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October 28, 2021

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

Re: **MPSC Case No. U-21090**

Dear Ms. Felice:

Attached for electronic filing in the above-referenced matter, please find the Testimony and Exhibits of Dr. Laura S. Sherman, Edward Burgess, and Sean Brady on behalf of The Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Clean Grid Alliance, and Proof of Service. Thank you for your assistance in this matter.

Very truly yours,
Laura A. Chappelle
Digitally signed by Laura A. Chappelle
Date: 2021.10.28 11:03:08 -04'00'
Laura A. Chappelle

LAC/srd
Enclosure
c. All parties of record.

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of CONSUMERS ENERGY COMPANY for approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	)))))	**Case No. U-21090**

TESTIMONY OF DR. LAURA S. SHERMAN

ON BEHALF OF

THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,

INSTITUTE FOR ENERGY INNOVATION,

AND

CLEAN GRID ALLIANCE

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I. INTRODUCTION AND QUALIFICATIONS

Q. State your name, business name and address.

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

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

A. I am appearing here as an expert witness on behalf of Michigan EIBC, IEI, and the Clean Grid Alliance ("CGA"), collectively referred to as "Michigan EIBC/IEI/CGA."

Q. Summarize your educational background.

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

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

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

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

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

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

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

Pricing Program case)/Case No. U-20851 (DTE Renewable Energy Plan case); and Case No. U-20693 (Consumers Energy general electric rate case).

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

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

In November 2020, with input from Michigan EIBC member companies, I provided comments in Commission Case No. U-20905 regarding the implementation of FERC Order 872 in Michigan.

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

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

A I have served as the President of Michigan EIBC and IEI since April 2019. Prior to that, from November 2017 through April 2019, I served as Vice President of Policy Development for Michigan EIBC and IEI. In these roles, I have led the trade organization's work on regulatory and legislative issues. As described above, I have participated in many workgroups at the Commission and written comments in a number of non-adjudicated cases. I also communicate formally and informally with Michigan EIBC member companies about each regulatory proceeding to understand how the advanced energy industry is affected by each proposed rule or case.

Q. What is the purpose of your testimony?

A. The purpose of my direct testimony is to describe, based on my experiences as the President of Michigan EIBC and IEI, as well as conversations with Michigan EIBC member companies, concerns related to the modeling of combined heat and power, as well as other concerns related to distributed generation, the Public Utility Regulatory Policies Act ("PURPA") Standard Offer Tariff, generation resource ownership, competitive procurement, power purchase agreement ("PPA") term lengths, and the financial compensation mechanism ("FCM").

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

- Exhibit EIB-1 (LSS-1): Résumé of Dr. Laura S. Sherman.
- Exhibit EIB-2 (LSS-2): Meegan Kelly and Jamie Scripps. 2020. Prepared by ICF for the State and Local Energy Efficiency Action Network. "Combined Heat and Power in Integrated Resource Planning: Examples and Planning Considerations."
- Exhibit EIB-3 (LSS-3): *CHP Roadmap for Michigan*. February 2018. Prepared for the Michigan Energy Office on behalf of the Michigan Agency for Energy and the U.S. Department of Energy.
- Exhibit EIB-4 (LSS-4): Caterpillar Press Release dated September 1, 2021. "Caterpillar to Offer Power Solutions Operating on 100% Hydrogen to Customers

in 2021."

- Exhibit EIB-5 (LSS-5): Discovery response 21090-MEIBC-CE-131.
- Exhibit EIB-6 (LSS-6): Discovery response 21090-MEIBC-CE-132.
- Exhibit EIB-7 (LSS-7): Legal memo from Varnum LLP regarding Distributed Generation and Electric Interconnection.
- Exhibit EIB-8 (LSS-8): Discovery response MEIBC-CE-143.
- Exhibit EIB-9 (LSS-9): Discovery response MEIBC-CE-143-Troyer_ATT_1.
- Exhibit EIB-10 (LSS-10): Discovery response MEIBC-CE-143-Troyer_ATT_2.
- Exhibit EIB-11 (LSS-11): Discovery response MEIBC-CE-140.
- Exhibit EIB-12 (LSS-12): Discovery response MEIBC-CE-141.
- Exhibit EIB-13 (LSS-13): Discovery response MEIBC-CE-145.
- Exhibit EIB-14 (LSS-14): Discovery response MEIBC-CE-147.

II. COMBINED HEAT AND POWER

Q. What are the benefits of considering combined heat and power ("CHP") in integrated resource planning?

A. CHP offers a number of important benefits as both a supply-side and demand-side resource in resource planning. One of the most important attributes of CHP is its efficiency. According to the U.S. Department of Energy, a properly designed CHP system will typically operate with an overall fuel use efficiency of 65 to 85%.[1] When electricity and

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[1] U.S. Department of Energy, Advanced Manufacturing Office. 2017. "Combined Heat and Power Technology Fact Sheet Series: Overview of CHP Technologies." Available at https://betterbuildingssolutioncenter.energy.gov/sites/default/files/attachments/CHP%20Overview-120817_compliant_0.pdf.

thermal energy are provided separately, overall fuel use energy efficiency ranges from 45 to 55%.[2] High-value applications of CHP can include: (1) providing efficient and reliable electricity and thermal energy to the industrial sector; (2) delivering resilient power to critical facilities; (3) supporting grid integration of renewable energy; and (4) providing an affordable, energy-efficient pathway to a lower carbon energy supply.[3] According to a recent report from the U.S. Department of Energy/U.S. Environmental Protection Agency's State and Local Energy Efficiency Action Network ("SEE Action") (Exhibit EIB-2, LSS-2),

> [when] developing plans for future resource options, utilities can gain value from evaluating CHP as a grid resource on the supply side, as an energy efficiency resource on the demand side, or as an overall resource solution.[4]

Whether CHP is utilized as a supply-side distributed energy resource ("DER") on the utility side of the meter, or as a demand-side DER on the customer side of the meter, it can bring numerous benefits to all users of the electric grid, which underscores the importance of thoroughly evaluating CHP in a utility IRP.[5]

Q. Are there federal and state policies that counsel toward the consideration of CHP?

A. Yes. A 10% federal investment tax credit ("ITC") is granted to an eligible property owner of a CHP system under section 48 of the Internal Revenue Code.[6] The eligibility of CHP for the ITC suggests that it is recognized as a beneficial energy solution and supported by

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[2] *Ibid.*
[3] Meegan Kelly and Jamie Scripps. 2020. Prepared by ICF for the State and Local Energy Efficiency Action Network. "Combined Heat and Power in Integrated Resource Planning: Examples and Planning Considerations." ("SEE Action")
[4] *Id.* p. 5.
[5] *Ibid.*
[6] U.S. Department of Treasury. Internal Revenue Service. Instructions for Form 3468. Available at https://www.irs.gov/pub/irs-pdf/i3468.pdf.

federal policymakers.

At the state level, the Michigan Energy Office has expressed support for the deployment and use of CHP in its *CHP Roadmap for Michigan*, a report published in 2018 (Exhibit EIB-2, LSS-2). According to the Michigan Office of Climate and Energy,

> [the] Combined Heat and Power (CHP) Roadmap for Michigan was a collaborative effort among state and regional partners to optimize CHP adoption based on significant stakeholder input. The overall project goal was to create a multifaceted, cohesive, replicable program to develop and deploy consensus based solutions for accelerating CHP deployment in Michigan.[7]

Notably, the *CHP Roadmap for Michigan* includes an express recommendation to require consideration of CHP in integrated resource planning as both a supply-side and demand-side resource.[8]

Also at the state level, the Council on Climate Solutions was created by Governor Whitmer's Executive Order 2020-182 and is tasked with formulating and overseeing the implementation of the MI Healthy Climate Plan, an action plan to reduce greenhouse gas ("GHG") emissions and transition the state's economy toward carbon neutrality. The industrial sector represents a significant source of GHG emissions – 23% of 2019 national GHG emissions according to the U.S. Environmental Protection Agency[9] – and is an important focus of the work of the Council on Climate Solutions. As explained in the SEE

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[7] Michigan Office of Climate and Energy. Combined Heat and Power (CHP) Roadmap. Available at https://www.michigan.gov/climateandenergy/0,4580,7-364-85453_85455_85516-540516--,00.html.

[8] Prepared for the Michigan Energy Office on behalf of the Michigan Agency for Energy and the U.S. Department of Energy. February 2018. "CHP Roadmap for Michigan." ("CHP Roadmap for Michigan"). p. 7.

[9] U.S. Environmental Protection Agency. Sources of Greenhouse Gas Emissions. Available at https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions.

Action report:

> The industrial sector consumes nearly one-third of all total energy consumption in the United States (EIA 2019a). For industrial customers with large continuous thermal loads and complex process integration, CHP is the most energy-efficient method of producing electricity and high-temperature steam that is required to drive many manufacturing processes. Support for CHP at industrial sites is often an important economic development tool for states and utilities to retain industrial companies and attract new manufacturers, while also supporting companies in achieving their resilience and sustainability goals.[10]

Hydrogen-fueled CHP systems may offer a particular opportunity to obtain significant benefits in a decarbonized industrial sector. For example, in September 2021, Michigan EIBC member-company Caterpillar announced it will begin offering:

> Cat® generator sets capable of operating on 100% hydrogen, including fully renewable green hydrogen, on a designed-to-order basis in the fourth quarter of 2021. Additionally, later this year Caterpillar will launch commercially available power generation solutions from 400 kW to 4.5 MW that can be configured to operate on natural gas blended with up to 25% hydrogen. (Exhibit EIB-4, LSS-4)

In failing to meaningfully evaluate CHP in its integrated resource plan, Consumers Energy is missing a significant opportunity to partner with and support Michigan's industrial sector in its efforts to decarbonize.

Q. Is the consideration of CHP in integrated resource planning required under Michigan law?

A. Yes. According to MCL 460.6t (5): "An integrated resource plan shall include all of the

[10] SEE Action, p. 9.

following … (g) Projected energy and capacity purchased or produced by the electric utility from a cogeneration resource."

