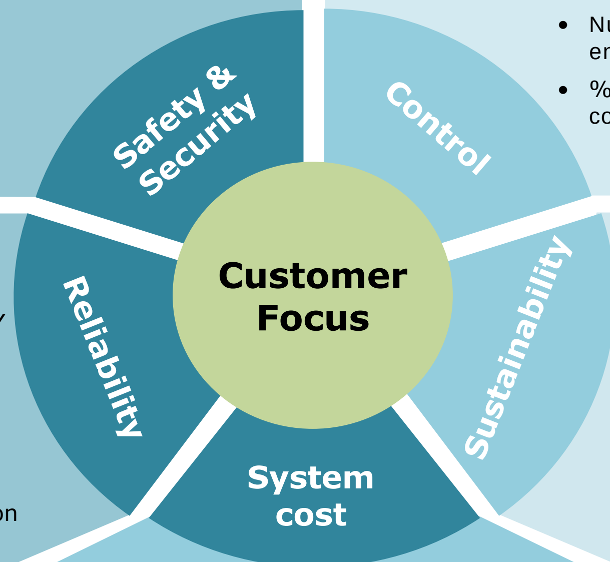
MPSC Technical Conference
August 7, 2018

Consumers Energy
Count on Us®

In our EDIIP, we presented our five objectives for the electric distribution system



We measure ourselves against these objectives with 14 key metrics that may evolve over time



Improve overall ***safety for our customers and employees****, including physical and cyber security*

- Recordable Incident Rate
- Wiredown Relief Factor

Provide customers with the ***data, technology, and tools to take greater control*** *over their energy supply and consumption*

- Number of residential customers enrolled in peak reduction programs
- % rating 9/10 on CE's efforts to help control usage (JDP)

Improve ***reliability & resiliency*** *via hardening and investments to more proactively manage the system*

- SAIDI (excl. MED)
- SAIFI (excl. MED)
- % of cust. with ≥3 interruption
- % of cust. with ≥ 1 5hr interruption
- % of cust. restored within 24hrs after MED interruption

Continue to look for opportunities to ***reduce waste*** *in the system and explore more sustainable options where economical*

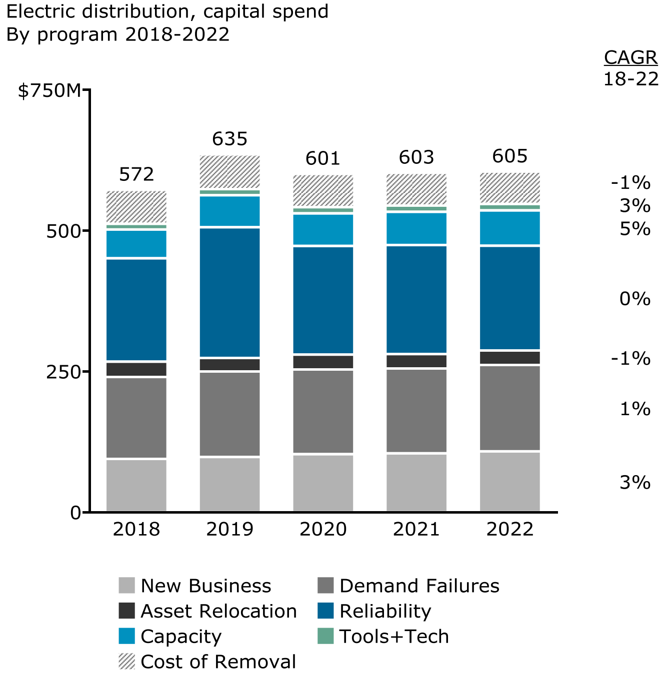
- Energy savings through energy efficiency programs
- Annual distribution system load factor
- % distribution energy loss

Optimize system cost *over the long-term with an equitable focus across the entire customer base*

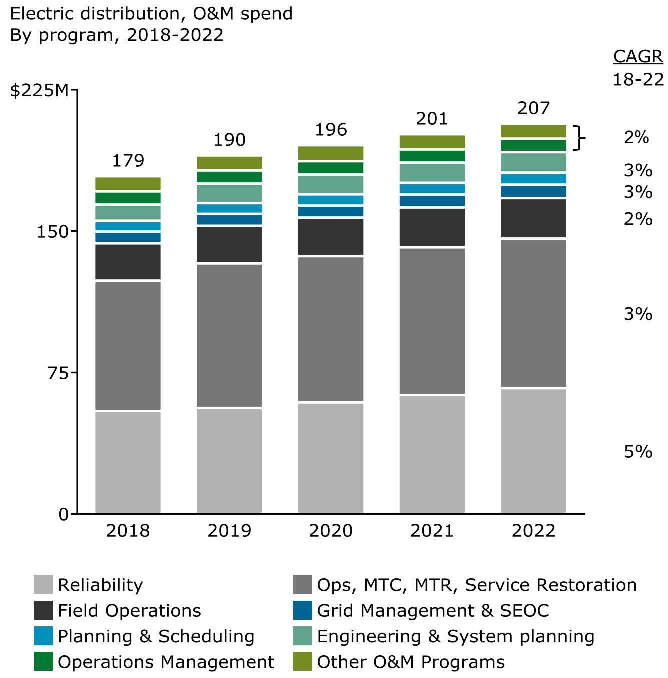
- Service restoration O&M cost per incident
- Forestry cost per line-mile trimmed

Over the next 5 years we plan to invest ~$3B of capital in our infrastructure, and ~$200M annually in O&M

Capital investment Programs 2018-2022 Plan

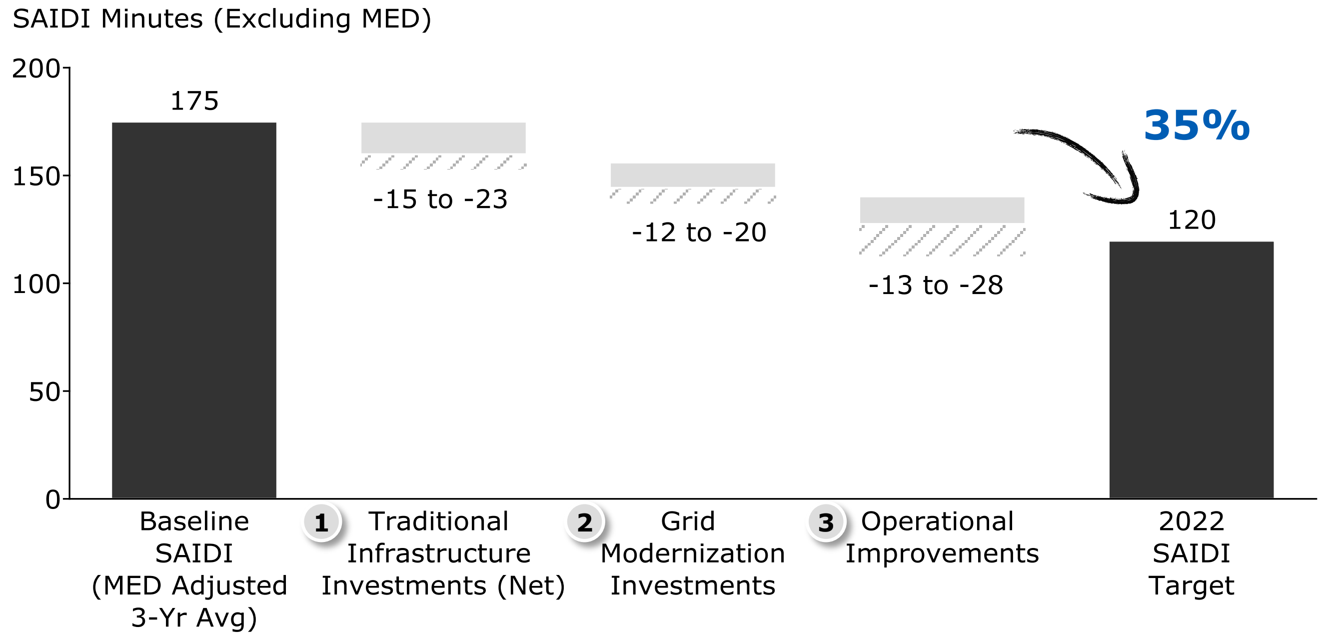


O&M Spending Programs 2018-2022 Plan



Note: Other O&M Programs includes Engineering Ops Support, Ops Performance, and Joint Pole Rental Costs

We are targeting a 35% SAIDI improvement by 2022, to reach the best SAIDI in our company's history…



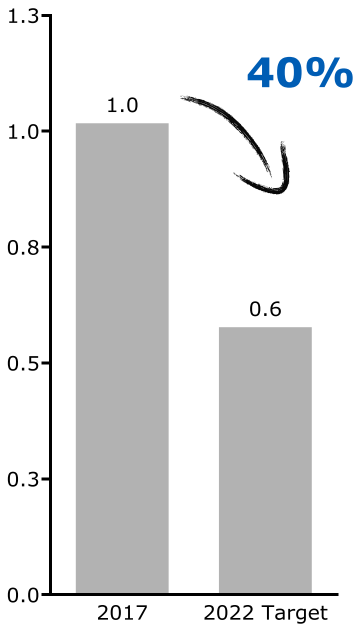
	Baseline	2022 Target
SAIFI	0.95	0.80
CAIDI	185	150

Note: The Traditional Infrastructure Investments bar includes the CAIDI impact from a new HQ, reduced primary outages, and tree trimming; Grid Mod benefit includes ~9 minutes from SAIFI based impact, and ~7 minutes from CAIDI based impact
Source: Grid MD; EDIIP Budget; Grid Mod reliability assessment

…as well as many other benefits to customers

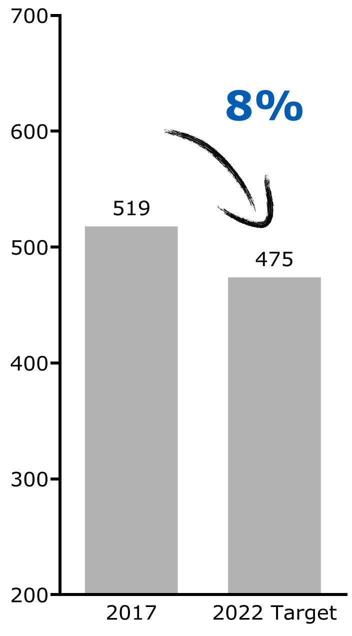
SAFETY & SECURITY

Electric Operation Recordable Incident Rate



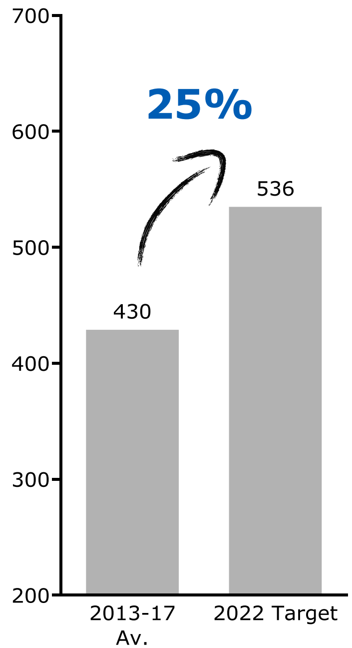
COST

Service restoration O&M cost per incident (3-year rolling avg.)



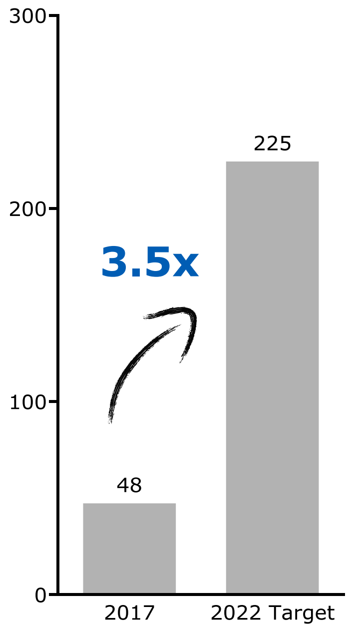
SUSTAINABILITY

Energy savings through Energy Efficiency programs (GWh)



CONTROL

Number of res. customers enrolled in the Peak Power Savers® programs



Note: Service restoration metric includes major event days (MED)

EDIIP represents a step in the journey towards achieving our broader set of customer-focused objectives

Historical approach → **EDIIP approach** → **Future state**

Key themes and focus areas:

- Objectives and metrics
- Distributed Energy Resources (DER) and Non-Wires Alternatives (NWA)
- Multi-dimensional data and analytics
- Alternative rate recovery mechanisms

Evolution through:

- Advanced technology investments
- Pilots and early, smaller-scale demonstration projects
- Organizational and cross-functional integration
- Multi-year investment recovery mechanism (IRM) and shared savings mechanisms

We are increasing cross-functional inputs to planning and prioritization of grid investments

	CUSTOMER	OPERATIONS	ENGINEERING	FINANCE	OTHER
Example data for determining investment priorities	• Number and type of customers (Residential, C&I) • Customer characteristics	• Operational centers and zones of control • Crew scheduling • Local work execution considerations	• Asset age and history • Reliability performance • SAIDI contribution of a repair or replacement	• Investment history • Short- and long-range budgets and forecasts	• Regulatory direction • Community and stakeholder feedback

*Building an **integrated view of the system**, based on **multi-dimensional data** and inputs to better prioritize investments across a broader set of **customer-focused objectives** and over a multi-year period*

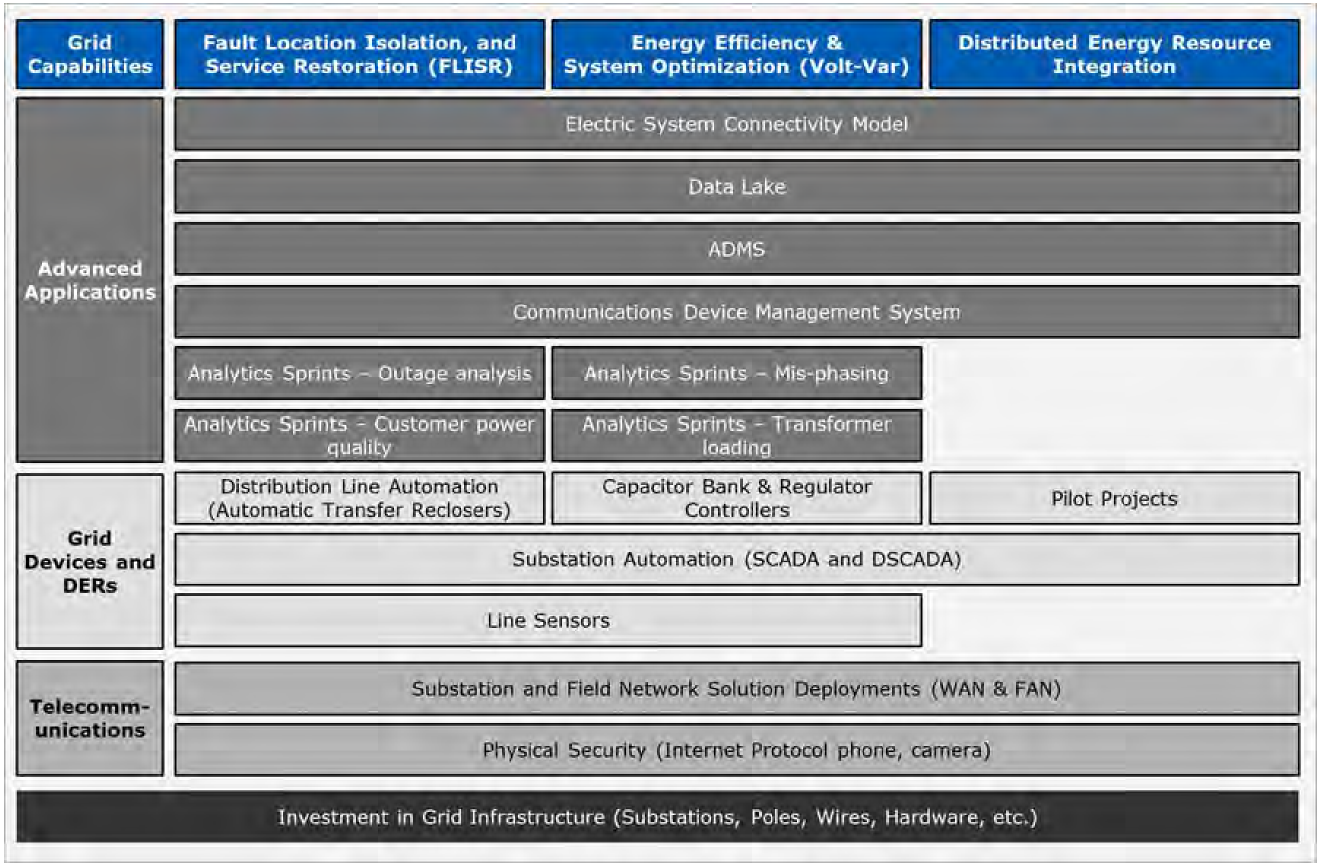
Appendix

On March 1, 2018 we filed the Electric Distribution Infrastructure Investment Plan (EDIIP) with the MPSC

SECTION		CONTENT
I	Executive Summary	• Summary of the report
II	Vision for the CE Electric Distribution System	• Our vision for the distribution grid based on the five objectives of reliability, safety/security, control, sustainability, and system costs. Includes metrics that we will use to measure success.
III	Description of CE Distribution System	• Overview of the current state of the system and current state of assets
IV	Overview of System Performance	• Our historical performance across critical metrics and how we benchmark against our peers; broken out system-wide, by HQ, and by circuit
V	Grid Capabilities	• The vision for the future state modernized grid, as well as our current progress and summary of future plan to build advanced grid capabilities
VI	Approach to Investment Planning	• High level overview of our current investment and engineering planning process and design standards (planning detail specific to programs is in Sections VIII and IX)
VII	Summary of Plan and Projected Impact	• Overview of current financial plan and impact on our 5-objectives
VIII	Capital Programs	• Detailed program narratives and financial plan for each capital investment program; includes discussion on investment and prioritization logic as well as individual program processes
IX	O&M Programs	• Detailed program narratives and financial plan for each O&M program.
X	Conclusion	• Closing comments

Consumers Energy Count on Us®

Grid Modernization Capability Schematic



Source: Figure 25, Consumers Energy Electric Distribution Infrastructure Investment Plan (EDIIP), page 46.

Consumers Energy

Count on Us®

20134-MEC-CE-455

Question:

9. Reference the testimony of Andrew J. Bordine, p. 19, lines 2-9. Mr. Bordine states that "the Company uses several critical inputs and analyses to aggregate multiple data sources in order to best target and prioritize customer reliability issues to address, identifying specific investments based on the probability of future issues." He then gives examples of feedback from "customer-facing groups in the Economic Development and Customer Care departments". Does the Company obtain and use data regarding the nature of the Company's Energy Waste Reduction (EWR) programs, the load shapes of the savings those programs produce, historic participation in those programs by different types of customers, and other related information to inform forecasts of demand for different components of the LVD system and therefore the likely date of need for capacity upgrades to those system components? If so, please explain how this is done? If not, why not?

Response:

The LVD Planning group does not currently have an integrated system with the Energy Efficiency group on energy reduction that would impact the need for capacity upgrades. The Substation Planning group performs long range plans to address substation equipment that is forecasted to become overloaded. We implemented a EWR solution in the Swartz Creek area to defer a $1M+ substation upgrade project needed due to a projected overload. The load did not grow to the level we anticipated diminishing the effectiveness of the project. The planning process for projecting overloaded conductors and devices takes place annually and typically evaluates the load for the following year rather than several years into the future. This is due to the uncertainty of the projected load.

Andrew J. Bordine
August 8, 2018

LVD Engineering

MAXWELL V. BAUMHEFNER

111 Sutter Street, 21st Floor, San Francisco, CA 94104 ♦ (415) 875-8204 ♦ *mbaumhefner@nrdc.org*

EXPERIENCE

Natural Resources Defense Council San Francisco, CA 2010-present
SENIOR ATTORNEY, CLIMATE & CLEAN ENERGY PROGRAM

Energy Bar Association, Western Chapter 2008 - 2010
LAW STUDENT DIRECTOR & CHAIR OF YOUNG LAWYERS COMMITTEE

California Public Utilities Commission San Francisco, CA 2008
EXTERN TO COMMISSIONER

Orrick, Herrington & Sutcliffe LLP Menlo Park, CA 2008
SUMMER ASSOCIATE

Energy Conservation Finance Institute San Francisco, CA 2007
VOLUNTEER

Backroads Berkeley, CA 2003 - 2007
TRIP LEADER IN U.S., FRANCE, ITALY, AND SWITZERLAND

Della Fattoria Petaluma, CA 2002 - 2006
BREAD BAKER & ASSISTANT MANAGER

EDUCATION

University of California Berkeley School of Law (Boalt Hall) Berkeley, CA
J.D. WITH ENVIRONMENTAL LAW CERTIFICATE, MAY, 2009

- *Honors:*
  - Prosser Prize in Civil Procedure II
  - Prosser Prize in Environmental Law and Policy
- *Activities:*
  - Internet Editor of the Ecology Law Quarterly
  - Outreach Director, Berkeley Energy Resources Collaborative @ Boalt

Pomona College Claremont, CA
B.A. IN HISTORY, MINOR IN FRENCH, *Cum Laude*, MAY, 2001

PUBLICATIONS

Guiding Principles for Utility Programs to Accelerate Transportation Electrification, NRDC, 2017.

Driving Out Pollution, NRDC, 2016.

Plugging Vehicles into Clean Energy, The Electricity Journal, 2013.

The Importance of Model Utility Electric Vehicle Policies, The Electricity Journal, 2012.

Negawatts as Green Energy: The Impact of the Inclusion of Energy Efficiency on the Goals of a RPS, American Bar Association Section of Environment, Energy, & Resources Newsletter (May, 2009).

The Ozone Saga, The Ecology Law Quarterly, Volume 35: 557 (2008).

Electric Vehicle Cost-Benefit Analysis

Plug-in Electric Vehicle Cost-Benefit Analysis: Michigan

MJB & A

July 2017

Contents

List of Figures

List of Tables

About M.J. Bradley & Associates

M.J. Bradley & Associates, LLC (MJB&A), founded in 1994, is a strategic consulting firm focused on energy and environmental issues. The firm includes a multi-disciplinary team of experts with backgrounds in economics, law, engineering, and policy. The company works with private companies, public agencies, and non-profit organizations to understand and evaluate environmental regulations and policy, facilitate multi-stakeholder initiatives, shape business strategies, and deploy clean energy technologies.

Our multi-national client base includes electric and natural gas utilities, major transportation fleet operators, clean technology firms, environmental groups and government agencies.

We bring insights to executives, operating managers, and advocates. We help you find opportunity in environmental markets, anticipate and respond smartly to changes in administrative law and policy at federal and state levels. We emphasize both vision and implementation, and offer timely access to information along with ideas for using it to the best advantage.

For questions or comments, please contact:

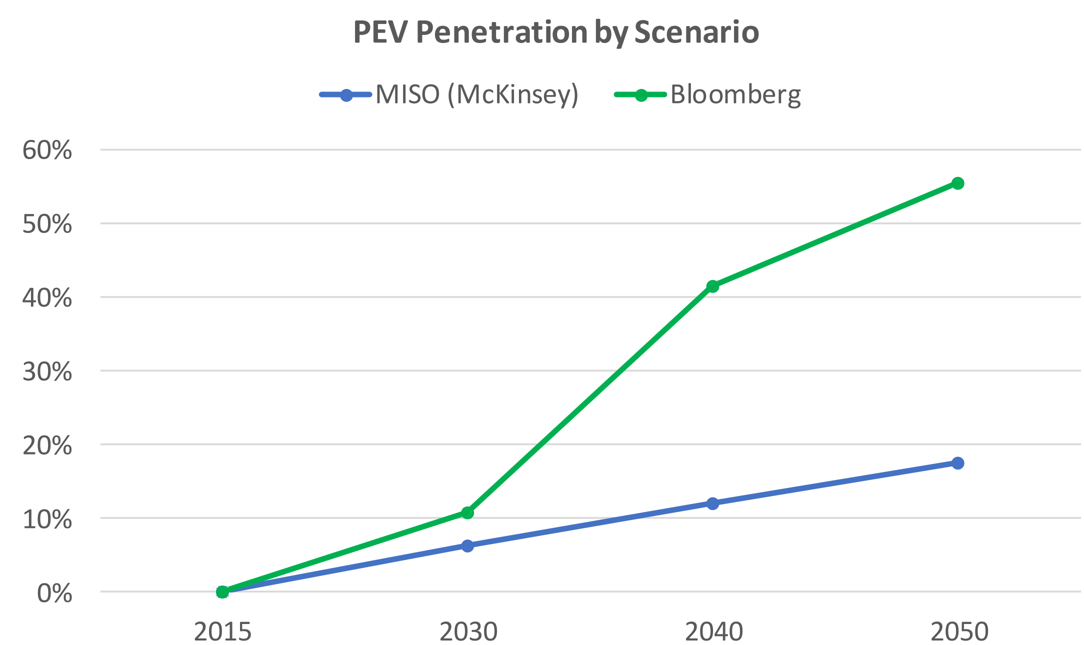
Dana Lowell
Senior Vice President
M.J. Bradley & Associates, LLC
+1 978 369 5533
dlowell@mjbradley.com

Executive Summary

This study estimated the costs and benefits of increased penetration of plug-in electric vehicles (PEV) in the state of Michigan. The study estimated the benefits that would accrue to all electric utility customers in Michigan due to greater utilization of the electric grid during off-peak hours, and increased utility revenues from PEV charging. In addition, the study estimated the annual financial benefits to Michigan drivers from owning PEVs– from fuel and maintenance cost savings compared to owning gasoline vehicles - and societal benefits resulting from reduced gasoline consumption and associated greenhouse gas (GHG) emissions.

Two different penetration levels between 2030 and 2050 are utilized to estimate costs and benefits.[1] The "Moderate PEV" scenario is based on levels of PEV penetration included in an on-going future planning analysis being conducted by the Midcontinent Independent System Operator (MISO), which is the regional transmission organization that covers Michigan. The "High PEV" scenario is based on Bloomberg New Energy Finance's (Bloomberg) July 2017 forecast of U.S. PEV sales through 2040. See Figure 1 for a comparison of the two scenarios through 2050.

Figure 1 Comparison of PEV Penetration Scenarios



Under the Moderate PEV (MISO) scenario, the number of PEVs registered in Michigan would increase from approximately 14,000 today to 591,828 in 2030, 1.13 million in 2040, and 1.7 million in 2050. This equates to approximately 6 percent of in-use light duty vehicles in Michigan in 2030, 12 percent in 2040, and 17.6 percent in 2050. Under the High PEV (Bloomberg) scenario there would be 999,450 PEVs in Michigan by 2030, rising to 3.9 million in 2040, and 5.4 million in 2050. This equates to 10.8 percent of in-use light duty vehicles in Michigan in 2030, rising to 41.5 percent in 2040 and 55.7 percent in 2050.

[1] PEVs include battery-electric vehicles (BEV) and plug-in hybrid vehicles (PHEV). This study focused on passenger vehicles and trucks; there are opportunities for electrification of non-road equipment and heavy-duty trucks and buses, but evaluation of these applications was beyond the scope of this study.

As shown in Figure 2, if Michigan PEV adoption follows the trajectory assumed by MISO, the net present value of **cumulative net benefits from greater PEV use in Michigan will exceed $8.6 billion state-wide by 2050**.[2] Of these total net benefits:

- $0.8 billion will accrue to electric utility customers in the form of reduced electric bills,
- $6.3 billion will accrue directly to Michigan drivers in the form of reduced annual vehicle operating costs, and
- $1.5 billion will accrue to society at large, as the monetized value of reduced GHG emissions.

As shown in Figure 3, if Bloomberg's projections for national EV sales are achieved in Michigan, which would result in even greater PEV penetration, the net present value of **cumulative net benefits from greater PEV use in Michigan could exceed $31 billion state-wide by 2050**. Of these total net benefits:

- $2.6 billion will accrue to electric utility customers in the form of reduced electric bills,
- $23.1 billion will accrue directly to Michigan drivers in the form of reduced annual vehicle operating costs, and
- $5.7 billion will accrue to society at large, as the monetized value of reduced GHG emissions.

A large portion of the direct financial benefits to Michigan drivers derives from reduced gasoline use - from purchase of lower cost, locally produced electricity instead of gasoline imported to the state. Under the Moderate PEV (MISO) scenario, PEVs will reduce cumulative gasoline use in the state by more than 5 billion gallons through 2050, helping to promote energy security and independence, and keeping more of vehicle owners' money in the local economy, thus generating even greater economic impact. In addition, this reduction in gasoline use will reduce net GHG emissions by 26 million metric tons[3], which would provide an additional societal benefit of $1.5 billion, from reduced pressure on climate warming.

With PEV penetration equivalent to the High PEV (Bloomberg) scenario, electrifying vehicles will reduce cumulative gasoline use in the state by more than 18 billion gallons through 2050, and will reduce GHG emissions by more than 99 million metric tons, which would provide an additional societal benefit of $5.7 billion.

In 2050, annual average gasoline savings will be approximately 209 gallons per PEV under the Moderate PEV (MISO) scenario, while savings under the High PEV (Bloomberg) scenario are nearly 250 gallons per PEV.

---

[2] Using a 3% discount rate

[3] Net of emissions from electricity generation

Figure 2 *NPV Cumulative Societal Net Benefits from MI PEVs – Moderate PEV (MISO) scenario*

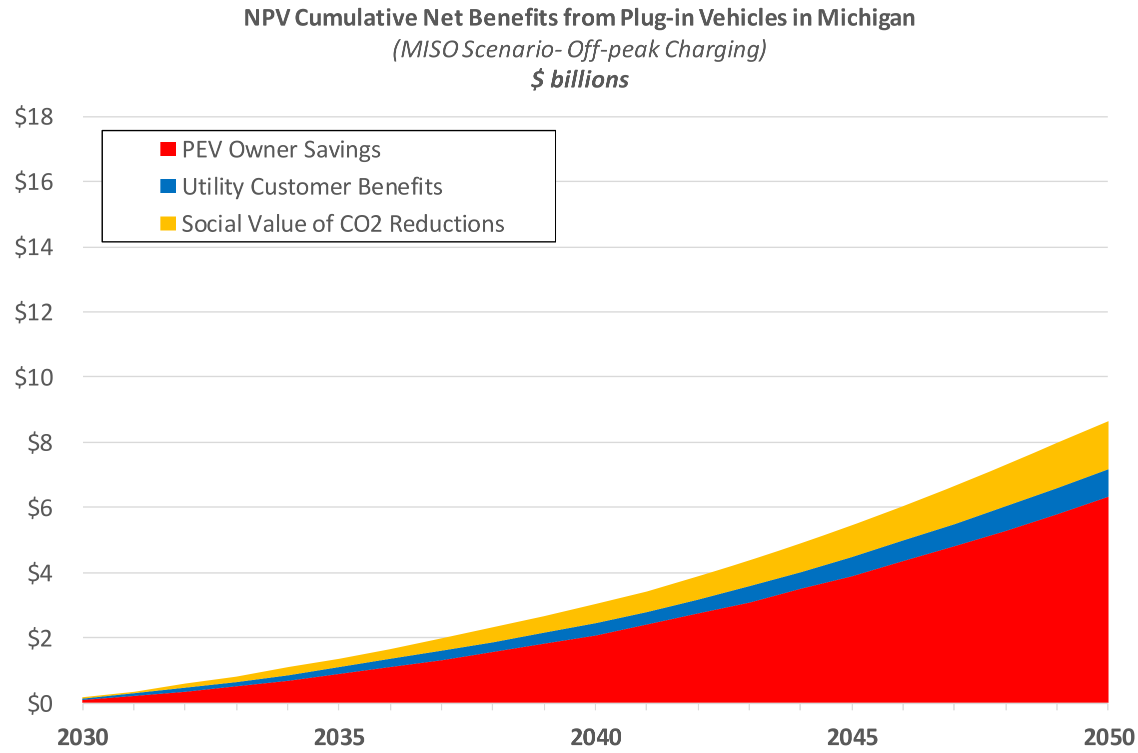
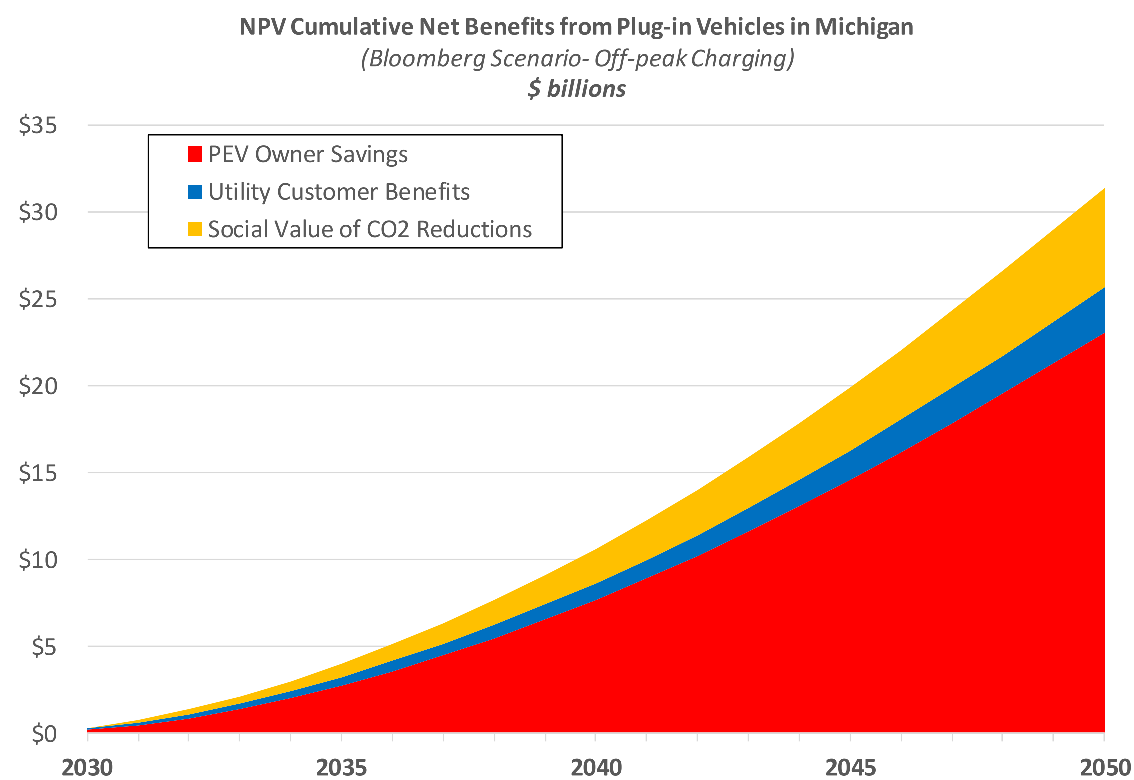


Figure 3 *NPV Cumulative Societal Net Benefits from MI PEVs – High PEV (Bloomberg) scenario*



Background - Michigan

For over 100 years, the auto industry has played a major role in Michigan's economy. Many of the major automakers, including Ford, General Motors and Chrysler began in Michigan. The auto industry employs thousands of workers in the state and have made commitments to develop and offer PEVs.

There are currently 3.4 million cars and 4.9 million light trucks registered in Michigan, and these vehicles travel 97.8 billion miles per year. Both the number of vehicles and total annual vehicle miles are projected to increase by 16 percent through 2050, to 9.6 million light duty vehicles traveling 113.4 billion miles annually. As of January 2016, there were about 14,000 PEVs (including battery-electric and plug-in hybrid vehicles) registered in Michigan and they comprised about 0.14 percent of the 8.3 million cars and light trucks registered in the State. In 2014 and 2015, sales of new PEVs in the state were less than one half of one percent of new vehicle sales. [1] Despite this relatively low percentage, Michigan ranks in the top ten states for PEV sales.

A wide range of policy makers and other stakeholders in Michigan have already demonstrated interest in accelerating PEV adoption in the state. Various policies, programs, and commitments adopted at the state, local, and company level have laid some of the groundwork necessary to support widespread transportation electrification.

The Michigan Public Service Commission has been considering the role of public utilities in promoting clean transportation since 2008, when it began a two-year, $5 million study to assess the environmental and electric system impacts of electric vehicles, with a goal of expanding the state's EV economy. The commission will continue these efforts in August 2017, with a technical conference that will focus on the role of regulated utilities and the MPSC in facilitating deployment of EVSE infrastructure. [5] The conference will also study how the expansion of alternative fuel and electric vehicles will impact the infrastructure of Michigan's utilities, and consequentially, ratepayers. [6]

In addition, a number of Michigan utilities have already initiated their own PEV programs. Indiana Michigan Power and the Lansing Board of Water and Light both currently offer rebates to customers who purchase a qualified PEV and install a charging station at home [2], and both DTE and Consumers Energy previously offered residential charging infrastructure rebates as part of a pilot program. Consumers Energy Company recently withdrew a similar, proposed plan that included the installation of *public* electric vehicle supply equipment (EVSE) infrastructure. [3] These utilities all offer a variety of electric rate plans for EV owners who own a home charging station. [4]

Michigan's state government has also made recent commitments to reduce energy waste and increase the use of renewable power in the state. After significant debate and uncertainty, in December 2016 the state's energy policies were updated. Among the adopted provisions were requirements for Integrated Resource Planning by regulated utilities, an extension of the energy waste reduction (EWR) standard with incentives for exceeding the targets, and an extension of the state's renewable portfolio standard (RPS). The RPS now requires 12.5 percent of annual electricity to be generated with renewables in 2019 and 15 percent in 2021. [7]

In addition, Michigan's largest utility, DTE Energy, announced in May 2017 that it would reduce its carbon emissions by 80 percent from 2005 levels by 2050. [8] Several cities –including Detroit, Ann Arbor, and Grand Rapids – have committed to a variety of emission reduction and renewable energy goals. [9] As part of its sustainability commitments, Detroit has committed to a 10 percent plug-in electric vehicle carve out for all service vehicles purchased in 2017. The city has also set an annual goal to replace 10 percent of light-duty vehicles taken out of service with plug-in electric vehicles and use Low Speed Electric Vehicles for transit police and safety and security staff. [10] At least fourteen municipalities in the state have pledged to uphold and adopt the goals of the Paris Agreement as a response to the federal government's recent decision to withdraw from the accord. [11]

In short, policymakers, utilities, NGOs, and others have expressed interest in developing initiatives that accelerate PEV adoption and decarbonize energy use in the state.

Study Results

This section summarizes the results of this study, including the projected number of PEVs; electricity use and load from PEV charging; projected gasoline savings and GHG reductions compared to continued use of gasoline vehicles; financial benefits to utility customers from increased electricity sales; and projected financial benefits to Michigan drivers compared to owning gasoline vehicles. All costs and financial benefits are presented as net present value (NPV), using a 3 percent discount rate.

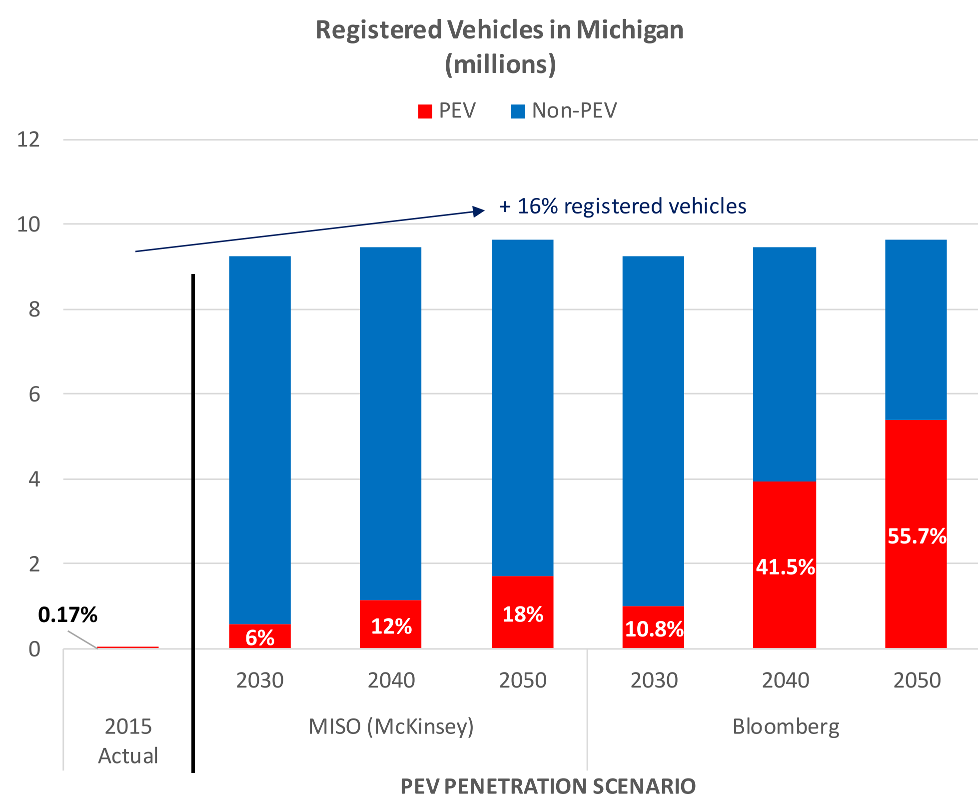
Plug-in Vehicles, Electricity Use, and Charging Load

Vehicles and Miles Traveled

The projected number of PEVs and conventional gasoline vehicles in the Michigan light duty fleet[4] under each PEV penetration scenario is shown in Figure 4, and the projected annual miles driven by these vehicles is shown in Figure 5. Under the Moderate PEV (MISO) scenario, the number of PEVs registered in Michigan would increase from approximately 14,000 today to 591,828 in 2030, 1.13 million in 2040, and 1.7 million in 2050. Under the High PEV (Bloomberg) scenario there would be 999,450 PEVs in Michigan by 2030, rising to 3.9 million in 2040, and 5.4 million in 2050.

Note that under both PEV penetration scenarios the percentage of total VMT driven by PEVs each year is lower than the percentage of plug-in vehicles in the fleet. This is because PEVs are assumed to have a "utility factor" less than one – i.e., due to range restrictions neither a BEV nor a PHEV can convert 100 percent of the miles driven annually by a baseline gasoline vehicle into miles powered by grid electricity. In this analysis BEVs with 200-mile range per charge are conservatively assumed to have a utility factor of 87 percent, while PHEVs are assumed to have an average utility factor of 72 percent in 2030, rising to 79 percent in 2050.

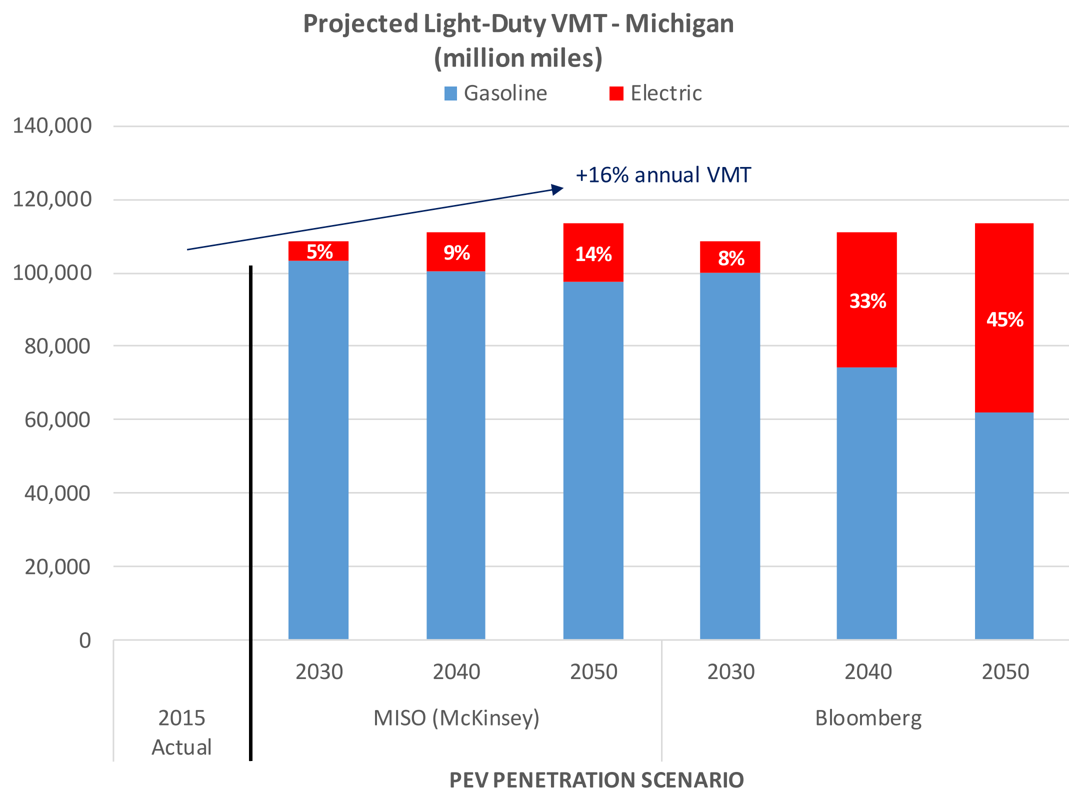
Figure 4 Projected Michigan Light Duty Fleet



[4] This analysis only includes cars and light trucks. It does not include medium- or heavy-duty trucks and buses.

This analysis estimates that under the High PEV (Bloomberg) scenario Michigan will reduce light-duty fleet gasoline consumption in 2050 by 45 percent compared to a baseline with no PEVs, due to 45 percent of fleet miles being driven by PEVs on electricity (Figure 5). However, in order to achieve this level of electric miles, 55.7 percent of light-duty vehicles will be PEVs (Figure 4).

Figure 5 Projected Michigan Light Duty Fleet Vehicle Miles Traveled



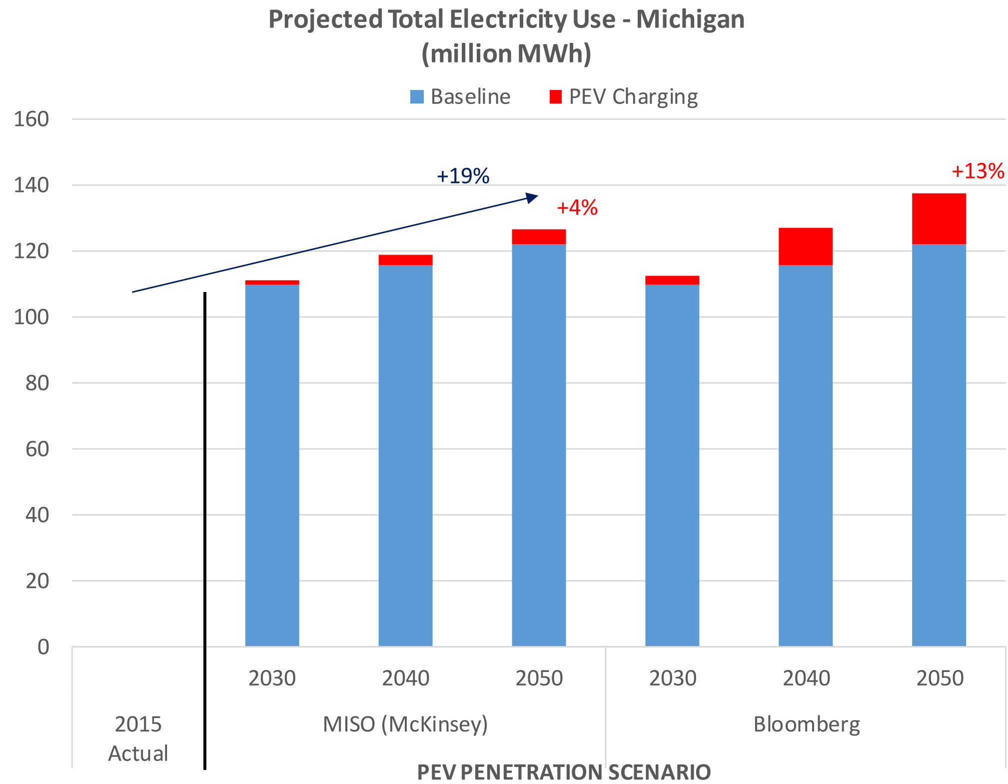
PEV Charging Electricity Use

The estimated total PEV charging electricity used in Michigan each year under the PEV penetration scenarios is shown in Figure 6.