Q. Has the Commission previously provided direction on the consideration of CHP in integrated resource planning?

A. Yes, the Commission has previously recognized the importance of meaningful evaluation of DG, such as CHP, in utility IRPs. Specifically, the Commission has previously rejected utility efforts to prematurely screen out DG, particularly customer-owned DG systems like CHP. In its February 20, 2020 Order in the most recent DTE IRP proceeding, Case No. U-20471, the Commission stated that:

> DTE Electric screened DG (including customer-owned solar and behind-the-meter CHP) out of its resource analysis for several reasons, including cost and the fact that DG is not dispatchable or schedulable.[11]

Subsequently, the Commission found

> that a DG analysis is imperative for IRPs. The Commission finds that the pace of changes in technology and customer behavior in this area demands that DTE Electric not screen out DG in its next IRP filing. The company's rationale that DG resources are not dispatchable or schedulable is unconvincing, as the same could be said for other elements of a modern electric grid. Similarly, its arguments over cost seem to ignore the investments customers have made in these systems, and focuses only on utility-owned DG resources. The Commission directs the company to fully analyze the effects of DG on the company's plan in its next IRP filing.[12]

Further, on October 13, 2021, Commission Chair Dan Scripps testified before the Michigan House Energy Committee that "we're in the process of updating our interconnection rules

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[11] Michigan Public Service Commission Order. February 20, 2020. Case No. U-20471. p. 61.
[12] *Id*., p. 62.

and removing barriers to distributed energy resources through the MI Power Grid initiative" and noted that:

> In 2012, in New York, the Superstorm Sandy that swept through took out essentially power to the entire city. But there was one location in the Bronx, Co-op City, that had a combined heat and power system installed in its residence, and that was the one beacon of light that you saw. So, looking at where we can look at distributed energy resources as a resilience play is also one of the priorities.[13]

The U.S. Department of Energy has echoed this support of CHP as a resilience resource, noting:

> When Superstorm Sandy made landfall on the eastern coast of the United States – New Jersey, New York and Connecticut were the most heavily hit areas. Extended power outages affected the region for days. However, some commercial and industrial facilities in the area were able to power through Superstorm Sandy due to onsite CHP.[14]

Q. What are best practices for utility consideration of CHP in integrated resource planning?

A. According to the *CHP Roadmap for Michigan*, Michigan has approximately 5 GW of CHP technical potential at more than 10,000 sites across 17 industrial and 24 commercial sectors.[15] Given this technical potential, a utility should "identify the portion of the CHP potential in their service territory that is optimal under various scenarios and in the context of the utility's complete resource portfolio."[16] As an alternative to other investments, the

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[13] Chair Dan Scripps of the Michigan Public Service Commission. October 13, 2021. Testimony before the House Energy Committee. Available at https://www.house.mi.gov/SharedVideo/PlayVideoArchive.html?video=ENER-101321.mp4.
[14] ICF on behalf of the U.S. Department of Energy. March 2013. *Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities*. Available at https://www.energy.gov/sites/prod/files/2013/11/f4/chp_critical_facilities.pdf. p.2.
[15] CHP Roadmap for Michigan. p. 9.
[16] SEE Action, p. 7.

utility can evaluate CHP as a resource on both the supply side and the demand side, potentially saving ratepayer dollars and supporting state and federal policies aimed at decarbonization.[17]

The *CHP Roadmap for Michigan* includes a recommendation to require utility IRPs to consider CHP as both a supply-side and demand-side resource.[18] According to the *CHP Roadmap for Michigan*,

> IRP analysis should incorporate CHP as both a supply and demand-side measure. On the supply side analysis, CHP would be included as another generation resource similar to combined cycle generation. Unlike combined cycle plants, CHP requires a host facility capable of using the thermal output. Relatedly, the value of this thermal load would need to be accounted for either through a credit or another mechanism to account for the total cost of CHP to the utility. Formally requiring Michigan utilities to assess CHP on both the supply-side and demand-side in an IRP would help ensure that these complicated projects are allotted equivalent analyses as other resources.[19]

Q. Please describe how Consumers Energy considered front-of-the-meter ("FTM") CHP in its proposed IRP.

A. Consumers Energy considered a single FTM CHP configuration during its initial screening phase. In its response to discovery question from Michigan EIBC/IEI/CGA (Exhibit EIB-5, LSS-5), which inquired about the Company's consideration of FTM CHP resources in its proposed IRP, witness Sara Walz stated that:

> As part of the initial screening process for prospective gas-fired generation technologies, a 2x1 Combined Heat and Power (CHP) Plant was

[17] *Ibid.*
[18] *Ibid.*
[19] *Id.* p. 94.

> investigated. The proposed CHP plant consists of two (2) GE LM6000 aeroderivative DLE (50) Spirit gas turbines with evaporative cooling and generators, two (2) – two pressure heat recovery steam generators, one (1) condensing steam turbine with high-pressure and low-pressure rotor sections and a generator, as well as a mechanical draft (wet) cooling tower. The proposed CHP plant is equipped with a high-pressure extraction and is capable of providing process steam with an energy flow of 65.79 MBtu/h. The plant's estimated summer time capacity is 114 MW, with a corresponding heat rate of 7,323 Btu/kWh. The 2021 overnight cost, in 2017 real dollars, is $1,507/kW.

Q. Was the single FTM configuration described above selected in the initial screening phase?

A. No. According to witness Walz (Exhibit EIB-5, LSS-5), "The CHP technologies were not selected in the initial screening phase."

Q. Please describe how Consumers Energy considered behind-the-meter ("BTM") CHP in its proposed IRP.

A. In its response to a discovery question from Michigan EIBC/IEI/CGA (Exhibit EIB-6, LSS-6), which inquired about the Company's consideration of BTM CHP resources in its proposed IRP, witness Walz stated that "No behind-the-meter combined heat and power options were considered in the IRP model."

Q. Did Consumers Energy adhere to best practices in its consideration of CHP in its proposed IRP?

A. No. Best practices recommend that CHP be evaluated as both a supply-side and demand-side resource. Here, the Company only looked at one FTM/supply-side configuration and did not consider CHP as a BTM/demand-side resource at all. Consumers Energy did not identify the portion of the CHP potential in their service territory that is optimal under various scenarios and in the context of the utility's complete resource portfolio. In failing to meaningfully evaluate CHP in its IRP, the Company missed the opportunity to potentially save ratepayer dollars and support state and federal policies aimed at decarbonization.

Q. What is the harm in not giving CHP adequate consideration in integrated resource planning?

A. According to the *CHP Roadmap for Michigan*:

> Michigan has the opportunity to capture enormous benefits by embracing optimal levels of combined heat and power (CHP) generation in its future energy mix. CHP provides a path to make Michigan businesses more competitive by lowering and stabilizing energy costs, reducing strain on the electric grid, improving on-site reliability and resiliency, and lowering harmful greenhouse gas emissions. Yet many studies have shown that CHP is a vastly underutilized energy resource across the country due to a combination of policy barriers, market impediments, and other factors.[20]

A failure to meaningfully evaluate CHP in an IRP, both as a supply-side and demand-side resource, is an example of such a barrier. In the words of the *CHP Roadmap for Michigan*:

> Regulatory barriers can dramatically affect a CHP project's bottom line and projected payback period. An overarching barrier that affects the valuation of CHP throughout regulatory and policy discussions stems from the failure to account for the full value of CHP, including qualities such as resilience. Ignoring gridwide and societal benefits affects how CHP is portrayed in standby rates, avoided cost rates, energy waste reduction standards and integrated resource planning.[21]

Q. What would you propose the Commission Order with respect to CHP?

[20] *Id*. p. 7.
[21] *Id.* p. 12.

A. Consumers Energy should be directed to amend its IRP to include a meaningful evaluation of CHP as both a supply-side and demand-side resource. Ideally, the Company would evaluate more than one configuration, taking into account customer interest in deployment and the technical potential for CHP in its territory.

III. DISTRIBUTED ENERGY RESOURCE ISSUES

Q. Did the Company consider whether other distributed energy resources ("DERs") could meet its resource needs in this IRP?

A. To some degree. However, in a similar manner to BTM CHP, other customer-sited DERs and DG resources were treated only in a limited manner and only as potential load reduction in the IRP. Specifically, according to witness Walz:

> Behind-the-meter generation is supply sources at customer locations. Since these are such small sources of electric supply, and since they are behind the meter and not accounted for on the utility distribution or transmission systems, the energy is modeled as a *reduction in load* instead of a supply resource.[22]

This decision is similarly described in several places in the Company's 2021 IRP Plan (Company Exhibit A-2):

> In other words, although the load forecast does not include an explicit adjustment for customer-owned generation, existing sources of customer-owned generation are implicitly included because of the impact to historical load information.[23]

During the Aurora modeling, according to witness Walz:

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[22] Direct Testimony of Sara T. Walz, on behalf of Consumers Energy Company. Case No. U-21090 ("Walz Direct"). pp. 19-20.
[23] Company Exhibit A-2. p. 94.

> Behind-the-meter-generation was included in sensitivity analysis, but not as a resource available for *selection*. Therefore, BTMG is not included in Exhibit A-13 (STW-10). Instead, BTMG was a "locked in" resource in specific sensitivities to understand which resources would be "kicked out" of selection. Generally, the customer-owned solar programs tend to reduce the amount of transmission- or distribution-connected solar resources, or battery storage resources.[24]

Again, this was similarly echoed in the Company's 2021 IRP Plan (Company Exhibit A-2):

> In addition to the above programs, the company continues to benchmark with other utilities and industry groups to learn best practices and trends for distributed generation resources. Distributed generation resources were not included within Aurora as an option the model could select, but the company will continue to monitor and understand trends and adoption rates of distributed generation resources in future planning processes.[25]

Q. Do these decisions reflect previous Commission Orders?

A. No. As described above, the Commission has previously recognized the importance of meaningful evaluation DERs and DG in utility IRPs. As noted above, in its Order in Case No. U-20471, the Commission found

> that a DG analysis is imperative for IRPs. The Commission finds that the pace of changes in technology and customer behavior in this area demands that DTE Electric not screen out DG in its next IRP filing. The company's rationale that DG resources are not dispatchable or schedulable is unconvincing, as the same could be said for other elements of a modern electric grid. Similarly, its arguments over cost seem to ignore the investments customers have made in these systems, and focuses only on utility-owned DG resources. The Commission directs the company to fully analyze the effects of DG on the company's plan in its next IRP filing.[26]

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[24] Walz Direct. pp. 64-65.
[25] Company Exhibit A-2. p. 138.
[26] *Id*., p. 62.