In Figure 6, projected baseline electricity use without PEVs is shown in blue and the estimated incremental electricity use for PEV charging is shown in red. State-wide electricity use in Michigan is currently 102 million MWh per year. Annual electricity use is projected to increase to 110 million MWh in 2030 and continue to grow after that, reaching 122 million MWh in 2050 (19 percent greater than 2015 level).

Under the Moderate PEV penetration scenario, electricity used for PEV charging is projected to be 1.7 million MWh in 2030 – an increase of 1.5 percent over baseline electricity use. By 2050, electricity for PEV charging is projected to grow to 4.5 million MWh – an increase of 3.7 percent over baseline electricity use. Under the High PEV (Bloomberg) scenario electricity used for PEV charging is projected to be 2.8 million MWh in 2030, growing to 15.5 million MWh and adding 13 percent to baseline electricity use in 2050.

Figure 6 Estimated Total Electricity Use in Michigan



PEV Charging Load

This analysis evaluated the effect of PEV charging on the Michigan electric grid under two different charging scenarios. Under both scenarios 80 percent of all PEVs are assumed to charge exclusively at home and 20 percent are assumed to charge both at home and at work. Under the baseline charging scenario all Michigan drivers are assumed to plug-in their vehicles and start charging as soon as they arrive at home or at work (if applicable) each day. Under the off-peak charging scenario 65 percent of Michigan drivers who arrive at home in the afternoon and early evening are assumed to delay the start of home charging until after midnight – in response to a price signal or incentive provided by their utility.[5]

See Figure 7 (baseline) and Figure 8 (off-peak) for a comparison of PEV charging load under the baseline and off-peak charging scenarios, using the 2040 High PEV penetration scenario as an example. In each of these figures the 2016 Michigan 95th percentile load (MW)[6] by time of day is plotted in orange, and the projected incremental load due to PEV charging is plotted in grey.

In 2016 daily electric load in Michigan was generally in the range of 11,900 – 13,100 MW from midnight to 5 AM, ramping up through the morning and early afternoon to peak at approximately 19,200 MW between 3 PM and 5 PM, and then falling off through the late afternoon and evening hours.

[5] Utilities have many policy options to incentivize off-peak PEV charging. This analysis does not compare the efficacy of different options.

[6] For each hour of the day actual load in 2016 was higher than the value shown on only 5 percent of days (18 days).

Figure 7 2040 Projected Michigan PEV Charging Load, Baseline Charging (High PEV (Bloomberg) scenario)

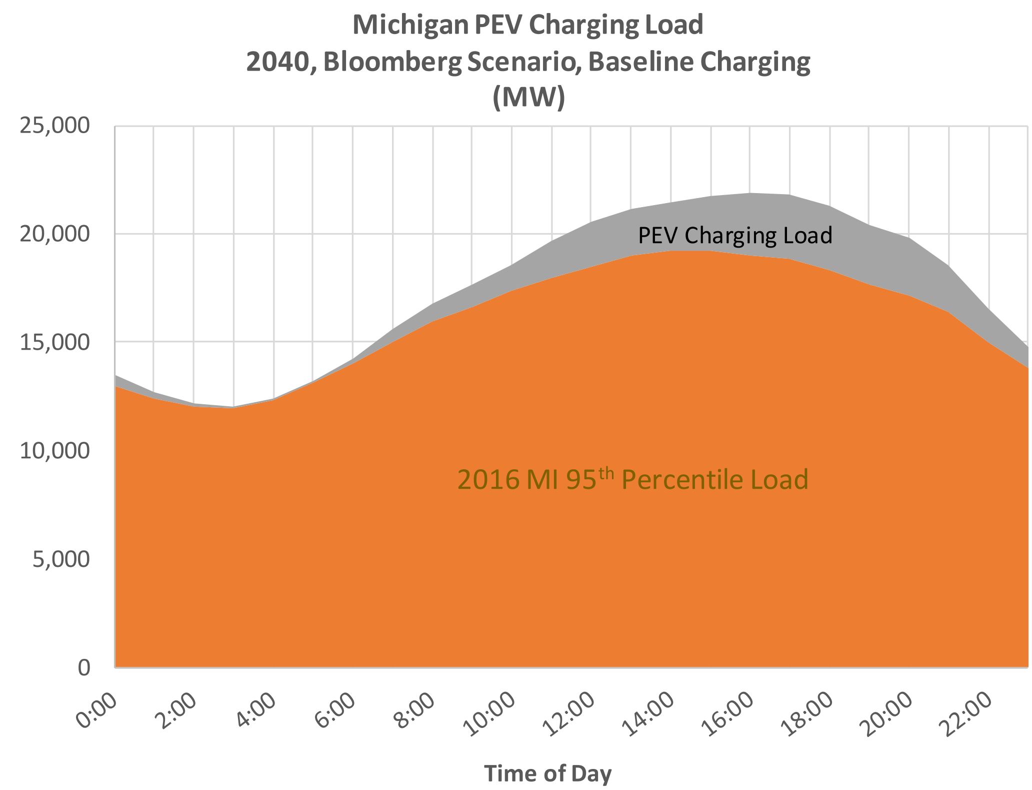
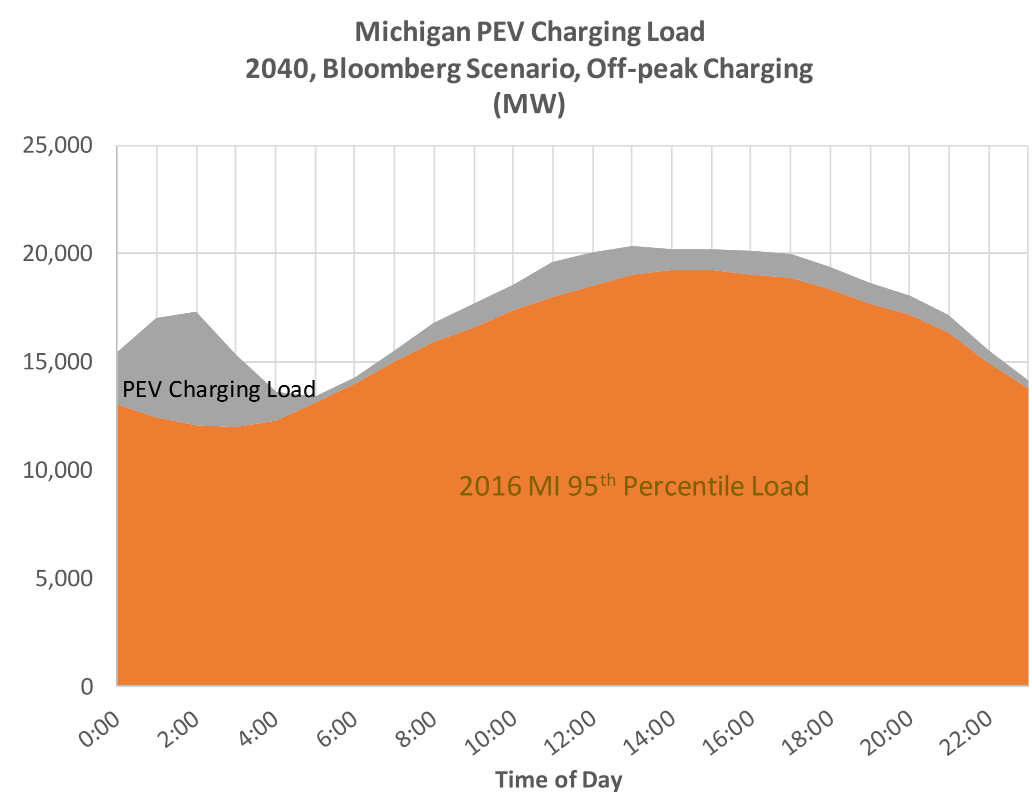


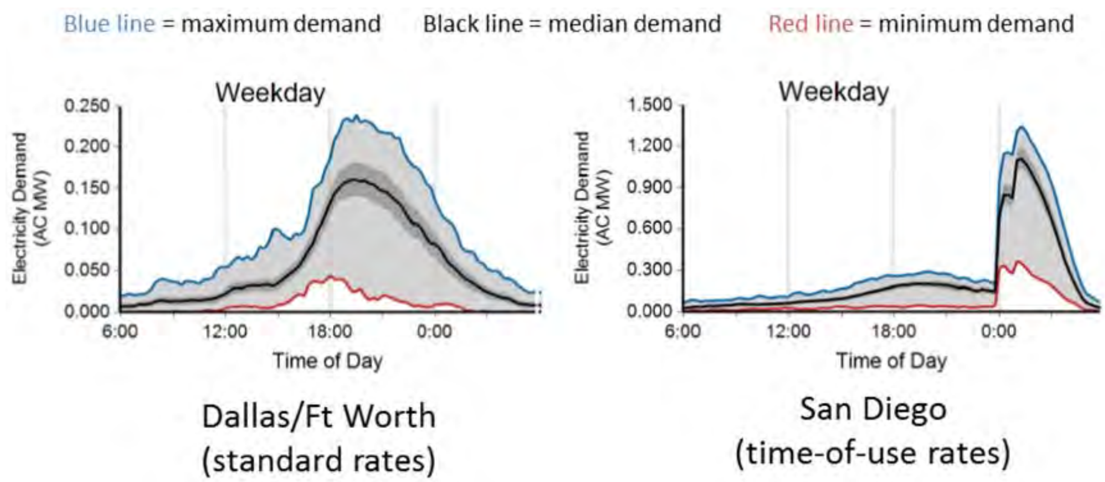
Figure 8 2040 Projected Michigan PEV Charging Load, Off-peak Charging (High PEV (Bloomberg) scenario)



As shown in Figure 7, baseline PEV charging is projected to add load primarily between 8 AM and 11 PM, as people charge at work early in the day and then at home later in the day. The PEV charging peak coincides with the existing afternoon peak load period between 3 PM and 5 PM. As shown in Figure 8, off-peak charging significantly reduces the incremental PEV charging load during the afternoon peak load period, but creates a secondary peak in the early morning hours, between midnight and 3 AM. The shape of this early morning peak can potentially be controlled based on the design of off-peak charging incentives. It should also be noted that those early morning hours are often the hours of the day when wind generation peaks.

These baseline and off-peak load shapes are consistent with real world PEV charging data collected by the EV Project, as shown in Figure 9. In Figure 9 the graph on the left shows PEV charging load in the Dallas/Ft Worth area where no off-peak charging incentive was offered to drivers. The graph on the right shows PEV charging load in the San Diego region, where the local utility offered drivers a time-of-use rate with significantly lower costs ($/kWh) for charging during the "super off-peak" period between midnight and 5 a.m. [12]

Figure 9 PEV Charging Load in Dallas/Ft Worth and San Diego areas, EV Project



See Table 1 for a summary of the projected incremental afternoon peak hour load (MW) in Michigan, from PEV charging under each penetration and charging scenario. This table also includes a calculation of how much this incremental PEV charging load would add to the 2016 95th percentile peak hour load. Under the Moderate PEV (MISO) penetration scenario, PEV charging would add 453 MW of load during the afternoon peak load period on a typical weekday in 2030, which would increase the 2016 baseline peak load by about 2 percent. By 2050, the afternoon incremental PEV charging load would increase to 1,242 MW, adding almost 7 percent to the 2016 baseline afternoon peak. By comparison the afternoon peak hour PEV charging load in 2030 would be only 166 MW for the off-peak charging scenario, increasing to 453 MW in 2050.

Under the High PEV penetration scenario, baseline PEV charging would increase the total 2016 afternoon peak electric load by about 21 percent in 2050, while off-peak charging would only increase it by about 8 percent.[7]

[7] Given projected significant increases in total state-wide electricity use through 2050, baseline peak load (without PEVs) is also likely to be higher in 2050 than 2016 peak load; as such the percentage increase in baseline peak load due to high levels of PEV penetration is likely to be lower than that shown in Table 1.

Table 1 Projected Incremental Afternoon Peak Hour PEV Charging Load (MW)

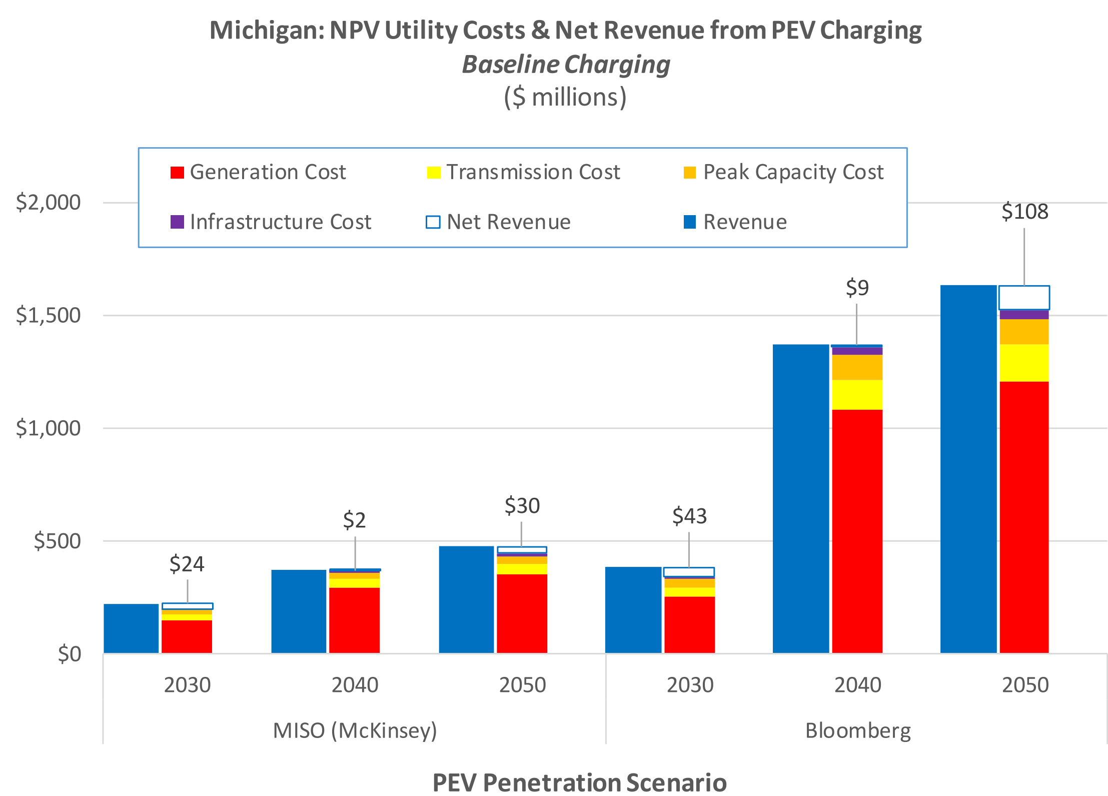
		Moderate PEV (MISO)			High PEV (Bloomberg)		
		2030	2040	2050	2030	2040	2050
Baseline Charging	PEV Charging (MW)	452.5	829.4	1,242.2	764.1	3,000.5	4,113.5
	Increase relative to 2016 Peak	2.4%	4.3%	6.5%	4.0%	15.6%	21.4%
Off-Peak Charging	PEV Charging (MW)	165.8	302.1	452.5	280.0	1,099.4	1,507.2
	Increase relative to 2016 Peak	0.9%	1.6%	2.4%	1.5%	5.7%	7.8%

As discussed below, increased peak hour load increases a utility's cost of providing electricity, and may result in the need to upgrade distribution infrastructure. As such, off-peak PEV charging can provide net benefits to all utility customers by bringing in significant new revenue in excess of associated costs.

Utility Customer Benefits

The estimated NPV of revenues and costs for Michigan' electric utilities to supply electricity to charge PEVs under each penetration scenario are shown in Figure 10, assuming the baseline PEV charging scenario.

Figure 10 NPV of Projected Utility Revenue and Costs from Baseline PEV Charging



Under the Moderate PEV penetration scenario, the NPV of revenue from electricity sold for PEV charging in Michigan is projected to total $223 million in 2030, rising to $475 million in 2050. Under the High PEV (Bloomberg) scenario, the NPV of utility revenue from PEV charging is projected to total $383 million in 2030, rising to $1.6 billion in 2050.

In Figure 10, projected utility revenue is shown in dark blue. The different elements of incremental cost that utilities would incur to purchase and deliver additional electricity to support PEV charging are shown in red (generation), yellow (transmission), orange (peak capacity), and purple (infrastructure upgrade cost). Generation and transmission costs are proportional to the total power (MWh) used for PEV charging, while peak capacity costs are proportional to the incremental peak load (MW) imposed by PEV charging. Infrastructure upgrade costs are costs incurred by the utility to upgrade their own distribution infrastructure to handle the increased peak load imposed by PEV charging.

The striped light blue bars in Figure 10 represent the NPV of projected "net revenue" (revenue minus costs) that utilities would realize from selling additional electricity for PEV charging under each PEV penetration scenario. Under the Moderate PEV penetration scenario, the NPV of net revenue in Michigan is projected to total $24 million in 2030, rising to $30 million in 2050. Under the High PEV (Bloomberg) scenario, the NPV of utility net revenue from PEV charging is projected to total $43 million in 2030, rising to $108 million in 2050. The NPV of projected annual utility net revenue averages $42 per PEV in 2030, and $18 - $20 per PEV in 2050.

Figure 11 NPV of Projected Utility Revenue and Costs from Off-peak PEV Charging

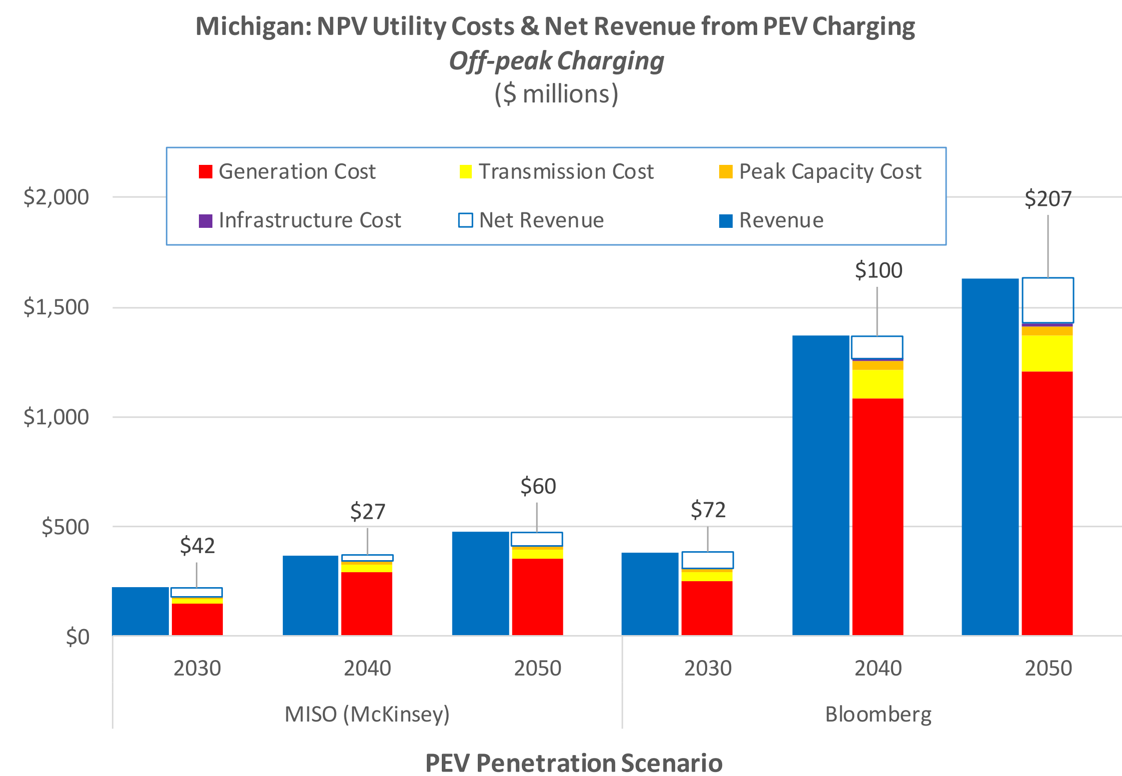
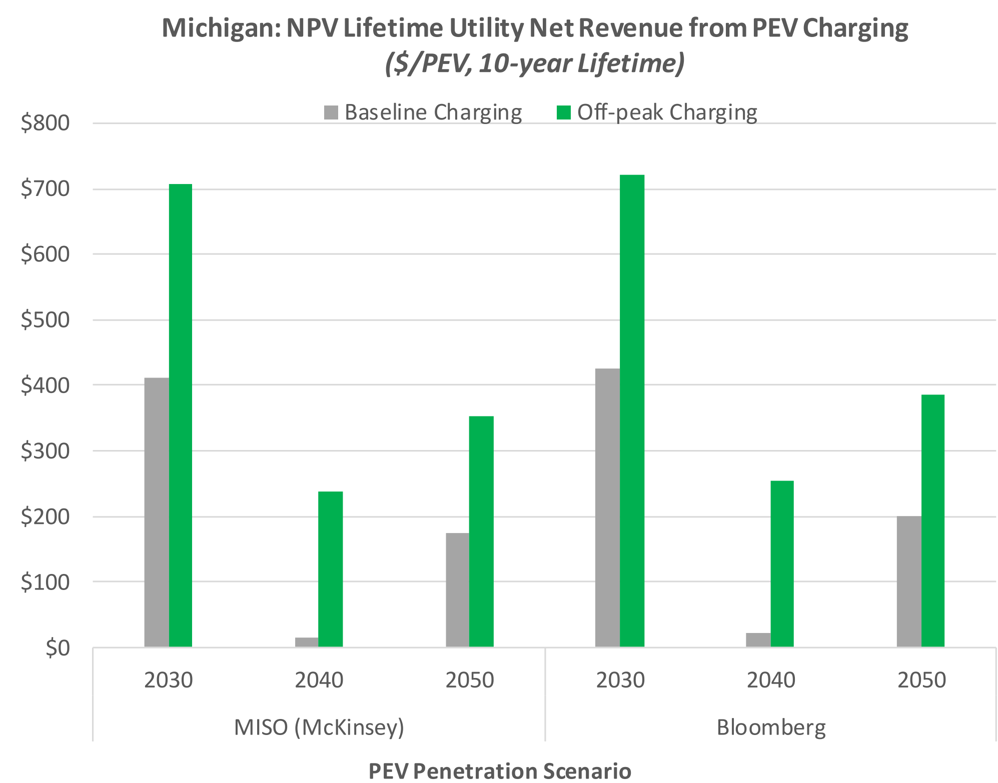


Figure 11 summarizes the NPV of projected utility revenue, costs, and net revenue for off-peak charging under each PEV penetration scenario. Compared to baseline charging (Figure 10) projected revenue, and projected generation and transmission costs are the same, but projected peak capacity and infrastructure costs are lower due to a smaller incremental peak load (see Table 1). Compared to baseline charging, off-peak charging will increase the NPV of annual utility net revenue by $17 million in 2030 and $30 million in 2050 under the Moderate PEV penetration scenario, due to lower costs. Under the High PEV (Bloomberg) scenario, off-peak charging will increase the NPV of annual utility net revenue by $30 million in 2030 and $99 million in 2050. This analysis estimates that compared to baseline charging, off-peak charging will increase the NPV of annual utility net revenue by $30 per PEV in 2030 and $18 per PEV in 2050.

The NPV of projected life-time utility net revenue per PEV is shown in Figure 12. Assuming a ten-year life, the average PEV in Michigan in 2030 is projected to increase utility net revenue by over $700 over its life-time, if charged off-peak. PEVs in service in 2050 are projected to increase utility net revenue by almost $390 over their life time (NPV) if charged off-peak.

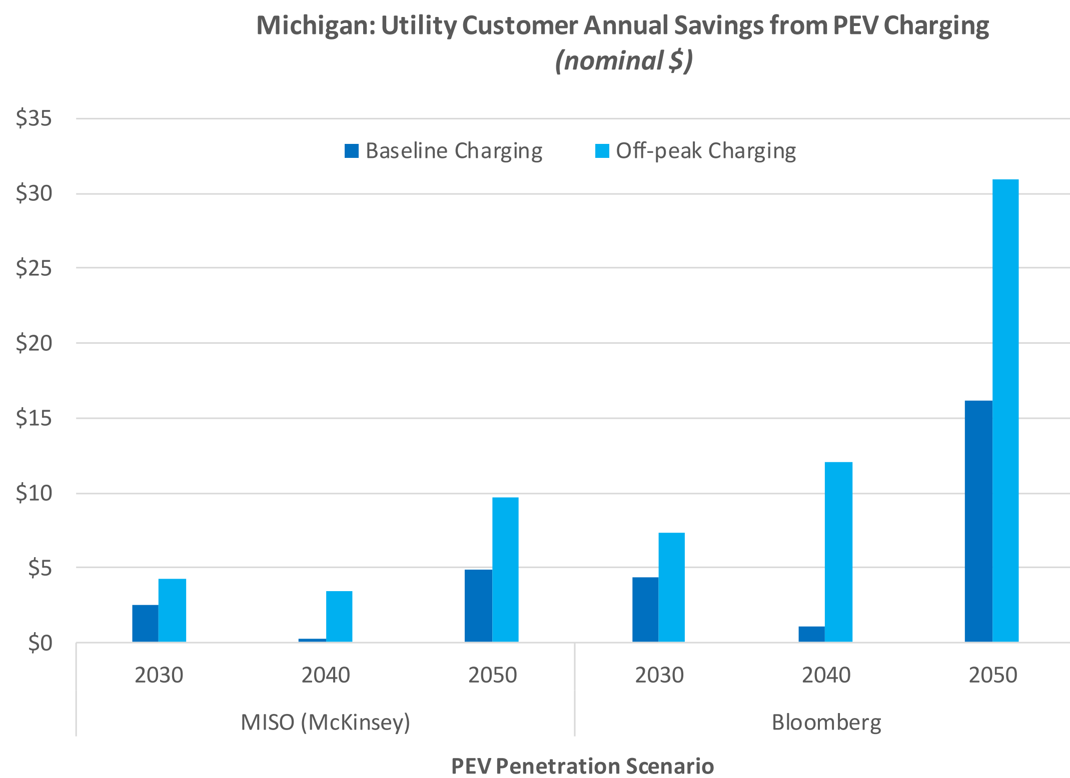
Figure 12 NPV of Projected Life-time Utility Net Revenue per PEV



In general, a utility's costs to maintain their distribution infrastructure increase each year with inflation, and these costs are passed on to utility customers in accordance with rules established by the state's Public Utilities Commission (PUC), via periodic increases in residential and commercial electric rates. However, under PUC rules net revenue from additional electricity sales generally offset the allowable costs that can be passed on via higher rates. As such, the majority of projected utility net revenue from increased electricity sales for PEV charging would in fact be passed on to utility customers in Michigan, not retained by the utility companies. In effect this net revenue would put downward pressure on future rates, delaying or reducing future rate increases, thereby reducing customer bills.

See Figure 13 for a summary of how the projected utility net revenue from PEV charging might affect average residential electricity bills for all Michigan electric utility customers.[8] As shown in the figure, under the High PEV (Bloomberg) scenario projected average electric rates in Michigan could be reduced up to 1.1 percent by 2050, resulting in an annual savings of approximately $31 (nominal dollars) per household in Michigan in 2050.

Figure 13 Potential Effect of PEV Charging Net Revenue on Utility Customer Bills (nominal $)



Michigan Driver Benefits

Current PEVs are more expensive to purchase than similar sized gasoline vehicles, but they are eligible for various government purchase incentives, including up to a $7,500 federal tax credit. These incentives are important to spur an early market, but as described below PEVs are projected to provide a lower total cost of ownership than conventional vehicles in Michigan by 2030, even without government purchase subsidies.

The largest contributor to incremental purchase costs for PEVs compared to gasoline vehicles is the cost of batteries. Battery costs for light-duty plug-in vehicles have fallen from over $1,000/kWh to less than $300/kWh in the last six years; many analysts and auto companies project that battery prices will continue to fall – to below $110/kWh by 2025, and below $75/kWh by 2030. [13]

Based on these battery cost projections, this analysis projects that the average annual cost of owning a PEV in Michigan will fall below the average cost of owning a gasoline vehicle by 2030, even without government purchase subsidies.[9] See Table 2 which summarizes the average projected annual cost of Michigan PEVs and gasoline vehicles under each penetration scenario. All costs in Table 2 are in nominal dollars, which is the primary reason why costs for both gasoline vehicles and PEVs are higher in 2040 and 2050 than in 2030 (due to

[8] Based on 2015 average electricity use of 7,728 kWh per housing unit in Michigan.
[9] The analysis assumes that all battery electric vehicles in-use after 2030 will have 200-mile range per charge and that all plug-in hybrid vehicles will have 50 mile all-electric range.

inflation). In addition, the penetration scenarios assume that the relative number of PEV cars and higher cost PEV light trucks will change over time; in particular the High PEV (Bloomberg) scenario assumes that there will be a significantly higher percentage of PEV light trucks in the fleet in 2050 than in 2030, which further increases the average PEV purchase cost in 2050 compared to 2030.

Table 2 Projected Fleet Average Vehicle Costs to Vehicle Owners (nominal $)

GASOLINE VEHICLE		MISO (McKinsey)			Bloomberg		
		2030	2040	2050	2030	2040	2050
Vehicle Purchase	$/yr	$4,281	$5,470	$6,963	$4,398	$6,198	$8,018
Gasoline	$/yr	$1,233	$1,603	$2,065	$1,254	$1,759	$2,320
Maintenance	$/yr	$261	$326	$400	$262	$337	$415
TOTAL ANNUAL COST	**$/yr**	**$5,775**	**$7,400**	**$9,428**	**$5,914**	**$8,293**	**$10,753**

PEV		MISO (McKinsey)			Bloomberg		
		2030	2040	2050	2030	2040	2050
Vehicle Purchase	$/yr	$4,505	$5,676	$7,117	$4,622	$6,391	$8,263
Electricity	$/yr	$576	$671	$772	$585	$715	$837
Gasoline	$/yr	$232	$259	$314	$236	$282	$348
Personal Charger	$/yr	$81	$101	$122	$81	$101	$122
Maintenance	$/yr	$146	$192	$239	$147	$197	$245
TOTAL ANNUAL COST	**$/yr**	**$5,540**	**$6,899**	**$8,564**	**$5,671**	**$7,685**	**$9,815**
Savings per PEV	$/yr	**$234**	**$501**	**$864**	**$244**	**$608**	**$937**

As shown in Table 2, even in 2050 average PEV purchase costs are projected to be higher than average purchase costs for gasoline vehicles (with no government subsidies), but the annualized effect of this incremental purchase cost is outweighed by significant fuel cost savings, as well as savings in scheduled maintenance costs. In 2030, the average Michigan driver is projected to save $234 – $244 per year compared to the average gasoline vehicle owner, without government subsidies. These annual PEV savings are projected to increase to an average of $501 - $608 per PEV in 2040, and $864 - $937 per PEV in 2050, as relative PEV purchase costs continue to fall, and the projected price of gasoline continues to increase faster than projected electricity prices. The NPV of annual savings for the average PEV owner in Michigan is projected to be $153 in 2030, rising to $320 in 2050.

The NPV of total annual cost savings to Michigan drivers from greater PEV ownership are projected to be $89 million in 2030 under the Moderate PEV penetration scenario, rising to $271 million in 2040 and $521 million in 2050. Under the High PEV (Bloomberg) scenario, the NPV of total annual cost savings to Michigan drivers from greater PEV ownership are projected to be $156 million in 2030, rising to $1.1 billion in 2040 and $1.8 billion in 2050.

Other Benefits

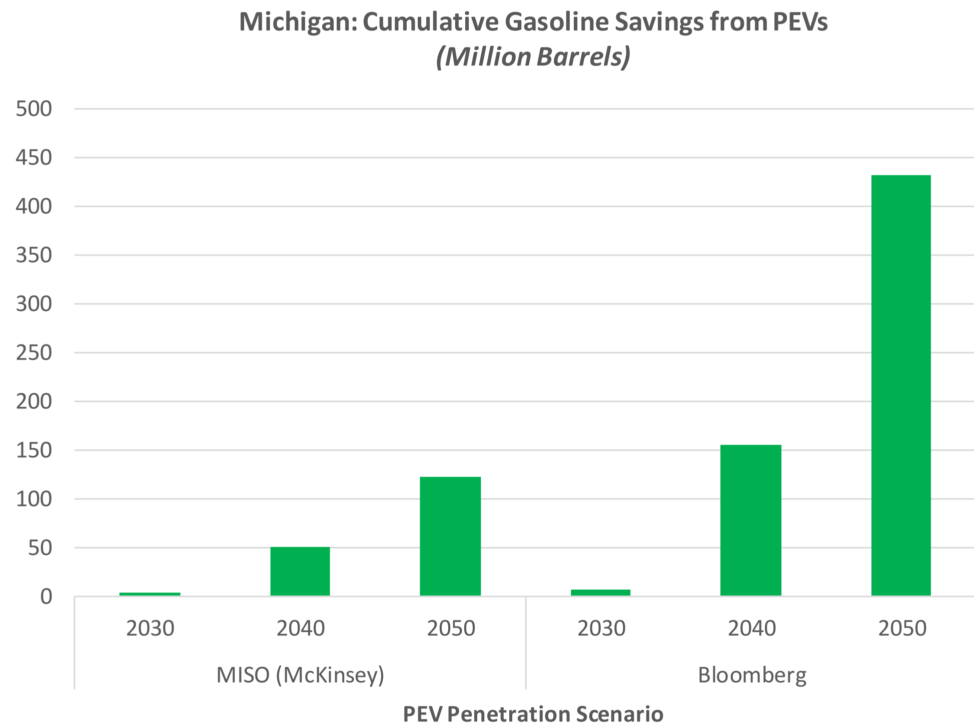
Along with the financial benefits to electric utility customers and PEV owners described above, light-duty vehicle electrification can provide additional societal benefits, including significant reductions in gasoline fuel use, and significant reductions in GHG emissions.

The estimated cumulative fuel savings (barrels of gasoline[10]) from PEV use in Michigan under each penetration scenario are shown in Figure 14. Annual fuel savings under the Moderate PEV penetration scenario are projected to total 3.3 million barrels in 2030, with cumulative savings of more than 122 million barrels by 2050. For the

[10] One barrel of gasoline equals 42 US gallons

High PEV (Bloomberg) scenario, annual fuel savings in 2030 are projected to be 5.8 million barrels, and by 2050 cumulative savings will exceed 432 million barrels. These fuel savings can help put the U.S. on a path toward energy independence, by reducing the need for imported petroleum. In addition, a number of studies have demonstrated that EVs can generate significantly greater local economic impact than gasoline vehicles - including generating additional local jobs - by keeping more of vehicle owners' money in the local economy rather than sending it out of state by purchasing gasoline. [14]

Figure 14 Cumulative Gasoline Savings from PEVs in Michigan



The projected annual greenhouse gas (GHG) emissions (million metric tons carbon-dioxide equivalent, CO_2-e million tons) from the Michigan light duty fleet under each PEV penetration scenario are shown in Figure 15. In this figure, projected baseline emissions from a gasoline fleet with few PEVs are shown in red for each year, and projected emissions under the PEV scenarios are shown in blue. The values shown represent "wells-to-wheels" emissions, including direct tailpipe emissions and "upstream" emissions from production and transport of gasoline. Estimated emission for the PEV scenarios includes GHG emissions from generating electricity to charge PEVs, as well as GHG emissions from gasoline vehicles in the fleet. Estimated emissions from PEV charging are based on EIA projections of average carbon intensity for the East North Central (ENC) electricity generation region, which includes Michigan.

As shown in Figure 15, GHG emissions from the light duty fleet in Michigan were approximately 49 million tons in 2015. Even without significant PEV penetration, baseline annual fleet emissions are projected to fall to 29.9 million tons by 2050, a reduction of 39 percent from current levels. This projected reduction is based on turnover of the existing vehicle fleet to more efficient vehicles that meet more stringent fuel economy and GHG standards issued by the Department of Transportation and Environmental Protection Agency. Under the Moderate PEV penetration scenario, PEVs are projected to reduce annual light duty fleet emissions by up to 1.9 million tons in 2050 compared to baseline emissions (-6 percent). Under the High PEV (Bloomberg) scenario, annual GHG emissions in 2050 will be as much as 7.7 million tons lower than baseline emissions (-26 percent).

Figure 15 Projected GHG Emissions from the Light Duty Fleet in Michigan

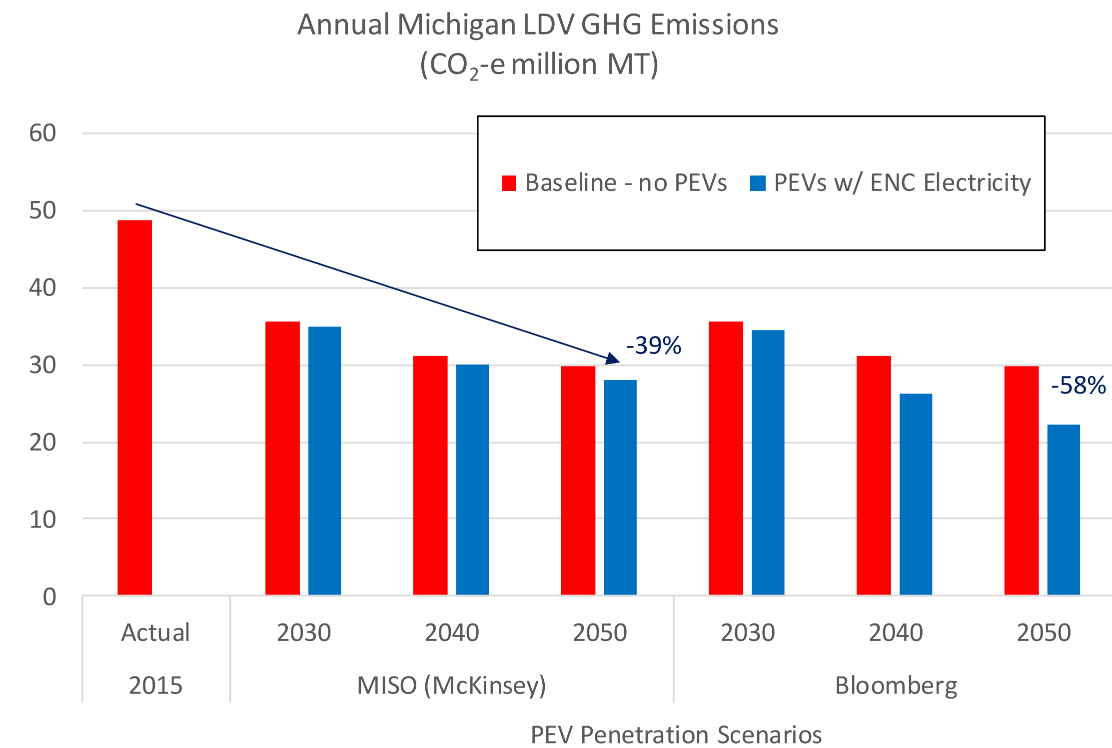


Figure 16 NPV of Projected Social Value of PEV GHG Reductions

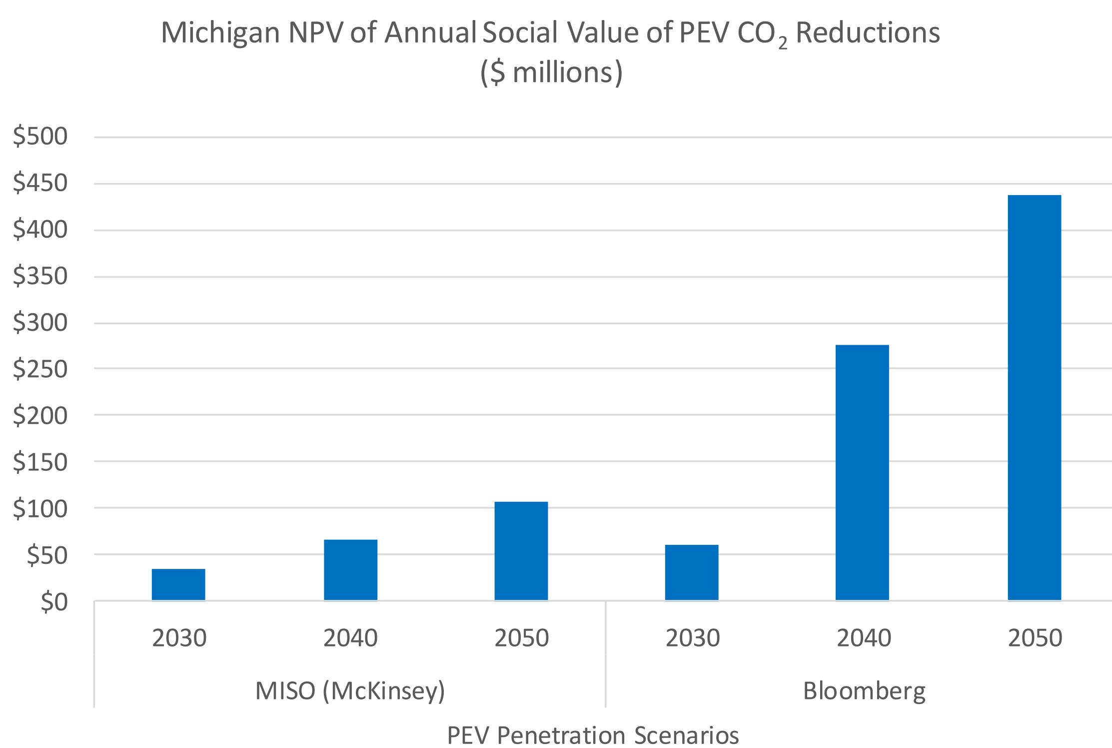


Figure 16 summarizes the estimated NPV of the monetized "social value" of GHG reductions that will result from greater PEV use in Michigan. The social value of GHG reductions represents potential societal cost savings from avoiding the negative effects of climate change, if GHG emissions are reduced enough to keep long term warming below two degrees Celsius from pre-industrial levels. The values summarized in Figure 16 were developed using the Social Cost of CO_2 ($/MT) as calculated by the U.S. government's Interagency Working Group on Social Cost of Greenhouse Gases [15].

The NPV of the monetized social value of GHG reductions resulting from greater PEV use is projected to total $35 million per year in 2030 under the Moderate PEV penetration scenario, rising to as much as $108 million per year in 2050. Under the High PEV (Bloomberg) scenario the NPV of the monetized social value of GHG reductions from greater PEV is projected to be $62 million per year in 2030, rising to as much as $438 million per year in 2050.

The NPV of the projected monetized social value of annual GHG reductions averages $61 per PEV in 2030, and $63 - $81 per PEV in 2050.

Total Societal Benefits

The NPV of total estimated societal benefits from increased PEV use in Michigan under each PEV penetration scenario are summarized in Figures 17 and 18. These benefits include cost savings to Michigan drivers, utility customer savings from reduced electric bills, and the monetized benefit of reduced GHG emissions. Figure 17 shows the NPV of projected societal benefits if Michigan drivers charge in accordance with the baseline charging scenario. Figure 17 shows the NPV of projected societal benefits if Michigan drivers charge off-peak. Both figures assume that GHG emissions from electricity production follow EIA's current projections for future carbon intensity of the regional electric grid.

As shown in Figure 17, the NPV of annual societal benefits are projected to be a minimum of $659 million per year in 2050 under the Moderate PEV penetration scenario and $2.3 billion per year in 2050 under the High PEV (Bloomberg) scenario. Approximately 78 percent of these annual benefits will accrue to Michigan drivers as a cash savings in vehicle operating costs, 5 percent will accrue to electric utility customers as a reduction in annual electricity bills, and 17 percent will accrue to society at large in the form of climate change mitigation due to reduced GHG emissions.

As shown in Figure 18, the NPV of annual societal benefits in 2050 will increase by $30 million under the Moderate PEV penetration scenario, and $99 million under the High PEV (Bloomberg) scenario if Michigan drivers charge off-peak. Of these increased benefits, all will accrue to electric utility customers as an additional reduction in their electricity bills.

Figure 17 Projected NPV of Total Societal Benefits from Greater PEV use in MI – Baseline Charging

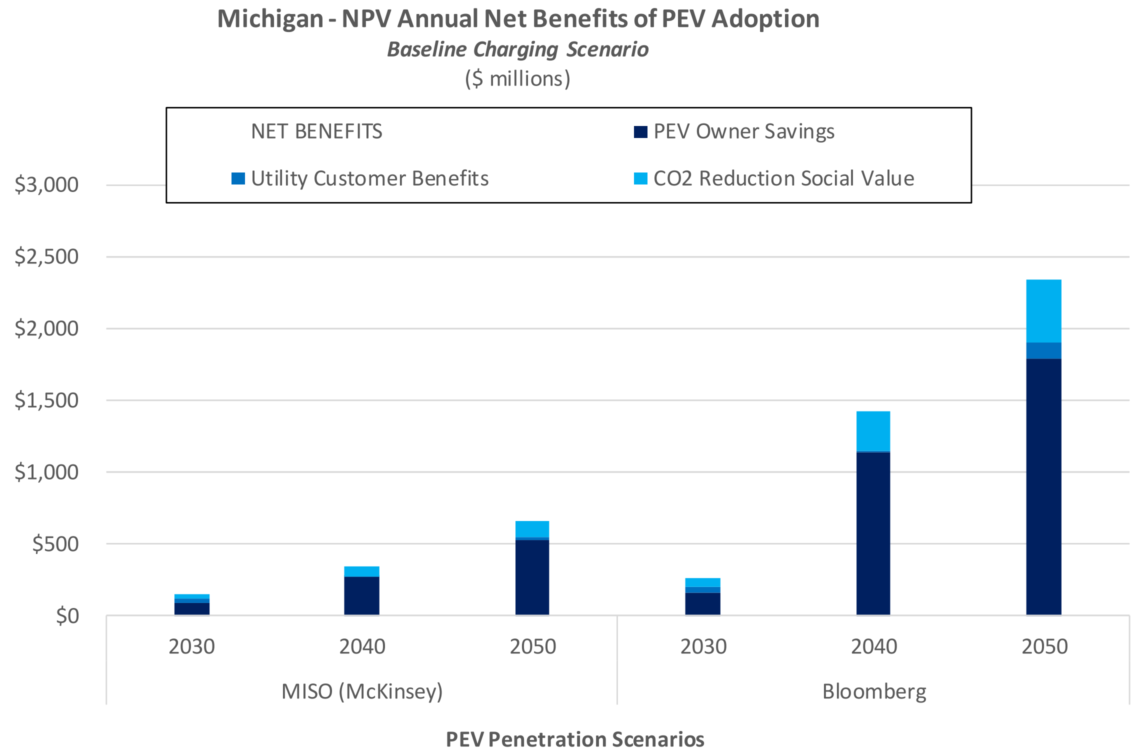
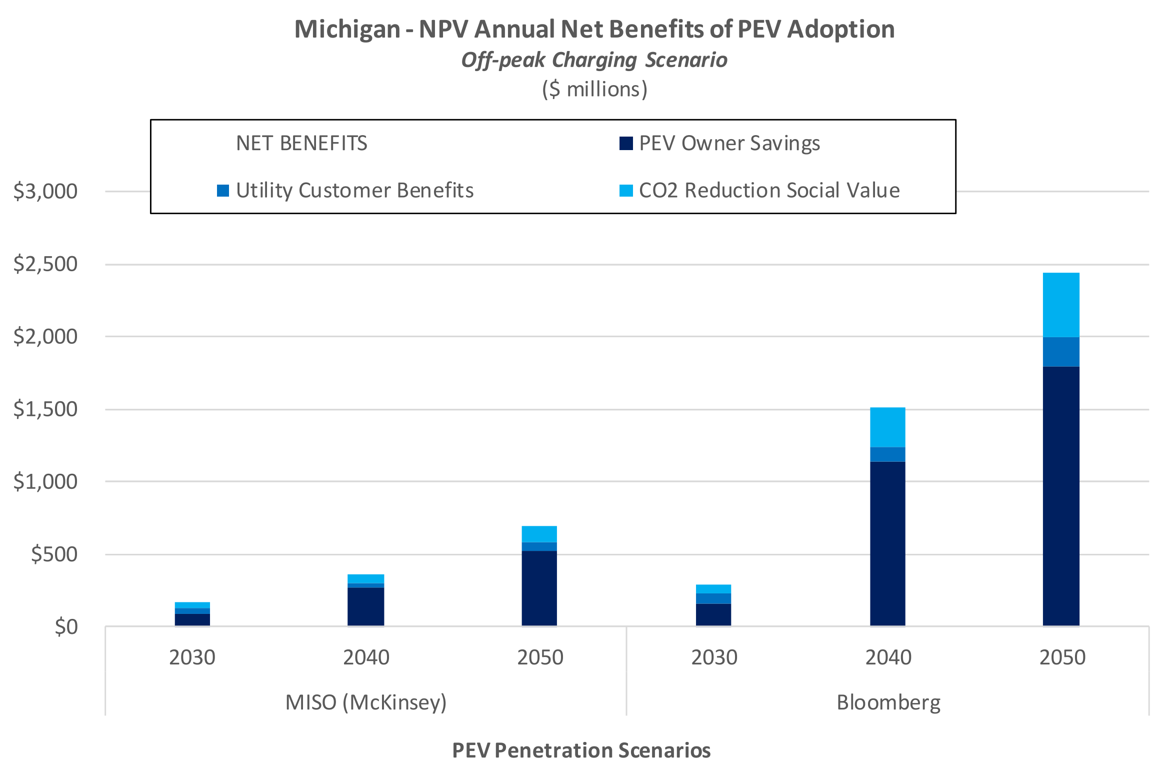


Figure 18 Projected NPV of Total Societal Benefits from Greater PEV use in MI – Off-peak



Study Methodology

This section briefly describes the methodology used for this study. For more information on how this study was conducted, including a complete discussion of the assumptions used and their sources, see the report: *Mid-Atlantic and Northeast Plug-in Electric Vehicle Cost-Benefit Analysis, Methodology & Assumptions* (October 2016).[11] This report can be found at:

http://mjbradley.com/sites/default/files/NE_PEV_CB_Analysis_Methodology.pdf

This study evaluated the costs and benefits of two distinct levels of PEV penetration in Michigan between 2030 and 2050, based on the range of publicly available PEV adoption estimates from various analysts.