Q. Does the Company's decision to treat DERs only as load reduction match with "best practices" among utilities?

A. No. Leading utilities are successfully using DER forecasting and finding that these resources can meet significant portions of future capacity needs. For example, in their 2021 Distribution System Plan, Portland General Electric ("PGE") developed a new model, called AdopDER, "to conduct bottom-up DER forecasting and assess DER potential at the system- and locational-level."[27] Using this model, PGE found that: "It is estimated that as much as 25% of flexibility could come from customers and distributed energy resources (DERs)."[28]

Q. Did limits on participation in the current DG program impact the Company's decision not to model DG as a generation resource?

A. The Company does not specifically reference the current statutory "soft caps" as the reason it chose not to model DG as a generation resource. Additionally, as described further below, customers should be able to access the distribution system with DG resources outside of the DG program in the future, should those participation caps be reached.

Q. How is participation in the current distributed generation program limited?

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[27] Portland General Electric. October 2021. "Distribution System Plan Part 1." Available at https://assets.ctfassets.net/416ywc1laqmd/6s2YaxlzY90LeSQS8thjCi/f1eda0a03219212876ad4a3ac0d08f54/PGE_DSP_2021_Report_101421.pdf. p. 100.

[28] *Id.* p. 9.

A. Participation in the distributed generation program is limited by statutory "soft caps." The caps for the DG program were established in 2008 in PA 295 and were retained in Section 173(3) of PA 342 of 2016, which provides that:

> (3) An electric utility or alternative electric supplier is not required to allow for a distributed generation program that is greater than 1% of its average in-state peak load for the preceding 5 calendar years. The electric utility or alternative electric supplier shall notify the commission if its distributed generation program reaches the 1% limit under this subsection. The 1% limit under this subsection shall be allocated as follows:
>
> > (a) No more than 0.5% for customers with an eligible electric generator capable of generating 20 kilowatts or less.
> >
> > (b) No more than 0.25% for customers with an eligible electric generator capable of generating more than 20 kilowatts but not more than 150 kilowatts.
> >
> > (c) No more than 0.25% for customers with a methane digester capable of generating more than 150 kilowatts.

There is no statutory prohibition of, nor is there a requirement for, a utility to increase the size of its DG program above 1% of its average in-state peak load for the preceding 5 calendar years. In addition, there is no statutory prohibition on a utility simply allowing customers to continue to participate in the DG program once the utility reaches its cap. As a result of this relatively arbitrary statutory framework, the growth of DG in Michigan is left largely to the discretion of the utilities, rather than the customer and the market at large.

Q. Why were these caps established?

A. I was not yet working in my current role or in Michigan during the efforts to craft the 2008 or 2016 energy laws. However, in my current capacity, I have had a number of conversations with stakeholders who were present during those negotiations. Based on those conversations, it is my understanding that the caps for the DG program was established in 2008 as part of PA 295 in combination with the initial institution of net metering in the state. At that time, Michigan did not have any experience with net metering, and it was unclear how the policy would affect uptake of solar PV systems, the grid, and utility revenue streams. I believe that there were two primary reasons that legislators determined that it was prudent to establish a cap on the net metering program: 1) to protect the distribution system in case DG systems caused any system reliability issues and 2) to protect customers without DG systems in case net metering caused cross-subsidization or cost-shifting. Subsequently, the 2016 energy laws ended net metering in favor of a cost-of-service based DG tariff.

Q. Have either of these concerns been born out?

A. No, not to my knowledge. To my knowledge, in previous general electric rate cases, the Company has not raised concerns regarding reliability of the distribution system related to DG systems. This is likely because the interconnection process governs the interconnection of any electric generator to the distribution grid and requires each utility to carefully assess the safety and integrity of the grid before approving an application. For example, if solar DG installations in a given neighborhood were reaching a point of overloading a local circuit, the utility would identify those issues during the interconnection application process. If those increasing installations mean that grid upgrades are needed before the *nth* rooftop solar system can be installed safely, that *nth* customer is required to pay for the upgrades or is not allowed to interconnect their system to the grid. By definition, other ratepayers do not pay for these upgrades. Instead, that individual person must decide how to proceed and must pay the costs of any necessary upgrades to maintain the safety and reliability of the grid.

To the second concern, as required by Section 6a(14) of 2016 PA 341, MCL 460.6a(14), the new DG tariff methodology established in Case No. U-18383 must reflect the "equitable cost of service" as determined by the Commission. As Mike Byrne, COO of the Commission, testified to the Senate Energy and Technology Committee in 2020,[29] under the new DG tariff as it is being implemented, there is no subsidy provided by non-solar customers to customers with solar in the DG program.

Q. What was agreed to regarding Consumer's distributed generation program in the 2018 IRP case?

A. In the Settlement Agreement of the 2018 Consumers IRP case (U-20165),[30] the parties agreed that the Company's next IRP would include "[consideration] of a distributed generation program, similar to Staff's Customer Distributed Generation Program proposed by Staff witness Meredith A. Hadala in this case."[31]

Q. Was Michigan EIBC/IEI a party to that Settlement Agreement?

A. Yes. Michigan EIBC/IEI was an intervening party in the 2018 Consumers IRP case and signed a statement of non-objection to the Settlement Agreement.

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[29] Testimony from Mike Byrne to the Senate Energy and Technology Committee on March 3, 2020. Committee webcast available at https://misenate.viebit.com/player.php?hash=Kz6rCPeWYHgu.

[30] Michigan Public Service Commission Order Approving Settlement Agreement. Case No. U-20165. June 7, 2019 ("Consumers' 2018 IRP Settlement").

[31] *Id,* p. 11.

Q. Please describe the "Customer Distributed Generation (CDG)" program proposed by Staff witness Hadala in the 2018 Consumers IRP case.

A. In witness Hadala's direct testimony in the 2018 Consumers IRP case, she recommended

> a Customer Distributed Generation Program for inclusion in the Company's IRP. The program size would be based on 2% of future competitive solicitations where eligible projects would be located at a customer site and limited in size to 550kWac. The price paid under the program would be initially set at the avoided cost established in the most recent competitive solicitation. A reverse auction framework, if necessary, would be used to allocate the capacity up to a maximum amount limited to 150% of the avoided cost. Any unfilled program capacity would be rolled into a future competitive solicitation. The contracts would be structured as buy-all, sell-all and will have a term of up to 20 years.[32]

Q. Does the Company propose such a Customer Distributed Generation Program in this IRP?

A. No, the Company does not propose any such program that would reserve a portion of future competitive solicitations for eligible DG projects up to 550 kWac in size.

Q. Why does the Company not include such a proposal?

A. According to Company witness Troyer's direct testimony, the Company did not include such a proposal because the Company voluntarily increased its total DG program cap from 1% of its average in-state peak load for the preceding 5 calendar years to 2% of its average

[32] Direct testimony of Meredeth A. Hadala, on behalf of Michigan Public Service Commission. Case No. U-20165. pp. 5-6.

in-state peak load for the preceding 5 calendar years, there is "sufficient access to rooftop solar for Consumers' customers."[33]

Q. Do you agree with witness Troyer that increasing Consumers' DG program cap to 2% provides sufficient access to rooftop solar?

A. No, not entirely. I agree that in the short-term, increasing the DG program cap to 2% provides the ability for more customers to install rooftop solar and interconnect to the grid. However, as further detailed below, based data provided by Consumers, I do not believe that this program cap increase will provide "sufficient access to rooftop solar for Consumers' customers" over the long-term.

Q. Why did the Company increase the size of its DG program?

A. According to witness Troyer, "[in] an effort to expand customer access to rooftop solar until an alternative compensation methodology is established, the Company voluntarily doubled its distributed generation program's cap to 2% of average peak load on January 1, 2021."[34]

Q. Do you agree that the Company abided by the 2018 IRP Settlement by considering Staff's DG proposal?

A. No, not entirely. The Company did double the DG program cap to 2% and this did enable an increase in customer access to rooftop solar. However, Staff's proposal as included in

[33] Direct Testimony of Keith G. Troyer, on behalf of Consumers Energy Company. Case No. U-21090 ("Troyer Direct"). pp. 11-13.
[34] Troyer Direct. p. 12.

the Consumers' 2018 IRP Settlement required more than simply increasing the DG program cap. In this regard, it is not clear how, or to what extent, the Company truly considered Staff's proposal. Moreover, it is important to note that although witness Troyer implies that the compensation methodology which existed at the time the program cap was increased was not ideal, in fact, the increase in the cap occurred *only after* approval by the Commission of the exact compensation methodology proposed by the Company in Case No. U-20697.

As required by PA 341 of 2016[35] and the subsequent Commission Order in Case No. U-18383, Michigan's utilities were required to file new proposed DG tariffs based on the Inflow/Outflow tariff but were also allowed to file an alternative DG tariff.[36] In its most recent general electric rate case (Case No. U-20697), Consumers Energy declined to file an alternative DG tariff and instead filed an Inflow/Outflow tariff. This filed Inflow/Outflow DG tariff was very similar to that approved for DTE Energy wherein inflow costs were set at the full retail rate and outflow credits set at power supply less transmission.

It is important to note, as described in the letter from the Company to the Commission, that Consumers conditioned the voluntary increase in the DG program cap to 2% upon its "review of the Distributed Generation tariff" approved in Case No. U-20697.[37] Although not explicitly stated in the letter filed on November 19, 2020, this language could be

[35] MCL 460.6a(14).
[36] Commission Order in Case No. U-18383. April 18, 2018. p. 18.
[37] Consumers Energy Company's Letter Regarding Net Metering Program. November 19, 2020. Case No. U-15787.

interpreted to mean that the Company was conditioning the voluntary increase in the DG program cap upon approval of the DG tariff proposed by the Company in the then ongoing general electric rate case. In contrast to witness Troyer's direct testimony in the current case, the Company stated in its Initial Brief in Case No. U-20697 that:

> the Inflow/Outflow method will hold a DG customer accountable for their use of the grid by billing the DG customer the normal production and delivery charges for the power they take from the grid and fairly compensating the DG customer for the power they produce and put back on the grid.[38]

Q. Is there any requirement under Michigan law that a utility allow a customer to interconnect a solar DG system with the grid if the cap is reached?

A. No, there are no Michigan laws requiring interconnection of small solar systems, although federal law (e.g., PURPA[39]) may provide such a requirement. As detailed in a legal memo written by Varnum LLP (Exhibit EIB-7 (LSS-7)):

> Our analysis found that there are no state statutes in Michigan which specifically require investor-owned utilities to interconnect residential and small commercial solar systems (<100 kW) to the utility grid once the distributed generation cap for that utility is reached. Interconnection of these systems may be required under federal law (i.e., PURPA), but this has not yet been legally tested in Michigan, as no [Commission] complaint case has been brought by a customer denied interconnection (e.g., in UPPCO's territory after the initial residential solar cap was reached in 2016).

Q. Prior to the cap increase, what happened to customers who wanted to install rooftop solar in Consumers' territory after the initial Category 1 and Category 2 caps were reached in November 2020?

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[38] Consumers Energy Initial Brief. Case No. U-20697. p. 481.

[39] Public Utility Regulatory Policies Act ("PURPA"), Pub L. No. 95-617, 92 Stat. 3117.

A. As of November 19, 2020, Consumers Energy stopped accepting new applications for the net metering program and began putting all customers who applied for the new DG program on a waiting list. According to Consumers Energy, that waiting list was maintained until the DG tariff proposed by the Company was approved in Case No. U-20697 and, subsequently, the Company increased the DG program size to 2% (Exhibit EIB-8, LSS-8). Applications were then processed from the waiting list for the DG program.

Q. Were customers provided with any alternatives to joining the waiting list for the DG program?

A. Theoretically, yes. However, in practice, customers do not appear to have been provided with information to allow them to access the existing alternative options and those existing options are far more onerous for residential/small business customers. Specifically, outside of the DG program, customers are technically able to execute PURPA Standard Offer Contracts under Rule C18[40] or "energy-only" contracts under Rule C11.1[41] (as detailed in EIB-8, LSS-8). However, in practice, this option was not explained to customers or installers in any of the materials distributed by the Company. In a letter sent to solar installers (EIB-9, LSS-9), the Company indicated that:

> All applications received after Nov. 19, 2020, will be reviewed and considered for the DG program if and when space becomes available. In the interim, customers can continue to apply to and receive permission to interconnect their solar systems regardless of program availability or participation. Customers can apply for the DG program via PowerClerk at https://consumersenergy.powerclerk.com.

[40] Consumers Energy Company Rate Book for Electric Service. No. 14. Issued December 13, 2019.
[41] *Ibid.*

Similarly, as shown in EIB-10, LSS-10, customers who applied to the program after November 19, 2020, were told that the net metering program was closed and that their application would be reviewed and considered after January 1, 2021.

It is contradictory to simultaneously state that all applicants to the DG program will be put on a waiting list, while also indicating that customers can continue to apply and receive permission to interconnect through the DG program. If, instead, Consumers meant to give customers the option of signing a PURPA Standard Offer Contract or "energy-only" contract, those processes should have been explained clearly to customers. However, none of these communications included instructions to customers regarding the steps required to sign a PURPA Standard Offer Contract or energy-only contract with the Company.

It is not simple or trivial for a residential or small business customer to navigate the process to sign a PURPA Standard Offer Contract or an "energy-only" contract. Neither of these processes is a simple, customer-friendly process with a single online application and low one-time fee – as is the case for the DG program. In addition, customers may be concerned about the implications and legal liability associated with signing a contract with a large utility company. The DG program does not require such a legal contract and, although this may be commonplace and not concerning for the Company, this is not an insignificant hurdle or concern for a residential ratepayer.

Q. Have any customers sought to sign a PURPA Standard Offer Contract with the Company for a distributed solar project less than 150 kW in size?

A. According to witness Troyer,

> since the Commission's approval of the IRP Settlement Agreement, the Company has neither (i) executed any Standard Offer Contracts with QFs up to 150 kW in size, nor (ii) been contacted by a generator up to 150 kW in size claiming to be a QF or asking for a PURPA-based PPA.[42]

This is not surprising, given the complexities associated with signing a contract with the Company and that all readily available information on the Company's website and in the Company's communications with customers (as provided in Exhibits EIB-8, LSS-8; EIB-9, LSS-9; and EIB-10, LSS-10) focuses on the DG program and provides no information for customers regarding the process to become a QF or execute a Standard Offer Contract with the Company. Customers who install solar systems less than 150 kW are homeowners, farmers, and small business owners. Typically, they choose to add solar to reduce their electricity bills, increase resiliency, and reduce carbon emissions. Most of these customers are not well-versed in energy policy and, without guidance from their utility, almost none (if any) would be able to navigate the Company's rate book to determine that there was an option outside of the DG program, let alone be able to undertake the steps necessary to execute a contract through one of those alternative options.

Overall, these numerous hinderances to customers certainly contradict the Company's position that simply raising the DG program cap to 2% allows for "sufficient access to rooftop solar for Consumers' customers."

Q. When does the Company predict that it will reach the new DG caps?

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[42] Troyer Direct. p. 20.

A. According to witness Troyer, the Company's internal forecast projects that both the Category 1 (1%, <20kW) cap (EIB-11, LSS-11) and the Category 2 (0.5%, 20-150kW) cap (EIB-12, LSS-12) will be reached in 2023.

Q. Do you agree with this prediction?

A. Yes. Based on data provided by Consumers Energy in this case and previously to the Commission, assuming that the growth rate of Category 1 and Category 2 installations continue at the same rate as observed in 2021 (after the institution of the DG tariff), I agree that the caps will be reached in 2023, prior to the expected filing of the Company's next IRP in 2024.

Q. What will happen when the new Category 1 and Category 2 caps are reached?

A. In my opinion, based on the Company's previous actions and statements, it is most likely that when the new Category 1 and 2 caps are reached, the Company will place customers on an indefinite waiting list for the DG program without providing adequate information regarding the other available options and without making those other options actually feasible for customers.

When the new Category 1 and Category 2 caps are reached, customers would still technically be able to secure either a PURPA Standard Offer Contract under Rule 18 or an "energy-only" contract under Rule C11.1 outside of the DG program. However, that will depend on the Commission's Order in this case. Specifically, Consumers Energy proposes in this case to remove the requirement that the Company pay full avoided cost rates to QFs 150 kW and below. Witness Troyer argues that:

> since the Company is using a competitive solicitation approach, in which QFs sized 150 kW or less are able to participate, for acquiring the Company's full capacity needs, there is no basis to require the Company to pay full avoided cost rates (which include a capacity component) to QFs 150 kW and below.[43]

Additionally, as described above, when the caps were reached in November 2020, the Company did not communicate the existence of these options to customers or installers. In addition, witness Troyer stated in a discovery response that "it is premature to state how Consumers Energy will communicate options when the new 2% cap is reached" (EIB-8, LSS-8).

Q. To your knowledge, have QFs sized 150 kW or less participated in Consumers Energy's competitive solicitations?

A. No, nor would it, in all likelihood, be feasible for them to do so. According to witness Troyer in a discovery response (EIB-13, LSS-13), there was one contract awarded as part of the 2019 and 2020 IRP solicitations that may be a QF, but it is a 30 MW project, and there are 10 MW remaining from the 2019 solicitation that were offered to PURPA QFs. Additionally, witness Troyer describes that:

> since the Commission's approval of the IRP Settlement Agreement, the Company has neither (i) executed any Standard Offer Contracts with QFs up to 150 kW in size, nor (ii) been contacted by a generator up to 150 kW in size claiming to be a QF or asking for a PURPA-based PPA.[44]

[43] Troyer Direct. p. 20.
[44] *Ibid.*

This makes sense both because the Company does not advertise this option to small solar customers and because, in general, homeowners, farmers, and small business owners generally do not have the technical energy knowledge, time, or financial ability to navigate the complicated competitive bidding process. For the 2019 Request For Proposals ("RFP"), for example, in order to submit a bid, each respondent had to be pre-qualified by submitting a Notice of Intent Package, non-refundable application fees, Credit Pre-Qualification Applications, and a refundable pre-bid security of $1500/MW. It is not plausible to suggest that a homeowner with a 10 kW rooftop solar system, or a farmer with a 100 kW solar system on their barn, would be able to successfully meet even these pre-qualification requirements, let alone then subsequently successfully submit a bid for a solar system less than 150kW in size for consideration.

It is contradictory to argue that customers with solar systems less than 150 kW in size have adequate access through the competitive bidding process, while also arguing that because no such small solar systems have participated in the competitive bidding process or sought PURPA Standard Offer Contracts, the option to receive full avoided cost rates for QFs less than 150 kW in size should be rescinded.

Q. What do you propose the Commission should order with respect to these DG issues?

A. Given that the Company is likely to reach the Category 1 and Category 2 caps sometime in 2023, the Commission should urge Consumers Energy to allow customers to participate in the DG program above and beyond the caps, without capacity limitations.

The Company should also be required to retain the PURPA Standard Offer Contract at full avoided cost rates as an option for these customers. However, the Commission should explore whether there may be ways to enable customers to access this option without the complexities and liabilities associated with signing a contract with the utility.

If the Company does not voluntarily lift the Category 1 and 2 caps, unless the caps are eliminated statutorily, alternative options for small DG systems need to be available, accessible, and communicated to customers both by the Company and by the Commission. At the very least, the Commission should require the Company to clearly communicate to installers and customers all available options to interconnect DG systems once the caps are reached. These communications should include clear steps to access those options, as an alternative or in addition to being placed on a waiting list. The Commission should also consider how it can best provide improved transparency and options on its website in addition to other manners of communication in order to ensure that customers are aware of their full legally available options once Consumers' DG caps are again reached.

Finally, given growth in customer interest in DERs generally and DG systems specifically, the Company should be required to model customer-sited DERs both as potential load reduction and generation resources in their next IRP.

IV. PURPA

Q. What does the Company propose to change with respect to its Standard Offer Tariff?

A. As described by witness Troyer, the Company proposes to reduce the size of its Standard Offer Contract from 2 MW to 100 kW.