Moderate PEV Scenario – MISO (McKinsey): Penetration of PEVs modeled by MISO Energy – the regional transmission organization that covers Michigan - during on-going MISO Transmission Expansion Planning (MTEP) efforts; this PEV penetration scenario was produced for MISO by McKinsey & Company [16]. Under this scenario approximately 6 percent of in-use light duty vehicles in Michigan will be PEV in 2030, rising to 12 percent in 2040, and 17.6 percent in 2050.

High PEV Scenario - Bloomberg: The estimated level of PEV penetration each year, based on Bloomberg New Energy Finance's (Bloomberg) July 2017 estimate of annual U.S. PEV sales through 2040, conservatively extended through 2050. [17] For this scenario the estimate of total in-use PEVs each year is based on cumulative PEV sales over the preceding thirteen years (average in-service life for light duty vehicles), and assuming that PEV sales in Michigan will be proportional to total vehicle sales. Under this scenario 10.8 percent of in-use vehicles will be PEV in 2030, rising to 41.5 percent in 2040 and 55.7 percent in 2050.

Both of these scenarios are compared to a baseline scenario with very little PEV penetration, and continued use of gasoline vehicles. The baseline scenario is based on future annual vehicle miles traveled (VMT) and fleet characteristics (e.g., cars versus light trucks) as projected by the Michigan Department of Transportation.

Based on assumed future PEV characteristics and usage, the analysis projects annual electricity use for PEV charging at each level of penetration, as well as the average load from PEV charging by time of day. The analysis then projects the total revenue that Michigan's electric distribution utilities would realize from sale of this electricity, their costs of providing the electricity to their customers, and the potential net revenue (revenue in excess of costs) that could be used to support maintenance of the distribution system.

The costs of serving PEV load include the cost of electricity generation, the cost of transmission, incremental peak generation capacity costs for the additional peak load resulting from PEV charging, and annual infrastructure upgrade costs for increasing the capacity of the secondary distribution system to handle the additional load.

For each PEV penetration scenario this analysis calculates utility revenue, costs, and net revenue for two different PEV charging scenarios: 1) a baseline scenario in which all PEVs are plugged in and start to charge as soon as they arrive at home each day, and 2) an off-peak charging scenario in which a significant portion of PEVs that arrive home between noon and 11 PM each day delay the start of charging until after midnight.

Real world experience from the EV Project demonstrates that, without a "nudge", drivers will generally plug in and start charging immediately upon arriving home after work (scenario 1), exacerbating system-wide evening

[11] This analysis used the same methodology as described in the referenced report, but used different PEV penetration scenarios, as described here. In addition, for this analysis fuel costs and other assumptions taken from the Energy Information Administration (EIA) were updated from EIA's Annual Energy Outlook 2016 to those in the Annual Energy Outlook 2017. Finally, for projections of future PEV costs this analysis used updated July 2017 battery cost projections from Bloomberg New Energy Finance.

peak demand.[12] However, if given a "nudge" - in the form of a properly designed and marketed financial incentive - many Michigan drivers will choose to delay the start of charging until off-peak times, thus reducing the effect of PEV charging on evening peak electricity demand (scenario 2). [18] As noted above, most Michigan utilities offer special rate plans for EV owners intended to incentivize off-peak charging.

For each PEV penetration scenario, this analysis also calculates the total incremental annual cost of purchase and operation for all PEVs in the state, compared to "baseline" purchase and operation of gasoline cars and light trucks. For both PEVs and baseline vehicles annual costs include the amortized cost of purchasing the vehicle, annual costs for gasoline and electricity, and annual maintenance costs. For PEVs it also includes the amortized annual cost of the necessary home charger. This analysis is used to estimate average annual financial benefits to Michigan drivers.

Finally, for each PEV penetration scenario this analysis calculates annual greenhouse gas (GHG) emissions from electricity generation for PEV charging, and compares that to baseline emissions from operation of gasoline vehicles. For the baseline and PEV penetration scenarios GHG emissions are expressed as carbon dioxide equivalent emissions (CO_2-e) in metric tons (MT). GHG emissions from gasoline vehicles include direct tailpipe emissions as well as "upstream" emissions from production and transport of gasoline.

For each PEV penetration scenario GHG emissions from PEV charging are calculated based on an electricity scenario that is consistent with the latest Energy Information Administration (EIA) projections for future average grid emissions in Michigan.

Net annual GHG reductions from the use of PEVs are calculated as baseline GHG emissions (emitted by gasoline vehicles) minus GHG emissions from each PEV penetration scenario. The monetized "social value" of these GHG reductions from PEV use are calculated using the Social Cost of Carbon ($/MT), as calculated by the U.S. government's Interagency Working Group on Social Cost of Greenhouse Gases. [19]

[12] The EV Project is a public/private partnership partially funded by the Department of Energy which has collected and analyzed operating and charging data from more than 8,300 enrolled plug-in electric vehicles and approximately 12,000 public and residential charging stations over a two-year period.

References

[1] R.L. Polk & Company, Light duty vehicle registrations, by county and state, as of January 2016

[2] *http://www.dleg.state.mi.us/mpsc/orders/electric/2017/u-18368_4-28-2017.pdf*

[3] http://www.michigan.gov/mpsc/0,4639,7-159-16400_17280-410433--,00.html

[4] *https://www.afdc.energy.gov/fuels/laws/ELEC/MI*

[5] *http://www.dleg.state.mi.us/mpsc/orders/electric/2017/u-18368_4-28-2017.pdf*

[6] https://www.afdc.energy.gov/fuels/laws/ELEC/MI

[7] *https://www.nrdc.org/experts/ariana-gonzalez/legislation-puts-michigan-path-clean-energy-future*

[8] *http://newsroom.dteenergy.com/2017-05-16-DTE-Energy-announces-plan-to-reduce-carbon-emissions-by-80-percent#sthash.dncrz1BP.NruSDarT.dpbs*

[9] *http://www.miclimateaction.org/michigan_cities_taking_action_on_climate*

[10] http://www.ecocenter.org/charge-midwest

[11] http://michiganradio.org/post/michigan-mayors-vow-uphold-paris-agreement-wake-us-abandonment

[12] Idaho National Laboratory, *2013 EV Project Electric Vehicle Charging Infrastructure Summary Report*, January 2013 through December 2013. [14] S. Morsy, Bloomberg New Energy Finance, *Long-Term Electric Vehicle Outlook 2017*, July 6, 2017

[13] S. Morsy, Bloomberg New Energy Finance, Advanced Transport, *Long-term Electric Vehicle Outlook 2017*, July 6, 2017

[14] AECOM and Quercus Consulting, *Ripple Effect, Forecasting the economic impact of electric vehicles in Florida,* August 2014

Drive Electric Ohio, *Electric Vehicle Readiness Plan for Ohio, 2013*

California Electric Transportation Coalition (2012), *Plug-in Electric Vehicle Deployment in California: An Economic Jobs Assessment*. http://www.caletc.com/wp-content/uploads/2012/11/Economic-Jobs-AssessmentExec-Summary.pdf

E. Korejwa, (2015), *The Returns to Vehicle Electrification: An Assessment of the Economic and Budgetary Impacts of Electric Vehicle Adoption in Oregon*, Drive Oregon. http://driveoregon.org/wp-content/uploads/2015/02/Oregon-EV-Returns.pdf

J. Todd, J. Chen, and F. Clogston, (2012), *Creating the Clean Energy Economy: Analysis of the Electric Vehicle Industry, 2013.* Originally from U.S. Energy Information Administration. Gasoline and Diesel Fuel Update. Retrieved from http://www.eia.gov/petroleum/gasdiesel/

J. Cortright, (2010) *New York City's Green Dividend*. CEOs for Cities. http://www.ceosforcities.org/pagefiles/NYCGD_elctrnc_FINAL.pdf

[15] Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis -Under Executive Order 12866 -Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, Appendix A, August 2016.

[16] The MISO PEV penetration estimates were provided by R. Konidena, Principal Advisor, Policy Studies, Midwest Independent System Operator.

[17] S. Morsy, Bloomberg New Energy Finance, Advanced Transport, *Long-term Electric Vehicle Outlook 2017*, July 6, 2017

[18] Idaho National Laboratory, *2013 EV Project Electric Vehicle Charging Infrastructure Summary Report*, January 2013 through December 2013

[19] Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis -Under Executive Order 12866 -Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, Appendix A, August 2016.

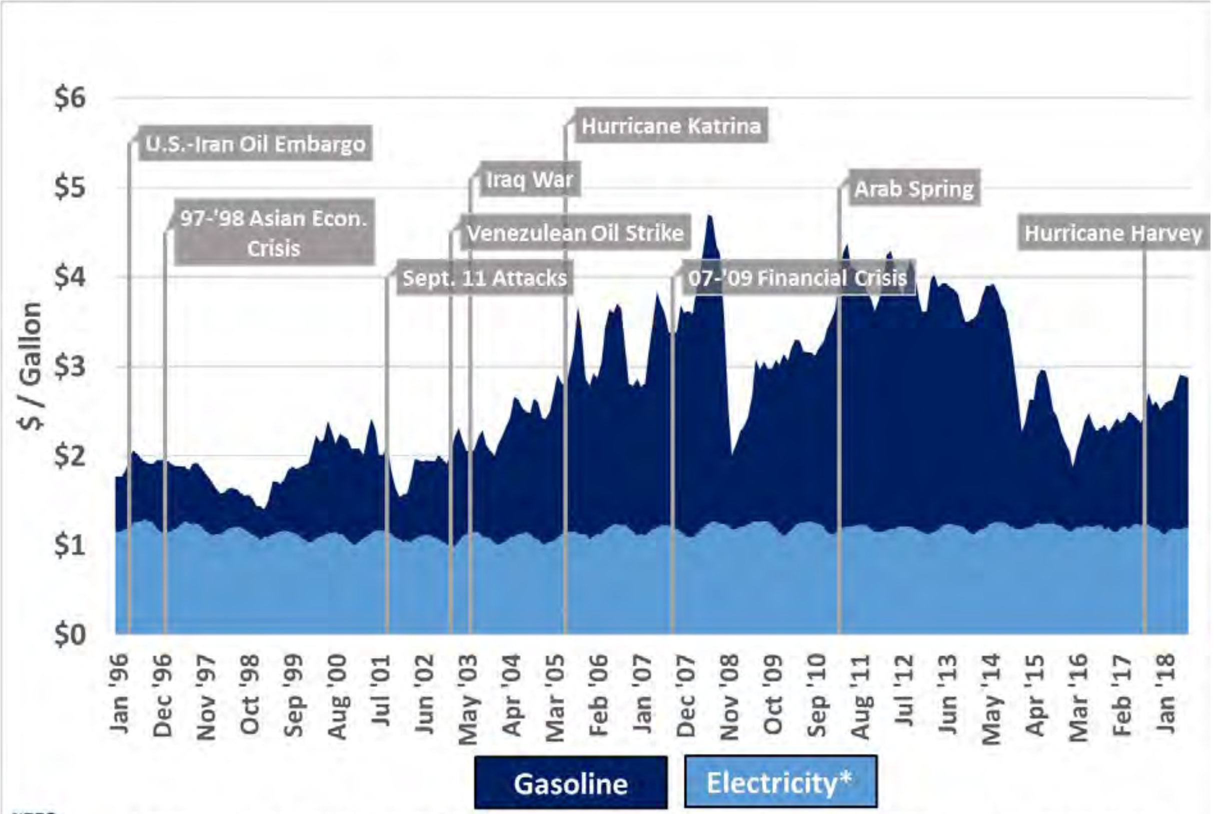
Acknowledgements

Lead Authors: Dana Lowell, Brian Jones, and David Seamonds

This study was conducted by M.J. Bradley & Associates for the Natural Resources Defense Council, Ecology Center, Sierra Club and ChargeUp Midwest. It is one of seven state-level analyses of plug-in electric vehicle costs and benefits for different U.S. states, including Colorado, Connecticut, Maryland, Massachusetts, New York, and Pennsylvania. These studies are intended to provide input to state policy discussions about actions required to promote further adoption of electric vehicles.

ChargeUp Midwest is a partnership of environmental and clean energy organizations actively working to increase electric vehicle deployment throughout the region in Illinois, Missouri, Michigan, Minnesota, and Ohio. Partner organizations include the Natural Resources Defense Council, Ecology Center, Great Plains Institute, Environmental Law and Policy Center, Clean Fuels Ohio, and Fresh Energy. Through ChargeUp Midwest these organizations seek to engage with a broad range of stakeholders to support actions that increase investment in electric vehicle infrastructure, create a more resilient and low-carbon grid, expand education of the public and policymakers about the benefits of electric vehicles, and otherwise accelerate the production, sales, and access to electric vehicles in the region for all Midwest residents.

This report, and the other state reports, are available at www.mjbradley.com.



** Shown in $/"eGallon" or the cost of fueling a vehicle with electricity compared to a similar vehicle that runs on gasoline*
Data source: Energy Information Administration, Aug 2018; Monthly averages

Question:

23. Reference the testimony of Michael Delaney, page 17, line 22 to page 18, line 3. Mr. Delaney explains that "[t]he default charging option will be for site hosts to pass through the Company TOU rate to customers," although site hosts will have the option to set their own terms for electricity pricing at stations they own and operate.

  a. Please state and explain whether Consumers will set a maximum price for charging services that site hosts will not be permitted to exceed and provide supporting documentation.

  b. Please state and explain whether site hosts who elect to set their own terms for pricing must charge by the kWh, or, alternatively, if they may charge by the minute, session, or some combination thereof. Please provide supporting documentation.

  c. Please state and explain whether the Company will require site hosts that receive a rebate as part of the Public and Workplace Charging Infrastructure Program or DC Fast Charging Infrastructure Program to report prices charged to EV drivers.

     i. If not, please explain why not.

  d. Please state whether, as part of the Public and Workplace Charging Infrastructure Program, the Company intends to inform site hosts about its available tariffs and rates, including any applicable time-of-use rates, in order to better inform site hosts about their options to effectively manage charging load. Please explain your response and provide supporting documentation.

     i. If not, please explain why not.

  e. Please state whether electricity usage at charging stations deployed under the Public and Workplace Charging Infrastructure Program or DC Fast Charging Infrastructure Program will be metered separately from other electricity usage at site host locations in all cases. Please explain your response and provide supporting documentation.

     i. If not, please explain why not.

Response:

  a. The Company is still evaluating how the Company will work with site hosts to ensure prices charged to EV drivers are within market rates.

b. Site hosts will have the option of providing no cost charging to EV drivers, direct charging to EV drivers, or using a third-party vendor to manage the charging sites. At this time, the Company is not contemplating a mandate as to the terms of pricing with respect to charging by the kWh, minute, session, or some combination thereof.

c. The Company is still evaluating what requirement there will be of site hosts with respect to reporting prices charged to EV drivers.

d. As a part of the site host recruitment and rebate processes, the Company intends to inform site hosts about its available tariffs and rates, including any applicable time-of-use rates, in order to better inform site hosts about their rate options.

e. The Company intends for the electricity usage at charging stations deployed under the public charging component or DC fast charging component to be metered separately from other electricity usage at site host locations. A second meter is currently standard practice when separate rates are being charged. The Company intends to focus on a single meter solution for charging multiple rates for the residential market segment because, due to the relative cost, a second meter for residential EV charging is a much higher barrier than for a public EV charger.

Michael J Delaney

Michael Delaney
June 29, 2018

Corporate Strategy

20134-MEC-CE-67
Page 1 of 2

Question:

19. Reference the testimony of Michael Delaney, page 17, lines 3 to 8. Mr. Delaney explains that the Company will experiment with lower rebate amounts than those proposed in his testimony in order to test effectiveness with motivating site hosts.

a. Assuming the Pilot Foundational Infrastructure Program is approved, what *actual* rebate amounts does the Company intend to offer to potential site hosts of charging stations at multi-dwelling units, workplaces and public locations at the start of the program? Please explain and providing supporting documentation.

b. Assuming the Pilot Foundational Infrastructure Program is approved, what *actual* rebate amounts does the Company intend to offer to potential hosts of DC fast charging infrastructure at the start of the program? Please explain and providing supporting documentation.

c. Please describe in detail how Company determine whether higher rebate amounts are necessary in order to incentivize site host participation, and provide supporting documentation.

d. Please state whether the Company considered providing higher rebate amounts for the multi-dwelling unit market segment, and provide all documentation, analysis and evaluations regarding such consideration.

i. If not, please explain why not.

Response:

a-b. The Company has not yet determined the actual rebate amounts the Company intends to offer at the start of the Program. The public charging station rebate is up to $5,000 per charger. The Company may pay less than that if the cost to the site host is less, e.g. if a company is installing multiple chargers and the unit cost is less than the rebate amount. In the event that rebate amounts prove ineffective at motivating site hosts to install charging stations, the Company may report back to the Commission at interim points to request changes to the rebate levels.

b. The DCFC rebate is up to $70,000 per charger. The Company may pay less than that if the cost to the site host is less. In the event that rebate amounts prove ineffective at motivating site hosts to install charging stations, the Company may report back to the Commission at interim points to request changes to the rebate levels.

c-d. The Company focused on the overall benefit to ratepayers in this program. The benefits of charging stations in the multi-dwelling unit market segment – benefits to the grid, and overall effectiveness in incentivizing the EV market - is still to be determined. The Company does not see adequate justification to set a higher rebate amount for multi-dwelling units at this time but is willing to consider higher rebate amounts for multi-dwelling units if presented with a well-supported case.

Michael J Delaney

Michael Delaney
June 29, 2018

Corporate Strategy

MPSC AUDIT REQUEST

CASE NO: U-20134
DATE OF REQUEST: 6/15/2018
NO. RGO-1
REQUESTED BY: Robert G. Ozar
DATE OF RESPONSE: 6/21/2018
RESPONDENT: Michael Delaney

Question:

Please provide the following documents or data, and answers to exploratory questions. If a requested item is already included in the Company's filing, please provide a reference to its location (exhibit, workpaper, etc.)

19. Would CE consider a nominal shift in Program funding so as to install several urban fast charge stations as part of the DCFC component of the overall pilot or in place of funding that would otherwise go to non-workplace or non-MUD Level-2 public charging stations (e.g the opportunity charging segment of the Public Charging Component of the program)?

Answer:

Yes, the Company would consider a nominal shift in Program funding to install urban fast charger stations. The Company intends to test best practices, functionality and customer awareness/adoption through the rebated DCFC stations. Using program funding to facilitate urban DCFC stations in addition to those along highway corridors would allow the Company to collect a more comprehensive data set and gain a broader understanding the benefits and best practices for DCFC stations.

Tyler Comings, Senior Researcher, Applied Economics Clinic
44 Teele Avenue, Somerville MA 02144 ꟹ tyler.comings@aeclinic.org ꟹ 617-863-0139

Professional Experience

Applied Economics Clinic. Somerville, MA. *Senior Researcher*, June 2017 – Present.

Provides technical expertise on electric utility regulation, energy markets, and energy policy. Clients are primarily public service organizations working on topics related to the environment, consumer rights, the energy sector, and community equity.

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate*, July 2014 – June 2017, *Associate*, July 2011 – July 2014.

Provided expert testimony and reports on energy system planning, coal plant economics and economic impacts. Performed benefit-cost analyses and research on energy and environmental issues.

Ideas42, Boston, MA. *Senior Associate*, 2010 – 2011.

Organized studies analyzing behavior of consumers regarding finances, working with top researchers in behavioral economics. Managed studies of mortgage default mitigation and case studies of financial innovations in developing countries.

Economic Development Research Group Inc., Boston, MA. *Research Analyst*, *Economic Consultant*, 2005 – 2010.

Performed economic impact modeling and benefit-cost analyses using IMPLAN and REMI for transportation and renewable energy projects, including support for Federal stimulus applications. Developed a unique web-tool for the National Academy of Sciences on linkages between economic development and transportation.

Harmon Law Offices, LLC., Newton, MA. *Billing Coordinator, Accounting Liaison*, 2002 – 2005.

Allocated IOLTA and Escrow funds, performed bank reconciliation and accounts receivable. Projected legal fees and costs.

Massachusetts Department of Public Health, Boston, MA. *Data Analyst* (contract), 2002.

Designed statistical programs using SAS based on data from health-related surveys. Extrapolated trends in health awareness and developed benchmarks for performance of clinics for a statewide assessment.

Education

Tufts University, Medford, MA
Master of Arts in Economics, 2007

Boston University, Boston, MA
Bachelor of Arts in Mathematics and Economics, 2002. Cum Laude, Dean's Scholar.

AFFILIATIONS

Society of Utility and Regulatory Financial Analysts (SURFA), Member

Global Development and Environment Institute, Tufts University, Medford, MA.
Research Fellow, 2017 – present

CERTIFICATIONS

Certified Rate of Return Analyst (CRRA), professional designation by Society of Utility and Regulatory Financial Analysts (SURFA)

PAPERS AND REPORTS

Stanton, E.A., and T. Comings. *Massachusetts Clean Energy Bill Provisions Boost Jobs.* Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Stanton, E.A., T. Comings, R. Wilson, S. Alisalad, E.N Marzan, C. Schlegel, B. Woods, J. Gifford, E. Snook, and P. Yuen. 2018. *An Analysis of the Massachusetts 2018 'Act to Promote a Clean Energy Future' Report.* Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Comings, T., E.A. Stanton, and B. Woods. 2018. *The ABCs of Boston CCE*. Applied Economics Clinic. Prepared for Barr Foundation. [OnlineStanton, E.A., T. Comings, and A. Sommer. 2018.*The Husker Power Plan: A New Energy Plan for Nebraska*. Applied Economics Clinic. Prepared for the Nebraska Wildlife Foundation. [Online]

Comings, T. and B. Woods. 2017. *The Future of the Martin Drake Power Plant. Applied Economics Clinic*. Applied Economics Clinic. Prepared for Green Cities Coalition and Southeastern Colorado Renewable Energy Society. [Online]

Comings, T., E.A. Stanton, B. Woods.. 2017. *An Analysis of Community Choice Energy for Boston.* Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Wilson, R., T. Comings, and E.A. Stanton. 2017. *Ratepayer Impacts of ConEd's 20-Year Shipping Agreement on the Mountain Valley Pipeline.* Applied Economics Clinic. Prepared for the Environmental Defense Fund. [Online]

Knight, P., A. Horowitz, P. Luckow, T. Comings, J. Gifford, P. Yuen, E. Snook, and J. Shoesmith. 2017. *An Analysis of the Massachusetts Renewable Portfolio Standard*. Synapse Energy Economics and Sustainable Energy Advantage for NECEC in Partnership with Mass Energy. [Online]

Knight, P., S. Fields, F. Ackerman, T. Comings, and A. Allison. 2017. *Empowering Kentucky*. Synapse Energy Economics for Kentuckians for the Commonwealth. [Online]

Comings, T. and A. Allison. 2017. *More Mileage for Your Money: Fuel Economy Increases While Vehicle Prices Remain Stable*. Synapse Energy Economics for Consumers Union. [Online]

Cook, R., J. Koo, N. Veilleux, K. Takahashi, E. Malone, T. Comings, A. Allison, F. Barclay, and L. Beer. 2017. *Rhode Island Renewable Thermal Market Development Strategy*. Meister Consultants Group and Synapse Energy Economics for Rhode Island Office of Energy Resources. [Online]

Fisher, J., P. Luckow, A. Horowitz, T. Comings, A. Allison, E.A. Stanton, S. Jackson, and K. Takahashi. 2016. *Michigan Compliance Assessment for the Clean Power Plan: MPSC/MDEQ EPA 111(d) Impact Analysis*. Prepared for Michigan Public Service Commission, Michigan Department of Environmental Quality, and Michigan Agency for Energy. [Online]

White, D., P. Peterson, T. Comings, and S. Jackson. 2016. *Preliminary Valuation of TransCanada's Hydroelectric Assets.* Prepared for the State of Vermont. [Online]

Comings, T., S. Jackson, and J. Fisher. 2016. *The Economic Case for Retiring North Valmy Generating Station*. Synapse Energy Economics for Sierra Club. [Online]

Comings, T., A. Allison, and F. Ackerman. 2016. *Higher Fuel Economy Standards Result in Big Savings for Consumers*. Synapse Energy Economics for Consumers Union. [Online]

Jackson, S., P. Luckow, E.A. Stanton, A. Horowitz, P. Peterson, T. Comings, J. Daniel, and T. Vitolo. 2016. *Reimagining Brayton Point: A Guide to Assessing Reuse Options for the Somerset Community*. Synapse Energy Economics for Coalition for Clean Air South Coast, Clean Water Action, and Toxics Action Center. [Online]

Stanton, E.A., P. Knight, A. Allison, T. Comings, A. Horowitz, W. Ong, N. R. Santen, and K. Takahashi. 2016. *The RGGI Opportunity 2.0: RGGI as the Electric Sector Compliance Tool to Achieve 2030 State Climate Targets.* Synapse Energy Economics for Sierra Club, Pace Energy and Climate Center, and Chesapeake Climate Action Network. [Online]

Stanton, E.A., P. Knight, A. Allison, T. Comings, A. Horowitz, W. Ong, N. R. Santen, and K. Takahashi. 2016. *The RGGI Opportunity: RGGI as the Electric Sector Compliance Tool to Achieve 2030 State Climate Targets.* Synapse Energy Economics for Sierra Club, Pace Energy and Climate Center, and Chesapeake Climate Action Network. [Online]

Ackerman, F. and T. Comings. 2015. *Employment after Coal: Creating New Jobs in Eastern Kentucky*. Synapse Energy Economics for the Mountain Association for Community Economic Development. [Online]

Vitolo, T., M. Chang, T. Comings, and A. Allison. 2015. *Economic Benefits of the Proposed Coolidge Solar I Solar Project*. Synapse Energy Economics for Coolidge Solar I, LLC. [Online]

Wilson, R., T. Comings, and E.A. Stanton. 2015. *Analysis of the Tongue River Railroad Draft Environmental Impact Statement.* Synapse Energy Economics for Sierra Club and Earthjustice. [Online]

Synapse Energy Economics, Labor Network for Sustainability and 350.org. 2015. *The Clean Energy Future: Protecting the Climate, Creating Jobs, and Saving Money.* [Online]

Fisher, J., T. Comings, F. Ackerman, and S. Jackson. 2015. *Clearing Up the Smog: Debunking Industry Claims that We Can't Afford Healthy Air.* Synapse Energy Economics for Earthjustice. [Online]

Stanton, E. A., T. Comings, S. Jackson, and E. Karaca. 2015. *Atlantic Coast Pipeline Benefits Review.* Synapse Energy Economics for Southern Environmental Law Center. [Online]

Takahashi, K., T. Comings, and A. Napoleon. 2014. *Maximizing Public Benefit through Energy Efficiency Investments.* Synapse Energy Economics for Sierra Club. [Online]

Comings, T., S. Fields, K. Takahashi, and G. Keith. 2014. *Employment Effects of Clean Energy Investments in Montana.* Synapse Energy Economics for Montana Environmental Information Center and Sierra Club. [Online]

Comings, T., J. Daniel, P. Knight, and T. Vitolo. 2014. *Air Emission and Economic Impacts of Retiring the Shawnee Fossil Plant.* Synapse Energy Economics for the Kentucky Environmental Foundation. [Online]

Comings, T., K. Takahashi, and G. Keith. 2013. *Employment Effects of Investing in Select Electricity Resources in Washington State.* Synapse Energy Economics for Sierra Club. [Online]

Stanton, E. A., T. Comings, K. Takahashi, P. Knight, T. Vitolo, and E. Hausman. 2013. *Economic Impacts of the NRDC Carbon Standard.* Synapse Energy Economics for Natural Resources Defense Council (NRDC). [Online]

Ackerman, F., T. Comings, and P. Luckow. 2013. *A Review of Consumer Benefits from a Corporate Average Fuel Economy (CAFE) Standards.* Synapse Energy Economics for Consumer Union. [Online]

Comings, T., P. Knight, and E. Hausman. 2013. *Midwest Generation's Illinois Coal Plants: Too Expensive to Compete? (Report Update)*. Synapse Energy Economics for Sierra Club. [Online]

Stanton, E. A., F. Ackerman, T. Comings, P. Knight, T. Vitolo, and E. Hausman. 2013. *Will LNG Exports Benefit the United States Economy?* Synapse Energy Economics for Sierra Club. [Online]

Vitolo, T., G. Keith, B. Biewald, T. Comings, E. Hausman, and P. Knight. 2013. *Meeting Load with a Resource Mix Beyond Business as Usual: A regional examination of the hourly system operations and reliability implications for the United States electric power system with coal phased out and high penetrations of efficiency and renewable generating resources.* Synapse Energy Economics for Civil Society Institute. [Online]

Keith, G., S. Jackson, A. Napoleon, T. Comings, and J. Ramey. 2012. *The Hidden Costs of Electricity: Comparing the Hidden Costs of Power Generation Fuels.* Synapse Energy Economics for Civil Society Institute. [Online]

Fagan, R., M. Chang, P. Knight, M. Schultz, T. Comings, E. Hausman, and R. Wilson. 2012 *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region.* Synapse Energy Economics for Energy Future Coalition. [Online]

Bower, S., S. Huntington, T. Comings, and W. Poor. 2012. *Economic Impacts of Efficiency Spending in Vermont: Creating an Efficient Economy and Jobs for the Future*. Optimal Energy, Synapse Energy Economics, and Vermont Department of Public Service for American Council for an Energy-Efficient Economy (ACEEE). [Online]

Comings, T. and E. Hausman. 2012. *Midwest Generation's Illinois Coal Plants: Too Expensive to Compete?.* Synapse Energy Economics for Sierra Club. [Online]

Woolf, T., J. Kallay, E. Malone, T. Comings, M. Schultz, and J. Conyers. 2012. *Commercial & Industrial Customer Perspectives on Massachusetts Energy Efficiency Programs*. Synapse Energy Economics for Massachusetts Energy Efficiency Advisory Council. [Online]

Hornby, R., D. White, T. Vitolo, T. Comings, and K. Takahashi. 2012. *Potential Impacts of a Renewable and Energy Efficiency Portfolio Standard in Kentucky*. Synapse Energy Economics for Mountain Association for Community Economic Development and the Kentucky Sustainable Energy Alliance. [Online]

Hausman, E., T. Comings, and G. Keith. 2012. *Maximizing Benefits: Recommendations for Meeting Long-Term Demand for Standard Offer Service in Maryland*. Synapse Energy Economics for Sierra Club. [Online]

Tantia, P., M.Dimova, T. Comings, and K. Davis. 2012. *Budget Finance Company: A Loan Modification Case Study.* [Online]

Keith, G., B. Biewald, E. Hausman, K. Takahashi, T. Vitolo, T. Comings, and P. Knight. 2011. *Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011*. Synapse Energy Economics for Civil Society Institute. [Online]

Hausman, E., T. Comings, K. Takahashi, R. Wilson, W. Steinhurst, N. Hughes, and G. Keith. 2011. *Electricity Scenario Analysis for the Vermont Comprehensive Energy Plan 2011*. Synapse Energy Economics for the Vermont Department of Public Service. [Online]

Steinhurst, W. and T. Comings. 2011. *Economic Impacts of Energy Efficiency Investments in Vermont*. Synapse Energy Economics for the Vermont Department of Public Service. [Online]

Datta, S., P. Tantia, and T. Comings. 2011. *WING Mobile Payments: A Product Design Case Study*. Ideas42 for International Finance Corporation. [Online]

Tantia, P. and T. Comings. 2011. *Kilimo Salama – Index-based Agriculture Insurance: A Product Design Case Study*. Ideas42 for International Finance Corporation. [Online]

Tantia, P. and T. Comings. 2011. *Emergency Hand Loan: A Product Design Case Study*. Ideas42 for International Finance Corporation. [Online]

Tantia, P. and T. Comings. 2011. *Commitment Savings Accounts in Malawi: A Product Design Case Study*. Ideas42 for International Finance Corporation. [Online]

Petraglia, L. and T. Comings, G. Weisbrod. 2010. *Economic Development Impacts of Energy Efficiency and Renewable Energy in Wisconsin*. Economic Development Research Group and PA Consulting Group for Wisconsin Department of Administration. [Online]

Economic Development Research Group. 2010. *The Economic Impact of Atlanta Hartsfield-Jackson International Airport*. Prepared for City of Atlanta. [Online]

Economic Development Research Group. 2009. *Economic Assessment of Proposed Brockton Power Facility*. Prepared for Brockton Power Company. [Online]

Economic Development Research Group and KEMA NV. 2009. *Economic Benefits of Connecticut's Clean Energy Program*. Prepared for the Connecticut Clean Energy Fund. [Online]

Howland, J., D. Murrow, L. Petraglia, and T. Comings. 2009. *Energy Efficiency: Engine of Economic Growth in Eastern Canada*. Economic Development Research Group and Environment Northeast. [Online]

Economic Development Research Group and KEMA NV. 2008. *New York Renewable Portfolio Standard: Economic Benefits Report*. Prepared for New York State Energy Research and Development (NYSERDA). [Online]

Colledge Transportation Consulting and Economic Development Research Group. 2008. *Northwest Corridor Trade and Manufacturing Strategy.* Prepared for Northern Development Initiative Trust and Canadian Manufacturers & Exporters. [Online]

Weisbrod, G. and T. Comings. 2008. *The Economic Role of the Gateway Transportation System in the Greater Vancouver Region*. Prepared for Greater Vancouver Gateway Council. [Online]

Cambridge Systematics and Economic Development Research Group. 2008. *Economic Impact Study of Completing the Appalachian Development Highway System*. Prepared for Appalachian Regional Commission. [Online]

Lynch, T., T. Comings, and G. Weisbrod. 2007. *Spatial Geography: Effects of Population Base and Airport Access*. Prepared for Appalachian Regional Commission. [Online]

BizMiner and Economic Development Research Group. 2007. *Program Evaluation of the Appalachian Regional Commission's Infrastructure and Public Works Projects*. Prepared for Appalachian Regional Commission. [Online]

Mead & Hunt and Economic Development Research Group. 2007. *Oregon Aviation Plan 2007*. Prepared for Oregon Department of Aviation. [Online]

Economic Development Research Group. 2007. *The Economic Impact of Philadelphia Convention Center*. Prepared for Pew Charitable Trusts. [Online]

Economic Development Research Group. 2006. *Environmental Impacts of Massachusetts Turnpike and Central Artery/Tunnel Projects*. Prepared for the Massachusetts Turnpike Authority. [Online]

TESTIMONY AND EXPERT COMMENTS

Comings, T. 2018. *Testimony on Vectren's Proposed Natural Gas Plant and Coal Retrofits.* Testimony to the Indiana Utility Regulatory Commission. Cause No. 45052. August 10, 2018.

Comings, T. 2018. *Testimony on Stranded Costs of Public Service Company of Colorado's Comanche 1 & 2 Coal Units*. Testimony to the Public Utilities Commission of Colorado. Proceeding No. 17A-0797E. March 28, 2018 and July 9, 2018.

Comings, T. 2017. *Testimony on the economic impact analysis of the proposed merger between AltaGas and WGL Holdings*. Testimony to the District of Columbia Public Service Commission. Formal Case No. 1142. September 29, 2017

Comings, T. 2017. *Testimony on the economics of the proposed acquisition of the Pleasants plant.* Testimony to the West Virginia Public Service Commission. Case No. 17-0296-E-PC. August 25, 2017.

Fagan, B. and T. Comings. 2017. *Joint testimony regarding the economic analysis of the Maritime Link Project.* Testimony to the Nova Scotia Utility and Review Board. Matter No. 07718. April 19, 2017.

Comings, T., A. Horowitz, and K. Takahashi. 2017. *Comments on Portland General Electric's 2016 Integrated Resource Plan*. Comments filed with the Oregon Public Utility Commission. Docket LC 66. January 24, 2017.

Comings, T. 2016. *Testimony regarding Dayton Power & Light's proposed Distribution Modernization Rider and the value of the Company's coal fleet*. Testimony to the Ohio Public Utilities Commission. Cases No. 16-0395-EL-SSO, 16-396-EL-ATA, and 16-397-EL-AAM. November 21, 2016.

Comings, T. 2016. *Testimony evaluating the economics of Oklahoma Gas & Electric's application to install dry scrubbers at the Sooner generating facility*. Testimony to the Oklahoma Corporation Commission. Cause No. PUD 201600059. March 14, 2016 and March 23, 2016.

Comings, T. and A. Horowitz. 2016. *Comments on Portland General Electric's Draft 2016 Integrated Resource Plan*. Comments filed with the Oregon Public Utility Commission. Docket LC 66. October 26, 2016.

Comings, T. 2015. *Testimony on the economic impacts of the proposed merger of NextEra Corporation and Hawaiian Electric Companies (HECO).* Testimony to the Hawaii Public Utilities Commission. Docket No. 2015-0022. August 10, 2015 and October 7, 2015.

Daniel, J. A. Napoleon, T. Comings, S. Fields. 2015. *Comments on Entergy Louisiana's 2015 Integrated Resource Plan*. Synapse Energy Economics for Sierra Club.

Comings, T., S. Jackson, K. Takahashi. 2015. *Comments on Indianapolis Power & Light Company's 2014 Integrated Resource Plan*. Synapse Energy Economics for the Sierra Club.

Comings, T. 2014. *Testimony evaluating the assumptions and analysis used by FirstEnergy Ohio in support of its application for approval of an electric security plan and related Retail Rate Stability Rider.* Testimony to the Ohio Public Utilities Commission. Case No. 14-1297-EL-SSO. December 22, 2014, May 11, 2015, October 13, 2015, December 30, 2015 and June 22, 2016.

Comings, T. 2014. *Testimony evaluating the assumptions in the analysis supporting Oklahoma Gas & Electric's request for authorization and cost recovery of a Clean Air Act compliance plan and Mustang modernization.* Testimony to the Oklahoma Corporation Commission. Cause No. PUD 201400229. December 16, 2014 and January 26, 2015.

Comings, T. 2014. *Testimony on the economic impact analysis filed by Exelon Corporation and Pepco Holdings, Inc. in their joint petition for the merger of the two entities.* Testimony to the Maryland Public Service Commission. Case No. 9361. December 8, 2014 and January 21, 2015.

Comings, T. 2014. *Testimony on the economic impact analysis filed by Exelon Corporation and Pepco Holdings, Inc. in their joint petition for the merger of the two entities.* Testimony to the State of New Jersey Board of Public Utilities. Docket No. EM14060581. November 14, 2014.

Comings, T. 2014. *Testimony on the economic impact analysis filed by Exelon Corporation and Pepco Holdings, Inc. in their joint petition for the merger of the two entities.* Testimony to the District of Columbia Public Service Commission. Formal Case No. 1119. November 3, 2014 and March 20, 2015.

Daniel, J., T. Comings, J. Fisher. 2014. *Comments on Preliminary Assumptions for Cleco's 2014/2015 Integrated Resource Plan.* Synapse Energy Economics for Sierra Club.

Fisher, J., T. Comings, D. Schlissel. 2014. *Comments on Duke Energy Indiana's 2013 Integrated Resource Plan*. Synapse Energy Economics and Schlissel Consulting for Mullet & Associates, Citizens Action Coalition of Indiana, Earthjustice and Sierra Club.

Comings, T. 2013. *Testimony regarding East Kentucky Power Cooperative's Application for Cooper Station Retrofit and Environmental Surcharge Cost Recovery*. Testimony to the Kentucky Public Service Commission. Case No. 2013-00259. November 27, 2013 and December 27, 2013.

Comings, T. 2013. *Testimony in the Matter of Indianapolis Power & Light Company's Application for a Certificate of Public Convenience and Necessity for the Construction of a Combined Cycle Gas Turbine Generation Facility*. Testimony to the Indiana Utility Regulatory Commission. Cause No. 44339. August 22, 2013.

Hornby, R., T. Comings. 2012. *Comments on Draft 2012 Integrated Resource Plan for Connecticut*. Synapse Energy Economics for AARP.

Resume dated May 2018

MEC-31C

CONFIDENTIAL EXHIBIT

MEC-32C

CONFIDENTIAL EXHIBIT

MEC-33C

CONFIDENTIAL EXHIBIT

MEC-34C

CONFIDENTIAL EXHIBIT

MEC-35C

CONFIDENTIAL EXHIBIT

20165-MEC-CE-4

Question:

1. For each of the Company's coal units, please provide the following information for each of the years 2010 through 2018 (latest available):

   a. Summer capacity rating
   b. Forced outage rate
   c. Planned outage rate
   d. Equivalent Availability Factor (EAF)
   e. Generation
   f. Fixed O&M costs
   g. Non-fuel variable O&M costs
   h. Fuel costs
   i. Fuel usage (MMBtu) by type
   j. Environmental capital costs
   k. Non-environmental capital costs

Response:

The requested information for subparts (a) through (k) can be found in Attachment A to this discovery response. The line items for Campbell Unit 3 represent only the portion of the plant owned by the Company. The Company reports "equivalent forced outage rates," rather than "forced outage rates." Similarly, the Company reports "equivalent planned outage factors," rather than "planned outage rates.". Additionally, the Company does not differentiate between fixed and variable O&M. Finally, the Company reports the costs requested in subparts (g), (h), (j), and (k) on a per-plant basis to FERC, which is how they are presented in Attachment A to this discovery response. Per unit costs are not readily available.

Norman J. Kapala
August 16, 2018

Coal Generation

20165-MEC-CE-4
Attachment A

Data	Unit	2010	2011	2012	2013	2014	2015	2016	2017	2018 YTD June 30
Equivalent Availability Factor	Campbell 1	90.93%	69.32%	92.63%	83.91%	87.93%	82.02%	76.66%	71.26%	71.84%
Equivalent Availability Factor	Campbell 2	92.14%	90.78%	83.08%	76.03%	85.68%	75.23%	70.44%	60.89%	54.23%
Equivalent Availability Factor	Campbell 3 (CE portion only)	84.80%	92.23%	81.74%	80.62%	81.77%	92.72%	61.08%	91.65%	71.22%
Equivalent Availability Factor	Karn 1	69.85%	63.27%	74.73%	65.09%	60.20%	48.08%	48.77%	73.63%	63.93%
Equivalent Availability Factor	Karn 2	74.46%	81.13%	72.92%	91.22%	55.76%	55.15%	70.87%	60.33%	87.69%
Equivalent Forced Outage Rate	Campbell 1	5.13%	0.43%	1.62%	1.72%	2.28%	1.46%	2.56%	0.62%	0.24%
Equivalent Forced Outage Rate	Campbell 2	0.58%	0.18%	8.98%	2.72%	1.59%	1.40%	0.39%	12.26%	14.28%
Equivalent Forced Outage Rate	Campbell 3 (CE portion only)	2.88%	4.19%	5.13%	6.00%	1.64%	0.21%	0.17%	0.37%	3.46%
Equivalent Forced Outage Rate	Karn 1	15.82%	6.42%	6.31%	5.20%	3.47%	5.12%	8.66%	1.61%	1.97%
Equivalent Forced Outage Rate	Karn 2	8.42%	9.34%	3.87%	0.90%	3.96%	4.13%	2.89%	0.20%	2.97%
Equivalent Planned Outage Factor	Campbell 1	0.00%	27.45%	0.27%	4.65%	4.53%	8.25%	11.35%	13.59%	19.97%
Equivalent Planned Outage Factor	Campbell 2	5.16%	6.34%	10.29%	20.94%	1.18%	22.30%	22.94%	12.45%	22.33%
Equivalent Planned Outage Factor	Campbell 3 (CE portion only)	11.38%	1.09%	9.82%	2.07%	7.03%	4.27%	37.74%	0.03%	21.67%
Equivalent Planned Outage Factor	Karn 1	8.41%	28.81%	9.94%	11.02%	24.62%	22.52%	40.00%	11.17%	29.39%
Equivalent Planned Outage Factor	Karn 2	18.04%	2.38%	10.12%	0.08%	30.66%	37.90%	24.28%	24.65%	5.28%
Env. Capital Costs	Karn 1&2	$ 65,661,703	$ 25,086,312	$ 63,998,514	$ 128,453,668	$ 47,486,312	$ 8,250,906	$ 2,690,475	$ 4,062,051	$ 3,927,112
Env. Capital Costs	Campbell 1&2	$ 62,665,118	$ 61,678,686	$ 65,786,666	$ 64,252,301	$ 82,434,954	$ 134,537,150	$ 51,084,990	$ 24,103,138	$ 1,827,643
Env. Capital Costs	Campbell 3 (CE portion only)	$ 7,761,183	$ 23,391,531	$ 33,720,995	$ 87,390,266	$ 134,216,499	$ 93,370,391	$ 94,114,035	$ 16,636,938	$ 3,179,155
Fuel Costs	Karn 1&2	$ 89,478,757	$ 96,566,755	$ 76,964,673	$ 84,470,456	$ 67,190,132	$ 56,322,009	$ 56,861,615	$ 63,126,713	$ 33,467,634
Fuel Costs	Campbell 1&2	$ 109,128,880	$ 93,904,426	$ 90,030,684	$ 100,182,397	$ 107,971,553	$ 90,810,082	$ 81,922,666	$ 64,435,648	$ 23,092,061
Fuel Costs	Campbell 3 (CE portion only)	$ 104,082,856	$ 142,690,494	$ 137,558,552	$ 147,071,032	$ 123,915,554	$ 134,557,084	$ 88,464,020	$ 140,107,858	$ 52,424,361
Non-Env. Capital Costs	Karn 1&2	$ 23,194,675	$ 19,620,165	$ 41,081,483	$ 44,613,530	$ 94,939,090	$ 49,510,054	$ 48,858,713	$ 10,646,955	$ 4,141,223
Non-Env. Capital Costs	Campbell 1&2	$ 14,931,041	$ 28,786,564	$ 15,878,144	$ 15,855,910	$ 5,335,652	$ 9,053,000	$ 7,259,874	$ 9,005,553	$ 14,778,806
Non-Env. Capital Costs	Campbell 3	$ 19,809,521	$ 7,550,159	$ 9,317,256	$ 2,625,439	$ 16,343,197	$ 19,634,904	$ 28,451,807	$ 1,420,362	$ 6,981,256
Non-Fuel ~~Variable~~ O&M	Campbell 1-2	$ 20,877,806	$ 32,701,969	$ 19,378,738	$ 22,549,239	$ 21,613,529	$ 24,194,632	$ 25,066,711	$ 20,389,593	$ 11,403,395
Non-Fuel ~~Variable~~ O&M	Campbell 3 (CE portion only)	$ 19,049,176	$ 19,307,627	$ 22,361,539	$ 18,888,275	$ 22,796,077	$ 20,260,711	$ 28,711,914	$ 21,090,811	$ 13,905,982
Non-Fuel ~~Variable~~ O&M	Karn 1-2	$ 21,508,267	$ 21,924,611	$ 24,979,943	$ 23,562,177	$ 26,656,681	$ 26,017,983	$ 29,328,941	$ 26,757,016	$ 13,832,484
Fixed O&M	Campbell 1-2	Consumers Energy does not differentiate between fixed and variable O&M								
Fixed O&M	Campbell 3 (CE portion only)	Consumers Energy does not differentiate between fixed and variable O&M								
Fixed O&M	Karn 1-2	Consumers Energy does not differentiate between fixed and variable O&M								
Fuel usage (MMBtu)	Karn 1	14,308,611	12,695,417	12,302,641	12,052,685	10,937,896	10,820,200	10,114,532	16,085,261	4,648,434
Fuel usage (MMBtu)	Karn 2	14,796,135	14,801,369	11,091,699	15,820,643	10,922,284	10,970,143	14,745,807	13,268,882	9,231,189
Fuel usage (MMBtu)	Campbell 1	19,663,795	13,357,621	17,795,394	17,385,200	16,902,931	16,191,211	13,617,504	11,389,442	4,268,680
Fuel usage (MMBtu)	Campbell 2	21,576,700	15,975,174	10,914,605	16,188,089	19,696,898	17,686,435	17,495,692	12,924,265	5,036,423
Fuel usage (MMBtu)	Campbell 3 (CE portion only)	56,893,524	54,946,830	50,161,003	53,216,159	48,866,534	55,213,550	34,014,784	53,142,053	22,401,680
Summer Net Demonstrated Capacity (MW)	Karn 1	255	255	255	255	251	255	234	255	255
Summer Net Demonstrated Capacity (MW)	Karn 2	260	260	260	260	259	260	260	260	260
Summer Net Demonstrated Capacity (MW)	Campbell 1	260	260	260	260	260	260	260	260	259
Summer Net Demonstrated Capacity (MW)	Campbell 2	360	355	355	355	351	343	350	348	345
Summer Net Demonstrated Capacity (MW)	Campbell 3 (CE portion only)	770	770	770	751	751	751	755	780	782
Total Net Generation (MWh)	Karn 1	1,352,895	1,201,814	1,140,753	1,092,401	1,002,961	952,929	865,004	1,379,529	749,169
Total Net Generation (MWh)	Karn 2	1,456,710	1,468,811	1,059,264	1,537,173	1,056,050	1,037,155	1,299,491	1,156,129	910,839
Total Net Generation (MWh)	Campbell 1	1,914,284	1,265,549	1,703,017	1,656,528	1,640,078	1,533,453	1,200,903	985,403	393,780
Total Net Generation (MWh)	Campbell 2	2,100,895	1,498,523	1,044,205	1,510,931	1,885,292	1,648,137	1,626,985	1,177,095	448,330
Total Net Generation (MWh)	Campbell 3 (CE portion only)	5,419,286	5,170,971	4,605,880	5,053,562	4,681,104	5,132,512	3,353,141	5,399,999	2,067,501

Question:

27. Reference the testimony of John P. Broschak, page 62 line 7 through page 63 line 12, and to Exhibit A-64 (JPB-7).

a. Produce the 2016 FERC Form 1 data used to calculate the non-fuel O&M/MWh cost for Karn Units 1 and 2 identified in column (e) of Exhibit A-64.

b. Produce the 2016 FERC Form 1 data used to calculate the non-fuel O&M/MWh cost for Campbell Units 1, 2, and 3 identified in column (e) of Exhibit A-64.

c. Confirm that Consumers reports in its FERC Form 1 filings data regarding non-fuel O&M costs and MWhs of generation for Campbell Unit 3 separately from the combined data for Campbell Units 1 and 2.

i. If confirmed, identify the 2016 non-fuel O&M/MWh cost for:

1. Campbell Units 1 and 2 combined

2. Campbell Unit 3

ii. If not confirmed, explain why not.

d. With regards to your claim that "Major maintenance can have a significant effect on individual plants or units," identify the amount of variation in annual non-fuel O&M/MWh costs for Karn Units 1 and 2, and Campbell Units 1-3, over the past five years.