Q. What did the Commission order regarding Standard Offer Tariffs in U-20905 *et al.*?

A. In the January 21, 2021, Order in U-20905 *et al.*, the Commission stated that

> the Commission agrees that the Staff's recommendation to set the standard offer cap at 5 MW may be a viable option given the lowering of the presumption of non-discriminatory market access from 20 MW to 5 MW. Therefore, should a utility receive authorization from FERC to terminate its obligation to purchase from QFs above 5 MW, the Commission directs the utility, in its next avoided cost review that follows the termination, to explain and support its position on the standard offer cap. Should a utility not propose a standard offer cap being set at 5 MW, it should provide a rationale as to why such a standard offer cap is not appropriate.[45]

Q. Has Consumers complied with this Order?

A. Partly. Since the filing of the Company's 2021 IRP, the Company has received authorization from the Federal Energy Regulatory Commission ("FERC") to terminate its obligation to purchase from QFs in excess of 5 MW.[46] The Commission, though, was arguably aware of the Company's FERC filing and can be assumed to have believed that the filing would be granted. The implication of the Commission's Order in U-20905 *et al.*, if not the direct wording of the Order, is that in the case that a utility has been granted authorization to lower its presumption of non-discriminatory market access from 20 MW to 5 MW, that same utility should propose a Standard Offer cap of 5 MW. Similarly, the Commission suggests that if a utility does not do so, it should provide sufficient rationale to support the decision not to set the Standard Offer cap at 5 MW. Not only does Consumers

[45] Commission Order in Case No. U-20905 *et al*. January 21, 2021. p. 26.
[46] Consumers Energy Company, 176 FERC ¶ 61,156 (September 10, 2021).

not propose in this case to set their Standard Offer Tariff at 5 MW, but also, they propose to significantly lower their Standard Offer Tariff from 2 MW to 100 kW. Although witness Troyer does provide three reasons to support Consumer's proposal, these are not sufficient or adequate to support such a change, especially given the Commission's stated preference that the Standard Offer Tariff be set at 5 MW.

Q. What reasons does the Company provide to support this proposed change?

A. Witness Troyer provides three reasons in his direct testimony.[47] First, he states that a Standard Offer Program for QFs up to 100 kW in size would be consistent with FERC's PURPA regulations. Second, he states that "[the] majority of requests for Standard Offer PPAs come from large sophisticated solar project developers and, based on the Company's experience, these developers have or are in the process of developing larger solar projects at or above 5 MW." Third, he argues that FERC Order 2222 will allow participation in the wholesale market for DERs that are 100 kW and larger.

Q. What concerns do you have with these arguments?

A. The argument that the majority of requests for Standard Offer Contracts come from what the utility has termed "large sophisticated solar project developers" is misplaced and irrelevant. The process of negotiating a non-standard contract with the utility is time-consuming, labor-intensive, and costly. Smaller projects, due to economies of scale, often have higher inherent per MW costs than larger projects. This is true no matter who the developer of the project is. It is therefore incorrect to assume that a solar project developer

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[47] Troyer Direct. pp. 22-23.

who has at one point developed or is currently developing a project larger in size than 5 MW should therefore somehow be ineligible for a Standard Offer Contract.

In addition, although FERC Order 2222 will eventually allow participation in the wholesale market for DERs, the Midcontinent Independent System Operator's ("MISO") initial compliance filing is not expected until April 2022 and will likely not be finalized for a year or more after that. After these rules are established, the Commission will need to establish appropriate interconnection processes and other regulations to ensure appropriate implementation. As a result, it will likely be multiple years before DERs 100 kW and larger in Michigan can participate in wholesale markets. These changes, therefore, are not relevant to this IRP and could be addressed, if they are warranted, in the Company's next IRP filing.

Q. What do you propose that the Commission should order with respect to the PURPA Standard Offer Tariff size?

A. Given the Commission's Order in U-20905 *et al.* and the lack of adequate rationale provided by the Company to lower its Standard Offer Tariff size, I would recommend that the Company's Standard Offer Tariff be set at 5 MW.

V. OWNERSHIP ISSUES

Q. Please describe the "50/50 split."

A. In Public Act 295 of 2008 (2008 PA 295, MCL 460.1001, *et seq.*), there was a provision commonly referred to as the "50/50 split,"[48] which required utilities to purchase a minimum 50% of the renewable energy required to meet the Renewable Portfolio Standard from third-party developers using PPAs. The remaining 50% could be met using Company-owned resources. This provision was removed with the passage of Public Act 342 in 2016.

Q. Have there been subsequent decisions related to this "50/50 split" in recent cases before the Commission?

A. Yes. In the last Consumers IRP case (Case No. U-20165), the parties reached a settlement agreement which included, at the request of Michigan EIBC/IEI, a provision requiring that:

> … new capacity that the Company intends to procure through the PCA, in each annual solicitation, shall be: (i) acquired through a competitive bidding process; and (ii) 50% will be from PPAs and 50% will be owned by the Company, as acquired through a competitive bidding process. The Company, at its sole discretion, may choose to acquire more than 50% of its new capacity from PPAs. The parties further agree that the Company's affiliates will be prohibited from bidding on the portion of the Company's new capacity acquired from PPAs.[49]

It is important to note that this 50/50 split agreed to in the 2018 IRP Settlement Agreement did not apply to any other procurement processes conducted by the Company and did not include consideration of any PURPA PPAs.

Separately, in the DTE Renewable Energy Plan Case (Case No. U-18232), the Commission noted in their Order on July 18, 2019 that DTE Electric misinterpreted the removal by

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[48] *See* Sec. 33(1)(b); MCL 460.1033(1)(b).

[49] Consumers' 2018 IRP Settlement Agreement in Case No. U-20165. Filed March 23, 2019. pp. 8-9.

Public Act 342 of the Public Act 295 provision that no more than 50% of an electric provider's RECs could come from renewable generation owned by the electric provider to mean that "the company has 'unfettered discretion to choose to pursue only company-owned renewable generation.'"[50]

Q. What changes does the Company propose in this IRP with respect to ownership of future generation assets?

A. In this IRP, the Company proposes to own *at least* 50% of the new generation capacity procured through the IRP. This means that the Company could own up to 100% of the new generation capacity procured through the IRP.

Q. Are you concerned with this proposal?

A. Yes, I am very concerned with this proposal. There are strong existing financial incentives for a utility like Consumers Energy to own all of the facilities from which the utility obtains electricity instead of contracting for energy and capacity using PPAs. This can create a situation where an investor-owned utility is strongly incentivized to avoid projects other than those that they build themselves or purchase from a developer after construction is complete. A financial compensation mechanism ("FCM") combined with a requirement to acquire a certain percentage of renewable generation (e.g., 50%) from PPAs can help address this existing ownership bias. If the proposal by Consumers to own *at least* 50% of the renewable energy procured through this IRP is accepted, I am concerned that this will lead to Company ownership of almost all, if not all, of the future resources procured under

[50] Commission Order in Case No. U-18232. July 18, 2019. p. 9.

this IRP. Furthermore, if this proposal were to be approved, it would contradict and regress from the 50/50 split mechanism agreed to in Case No. U-20165.

Q. Why is it necessary for Consumers Energy to procure both PPAs and company-owned assets?

A. One essential role of the Commission is to determine whether utility proposals are "reasonable and prudent" and whether an IRP's Proposed Course of Action ("PCA") represents the most cost-effective choice for meeting the utility's capacity needs. In previous cases and solicitations including the 2019 and 2020 IRP solicitations, it has been shown that PPAs including the FCM are cost-competitive with or cheaper than Company-owned build-transfer agreement ("BTA") projects. As noted by the Commission in Case No. U-18232, previous Commission reports have shown that

> . . . since 2009, 'for each year in which there were both company-owned projects and purchased power agreements, the weighted average cost of the purchased power agreements was lower than the company-owned projects in that respective year.' MPSC, *Report on the Implementation and Cost Effectiveness of the PA 295 Renewable Energy Standard*, February 15, 2017, p. 19.[51]

Staff witness Meredith A. Hadala similarly noted in direct testimony in Case No. 20984 that:

> PPAs could provide [Voluntary Green Pricing] VGP subscribers with a lower cost option for solar assets. For example, earlier this year, the Commission approved applications requesting approval of solar contracts resulting from the 2019 [IRP] competitive solicitation. The average PPA and financial compensation mechanism (FCM) cost for the 25-year 140 MW Calhoun Solar Energy project is $57.73/MWh.[1] The company-owned BTA for the 150 MW Mustang Mile Solar project has a 25-year average

[51] *Id.*, p. 23.

> cost of $66.51/MWh.[2] In this instance, the PPA with FCM is 13% less costly than the company-owned BTA. The Calhoun Solar Energy and Mustang Mile projects have expected commercial operation dates of 2022 and 2023, respectively. If the Company were to utilize PPAs, it could result in lower costs to VGP customers when compared to the Company's proposal to utilize only company-owned BTAs.[52]

Q. Are there differences in oversight or obligations to communities between Company-owned assets and PPA assets?

A. To my knowledge, there are no material differences. Based on my conversations with Michigan EIBC member companies and experience with the MPSC, witness Troyer's claims in his direct testimony that there are differences in oversight and obligation to care for communities between Company-owned and PPA projects are not accurate.[53] To my knowledge, based on information provided by the Company, of the projects awarded contracts as a result of the 2019 and 2020 RFPs, none of the Company-owned projects were actually developed and built by Consumers Energy. Instead, those projects were developed and constructed by a third-party developer and then ownership was transferred to the Company under a BTA. A given third-party developer may focus on PPA arrangements, BTA arrangements, or may enter into both types of agreements. There is no inherent difference in the types or nature of the parties developing these projects that is dependent upon the final owner of the projects.

Similarly, there are no differences in the regulations from the MPSC or local permitting requirements for PPA projects compared to BTA projects. All of these projects must meet

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[52] Direct Testimony of Meredith A. Hadala, on behalf of the Michigan Public Service Commission. Case No. U-20984. p. 6, citing MPSC Case No. U-20165, Application dated February 12, 2021, Exhibit A-2 (footnote 1) and Exhibit A-3 (footnote 2).

[53] Troyer Direct. pp. 42-43.

the same standards and undergo the same rigorous approval processes at the local and state level. In addition, witness Troyer argued that for Company-owned facilities, "[the] reasonableness of expense(s), whether capital or O&M, are constantly reviewed through the life of the asset."[54] While that is technically correct, to my knowledge, O&M costs for individual projects are generally not reported, at least in general rate cases. Instead, these expenses are usually reported in combination with other O&M costs. It is therefore not simple, and perhaps not possible, for the Commission to actually "constantly review" project-specific O&M expenditures.