Response:

a. Please see the attached Excel file: 20134-MEC-CE-75(a).xlsx and 20134-MEC-CE-75(a).pdf.

Please also see the attached Excel file: 20134-MEC-CE-75 – 2016 Benchmark Study.xlsx.

The second Excel file (20134-MEC-CE-75 – 2016 Benchmark Study) was included in this response as the numbers in Exhibit No. A-64 (JPB-7) (specifically columns (e) through (j), lines 1 through 6) were found to be incorrect.

The attached Excel file (20134-MEC-CE-75 – 2016 Benchmark Study) provides the correct numbers for the Company's 2016 Benchmark Study.

b. Please see sub-part (a).

c. Confirmed.

Please see sub-part (a).

i. Please see sub-part (a).
ii. Please see sub-part (c) i.

d. Please see the attached file: 20134-MEC-CE-75(d).pdf.

John P. Broschak
July 2, 2018

Generation Operation

(NOTE: Attached are numbered documents 13400134 through 13400167.)

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Non Fuel O&M/MWh for 2011
Source: SNL Financial

Case No: U-17087
Witness: DBKehoe
Exhibit: A-30 (DBK-5)
Date: September 2012
Page 1 of 1

2011 Non Fuel O & M / MWh

Line No. (a)	Plant (b)	No. (c)	Capacity (d)	Consumers Weighting (e)	4 Quartile (f)	3rd Quartile (g)	Middle Quartile (h)	2nd Quartile (i)	1st Quartile (j)
1	Whiting	1	100	11.09	20.46	16.58	13.18	10.97	8.32
2	Whiting	2	100	11.09	20.46	16.58	13.18	10.97	8.32
3	Whiting	3	125	11.09	20.46	16.58	13.18	10.97	8.32
4	Cobb	4	155	13.62	43.96	12.84	9.54	6.90	4.23
5	Cobb	5	155	13.62	43.96	12.84	9.54	6.90	4.23
6	Weadock	7	150	10.51	43.96	12.84	9.54	6.90	4.23
7	Weadock	8	150	10.51	43.96	12.84	9.54	6.90	4.23
8	Karn	1	256	7.96	21.25	14.35	10.86	8.13	3.76
9	Karn	2	256	7.96	21.25	14.35	10.86	8.13	3.76
10	Campbell	1	250	6.22	21.25	14.35	10.86	8.13	3.76
11	Campbell	2	350	6.22	21.25	14.35	10.86	8.13	3.76
12	Campbell	3	820	6.22	20.67	9.39	7.66	5.97	2.89
13				$8.58	$25.83	$12.86	$9.93	$7.57	$4.13

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Non-Fuel O&M/MWh for 2013
Source: SNL Financial

Case No.: U-17735
Witness: DBKehoe
Exhibit: A-48 (DBK-5)
Date: December 2014
Page 1 of 1

2013 Non-Fuel O & M / MWh

Line No.	Plant	No.	Capacity	Consumers Weighting	4 Quartile	3rd Quartile	Middle Quartile	2nd Quartile	1st Quartile
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Whiting	1	100	8.46	24.00	14.86	8.52	6.53	4.57
2	Whiting	2	100	8.46	24.00	14.86	8.52	6.53	4.57
3	Whiting	3	125	8.46	24.00	14.86	8.52	6.53	4.57
4	Cobb	4	155	8.71	24.00	14.86	8.52	6.53	4.57
5	Cobb	5	155	8.71	24.00	14.86	8.52	6.53	4.57
6	Weadock	7	150	8.53	24.00	14.86	8.52	6.53	4.57
7	Weadock	8	150	8.53	24.00	14.86	8.52	6.53	4.57
8	Karn	1	256	12.35	22.87	16.86	9.77	7.42	3.50
9	Karn	2	256	12.35	22.87	16.86	9.77	7.42	3.50
10	Campbell	1	250	4.87	22.87	16.86	9.77	7.42	3.50
11	Campbell	2	350	4.87	22.87	16.86	9.77	7.42	3.50
12	Campbell	3	820	4.87	41.30	11.50	8.89	6.54	2.91
13				$6.80	$28.51	$14.67	$9.11	$6.88	$3.68

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Non-Fuel O&M/MWh for 2014
Source: SNL Financial

Case No.: U-17990
Exhibit: A-46 (DBK-5)
Witness: DBKehoe
Date: March 2016
Page: 1 of 1

2014 Non-Fuel O & M / MWh

Line No.	Plant	No.	Capacity	Consumers Weighting	4 Quartile	3rd Quartile	Middle Quartile	2nd Quartile	1st Quartile
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Karn	1	256	13.23	30.63	18.36	11.79	7.56	3.58
2	Karn	2	256	13.23	30.63	18.36	11.79	7.56	3.58
3	Campbell	1	250	5.11	30.63	18.36	11.79	7.56	3.58
4	Campbell	2	350	5.11	30.63	18.36	11.79	7.56	3.58
5	Campbell	3	820	5.11	259.78	11.50	7.84	5.91	2.98
6				$6.74	$127.89	$15.45	$10.11	$6.86	$3.33

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-18322
Exhibit: A-62 (DMH-5)
Witness: DMHill
Date: March 2017
Page 1 of 1

Consumers Energy Company
Summary of Non-Fuel O&M/MWh for 2015
Source: SNL Financial

2015 Non-Fuel O&M / MWh

Line No.	Plant	No.	Capacity	Consumers Weighting	4 Quartile	3rd Quartile	Middle Quartile	2nd Quartile	1st Quartile
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Karn	1	255	12.94	33.31	12.72	9.53	7.35	1.67
2	Karn	2	260	12.94	33.31	12.72	9.53	7.35	1.67
3	Campbell	1	260	3.70	33.31	12.72	9.53	7.35	1.67
4	Campbell	2	360	3.70	33.31	12.72	9.53	7.35	1.67
5	Campbell	3	835	3.70	26.77	11.35	8.85	7.16	2.89
6				$6.50	$30.54	$12.14	$9.25	$7.27	$2.19

20134-MEC-CE-75
MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Non-Fuel O&M/MWh for 2016
Source: SNL Financial

2016 Non-Fuel O & M / MWh

Line No.	Plant	No.	Capacity	Consumers Weighting	4 Quartile	3rd Quartile	Middle Quartile	2nd Quartile	1st Quartile
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Karn	1	255	12.93	58.89	16.31	9.98	7.39	1.09
2	Karn	2	260	12.93	58.89	16.31	9.98	7.39	1.09
3	Campbell	1	260	8.02	58.89	16.31	9.98	7.39	1.09
4	Campbell	2	360	8.02	58.89	16.31	9.98	7.39	1.09
5	Campbell	3	787	8.20	57.04	17.81	10.23	7.30	1.09
6				$9.37	$58.13	$16.92	$10.08	$7.35	$1.09

20134-MEC-CE-334

<u>Question:</u>

2. Refer to your response to MEC-CE-75, the MEC-CE-75 (2016 Benchmark Study) ATT Excel file, Exhibit A-64 (JPB-7), and pages 62 line 7 through page 63 line 8 of the Direct Testimony of John Broschak.
   a. Confirm that, based on Consumers' weighting, the 2016 non-fuel O&M/MWh for the Karn and Campbell coal units combined ranks between the second and middle quartile in the nation. If not confirmed, explain why not.
   b. State whether Consumers intends to submit a corrected Exhibit A-64 and revisions to Mr. Broschak's testimony regarding Exhibit A-64 to reflect the corrected data presented in MEC-CE-75 (2016 Benchmark Study) ATT. If so, when? If not, why not?

<u>Response:</u>

a. Consumers Energy's 2016 Non-Fuel O&M/MWh of $9.37 (as identified in 20134-MEC-CE-75 – 2016 Benchmark Study.xlsx, column (e), line 6) is second quartile (or top half) in the nation.

   The top of the first quartile (or lowest cost Non-Fuel O&M/MWh in the study) is found in column (j), line 6, and is identified as $1.09. The top of the second quartile is found in column (i), line 6, and is identified as $7.35. The top of the third quartile is found in column (h), line 6, indicated as the "middle quartile" in the exhibit, and is identified as $10.08. The top of the fourth quartile is found in column (g), line 6, indicated as the third quartile in the exhibit, and is identified as $16.92. The bottom of the fourth quartile (or highest cost Non-Fuel O&M/MWh in the study) is found in column (f), line 6 and is identified as $58.13.

   Therefore, any value between the top of the first quartile ($1.09) and the top of the second quartile ($7.35) is in the first quartile. Similarly, any value between the top of the second quartile ($7.35) and the top of the third quartile ($10.08) is in the second quartile. Any value between the top of the third quartile ($10.08) and the top of the fourth quartile ($16.92) is in the third quartile, and any value between the top of the fourth quartile ($16.92) and the bottom of the fourth quartile ($58.13) is in the fourth quartile.

   Because Consumers Energy's 2016 Non-Fuel O&M/MWh of $9.37 falls between $7.35 (the top of the second quartile) and $10.08 (the top of the third quartile), it is in the second quartile (or top half) in the nation.

b. Consumers Energy will file a corrected version of Exhibit A-64 soon. Regarding Mr. Broschak's testimony, because there are minimal changes, the Company plans to make these updates closer to or at cross examination.

John P. Broschak

20134-AG-CE-513

Question:

114. Refer to page 33, lines 17-23, of Mr. Torrey's direct testimony. Please:

a. Identify the minimum amount of rate relief that the Company would deem acceptable in the Commission order to keep its commitment to defer filing the next general rate case to late February 2021.

b. Identify what IRM terms would be acceptable or not acceptable to the Company to keep its commitment to defer filing the next general rate case to late February 2021.

c. Identify any other conditions other than the two above that would need to occur or not occur for the Company to keep its commitment to defer filing the next general rate case to late February 2021.

Response:

a. The minimum amount of rate relief for the test year 2019 and IRM periods 2020 and 2021 acceptable in order to keep its commitment to defer filing the next general rate case will require evaluation by the Company's senior management at the time of the Commission order. Refer to my direct testimony page 31, line 15 through page 32, line 6.

b. Refer to my direct testimony page 31, line 10 through page 35, line 22.

c. Unforeseen, exogenous events such as catastrophic storms, a significant change in state or federal energy policy or tax law, or the loss of a major customer are potential items that may cause the Company to file a general rate application before late February 2021. While this list of examples is not exhaustive, the MPSC has within its authority the ability to approve deferred accounting for such items which may allow the IRM to continue in effect.

Michael A. Torrey

Michael A. Torrey
August 21, 2018

Rates and Regulation

20134-AG-CE-515 (Partial)

Question:

116. Refer to page 34, lines 21-23, and page 35, lines 1-13, of Mr. Torrey's direct testimony. Please:

a. Confirm that the Company does not want the Commission to impose any minimum or maximum limits to the proposed IRM spending level either in total or within each program. If not confirming, please explain.

b. Provide the procedure and sample calculation of any refunds the Company would make if the proposed spending level is not achieved each year.

c. Given that the Company had a revenue sufficiency of $17.4 million in the 2017 historical year, why is an IRM necessary at all?

Response:

a. The Company has proposed a total maximum spend level for IRM recovery in 2020 and 2021. It is the Company's proposal that, in the reconciliation, actual spending on individual programs be reviewed to determine if it was consistent with the plan, was reasonable and provided value to customers in that it was necessary to provide quality electric service.

c. The IRM addresses cost recovery for planned expenditures totaling over $1 billion in 2020 and 2021.

Michael A. Torrey

Michael A. Torrey
August 21, 2018

Rates and Regulation

20134-AG-CE-515 (Partial)

Question:

116. Refer to page 34, lines 21-23, and page 35, lines 1-13, of Mr. Torrey's direct testimony. Please:

a. Confirm that the Company does not want the Commission to impose any minimum or maximum limits to the proposed IRM spending level either in total or within each program. If not confirming, please explain.

b. Provide the procedure and sample calculation of any refunds the Company would make if the proposed spending level is not achieved each year.

c. Given that the Company had a revenue sufficiency of $17.4 million in the 2017 historical year, why is an IRM necessary at all?

Response:

b. Please refer to pages 26 through 30 of the direct testimony of Heidi Myers for the reconciliation procedure. If total capital spending for 2020 is less than the capital spending included in the IRM calculation, the revenue requirement calculation for the IRM would be recalculated with the lower total capital spending. The recalculated revenue requirement would be compared to the IRM revenue requirement approved and the difference would be refunded to customers. Any reduced ending balances would carry over to the 2021 reconciliation also reducing the actual revenue requirement for 2021. Attached is the recalculation of the IRM revenue requirement for 2020 and 2021 for total capital spending in 2020 that is less than proposed.

Heidi Myers
August 21, 2018

Rates and Regulation

Question:

27. Reference the testimony of Timothy J. Sparks, page 5, lines 14-16. Please identify and describe the groups, titles, and area of focus for all personnel involved in the EDIIP.

Response:

The Company's Electric Distribution Infrastructure Investment Plan (EDIIP) was the result of a highly cross-functional and collaborative effort, engaging a number of stakeholders, subject matter experts, leadership and data sources from across multiple organizations. The primary personnel involved in the development of the EDIIP (plan and/or report) included the following (name, title, SVP/VP department, area of focus for the EDIIP):

1. Andrew Bordine, Executive Director of Grid Infrastructure, Electric Grid Integration, LVD planning and engineering;
2. Andrew Denato, Assistant Corporate Controller, Controller/Chief Accounting Officer, corporate accounting and reporting;
3. Andrew Snider, Electric Operations Zone Manager I, Electric Operations, LVD new business;
4. Aric Root, Senior Engineer Lead, Electric Grid Integration, HVD planning;
5. Brent Henige, Senior Engineer Lead, Electric Grid Integration, LVD planning;
6. Brian Bushey, Grid Technologies Manager, Electric Grid Integration, grid modernization;
7. Brian Niemi, Substation Operations Manager, Electric Operations, substations operations;
8. Brock Lehmeyer, Senior Engineering Technical Analyst Lead, Electric Grid Integration, system model enhancement;
9. Chris Shellberg, Executive Director of HVD and Forestry Management, Electric Operations, electric operations;
10. Christopher Niemi, Manager Systems Forestry, Electric Operations, forestry;
11. Colleen Satkowiak, Outage Experience Manager, Customer Experience, service restoration;
12. David Duchaine, Senior Engineer Lead, Electric Operations, restoration management;
13. David Tomczack, Senior Engineer II, Electric Grid Integration, metro planning;

14. Donald Lynd, Director Electric Transmission Planning and Protection, Electric Grid Integration, system protection;
15. Douglas Chapel, Senior Business Support Consultant II, Electric Grid Integration, regulatory and EDIIP project management;
16. Douglas Meyers, Senior Engineer Lead, Electric Grid Integration, systems engineering programs;
17. Dwayne Parker, Director Customer and Service Infrastructure – HVD, Electric Grid Integration, HVD planning;
18. Edward Mathews, Senior Engineer Lead, Electric Grid Integration, HVD planning;
19. Ekaterina Miller, Restoration Manager, Electric Operations, restoration management;
20. Garret Miller, Director Safety, Operations Support, employee and public safety;
21. Gregory Kral, Senior Engineer Lead, Electric Grid Integration, substation planning and reliability;
22. Heidi Myers, Director Revenue Requirement and Analysis, Rates and Regulation, revenue requirements and analysis;
23. Hubert Miller, Regulatory Reporting Manager, Customer Experience, energy efficiency and demand response regulatory reporting;
24. James Anderson, Executive Director of HVD and Transmission Engineering, Electric Grid Integration, HVD planning and engineering;
25. Jason Rhinehart, Director LVD Engineering, Electric Grid Integration, LVD planning and engineering;
26. Jason Shore, Executive Director of Planning, Budgeting and Analysis, Controller/Chief Accounting Officer – Budget, Planning & Analysis, utility budget planning and analysis;
27. Jeffrey Chilson, Senior Engineer Lead, Electric Grid Integration, HVD models and dynamics;
28. Jeffrey Floyd, Senior Engineer LVD Planning-Metro, Electric Grid Integration, Metro planning;
29. Jeffrey Shingler, Executive Director of LVD-East, Electric Metering, Customer Field Services; Electric Operations; electric operations;
30. Jennifer Horsfall, Electric Planning Lead, Electric Operations, electric planning and resource management;
31. Jennifer Rose, Executive Director of Electric Regulatory and Strategy Implementation, Electric Grid Integration, regulatory and EDIIP filing project management;

32. Jim Beechey, Executive Director of Security, Customer Experience and Technology, security;
33. Jim Chilson, Manager of Asset Strategy, Electric Grid Integration, electric distribution asset strategy and modeling;
34. John O'Connor, Senior Technical Analyst Lead, Electric Operations, forestry;
35. Jon Schaible, Senior Financial Analyst Lead, Controller/Chief Accounting Officer, electric distribution budgeting and planning;
36. Joseph Eckert, ASP Financial Operations Manager, Customer Experience, business demand response;
37. Julia Fox, Director LVD Planning, Electric Grid Integration, LVD planning;
38. Karen Wienke, Regulatory Affairs Client Lead, Rates and Regulation, regulatory affairs;
39. Karl Grieve, Principal Technical Analyst Lead, Electric Grid Integration, grid analytics;
40. Keith Kurdziel, Director Distribution Standards and Materials, Electric Grid Integration, LVD standards and materials;
41. Kyle Desser, Senior Engineer I, Electric Grid Integration, LVD planning;
42. Kyle Reininger, Director Electric Transmission and HVD Engineering, Electric Grid Integration, HVD standards and materials;
43. Libby Wilson, Senior Business Support Analyst, Customer Experience, customer analysis;
44. Louis Hincka, Senior Engineer II, Electric Grid Integration, HVD engineering;
45. Marc Bleckman, Executive Director of Financial Analysis, Chief Financial Officer – Financial Forecasting, financial planning;
46. Mark Ortiz, Principal Technical Analyst Lead, Electric Grid Integration, grid modernization;
47. Matthew Good, Senior Engineer Lead, Electric Grid Integration, substation planning and reliability;
48. Matthew Seibert, Senior Engineer II, Electric Grid Integration, grid modernization;
49. Michael Delaney, Executive Director of Corporate Strategy, Strategy, corporate strategy;
50. Michelle Savicki, Senior Business Support Consultant Specialist, Electric Operations, electric reliability analysis;
51. Nathan Washburn, Senior Engineer II, Electric Grid Integration, distribution standards and materials;

52. Ray Klavon, Executive Director of Grid Management, Electric Operations, grid management;
53. Richard Pienkos, Principal Engineer Lead, Electric Grid Integration, system protection;
54. Robert Vermurlen, Senior Engineer II, Electric Grid Integration, grid analytics;
55. Ryan Kiley, Director Strategic Projects, Strategy, strategic projects;
56. Sarah Barbo, Manager Corporate Strategy, Strategy, corporate strategy;
57. Sarah Jorgensen, Regulatory Client Liaison II, Rates and Regulation, regulatory affairs;
58. Stacie Tello, Director Strategic Mobilization, Human Resources, energy efficiency and demand response;
59. Stephen Stubleski, Director Cost, Pricing, Rates Administration; Rates and Regulation, rates administration, cost and pricing;
60. Tammy LoPresto, Director Portfolio Planning, Controller/Chief Accounting Officer – Budget, Planning & Analysis, engineering and operations financial planning;
61. Teri VanSumeren, Executive Director of Clean Energy Products; Customer Experience, energy efficiency and demand response;
62. Timothy Sparks, Vice President of Electric Grid Integration, Electric Grid Integration, EDIIP executive project sponsor;
63. Victor Ex, Senior Engineer I, Electric Grid Integration, LVD planning;
64. William Ware, Director Customer Research, Customer Experience, customer research; and
65. Zakiya Harris, Senior Field Leader II, Rates and Regulation, regulatory affairs.

Through the course of the development of the EDIIP, Company Officers were also kept informed of progress and given opportunity to review and provide input and feedback.

Tim Sparks

Timothy J. Sparks
July 19, 2018

20134-ST-CE-685

Question:

12. Has the Company reviewed the stakeholder comments on their EDIIP?

a. If yes, please provide a synopsis of the Company's conclusion of the stakeholder comments?

Response:

Yes.

a. The Company's conclusions regarding stakeholder comments on the EDIIP were incorporated into the Company's presentation given at the August 7, 2018, technical conference. That presentation is included in Exhibit MEC-21 in this case. In preparing for the technical conference, the Company summarized the comments in the document provided as Attachment A to this discovery response.

(NOTE: Attached is numbered document 13400978.)

Tim Sparks

Timothy J. Sparks
September 26, 2018

Electric Grid Integration

Theme	Issue – Generic Description	Intervenors – Unique Points
Ratemaking Policy: Investment Recovery Mechanisms, Performance-Based Ratemaking, and Performance Metrics	IRM – Can the Company pursue a multi-year IRM to recover investments in distribution, with a means to monitor program activity and spending?	ABATE – Opposes IRM for the following reasons: 1. Shifts risk from investors to ratepayers, as recovery may be guaranteed with no demonstrated benefit 2. "Single-issue ratemaking" when the IRM only follows certain cost categories 3. IRMs compromise incentives for prudence and due diligence 4. EDIIP does not propose anything with volatile costs 5. CE files rate cases too often to justify an IRM 6. The MPSC lacks statutory authority to authorize and IRM
	PBR & Metrics – Should Michigan move from cost-of-service-based ratemaking to performance-based ratemaking? • What are appropriate metrics to tie to PBR? • How should targets for metrics be set? • Which parties get a role in setting metrics and targets? What alignment and collaboration is possible, with and among stakeholders, on setting of metrics?	ABATE – Supports PBR; tying rate recovery to performance rather than simple capital expansion removes incentives to build for its own sake. Specific metrics are not proposed, but ABATE supports proposed approach from Minnesota.
		MEIBC – Supports PBR based on performance metrics; metrics and targets should be determined by meetings involving all stakeholders, with a goal of eliminating capital bias when operational spending may be more prudent. Several metrics are suggested, with a goal of granularity to support DER deployment and siting: • System efficiency: peak load reduction, load factor • Interconnection: speed of processing requests, user satisfaction with process • Percentage of customers with access to engagement communication • Customer and third party access to data: timeliness of data request responses, automation of data exchange, ability to access data through self-service tools • Energy waste reduction: kWh and thermal reduction relative to baseline
Future of Distributed Energy Resources: Increasing Use and Enhanced Distribution System Planning	Increasing Use of DER – Intervenors want rapid expansion of DERs as part of any future distribution planning, and criticize CE for not considering DERs more as distribution NWAs in the EDIIP	MEIBC – In addition to HCAs, there should be uniform DER interconnection study parameters and DER interconnection standards
		ELPC – CE should accelerate its current roll-out of DER and NWA pilots, which are currently too limited
		MAUI – Increased use of DERs, as a part of microgrids, will promote resilience, which is necessary because outages cannot be entirely engineered away
		NRDC – CE should increase rollout of DERs and NWAs now by considering them against proposed EDIIP capital projects • "Stacking" multiple DERs can promote reliability and resiliency just as well as infrastructure and forestry improvements • Ultimately DERs should be considered simultaneously for both IRPs and distribution planning
	Increased Stakeholder Input – Intervenors want distribution planning process in which they have an increased decision-making role, styled after IRP, rather than simply reacting to rate cases or other filings, particularly to be able to advocate for more DERs	MEIBC – Envisions a formal distribution planning process at MPSC: • Standardized process including role for stakeholders • Standardized cost-benefit analysis framework • Require multiple probabilistic load and DER forecast scenarios, with stakeholder input on assumptions
		MAUI – Municipalities should have defined role and rights in the distribution planning process • Coordination with municipalities would reduce tradeoffs on aesthetics and reduce situations where, for example, recently repaired roads must be torn up again to facilitate electric work
		ELPC – "Integrated Distribution Planning" should act like an IRP, with broad stakeholder input to define scenarios, forecasting approaches, standard cases for HCAs, etc.
	Increased Sharing of Data – Intervenors want a) better use of data in distribution planning and b) full access to data, particularly relating to Hosting Capacity Analyses that identify potential for DERs	MEIBC – CE does not plan to spend enough on data provision and utilization • CE should provide more transparency, disclosing DER forecasting methodology • CE should provide more data to support cost-benefit analyses
		ELPC – HCAs should be conducted for the entire system, updated regularly, and made available for public download
		NRDC – The MPSC should require greater data disclosure to stakeholder groups as part of ongoing technical conferences • CE should better explain how it will use AMI data to forecast and manage the system • CE should develop a single communication network to integrate all data sources including ADMS

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to require **CONSUMERS ENERGY COMPANY** to provide electric power reliability information in its annual power quality report	)))))	Case No. U-16066

CONSUMERS ENERGY COMPANY'S ANNUAL POWER QUALITY REPORT:
I. RELIABILITY INDICES
II. PRIMARY CUSTOMER POWER QUALITY INVESTIGATIONS
III. INCREASED REPORTING REQUIREMENTS

Background

On September 15, 2009, the Michigan Public Service Commission ("MPSC" or the "Commission") issued an Opinion and Order in Case No. U-16066, in which it directed that the two major Michigan utilities: (i) provide information related to System Average Interruption Frequency Index ("SAIFI"),[1] Customer Average Interruption Duration Index ("CAIDI"),[2] and System Average Interruption Duration Index ("SAIDI")[3] reliability indices with and without major events, on a rolling five-year average basis, using the industry standard Institute of Electrical and Electronics Engineers ("IEEE") method of calculation; and (ii) file an annual power quality report which contains data on all primary customer power quality investigations conducted in the past year for end-use customers, derived from their power quality meters, and the outcome of each investigation.

On December 4, 2014, the Commission issued an Opinion and Order in Case No. U-17542, in which it directed that the two major Michigan utilities provide the following additional information on an annual basis:

[1] SAIFI represents the average number of interruptions per customer per year.
[2] CAIDI represents the average restoration time per outage.
[3] SAIDI represents the average number of minutes of interruptions per customer.

i. A list of their 10 worst performing circuits for the prior year in terms of both SAIDI and SAIFI;

ii. For each of the 10 worst performing circuits, the utility shall provide the following information: (a) SAIDI and SAIFI excluding major events for the year; (b) circuit name, number, and location; (c) length of circuit (miles); (d) number of customers served; (e) substation name; (f) last circuit trim; (g) list of outages and causes; and (h) corrective action plan to improve performance;

iii. Number of Customers Experiencing Multiple Interruptions ("CEMI") reporting for indices $CEMI_0$ through $CEMI_{10+}$; and

iv. Number of Customers Experiencing Long Interruption Durations ("CELID") reporting for indices $CELID_{60hrs}$ and $CELID_{8hrs}$ (excluding catastrophic events).

This report contains Consumers Energy Company's ("Consumers Energy" or the "Company") January 1, 2017 through December 31, 2017 results and compliance status per these requirements.

I. RELIABILITY INDICES

Consumers Energy's rolling five-year average SAIDI, SAIFI, and CAIDI indices are summarized in the following table. These indices were calculated using the Major Event Day ("MED") methodology contained in IEEE Standard 1366-2012. Graphical representations of this data can be found on pages 6 through 8.

Year	All Conditions						Excluding Major Event Days					
	SAIDI		SAIFI		CAIDI		SAIDI		SAIFI		CAIDI	
	Annual	5 Year Avg.	Annual	5 Year Avg.	Annual	5 Year Avg.	Annual	5 Year Avg.	Annual	5 Year Avg.	Annual	5 Year Avg.
2008	710	525	1.50	1.55	473	338	281	249	1.08	1.19	260	210
2009	346	522	1.23	1.52	283	341	222	254	1.05	1.18	212	216
2010	463	536	1.40	1.48	331	358	216	250	1.04	1.14	207	220
2011	668	540	1.64	1.47	407	364	305	257	1.36	1.16	224	222
2012	508	539	1.38	1.43	369	372	204	245	1.06	1.12	192	219
2013	1108	619	1.50	1.43	738	425	218	233	1.00	1.10	218	211
2014	377	625	1.10	1.40	342	437	168	222	0.91	1.08	184	205
2015	441	620	1.18	1.36	374	446	177	214	0.98	1.06	180	200
2016	284	544	1.15	1.26	247	414	207	194	1.01	0.99	206	196
2017	606	563	1.31	1.25	464	433	161	186	0.89	0.96	181	194

Since 2011, multiple tactics have been employed each year at Consumers Energy to continue to improve the operational performance of its electrical infrastructure and response to customer outages. In 2017, Consumers Energy further improved in these areas by implementing tactics as follows:

- Continuing use of a Reliability Rally Room; a collaboration space and forum for coordinated problem solving that minimizes organizational barriers and promotes visibility and accountability. The Rally Room concept is not unique to Consumers Energy, it is a key element of the lean system that has been used across manufacturing industries to implement continuous improvement initiatives;

- Developing a key performance indicator tree to connect daily work to reliability improvements and identify leading indicators for performance measurement;
- Using visual management to understand the performance drivers, align on the plan, validate performance, and adjust based on key performance metrics;
- Continuing Daily, Weekly, and Monthly Operating Review cadences to understand performance against targets and quickly identify opportunities for improvement;
- Enhancing tracking of work plan progress and identifying barriers, for example; required permits and finding alternate design solutions to complete construction on the worst performing circuits;
- Completing full circuit line clearing on the worst performing circuits and completing targeted annual maintenance programs;
- Completing construction of substation animal mitigation projects;
- Completing rebuild of High Voltage Distribution (“HVD”) lines and pole top rehabilitation;
- Continuing proactive preparation for response to customer outages utilizing Incident Command System principles;
- Conducting tabletop restoration exercises, restoration process assessments, and after action reviews as part of the sustainability plan for emergency response;
- Implementing integration between the Outage Management System and Automated Metering Infrastructure to improve customer communication, and outage analysis capabilities;
- Increasing electric system investments to improve reliability; and
- Leveraging Distribution Supervisory Control and Data Acquisition remote operations and enhancing infrastructure resilience by installing Distribution Automation.

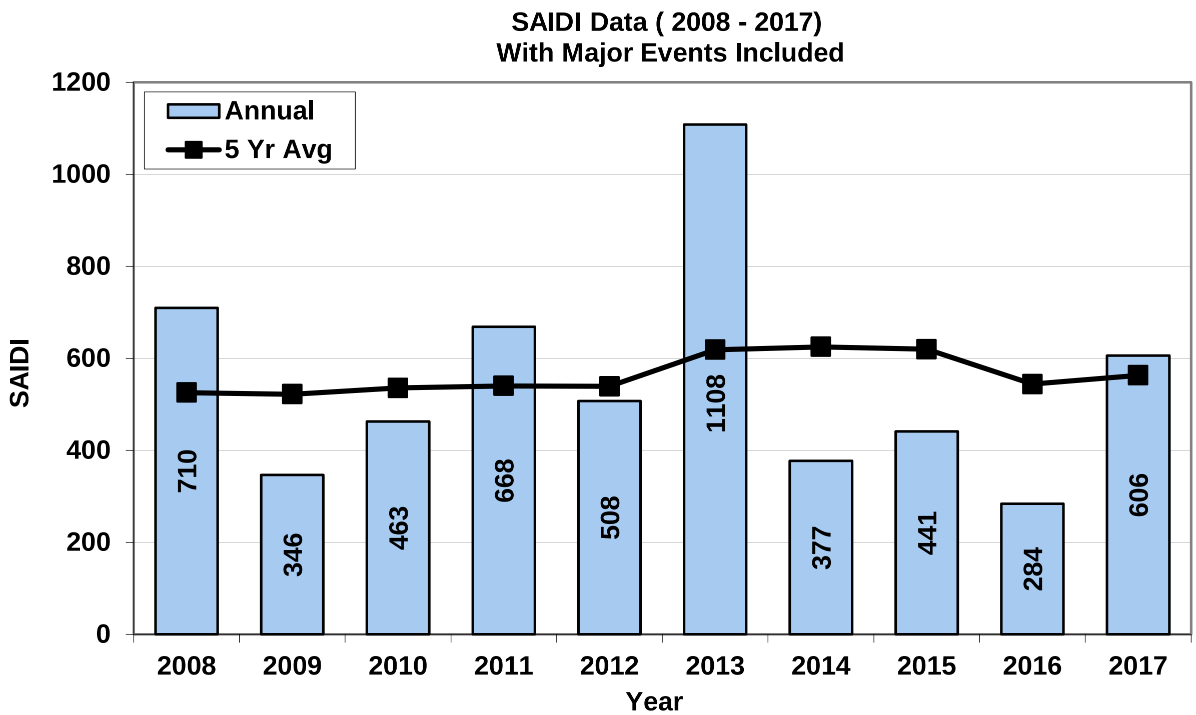
The operational and infrastructure investments have driven system and operational improvements, which are benefiting our customers. The average duration of outage each customer experienced (SAIDI, excluding MEDs) in 2017 has improved from the 2012 through 2016 average with a 17% decrease from 194 to 161 minutes per customer, demonstrating a continuous positive trend. The improvement is also reflected in SAIDI (excluding MEDs) being the lowest value in the last 17 years. The average number of interruptions that impacted our customers (SAIFI, excluding MEDs) in 2017 also improved from the 2012 through 2016 average with a 10% decrease from 0.99 to 0.89 interruptions per customer, also demonstrating a positive trend. The positive SAIFI trend equates to 180,000 fewer customers experiencing interruptions. The improvement also resulted in SAIFI being the lowest value since the Company began tracking this metric using the IEEE definition in 2001. The duration of an average interruption a customer experienced when impacted (CAIDI, excluding MEDs) in 2017 showed a decrease from the 2012 through 2016 average with an 8% change from 196 to 181 minutes. There were 32 weather events resulting in customer outages with two catastrophic storms creating difficult conditions for restoration due to significant wind damage. The Company experienced eight MEDs in 2017, four of which were part of the two catastrophic storms.

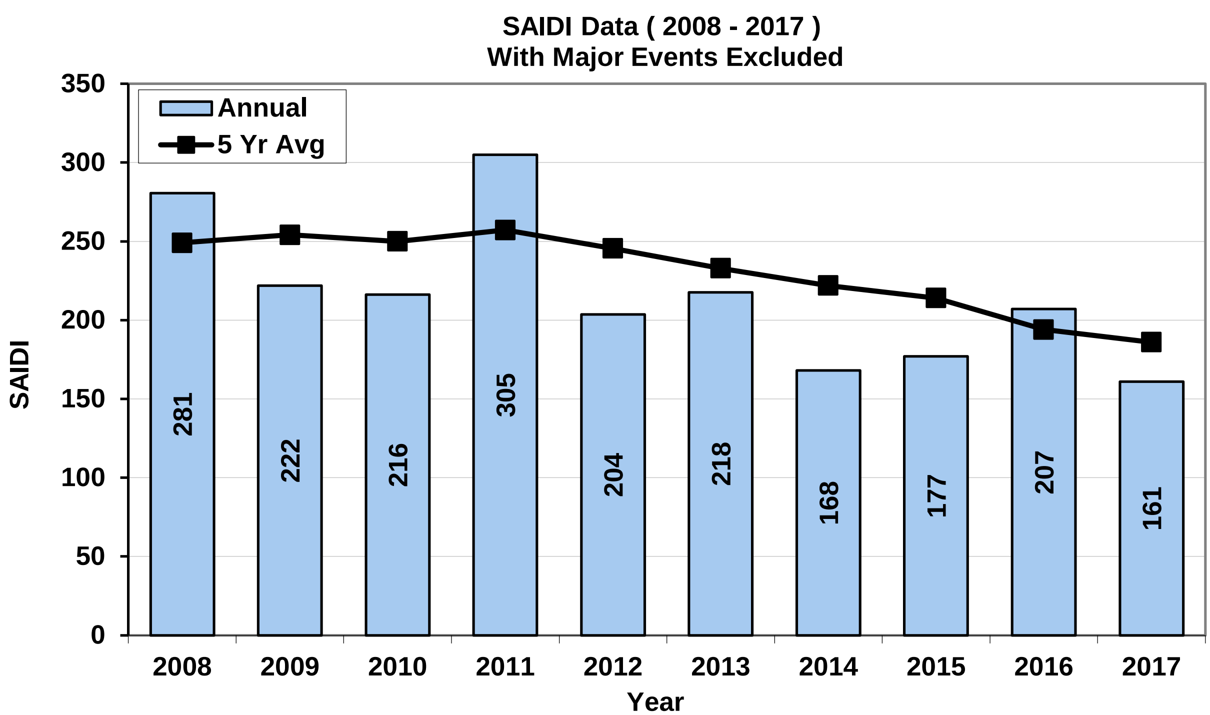
A. Reliability Indices Summary

The Company's goal for 2018 is to achieve an IEEE Benchmarking of third quartile SAIDI reliability performance in order to improve customer service and satisfaction, as well as advance the Company's reliability performance relative to its utility peers. To achieve this goal, the Company will continue to use visual management and operating reviews in the Reliability Rally Room to measure performance, identify barriers, and drive improvements. Leveraging data analytics and focusing on leading indicators in the Reliability Rally Room has increased problem solving across organizations and will continue to be the focus for the core team consisting of Operations, Engineering and support organizations. These areas of focus combined with reliability investments, maintenance programs, and an advanced utilization of electric system automation should produce improvement of these important reliability metrics to the benefit of our customers.

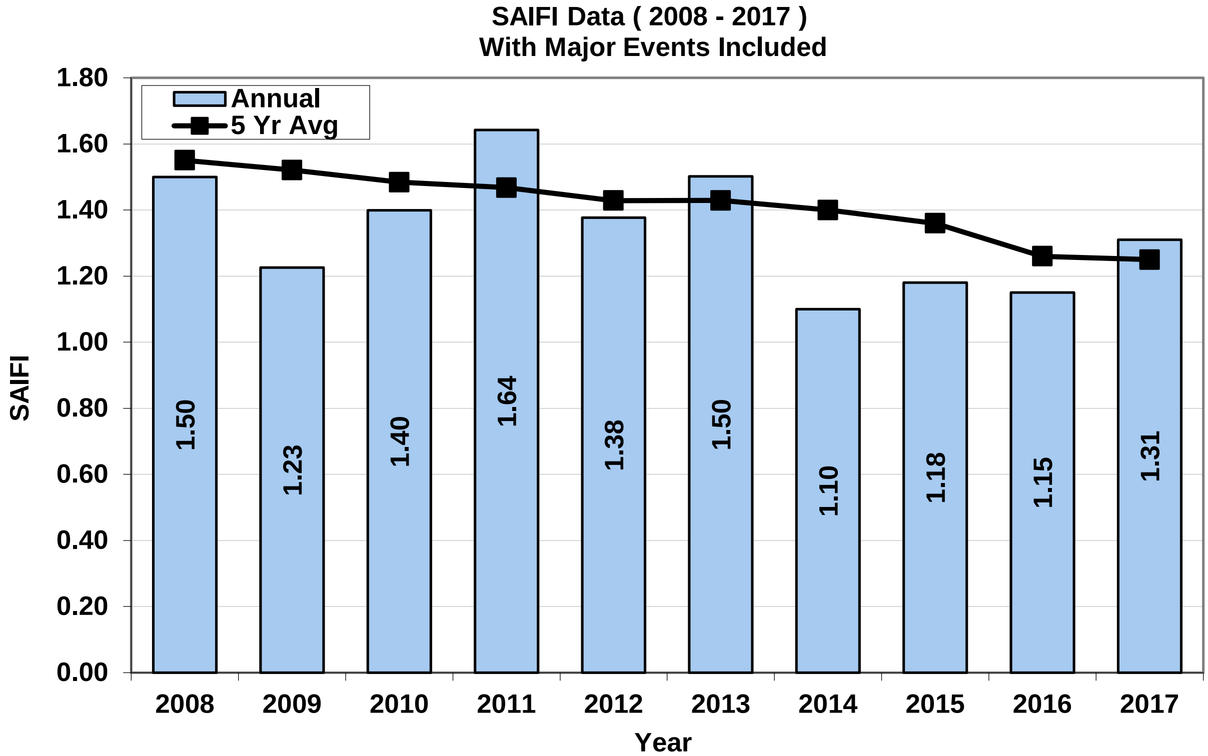
It is noteworthy that all the reliability indices (SAIDI/SAIFI/CAIDI), excluding MEDs, five year average results have continuously improved since 2011.

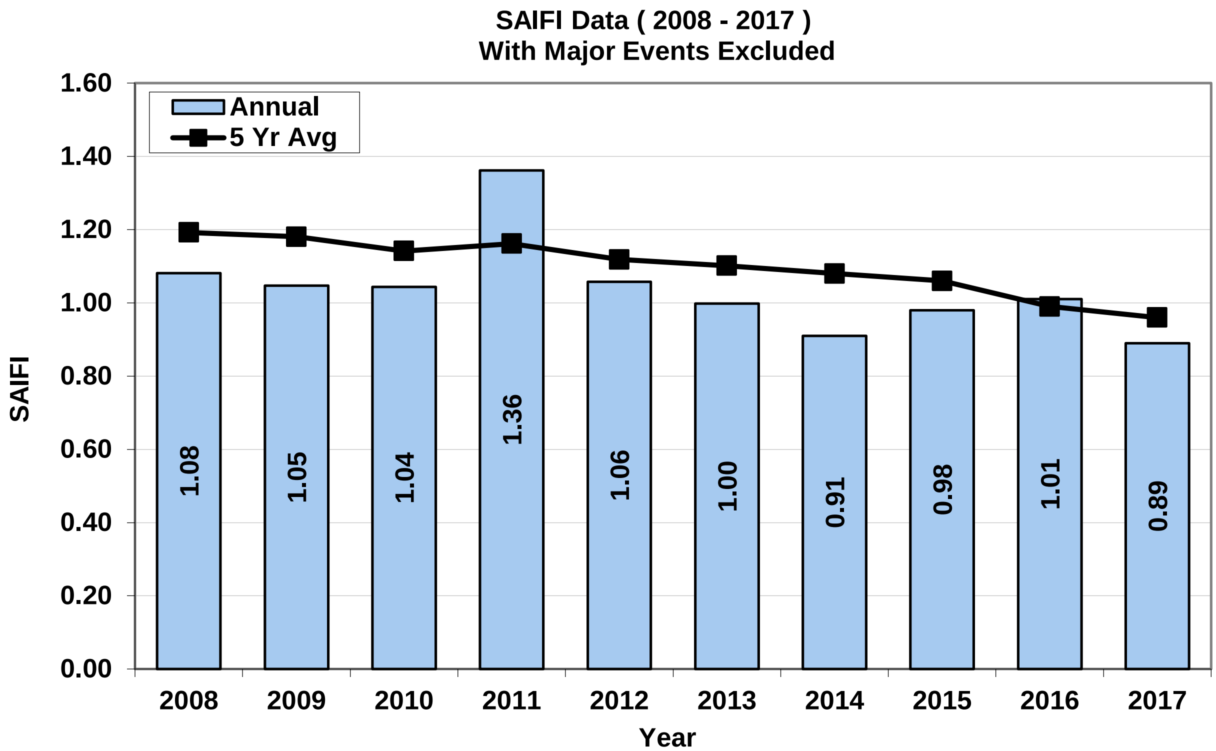
The annual and rolling five-year average values for SAIDI including and excluding major events are shown in the following graphs:





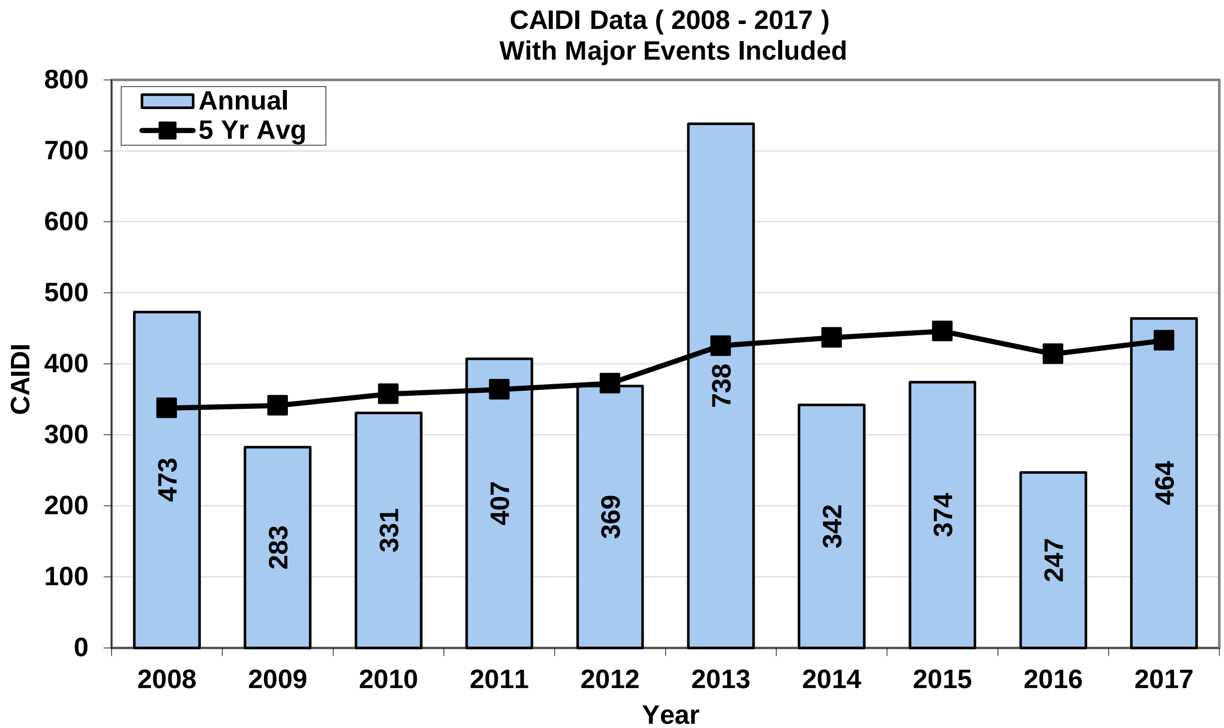
The annual and rolling five-year average values for SAIFI including and excluding major events are shown in the following graphs:

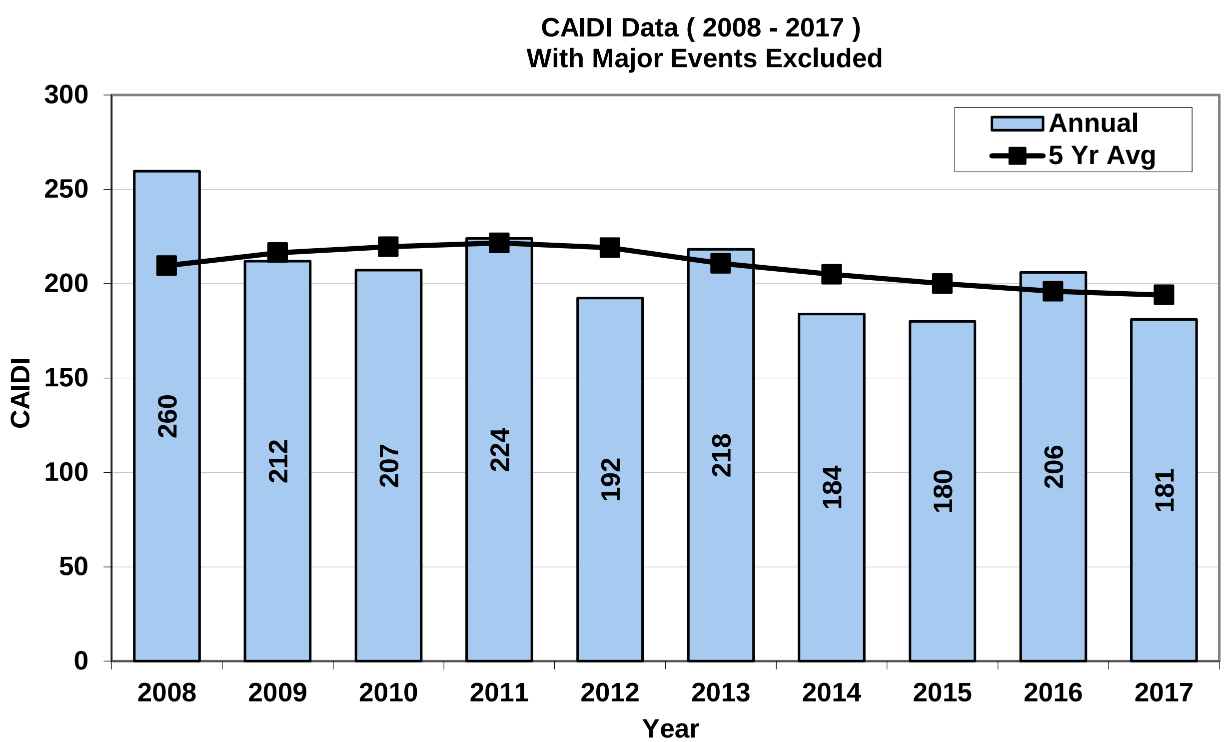




re0418-1-241

The annual and rolling five-year average values for CAIDI including and excluding major events are shown in the following graphs:





II. PRIMARY CUSTOMER POWER QUALITY INVESTIGATIONS

A. Power Quality Process

Consumers Energy continually monitors power quality at 226 industrial and commercial locations that have primary metering. These monitors are primarily installed at dedicated substations that have a load greater than 1 Mega Volt Amp ("MVA"); however, monitors are also installed on a few customers on the distribution system in response to power quality concerns. Power quality monitoring uses a comprehensive process to monitor the electric system and provide customers with potential solutions to meet their needs.

The power quality data is downloaded periodically from the monitors. This data is imported and stored in an analysis database which is used to generate reports daily and on demand. Power quality information including voltage, current, power trends, harmonics, voltage and current unbalance, and detailed disturbance data is made available to customers upon request through Consumers Energy Corporate Account Managers. On many occasions, the daily monitoring by Consumers Energy's engineers has helped identify issues on the electric system.

B. 2017 Power Quality Data

Power quality issues are not widespread within Consumers Energy's electric system; however, customer inquiries are generated as a result of experienced or perceived voltage sags, overvoltage, voltage transients, voltage flicker, high frequency noise, voltage unbalance, momentary outages, or equipment problems. In 2017, there were 34 power quality events which generated customer inquiries. Of these, 20 (59%) of the 34 events were attributable to the customer's electric system. The remaining 14 (41%) events were electrical faults, issues pertaining to operational configuration, or equipment malfunctions occurring on the utility electric system. The causes of these faults included lightning, windstorms, equipment failure, third party contact, and animal contact on the utility system owned by Consumers Energy or its transmission provider. For 8 of the 14 events attributed to the utility system, Consumers Energy or its transmission provider made repairs to the system or scheduled projects to address system performance. The remaining 6 events (of 14) were faults that were restored automatically by the electric system or that required no repairs or modifications of the electric system.

The table below indicates the power quality issues brought to the attention of Consumers Energy's Power Quality Monitoring group in 2017 where Power Quality Monitors ("PQM") were installed.

Inquiries			Power Quality Event [4]							Source of PQ Event			Outcomes		
Event	Date	Locations Impacted [5]	Transient	Voltage Sag	Voltage Swell	Interruption	Overvoltage	Under voltage	Other (inc. Harmonics)	Consumers Energy [6]	Transmission Provider [7]	Customer [8]	Customer Contact [9]	Modifications [10]	Description
01	01/03	1							x			x	x		Customer reported Power Quality event but PQM showed voltage to be within limits.
02	01/12	1		x							x		x	x	138kV sub fault due to failed insulator; Replaced failed equipment.

[4] Heading definitions per IEEE Standard 1159-2009 Table 2 – Categories and Typical Characteristics of Power System Phenomena.
[5] Number of customer locations impacted per event.
[6] Equipment owned by Consumers Energy (138 kV, 46 kV, <25 kV).
[7] Equipment owned by transmission provider (345 kV or 138 kV).
[8] Source of the event was within the customer's electrical system.
[9] Consumers Energy provided a response to the customer including the cause of the event and any modifications planned or completed.
[10] Consumers Energy made a like for like repair to return the system to normal or scheduled a project to address system performance.

Inquiries			Power Quality Event [4]							Source of PQ Event			Outcomes		
Event	Date	Locations Impacted [5]	Transient	Voltage Sag	Voltage Swell	Interruption	Overvoltage	Under voltage	Other (inc. Harmonics)	Consumers Energy [6]	Transmission Provider [7]	Customer [8]	Customer Contact [9]	Modifications [10]	Description
03	02/02	1			x					x			x	x	46 kV capacitor switching during planned 46kV & 138 kV line maintenance configuration; Adjusted 46 kV capacitor switching for remainder of maintenance configuration.
04	02/22	1		x								x	x		Substation fault at a nearby customer owned substation.
05	03/23	1		x								x	x		Customer reported voltage sag, but PQM showed voltage to be within limits.
06	03/27	1							x			x	x		Customer reported customer owned generation tripped off but PQM showed voltage within limits.
07	04/05	1				x				x			x	x	46 kV Line fault due to failed conductor; Repaired failed conductor.
08	05/09	1		x								x	x		Customer reported voltage sag, but PQM showed voltage to be within limits.
09	05/10	1				x						x	x		Substation fault caused by animal contact.
10	05/15	1							x			x	x		Customer reported customer owned variable frequency drive (“VFD”) tripped off but PQM showed voltage within limits.
11	05/17	1				x				x			x		46kV line fault due to animal contact; Cleared fault and restored system.

Inquiries			Power Quality Event [4]							Source of PQ Event			Outcomes		
Event	Date	Locations Impacted [5]	Transient	Voltage Sag	Voltage Swell	Interruption	Overvoltage	Under voltage	Other (inc. Harmonics)	Consumers Energy [6]	Transmission Provider [7]	Customer [8]	Customer Contact [9]	Modifications [10]	Description
12	05/17	1		x								x	x		Customer reported voltage sag but PQM showed voltage to be within limits.
13	05/21	1		x						x			x	x	46kV system line fault due to car-pole accident; Replaced failed structure.
14	06/01	1		x						x			x	x	Voltage sag due to failed distribution regulator; Replaced failed equipment.
15	07/02	1				x						x	x		Fault on customer-owned line due to customer-owned equipment.
16	07/17	1		x						x			x		Customer reported voltage sag, cause unknown; Cleared fault and restored system.
17	07/22	1						x				x	x		Customer reported low voltage, but PQM showed voltage to be within limits.
18	07/27	1			x							x	x		Customer reported voltage swell, but PQM showed voltage to be within limits.
19	07/31	1		x								x	x		Customer reported voltage sag, but PQM showed voltage to be within limits.
20	07/31	1		x								x	x		Customer reported voltage sag, but PQM showed voltage to be within limits.
21	08/01	1		x								x	x		Customer reported voltage sag, but PQM showed voltage to be within limits.

Inquiries			Power Quality Event [4]							Source of PQ Event			Outcomes		
Event	Date	Locations Impacted [5]	Transient	Voltage Sag	Voltage Swell	Interruption	Overvoltage	Under voltage	Other (inc. Harmonics)	Consumers Energy [6]	Transmission Provider [7]	Customer [8]	Customer Contact [9]	Modifications [10]	Description
22	08/01	1		x								x	x		Customer reported voltage sag, but PQM showed voltage to be within limits.
23	08/04	1		x						x			x	x	46kV line fault due to failed pole; Replaced failed equipment.
24	08/09	6		x							x		x		345 kV line fault, cause unknown; Cleared fault and restored system.
25	08/13	6		x							x		x		345 kV line fault due to failed insulator; Cleared fault and restored system.
26	08/15	1				x						x	x		Electrical issue in customer's facility.
27	09/11	1						x				x	x		Customer reported low voltage, but PQM showed voltage to be within limits.
28	09/14	1							x			x	x		Customer reported power quality event but PQM showed voltage to be within limits.
29	09/25	1							x			x	x		Customer reported voltage phase imbalance, but PQM showed voltage to be within limits.
30	11/10	1			x							x	x		Customer reported voltage swell, but PQM showed voltage to be within limits.
31	11/13	1				x				x			x	x	Primary relay failed causing momentary outage; Replaced failed equipment.
32	11/17	1		x							x		x		345 kV line fault; Cleared fault and restored system.
33	12/01	6		x							x		x		345 kV line fault,

re0418-1-241

Inquiries			Power Quality Event [4]							Source of PQ Event			Outcomes		
Event	Date	Locations Impacted [5]	Transient	Voltage Sag	Voltage Swell	Interruption	Overvoltage	Under voltage	Other (inc. Harmonics)	Consumers Energy [6]	Transmission Provider [7]	Customer [8]	Customer Contact [9]	Modifications [10]	Description
															cause unknown; Cleared fault and restored system.
34	12/05	1		x						x			x	x	46kV line fault caused by failed insulator; Replaced failed equipment.
	34	**49[11]**	**0**	**18**	**3**	**6**	**0**	**2**	**5**	**9**	**5**	**20**	**34**	**8**	

C. Power Quality Summary

None of the power quality events referenced in the above table resulted in a formal MPSC complaint. Additionally, Consumers Energy shares information gathered from its PQM with customers via its Customer Account Managers in response to requests regarding power factor, equipment loading, high-energy usage, billing comparisons, and other general inquiries.

[11] These 49 locations represent 25 unique customer locations

III. INCREASED REPORTING REQUIREMENTS

A. Worst Performing Circuits

The following tables show 2017 performance for Consumers Energy's 10 poor performing circuits as ranked by circuit SAIFI and SAIDI metrics, excluding MEDs. The circuit performance is driven by the outage incident types and each circuit is reviewed in detail to develop a specific corrective action plan targeted at improving reliability.

10 Worst SAIFI Performing Circuits for 2017

Circuit SAIFI Excluding MEDs	Feeder ID	Substation Name	Circuit Name	Service Center Location	Length (Miles)	Number of Customers Served	Last Circuit Trim	Number of Customers Interrupted	Outage Causes	Corrective Action Plan to Improve Performance
8	48702	Peach Ridge	Kenowa	North Kent	28	416	2001	3,443	Substation Equipment Trees	2017 - 2018 - HVD Line Projects 2017 - 2018 - Substation Project 2017 - 2019 - LVD Line Project
8	35801	Frontier	Ransom	Adrian	69	831	2010	6,749	Weather HVD Equipment Trees Outside Right of Way ("ROW")	2017 - 2018 - HVD Line Projects 2018 - Substation Project 2018 - LVD Line Projects
7	151401	Mccandlish	Bush Creek	Flint	25	393	1988	2,853	LVD Equipment Trees	2017 - 2018 - HVD Line Projects 2017 - LVD Line Projects
7	93901	Lyon Manor	Treasure	West Branch	20	923	1997	6,574	Trees Weather	2018 - Full Circuit Forestry Clearing 2018 - HVD Line Project 2019 - LVD Line Project
7	95202	Peck Road	M-91	Greenville	25	583	1988	4,061	HVD Equipment	2017 - 2019 - HVD Line Projects
7	42601	Pittsford	Church Road	Adrian	98	791	2006	5,156	Weather HVD Equipment	2018 - Full Circuit Forestry Clearing 2017 - 2018 - HVD Line Projects 2018 - Substation Project 2017 - 2018 - LVD Line Project
6	37101	Delton	Cloverdale	Hastings	59	1389	2016	8,430	Trees Weather HVD Equipment Planned	2017 - 2019 - HVD Line Projects 2017 - Substation Projects 2017 - 2018 - LVD Line Projects
6	133901	Watkins	Christy	Battle Creek	11	800	2017	4,816	Trees Weather	2017 - Full Circuit Forestry Clearing 2019 - HVD Line Project 2017 - Substation Project 2017 - LVD Line Project
6	97102	Delton	Delton	Kalamazoo	40	1079	2015	6,329	Weather Substation Planned HVD Equipment	2017 - 2019 - HVD Line Projects 2017 - Substation Project 2017 - LVD Line Projects
6	42602	Pittsford	Bird Lake	Adrian	86	1620	2016	9,382	HVD Equipment Weather Planned	2017 - 2018 - HVD Line Projects 2018 - Substation Project 2018 - LVD Line Project

10 Worst SAIDI Performing Circuits for 2017										
Circuit SAIDI Excluding MEDs	Feeder ID	Substation Name	Circuit Name	Service Center Location	Length (Miles)	Number of Customers Served	Last Circuit Trim	Number of Customers Interrupted	Outage Causes	Corrective Action Plan to Improve Performance
2151	93901	Lyon Manor	Treasure	West Branch	20	923	1997	6,574	Trees Weather	2018 - Full Circuit Forestry Clearing 2018 - HVD Line Project 2019 - LVD Line Project
2011	42601	Pittsford	Church Road	Adrian	98	791	2006	5,156	Weather HVD Equipment	2017 - 2018 - HVD Line Projects 2018 - Substation Project 2017 - 2018 - LVD Line Project
1820	151602	Hubbard Lake	Miller Road	West Branch	63	623	2017	2,460	Weather Trees Animal	2017 - Full Circuit Forestry Clearing 2017 - Substation Project 2017 - 2018 - LVD Line Projects
1720	2101	Rogers Hydro	Stanwood	Big Rapids	44	456	2015	2,081	Animal Planned Weather	2019 - HVD Line Projects 2017 - 2019 - LVD Line Project
1702	42602	Pittsford	Bird Lake	Adrian	86	1620	2016	9,382	HVD Equipment Weather Planned	2017 - 2018 - HVD Line Projects 2018 - Substation Project 2018 - LVD Line Project
1651	37101	Delton	Cloverdale	Hastings	59	1389	2016	8,430	Trees Weather HVD Equipment Planned	2017 - 2019 - HVD Line Projects 2017 - Substation Projects 2017 - 2018 - LVD Line Projects
1571	74802	Webb Road	Plainfield	West Branch	18	498	2015	951	Weather Trees	2017 - 2018 - HVD Line Project 2018 - LVD Line Project
1547	48702	Peach Ridge	Kenowa	North Kent	28	416	2001	3,443	Substation Equipment Trees	2017 - 2018 - HVD Line Projects 2017 - 2018 - Substation Project 2017 - 2019 - LVD Line Project
1518	37102	Delton	Delton	Kalamazoo	40	1079	2015	6,329	Weather Substation Planned HVD Equipment	2017 - 2019 - HVD Line Projects 2017 - Substation Project 2017 - LVD Line Projects
1437	42302	Gerrish	Golf Club	West Branch	34	702	2005	856	HVD Equipment Trees	2018 - HVD Line Projects

The SAIFI and SAIDI values shown are circuit-specific based on the number of customers served by the circuit. It should be noted that circuit reliability performance is evaluated on a two-year-combined basis and a single year of poor performance may not result in identification of near-term corrective actions. Also, circuit performance is evaluated on the contribution to overall system performance in determining prioritization for capital investment and maintenance. A list of outages and causes for each of these circuits can be provided upon request.

B. CEMI

The CEMI for 2017 are shown in the table below.

Interruptions Experienced	0	1	2	3	4	5	6	7	8	9	10+
Customers Affected	675,966	531,035	309,122	147,392	72,881	34,984	19,857	9,896	6,770	4,472	2,944

Customers experiencing zero outages decreased by 7% from the 2016 level of 730,288. The number of customers experiencing greater than ten outages significantly increased from the 2016 level of 651. There are no exclusions for this metric, and two catastrophic storms impacting similar territories increased the number of customers experiencing multiple outages. This metric is monitored on a bi-weekly basis throughout the year and work plans are adjusted as targeted zones are identified. The Company is currently re-evaluating how the report is analyzed to proactively identify targeted zones for HVD, Substations, LVD, and Forestry planning teams to allow for partnership in completing work and delivering greatest customer benefit.

It should be noted that the $CEMI_n$ calculation differs from the Same Circuit Repetitive Interruption calculation in that individual customer interruptions are included in the $CEMI_n$ calculation whereas only interruptions impacting more than ten customers are included in the Same Circuit Repetitive Interruptions per its definition found in R460.702(s) of the MPSC Service Quality and Reliability Standards for Electric Distribution Systems.

C. CELID

The CELID for 2017 are shown in the table below for Normal and Catastrophic Conditions. It should be noted that there were two events designated Catastrophic in 2017.

CELID exceeding 8hrs during Normal Conditions	170,678
CELID exceeding 60hrs during Catastrophic Conditions	35,320

The number of customers experiencing outages exceeding eight hours during normal conditions significantly decreased from the 2016 level of 241,299. The customers experiencing outages exceeding 60 hours during catastrophic conditions increased from 2016, due to 2016 not having any catastrophic storms. Comparing this to the 2015 results when there were two catastrophic storms, the numbers show an increase of 39% primarily due to the severe and unprecedented wind storm with winds near tropical storm strength that impacted Michigan's Lower Peninsula starting March 7.

Respectfully submitted,

Dated: April 2, 2018 CONSUMERS ENERGY COMPANY

REPORT ON THE STUDY OF PERFORMANCE-BASED REGULATION

Sally A. Talberg, Chairman
Norman J. Saari, Commissioner
Rachael A. Eubanks, Commissioner

MICHIGAN PUBLIC SERVICE COMMISSION
Department of Licensing and Regulatory Affairs
In compliance with Act 341 of 2016

April 20, 2018

Table of Contents

Executive Summary

This report by the Michigan Public Service Commission (PSC or Commission), on performance-based regulation (PBR) and its potential applicability in Michigan, was developed to comply with Section 6u of Public Act 341 of 2016 (PA 341). That statute implemented a comprehensive reform of energy policies in the state and directed the Commission to perform a study of PBR in other states and countries, including a well-established PBR approach used in the United Kingdom. The Commission was directed to engage stakeholders on this topic and evaluate four specific factors: (1) methods for estimating revenue needed, (2) methods to increase the time between rate cases, (3) options for establishing incentives and penalties, and (4) profit-sharing provisions that can spread efficiency gains among consumers and utility stockholders and can reduce the degree of downside risk associated with innovation.

The rates of investor-owned electric and natural gas utilities in Michigan are regulated by the Commission under cost-of-service regulation.[1] Under this traditional regulatory approach, utilities have been incentivized to build infrastructure to meet a multi-decade period of increasing energy demand. In more recent years, however, stagnant growth in energy demand has challenged the assumption that utility investment can be funded by anticipated future growth, causing rate cases to be filed more frequently. During a time of increased technology innovation, digitalization, and customer engagement affecting the energy industry, it is also difficult to encourage innovation and operating efficiency within the traditional regulatory model. PBR has been used in other jurisdictions to help adapt to these drivers of change, meet policy goals, extend time between rate cases, and remove disincentives inherent in traditional regulation for non-capital solutions such as energy waste reduction or customer-owned generation. As discussed in this report, PBR is complex and has both advantages and disadvantages. Accordingly, the direction from the Michigan Legislature and Governor for the Commission to undertake a comprehensive examination of PBR as a first step is timely.

The Commission examined PBR mechanisms in two jurisdictions: (1) the United Kingdom (revenues, incentives, inputs, and outputs for 8 years), and (2) New York (distribution rate freeze for 2 years). The Commission also created an inventory of four other PBR applications in (1) Alberta, Canada (distribution price cap for 5 years); (2) Australia (transmission revenue cap for 5 years); (3) Norway (transmission revenue cap for 5 years); and (4) Ontario, Canada (distribution price cap for 5 years). In addition to considering PBR mechanisms in other jurisdictions, the Commission also analyzed potential PBR approaches related to PA 341, including: (a) cost-of-service with targeted incentives, (b) performance incentive mechanisms for demand response, (c) shared-saving approaches, and (d)

[1] Cost-of-service regulation is also referred to as cost-plus-return regulation. In regulatory jargon, the term “cost-of-service” also refers to setting rates for individual classes of customer (e.g., residential, industrial) based on the utility’s cost to serve those groups of customers.

approaches to optimize overall capital expenditures and operating costs. The Commission analyzed these approaches in light of five specific objectives in PA 341: (1) customer satisfaction, (2) safety, (3) reliability, (4) environmental impact, and (5) social obligations. The MPSC relied on numerous secondary sources for its study of PBR.[2]

The Commission's review of PBR mechanisms in other jurisdictions indicates that similar approaches can be used to augment the existing regulatory model, provided they are tailored to specific requirements in Michigan. Sec. 6u did not create any new or revised authority addressing the Commission's ability to approve PBR but Sec. 6u (5) states that Sec. 6u does not limit the Commission's *existing* authority to authorize PBR. Notwithstanding, it is clear that *how* rates are set—whether through traditional regulatory methods or PBR—provides strong incentives that affect utility investments and behaviors. Integrating forms of PBR into the existing cost-of-service regulatory model could help utilities and regulators adapt to potentially profound changes affecting the energy industry in the coming years as discussed above. Consequently, the Commission intends to: (a) proceed through the use of pilot programs to evaluate the feasibility of different approaches, (b) integrate PBR with other energy planning and infrastructure programs, and (c) continue to keep stakeholders involved. More specifically, the Commission has a well-established program to accelerate the replacement of aging natural gas main pipelines that could be expanded to address other infrastructure challenges in conjunction with additional performance metrics. In addition, the Commission has a new electric distribution planning initiative to increase transparency and stakeholder engagement on grid modernization goals, metrics, and investment strategies that could provide a foundation for PBR. The Commission intends to evaluate the inclusion of PBR metrics in these programs and also review other programs that may prove fruitful for the use of PBR.

[2] One comprehensive source on PBR—a September 2017 report by the Regulatory Assistance Project (RAP) and the National Renewable Energy Laboratory is particularly timely and relevant given their research on the latest U.S. and global experience with respect to PBR and analysis of new regulatory trends involving the use of performance incentive mechanisms, or PIMs, to augment existing regulatory structures to achieve a diverse array of targeted policy outcomes. Due to its relevance, the RAP/NREL report on Next-Generation Performance-Based Regulation is referenced as Appendix F, the RAP report on Performance Based Regulation Options is referenced as Appendix G, and the report on Incentive Regulation of Distribution Utilities is referenced in Appendix H to this MPSC report.

Study Criteria

Act 341 of 2016, which amended Act 3 of 1939, charges the Commission to undertake a study of PBR, and to report on its findings with written recommendations (Sec. 6u). In conducting this study, the Commission was tasked with collaborating with representatives of each customer class, regulated utilities, and other interested parties.

Sec. 6u (1) defines PBR, in part, as a regulatory system in which a utility's authorized rate of return would depend on the utility achieving targeted policy outcomes. Such outcomes could relate to cost control, customer service, reliability, safety, innovation, environmental performance, or other considerations. Regulatory mechanisms with targeted objectives are commonly referred to as performance incentive mechanisms, or PIMs.

Sec. 6u (2) directs the MPSC to examine PBR applications in other states and countries including, but not limited, the United Kingdom's RIIO (revenue = incentive, + innovation + outputs) model. RIIO is a broad-based PBR alternative to traditional cost-of-service regulation. Other jurisdictions have used PBR mechanisms such as PIMs to augment existing cost-of-service regulation.

Sec. 6u (3) directs the MPSC to evaluate four specific factors associated with PBR:

1. Methods for estimating revenue needed during a multi-year pricing period that uses forecasts of efficient total expenditures (i.e., TOTEX as used in the RIIO model);
2. Methods to increase the time between rate cases to provide the utility with opportunity to retain cost savings and to encourage investments that have extended payback periods;
3. Options (i.e., mechanisms) for establishing incentives and penalties that pertain to customer satisfaction, safety, reliability, environmental impact, and social obligations; and,
4. Profit sharing provisions that can spread efficiency gains among consumers and utility stockholders and reduce the degree of downside risk associated with innovation.

Comparison of Traditional Cost-of-Service Regulation and PBR

Economic Regulation of Public Utilities in Michigan

The origins of the MPSC as a regulatory body, and its jurisdiction over public utilities, stem from Act 3 of 1939 (Act 3). It is the Commission's core enabling legislation and outlines the scope of its legal authority to regulate public utilities.

Both Act 419 of 1919, and Act 9 of 1929, preceded Act 3. Act 419 created the Michigan

Public Utilities Commission, having jurisdiction over electric, manufactured gas and power. Act 9 expanded the MPUC's jurisdiction to include rate authority over amended natural gas purchase contracts, and the transmission and distribution of natural gas within Michigan. Act 3 replaced the Public Utilities Commission with the Public Service Commission, and consolidated the Commission's regulatory authority over public utilities. The Act granted the Commission broad ratemaking authority over investor-owned natural gas, steam, and electric utilities.[3]

There have been several major and minor amendments to Act 3 over the years to modify the structure of utility regulation in Michigan to respond to changes in the regulatory environment, and to modify the procedures and processes used to evaluate applications for rate increases.

Table 1: Economic Regulation of Public Utility

YEAR	PA #	TITLE
1919	419	Michigan Public Utilities Commission
1929	9	Natural Gas
1939	3	Michigan Public Service Commission
1982	304	Amended Act 3 of 1939
2000	141	Customer Choice and Electricity Reliability Act
2008	286	Amended Act 3 of 1939
2008	295	Clean and Renewable and Efficient Energy Act
2016	341	Amended Act 3 of 1939
2016	342	Amended Act 295 of 2008

The utility regulatory structure was developed over nearly a century with refinements over time to the core approach, known as "cost-plus-return" or cost-of-service regulation. Under this form of economic regulation, utility rates are set to allow the utility the opportunity to recover capital investments over time (including a return, or profit, on those investments) plus operations and maintenance expenses such as tree trimming, labor expenses, insurance, and taxes.

Under cost-of-service regulation, the following formula is used:
Revenue Requirement = Rate Base * r + D + O + T

Where:

Rate Base = Unrecovered <u>Capital Investment</u>
r = Cost of Capital; return "ON" capital
D = Depreciation; return "OF" capital
O = Operating and Maintenance Expenses
T = Taxes

[3] Changes to Michigan law in 2008 authorized cooperatives to become regulated, for purposes of setting rates, by their elected board of directors. All but one cooperative (Presque Isle Gas Cooperative) are now member regulated.

With the utility's profit tied to the level of capital investment, this approach provides a strong incentive for utilities to make capital investments in energy infrastructure. It has enabled utilities to build infrastructure to respond to a multi-decade expansion of energy demand and broad changes in the economy.

For decades, Michigan applied this rate-setting formula with historical data on the utility's revenue, sales, and costs, known as a historical test-year.[4] Act 286 of 2008 permitted regulated utilities to file rate case applications using projected costs and revenues for a future consecutive 12-month period (i.e., a *fully projected* test year, as opposed to the limited adjustments to actual costs and revenues made in a historical test year calculation).[5] While there are arguments made against the use of projected test years,[6] Michigan's experience with them does provide a foundation for PBR in that it better informs the Commission with respect to short-term utility capital planning and related goals (e.g., reliability improvement) to be met from the planned investments and such review can occur prior to the expenditure being made.

Under traditional regulation, prudence reviews often occur after the fact (although with projected test years, utilities may wait to make certain investments or incur expenses until they are approved by the Commission in a rate case given the potential uncertainty of cost recovery). Quality service is to be provided according to the performance requirements implicit in traditional utility regulation combined with prescriptive technical and customer service standards promulgated by the MPSC.

Traditional cost-of-service regulation incentivizes certain behaviors: regulated utilities recognize they can maximize revenue and profits by building more generation, distribution, and other infrastructure and by selling more electricity between rate cases.[7] This can work well for a system featuring large, centralized power plants that required large investments of capital resources with growing energy demand.

[4] A historical test year is a *pro forma* calculation of revenue requirements using the requesting utility's books and records as a cost foundation (pro forma means based on historical costs, as adjusted for non-recurring events). Typically, historical costs were adjusted for "known and measurable" changes. A historical test-year did allow for the use of projected sales levels to ensure that the final rates for the various rate schedules fairly recovered a utility's approved revenue requirement.

[5] All rate case applications since the passage of Act 286 have used projected test years. In various rate case orders since 2008, the Commission has clarified its standards for utilities using projected test years, and in some instances relies on historical information for certain cost items.

[6] Use of projected costs in determining a utility's revenue deficiency can blunt the "regulatory lag" associated with the strict use of actual (historical) costs and revenues to set rates. Regulatory lag is the lapse of time between a petition for a rate increase and action by the regulatory body. Some entities and academics argue that such regulatory lag is a critical and positive feature of traditional cost-of service regulation, creating economic incentives for utilities to pursue cost efficiencies.

[7] In a rate case, to somewhat simplify, the rate is set by dividing the revenue requirement by expected sales to yield an allowed rate that utilities charge to customers on a volumetric basis of cents per kilowatt-hour. If the volume increases above the expected sales figure used in the rate case, that excess revenue is above the revenue requirement, and is traditionally retained by the utility. Decoupling and other revenue adjustment mechanisms can alter this outcome by adjusting rates if sales increase.

Drivers of Change

Several factors are leading to a re-examination of the traditional utility business model and regulatory approaches. These factors include, but are not limited to, technological change (e.g., electric vehicles, energy storage, renewable energy, Internet of Things, digitalization), stagnant growth in energy demand due largely to end-use efficiency improvements, and evolving customer preferences and engagement relating to energy sources and use. As utilities undertake significant capital investments to replace aging infrastructure, there is also an opportunity to integrate technological innovations and rethink approaches to energy production and delivery.

New capital investment to upgrade aging infrastructure such as gas pipelines, substations, poles, and generation equipment is the primary driver of rate cases in Michigan. The level of investment—on the order of $3 billion per year—is leading to regular rate cases before the Commission. The Commission had an unprecedented 11 rate cases in some stage of the process during 2017, and multiple cases are slated for decisions or to be filed in 2018.[8] The frequency of these cases (and the time and cost involved for the Commission, utilities, and stakeholders) has also led to questions about the traditional regulatory approach, and whether PBR could play a role in potential reforms.

As discussed further below, PBR is viewed as an option to help adapt to these drivers of change by specifying expectations of utility performance and outcomes for consumers, while staying agnostic to the exact means of delivery. PBR can also be designed to provide incentives and penalties to meet certain policy goals (e.g., service quality, reliability, power plant performance, innovation), extend time between rate cases, and remove disincentives inherent in traditional regulation for non-capital solutions such as energy waste reduction or customer-owned generation.

PBR vs. Traditional Cost-of-Service Regulation

In its most basic form, a transition to PBR entails capping utility rates or revenues (often with some provision for inflationary adjustments) and shifting to a series of pre-defined goals or metrics to ensure specific performance outputs and outcomes are met. Regulators began adopting various forms of PBR in the 1980’s and 1990’s.[9] Early forms of PBR focused almost exclusively on cost-control, and PBR has been used in the telecommunication and railroad industries as well. More recently, PBR has expanded beyond cost-control, and is now being utilized as a means to focus regulated utilities on jurisdictional goals ranging from energy efficiency and renewable integration, to grid modernization goals. Under traditional

[8] An increasing portion of utility rate increases are directly related to capital investment programs, reflecting a combination of low inflation (reducing the rate of increase in operating expenses or even reducing overall operating expenses) and major new infrastructure investment.

[9] Elenchaus Research Associates, Inc. (2015). Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Québec Distribution and Transmission Divisions. Retrieved from: http://publicsde.regie-energie.qc.ca/projets/272/DocPrj/R-3897-2014-A-0003-Dec-Dec-2015_03_04.pdf

regulation, the levels of sales and capital expenditures primarily drive utility financial earnings, whereas PBR can be designed to optimize total utility expenditures regardless of whether they are operational or capital in nature.

In general, the goal of PBR is to embed explicit incentives and/or disincentives into the regulatory regime to directly encourage a utility to make investment and operating decisions that achieve certain policy or regulatory outcomes. More specifically, PBR has the ability to connect goals, targets, and measures to utility performance, executive compensation, and investor returns. PBR mechanisms determine utility revenue based on specific performance metrics and other non-investment factors. PBR can include multi-year rate plans (MRPs), performance incentive mechanisms (PIMs), alternative rate mechanisms, and rate or revenue caps, which are discussed in this report and in Appendix A. PIMs are metrics and formulas that determine the levels of financial rewards or penalties (i.e., adjustments to allowed revenues) for achievement of specified outputs and outcomes. A rate cap literally limits the rate a utility can charge its customers. A utility is allowed to keep some or all efficiency gains so long as rates do not increase. A revenue cap limits how much revenue a utility can recover so utility revenue cannot exceed a certain level.[10] In designing PBR metrics, regulators and policy makers can clearly articulate expectations for utility operations on particular targets and outcomes—such as reliability improvements, cost-effective energy efficiency or grid modernization—in advance of any utility decisions or expenditures.

On the other hand, successful PBR requires the targets and incentives to be carefully designed so the incentives, whether negative or positive, do not unnecessarily burden ratepayers or generate unfair profits for the utility. Depending on the expenditure, it may be difficult for the regulator to foresee at the outset all possible unintended outcomes of the PBR metric. A conceptual review of a shift to a more performance based regulatory regime is shown below in Table 2. While the figure describes traditional cost-of-service regulation as "reactive," it is worth mentioning that projected test years can provide some visibility into near-term plans prior to certain expenditures being made. But even with projected test years, the model is still best characterized as reactive.

[10] Migden-Ostrander, J., Littell, D., Shipley, J., Kadoch, C., and Sliger, J. (2018) Recommendations for Ohio's Power Forward Inquiry. Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/wp-content/uploads/2018/02/rap-recommendations-ohio-power-forward-inquiry-2018-february-final2.pdf

Table 2: Conceptual Contrast of Cost-of-Service Regulation with Performance-Based Regulation.[11]

Cost-of-Service Regulation	Comprehensive Performance-Based Regulation
Regulatory Involvement	
After-the-Fact	Before-the-Fact
Reactive	Proactive
Large regulatory input with imprudence	Large regulatory input up-front
Specificity of Regulatory Guidance	
Little regulatory guidance	Specific targets set
Less Innovation	Flexibility in methods to achieve outcomes

Well-designed PBR provides incentives and disincentives based on utility performance, and has the potential to benefit consumers and utilities alike. PBR provides goals and metrics that enable utilities to forecast efficient total expenditures. Some forms of PBR, such as multi-year rate plans, increase the time between rate cases, which provides utilities with more opportunity to retain cost savings without the threat of imminent rate adjustments. However, multi-year rate plans require detailed policy objectives at the outset. PBR encourages utilities to make investments that have extended payback periods, which can shift the focus from traditional capital plant investments to a longer horizon focused on designated performance outcomes. PBR can also be designed to provide incentives and disincentives that help the utility focus on and improve customer satisfaction, safety, reliability, and environmental performance.

PBR should not be viewed as a mechanism to avoid increases in utility rates, since the expected level of new capital investment, even with the deployment of new technologies, will be significant over the coming years. PBR is best defined as a unique regulatory tool that uses incentives to guide innovation and cost efficiencies, which may provide utility management flexibility to choose among operational options that can lead to improved performance and customer benefits.

The UK's RIIO (Revenues-Incentives-Inputs-Outputs) Mechanism

Pursuant to Sec. 6u of Act 341, the MPSC has evaluated the United Kingdom's (UK's) RIIO performance-based regulation model and its suitability for Michigan, in whole, or in part. The

[11] Hopkins, A. (2017). Utility Performance Regulation: Presentation to NASEO Western Regional Meeting. Cambridge, MA: Synapse Energy Economics. Retrieved from: http://www.naseo.org/Data/Sites/1/events/regional/west/2017/Hopkins--Utility-Performance-Regulation.pdf
NOTE: After-the-fact and reactive review is the case for historic test years, while projected test years include some before-the-fact and proactive review.

main goal of RIIO is the 'timely delivery of a sustainable energy sector at a lower cost to consumers than would be the case under the existing regimes.'[12] RIIO is a framework which retains strong cost control incentives while attempting to focus on long-term performance, outputs, and outcomes, with less focus on ex-post review of investment costs.[13] RIIO was intended to begin a transition away from the traditional approach of simply rewarding investment in networks under the prior regime to an outcome-based approach—a shift from inputs to outputs through revenue-based regulation overlaid with a system of financial rewards for achievement of specified goals (performance).[14] U.K. regulators changed their price and revenue control mechanism to remove any bias that may normally exist between capital expenditures and operational expenses that would tend to lead utilities to prefer capital expenditures. This approach, which has been referred to as TOTEX (i.e., total expenditures),[15] means there is an incentive to deliver outputs rather than simply build new infrastructure.[16] As discussed later in this report, the differences between the electricity industry structure in the UK and Michigan could make some of the UK approaches difficult to replicate. However, the Commission also examined this model to assess learnings for potential application in Michigan if elements of RIIO were used to augment the current cost-of-service based regulation structure. This review is attached as Appendix B of the Commission's study.

Key Incentive/PBR Mechanisms and Implementation in the U.S.

Michigan continues to employ traditional cost-of-service methods for regulating utilities, but has utilized incentive mechanisms, alternative methods, or performance metrics on a limited basis over the past 30 years. Although Michigan's utility regulatory past has not featured a formal PBR structure, Michigan has used variations of performance mechanisms designed to achieve improved energy efficiency, reliability, and quality and service. An ongoing issue for policy makers addressing PBR/incentive/penalty systems has been determining whether incentives should be applied to all phases of rates in a case or on a goal-specific basis. Regulators must then decide how to value those incentives and penalties associated with the chosen design based on specific goals and metrics. This report examines Michigan's past incentive mechanisms as well as implementation of PBR mechanisms in the United States and other countries.

Table 3 shows PBR for cost control in six jurisdictions. This review of incentive mechanisms can be found in Appendix C.

---

[12] Ofgem (2010): RIIO: A new way to regulate energy networks. Factsheet. Retrieved from: https://www.ofgem.gov.uk/ofgem-publications/64031/re-wiringbritainfs.pdf

[13] Littell, D., Kadoch, C., Baker, P., Bharvirkar, R., Dupuy, M., Hausauer, B., Linvill, C., Migden-Ostrander, J., Rosenow, J., Wang, X., Zinaman, O., and Logan, J. (2017). Next-Generation Performance-Based Regulation. Golden, Colorado: National Renewable Energy Laboratory. Retrieved from: https://www.nrel.gov/docs/fy17osti/68512.pdf.

[14] Id. By "revenue-based," we mean a method by which "target" or "allowed" revenue levels are determined by regulators and collected by means of adjustments to prices as sales vary (as they inevitably do) from expected levels. (This is what is known as decoupling in the United States.) The allowed revenues themselves may be periodically adjusted to deal with non-sales-related cost drivers, such as inflation, productivity improvements, and approved changes in investment. Such changes are often formulaic in nature and embedded in multi-year regulatory plans.

[15] The move to a total expenditure, or TOTEX, regime was first suggested by Ofgem in March 2008, when the energy regulator launched its RPI-X@20 review. From this comprehensive review of the previous regulatory regime, which had endured since privatization in 1989, emerged the RIIO model.

[16] Littell, D., Kadoch, C., Baker, P., Bharvirkar, R., Dupuy, M., Hausauer, B., Linvill, C., Migden-Ostrander, J., Rosenow, J., Wang, X., Zinaman, O., and Logan, J. (2017). Next-Generation Performance-Based Regulation. Golden, Colorado: National Renewable Energy Laboratory. Retrieved from: https://www.nrel.gov/docs/fy17osti/68512.pdf.

Table 3: PBR for Cost-Control in Six Jurisdictions[17]

Jurisdiction	**Alberta, CA**	**Australia**	**New York, USA**[18]	**Norway**	**Ontario, CA**	**UK**
Service	Distribution	Transmission (TranGrid)	Distribution (Consolidated Edison)	Transmission	Distribution	Transmission
Term	5 years	5 years	2 years	5 years	5 years	8 years
Form	Price Cap (I-X)	Revenue Cap (CPI-X)[19]	Rate Freeze	Revenue Cap (Yardstick)	Price Cap (I-X)	RIIO (Rev = Incentives + Innovation + Outputs)
Cost Benchmarking	No	Yes	No	Yes	Yes	Yes
Service Quality	Yes	Yes	Yes	Yes	Yes	Yes

Cost-of-Service Regulation with Added Targeted Incentives

A broad approach to PBR in Michigan might look like revenue-cap or rate-cap regulation[20] to limit cost increases over time with specific PIMs to encourage a set of desired activities such as energy waste reduction, demand response and perhaps electric vehicle integration. Broad use of PIMs is a relatively new concept with little real-world experience among regulatory jurisdictions across the country. New York is an exception, being an example of a state leading PBR implementation in the U.S. There may be value to Michigan in considering incremental PBR additions built on the foundation of Michigan's existing cost-of-service regulation that has been refined over many years.

With specific PIMs, PBR can elevate the goals referenced in Act 341 related to customer satisfaction, safety, reliability, environmental impact, and social obligations. However, addressing all five goals at once is a tall order as each goal needs to be refined with incentive, performance criteria and metrics with a sense of the benefits, costs, and cost savings involved in moving forward with each. More narrowly, the MPSC may explore other specific objectives, such as the use of PIMs to integrate distributed energy resources or

[17] Elenchaus Research Associates, Inc. (2015). Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Québec Distribution and Transmission Divisions. Retrieved from: http://publicsde.regie-energie.qc.ca/projets/272/DocPrj/R-3897-2014-A-0003-Dec-Dec-2015_03_04.pdf

[18] The PBR mechanism referred to in this chart is an electric revenue adjustment mechanism, not NY REV. More information on the mechanism can be found at Elenchaus Research Associates, Inc. (2015). Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Québec Distribution and Transmission Divisions. Retrieved from: http://publicsde.regie-energie.qc.ca/projets/272/DocPrj/R-3897-2014-A-0003-Dec-Dec-2015_03_04.pdf

[19] Maximum allowed revenue is based on forecasts of the cost-of-service over the regulatory term.

[20] Multi-year rate plans often feature a rate cap or a revenue cap. A rate cap literally limits the rate a utility can charge its customers. A utility is allowed to keep some or all savings from efficiency gains so long as rates do not increase. A revenue cap limits how much revenue a utility can recover so utility revenue cannot exceed a certain level. The two concepts can be augmented with a formula, such as tying return on equity to a market index or a process, such as annual review of capital. An augmented approach may result in an adjustment of rates and revenues during the plan.

electrical vehicles in a cost-effective manner. Each effort would require stakeholder and public input and vetting so ratepayers understand what they are being asked to pay for and why it is valuable.

Targeted pilots could demonstrate results that could be achieved on a larger scale. In this manner, the MPSC could determine whether or not the PIM approach is able to meaningfully achieve the multi-faceted policy outcomes delineated in Sec. 6u of PA 341. Should pilots be undertaken, the MPSC recommends a regulatory process with a strong stakeholder focus, as is case with the UK's RIIO incentive regulation system.

With these general caveats, the Commission observes that the changing power sector -- including penetration of new disruptive technologies such as decentralized supply, growth of demand side resources, increasing intelligence and digitalization of networks -- will change what regulation looks like in the 21st century. PBR both to control costs and integrate these new technologies into Michigan's grid may prove a valuable concept in the future path for Michigan's utility regulation. Performance Incentive Mechanisms that may work for Michigan are further discussed below and in Appendix D.

PIM Options

Demand Response PIM

Michigan's 2016 energy laws require the Commission to promote voluntary load management programs such as demand response programs, time-of-use and peak pricing, and air conditioner remote shut off. Additionally, certain utility companies are required to offer Commission-approved demand response programs. A PIM could be used as an implementation mechanism for some or most of these requirements and provide guidance to utilities on achieving successful demand response program participation to meet PSC-set performance criteria.

Regulators can use generic or utility-specific economic and engineering studies to set targets. Energy efficiency and demand response potential studies that were undertaken pursuant to the energy laws can identify the level of cost-effective investments for utilities. These studies can help regulators identify and define specific resource investment targets and costs.[21]

Metrics associated with demand response depend in part on the specific goals to be achieved. Demand response can be used for multiple purposes such as peak load reduction, load reduction to avoid targeted infrastructure investment, displacing energy purchases during high price periods, customer engagement, operational load management including

21 Whited, M., Woolf, T., and Napoleon, A. (2015). Utility Performance Mechanisms: A Handbook for Regulators. Synapse Energy Economics. Retrieved from: http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p.37

emergency load reductions, and ancillary services to accommodate variations in net load. Metrics should reflect whether or not the underlying policy goal is being met; e.g., if peak demand has decreased over the prior year.[22]

Shared-Saving PIM for DR

By January 1, 2021, PA 341 requires the MPSC to authorize a shared savings mechanism for an electric utility to the extent the utility has not otherwise capitalized the costs of the EWR, conservation, demand reduction, and other waste reduction measures as follows:

a) A savings of 1 percent to 1.25 percent of the utility's total annual weather-adjusted retail sales in megawatt hours in the previous calendar year equals a shared savings incentive of 15 percent of the net benefits validated as a result of the programs implemented by the electric utility related to EWR, conservation, demand reduction, and other waste reduction, but not to exceed 20 percent of the utility's expenditures associated with implementing EWR programs for the calendar year in which the shared savings mechanism was authorized. The bill details how the MPSC is to determine the net benefits.
b) At least 1.25 percent to 1.5 percent savings equals a shared savings incentive of 17.5 percent of the net benefits, with a cap of at 22.5 percent of expenditures.
c) Greater than 1.5 percent savings equals a shared savings incentive of 20 percent of the net benefits, with a cap of 25 percent of expenditures.[23]

A similar shared net benefits scheme could be developed for demand response programs that save the utility and customers' expenditures on peak energy supply costs including the costs of fuel, peaking capacity, and avoided transmission and distribution plant costs. The potential for savings from demand response programs administered by the utilities is particularly strong if specific power plant, distribution and transmission investments can be avoided through demand-response. A shared savings mechanism ideally would provide sufficient benefit to the utility that the utility prefers demand response solutions where feasible to traditional capital investments in infrastructure. Shared savings from avoided system investments can create a "profit" for the utility and a savings for customers. That said, the savings shared with customers must be fair so there is some form of joint savings from innovative cost-effective implementation.