Finally, any commitments made by a developer to a community will carry through to the ultimate owner of the project. The commercial situation (third-party or Company-ownership) does not change any obligation or commitment made by the developer. Instead, those obligations, as affirmed in binding contracts, must be withheld no matter the final owner. It is important to note that, in fact, many communities have experienced legal challenges to tax revenue commitments made by developers for wind projects when the initial turbine valuations have been brought to the Michigan Tax Tribunal by the utilities who own the projects. These local experiences suggest that utility ownership does not provide additional protection to communities and assurance that obligations will be fulfilled and may, in fact, provide just the opposite.

Q. Since the 2018 IRP Settlement Agreement, what is the split between PPA and BTA projects acquired by the Company?

[54] Troyer Direct. p. 42.

A. According to witness Troyer, the Company has added 20% Company-owned projects and 80% PPA projects to its supply-side portfolio since the 2018 IRP Settlement Agreement.[55] However, these percentages are misleading. The Company has, as required by the 2018 IRP Settlement Agreement, added 150 MW of BTA capacity (Mustang Mile BTA) and 150 MW of PPA capacity (Calhoun Solar plus 10 MW of PURPA projects). The additional PPA capacity included by witness Troyer in his calculations was a result of the Commission's September 11, 2019, Order in Case No. U-20615, which approved a settlement agreement to resolve long-standing disagreements related to PURPA claims. That settlement resulted in the execution of 170 MW of PURPA PPAs at the full PURPA avoided cost from Case No. U-18090 and 414 MW of PURPA PPA entitlements at a reduced avoided cost rate. Because this settlement agreement was separate from the Company's IRP and resolved long-standing PURPA claims, it is unreasonable and misleading to count those PPAs when determining the split between Company-owned and PPA projects. Therefore, I would argue that it is more accurate to state that since the 2018 Settlement Agreement, the Company has acquired 50% PPA projects and 50% Company-owned projects, with additional PPAs acquired through a separate PURPA Settlement Agreement.

Q. What do you propose the Commission should order with respect to these ownership issues?

A. With respect to the resource ownership issues, I would strongly urge the Commission to:

[55] Troyer Direct. p. 39.

1) reject the Company's proposal to own at least 50% of the resources acquired under this IRP and instead institute an ownership model as agreed to in the 2018 IRP Settlement Agreement with at least 50% of the resources acquired via PPAs ("50/50 split"); and 2) allow the 50/50 split to be accomplished over the 5-year Proposed Course of Action, instead of within each RFP process to allow for increased flexibility.

VI. COMPETITIVE BIDDING GUIDELINES

Q. Do you have an understanding of best practices for competitive bidding processes?

A. Yes. Part of my work on behalf of Michigan EIBC is to understand industry standards with respect to competitive bidding. From September 2020 through March 2021, on behalf of Michigan EIBC members, I participated in the Competitive Procurement Workgroup, including submitting multiple sets of comments on behalf of Michigan EIBC and AEE and presenting to the group during two workgroup sessions.

There are several well-regarded organizations that provide practical explanations of how an effective competitive bidding process should be designed. According to the National Association of Regulatory Utility Commissioners ("NARUC"),[56] the competitive bidding process should be "designed to encourage a competitive response from the market." Public Act 295 of 2008 (MCL 460.1001 Sec.1(2)I) similarly establishes the goal of "[encouraging] private investment in renewable energy and energy efficiency."

[56] Tierney, S. F. and Schatzki, T. 2008. "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices." Available at http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/competitive_procurement.pdf.

Q. What is the value of using a competitive bidding process?

A. Michigan EIBC/IEI/CGA, along with customer and environmental advocates, have long espoused the inclusion of independent power producers and properly structured competitive solicitations for project selection processes to ensure that customers have access to competitively-priced renewable energy. To determine the lowest cost, most reasonable and prudent resources and ownership models, it is best practice to utilize fair, transparent, all-inclusive RFPs and competitive bidding processes.

Q. Does the Commission have uniform guidelines for competitive bidding?

A. Yes. Following the MI Power Grid Competitive Procurement Workgroup, the Staff filed a report with draft guidelines on June 22, 2021, in Case No. U-20852. The Commission issued an Order on September 9, 2021, in Case No. U-20852 accepting the guidelines with minor modifications, stating that:

> . . . the Commission finds that the guidelines achieve the Commission's stated intention of setting out a competitive procurement process that reveals available resource options, ensure emerging technologies are appropriately considered, and results in lower costs and higher value for customers.[57]

Q. Are utilities required to follow these guidelines for all procurements?

A. Not always. As stated by the Commission in the Order in Case No. U-20852, issued on September 9, 2021,

> . . . the Commission clarifies that the adoption of the guidelines does not make conformity with the guidelines a requirement for all rate-regulated utilities in every resource procurement. As stated in the guidelines, the Commission encourages the use of the competitive procurement guidelines for the solicitation of all long-term resources but is not imposing their use

[57] Commission Order in Case No. U-20852. September 9, 2021. p. 24.

> as a requirement for cost recovery. Should a utility opt to conform its RFP to the competitive procurement guidelines, it will receive the benefit of a presumption that its resulting procurement in accordance with the guidelines is reasonable and prudent. Additionally, to further address concerns regarding the presumption of reasonableness and prudence, the Commission clarifies that the guidelines are intended to set out a standard for the Commission's expectations of a fair, transparent, non-discriminatory bidding process. However, the guidelines do not foreclose the possibility that procurement by other means may also be reasonable and prudent.[58]

However, in the case of a utility, such as Consumers Energy, that chooses to use competitive solicitations as a means for establishing its PURPA avoided costs, the competitive procurement guidelines state that:

> This guidance will be utilized when the utility intends to use Competitive Procurement as the means for establishing its Public Utility Regulatory Policies Act of 1978 (PURPA) avoided costs and as a basis for determining an avoided capacity cost of zero outside the competitive solicitation process.[59]

Q. In your opinion, what are the critical provisions of the competitive procurement guidelines adopted by the Commission in Case No. U-20852?

A. There are a number of provisions in the competitive procurement guidelines that are important to ensure a fair, transparent, and competitive bidding process. A few of these include:

- *Independent Administrator:* An Independent Administrator must be used when a bidding process is used to determine PURPA avoided costs to ensure that bids are evaluated fairly and without bias. This independent third-party administrator should not be affiliated with the utility, should be a neutral party and, ideally, should not

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[58] *Id.* pp. 23-24.
[59] *Id*. Exhibit A.

be an advanced energy developer who could serve to benefit from access to confidential information about bidders.

- *Open to all technologies:* It is important that bidding is open to all resources that can meet relevant system and program needs to allow all technologies to compete. Rather than pre-determining the outcome, it is important to find the most cost-effective, appropriate, and advantageous solution for a given capacity or resource need within the program and system requirements.
- *Non-price factors:* Use of non-price factors should be clear and transparent so that bidders understand what parameters are most important to the utility and how those parameters will be weighed.
- *Terminal value analysis:* A bidder should be allowed to submit a bid of the same length as the expected operational life of the asset (e.g., 35 years for a solar project) and not have that bid subject to a terminal value analysis (TVA). In the case that a TVA is conducted, it should be calculated as the LCOE of the project as bid.

Q. What does the Company propose to change with respect to the evaluation of bids in the solicitation process?

A. As described by witness Troyer, the Company intends to remove the ranking of proposals on a net cost basis and the establishment of $/MWh values for value-added criteria.

Q. Do you have any concerns with these proposals?

A. Yes. While I agree with witness Troyer that concerns can arise with a set $/MWh value for each value-added criteria, this system was clear and transparent to all bidders. It enabled a bidder to understand the relative importance to the utility of each value-added criterion. If the Company moves away from this $/MWh system, the new points-based system for value-added criteria must be equally clear and transparent to all bidders. It would not be sufficient and would not comply with the current Commission approved guidelines for the Company to simply list in a RFP value-added criteria that may be considered using a points-based system. It must be clear to each bidder the relative "value" of each value-added criteria and exactly what is required to gain that "value" so that the bidder can assess how best to structure a proposal to achieve common goals with the utility. I am concerned that by setting aside the $/MWh system, the Company is moving away from a transparent, clear system to one in which there is much less accountability and transparency.

Q. What do you propose the Commission should order with respect to competitive bidding?

A. The Commission should only approve the Company's PCA if the Company agrees to utilize the competitive bidding guidelines approved by the Commission in its Order in Case No. U-20852 on September 9, 2021, including the establishment of a fair and transparent solicitation process.

VII. PPA TERM LENGTHS

Q. How does the Company propose to change PPA term lengths?

A. According to witness Troyer, instead of soliciting PPA term lengths up to 25 years, the Company proposes to solicit PPAs which are 10 and 15 years in length. On the option of the Company, each PPA could be extended in 5-year increments (EIB-14, LSS-14).

Q. Are you concerned with this proposal?

A. Yes. According to my conversations with Michigan EIBC member companies, a PPA term length of shorter than 25 years would be an outlier among utilities across the country and would likely result in higher cost PPAs. Longer-term PPAs allow developers to negotiate more favorable financing terms, primarily because the types of investors who finance utility PPAs are seeking long-term, stable cash flows (e.g., pension funds). These investors are willing to accept lower returns on equity for the lower risk and higher stability provided by long-term utility PPA investments. In contrast, investors who seek shorter-term investments are often willing to accept higher risk commercial and industrial ("C&I") PPAs, but require higher returns on equity.

As a result, 25-year, long-term PPAs are less expensive to finance, thereby allowing third parties to offer lower cost bids and, ultimately, providing lower costs to ratepayers. Therefore, I expect that reducing the term lengths of PPAs from 25 years to 10 or 15 years would result in higher cost PPAs and a less robust response from bidders to Consumers' solicitations.

This proposal would also likely have the added effect of making PPA proposals, especially with any added terminal value analysis, uncompetitive with BTA projects bid into the same solicitations. This proposal, combined with the Company's proposal to allow for up to 100% Company-ownership of new supply-side resources, indicates an increasing hostility toward PPA projects and appears to be yet another attempt to make PPA projects uneconomic, likely leading to increased Company-ownership of future generation.