With a shared net-benefit incentive structure, the utility shares with ratepayers in the benefits associated with, and identified from, its performance and the metric achieved. This can mean sharing in financial benefits between the utility and ratepayers. A shared net benefits approach needs to be carefully designed and implemented to clearly identify the shared

22 Whited, M., Woolf, T., and Napoleon, A. (2015). Utility Performance Mechanisms: A Handbook for Regulators. Synapse Energy Economics. Retrieved from: http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf

23 Michigan Public Service Commission. (2017). Energy Law Updates. Retrieved from: http://www.michigan.gov/mpsc/0,4639,7-159-80741---,00.html

benefits, ensure the utility appropriately controls costs, and that the mechanism cannot be gamed. Implementation of shared savings schemes can be difficult because the focus on evaluation, measurement and verification (EM&V), the concept of shared net-benefit's inherent imprecision, and translation to dollars can negatively impact a utility-regulatory-ratepayer relationship. This approach relies upon accurate benefit calculations through evaluation and measurement, and a clear EM&V plan based on objective metrics.

Positive and Negative PIMs for Optimizing CAPEX and OPEX

If a good estimate of overall capital expenditures (CAPEX) and operational expenditures (OPEX) costs and timeframe can be set in advance through a formal proceeding, such as a general rate case, it is possible to use a carefully designed PIM mechanism to provide incentives and penalties for utility optimization of capital investment and operational expenses. Such a CAPEX/OPEX mechanism would provide incentives for cost savings and penalties for cost overruns.

While such a CAPEX/OPEX PIM could stand alone, a PIM for capital expenditures could also be built into a cost-cap regime. Either way, the "new" capital expenditures would need to be added into the revenue requirement cap and translated to a rate cap adder for additional capital expenditures beyond those involved in business-as-usual operations. A focal point of such a system is to ensure that business-as-usual capital expenditures are counted only once in either the revenue requirement or the capital expenditure adder to avoid double recovery of these costs. Beyond that, the critical element that would require substantial effort up front is to establish a reasonable CAPEX budget and timeframe on which to calculate the capital expenditure adder (or rider) that savings would be measured from using OPEX judiciously. This would involve a substantial initial effort by the regulators and utility to determine a reasonable capital expenditure plan over some time frame such as three, five or eight years based on a proposed and adjudicated capital investment plan.

From a capital expenditure plan and timeframe, a series of incentives could be designed to reward the utility for implementation under budget or ahead of schedule, and penalize the utility with disallowances of some percentage of costs for delays or over-budget projects. As an example, if a utility completes a set of distribution upgrades on time with savings of 10 percent from the project budget, the utility could be allowed to keep half of those savings and half could be "returned" to ratepayers. While the symmetry of such a proposal may appear elegant, the current system results in utilities often keeping 100 percent of any saving from a future test year, so the utilities may not be motivated to share these saving with ratepayers. If capital projects are managed to miss timeframes or run over budget, a penalty of disallowing some utility recovery of expense or profit might be imposed. So, if a set of distribution upgrades is completed 10 percent over budget, the utility may only be allowed to recover half from ratepayers, and utility shareholders would be expected to absorb half of the cost overruns. Again, while the symmetry of this may appear elegant, it is worth noting that the risk of cost overruns is typically placed on ratepayers under traditional regulation (unless a prudence review finds utility imprudence). For this reason, utilities likely would oppose any disallowances for cost overruns.

The benefits to the utility of sharing in savings from optimizing capital and operation costs is that they may be able to achieve long-term capital investment certainty over a specified time frame such as three, five, or eight years. They also could share in benefits if the utility can use OPEX to operate more efficiently. With that certainty, utility management can focus on project management and implementation and assessing the least costly options to address known system deficiencies.

Output Goals: Customer Satisfaction

PBR can focus on improving customer satisfaction and can also promote customer empowerment. Customer empowerment is defined here as the ability of customers to provide feedback on utility service, adopt demand-side energy options, and the ability to see publicly reported performance data on their utility.

Case studies from around the world indicate that paying attention to customer satisfaction is an important indicator of utility performance. And done well, these metrics can help transform the utility business model by focusing utility attention on meeting customer needs and preferences. Focus on customer satisfaction can range from public reporting of customer satisfaction rankings, to metrics focused on utility customer empowerment, to public reporting scorecards.

Output Goals: Safety

PIMs for safety generally focus on employee and public safety goals. These are usually to require a high and improving level of both employee and public safety. Metrics in this area are intended to provide indicators of incidents, injuries, and fatalities associated with the contact with the electric and gas system, and adequacy of response to emergency situations.[24] Metrics associated with natural gas operations safety compliance or reducing gas system losses could also be explored.

Output Goals: Reliability

Setting reliability goals, performance criteria, or metrics is universally recognized as desirable since it effectuates one of the central public utility service goals: safe and reliable service. For electric utilities, there are well established reliability metrics and benchmarking data addressing the frequency and duration of power outages such as:

---

24 id.

SAIDI – System Average Interruption Duration Index – The average number of service interruptions a customer served by the utility would expect to endure in a given year.

$$SAIFI = \frac{sum\ of\ all\ customer\ interruptions}{total\ number\ of\ customer\ served}$$

SAIFI – System Average Interruption Frequency Index – The average duration (minutes) of service interruptions a customer served by the utility would expect to endure in a given year.

$$SAIDI = \frac{sum\ of\ all\ customer\ interruption\ durations}{total\ number\ of\ customer\ served}$$

CAIDI – Customer Average Interruption Duration Index – The average time it takes the utility to restore service (minutes) after an outage has occurred on the system.

$$CAIDI = \frac{sum\ of\ all\ customer\ interruption\ durations}{total\ number\ of\ customer\ interruptions} = \frac{SAIDI}{SAIFI}$$

Governor Snyder has established goals for these reliability metrics to improve electric distribution reliability in the state.

Even with these and other established industry metrics, defining the precise incentive or penalties, and performance criteria can be difficult. It is important to ensure that customers receive reasonable value and return on reliability investments. There is a point of diminishing returns with respect to reliability investments. Low cost reliability improvements are certainly worth pursuing, whereas expensive reliability improvements should be weighed to consider whether consumers really desire to pay those costs to obtain the reliability benefits gained.

Output Goals: Environmental Impact

Michigan's 2016 energy laws provided a framework to transition to cleaner sources of electricity. Michigan is also known as a technological and industrial innovator. The breadth of advanced energy technologies being developed and deployed makes tracking any one set of technologies a significant challenge. But this does not mean that regulators cannot set up accommodating utility structures to integrate advanced technologies into Michigan's grid and resource planning and investments. Such alternatives could present new least-cost solutions that benefit not only individual customers, but all utility customers.

The challenge is to set up a flexible performance-based structure that encourages utilities, third-party providers, and customers to move toward environmentally beneficial and least-cost solutions whether those are traditional investments or more distributed options owned by the utility, third party, and/or the customer. With advanced technologies entering the market and quickly evolving in terms of cost and capabilities, it is almost impossible to determine cost-effectiveness in advance. But regulatory structures can create "facilitated competition" space where utilities are rewarded for acquiring competitively bid services that reduce overall system costs. Most advanced customer-site resources (excepting distributed fossil generators) will have an environmentally beneficial effect so it is possible to focus on achieving the least-cost set of distributed solutions and comparing those to a set of energy infrastructure upgrade costs.

Output Goals: Social Obligations

It is important for the regulator to be able to assess impact on low-income and vulnerable customers, and to correspondingly assess utility response to low-to-moderate income impacts. PBR and specific PIMs focused on these areas can help the regulator, the utility, and other stakeholders address and empower this segment of the population. The primary question with PBR schemes that is often raised by low-income and other consumer advocates, is how to craft incentives that force meaningful utility action in exchange for reasonable, but not excessive, revenues.[25] There are two components to metrics in this area:

1. Protection of low-income customers and attention to payment method options, disconnection rates, prepayment meters, etc.
2. Customer empowerment that enables vulnerable customers to pro-actively manage their consumption and make energy bills more affordable.

Multi-Year Rate Plans

The MPSC was also charged by law to evaluate methods to increase the time between rate cases with a view to encourage utility investments having extended payback periods and that promote cost efficiency. Multi-year rate plans, a first effort at PBR, were first used in in the 1980s for railroads, telecommunications, and other industries facing competition and changing demand, and were introduced for U.S. electric utilities in the 1990s. The purpose of these plans was to motivate efficient operations and thus low-cost service while maintaining reliability and customer service. Traditional cost-of-service regulation essentially assumes that sales growth is a predictor of cost growth. To address this, PBR is often explicit in allowing utilities to earn higher profits if they become more efficient by cutting cost and continuing to provide quality service.[26] The PBR construct to control costs is to set utility revenue over a number of years and then allow the utility to retain all or some portion of cost savings resulting from efficiency gains. The utility has a potential gain to increase earnings and also takes on the risk that it can operate more efficiently. Multi-year rate cases are nearly always negotiated in settlements with utilities, so any inherent risks in a negotiated

25 Thompson, A. (2016). Protecting Low-Income Ratepayers as the Electricity System Evolves. Energy Bar Association. Retrieved from: http://eba-net.org/sites/default/files/18-265-305-Thompson%20-%20FINAL_0.pdf

26 Regulatory Assistance Project. (2000). Performance-Based Regulation for Distribution Utilities. Montpelier, VT: The Regulatory Assistance Project. Retrieved from: http://www.raponline.org/wp-content/uploads/2016/05/rap-performancebasedregulationfordistributionutilities-2000-12.pdf, p. 35.

settlement are ones that the utility believes are reasonable in comparison to the potential gain. The Commission has examined multi-year rate plans in other states as required. Please refer to Appendix E.

PBR over multiple years should be based on projections of costs, revenues, inflation and productivity in the future. PBR focused on cost control often takes the form of a multi-year rate plan, with various mechanisms: productivity indexes, attrition relief mechanisms, earning sharing mechanisms and PIMs. Without those mechanisms being in place, and without earnings sharing mechanisms, multi-year rate plans could fail to achieve cost-control incentives and fail to encourage increased utility productivity.[27]

The MPSC could test whether PIMs can be used to extend the period between general rate cases. In doing so, it would be necessary to utilize a diverse set of target performance mechanisms allowing for both positive incentives (rewards for good performance) and negative incentives (for unacceptable performance). At a minimum, such PIMs would address known potential issues arising out of multi-year rate setting periods, such as reduced customer service and service quality that are well established as issues in many other jurisdictions using multi-year rate plans.

Prudent PBR design in the U.K. and other U.S. States has recognized the need for a symmetric mix of incentives, both positive and negative, to ensure utilities continuously perform in a manner warranting annual rate increases absent the direct regulatory review that occurs in single year rate cases prior to a rate increases being granted. The mixture of incentives that can enhance well-established and time tested traditional regulation is different for the priorities of each jurisdiction.

Public Reporting Mechanisms

Public reporting obligations, such as tracking specific performance criteria and metrics that are important for Michigan's regulatory goals, are a way to build experience with performance metrics prior to attaching rewards or penalties. The benefit of a public report-only metric is that regulators and utilities can implement performance metrics without attaching financial awards to gain experience and training as the performance metrics are fine-tuned. The establishment of a reporting obligation communicates the importance of that performance criteria and metric to the utility, stakeholders, and the public.

The requirement that utilities track, analyze, and report specific information can encourage different utility behavior, assist in establishing incentives attached to some or all of the metrics, and provide transparency which may allow other stakeholders to interact in more predictable ways with the utility that are important for supporting third-party energy service

[27] Lowry, M., Woolf, T., and Schwartz, L. (2016). Performance-Based Regulation in a High Distributed Energy Resources Future. Berkley, CA: Lawrence Berkley National Lab. Retrieved from: https://emp.lbl.gov/sites/all/files/lbnl-1004130.pdf

businesses and customer investments in on-site generation, demand response, or energy waste reduction. Some of the above-mentioned PIMs could first be instituted as public reporting only measures. Additional options Michigan might consider for a public tracking metric include progress on green pricing programs and on-bill financing.

Green Pricing:

Under Public Act 342, electric utilities must offer customers the option to participate in a voluntary green pricing program. Under this law, customers can specify the amount of electricity provided to the customer that will be generated from renewable energy. Utilities submitted proposed green pricing programs, which are under Commission review based on criteria such as:

1. Whether different customer preferences or objectives are met;
2. How program costs are calculated;
3. How much of fees go to marketing and administration; and
4. Whether the program is based on cost-of-service principles.

A public tracking metric or metrics, based on survey results of customers enrolled in the green pricing programs, could help the Commission and utilities identify whether customer objectives and preferences are being met, and make clarifications or improvements.

On-Bill Financing:

Under the new energy law, rate-regulated utilities may offer residential customers the option to finance home energy improvement projects, and the ability to pay off the costs of those projects on their utility bill. The Commission is working with utilities and other interested parties to create a framework for such “on-bill financing” programs. A public tracking metric could be developed as part of this framework to enable the Commission and utilities to track the number of improvement projects that use on-bill financing, customer savings, and feedback from customers on various the utility offerings and implementation of this option.

Potential Applicability of Broad-Based PBR in Michigan

RIIO as Applied in the UK Would Not be Appropriate for Michigan under Existing Market Structure

The RIIO incentive structure now in place in the UK is an evolution from the regulatory framework that was in place before it, called RPI-X. RPI-X was itself an incentive-based regulatory scheme, focused primarily on price and revenue caps. RIIO is a regulatory evolution building on experience and lessons learned from many years of utilizing incentive regulation in the UK’s utility sector. UK regulators made improvements over the course of many years to result in the broad-based incentive PBR model now in place. The multi-year regulatory review prior to finalization of RIIO as well as its incremental implementation were

critical to building stakeholder support for the reforms.[28] The prior projections of efficient future costs were an essential element of RIIO and would require a modeling and economic projection ability beyond that currently in use in setting rates in any U.S. jurisdiction.
If Michigan were to move toward a similarly ambitious performance incentive regime it would likely require a similar regulatory review and stakeholder engagement over a multi-year timeframe.

Though the comprehensive RIIO process in full form is likely unrealistic for Michigan to pursue, there are some lessons learned from RIIO that could be applicable here. First, the UK regulators' initial focus on cost control resulted in regulated firms cutting back on customer service, reliability, and service quality to achieve maximum cost savings. Regulators corrected this by implementing incentive mechanisms that focused on customer service and service quality. Second, UK regulators learned that cost cap regulation was not producing the kinds of consumer savings they desired and implemented shared-savings mechanisms to balance utility and customer benefit. These types of incentive design features are ones that Michigan could consider in a PBR scheme, even if not as broad-based a regulator apparatus as RIIO.

In undertaking RIIO, UK regulators recognized the need for substantial new capital investment in the utility system to replace aging infrastructure and maintain reliability and grid services. They also recognized that the investment in the existing grid could not consist simply of a one-for-one replacement of retiring assets if decarbonization goals were going to be met. Thus, the regulators set innovation as one of the primary goals for incentives in RIIO. Several innovation rewards were created including competitive awards for innovative proposals to improve environmental performance of distribution networks and an annual competition to fund up to 90% of costs for large-scale projects that demonstrate environmental benefits. There are a variety of approaches that Michigan could take from RIIO in this area, including PIMs (incremental increase in return on base revenue) or monetary rewards for innovative projects or for replacing aging infrastructure with new, decentralized technologies. Michigan's traditional leadership in the automobile industry may also lend itself to innovation in integration platforms for utility- or aggregator- models for EV charging linked to modern distribution system investments.

As discussed earlier, the differences between the electricity industry structure in the UK and Michigan could make some of the UK approaches difficult to replicate. The "unbundled" nature of the electric industry in the UK with generation separate from transmission and distribution contributes to the difficulty regulators there face in achieving environmental goals. This structure means that UK regulators oversee network distribution companies but have little authority over the sources of electricity supply, or how end-use consumers behave. As a result, much of RIIO's environmental incentives are focused on encouraging network

[28] Guarini Center's (NYU/Law) January 2015 report to the New York Public Service Commission.

companies to take measures that reduce environmental impacts, but does not hold network companies accountable for a low-carbon transition. This is one potential shortcoming that need not exist in vertically integrated states like Michigan where utilities have more direct control over the generation fleet and therefore the environmental attributes associated with electricity supply.

Pros and Cons of Different Approaches and Conditions for Successful Implementation

Stand-alone PIMs are not prohibited under Michigan's current regulatory framework. They are available ratemaking tools as long as rates remain just and reasonable. Some PIMs, such as cost trackers, are already a part of the regulatory framework. Trackers, an accounting of specific costs for recovery in the next rate case or on top of approved rates, have been used in a limited manner in Michigan in recent years. Trackers can be used to track and reconcile specific types of expenses or investments. Trackers can reduce regulatory lag and provide certainty on an approved investment strategy that could increase cost efficiencies through material procurement and better workforce planning. The use of trackers, such as uncollectible expense equalization mechanisms, have been tested at the Court of Appeals and validated as an appropriate ratemaking tool under Michigan's regulatory framework. In re Application of Consumers Energy Co., 279 Mich. App. 180 (2008). Trackers are currently in place for utilities' natural gas main pipeline replacement programs to accelerate the replacement of at risk pipe made of vintage materials.

Another example of a PIM available under the current statutory scheme is a revenue decoupling mechanism (RDM). RDMs are available for gas utilities; for electric utilities the statute limits RDMs for companies with fewer than one million customers. Power supply cost recovery (PSCR) and gas cost recovery (GCR) mechanisms (where fuel and purchased power costs which are estimated in a plan and trued-up through a separate reconciliation under the law) are similar to a PIM and permissible under the current regulatory framework.

Summary and Recommendations

This report examines PBR systems that have been implemented across the United States and in other countries. The majority of states have maintained, at least in large part, the traditional cost-of-service ratemaking structure. This structure, which dates from the late 1800s, has evolved over time to meet emerging issues, such as changing economic conditions, the growth of wholesale energy markets, aging infrastructure, and evolving consumer needs. This evolution continues today, with the introduction of advanced technologies in the utility industry, the potential for expanding renewable and distributed generating resources, and enhanced focus on reliability and grid resilience. States that have implemented some form of PBR have also retained cost-of-service regulation as a foundation.

The Commission's review of PBR mechanisms indicates that they can be used to augment the existing cost-of-service approach provided that they are tailored to the specific requirements associated with utility regulation in Michigan. The Commission is mindful that Michigan courts have repeatedly held that the "PSC's power to fix and regulate rates does not carry with it, explicitly or implicitly, the power to make managerial decisions." Detroit Edison v Michigan Public Service Commission 221 Mich App 370, 386 (1997). Consequently, any PBR program must distinguish between the Commission's regulatory authority to set rates and the utility's managerial decision-making powers. Notwithstanding, it is clear that how rates are set – whether through traditional regulatory methods or PBR – provides strong incentives that affect utility investments and behavior. Integrating forms of PBR into the existing cost-of-service regulatory model could help utilities and regulators adapt to potentially profound changes affecting the energy industry. A variety of approaches are available.

Multi-year rate plans, for example, build on the foundation of cost-of-service regulation by providing incentives for cost-control to the utility. PBR also has the potential to enhance customer satisfaction through public reporting metrics on various measures of customer satisfaction. PIM's for demand response, shared-saving approaches, and approaches to optimize overall capital expenditures and operating costs could complement Michigan's existing regulatory model if carefully designed and implemented to ensure ratepayers receive the benefits of enhanced utility performance. PBR can also be used to encourage "non-wires" alternatives, which may in certain applications be more cost-effective than traditional utility capital investments in transmission or distribution upgrades such as a new substation. In any event, well-designed PBR should include both positive incentives (rewards for good performance) and negative incentives (for unacceptable performance such as reduced customer service and service quality) in order to improve utility performance.

The Commission will continue to explore whether diverse PBR approaches facilitate the evolution of regulated utilities in Michigan toward a more reliable, resilient grid, while increasing value to customers. This will likely require shifting the traditional focus of infrastructure maintenance from a like-for-like replacement of grid assets toward the development of lower life-cycle cost, advanced technologies and practices. Regulated utilities, under this approach, would have (in addition to their traditional role as retail energy supplier) a stronger role of providing network services to a diverse group of users. Such an approach will be explored in the context of current initiatives in long-term distribution planning, energy waste reduction programs, distributed generation tariffs, interconnection standards and processes, PURPA proceedings, and the integrated resource planning approach recently put in place under Act 341. Such transformative changes would not be made to the entire regulatory paradigm overnight; the Commission is more inclined to test the efficacy of PBR through specific natural gas and electric utility pilot programs or other targeted opportunities. This study has demonstrated that incorporation of a public process with stakeholders and utilities is important to the success of new and innovative programs. This is particularly the case as advanced technologies offer grid and customer values simultaneously, and the Commission intends to keep all stakeholders engaged as it moves forward.

20134-AG-CE-613

Question:

214. Refer to page 8, lines 5-7, of Mr. Sparks' direct testimony. Please:

a. Explain why Asset Relocations are part of the IRM given that they do not specifically address under-performing or problematic distribution infrastructure but are instead third-party requests not directly tied to the Company's priority to improve system resiliency, safety and reliability.

b. Explain why Tools and Technology are part of the proposed IRM given that they do not specifically address under-performing or problematic distribution infrastructure to improve system resiliency, safety and reliability.

Response:

a. The Company's proposed IRM includes all distribution capital spending as presented and supported by the Electric Distribution Infrastructure Investment Plan (EDIIP). This provides a comprehensive picture of all distribution related investment needs. Excluding a piece of the investment plan will lessen the value of future IRM reconciliation reviews because interested parties will not be looking at the complete picture. As indicated by Company witness Michael Torrey, the Commission is interested in informed ratemaking and now has a view into the Company's comprehensive future plan through the EDIIP. See pages 32 and 33 of the testimony of Company witness Michael Torrey.

b. Please see the response to subpart a.

Timothy J. Sparks
August 23, 2018

Electric Grid Integration

20134-AB-CE-737

Question:

Interrogatory No. 52.
Please identify the "several investors" that Mr. Maddipati references on page 16, lines 13-14.

Response:

Mr. Maddipati in his role as Vice President of Investor Relations and Treasurer of Consumers Energy has extensive interaction with analysts, investors, ratings agencies, banks and other market participants. His general views of both Consumers Energy and the utility industry are informed by over a decade of experience in financial markets and with investors.

Srikanth Maddipati
October 11, 2018

Treasury

20134-AB-CE-738

Question:

Interrogatory No. 53.
Mr. Maddipati makes the following statement at the bottom of page 16: "Staff's testimony in the most recent electric rate case (Case No. U-18322) raised concerns among the investment community as evidenced by the following quote from Deutsche Bank's equity research analyst on August 11, 2017."

a) Approximately how many equity research analysts cover CMS?
b) In addition to Deutsche Bank, please indicate which analysts were concerned by Staff's testimony in Case No. U-18322.
c) Please provide a copy of the report where each additional analyst expressed concern about Staff's testimony in Case No. U-18322.

Response:

Mr. Maddipati in his role as Vice President of Investor Relations and Treasurer of Consumers Energy has extensive interaction with analysts, investors, ratings agencies, banks and other market participants. His general views of both Consumers Energy and the utility industry are informed by over a decade of experience in financial markets and with investors.

Page 15 of Mr. Maddipati's direct testimony also provides quotes from other research analysts regarding ROE.

Sri M.

Srikanth Maddipati
October 11, 2018

Treasury

Question:

11. Refer to MEC-CE-79 ATT.
    a. Explain what “Emergent” refers to.
    b. For projects identified as “Deferred”:
        i. Explain why the projects were deferred
        ii. Confirm whether you currently still plan to carry out the deferred projects.
        iii. Identify the impact to the heat rate, boiler efficiency, and availability of Campbell Units 1 and/or 2 of the deferral of such projects.
        iv. For deferred projects for which the deferral year is identified as “TBD,” explain why a deferral year has not yet been identified and when it will be identified.

Response:

a. An emergent item is a capital expenditure or an expense that is added to the plan after the plan is approved in the budget cycle. Examples include:

- Replacement of broken equipment
- Acceleration of project (pull forward) based upon a condition assessment.

b. Please see the attached Excel file: 20134-MEC-CE-343.xlsx. A column has been added to provide additional detail on the status of the TBD items.

    i. Each year, Consumers Energy must use its limited resources to maximize customer value and ensure the highest priority projects are completed.

    As emergent projects arise, all projects must be reviewed to identify what, if any, projects can be deferred in order to maintain the operating budget.

    Most compliance and regulatory projects cannot be deferred. However, Consumers Energy still evaluates implementation timelines to determine whether adjustments can be made while still meeting all requirements.

    Degraded equipment and economic projects are also evaluated to determine if any work can be performed at a later date, again to accommodate emergent projects that, by definition, were not planned for.

    Consumers Energy also evaluates current market conditions and overall project benefit, and identifies projects that can be deferred in order to optimize customer value.

ii. Projects with specified years in the "Deferral year" column are planned for implementation in the year specified, as illustrated on the attached spreadsheet.

iii. Target ROR and heat rate values have been set for each unit. The target ROR value for 2019 for Campbell Unit 1 is 10.5%. The target ROR value for 2019 for Campbell Unit 2 is 7.5%. The target heat rate for 2019 for Campbell Unit 1 is [redacted] btu/kw and the target heat rate for Campbell Unit 2 in 2019 is [redacted] btu/kw.

It is anticipated that the level of investment sponsored by the Company in this proceeding will allow the ROR targets to be achieved. Heat rate is highly impacted by market dispatch. The level of investment proposed by the Company in this proceeding is intended to allow the heat rate targets to be achieved, assuming that unit dispatch matches the Company's anticipated dispatch.

These targets, and economic projects aimed at improving these performance levels, will continue to be evaluated to ensure that the projects are cost effective prior to making the investments.

iv. See the response above.

John P. Broschak

John P. Broschak
July 30, 2018

Generation Operations

	A	B	C	D	E	F	G	H	I	J	K
1	**20134-MEC-CE-343**				(b)					**79a_i_2017 JHC 1&2**	
2	**Title**	**U-17990**	**U-20134**	**Delta**	**Reason for Change**	**Deferral Year**					
3	JHC 1 Re-align 4160V switchgear with AQCS implementation	2,070,000	482,165	1,587,835	Adjusted Scope						
4	JHC1 Mill Overhauls (grinding section & gearbox)	600,000	640,649	(40,649)	Adjusted Scope						
5	JHC1 SH Outlet Pendant Replacement	49,500		49,500	Deferred	TBD	JHC 1 2020 major outage			Summary	
6	JHC2 Replace 299 Generator Breaker	341,000		341,000	Deferred	TBD	JHC 2 2023 installation			U-17990 JHC 1&2	46,150,000
7	LP Turbine blade replacement, row L-0.	25,000		25,000	Deferred	2019	JHC 1 2020 major outage			Other Environmental	(19,977,600)
8	Replacement of the JHC 1-1 LPH and Drain Cooler	150,000		150,000	Deferred	TBD	Under evaluation			Project Acceleration	2,574,072
9	Upgrade unit 1 turbine control system	125,000		125,000	Deferred	2018	JHC 1 2020 major outage			Site Commons Allocation	1,684,733
10	JHC1 Condenser retube	100,000	947,211	(847,211)	Accelerated from 2018 & 2019 to 2017 & 2018					Deferred Projects	(22,345,000)
11	Replace FD fan variable inlet vanes	-	697,935	(697,935)	Accelerated from 2019 to 2017					Cancelled Projects	(300,000)
12	JHC2 Horz RH Replacement	2,202,000		2,202,000	Deferred	TBD	JHC 2 2021			Emergent Projects	1,941,338
13	JHC-2 BOILER REPLACE PENDANT REHEATER AND CROSS OVER TUBES	3,216,000		3,216,000	Deferred	TBD	Under evaluation			Adjusted Scope	(1,547,186)
14	JHC2 Catalyst Management	3,063,400		3,063,400	Other Environmental in U-20134					Project Close Out	(324,183)
15	JHC2 Convection Pass Wall Replacements	834,000		834,000	Deferred	TBD	Under evaluation				
16	JHC2 Furn-Convection Pass Cleaning (sootblowers)	1,850,000		1,850,000	Deferred	TBD	Under evaluation			Total Changes	7,856,174
17	JHC2 Mill Overhauls (grinding section & gearbox)	600,000	1,370,806	(770,806)	Accelerated from 2018 to 2017					U-20134 JHC 1&2	7,856,174
18	JHC2 PSH Element Replacement	1,802,000		1,802,000	Deferred	TBD	Under evaluation			Check	-
19	JHC2 rebuild Spare Hydraulic Coupling Rotor Removed in 2009 Outage	-	258,120	(258,120)	Accelerated from 2020 to 2017						
20	JHC2 Refurbish and install spare HP/IP turbine rotor.	1,400,000		1,400,000	Deferred	2018 & 2019					
21	JHC2 Replace glycol heat exchanger tube bundle	353,000	14,313	338,687	Project Close Out						
22	Re-align JHC2 4160 volt switchgear with AQCS Implementation.	2,329,000		2,329,000	Other Environmental in U-20134						
23	Replace air and flue gas expansion joints JHC 2	45,700		45,700	Deferred	2018 & 2019					
24	Replace combustion air heat exchanger banks JHC 2	107,600		107,600	Deferred	2018 & 2019					
25	replace Fuel Handling Conv. Belts	300,000		300,000	Cancelled						
26	Replace Furnace Screen Tubes	1,837,000		1,837,000	Deferred	TBD	Under evaluation				
27	Replace JHC2 turbine right side Reheat Stop Vave body.	1,850,000		1,850,000	Deferred	TBD	JHC 2 2021 outage				
28	Replace primary air heater JHC 2	1,678,300		1,678,300	Deferred	TBD	Under evaluation				
29	Replace secondary air heater radial seals JHC 2	54,000		54,000	Deferred	2019					
30	Replace secondary air heater rotor JHC 2	4,777,900		4,777,900	Deferred	TBD	Under evaluation				
31	Replace SIX JHC2 burner assemblies in 2017 outage	511,200		511,200	Other Environmental in U-20134						
32	JHC 1-2 Fly Ash	14,074,000		14,074,000	Other Environmental in U-20134						
33	JHC 1&2 (Site Commons Allocation)	(195,600)	1,489,133	(1,684,733)	Site Commons Allocation						
34	Replace 4160V DWD and Construction Power Box		132,865	(132,865)	Emergent						
35	JHC Coal Dumper HVAC		15,360	(15,360)	Emergent						
36	JHC2 Turbine Aux Oil Pump & Motor - Emergent Request		443,885	(443,885)	Emergent						
37	JHC 1 FD Fan Damper Drive		2,441	(2,441)	Project Close Out						
38	JHC1 HP Htr FW Inlet Valve Replacement		435	(435)	Project Close Out						
39	JHC1&2 Lighting Tie in to Diesel Generat		8,324	(8,324)	Project Close Out						
40	JHC 1&2 O Floor East End HVAC		28,038	(28,038)	Emergent						
41	JHC 1&2 Pigeon Lake Jetty Gate		2,343	(2,343)	Emergent						
42	JHC 1&2 CENTAC Soot Blowing Air Compressor Overhaul		649,744	(649,744)	Emergent						
43	JHC 2 Start-Up Boiler Feed Pump (SUBFP) Capital Rebuild		165,322	(165,322)	Emergent						
44	JHC 1&2 Pigeon Lake Channel South Jetty Bank Rebuild		56,663	(56,663)	Emergent						
45	JHC 2 138kV 999 Oil Circuit Breaker Bush		68,350	(68,350)	Emergent						
46	JHC FH 12B Magnetic Separator		3,304	(3,304)	Project Close Out						
47	JHC 2 Hydrogen Dryer		59,325	(59,325)	Emergent						
48	JHC 3 3C Condensate Pump Rebuild, net of muni cr		218,090	(218,090)	Emergent						
49	Breaker House Electric Room HVAC		101,352	(101,352)	Emergent						

	A	B	C	D	E	F	G	H	I
1	**20134-MEC-CE-343**				(b)				
2	**Title**	**U-17990**	**U-20134**	**Delta**	**Reason for Change**	**Deferral Year**	**Status of TBD items**	**79a_ii_2018 JHC 1&2**	
3	JHC 1 Re-align 4160V switchgear with AQCS implementation	2,933,000	-	2,933,000	Adjusted Scope				
4	JHC1 SH Outlet Pendant Replacement	3,540,800		3,540,800	Deferred	TBD	JHC 1 2020 major outage		
5	JHC2 Replace 299 Generator Breaker	108,000		108,000	Deferred	TBD	JHC 2 2023 Installation	Summary	
6	LP Turbine blade replacement, row L-0.	1,700,000		1,700,000	Deferred	2020	JHC 1 2020 major outage	U-17990 JHC 1&2	89,957,700
7	Replace JHC-1 Burner assemblies. Corner 1,4,5 & 8	150,000		150,000	Other Environmental in U-20134			Other Environmental	(12,092,300)
8	Replacement of the JHC 1-1 LPH and Drain Cooler	1,152,000		1,152,000	Deferred	TBD	Under evaluation	Project Acceleration	(552,000)
9	Upgrade unit 1 turbine control system	2,450,000	125,000	2,325,000	Deferred	2019	JHC 1 2020 major outage	Site Commons Allocation	(11,331,960)
10	Replace burners corner 2,3,6 &7	647,000		647,000	Other Environmental in U-20134			Deferred Projects	(59,291,400)
11	Upgrade Exciter Controls to Basler based DECS 2100	219,000		219,000	Deferred	TBD	JHC 1 2020 major outage	Cancelled Projects	-
12	Replacement of the JHC 1-3 Low Pressure Heater	235,000		235,000	Deferred	TBD	JHC 1 2020 major outage	Emergent Projects	1,645,000
13	JHC 1 Replace air preheater baskets and seals	1,472,700		1,472,700	Deferred	TBD	Under evaluation	Adjusted Scope	(2,933,000)
14	JHC-1 boiler rear wall hangertubes/roof tubes and headers	1,301,000		1,301,000	Deferred	TBD	Under evaluation	Project Close Out	119,000
15	REMOVE AND REPLACE JHC-1 BOILER HORIZONTAL SUPERHEAT	3,787,000		3,787,000	Deferred	TBD	Under evaluation		
16	JHC-1 FRONT UPPER WATER WALL AND RAIDIANT REHEATER REPLACEMENT	1,062,200		1,062,200	Deferred	TBD	Under evaluation	Total Changes	5,521,040
17	JHC1 Condenser retube	1,934,000	1,982,000	(48,000)	Accelerated from 2018 & 2019 to 2017 & 2018			U-20134 JHC 1&2	5,521,040
18	JHC 1 Replace air and flue gas expansion joints	196,500		196,500	Deferred	TBD	JHC 1 2020 major outage	Check	-
19	Replace FD fan variable inlet vanes	-	119,000	(119,000)	Project Close Out				
20	JHC-1 BACKPASS PC SOOT BLOWERS	355,000		355,000	Deferred	TBD	Under evaluation		
21	JHC2 Horz RH Replacement	7,800,000		7,800,000	Deferred	2021	JHC 2 2021		
22	JHC-2 BOILER REPLACE PENDANT REHEATER AND CROSS OVER TUBES	5,864,000		5,864,000	Deferred	TBD	Under evaluation		
23	JHC2 Catalyst Management	5,087,300		5,087,300	Other Environmental in U-20134				
24	JHC2 Convection Pass Wall Replacements	3,057,000		3,057,000	Deferred	TBD	Under evaluation		
25	JHC2 Furn-Convection Pass Cleaning (sootblowers)	4,180,000		4,180,000	Deferred	TBD	Under evaluation		
26	JHC2 Mill Overhauls (grinding section & gearbox)	600,000		600,000	Accelerated from 2018 to 2017				
27	JHC2 PSH Element Replacement	6,097,000		6,097,000	Deferred	TBD	Under evaluation		
28	JHC2 Refurbish and install spare HP/IP turbine rotor.	800,000	390,000	410,000	Deferred	2019			
29	Re-align JHC2 4160 volt switchgear with AQCS Implementation.	965,000		965,000	Other Environmental in U-20134				
30	Replace air and flue gas expansion joints JHC 2	365,200	30,000	335,200	Deferred	2019			
31	Replace combustion air heat exchanger banks JHC 2	471,300	100,000	371,300	Deferred	2019			
32	replace Fuel Handling Conv. Belts	320,000		320,000	Deferred	TBD	Condition based - likely in 2019		
33	Replace Furnace Screen Tubes	4,573,000		4,573,000	Deferred	TBD	Under evaluation		
34	Replace JHC2 turbine right side Reheat Stop Vave body.	675,000		675,000	Deferred	2019	JHC 2 2021 outage		
35	Replace primary air heater JHC 2	2,235,700		2,235,700	Deferred	TBD	Under evaluation		
36	Replace secondary air heater radial seals JHC 2	106,500		106,500	Deferred	2019			
37	Replace secondary air heater rotor JHC 2	2,676,100		2,676,100	Deferred	TBD	Under evaluation		
38	Replace SIX JHC2 burner assemblies in 2017 outage	635,000		635,000	Deferred	TBD	JHC 2 2019 outage		
39	Install JHC 2 Beckwith relay	54,000		54,000	Deferred	2019			
40	PJFF bag replacement JHC 2	2,447,400		2,447,400	Deferred	2019			
41	JHC 1-2 Fly Ash	5,243,000		5,243,000	Other Environmental in U-20134				
42	JHC 1&2 (Site Commons Allocation)	12,462,000	1,130,040	11,331,960	Site Commons Allocation				
43	JHC2 SAH Replace baskets and seals		1,285,000	(1,285,000)	Emergent				
44	Replace 4160V DWD and Construction Power Box		100,000	(100,000)	Emergent				
45	JHC1 and 2 DME Install NERC Required		50,000	(50,000)	Emergent				
46	JHC2 RH Drying		50,000	(50,000)	Emergent				
47	JHC 1 1D Boiler Circ Water Pump Motor Rewind		150,000	(150,000)	Emergent				
48	JHC2 - Overhaul JHC2 FD Fan Motors		10,000	(10,000)	Emergent				

	A	B	C	D	E	F	G	H	I
1	**20134-MEC-CE-343**				(b)	Implement in		**79a_iii_2019 JHC 1&2**	
2	**Title**	**U-17990**	**U-20134**	**Delta**	**Reason for Change**	**Deferral Year**			
3	JHC 1 Re-align 4160V switchgear with AQCS implementation	782,000		782,000	Adjusted Scope				
4	JHC1 Mill Overhauls (grinding section & gearbox)	600,000	656,000	(56,000)	Adjusted Scope				
5	JHC1 SH Outlet Pendant Replacement	2,467,500		2,467,500	Deferred	2020	JHC 1 2020 major outage	Summary	
6	LP Turbine blade replacement, row L-0.	1,700,000	25,000	1,675,000	Deferred	2020	JHC 1 2020 major outage	U-17990 JHC 1&2	43,780,000
7	Replace JHC-1 Burner assemblies. Corner 1,4,5 & 8	1,423,000		1,423,000	Other Environmental in U-20134			Other Environmental	(7,528,600)
8	Replacement of the JHC 1-1 LPH and Drain Cooler	1,121,000		1,121,000	Deferred	TBD	Under evaluation	Project Acceleration	(191,500)
9	Upgrade unit 1 turbine control system	1,900,000	1,450,000	450,000	Deferred	2020	JHC 1 2020 major outage	Site Commons Allocation	(2,562,660)
10	Replace burners corner 2,3,6 &7	1,730,000		1,730,000	Other Environmental in U-20134			Deferred Projects	(25,114,700)
11	Upgrade Exciter Controls to Basler based DECS 2100	76,000	223,000	(147,000)	Deferred	2020		Cancelled Projects	-
12	Replacement of the JHC 1-3 Low Pressure Heater	1,926,000		1,926,000	Deferred	TBD	JHC 1 2020 major outage	Emergent Projects	3,631,100
13	JHC 1 Replace air preheater baskets and seals	1,219,200		1,219,200	Deferred	TBD	Under evaluation	Adjusted Scope	(726,000)
14	JHC-1 boiler rear wall hangertubes/roof tubes and headers	4,515,000		4,515,000	Deferred	TBD	Under evaluation	Project Close Out	-
15	REMOVE AND REPLACE JHC-1 BOILER HORIZONTAL SUPERHEAT	2,766,000		2,766,000	Deferred	TBD	Under evaluation		
16	JHC-1 FRONT UPPER WATER WALL AND RAIDIANT REHEATER REPLACEMENT	3,027,700		3,027,700	Deferred	TBD	Under evaluation	Total Changes	11,287,640
17	Unit 1 ashpit replacement	321,000		321,000	Deferred	TBD	Under evaluation	U-20134 JHC 1&2	11,287,640
18	Replacement of the JHC 1 Condenser Vacuum Pumps	795,000		795,000	Deferred	TBD	Condition based - likely in 2019	Check	-
19	JHC1 Condenser retube	608,000		608,000	Accelerated from 2018 & 2019 to 2017 & 2018				
20	JHC 1 Replace air and flue gas expansion joints	518,300		518,300	Deferred	TBD	Condition based - likely in 2020		
21	Replace FD fan variable inlet vanes	899,500		899,500	Accelerated from 2019 to 2017				
22	JHC-1 BACKPASS PC SOOT BLOWERS	2,223,000		2,223,000	Deferred	TBD	Under evaluation		
23	JHC2 Catalyst Management	3,020,600		3,020,600	Other Environmental in U-20134				
24	JHC2 Mill Overhauls (grinding section & gearbox)	600,000		600,000	Deferred	TBD	Condition based - likely in 2020		
25	JHC2 rebuild Spare Hydraulic Coupling Rotor Removed in 2009 Outage	-	85,000	(85,000)	Accelerated from 2022 to 2019				
26	JHC2 Refurbish and install spare HP/IP turbine rotor.	-	1,800,000	(1,800,000)	Deferred	2018 & 2019			
27	Purchase spare secondary air heater rotor assembly JHC 2	-	100,000	(100,000)	Accelerated from 2020 to 2019				
28	Replace air and flue gas expansion joints JHC 2	-	456,000	(456,000)	Emergent				
29	Replace combustion air heat exchanger banks JHC 2	-	332,500	(332,500)	Emergent				
30	Replace secondary air heater radial seals JHC 2	-	135,000	(135,000)	Emergent				
31	Install JHC 2 Beckwith relay	-	100,000	(100,000)	Accelerated from 2020 to 2019				
32	PJFF bag replacement JHC 2	1,355,000		1,355,000	Other Environmental in U-20134				
33	Replace unit 1&2 auxiliary boiler	4,085,000		4,085,000	Deferred	TBD	Under evaluation		
34	JHC 1-2 Fly Ash	-		-	Other Environmental in U-20134				
35	JHC 1&2 (Site Commons Allocation)	4,101,200	1,538,540	2,562,660	Site Commons Allocation				
36	JHC2 SAH Replace baskets and seals		1,343,600	(1,343,600)	Emergent				
37	JHC1 and 2 DME Install NERC Required		112,000	(112,000)	Emergent				
38	JHC2 RH Drying		250,000	(250,000)	Emergent				
39	JHC2 - Overhaul JHC2 FD Fan Motors		402,000	(402,000)	Emergent				
40	JHC1 B MBFWP inspection		273,000	(273,000)	Deferred	2020			
41	JHC1 HP Turbine Blading Replacement		375,000	(375,000)	Deferred	2020			
42	JHC2 Turbine Lube Oil Fitration System Upgrade		250,000	(250,000)	Emergent				
43	Unit 1 DCS and Simulator Upgrade		1,031,000	(1,031,000)	Accelerated from 2020 to 2019				
44	Overhaul Unit 2 CCWP		350,000	(350,000)	Emergent				

20134-MEC-CE-346 (REDACTED)

Page 1 of 2

Question:

14. Refer to MEC-CE-82 ATT.
    a. Explain what "Emergent" refers to.
    b. For projects identified as "Deferred":
        i. Explain why the projects were deferred.
        ii. Confirm whether you currently still plan to carry out the deferred projects.
        iii. Identify the impact to the heat rate, boiler efficiency, and availability of Karn Units 1 and/or 2 of the deferral of such projects.
        iv. For deferred projects for which the deferral year is identified as "TBD," explain why a deferral year has not yet been identified and when it will be identified.

Response:

a. An emergent item is a capital expenditure or an expense that is added to the plan after the plan is approved in the budget cycle. Examples include:

- Replacement of broken equipment
- Acceleration of project (pull forward) based upon a condition assessment.

b. Please see the attached Excel file: 20134-MEC-CE-346.xlsx. A column has been added to provide additional detail on the status of the TBD items.

i. Each year, Consumers Energy must use its limited resources to maximize customer value and ensure the highest priority projects are completed.

As emergent projects arise, all projects must be reviewed to identify what, if any, projects can be deferred in order to maintain the operating budget.

Most compliance and regulatory projects cannot be deferred. However, Consumers Energy still evaluates implementation timelines to determine whether adjustments can be made while still meeting all requirements.

Degraded equipment and economic projects are also evaluated to determine if any work can be performed at a later date, again to accommodate emergent projects that, by definition were not planned for.

Consumers Energy also evaluates current market conditions and overall project benefit, and identifies projects that can be deferred in order to optimize customer value.

ii. Projects with specified years in the "Deferral year" column are planned for implementation in the year specified, as illustrated on the attached spreadsheet.

iii. Target ROR and heat rate values have been set for each unit. The target ROR value for 2019 for Karn 1 is 14.50%. The target ROR value for 2019 for Karn 2 is 7.50%. The target heat rate for 2019 for Karn 1 is [redacted] btu/kw and the target heat rate for Karn 2 in 2019 is [redacted] btu/kw.

It is anticipated that the level of investment sponsored by the Company in this proceeding will allow the ROR targets to be achieved. Heat rate is highly impacted by market dispatch. The level of investment proposed by the Company in this proceeding is intended to allow the heat rate targets to be achieved, assuming that unit dispatch matches the Company's anticipated dispatch.

These targets, and economic projects aimed at improving these performance levels, will continue to be evaluated to ensure that the projects are cost effective prior to making the investments.

iv. See the response above.

John P. Broschak

John P. Broschak
July 30, 2018

Generation Operations

	A	B	C	D	E	F	G	H	I
1	**20134-MEC-CE-346 (2017)**								
2	(a)				(b)				
3	**Title**	**U-17990**	**U-20134**	**Delta**	**Reason for Change**	**Deferral Year**	**Status of TBD items**		
4	1B Pulverizer Capital Overhaul - 2017	1,493,647		1,493,647	Accelerated from 2017 to 2016				
5	K1 - Fabric Filter Bag Replacement	2,633,000		2,633,000	Other Environmental in U-20134				
6	K1 "C" BFP overhaul	175,000		175,000	Deferred	TBD	Under evaluation	Summary	
7	K12 FH DCS Evergreen Upgrade	400,000		400,000	Deferred	TBD	Under evaluation	U-17990 DEK 1&2	43,144,000
8	Karn 1 DCS Upgrade Advantage (HMI & Logic)	350,000		350,000	Deferred	TBD	Under evaluation	Other Environmental	(4,087,000)
9	Karn 1 ID Fan to Stack Exp Joints Replacement	-	29,748	(29,748)	Emergent			Project Acceleration	(1,431,188)
10	Karn 1 Install LNCFS with SOFA in 2018	4,616,000		4,616,000	Deferred	TBD	Under evaluation	Site Commons Allocation	(3,307,753)
11	Karn 1 MHM Vibration Server Upgrade	-	32,144	(32,144)	Emergent			Deferred Projects	(19,231,100)
12	Karn 1 safety - Install New Coal Burner Isolation Valves	796,000		796,000	Deferred	TBD	Under evaluation	Cancelled Projects	(850,000)
13	Karn 1 Secondary Air Duct Expansion Joints Replacement	418,100		418,100	Deferred	2018		Emergent Projects	13,062,851
14	Remove / Replace Karn 1-3 LP FW htr	(500)	500	(1,000)	Emergent			Adjusted Scope	(12,042,157)
15	Safety Karn 1 Mill Hoist System Replacement	-	291,396	(291,396)	Emergent			Project Close Out	(3,441,127)
16	Karn 1 DCS Upgrades (Evergreen)	-	117,412	(117,412)	Emergent				
17	Steam Inert Control Valve Replacement	-	40,369	(40,369)	Emergent			Total Changes	11,816,527
18	Seal Oil Duplex Filter Upgrade	-	(204)	204	Project Close Out			U-20134 DEK 1&2	11,816,527
19	Replace K1 BFP min flow station vlvs & MOV	-	1,220	(1,220)	Emergent			Check	-
20	K1 Voltage Regulator HMI & Controller Replacement	-	(5,232)	5,232	Project Close Out				
21	Replace K1 FW control valve Rexa controller	-	(4,670)	4,670	Project Close Out				
22	K1 Start Up Exciter Rewind	-	(4)	4	Project Close Out				
23	K1 HP-IP Blade Replacement	-	(519,081)	519,081	Project Close Out				
24	K2 - Fabric Filter Bag Replacement	2,606,000		2,606,000	Deferred	2020			
25	K2 "A" BFP overhaul	175,000		175,000	Accelerated from 2017 to 2016				
26	K2 Mill Classifier VFD Replace	-	5,869	(5,869)	Emergent				
27	Karn 2 DCS Combustion Optimization Package	275,000		275,000	Cancelled				
28	Karn 2 DCS Q-Line to R-Line IO Upgrade	834,000		834,000	Deferred	2019			
29	Karn 2 DCS Upgrade Advantage (HMI & Logic)	400,000		400,000	Cancelled				
30	Karn 2 DCS Upgrades (Evergreen)	1,383,000		1,383,000	Deferred	2020			
31	Karn 2 install new feeder / mill isolation valves	-	105,544	(105,544)	Emergent				
32	Karn 2 Primary Superheat Lower Bank Replacement	7,653,000		7,653,000	Deferred	TBD	Under evaluation		
33	Karn 2 SCR 2nd Layer Catalyst Replacement	1,454,000		1,454,000	Other Environmental in U-20134				
34	Karn 2 McDaniels Tee (Safety)	-	237,459	(237,459)	Accelerated from 2018 to 2017				
35	Replace Karn 2 Throttle and Governor valves	-	(420,549)	420,549	Project Close Out				
36	K2 Voltage Regulator HMI & Controller Replacement	-	(5,407)	5,407	Project Close Out				
37	K2 REPLACE CCWP DISCHARGE VALVES & DIVISION VALVE	-	32,294	(32,294)	Emergent				
38	K2 Drum Level Controls	-	2,873	(2,873)	Emergent				
39	Replace Karn 2 CCW Screen Drive	-	966,714	(966,714)	Emergent				
40	Replace chemical feed system on Karn 2	-	4,599	(4,599)	Emergent				
41	Replace Karn 2-3 LP FW htr	-	12,860	(12,860)	Emergent				
42	Karn 2 Coal Pipe Adjustable Orifices	-	(2,200)	2,200	Project Close Out				
43	Karn 2 ID Fan to Stack Exp Joints Replacement	-	836,509	(836,509)	Emergent				
44	K2 Cutsforth Brush Holders	175,000		175,000	Cancelled				
45	K2 Fire Protection Replace	-	3,750	(3,750)	Emergent				
46	Karn Plant Reverse Osmosis System	14,000,000	1,957,843	12,042,157	Adjusted Scope				
47	Site Commons Allocation	3,307,753		3,307,753	Site Commons Allocation				
48	04158 K1 DCS SOFT & HARD UPGRADE		(2,130)	2,130	Project Close Out				
49	K1&2 - Demineralizer Check Valves		6,891	(6,891)	Emergent				
50	FH K/W Cyber Security Brker House Camera		(14,676)	14,676	Project Close Out				
51	Karn1&2 Ash Lines		(40,550)	40,550	Project Close Out				
52	KW - Train Track Removal		5,182	(5,182)	Emergent				
53	K1 Reheat Stop Valve Replacement		(418,293)	418,293	Project Close Out				
54	K1 2014 Boiler Outage (MP&C)		(1,188,646)	1,188,646	Project Close Out				
55	K2 2014 Boiler Outage (MP&C)		50,179	(50,179)	Emergent				
56	K2 Reheat Stop Valves		(347,235)	347,235	Project Close Out				
57	Karn 2 Activated Carbon Injection		110	(110)	Emergent				
58	K1 BFP Injection Booster Pump Ctrl Valve		(13,580)	13,580	Project Close Out				
59	K1&2 HSW Pump Automation Controls		(1,273)	1,273	Project Close Out				
60	K2 Boiler Excess O2 Monitor Replacement		(462)	462	Project Close Out				
61	K1 Boiler Excess O2 Monitor Replacement		(647)	647	Project Close Out				
62	K1 CCWP Discharge Valve Replacement		(16,880)	16,880	Project Close Out				
63	K1 Replace 1A&B Condenser Vacuum Pump		3,628	(3,628)	Emergent				
64	K1 TACWP Strainer Replacement		(14,055)	14,055	Project Close Out				
65	K2 TACWP Strainer Replacement		(12,416)	12,416	Project Close Out				
66	K1 Turbine Bearing Oil Pres Transmitter		(235)	235	Project Close Out				
67	KW Construction Transformer Rplmt - ESD		(768)	768	Project Close Out				
68	K1 Chemical Feed System		2,559	(2,559)	Emergent				
69	KW FH Soft Start Replacement Study		(1,490)	1,490	Project Close Out				
70	K2 HP Turbine Blade Replacement		(97,777)	97,777	Project Close Out				
71	Karn 2 -1 HP Feedwater Htr. Level Sensor		(591)	591	Project Close Out				
72	K1 1-3 LPFWH Drains Controls&Controller		500	(500)	Emergent				
73	Karn Substation		(26,408)	26,408	Project Close Out				
74	K2 2-1 HP FWH Drips regulator		(2,071)	2,071	Project Close Out				
75	KW Annex Backup Generator		(12,425)	12,425	Project Close Out				
76	KW Fuel Handling Emergency Generator		(7,291)	7,291	Project Close Out				
77	Karn 1-2 LP FW heater Replacement		(34,866)	34,866	Project Close Out				
78	K2 2-1 HP FWH extraction steam isolation		(2,775)	2,775	Project Close Out				
79	K12 480V-120V Receptacles - Engineering		(3,625)	3,625	Project Close Out				
80	K1 Drum Level Controls		(3,778)	3,778	Project Close Out				
81	K1 TSI		(527)	527	Project Close Out				
82	K1 ITE Control Breaker Replacement		(1,609)	1,609	Project Close Out				
83	K2 ITE Control Breaker Replacement		(1,406)	1,406	Project Close Out				
84	K1&2 Breaker Building Pug Mill Installt		12,415	(12,415)	Emergent				
85	K1 1-1 HP Htr Extrct Steam Pres Transmit		(2)	2	Project Close Out				
86	K1 Air Heater Magnetic Couplings		5,813	(5,813)	Emergent				
87	K1 Condenser Outlet WB Outlet Exp Joint		(166,022)	166,022	Project Close Out				
88	KW FH Dumper Blding Hammermil Lighting		(2,320)	2,320	Project Close Out				
89	K1 Condenser Debris Filter Elec. Panel		(363)	363	Project Close Out				
90	K1&2 "A" SBAC Rebuild		1,729	(1,729)	Emergent				
91	DEK 1-4 Fire Hydrant & PIV Replacement		(2,074)	2,074	Project Close Out				
92	K1 1B Mill Major Rebuild		1,340	(1,340)	Emergent				
93	K12 Chlorine Retention Valve Replacement		(2,357)	2,357	Project Close Out				
94	K1&2 FH 'A' Tunnel Sump Pumps		(33,306)	33,306	Project Close Out				
95	DEK Karn Auxiliary Operator Office Installation		15,334	(15,334)	Emergent				
96	Replace Failed 480V Bus Near 22C Transformer		180,000	(180,000)	Emergent				
97	Karn 1 1D Mill Major Overhaul		1,700,185	(1,700,185)	Emergent				
98	DEK GSI Treatment System		561,322	(561,322)	Emergent				
99	Karn 3 3A & 3B FD Fan Outlet Damper & Actuator		411,311	(411,311)	Emergent				
100	K2 2A&2B Turning Gear Wiring		(189)	189	Project Close Out				
101	Karn 2 Burner Replacement		169,000	(169,000)	Emergent				
102	K2 2A BFP overhaul		15,850	(15,850)	Emergent				
103	Lime Slaker Rotary Valve		64,619	(64,619)	Emergent				
104	K2 ID Fan "B" Expansion Joint Rplcmt		(8,645)	8,645	Project Close Out				
105	K2 Mill Ladder Replacement		24,783	(24,783)	Emergent				
106	K1 MTLO Cooling Discharge Valve		14,915	(14,915)	Emergent				
107	K1 EHC Fluid Leak Insulation Replacement		66,419	(66,419)	Emergent				
108	K1&2 DI System Phase 2		525	(525)	Emergent				
109	K12 Retire Hydrant 5 and Feeder Header (In Place)		52	(52)	Emergent				
110	Karn 3 Repl AVR Parts		414,306	(414,306)	Emergent				
111	DEK2 RH Drying System		578,775	(578,775)	Emergent				
112	Karn Fuel Path Foam Dust Control System		7,847	(7,847)	Emergent				
113	K1 Blow Down and Economizer Valve Replacements		95,258	(95,258)	Emergent				
114	2C Mill Foundation Replacement		(18)	18	Project Close Out				
115	DEK1 RH Drying System		21,870	(21,870)	Emergent				
116	K1 & 2 'A' Belt Return Training Roller Upgrade		43,983	(43,983)	Emergent				
117	Karn Dumper Lighting Upgrade to Class 2-Div 1		471,362	(471,362)	Emergent				
118	Electrode Repl - Dsicharge Channel Fish Fence		162,505	(162,505)	Emergent				
119	K1-2 Tandem Hypochlorite Pump		19,301	(19,301)	Emergent				
120	K1-2 Lab Purification Unit		7,875	(7,875)	Emergent				
121	Remove Replace Karn 2 Condenser Outlet Water Box Rubber - Down Level		32,233	(32,233)	Emergent				
122	Karn Underground Fire Header		15,752	(15,752)	Emergent				
123	K2 Lime Slurry Transfer Pump		20,537	(20,537)	Emergent				
124	Karn 2A Mill Capital Overhual		1,169,718	(1,169,718)	Emergent				
125	Coal Dust Suppression Sprinkler Pole Replacement		24,697	(24,697)	Emergent				
126	Diesel Generator Contactor Replacement		3,691	(3,691)	Emergent				
127	K12 Battery Bank Replacement		4,768	(4,768)	Emergent				
128	Karn Fuel Handling 18 Conveyor Gearbox Replacement		85,407	(85,407)	Emergent				
129	K2 Steam Inerting Control Valves		69,773	(69,773)	Emergent				
130	K2 Hydrojet Controls		24,679	(24,679)	Emergent				
131	K1 1A Mill Exhauster Replacement		191,993	(191,993)	Emergent				
132	Karn Site Trailer Safety Upgrades		290,047	(290,047)	Emergent				
133	K2 Burner Air Register Replacement		220,147	(220,147)	Emergent				
134	K2A Mill Damper Drive Replacement		154,930	(154,930)	Emergent				
135	K2 Coal Chute Rappers		11,675	(11,675)	Emergent				
136	Karn 1 Steam Drum Level Controller		23,299	(23,299)	Emergent				
137	Karn 2 Steam Drum Level Controller		38,404	(38,404)	Emergent				
138	K2 D Mill Classifier Gearbox Replacement		126,293	(126,293)	Emergent				
139	Dumper Building Cntrl Rm HVAC		23,112	(23,112)	Emergent				
140	K1-4 CO2 Pipe Replacement		68,596	(68,596)	Emergent				
141	Replace K2 Bottom Ash Clinker Grinder		267,815	(267,815)	Emergent				
142	DEK 1&2 Bunker Rm Lighting Upgrade		143,262	(143,262)	Emergent				
143	Karn 1&2 Replace #7 HSW Emergency Pump		29,729	(29,729)	Emergent				
144	K2 Mill Discharge Valve Replacement		248,041	(248,041)	Emergent				
145	K1-4 CEMS Server and Software Upgrade		40,864	(40,864)	Emergent				
146	Karn Cyber Security Upgrade (PWCS)		95,188	(95,188)	Emergent				
147	K1A BCWP		40,766	(40,766)	Emergent				
148	K1&2 Steam Regulating Valve		3,103	(3,103)	Emergent				
149	Fuel Handling Locomotive Controls		16,474	(16,474)	Emergent				
150	K1 C Mill Shaft Replacement		571,695	(571,695)	Emergent				
151	K1&2 "C" Conveyor Gearbox Replacement		39,403	(39,403)	Emergent				
152	Dumper Control Rm Explosion Proof Window		15,027	(15,027)	Emergent				
153	DEK Exterior Warehouse Lighting Upgrade		35,742	(35,742)	Emergent				
154	K1&2 FH Breaker Drum Chute		25,386	(25,386)	Emergent				
155	K1&2 FH C-D Transfer Chute		14,192	(14,192)	Emergent				
156	K1 Hydrogen Valve Replacement		21,602	(21,602)	Emergent				
157	Karn Annex Exterior Lighting		3,537	(3,537)	Emergent				
158	K2 GSU Transformer HV Bushings		96,295	(96,295)	Emergent				
159	K1&2 Dumper Roadway Lighting Upgrade		3,466	(3,466)	Emergent				
160	K2 IP Cooling Valve		7,060	(7,060)	Emergent				
161	Small Tools and Equipment		738,922	(738,922)	Emergent				
162	CapitalBelt Replacement		76,816	(76,816)	Emergent				
163	FH Rail Road Replacement and Upgrade		110,519	(110,519)	Emergent				
164	Unit 2 El Mill Rebuild and Upgrade		196,153	(196,153)	Emergent				

	A	B	C	D	E	F	G	H	I
1	**20134-MEC-CE-346 (2018)**				(b)				
2	**Title**	**U-17990**	**U-20134**	**Delta**	**Reason for Change**	**Deferral Year**	**Status of TBD items**		
3	Karn 1 Install LNCFS with SOFA in 2018	4,854,000		4,854,000	Deferred	TBD	Under Evaluation		
4	Karn 1 safety - Install New Coal Burner Isolation Valves	1,350,000		1,350,000	Deferred	TBD	Under Evaluation		
5	Karn 1 Secondary Air Duct Expansion Joints Replacement	616,700	236,000	380,700	Adjusted Scope			Summary	
6	Safety Karn 1 Mill Hoist System Replacement	-	285,000	(285,000)	Emergent			U-17990 DEK 1&2	25,894,000
7	Karn 1 DCS Upgrades (Evergreen)	1,134,000	1,142,000	(8,000)	Adjusted Scope			Other Environmental	-
8	K1 Voltage Regulator HMI & Controller Replacement	150,000		150,000	Deferred	2019		Project Acceleration	(107,000)
9	Karn 1 Performance Advisor	155,000		155,000	Deferred	TBD	Under Evaluation	Site Commons Allocation	(4,696,800)
10	K1 "A" BFP overhaul	175,000		175,000	Adjusted Scope			Deferred Projects	(18,539,500)
11	Karn 2 DCS Upgrade Advantage (HMI & Logic)	400,000		400,000	Cancelled			Cancelled Projects	(625,000)
12	Karn 2 DCS Upgrades (Evergreen)	-	149,000	(149,000)	Emergent			Emergent Projects	4,517,418
13	Karn 2 Primary Superheat Lower Bank Replacement	6,389,000		6,389,000	Deferred	TBD	Under Evaluation	Adjusted Scope	(547,700)
14	Karn 2 Safety - Coal Bunker Mass Flow Installation	2,277,000		2,277,000	Deferred	TBD	Under Evaluation	Project Close Out	-
15	Karn 2 McDaniels Tee (Safety)	107,000		107,000	Accelerated from 2018 to 2017				
16	K2 Voltage Regulator HMI & Controller Replacement	150,000		150,000	Deferred	TBD	Under Evaluation	Total Changes	5,895,418
17	Karn 2 Generator Stator Rewind	162,700		162,700	Deferred	TBD	Under Evaluation	U-20134 DEK 1&2	5,895,418
18	DE Karn Unit 2 Primary Superheat Lower Bank Replacement	325,000		325,000	Deferred	TBD	Under Evaluation	Check	-
19	KARN 2 CONDENSER BALL CATCHER MOD	35,000		35,000	Deferred	TBD	Under Evaluation		
20	K2 REPLACE CCWP DISCHARGE VALVES & DIVISION VALVE	75,000		75,000	Deferred	TBD	Under Evaluation		
21	Install DE Karn Unit 2 Penthouse Isomembrane	140,000		140,000	Deferred	TBD	Under Evaluation		
22	K2 Drum Level Controls	-	50,000	(50,000)	Emergent				
23	K2 Cutsforth Brush Holders	225,000		225,000	Cancelled				
24	K2 Start Up Exciter Rewind	175,000		175,000	Deferred	TBD	Under Evaluation		
25	K2B Stator Exciter Rewind	360,000		360,000	Deferred	TBD	Under Evaluation		
26	K2 Breaker Wiring to DCS	150,000		150,000	Deferred	TBD	Under Evaluation		
27	Replace K1 Turbine Bleed Stm Isol Vlvs w/Auto Vlvs	35,000		35,000	Deferred	TBD	Under Evaluation		
28	Karn 2 Boiler Front Wall Replacement - Full	1,756,800		1,756,800	Deferred	TBD	Under Evaluation		
29	Karn Plant Reverse Osmosis System	-	125,000	(125,000)	Emergent				
30	Site Commons Allocation	4,696,800		4,696,800	Site Commons Allocation				
31	Diesel Generator Contactor Replacement		250,000	(250,000)	Emergent				
32	K12 Battery Bank Replacement		400,000	(400,000)	Emergent				
33	K1 1A Mill Exhauster Replacement		(47,000)	47,000	Emergent				
34	Karn Site Trailer Safety Upgrades		12,000	(12,000)	Emergent				
35	Karn 1 Steam Drum Level Controller		13,000	(13,000)	Emergent				
36	K2 Mill Discharge Valve Replacement		8,000	(8,000)	Emergent				
37	K1 C Mill Shaft Replacement		165,000	(165,000)	Emergent				
38	Small Pumps and Motors		50,000	(50,000)	Emergent				
39	Small Valves and Instrumentation		100,000	(100,000)	Emergent				
40	Small Tools and Equipment		105,000	(105,000)	Emergent				
41	K1 Economizer Drag Conveyor Valve Replacement		10,000	(10,000)	Emergent				
42	K1 Exhauster Slide Gates Automation		10,000	(10,000)	Emergent				
43	K1 A BFP Remachine barrel and replace element		400	(400)	Emergent				
44	Karn 1&2 FH Thaw Shed Roll-Up Door Replacement		26,000	(26,000)	Emergent				
45	K 1&2 Replace Trestle Sump Pumps		27,000	(27,000)	Emergent				
46	Site EDS Server Replacement		50,000	(50,000)	Emergent				
47	1-A CCWP Overhaul 07MDEK120305		87,000	(87,000)	Emergent				
48	Karn 1 Bottom blow down valve replacement		75,000	(75,000)	Emergent				
49	K2 A BFP Remachine barrel and replace element		250,000	(250,000)	Emergent				
50	FH Rail Road Replacement and Upgrade		118,000	(118,000)	Emergent				
51	Karn-Weadock Fuel Handling DCS Upgrades-Evergreen		400,000	(400,000)	Emergent				
52	Unit 2 El Mill Rebuild and Upgrade		1,049,000	(1,049,000)	Emergent				
53	1D BCWP Rebuild - Condition Based		61,009	(61,009)	Emergent				
54	1A BCWP Rebuild - Condition Based		61,009	(61,009)	Emergent				
55	Karn 3 Repl AVR Parts		525,000	(525,000)	Emergent				
56	Karn 2A Mill Capital Overhual		103,000	(103,000)	Emergent				

	A	B	C	D	E	F	G	H	I
1	**20134-MEC-CE-346 (2019)**				(b)				
2	**Title**	**U-17990**	**U-20134**	**Delta**	**Reason for Change**	**Deferral Year**	**Status of TBD items**		
3	Karn 1 Secondary Air Duct Expansion Joints Replacement	-	150,000	(150,000)	Emergent				
4	Karn 1 SCR 2nd Layer Catalyst Replacement	700,000		700,000	Other Environmental in U-20134				
5	K1 Voltage Regulator HMI & Controller Replacement	-	150,000	(150,000)	Emergent			Summary	
6	DEKarn 1 H2 Damaged Water Wall Tubing Replacement	1,846,000		1,846,000	Deferred	TBD	Under evaluation	U-17990 DEK 1&2	55,106,000
7	K1 Breaker Replacements	-	125,000	(125,000)	Emergent			Other Environmental	(700,000)
8	K2 GSU Oil Pumps Replace	450,000		450,000	Deferred	TBD	Under evaluation	Project Acceleration	(146,000)
9	Karn 2 DCS Q-Line to R-Line IO Upgrade	-	100,000	(100,000)	Adjusted Scope			Site Commons Allocation	(7,237,560)
10	Karn 2 DCS Upgrade Advantage (HMI & Logic)	100		100	Cancelled			Deferred Projects	(46,841,340)
11	Karn 2 LPA Screen Replacement	289,000		289,000	Deferred	TBD	Under evaluation	Cancelled Projects	(100)
12	Karn 2 Safety - Coal Bunker Mass Flow Installation	11,945,000		11,945,000	Deferred	TBD	Under evaluation	Emergent Projects	5,449,000
13	Karn 2 McDaniels Tee (Safety)	146,000		146,000	Accelerated from 2018 to 2017			Adjusted Scope	100,000
14	Replace Karn 2-4 Extraction bleed turbine nozzle	189,000		189,000	Deferred	TBD	Under evaluation	Project Close Out	-
15	Karn 2B Exciter Stator Rewind	360,000		360,000	Deferred	TBD	Under evaluation		
16	K2 2A Tilt Pad Bearing Upgrade	325,000		325,000	Deferred	TBD	Under evaluation	Total Changes	5,730,000
17	KARN 2 CONDENSER BALL CATCHER MOD	1,029,000		1,029,000	Deferred	TBD	Under evaluation	U-20134 DEK 1&2	5,730,000
18	K2 REPLACE CCWP DISCHARGE VALVES & DIVISION VALVE	1,219,000		1,219,000	Deferred	TBD	Under evaluation	Check	-
19	Install DE Karn Unit 2 Penthouse Isomembrane	3,185,000		3,185,000	Deferred	TBD	Under evaluation		
20	DEK 2 Coal Pipe Replacement 2017	181,000	181,000	-	Adjusted Scope				
21	Karn 2 MHM Vibration Server Upgrade	353,000		353,000	Deferred	TBD	Under evaluation		
22	K2 Drum Level Controls	71,000		71,000	Deferred	TBD	Under evaluation		
23	Karn 2 Performance Advisor (OLHR)	171,000		171,000	Deferred	TBD	Under evaluation		
24	Karn 2 DCS Coordinated Controls Optimization Package	27,000		27,000	Deferred	TBD	Under evaluation		
25	Replace K2 FW control valve Rexa controller	69,000		69,000	Deferred	TBD	Under evaluation		
26	Karn 2 condenser outlet WB hogger	31,300		31,300	Deferred	TBD	Under evaluation		
27	Replace K2 Condenser inlet waterbox butterfly vlvs and actuators	6,000		6,000	Deferred	TBD	Under evaluation		
28	K2 Replace HP rotor & inner cylinder	4,562,000		4,562,000	Deferred	TBD	Under evaluation		
29	Karn 2, Install Natural Gas Ignitors	5,090,000		5,090,000	Deferred	TBD	Under evaluation		
30	Karn 2 Boiler Roof Tube Replacement	8,745,000		8,745,000	Deferred	TBD	Under evaluation		
31	Karn 2 FD Fan Outlet Dampers	-	63,000	(63,000)	Emergent				
32	Karn 2 Boiler Acoustic Leak Detection	535,000		535,000	Deferred	TBD	Under evaluation		
33	Karn 2 Online Coal Flow Measurement	531,000		531,000	Deferred	TBD	Under evaluation		
34	Vibration Monitoring System for Karn 2 CCWP	83,000		83,000	Deferred	TBD	Under evaluation		
35	Karn 2 Performance Advisor	155,000		155,000	Deferred	TBD	Under evaluation		
36	Karn 2 DCS Coordinated Controls Optimization	75,000		75,000	Deferred	TBD	Under evaluation		
37	K2 DCS Q-line to R-line IO Conversion	838,000		838,000	Deferred	TBD	Under evaluation		
38	K2 Sequence of Events to DCS	150,000		150,000	Deferred	TBD	Under evaluation		
39	Replace K1 Turbine Bleed Stm Isol Vlvs w/Auto Vlvs	666,000		666,000	Deferred	TBD	Under evaluation		
40	Remove and Replace 2A BFP discharge outlet valve and MOV	192,610		192,610	Deferred	TBD	Under evaluation		
41	Remove and Replace 2B BFP discharge outlet valve and MOV	168,920		168,920	Deferred	TBD	Under evaluation		
42	Remove and Replace 2C BFP discharge outlet valve and MOV	192,610		192,610	Deferred	TBD	Under evaluation		
43	Remove / Replace Karn 2A & B Condenser Circ Water Pumps	30,900		30,900	Deferred	TBD	Under evaluation		
44	Karn 2 - Install new reheat drying system	575,000		575,000	Deferred	TBD	Under evaluation		
45	K2 "B" BFP overhaul	175,000		175,000	Deferred	TBD	Under evaluation		
46	Karn 2 Boiler Front Wall Replacement - Partial	1,511,000		1,511,000	Deferred	TBD	Under evaluation		
47	DEK 2 PA Fan Pedestals	1,000,000		1,000,000	Deferred	TBD	Under evaluation		
48	Site Commons Allocation	7,237,560		7,237,560	Site Commons Allocation				
49	Ash Haul Road in fill Area - phase 2		575,000	(575,000)	Emergent				
50	Small Pumps and Motors		100,000	(100,000)	Emergent				
51	Small Valves and Instrumentation		205,000	(205,000)	Emergent				
52	Small Tools and Equipment		205,000	(205,000)	Emergent				
53	1-B CCWP Overhaul		24,000	(24,000)	Emergent				
54	K2B CCWP Overhaul		29,000	(29,000)	Emergent				
55	K2-A CCWP Overhaul 08MDEK120306		29,000	(29,000)	Emergent				
56	Cyber Security Capital		75,000	(75,000)	Emergent				
57	Replace 2-3 LPH level control valve		70,000	(70,000)	Emergent				
58	Karn 2 B PA Fan Motor Upgrade		150,000	(150,000)	Emergent				
59	Karn 2 C PA Fan Motor Upgrade		150,000	(150,000)	Emergent				
60	Karn 2 D PA Fan Motor Upgrade		150,000	(150,000)	Emergent				
61	Karn 2 E PA Fan Motor Upgrade		150,000	(150,000)	Emergent				
62	Karn 2 F PA Fan Motor Upgrade		150,000	(150,000)	Emergent				
63	CapitalBelt Replacement		181,000	(181,000)	Emergent				
64	K1 Mill Air Diffuser		200,000	(200,000)	Emergent				
65	K2 Replace HP IP Nozzle blocks 1st stage stationary blading		250,000	(250,000)	Emergent				
66	"C" SBAC Rebuild		275,000	(275,000)	Emergent				
67	FH Rail Road Replacement and Upgrade		243,000	(243,000)	Emergent				
68	Ovation Security Center Upgrade (Evergreen)		500,000	(500,000)	Emergent				
69	Unit 2 El Mill Rebuild and Upgrade		1,250,000	(1,250,000)	Emergent				

20134-MEC-CE-690

Question:

1. Refer to the Rebuttal Testimony of John Broschak, page 11 lines 10-15 and page 12 lines 3-5.

   a. Identify the Non-Fuel O&M/MWh quartile for Karn Units 1 and 2 in each of the years 2011 through 2015.

   b. Identify the Non-Fuel O&M/MWh quartile in 2017 for each of Karn Units 1 and 2, Campbell Units 1 and 2, and Campbell Unit 3.

Response:

a. My Rebuttal Testimony (page 12, lines 3-5) states, "In the 2011, 2013, 2014, and 2015 Non-Fuel O&M Benchmark Studies, the Company's Non-Fuel O&M was in the first quartile three years (2013, 2014, and 2015) and second quartile in one year (2011)."

   The Non-Fuel O&M/MWh quartiles for Karn Units 1 and 2 are as follows (2012 is excluded because the Company did not file a Non-Fuel O&M Benchmark Study in a rate case in 2012):

2011	2013	2014	2015
2nd	3rd	3rd	4th

   Please also see the response to 20134-MEC-CE-75, which includes as an attachment the Benchmark Studies for these years as filed in Company rate cases.

b. Consumers Energy did not provide 2017 Non-Fuel O&M/MWh in this proceeding – as 2017 Non-Fuel O&M/MWh industry data was not yet available when this case was filed in May 2018, and the Company has not performed a 2017 Non-Fuel O&M/MWh Benchmark Study.

John P. Broschak

John P. Broschak
October 9, 2018

Generation Operations

Question:

26. Reference the testimony of John P. Broschak, page 7 line 8 through page 8 line 7, and to Column (f) on Exhibit A-60 (JPB-3). With regards to the "Actual NEV 2014-2017" for each of Campbell Units 1, 2, and 3, and Karn Units 1 and 2:

a. Produce any workpapers, modeling input and output files, and other documents used in calculating the "Actual NEV" values identified in Column (f).

b. Identify each category of revenues factored into the calculation of the "Actual NEV" values identified in Column (f).

c. Identify each category of costs factored into the calculation of the "Actual NEV" values identified in Column (f).

d. State whether each of the following categories of costs were factored into the calculation of the "Actual NEV" values identified in Column (f):

   i. Capital

   ii. Major maintenance

   iii. Fixed O&M

   iv. Property taxes

   v. Any other non-variable costs

e. For each category of cost listed in subsection d that was not factored in to the calculation of the "Actual NEV" values identified in Column (f), identify the total cost from 2014 through 2017 for each of Campbell Units 1, 2, and 3, and Karn Units 1 and 2.

f. Identify the "Actual NEV" for each of Campbell Units 1, 2, and 3, and Karn Units 1 and 2 for each of the years 2014 through 2017.

g. Identify the projected NEV for each of Campbell Units 1, 2, and 3, and Karn Units 1 and 2 for each of the years 2018 and 2019.

Response:

a. See attached Excel file: 20134-MEC-CE-74(a) CONFIDENTIAL.xlsx. The attachment is confidential and is being provided pursuant to the terms of the protective order in this proceeding.

   This file was created using a third party proprietary software from Power Cost Inc. This software houses MISO offers, unit output and MISO settlements data. The file was created on April 3rd, 2018 by entering the dates and units and the program calculated these values based on the MISO market settlements at that time. This is the only output from the program.

b. The revenues included in column (f) on Exhibit A-60 (JPB-3) include:
   - Day Ahead Total Revenue, column (h)
   - Real Time Energy Revenue, column (i)
   - Real Time Ancillary Service Revenue, column (j)
   - Net Regulation Generation Adjustment, column (k)
   - Price Volatility Make Whole Payment, column (l)
   - Revenue Sufficiency Guarantee Make Whole Payment, column (m)

c. The costs included in column (f) on Exhibit A-60 (JPB-3) include:
   - Revenue Sufficiency Guarantee Penalty, column (n)
   - Ancillary Service Penalty, column (r)
   - Real Time Administrative Fee, column (s)
   - Real Time Startup Cost, column (v)
   - Real Time Energy Cost, column (w)
   - Real Time Ancillary Service Cost, column (x)

d. Capital, major maintenance, fixed O&M, property taxes, and any other non-variable costs were not factored into this calculation.

e. Please see the attached Excel file: 20134-MEC-CE-74(e).xlsx.

f. The “Actual NEV” for each of Campbell Units 1, 2 and 3 and Karn Units 1 and 2 for each of the years 2014 through 2017 was provided in response to part (a) of this question. NEV is determined using only the variable costs associated with energy generation. Typically, if total unit value were to be considered (i.e. fixed and variable costs) it would be necessary to consider total value (i.e. energy and capacity value). Given the significance of these five units to Local Resource Zone 7, representing approximately 1,800 Zonal Resource Credits, a reasonable capacity value is MISO’s published Cost of New Entry for each planning year in question. This value would need to be added to the fixed costs and the Actual NEV values provided in part (a) to determine a total net value to customers.

g. Consumers Energy does not project 2018 and 2019 NEV values.

John P. Broschak
July 2, 2018

Generation Operations

20134-MEC-CE-333

Question:

1 Refer to your response to MEC-CE-74(f).

a. Identify what the capacity value of Karn Units 1 and 2 was for each of the years 2014 through 2017 using MISO's Cost of New Entry ("CONE").
b. Identify the total net value for each of Karn Units 1 and 2, and Campbell Units 1, 2, and 3, for each of the years 2014 through 2017 using CONE. Produce any workpapers or other documents used to calculate such total net values.
c. Explain why you would calculate the capacity value of the Karn Units 1 and 2 and Campbell Units 1, 2, and 3 using CONE, rather than using the estimated cost of acquiring replacement capacity.

Response:

Objection of Counsel: **Consumers Energy Company objects to this discovery request because it requests the results of a calculation that Consumers Energy Company has not performed. Without waiving this objection, Consumers Energy Company responds as follows:**

a. No such calculation has been completed at this time. The values could be determined by multiplying MISO's FERC-filed CONE values publically available at MISO's website by the ZRCs identified for Karn Units 1 and 2 provided in the Company's annual capacity demonstration filings for 2014 through 2017.
b. No such calculation has been completed at this time.
c. Ideally, one would calculate the value of capacity using the estimated cost of acquiring replacement capacity, but it is difficult to know the replacement capacity cost without identifying the specific resources that would be used to replace each of these units. It is reasonable to assume that the replacement of such a significant amount of capacity (approximately 1,800 ZRCs) would result in prices at or near CONE. MISO CONE is intended to represent the cost of a new simple cycle combustion turbine. While that may not be the specific resource selected to replace all 1,800 ZRCs associated with the units identified, it is likely a reasonable approximation.

Thomas P. Clark
July 31, 2018

Merchant Operations and Resource Planning

<u>Question:</u>

11. Refer to your response to MEC-CE-333(c). With regards to the replacement capacity costs discussed therein:

    a. State whether it would be reasonable to assume that the replacement of the ZRCs for only Karn units 1 and 2 (as opposed to the "approximately 1,800 ZRCs" referenced in your response) would result in prices at or near CONE.

        i. If so, explain why, and identify and produce any analyses, studies, or other documents supporting such assumption.

        ii. If not, explain why not and identify what replacement capacity cost, expressed as a percentage of CONE, would be reasonable to assume.

    b. With regards to any capacity that you have obtained since January 1, 2014 through a reverse capacity auction, Request for Proposal, or any other non-MISO Planning Resource Auction ("PRA") purchase, identify:

        i. The amount of capacity purchased

        ii. The timeframe for which such capacity was purchased

        iii. The price paid for such capacity in dollars and as a percent of the MISO CONE.

<u>Response:</u>

a. Analysis included in the Company's integrated resource plan filing, MPSC Case No. U-20165, indicates that the replacement of just the capacity from Karn 1 and 2 could be accomplished at a price less than 100% of CONE.

    ii. The analysis included in that proceeding indicates that the last increment of additional capacity to replace just Karn 1 and 2 would be provided by demand response ("DR") resources. The DR resources modeled for the IRP had a levelized cost of $55,830/MW-Year or approximately 57.5% of MISO CONE when using the capacity prices relied on in MPSC Case No. U-20165 (identified in the table below).

b. See the table below.

RCA	9/23/14						10/20/16	4/5/17
Case Number	U-17725						U-18194	U-18382
Planning Year	PY15	PY16	PY17	PY18	PY19	PY20	PY17	PY18
ZRCs	350	150	20	20	20	20	180	525
Price ($M)	10,887	7,305	1,095	1,095	1,198	1,198	9,320	26,483
$/ZRC-Year	31,105	48,699	54,750	54,750	59,900	59,900	51,778	50,443
CONE ($/ZRC-Year)	90,530	94,830	94,900	97,178	99,510	101,898	94,900	90,740
% of CONE	34%	51%	58%	56%	60%	59%	55%	56%
Was Capacity Purchased (Y/N)	Y	Y	Y	Y	Y	Y	Y	N

Thomas P. Clark
August 21, 2018

Merchant Operations and Resource Planning

20134-MEC-CE-693 (Partial)

Question:

4. Refer to your response to MEC-CE-665 and the Excel attachment to that response, and to the Excel attachment to your response to MEC-CE-74(e). For each of Campbell 1&2, Campbell 3, and Karn 1&2:

   a. Provide the capital revenue requirements for each of the years 2014 through 2017 for the capital expenditures identified in the attachment to MEC-CE-74(e).

   b. Provide supporting documentation for the capital costs provided and explain how those costs were calculated.

   c. Confirm that the 2019 revenue requirements provided in the attachment to MEC-CE-665 only include capital costs incurred between 2014 and 2017. If confirmed, provide total capital revenue requirements for 2014 through 2017 (inclusive) including capital costs incurred before 2014.

Response:

a. See Company witness Heidi Myers response.

b. Please see the attached Excel file: 20134-MEC-CE-693(b).xlsx.

   The 2014 through 2017 capital costs were taken from Consumers Energy's internal accounting records.

   The $2,000 difference in 2014 and $3,000 difference in 2017 is due primarily to the level of detail requested in each question and rounding. MEC-74(e) requested yearly totals, while MEC-693(b) requested yearly totals by project. Consumers Energy used the same internal accounting records and reports for both MEC-74(e) and MEC-693(b).

c. See Company witness Heidi Myers response.

John P. Broschak
October 9, 2018

Generation Operations

20134-MEC-CE-693 (Partial)

Question:

4. Refer to your response to MEC-CE-665 and the Excel attachment to that response, and to the Excel attachment to your response to MEC-CE-74(e). For each of Campbell 1 & 2, Campbell 3, and Karn 1 &2:

a. Provide the capital revenue requirements for each of the years 2014 through 2017 for the capital expenditures identified in the attachment to MEC-CE-74(e).

b. Provide supporting documentation for the capital costs provided and explain how those costs were calculated.

c. Confirm that the 2019 revenue requirements provided in the attachment to MEC-CE-665 only include capital costs incurred between 2014 and 2017. If confirmed, provide total capital revenue requirements for 2014 through 2017 (inclusive) including capital costs incurred before 2014.

Response:

a. Please see attached. Please note that the revenue requirements for each year would represent the revenue requirement for that year. The 2014 revenue requirement would only include 2014 capital spending from MEC-CE-74(e). Years 2015 through 2017 would include the capital spending for the respective year as well as the capital spending for the previous years going back to 2014.

c. The 2019 revenue requirements provided in the attachment to MEC-CE-665 only includes capital costs incurred between 2014 and 2017. Please see attached for the total capital revenue requirements.

Heidi Myers
Heidi Myers
October 5, 2018

Rates and Regulation

20134-MEC-CE-693(a)

In thousands

Line No.	Unit/Categories	12 Mos Ended 2014	12 Mos Ended 2015	12 Mos Ended 2016	12 Mos Ended 2017
1	*Capital:*				
2	JHC 1&2	5,965	9,053	7,260	7,856
3	JHC 3	16,370	19,635	28,452	2,570
4	Karn 1&2	95,278	49,508	48,853	11,816

2014

	Average Rate Base	Return	Depreciation	Property Tax	2014 Total Revenue Requirement
JHC 1&2	2,909	229	147	32	409
JHC 3	7,983	629	404	88	1,121
Karn 1&2	46,462	3,661	2,353	511	6,526

2015

	Average Rate Base	Return	Depreciation	Property Tax	2015 Total Revenue Requirement
JHC 1&2	10,132	798	518	111	1,428
JHC 3	25,257	1,990	1,294	278	3,562
Karn 1&2	115,301	9,086	5,930	1,268	16,284

2016

	Average Rate Base	Return	Depreciation	Property Tax	2016 Total Revenue Requirement
JHC 1&2	17,569	1,384	921	193	2,499
JHC 3	47,413	3,736	2,481	522	6,739
Karn 1&2	157,337	12,398	8,359	1,731	22,488

2017

	Average Rate Base	Return	Depreciation	Property Tax	2017 Total Revenue Requirement
JHC 1&2	23,972	1,889	1,295	264	3,447
JHC 3	59,939	4,723	3,248	659	8,630
Karn 1&2	177,976	14,025	9,858	1,958	25,840

*Calculations assume pre-tax cost of capital, depreciation rates, and property tax rates as proposed in this case.

20134-MEC-CE-693(c)

000

2014

	Average Rate Base	Return	Depreciation	Property Tax	2014 Total Revenue Requirement
JHC 1&2	570,325	44,942	37,621	6,274	88,836
JHC 3	593,517	46,769	52,992	6,529	106,289
Karn 1&2	641,296	50,534	40,963	7,054	98,551

2015

	Average Rate Base	Return	Depreciation	Property Tax	2015 Total Revenue Requirement
JHC 1&2	545,656	42,998	37,648	6,002	86,648
JHC 3	552,983	43,575	53,110	6,083	102,768
Karn 1&2	831,838	65,549	50,685	9,150	125,384

2016

	Average Rate Base	Return	Depreciation	Property Tax	2016 Total Revenue Requirement
JHC 1&2	642,244	50,609	43,706	7,065	101,380
JHC 3	811,779	63,968	67,225	8,930	140,123
Karn 1&2	913,048	71,948	55,586	10,044	137,577

2017

	Average Rate Base	Return	Depreciation	Property Tax	2017 Total Revenue Requirement
JHC 1&2	737,733	58,133	49,899	8,115	116,148
JHC 3	1,061,556	83,651	81,476	11,677	176,804
Karn 1&2	941,390	74,182	57,969	10,355	142,506

*Calculations assume pre-tax cost of capital, depreciation rates, and property tax rates as proposed in this case.

Question:

9. Refer to page 1 of Exhibit A-61 (JPB-4).

a. Identify all projects and expenditures for each of the retirement scenarios that are included in the “avoidable” capital cost category.
b. Identify all projects and expenditures for each of the retirement scenarios that are included in the “incremental” capital cost category.
c. Explain why each incremental project and expenditure identified in response to subsection b is necessary in the identified time frame.
d. Explain the current status of the projects included in the 2018 Karn 3 & 4 “incremental” capital cost category, including whether you currently intend to carry out each project in 2018 and, if not, when you intend to do so.
e. Explain the current status of the projects included in the 2019 Karn 3 & 4 “incremental” capital cost category, including whether you currently intend to carry out each project in 2019 and, if not, when you intend to do so.

Response:

a. The following projects and expenditures are avoidable under the Campbell 1 retirement scenario:

Project Name	2018	2019
Upgrade Exciter Controls to Basler Based DECS 2100		$145,000
DCS and Simulator Upgrades		$258,000

The following projects and expenditures are avoidable under the Campbell 2 retirement scenario:

Project Name	2018	2019
RH Drying	$50,000	$250,000

The following projects and expenditures are avoidable under the Karn 1 and 2 retirement scenario:

Project Name	2018	2019
K2 FD Fan outlet Dampers		$63,000
K2 DCS Q-Line to R-Line IO Replacement		$100,000
K1 Breaker Replacements		$125,000
K2 B PA Fan Motor Upgrade		$150,000
K2 C PA Fan Motor Upgrade		$150,000
K2 D PA Fan Motor Upgrade		$150,000
K2 E PA Fan Motor Upgrade		$150,000
K2 F PA Fan Motor Upgrade		$150,000
K2 Coal Pipe Replacement		$181,000

K2 Replace HP IP Nozzle Blocks 1st State Stationary Blading		$250,000
K2 El Mill Rebuild and Upgrade		$1,250,000

b. The following projects and expenditures are incremental under the Campbell 1 retirement scenario:

Project Name	2018	2019
HP Turbine Blading Replacement	$375,000	$625,000
LP Turbine Blading Replacement – Row L-0	$25,000	$3,475,000
Replacement of LP Heater	$843,000	$1,070,000
Replace burners corner 1-8	$50,000	$2,750,000
Upgrade Exciter Controls to Basler based DECS2100	$223,000	
1D Boiler Circ Water Pump Motor Rewind		$500,000
Turbine Overhaul – Major		$1,000,000
Turbine Control System Upgrade		$1,500,000
Ashpit Rebuild		$432,000

The following projects and expenditures are incremental under the Campbell 2 retirement scenario:

Project Name	2018	2019
Horz RH Replacement	$5,053,000	$7,898,000
Replace Burner Assemblies – 6	$550,000	$1,350,000
Replace Turbine right side Reheat Stop Vlv body		$1,850,000
DCS and Simulator Upgrade		$1,000,000
Boiler Component Replacement		$1,000,000

The following projects and expenditures are incremental under the Karn 1 and 2 retirement scenario:

Project Name	2018	2019
Cut & Cap (Compressed Air, City Water, Sanitary, Natural Gas, H, CO_2, and Heating)		
Soot Blowing Air Compressor Repairs		
Demineralized Water System		
LP House Service Water Modifications		
Intake & Discharge Channel Freeze Prevention		
138kV Substation Control		
Resupply Power to Surrounding Buildings		
Reconfigure Communication Network		
Relocate HSW Chlorination System		

Distributed Control System Modifications		
Electrical Distribution to Feed New Loads		
Estimated Cost for All Above Projects	$8,000,000	$7,250,000

The above estimates are based on preliminary engineering studies and are subject to change as additional engineering scope and studies are completed.

c. When Consumers Energy developed the incremental expenditures identified in this filing, the belief was that work (on separating the units) would need to proceed immediately – due to the; short lead-time, amount of work to be completed, and degree of complexity.

However, the Company now believes it is prudent to delay all incremental work and expenditures until the Commission issues its order in the Company's IRP filing.

The Company does not currently plan to make any of the 2018 incremental expenditures and plans to make less than $1 million in incremental expenditures in 2019.

d. The 2018 Karn 3 & 4 incremental capital costs are on hold due to the IRP not being approved. Based on the timing of the expected response for the IRP, no project work is anticipated to occur in 2018.

e. The 2019 Karn 3 & 4 incremental capital costs are on hold due to the IRP not being approved. If the Commission approves the early retirement (2023) of Karn 1 & 2 in 2019, the projects will be initiated.

John P. Broschak
September 26, 2018

Generation Operations

20134-MEC-CE-691

Question:

2. Refer to Exhibit A-61 (JPB-4), page 1, lines 17-20. Identify the level of projected capital expenditures for Karn Units 1 and 2 for each of the years 2018 and 2019 that would be avoidable if Karn Units 1 and 2 were to retire by the end of 2019.

Response:

The Company is not considering the 2019 retirement of Karn 1 and 2, and has not identified what capital expenditures would be avoidable if Karn 1 and 2 were to retire by the end of 2019.

John P. Broschak
October 9, 2018

Generation Operations

20134-MEC-CE-692

Question:

3. Refer to Exhibit A-61 (JPB-4), page 1, lines 17-20.

a. Explain the current status of each of the projects included in the 2018 Karn 1 and 2 "unavoidable" capital cost category, including whether you have or currently intend to carry out each project in 2018 and, if not, when you intend to do so.

b. Identify the current status of each of the projects included in the 2019 Karn 1 and 2 "unavoidable" capital cost category, including whether you currently intend to carry out each project in 2019 and, if not, when you intend to do so.

Response:

a. Please see the attached Excel file: 20134-MEC-MEC-CE-692.xlsx – Tab 2018.

All but three projects in the 2018 unavoidable category have been, or will be, completed. Three projects totaling $547,000 were deferred due to condition assessments and/or the unavailability of parts. Additional details are provided in the attached Excel file.

b. Please see the attached Excel file: 20134-MEC-CE-692.xlsx – Tab 2019.

All projects in the 2019 unavoidable category currently remain in the plan for execution.