Q. Why does the Company believe that it should shorten PPA term lengths?

A. Witness Troyer argues that:

> Based on recent research into renewable PPA terms and competitive procurement, the Company anticipates that shortening the PPA term and including options that the Company may enforce during the PPA term will result in financeable PPAs for the developer while increasing value to our customers.[60]

Witness Troyer describes a Wood Mackenzie report ("report") contracted by the Company (Company Exhibit A-46) to compare PPA strategies between utilities and C&I customers. Based on this research, witness Troyer concludes the utility should offer short 10 and 15-year PPA term lengths.

Q. What analysis does the Wood Mackenzie report provide regarding PPA term lengths?

A. The report describes that most utilities contract for physical or hybrid PPAs (instead of financial or virtual PPAs) with contract term lengths of 20 years or more. In contrast, the report describes that C&I customers implement both physical and financial PPAs with generally shorter contract term lengths (12 to 15 years).

The report indicates that it is easier given faster procurement timelines and less onerous requirements for third-party developers to contract with C&I customers. As a result,

[60] Troyer Direct. p. 44.

developers are more willing to accept shorter PPA term lengths for C&I customers. However, public sector customers, such as municipalities, government facilities, and schools, are more willing to sign 20 to 25-year PPAs. For corporate governance reasons, many non-public sector C&I customers cannot sign 20-year contracts, but long-standing institutions created to serve the public good, like utilities, and public sector customers can accept longer contracts.

Q. Is it reasonable to draw conclusions regarding utility PPA term lengths based on a study of C&I PPAs?

A. No. Comparing utility physical PPAs to C&I (often financial) PPAs is like comparing apples to oranges. Utilities and C&I customers are vastly different in terms of planning time horizons, capital requirements, financial models, and market structures. In addition, utility PPAs and C&I PPAs are very different both in investor return on equity and risk requirements (as described above) and in the contract terms themselves. For example, utility PPAs are often bundled and include not only energy, but also, capacity, Renewable Energy Credits ("RECs") and ancillary services. In contrast, many C&I PPA contracts are for energy-only. As a result, a third-party developer is able to contract with other entities for those other attributes of the project (i.e., capacity, RECs, and ancillary services), gaining additional revenue streams. For all of these reasons, third-party developers are able to finance and offer shorter-term C&I PPAs, but would likely be unable to finance short-term utility PPAs at reasonable prices. The report fails to describe these differences and fails to indicate that lessons learned regarding C&I PPAs cannot be directly applied to utility PPAs.

Q. How are PPA term lengths related to pricing?

A. Although the report notes that "a longer-term PPA may not always be more expensive than a shorter-term PPA,"[61] in general, because financing terms will be more favorable for a stable longer-term contract, a developer is more likely to be able to provide a lower cost PPA if the term length is longer. The report does note that:

> Customers are willing to adjust other aspects of the contract in order to receive the lowest PPA price. For example, customers will request short PPA terms, but will ultimately accommodate longer PPAs when they see the impact on price.[62]

In addition, in the illustrative table provided in the report, the authors indicate that a 25-year PPA is assumed to cost \$32/MWh whereas a 12-year PPA is assumed to cost \$33/MWh. This suggests that although perhaps "not always" the case, in general, PPAs with shorter term lengths are higher priced than PPAs with longer term lengths.

Q. How does the report argue that shorter PPA terms will reduce costs?

A. The report provides an illustrative table based on current and predicted PPA prices as well as capital costs of solar in nominal dollars per Watt$_{DC}$. According to the analysis, because Wood Mackenzie predicts that the capital costs of solar will decrease by 38% and PPA prices will decrease by 24% from 2021 to 2033, it would be cheaper for a utility to sign a 12-year PPA (from 2021-2032) and a subsequent 13-year PPA (from 2033-2045) than to sign one 25-year PPA (from 2021-2045).[63]

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[61] Company Exhibit No. A-46 (KGT-2). p. 11.
[62] *Id.* p. 12.
[63] *Id.* p. 20.

Q. How does the Company assume solar capital costs will change over time?

A. According to witness Jeffrey E. Battaglia, the Company used NREL's 2019 Annual Technology Baseline report to determine the long-term capital cost projections used in the IRP modeling. Witness Battaglia states that:

> Under these calculations, solar capital costs are projected to decline through 2030 at a rate of approximately 1% per year on a nominal dollars basis – or 3% per year on a real dollars basis; and then stay relatively flat beyond 2030 in nominal dollars – or approximately 2% continued cost declines, on a real dollars basis.[64]

These data for each IRP modeling scenario are summarized in Company Exhibit A-42. Under all three IRP modeling scenarios, from 2021 to 2033, the predicted decrease in the capital cost of transmission-connected solar on a nominal dollars basis is 7.6%. This predicted decrease in solar capital costs is significantly less than the 38% decrease predicted by the Wood Mackenzie report over the same time period. Despite that any such predication of future costs is a best guess based on current data, it is clear, given the assumptions made by the Company in their IRP modeling scenarios, that the Company does not actually believe that solar capital costs are going to decrease over the next 12 years by 38%. If solar capital costs in fact only decrease by 7.6% between 2021 and 2033, it does not make sense from a cost perspective to sign a 12-year PPA and a subsequent 13-year PPA. Instead, given that a longer-term PPA will likely have more favorable financing terms and will, thereby, be most cost-effective, it would make more sense from a cost perspective to sign a 25-year PPA.

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[64] Direct Testimony of Jeffrey E. Battaglia, on behalf of Consumers Energy Company. Case No. U-21090 ("Battaglia Direct"). p. 10.

Q. What do you propose the Commission should order with respect to PPA term lengths?

A. Given that the provided Wood Mackenzie report fails to prove that shorter-term PPAs will benefit customers and given that shorter-term PPAs will in fact likely be more expensive, the Commission should require the Company to continue to contract for PPAs that are up to the depreciation schedule of a similar Company asset (i.e., 25 years for solar).

VIII. FINANCIAL COMPENSATION MECHANISM

Q. Do you believe it is appropriate for a utility, in general, to seek a financial compensation mechanism ("FCM") for PPAs?

A. Yes, in general. However, in this case specifically, my support for the FCM is conditional upon the Company agreeing to contract at least 50% of new capacity under the PCA from PPAs.

As described previously, generally, there are strong existing financial incentives for a utility like Consumers Energy to build and own all of the facilities from which the utility obtains electricity and a lack of incentives for the utility to contract for electricity using PPAs. This can create a situation where an investor-owned utility is strongly incentivized to avoid projects other than those that they build themselves or purchase from a developer after construction is complete. Section 6t(15) of Public Act 341 of 2016[65] established the ability for the Commission to authorize an FCM for PPAs. It is my understanding that the intent of this legislation was to change the utility's financial incentives and ensure that PPAs were not unfairly disadvantaged by this inherent financial bias.

[65] MCL 460.6t(15).

Although each developer has a different business model, under certain circumstances, a developer may prefer to pursue a deal using a PPA rather than a build-transfer agreement. In this situation, it would be beneficial to the developer if their interests were aligned with, rather than at odds with, the utility conducting the competitive bidding process and contracting for the resources.

Q. What basic principles should apply to any future FCM?

A. It is critical that calculation of any future FCM is transparent and understandable to all potential participants in a given competitive bidding process. Potential bidders should be able to easily calculate exactly what price mark-up to expect for a proposed PPA project in comparison to a build-transfer or Company-owned project. This requires that granular information on the FCM be provided to potential participants.

Additionally, any FCM should not be so large as to disadvantage PPA projects in comparison to Company-owned BTA projects. Because I am not a finance expert, I do not intend to comment on the specific methodology that Consumers Energy proposes to determine the FCM in the current proceeding. However, it is important that any new methodology that is accepted by the Commission not result in such a significant adder to PPA projects that these projects are unfairly disadvantaged.

IX. CONCLUSIONS AND RECOMMENDATIONS

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

A. I recommend that the Commission:

1) Direct the Company to amend its IRP to include a meaningful evaluation of CHP as both a supply-side and demand-side resource. This evaluation should include more than one configuration, taking into account customer interest in deployment and the technical potential for CHP in its territory.

2) Encourage the Company to accept applications to the DG program above and beyond the Category 1 and Category 2 caps.

3) Require the Company to retain the PURPA Standard Offer Contract at full avoided cost rates as an option for DG systems <150 kW in size.

4) Require the Company to clearly communicate all options available to DG installers and customers once the DG caps are reached, including clear steps to access those options, as an alternative or in addition to being placed on a waiting list.

5) Consider how the Commission can also provide increased transparency and communicate all options available to DG installers and customers once Consumers' DG caps are reached.

6) Require the Company to model customer-sited DERs as demand-side and generation resources in its next IRP.

7) Require the Company to set its Standard Offer Tariff at 5 MW.

8) Reject the Company's proposal to own at least 50% of the resources acquired under this IRP and instead institute an ownership model as agreed to in the 2018 IRP Settlement Agreement with at least 50% of the resources acquired via PPAs ("50/50 split").

9) Only approve the Company's PCA if the Company agrees to utilize the competitive bidding guidelines approved by the Commission in its Order in Case No. U-20852 on September 9, 2021, including the establishment of a fair and transparent solicitation process.

10) Require the Company to continue to offer PPA term lengths up to 25 years.

11) Ensure that any future FCM does not unfairly disadvantage PPA projects.

Q. Does that complete your testimony?

A. Yes.

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the Application of	)	
CONSUMERS ENERGY COMPANY	)	
for approval of an Integrated Resource Plan	)	**Case No. U-21090**
under MCL 460.6t, certain accounting	)	
approvals, and for other relief	)	

EXHIBITS OF DR. LAURA S. SHERMAN

ON BEHALF OF

MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL

AND

ENERGY INNOVATION

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PROFESSIONAL EXPERIENCE:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SERVICE & LEADERSHIP:

2021-present **Board Member** of Zero Emission Transportation Association Education Fund Board
2020-present **Board Member** of University of Michigan Earth and Environmental Sciences Alumni Board
2019-2020 **Board Member** of Advancing Women in Energy
2017-2019 **Communications Chair** for Advancing Women in Energy
2013-2014 **Supported** the Ann Arbor Energy Commission on community solar projects
2009-2014 **Peer reviewer** of more than 20 scientific manuscripts
2009 **Initiator and organizer** of new departmental seminar series, University of Michigan
2008-2010 **President** of department student organization (GeoClub), University of Michigan
2008 **Lead organizer** of Michigan Geophysical Union Poster Conference
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Ph.D. 2012 Earth and Environmental Sciences, **University of Michigan** (GPA: 8.837 out of 9.0)

B.S. 2005 Geological and Environmental Science, **Stanford University** (GPA: 4.007 out of 4.33)

DOE/EE-2276

SEE Action
STATE & LOCAL ENERGY EFFICIENCY ACTION NETWORK

Combined Heat and Power in Integrated Resource Planning: Examples and Planning Considerations

Industrial Energy Efficiency and Combined Heat and Power Working Group

November 2020

The State and Local Energy Efficiency Action Network is a state and local effort facilitated by the federal government that helps states, utilities, and other local stakeholders take energy efficiency to scale and achieve all cost-effective energy efficiency by 2020.