John P. Broschak
October 9, 2018

Generation Operations

Plant	Unit	Title	2018	Comment
Karn 1&2	1&2 Commons	RCRA - DEK Double Lined Pond - CAP	$ 5,098,173	Project In Progress
Karn 1&2	1	1D BCWP Rebuild - Condition Based	$ 61,009	Project Deferred - Condition Assesment did not require overhaul in 2018, delayed to 2020.
Karn 1&2	1	1A BCWP Rebuild - Condition Based	$ 61,009	Project Complete
Karn 1&2	1&2 Commons	DE Karn SEEG - Waste Water Treatment	$ 599,895	Project In Progress
Karn 1&2	1&2 Commons	DEK 12 - 316B Demonstration Testing	$ 60,000	Project Complete - Waiting for MDEQ results.
Karn	1&2 Commons	K1&2 Reverse Osmosis System	$ 125,000	Project Complete
Karn 1&2	1	Karn 1 Mill Hoist	$ 285,000	Project Complete
Karn 1&2	2	Karn 2 SCR 2nd Layer Catalyst Replacement	$ 1,540,000	Project In Progress
Karn	1&2 Commons	Dike Improvements	$ 10,000	Project Complete
Karn	1&2 Commons	Karn 3 Repl AVR Parts	$ 525,000	Project Complete
Karn 1&2	1	K1 - Fabric Filter Bag Replacement	$ 1,444,210	Project Complete
Karn 1&2	2	Karn 2A Mill Capital Overhual	$ 103,000	Project Complete
Karn 1&2	1&2 Commons	Diesel Generator Contactor Replacement	$ 250,000	Project Deferred - No replacement parts available. Plan to recondition in 2019.
Karn 1&2	1&2 Commons	K12 Battery Bank Replacement	$ 400,000	Project In Progress
Karn 1&2	1	K1 1A Mill Exhauster Replacement	$ (47,000)	Project Complete
Karn 1&2	1&2 Commons	Fuel Handleing- 18 Conveyor Telescoping Chute	$ 370,000	Project Complete
Karn	1&2 Commons	Karn Site Trailer Safety Upgrades	$ 12,000	Project Complete
Karn 1&2	1	Karn 1 Steam Drum Level Controller	$ 13,000	Project Complete
Karn 1&2	2	K2 Mill Discharge Valve Replacement	$ 8,000	Project Complete
Karn 1&2	1	K1 C Mill Shaft Replacement	$ 165,000	Project Complete
Karn	1&2 Commons	Small Pumps and Motors	$ 50,000	In progress
Karn	1&2 Commons	Small Valves and Instrumentation	$ 100,000	In progress
Karn 1&2	1	K1 Economizer Drag Conveyor Valve Replacement	$ 10,000	Project Complete
Karn 1&2	1	K1 Exhauster Slide Gates Automation	$ 10,000	Project Complete
Karn	1&2 Commons	Small Tools and Equipment	$ 105,000	In progress
Karn 1&2	1&2 Commons	Karn 1&2 SDA Emergency Lights and Exit Sign Improvements	$ 107,000	Project Complete
Karn 1&2	1	K1 A BFP Remachine barrel and replace element	$ 400	Project Complete
Karn 1&2	1&2 Commons	Karn 1&2 FH Thaw Shed Roll-Up Door Replacement	$ 26,000	Project Complete
Karn 1&2	1&2 Commons	K 1&2 Replace Trestle Sump Pumps	$ 27,000	Project Complete
Karn 1&2	2	K2 Drum Level Controls 15CDEK0223001	$ 50,000	Project Complete
Karn	1&2 Commons	Site EDS Server Replacement	$ 50,000	Planned to complete in October
Karn 1&2	1	1-A CCWP Overhaul 07MDEK120305	$ 87,000	Planned to complete in October
Karn 1&2	1&2 Commons	Karn 1 Bottom blow down valve replacement	$ 75,000	Project Complete
Karn 1&2	2	Karn 2 DCS Upgrades - Evergreen	$ 149,000	Project Complete
Karn 1&2	2	Karn 2 PJFF Clean Air Blower Replacements	$ 125,000	Project In Progress
Karn 1&2	1	Karn 1 PJFF Clean Air Blower Replacements	$ 125,000	Project In Progress
Karn 1&2	2	K2 A BFP Remachine barrel and replace element	$ 250,000	Project Complete
Karn 1&2	1&2 Commons	Karn Ash Ponds Cost of Removal	$ 150,000	Project In Progress
Karn 1&2	1	Karn 1 Secondary Air Expansion Joint Replacement	$ 236,000	Project Deferred - No failed joints during condition assesment -plan to perform in 2019
Karn	1&2 Commons	FH Rail Road Replacement and Upgrade	$ 118,000	Project Complete
Karn 1&2	1&2 Commons	Karn-Weadock Fuel Handling DCS Upgrades-Evergreen	$ 400,000	Project Complete
Karn 1&2	1	Karn 1 DCS Upgrades - Evergreen	$ 1,142,000	Planned to complete in October
Karn 1&2	2	Unit 2 El Mill Rebuild and Upgrade	$ 1,049,000	Project Complete
			$ 15,524,695	

Plant	Unit	Title	2019	Comment
Karn	1&2 Commons	Ash Haul Road in fill Area - phase 2	$ 575,000	
Karn	1&2 Commons	Small Pumps and Motors	$ 100,000	
Karn	1&2 Commons	Small Valves and Instrumentation	$ 205,000	
Karn	1&2 Commons	Small Tools and Equipment	$ 205,000	
Karn 1&2	1	1-B CCWP Overhaul	$ 24,000	
Karn 1&2	2	K2B CCWP Overhaul	$ 29,000	
Karn 1&2	2	K2-A CCWP Overhaul 08MDEK120306	$ 29,000	
Karn	1&2 Commons	Cyber Security Capital	$ 75,000	
Karn 1&2	2	Replace 2-3 LPH level control valve	$ 70,000	
Karn 1&2	2	K2 - Fabric Filter Bag Replacement	$ 100,000	
Karn 1&2	1	K1 Voltage Regulator HMI and Controller Replacement	$ 150,000	
Karn 1&2	2	Karn 2 PJFF Clean Air Blower Replacements	$ 60,000	
Karn 1&2	1&2 Commons	CapitalBelt Replacement	$ 181,000	
Karn 1&2	1	Karn 1 PJFF Clean Air Blower Replacements	$ 60,000	
Karn 1&2	1	K1 Mill Air Diffuser	$ 200,000	
Karn 1&2	1&2 Commons	"C" SBAC Rebuild	$ 275,000	
Karn 1&2	1&2 Commons	Karn Ash Ponds Cost of Removal	$ 75,000	
Karn 1&2	1	Karn 1 Secondary Air Expansion Joint Replacement	$ 150,000	
Karn	1&2 Commons	FH Rail Road Replacement and Upgrade	$ 243,000	
Karn 1&2	1&2 Commons	Ovation Security Center Upgrade (Evergreen)	$ 500,000	
Karn 1&2	2	Karn 2 Nox Analyzers - Install	$ 679,000	
Karn 1&2	1	Karn 1 SCR 2nd Layer Catalyst Replacemen	$ 700,000	
			$ 4,685,000	

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's places WEC Energy and Integrys on review for downgrade

01 Jun 2018

Approximately $2.6 billion of debt securities affected

New York, June 01, 2018 -- Moody's Investors Service ("Moody's") placed the long-term ratings of WEC Energy Group, Inc. (WEC), Wisconsin Energy Capital Corporation (WECC) and Integrys Holding, Inc (Integrys), including their A3 senior unsecured ratings (see full debt list below) on review for downgrade.

The Prime-2 short-term ratings of WEC and Integrys are not on review.

RATING RATIONALE

"Today's rating action placing the long-term ratings of WEC, WECC, and Integrys on review for downgrade reflects heightened structural subordination risk from higher parent company debt levels and declining consolidated financial metrics", said Natividad Martel, Vice-President/Senior Analyst.

The review will consider if WEC's holding company debt will remain elevated on a sustained basis going forward (2017: 29%), evaluate the overall negative effect of tax reform on the group's consolidated cash flows, and understand future trends with regard to consolidated credit metrics, that have been weak for its credit profile.

The review will also assess the impact on consolidated financial metrics and holding company debt of management's decisions regarding the financing of the group's material capital expenditure program, its target dividend payout ratio between 65% and 70%, the negative impact of tax reform, along with the positive effects from the implementation of cost saving initiatives. Unlike many of their peer utility holding companies, WEC management has indicated that it expects no equity issuances to offset the negative impact tax reform.

On Review for Downgrade:

..Issuer: Integrys Energy Group, Inc.

....Junior Subordinated Regular Bond/Debenture, Placed on Review for Downgrade, currently Baa1

....Senior Unsecured Regular Bond/Debenture, Placed on Review for Downgrade, currently A3

..Issuer: Integrys Holding, Inc.

.... Issuer Rating, Placed on Review for Downgrade, currently A3

..Issuer: WEC Energy Group, Inc.

.... Issuer Rating, Placed on Review for Downgrade, currently A3

....Junior Subordinated Regular Bond/Debenture, Placed on Review for Downgrade, currently Baa1

....Senior Unsecured Regular Bond/Debenture, Placed on Review for Downgrade, currently A3

..Issuer: Wisconsin Energy Capital Corporation

....Senior Unsecured Regular Bond/Debenture, Placed on Review for Downgrade, currently A3

Outlook Actions:

..Issuer: Integrys Holding, Inc.

....Outlook, Changed To Rating Under Review From Negative

..Issuer: WEC Energy Group, Inc.

....Outlook, Changed To Rating Under Review From Negative

..Issuer: Wisconsin Energy Capital Corporation

....Outlook, Changed To Rating Under Review From Negative

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in June 2017. Please see the Rating Methodologies page on www.moodys.com for a copy of this methodology.

Headquartered in Milwaukee, WEC Energy Group, Inc. (WEC) is a diversified energy holding company with electricity and natural gas operations. It holds, directly or indirectly, ownership-stakes in several utility subsidiaries. These include Wisconsin Electric Power Company (WEPCO; A2 stable), We power (unrated), Wisconsin Gas LLC (WG; A2 negative) and Upper Michigan Resources Corporation (UMERC, unrated). The intermediate holding company, Integrys Holdings, Inc (A3 on review for downgrade), is the direct parent company of Wisconsin Public Service Corporation (WPS; Issuer rating: A2 stable) as well as the natural gas distribution companies (LDC): The Peoples Gas, Light and Coke Company (PGL, A2 stable), North Shore Gas Company (NSG; A2 stable), Minnesota Energy Resources Corporation (MERC; unrated), Michigan Gas Utilities Corporation (MGU, unrated). WEC also holds an indirect 60% economic interest (34% voting rights) in American Transmission Company LLC (ATC; A2 stable).

REGULATORY DISCLOSURES

For ratings issued on a program, series or category/class of debt, this announcement provides certain regulatory disclosures in relation to each rating of a subsequently issued bond or note of the same series or category/class of debt or pursuant to a program for which the ratings are derived exclusively from existing ratings in accordance with Moody's rating practices. For ratings issued on a support provider, this announcement provides certain regulatory disclosures in relation to the credit rating action on the support provider and in relation to each particular credit rating action for securities that derive their credit ratings from the support provider's credit rating. For provisional ratings, this announcement provides certain regulatory disclosures in relation to the provisional rating assigned, and in relation to a definitive rating that may be assigned subsequent to the final issuance of the debt, in each case where the transaction structure and terms have not changed prior to the assignment of the definitive rating in a manner that would have affected the rating. For further information please see the ratings tab on the issuer/entity page for the respective issuer on www.moodys.com.

For any affected securities or rated entities receiving direct credit support from the primary entity(ies) of this credit rating action, and whose ratings may change as a result of this credit rating action, the associated regulatory disclosures will be those of the guarantor entity. Exceptions to this approach exist for the following disclosures, if applicable to jurisdiction: Ancillary Services, Disclosure to rated entity, Disclosure from rated entity.

Regulatory disclosures contained in this press release apply to the credit rating and, if applicable, the related rating outlook or rating review.

Please see www.moodys.com for any updates on changes to the lead rating analyst and to the Moody's legal entity that has issued the rating.

Please see the ratings tab on the issuer/entity page on www.moodys.com for additional regulatory disclosures for each credit rating.

Natividad Martel
Vice President - Senior Analyst
Infrastructure Finance Group
Moody's Investors Service, Inc.
250 Greenwich Street
New York, NY 10007
U.S.A.
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

Jim Hempstead

MD - Utilities
Infrastructure Finance Group
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

Releasing Office:
Moody's Investors Service, Inc.
250 Greenwich Street
New York, NY 10007
U.S.A.
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

MOODY'S
INVESTORS SERVICE

reliable. Because of the possibility of human or mechanical error as well as other factors, however, all information contained herein is provided "AS IS" without warranty of any kind. MOODY'S adopts all necessary measures so that the information it uses in assigning a credit rating is of sufficient quality and from sources MOODY'S considers to be reliable including, when appropriate, independent third-party sources. However, MOODY'S is not an auditor and cannot in every instance independently verify or validate information received in the rating process or in preparing the Moody's publications.

To the extent permitted by law, MOODY'S and its directors, officers, employees, agents, representatives, licensors and suppliers disclaim liability to any person or entity for any indirect, special, consequential, or incidental losses or damages whatsoever arising from or in connection with the information contained herein or the use of or inability to use any such information, even if MOODY'S or any of its directors, officers, employees, agents, representatives, licensors or suppliers is advised in advance of the possibility of such losses or damages, including but not limited to: (a) any loss of present or prospective profits or (b) any loss or damage arising where the relevant financial instrument is not the subject of a particular credit rating assigned by MOODY'S.

To the extent permitted by law, MOODY'S and its directors, officers, employees, agents, representatives, licensors and suppliers disclaim liability for any direct or compensatory losses or damages caused to any person or entity, including but not limited to by any negligence (but excluding fraud, willful misconduct or any other type of liability that, for the avoidance of doubt, by law cannot be excluded) on the part of, or any contingency within or beyond the control of, MOODY'S or any of its directors, officers, employees, agents, representatives, licensors or suppliers, arising from or in connection with the information contained herein or the use of or inability to use any such information.

NO WARRANTY, EXPRESS OR IMPLIED, AS TO THE ACCURACY, TIMELINESS, COMPLETENESS, MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE OF ANY SUCH RATING OR OTHER OPINION OR INFORMATION IS GIVEN OR MADE BY MOODY'S IN ANY FORM OR MANNER WHATSOEVER.

Moody's Investors Service, Inc., a wholly-owned credit rating agency subsidiary of Moody's Corporation ("MCO"), hereby discloses that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by Moody's Investors Service, Inc. have, prior to assignment of any rating, agreed to pay to Moody's Investors Service, Inc. for appraisal and rating services rendered by it fees ranging from $1,500 to approximately $2,500,000. MCO and MIS also maintain policies and procedures to address the independence of MIS's ratings and rating processes. Information regarding certain affiliations that may exist between directors of MCO and rated entities, and between entities who hold ratings from MIS and have also publicly reported to the SEC an ownership interest in MCO of more than 5%, is posted annually at www.moodys.com under the heading "Investor Relations — Corporate Governance — Director and Shareholder Affiliation Policy."

Additional terms for Australia only: Any publication into Australia of this document is pursuant to the Australian Financial Services License of MOODY'S affiliate, Moody's Investors Service Pty Limited ABN 61 003 399 657AFSL 336969 and/or Moody's Analytics Australia Pty Ltd ABN 94 105 136 972 AFSL 383569 (as applicable). This document is intended to be provided only to "wholesale clients" within the meaning of section 761G of the Corporations Act 2001. By continuing to access this document from within Australia, you represent to MOODY'S that you are, or are accessing the document as a representative of, a "wholesale client" and that neither you nor the entity you represent will directly or indirectly disseminate this document or its contents to "retail clients" within the meaning of section 761G of the Corporations Act 2001. MOODY'S credit rating is an opinion as to the creditworthiness of a debt obligation of the issuer, not on the equity securities of the issuer or any form of security that is available to retail investors. It would be reckless and inappropriate for retail investors to use MOODY'S credit ratings or publications when making an investment decision. If in doubt you should contact your financial or other professional adviser.

Additional terms for Japan only: Moody's Japan K.K. ("MJKK") is a wholly-owned credit rating agency subsidiary of Moody's Group Japan G.K., which is wholly-owned by Moody's Overseas Holdings Inc., a wholly-owned subsidiary of MCO. Moody's SF Japan K.K. ("MSFJ") is a wholly-owned credit rating agency subsidiary of MJKK. MSFJ is not a Nationally Recognized Statistical Rating Organization ("NRSRO"). Therefore, credit ratings assigned by MSFJ are Non-NRSRO Credit Ratings. Non-NRSRO Credit Ratings are assigned by an entity that is not a NRSRO and, consequently, the rated obligation will not qualify for certain types of treatment under U.S. laws. MJKK and MSFJ are credit rating agencies registered with the Japan Financial Services Agency and their registration numbers are FSA Commissioner (Ratings) No. 2 and 3 respectively.

MJKK or MSFJ (as applicable) hereby disclose that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by MJKK or MSFJ (as applicable) have, prior to assignment of any rating, agreed to pay to MJKK or MSFJ (as applicable) for appraisal and rating services rendered by it fees ranging from JPY200,000 to approximately JPY350,000,000.

MJKK and MSFJ also maintain policies and procedures to address Japanese regulatory requirements.

20134-MEC-CE-65

Question:

17. Reference the testimony of Michael Delaney, page 18, lines 6 to 13. Mr. Delaney explains that the Company intends to provide DC fast charging infrastructure along highway corridors in order to alleviate "range anxiety."

a. Please state whether the company considered deploying DC fast charging infrastructure in urban settings (*e.g.*, in order to serve EV drivers living in multi-dwelling unit housing or for electric ride-share or car-share drivers) in addition to highway corridors? Please explain and provide supporting documentation.

b. Is the Company willing to consider deployment of DC fast charging infrastructure in urban settings in its Pilot Foundational Infrastructure Program or in a future program? If not, please explain why not.

Response:

a. Yes, the Company considered deploying DC fast charging infrastructure in urban settings, as a way to serve similar customer segments as Level 2 workplace and public chargers. A consideration is that upfront investment costs for DCFCs are significantly higher than Level 2 chargers and may be cost prohibitive for site hosts, especially given the limited customer usage data that exists based on a small number of DCFCs in Michigan.

b. Yes, the Company is willing to consider deployment of DC fast charging infrastructure in urban settings in the Program or in a future program.

Michael J Delaney

Michael Delaney
June 29, 2018

Corporate Strategy

MEC-62

CONFIDENTIAL EXHIBIT

20134-MEC-CE-728
Page 1 of 2

Question:

4. Please refer to the rebuttal testimony of Ms. Collins, page 11, stating "The Company agrees that a larger differential between the off-peak and super off-peak rates would further incent customers to use during off-peak hours. To that extent, the Company has increased the differential to lower the super off-peak rate for both the Nighttime Savers rate and REV rate reflected in Exhibits A-143 (LMC-7) through A-145 (LMC-9)."

   a. Does the Company agree that a primary purpose of time-of-use rates such as the Residential Service Nighttime Savers Rate is to encourage customers to shift usage from on-peak periods to off-peak and super-off-peak periods? If not, please explain why not.

   b. Does the Company agree that electricity prices should encourage customers to use electricity during off-peak and super-off-peak periods rather than on-peak periods? If not, please explain why not.

   c. Does the Company agree that on-peak prices should generally be higher than both off-peak and super-off-peak prices? If not, please explain why not.

   d. Does the Company agree that increasing the price differential between on-peak and super-off-peak prices would strengthen the incentive for customers to shift usage from on-peak hours to super-off-peak hours? If not, please explain why not.

   e. Please explain why Ms. Collins' testimony refers to increasing the differential between the off-peak and super-off-peak rates, rather than increasing the differential between the on-peak and super-off-peak rates. Please provide data to support your response.

   f. Please discuss whether the rationale described in (e) would apply to other residential time-differentiated rates, such as REV-1 and REV-2.

Response:

a. Yes.
b. Yes.
c. Yes.
d. Yes.

e. The goal of the Nighttime Savers rate and REV rates is to encourage usage and/or electric vehicle charging during the overnight hours. To accomplish that, the Company increased both the differential ratio used between the on peak and super off peak rate and the differential ratio used between the off peak and super off peak rate. This can be seen by comparing the differentials in WP-LMC-15 and WP-LMC-15 Rebuttal. Both these workpapers are attached to this response and the differentials are highlighted in yellow.
f. Yes, the same rationale should apply to the REV-1 and REV-2

Laura Collins

Laura Collins
October 9, 2018

Rates and Regulation Department

20134-MEC-CE-727

Question:

3. Please refer to the rebuttal exhibits of Ms. Collins, Exhibit No. A-145 (LMC-9), Schedule F-3, page 10 of 30 regarding the residential service Nighttime Savers Rate.

   a. Please confirm that the off-peak rate presented here is higher than the on-peak rate.

   b. If (a) is confirmed, please explain whether it was the intent of the Company to set the off-peak rate higher than the on-peak rate.

   c. If it was the intent of the Company to set the off-peak rate higher than the on-peak rate, please explain the rationale for doing so and provide data to support this rationale.

   d. If it was the intent of the Company to set the off-peak rate higher than the on-peak rate, please identify and describe the categories of costs that were shifted from the on-peak and super-off-peak periods to the off-peak period to develop the new Nighttime Savers Rate presented in Ms. Collins' rebuttal exhibits.

   e. Please provide the data and workpapers in their native format (e.g., Microsoft Excel) used to develop the new Nighttime Savers Rate presented in Ms. Collins' rebuttal exhibits.

Response:

a. Yes, the initial filed rebuttal exhibit unintentionally had an off peak rate that was higher than the on peak rate.
b. This was unintentional and a corrected exhibit was filed on October 8, 2018.
c. Please see response to part b above.
d. Please see response to part b above.
e. Attached is the rate design model which contains the development of the Nighttime Savers Rate.

Laura Collins

Laura M. Collins
October 5, 2018

Rates and Regulation Department

Question:

2. Please refer to the rebuttal testimony of Ms. Brege, page 3, responding to Mr. Jester's recommendation to provide specific outage and duration information on customer's bills and on the Company's website.

   a. Regarding the potential for extensive outages in a geographic area to result in meters failing to report an outage, please identify how often such situations arose in 2017 and 2018 (so far), and describe the situations.

   b. Regarding the concern that a population of customers would be excluded:

      i. Please identify (or approximate as accurately as reasonable) the number of customers, and the percentage of total customers, who have selected to retain non-communicating meters, who would be excluded from this recommendation;

      ii. Please identify (or approximate as accurately as reasonable) the number of customers, and the percentage of total customers, who live in areas where the use of communicating meters has been more challenging and would thus be excluded from this recommendation.

   c. Has the Company evaluated how to make customer outage data billing-compliant?

      i. If so, please describe such evaluations, and provide supporting documentation.

      ii. Please provide an estimated cost to implement Mr. Jester's recommendation to provide specific outage and duration data on customer's bills.

      iii. Please provide an estimated date or timeframe when the Company may be able to provide specific outage and duration data on customer's bills.

   d. Regarding Mr. Jester's recommendation to post specific outage and duration data to the Company's website, please provide an estimated cost and date (or timeline) to implement this recommendation.

Response:

2(a) According to our Smart Energy Operations Center, the number of occurrences or number of meters failing to report an outage in 2017 and 2018 cannot be tracked. Communicating meters utilize cell towers which have bandwidth limitations. When multiple meters communicate an outage to a cell phone tower, it is a reasonable expectation that not every single communication will be successful. The notifications serve a purpose at a high level – to quickly identify potential issues impacting a population of customers. This type of alert has not been used and was not intended to be used to record customer specific outage data for purposes of issuing outage credits. The Company asks customers to report outages using our online outage tool or by calling 800-477-5050.

The Company is in compliance with the Service Quality and Reliability Standards for Electric Distribution Systems by issuing credits for affected customers who notify the Company as described in the Service Quality and Reliability Standards and qualify for a credit under Rules R460.474, R460.475 and R460.476.

2(b)(i) As stated in the direct testimony of Lincoln D. Warriner, there were 9,848 electric customers active in the Non-Transmitting Meter Provision in December 2017, which is approximately 0.5% of all the electric customers. Page 33, Lines 6-8.

2(b)(ii) According to our Smart Energy Operations Center, there are approximately 14,337 intermittent communicating meters and 1,394 meters that need to be replaced, which is approximately 0.9% of all electric customers. These numbers fluctuate daily due to meters being replaced, meters failing to communicate and meters communicating that were not communicating previously.

2(c) To clarify, the system I was referred to in my rebuttal testimony as non-compliant for billing purposes is PI Historian. PI Historian maintains AMI meter notification data which can be accessed for the validation of outage duration metrics. The Company has not evaluated how to make PI Historian data billing-compliant.

2(c)(i) No evaluations have been completed, there is no supporting documentation.

2(c)(ii) The Company has not estimated the cost to implement Mr. Jester's recommendation to provide specific outage and duration data on customer invoices – according to Mr. Jester's testimony, 71,663 customers of the Company's 1.8 million electric customers, which is approximately 3.9% of all customers, were eligible for a credit in 2017 under Rules R460.474, R460.475 and R460.476. Although specific outage and duration data is not shown on customer invoices, customers can complete the Electric Outage Credit Form on the Company's website or call 800-477-5050 to determine eligibility. The Company is in compliance with the Service Quality and Reliability Standards for Electric Distribution Systems by issuing credits for affected customers who notify the Company as described in the Service Quality and Reliability Standards and qualify for a credit under Rules R460.474, R460.475 and R460.476.

2(c)(iii) The Company does not have an estimated timeframe to implement Mr. Jester's recommendation to provide specific outage and duration data on customer invoices. As noted above, approximately 3.9% of all customers were eligible for a credit in 2017 under Rules R460.474, R460.475 and R460.476. The Company does not have available resources to modify systems at this time, as it is prioritizing configuration work necessary to modify its residential rates, including the implementation of the required transition to the proposed Residential Summer On-Peak Basic Rate, impacting all residential customers. Although specific outage and duration data is not shown on customer invoices, customers may complete the Electric Outage Credit Form on the Company's website or call 800-477-5050 to determine eligibility.

2(d). The Company does not have an estimated timeframe to implement Mr. Jester's recommendation to post specific outage and duration data to the Company's website. As noted above, approximately 3.9% of all customers were eligible for a credit in 2017 under Rules R460.474, R460.475 and R460.476. Affected customers have the ability to complete the Electric Outage Credit Form on the Company's website or call 800-477-5050 to determine eligibility. The Company does not have available resources to modify systems at this time, as it is prioritizing configuration work necessary to modify its residential rates, including the implementation of the required transition to the proposed Residential Summer On-Peak Basic Rate, impacting all residential customers.

Rachel L. Brege

Rachel L. Brege
October 11, 2018

Rates and Regulation

20134-FGR-CE-697

Question:

1. Refer to the rebuttal testimony of Josnelly Aponte, page 3: produce the workpaper or other source of the estimate that "the allocation of production costs for the Lighting & Unmetered rates would more than double under the NCP A&E method compared to the current 4CP 75/0/25 method and the 4CP A&E method."

Response:

Please refer to the Excel file attached "20134-FGR-CE-697".

Josnelly Aponte
October 5, 2018

Rates & Regulation

Production allocator

	Total Lighting & Unmetered		
4CP A&E	0.177697	232%	From EX JCA-8 model provided in FGR-CE-689
4CP 75/0/25	0.301031	96%	Same as in EX JCA-8 model provided in FGR-CE-689
NCP A&E	0.589238		

20134-MEC-CE-694

Question:

5. Refer to the Rebuttal Testimony of Josnelly Aponte, pages 5-6:

a. Clarify whether the combined cycle units at the Jackson and Zeeland plants are considered "peakers" as the witness uses that term.

b. If the answer to question (a) is yes, describe the witness's understanding of how the allocated production costs of the Jackson and Zeeland CC's compare to the coal plants identified in the witness's testimony (e.g., more, less, equal, etc.); and produce the information on which the witness relied for her understanding as it relates to this section of testimony.

c. If the answer to question (a) is yes, describe the witness's understanding of how the allocated production costs of the Jackson and Zeeland CC's compare to the Company's combustion turbine and oil-fired units (e.g., more, less, equal, etc.); and produce the information on which the witness relied for her understanding as it relates to this section of testimony.

d. Provide estimates of the contributions to minimum load provided by each category of Company-owned generating unit or category of units (e.g., the categories identified on page 4 of witness Broschak's direct testimony), and produce the information relied on by the witness for those estimates.

e. Produce the information the witness is relying on for the assumption or conclusion that only the minimum load of the coal units is being used to fulfill the system minimum load requirements.

f. Why are Company-owned hydro units not classified as baseload for purposes of the exercise presented in Exhibit A-128?

Response:

<u>Objection by Counsel:</u> Consumers Energy Company objects to this discovery request to the extent the request seeks the results of an analysis that Consumers Energy has not performed. Subject to and without waiving this objection, Consumers Energy responds as follows:

a. The categories of baseload, intermediate, and peaking generation have lost their traditional meaning in the last decade mainly due to changing market conditions, including declining gas prices. The Company does not consider Jackson and Zeeland plants as "peakers" in the traditional sense because they do not only serve peak load, as explained in my rebuttal testimony.

b. Not applicable.

c. Not applicable.

d. The Company has not calculated the contribution to minimum load as requested. However, capacity factors (actual production versus potential production) show how the utilization of the units has changed overtime. For example, the capacity factor of coal units Campbell 1 and 2 has decreased 26% since 2015, compared to the utilization factor of the prior 8 years. In the case of Zeeland gas combined-cycle, the capacity factor has increased by 169% since 2015, compared to the prior 8 years. Moreover, in recent years (2016 and 2018), Zeeland gas combined-cycle had a higher capacity factor than all coal units. Please refer to Excel file attached "Capacity Factors 2007-2018YTD"

e. Only the minimum load of the coal plants should be considered "base load" for the purposes of Staff's calculation because, depending on market conditions, natural gas units may be offered into MISO rather than ramping up the production of a coal plant. See also the discussion at page 6 of my rebuttal testimony. As discussed in subpart e, the capacity factors of the coal units have been decreasing while the capacity factors of other units (such as Zeeland combined-cycle) have been increasing.

f. Please refer to my rebuttal testimony, page 6, lines 16 through 18.

Josnelly Aponte
October 8, 2018

Rates & Regulation

Capacity Factors

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018 YTD - August	Average 2015-2018	Average 2007-2014	% Change
Campbell 1-2	79.7	72.3	60.9	74.1	51.0	50.6	58.5	65.1	59.0	52.1	40.0	38.2	47.3	64.0	-26%
Campbell 3 (CPCo Only)	52.2	84.0	86.8	79.8	76.2	67.6	74.9	69.4	76.0	49.8	79.6	67.4	68.2	73.9	-8%
Karn 1-2	81.2	45.8	60.8	62.3	59.2	48.6	58.3	45.8	44.1	48.0	56.2	64.2	53.1	57.7	-8%
Cobb 4-5	77.4	71.7	62.3	69.5	54.1	56.2	65.0	68.2	65.7	69.4	[redacted]		67.6	65.6	3%
Weadock 7-8	67.8	65.5	68.8	64.0	65.2	57.5	60.4	63.1	71.6	69.5			70.6	64.0	10%
Whiting 1-3	83.3	76.7	59.6	68.3	56.0	46.8	58.1	64.4	62.5	54.4			58.5	64.2	-9%
Karn 3-4	1.9	0.7	0.2	0.9	0.8	0.7	0.3	(0.1)	0.0	0.8	0.9	0.4	0.5	0.7	-23%
Zeeland CC	[redacted]	11.2	7.9	14.7	34.0	52.0	25.0	38.2	67.0	75.7	62.8	75.6	70.3	26.2	169%
Zeeland CT		6.8	4.2	7.7	5.4	12.7	5.8	5.1	7.1	10.3	5.5	11.4	8.6	6.8	26%
Other CTs	0.6	0.1	0.6	0.1	0.4	0.4	0.7	4.1	(0.3)	0.3	0.3	0.3	0.2	0.9	-83%
Jackson	[redacted]								32.3	44.5	39.8	42.1	39.7	0.0	100%
Lake Winds							29.5	32.9	29.8	28.7	29.2	26.7	28.6	0.0	100%
Cross Winds									37.6	38.2	34.5	35.7	36.5	0.0	100%
Ludington	7.3	5.8	4.5	5.3	5.5	4.2	5.3	8.2	5.4	8.4	7.5	9.2	7.6	5.8	32%
Other Hydros	58.9	64.0	66.8	52.2	61.0	56.5	63.0	64.2	60.1	64.8	68.9	69.8	65.9	60.8	8%
Solar	[redacted]										17.0	16.8	16.9	0.0	100%

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-17735

Volume No. 6

PUBLIC RECORD

CROSS-EXAMINATION

Proceedings held in the above-entitled matter before Mark E. Cummins, Administrative Law Judge with MAHS, at the Michigan Public Service Commission, 7109 West Saginaw, Lake Michigan Room, Lansing, Michigan, on Thursday, June 11, 2015, at 9:05 a.m.

APPEARANCES:

BRET A. TOTORAITIS, ESQ.
KELLY M. HALL, ESQ.
ANNE M. UITVLUGT, ESQ.
ROBERT BEACH, ESQ.
Consumers Energy Company
One Energy Plaza, Room EP11-223
Jackson, Michigan 49201

On behalf of Consumers Energy Company

CHRISTOPHER M. BZDOK, ESQ.
Olson Bzdok & Howard, PC
420 East Front Street
Traverse City, Michigan 49686

On behalf of Michigan Environmental Council, National Resources Defense Council, and Citizens Against Rate Excess

(Continued)

APPEARANCES Continued:

DON L. KESKEY, ESQ.
Public Law Resource Center, PLLC
333 Albert Avenue, Suite 425
East Lansing, Michigan 48823

On behalf of Michelle Rison and the
Residential Customer Group

JOHN JANISZEWSKI,
Assistant Attorney General
525 W. Ottawa Street, 7th floor
P.O. Box 30755
Lansing, Michigan 48909

On behalf of Attorney General Bill Schuette

LAUREN DONOFRIO,
AMIT T. SINGH,
BRYAN A. BRANDENBURG,
GRAHAM FILLER,
Michigan Department of Attorney General
7109 West Saginaw, Floor 3
Lansing, Michigan 48917

On behalf of Michigan Public Service
Commission Staff

\- - -

REPORTED BY: Marie T. Schroeder, CSR-2183
Lori Anne Penn, CSR-1315

I N D E X

E X H I B I T S

NUMBER	DESCRIPTION	MRKD	OFRD	RECD
A-10	(Miller) HWM-1 through HWM-4	--	761	801
A-29	(Harry) DLH-1	--	636	673
A-30	(Harry) DLH-2	--	636	673
A-31	(Harry) DLH-3	--	636	673
A-32	(Harry) DLH-4	--	636	673
A-33	(Harry) DLH-5	--	636	673
A-44	(Kehoe) DBK-1	--	677	737
A-45	(Kehoe) DBK-2	--	677	737
A-46	(Kehoe) DBK-3	--	677	737
A-47	(Kehoe) DBK-4	--	677	737
A-48	(Kehoe) DBK-5	--	677	737
A-69	(Varvatos) CJV-1	--	833	906
A-70	(Varvatos) CJV-2	--	833	906
A-71	(Varvatos) CJV-3	--	833	906
A-72	(Varvatos) CJV-4	--	833	906
A-73	(Varvatos) CJV-5	--	833	906
A-74	(Warriner) LDW-1	--	929	--
A-75	(Warriner) LDW-2	--	929	--
A-76	(Warriner) LDW-3	--	929	--
A-96	(Kehoe) DBK-6	--	677	737
A-97	(Kehoe) DBK-7	--	677	737
A-98	(Kehoe) DBK-8	--	677	737
A-99	(Kehoe) DBK-9	--	677	737

E X H I B I T S

NUMBER	DESCRIPTION	MRKD	OFRD	RECD
A-100	(Kehoe) DBK-10	--	677	737
A-101	(Kehoe) DBK-11	--	677	737
A-102	(Kehoe) DBK-12	--	677	737
A-103	(Kehoe) DBK-13	--	677	737
A-104	(Kehoe) DBK-14	--	677	737
A-105	(Kehoe) DBK-15	--	677	737
A-106	(Kehoe) DBK-16	--	677	737
A-107	(Kehoe) DBK-17	--	677	737
A-108	(Kehoe) DBK-18	--	677	737
A-109	(Miller) HWM-6	--	761	801
A-110	(Miller) HWM-7	--	761	801
A-111	(Miller) HWM-8	--	761	801
A-118	(Varvatos) CJV-6	--	833	906
A-119	(Varvatos) CJV-7	--	833	906
A-120	(Varvatos) CJV-8	--	833	906
A-121	(Warriner) LDW-4	--	929	--
A-122	(Warriner) LDW-5	--	929	--
A-123	(Warriner) LDW-6	--	929	--
A-124	(Warriner) LDW-7	--	929	--
MEC-38	Discovery Response 17735-MEC-DE-551 Question 18(a-b-c)	984	990	--
MEC-39	Discovery Response 17735-MEC-CE-61 Question 12(a-b-c)	925	925	925

E X H I B I T S

NUMBER	DESCRIPTION	MRKD	OFRD	RECD
MEC-40	Discovery Response 17735-MEC-CE-62 Question 13(a-b-c)	925	925	925
MEC-41	Discovery Response 17735-MEC-CE-63 Question 14(a-b-c)	925	925	925
MEC-42	Discovery Response 17735-MEC-CE-64 Question 15	925	925	925
MEC-43	Discovery Response 17735-MEC-CE-65 Question 16	925	925	925
AG-25	Excerpt of Hubert W. Miller, III, Rebuttal Testimony in U-17735	783	787	802
S-12	CONFIDENTIAL	1005	1012	1012
S-13	CONFIDENTIAL	1005	1012	1012

Q. Why was a linear regression model used to forecast Base O&M expenses?

A. Several different forecasting methods have been considered over the years, however, the linear regression model was chosen because it was found to be the most accurate method of calculating the predictable nature of the projected Base O&M amount.

Q. Why are Base O&M expenses decreasing?

A. In December 2011, Consumers Energy announced Cobb units 4&5, Weadock units 7&8, and Whiting units 1-3 would be mothballed as a result of new Environmental Protection Agency ("EPA") emission standards. Since that time, the Company committed to retire and demolish these units. As explained later in my testimony, Base O&M costs are determined by a generating unit's operating history and are broken into two categories – labor and non-labor. Since the December 2011 announcement, the Company has reduced both labor and non-labor spending at the Cobb, Weadock, and Whiting sites.

Q. Can you explain each of the expenses listed on lines 3 through 5 of Exhibit A-46 (DBK-3)?

A. Yes. These expenses identify emerging or changing costs and consist of:

- **Environmental Operations:** As Federal and State emissions standards require cleaner air, Consumers Energy is installing Air Quality Control Systems ("AQCS") to comply with these regulations. As the number of AQCS devices increase, so do the costs to operate and maintain these critical pieces of equipment. This expense is included on line 3 and is comprised of Material and Labor.

- **Jackson Plant:** In January 2014, Consumers Energy announced plans to purchase the 540 MW DPC Juniper gas-fired power plant in Jackson, MI. The purchase of this facility is projected to occur in December 2015 and is intended to partially replace the generating capacity that will be lost when the Company's seven oldest coal-fired power plants retire. Company witness Ronk provides further details of this purchase in his testimony. This expense is included on line 4 and is comprised of Labor, Material, and LTSA obligations.

- **Major Maintenance:** To maintain and improve the performance of our generating fleet, Consumers Energy attempts to do major maintenance on a

DAVID B. KEHOE
DIRECT TESTIMONY

Q. Please identify the capital expenditures that will be made for the Jackson Plant.

A. Page 1, line 7 of Exhibit A-47 (DBK-4) identifies the total capital expenditures for the Company's newest gas plant. In January 2014, Consumers Energy announced an agreement had been reached with an independent third party to purchase the 540 MW combined cycle natural gas plant located in Jackson, MI. The Company will incur expenses in 2014 and 2015 for monitoring operations and preparing for the Company's projected December 2015 purchase. In 2016 through 2018, Jackson will incur expenses for the LTSA with GE. Company witness Ronk provides further insight into the purchase of the Jackson Plant.

Q. Was the purchase of the Jackson Plant a prudent decision?

A. Yes. The Jackson Plant is an existing facility with a proven track record of being efficient, flexible, and available when called upon to operate. Also, the purchase of the Jackson Plant will allow Consumers Energy to continue to lower emissions and capitalize on today's lower natural gas prices while providing customers with immediate value. As noted above, the purchase of this plant partially replaces the generating capacity that will be lost when the Company's seven oldest coal-fired power plants retire.

Q. Please describe the design features that allow the Jackson Plant to be efficient, flexible, and available.

A. The Jackson Plant was designed to take advantage of rapid-changing load and market conditions. Unlike a traditional combined cycle plant with two large frame combustion turbines and one steam turbine, the Jackson Plant has six smaller GE LM6000 turbines, a GE 7EA turbine and two steam turbines. All seven turbines have their own heat recovery steam generators ("HRSG") with supplemental duct firing – steam from the HRSG's supply steam to the two steam turbines. The LM6000s and 7EA turbine designs are among the most common in the power industry and have a long-proven track record. Also, the LM6000s have inlet cooling and water injection to raise their efficiency towards the top in their class. Finally, the Jackson Plant's availability has routinely been above 98%.

Q. What makes the Jackson Plant so flexible and reliable?

A. As in the prior response, the Jackson Plant is a "seven-on-two" combined cycle plant. The smaller turbines and HRSGs allow start-up and warm-up times to be approximately half of a traditional combined cycle plant. This allows quicker response to changing load conditions along with much lower fuel consumption during start-ups.

The Jackson Plant can also reach near-design output during maintenance or failure of any one of the seven combustion turbines or steam turbines. In comparison, if a traditional combined cycle plant loses one of its two combustion turbines, the output is reduced by 50%, and if the steam turbine fails, the plant must be taken off-line. Also, outages for the smaller combustion turbines are routinely shorter than the larger frame turbines. If necessary, the Jackson Plant has a spare LM6000 turbine on-site, this would allow the Company to maintain generation efficiency if an operating turbine fails.

Q. Does the Jackson Plant offer additional flexibility?

A. Yes. The six LM6000s have a much lower minimum load point than traditional ("2x1") combined cycle plants – two combustion turbines and one steam turbine. Traditional 2x1 plants have a minimum load point of 50% of its rated output – so a 540 MW plant would have a minimum load point of approximately 270 MWs. In contrast, the Jackson Plant has a minimum load point of 150 MWs. Finally, the Jackson Plant can change load at rates of 30 MWs per minute compared to 10 MWs per minute for a traditional combined cycle plant(s).

Q. Please identify the capital expenditures that will be made for the proposed Thetford gas plant ("Thetford Plant").

A. Page 1, line 8 of Exhibit A-47 (DBK-4) identifies the total capital expenditures for the deferred Thetford Combined Cycle gas plant and the addition of a simple cycle combustion turbine. In 2013 and 2014, expenses were incurred for the owners engineer, site testing and land acquisition of the deferred Thetford Plant. In 2018, Thetford will incur expenditures for the development of a new simple cycle unit. This new unit is intended to meet the needs of the Company's projected capacity shortfall with Midcontinent Independent System Operator. Company witness Ronk provides further insight into this addition.

Q. Please identify the capital expenditures that were made at and are planned for the Company's combustion turbines ("CTs").

A. Page 1, line 9 of Exhibit A-47 (DBK-4) identifies the total capital expenditures for the Company's CT fleet. In 2013 through 2018, the CTs will incur minor expenses for valves, instruments, tools, and batteries. These expenses will be limited to the following sites – Thetford, Gaylord, and Straits.

Q. Please identify the capital expenditures that were made at and are planned for Weadock units 7-8.

A. Page 1, line 10 of Exhibit A-47 (DBK-4) identifies the total capital expenditures for Weadock units 7-8. In 2014, Weadock incurred costs for asbestos removal, ash pond

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.	U-20134 ALJ Sharon L. Feldman

PROOF OF SERVICE

On the date below, an electronic copy of **Official Exhibits of the Michigan Environmental Council, Natural Resources Defense Council and Sierra Club (MEC-1 through MEC-45, MEC-48 and MEC-49, MEC-51 through MEC-67** was served on the following:

Name/Party	E-mail Address
Administrative Law Judge Hon. Sharon L. Feldman, ALJ	feldmans@michigan.gov
Counsel for Consumers Energy Co. Bret A. Totoraitis Robert W. Beach Gary A. Gensch, Jr. Anne M. Uitvlugt Theresa A. Staley Michael C. Rampe	mpscfilings@cmsenergy.com bret.totoraitis@cmsenergy.com robert.beach@cmsenergy.com gary.genschjr@cmsenergy.com anne.uitvlugt@cmsenergy.com Theresa.staley@cmsenergy.com Michael.rampe@cmsenergy.com
Counsel for MPSC Staff Heather M.S. Durian Michael J. Orris Monica M. Stephens Daniel Sonneveldt	durianh@michigan.gov orrism@michigan.gov stephensm11@michigan.gov sonneveldtd@michigan.gov
Counsel for Hemlock Semiconductor Corp. Jennifer Utter Heston	jheston@fraserlawfirm.com
Counsel for Environmental Law & Policy Center and Ecology Center Margrethe Kearney Robert Kelter	mkearney@elpc.org rkelter@elpc.org
Counsel for the Kroger Company Kurt J. Boehm Michael L. Kurtz Jody Kyler Cohn	KBoehm@BKLlawfirm.com mkurtz@BKLlawfirm.com JKylerCohn@BKLlawfirm.com

Counsel for Midland Cogeneration Venture, LP Richard Aaron Jason Hanselman John Janiszewski	raaron@dykema.com jhanselman@dykema.com jjaniszewski@dykema.com
Counsel for Energy Michigan, Inc. Timothy Lundgren Laura A. Chappelle Kimberly Champagne Alex Zakem Douglas Jester	tjlundgren@varnumlaw.com lachappelle@varnumlaw.com kjchampagne@varnumlaw.com ajz-consulting@comcast.net djester@5lakesenergy.com
Counsel for Department of Attorney General Celeste R. Gill	Gillc1@michigan.gov Ag-erna-spec-lit@michigan.gov
Counsel for ChargePoint, Inc. Justin Ooms Timothy Lundgren	jkooms@varnumlaw.com tjlundgren@varnumlaw.com
Counsel for Michigan Energy Innovation Business Council Toni L. Newell Timothy Lundgren	tlnewell@varnumlaw.com tjlundgren@varnumlaw.com
Counsel for Michigan State Utility Workers Council, UWUA, AFL-CIO John R. Canzano	jcanzano@michworkerlaw.com
Counsel for Residential Customer Group Don L. Keskey Brian W. Coyer	donkeskey@publiclawresourcecenter.com bwcoyer@publiclawresourcecenter.com
Counsel for Wal-Mart Stores, East, LP and Sam's East, Inc. Melissa M. Horne	mhorne@hcc-law.com
Counsel for Michigan Cable Telecommunications Association Michael S. Ashton	mashton@fraserlawfirm.com

Counsel for Association of Businesses Advocating Tariff Equity (ABATE) Bryan A. Brandenburg Michael J. Pattwell Jennifer M. Johnson Lauren K. Degnan Jeffrey C. Pollock Billie S. LaConte Kitty A. Turner	bbrandenburg@clarkhill.com mpattwell@clarkhill.com jmjohnson@ClarkHill.com LDegnan@ClarkHill.com Jcp@jpollockinc.com BSL@jpollockinc.com KAT@jpollockinc.com
Counsel for Michigan Environmental Council, Natural Resources Defense Council and Sierra Club Christopher M. Bzdok Tracy Jane Andrews Kimberly Flynn Karla Gerds	chris@envlaw.com tjandrews@envlaw.com kimberly@envlaw.com karla@envlaw.com

The statements above are true to the best of my knowledge, information and belief.

OLSON, BZDOK & HOWARD, P.C.
Counsel for MEC-NRDC & Sierra Club

Date: October 22, 2018

By: Breanna Thomas
cn=Breanna Thomas,
email=breanna@envlaw.com, c=US
2018.10.22 14:58:47 -04'00'

Kimberly Flynn, Legal Assistant
Karla Gerds, Legal Assistant
Breanna Thomas, Legal Assistant
420 E. Front St.
Traverse City, MI 49686
Phone: 231/946-0044
Email: kimberly@envlaw.com
karla@envlaw.com and
breanna@envlaw.com