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This study was prepared under DOE's authority to encourage and facilitate the exchange of information among State and local governments with respect to energy conservation and energy efficiency, and provide technical assistance on such matters. This study was specifically prepared for the use and dissemination of the State & Local Energy Efficiency Network (SEE Action), a DOE program that DOE and the U.S. Environmental Protection Agency facilitates, to offer resources and technical assistance to state and local decision makers as they provide low-cost, reliable energy to their communities through energy efficiency. The purpose of SEE Action is not to provide advice or recommendations to DOE or the Federal government.

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All opinions, errors and omissions remain the responsibility of the authors. All reference URLs were accurate as of the date of publication.

Acronyms

ACEEE	American Council for an Energy-Efficient Economy
AEP	American Electric Power
BTMG	Behind-the-meter-generation
CC	Combined cycle
CHP	Combined heat and power
CT	Combustion turbine
DER	Distributed energy resource
DR	Demand response
DOE	Department of Energy
EE	Energy efficiency
HRSG	Heat recovery steam generator
I&M	Indiana Michigan Power
IPL	Indiana Power & Light Company
IRP	Integrated resource plan
LCOE	Levelized cost of electricity
MDE	Missouri Division of Energy
MW	Megawatt
MWh	Megawatt hour
O&M	Operations and maintenance
PSC	Public service commission
PV	Photovoltaic
RFP	Request for Proposals
SCR	Selective catalytic reduction
TAP	Technical Assistance Partnership
WHP	Waste heat to power

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Executive Summary

As states, local governments, and utilities gain experience with new planning approaches that account for the full range of benefits of distributed energy resources (DERs), there is increased interest in the consideration of combined heat and power (CHP) as both a supply-side and demand-side resource in utility integrated resource plans (IRPs). The purpose of this report is to assist state-level policy makers, state energy offices, utility commissions, and utility system planners in exploring the role of CHP in integrated resource planning.

Significant potential exists for increasing CHP installations across the U.S. While about 81 GW of CHP capacity is in operation today, an estimated 149 GW of technically viable capacity remains to be developed. As states and utilities explore scenarios to meet energy-related goals, CHP can continue to provide value and help balance key priorities, including: 1) providing efficient and reliable electricity and thermal energy to the U.S. industrial sector; 2) increasing our power system's resilience to support our nation's critical infrastructure; 3) supporting grid integration of wind, solar, and energy storage technologies; and 4) helping the U.S. maintain its global leadership position in reducing carbon dioxide and other emissions while keeping electricity prices affordable.

An integrated resource plan (IRP) is a utility plan for meeting forecasted annual peak and energy demand through a combination of supply-side and demand-side resources over a specified future period. When developing plans for future resource options, utilities can gain value from evaluating CHP as a grid resource on the supply side, as an energy efficiency resource on the demand side, or as an overall resource solution. A handful of recent state policy activities have encouraged the consideration of CHP in utility resource plans. Policymakers in some states have updated statutory requirements or other rules to explicitly require consideration of CHP in future integrated resource plans; in other states, stakeholders have intervened in utility commission proceedings to discuss consideration of CHP and ensure utilities conduct an adequate review of CHP as a resource.

Examples of utility consideration of CHP in IRPs show that some utilities indicate a preference for owning CHP assets, while others do not take a position on ownership in their consideration of the costs and benefits of CHP. Modeling assumptions needed to characterize CHP in an IRP include: 1) resource potential; 2) customer thermal loads; and 3) CHP system characteristics. Traditionally, utilities have compared the cost-effectiveness of CHP to other resources through reference to levelized cost of electricity (LCOE). However, many features of CHP, such as increased resilience, lower emissions, or state economic development are more challenging to value in traditional cost-benefit frameworks. New planning frameworks that consider the full range of CHP attributes may indicate that CHP can be a useful solution that minimizes system costs and maximizes customer benefits.

With an understanding of the role CHP can play in future resource planning, states and local governments can benefit from actions that: 1) evaluate how CHP is treated in state planning rules; 2) explore the role of CHP in electric utility planning; 3) provide guidance on utility ownership of CHP as a component of the rate base; 4) revise IRP rules to ensure inclusion of CHP; 5) issue guidance on modeling frameworks that value the benefits of CHP; 6) encourage collaboration across state agencies; and 7) require utilities to solicit stakeholder input in developing resource plans. Similarly, utilities may consider moves to: 1) identify CHP potential in their service territory; 2) assess CHP interest in their service territory; 3) conduct feasibility assessments; 4) issue a Request for Proposals (RFPs) for CHP projects; 5) develop a project priority pipeline; and 6) measure CHP's long-term benefits in integrated resource planning.

Introduction

Combined heat and power (CHP) has not traditionally been viewed as a utility resource like other generation resources. Instead, many electric utility companies view CHP as a customer resource that results in a loss of load, because customers that generate their own power purchase less electricity from their utility. However, the situation is changing as states and utilities increasingly look to energy efficiency and demand response as resource solutions and not just as reductions in demand. As decisionmakers explore and gain experience with new capacity planning approaches and business models there may be increased opportunities for realizing the benefits of CHP to utilities and customers.[1]

Within these evolving frameworks, state leaders and utilities can include an assessment of the full range of benefits of CHP as both a supply-side distributed energy resource (DER) on the utility side of the meter, and as a demand-side DER on the customer side of the meter. In both approaches, CHP can bring more affordable, secure, reliable and clean power to customers with large continuous thermal loads and all users of the electric grid through addition of DER located near or at critical customer loads.

Utilities are demonstrating interest in deploying more CHP. In the last 10 years, more than 20 utilities across the country piloted and implemented CHP programs for their customers in at least 12 states in the U.S. (Kelly and Hampson 2018). In a more recent survey of American utility executives, while most had no current or planned investments in owning CHP, 34% of utilities expected an overall moderate increase and 4% expected a significant increase in CHP deployment in their service territory (Bade 2019). For utilities that are interested in exploring the benefits of CHP for their customers and the grid, this report may offer useful information.

The purpose of this report is to assist state-level policy makers, state energy offices, utility commissions, and utility system planners in exploring the role of CHP in integrated resource planning.[2] This first section summarizes current trends, benefits, and potential for CHP deployment. The second section provides an overview of integrated resource planning and how CHP is treated, including descriptions of recent state-level activity related to CHP in integrated resource planning. The third section provides three specific examples of utilities that have considered CHP in an IRP process, and highlights how CHP was analyzed. The fourth section describes technical considerations for modeling CHP as an alternative to traditional utility investments. The final section previews considerations and next steps states and utilities could take to further explore CHP in integrated resource planning.

1. Benefits, Potential, and Current Trends for CHP

CHP is an energy-efficient method of generating electric power and useful thermal energy from a single fuel source at the point of use, replacing or supplementing electricity provided through a utility's distribution system and fuel burned in an on-site boiler or furnace. When electricity and thermal energy are provided separately, overall fuel use energy efficiency ranges from 45–55%. While efficiencies vary for CHP installations based on site-specific parameters, a properly designed CHP system will typically operate with an overall fuel use efficiency of 65–85% (DOE 2017).

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[1] *See* U.S. Department of Energy, Oak Ridge National Laboratory, Combined Heat and Power: Effective Energy Solutions for a Sustainable Future (December 2008), *available at* https://www.energy.gov/sites/prod/files/2013/11/f4/chp_report_12-08.pdf; U.S. Department and Energy and U.S. Environmental Protection Agency, Combined Heat and Power: A Clean Energy Solution (August 2012) *available at* https://www.energy.gov/sites/prod/files/2013/11/f4/chp_clean_energy_solution.pdf.

[2] Consumer-owned utilities and the agencies that oversee them can also benefit from considerations in this report, although the report is focused on integrated resource planning by investor-owned utilities. Consumer-owned utilities serve around 25 percent of the nation's population, including cities and many large rural areas. These include municipal utilities, co-ops, and public power districts, and are often distribution-only entities. In most states, regulation and oversight of consumer-owned utilities is left to local governmental bodies and elected utility boards. *See* Lazar, J. (2016). Electricity Regulation in the US: A Guide. Second Edition.
Montpelier, VT: The Regulatory Assistance Project, p. 12, *available at* http://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf.

For end users, CHP also results in decreased energy costs, enhanced energy resilience, reduced risk from uncertain energy commodity prices, and increased economic competitiveness. Local, regional and national benefits of CHP include increased use of domestic fuel sources including renewable natural gas, increased energy resilience of critical infrastructure and operations, enhanced electric grid reliability, and enhanced local economic growth and development.[3]

1.1. CHP Potential and Integrated Resource Planning

CHP is currently installed at nearly 4,600 sites around the country and the number of systems continues to increase, with 120 new installations that came online in 2018 (DOE 2018a). Significant potential exists for increasing CHP installations in the U.S. While about 81 GW of CHP capacity is in operation today, almost double that amount – an estimated 149 GW of technically viable capacity spread across more than 290,000 commercial and industrial facilities – remains to be developed. In Figure 1, existing capacity and technical CHP potential in the industrial sector are illustrated on the left, with existing capacity and technical potential in the commercial sector illustrated on the right (DOE 2016).[4]

All states and the District of Columbia have technical potential for CHP, including both on-site CHP (where system output is consumed at the host facility) and export potential (where all electricity in excess of what can be used by the host facility is sold to the electric grid). A utility's IRP can identify the portion of the CHP potential in their service territory that is optimal under various scenarios and in the context of the utility's complete resource portfolio.

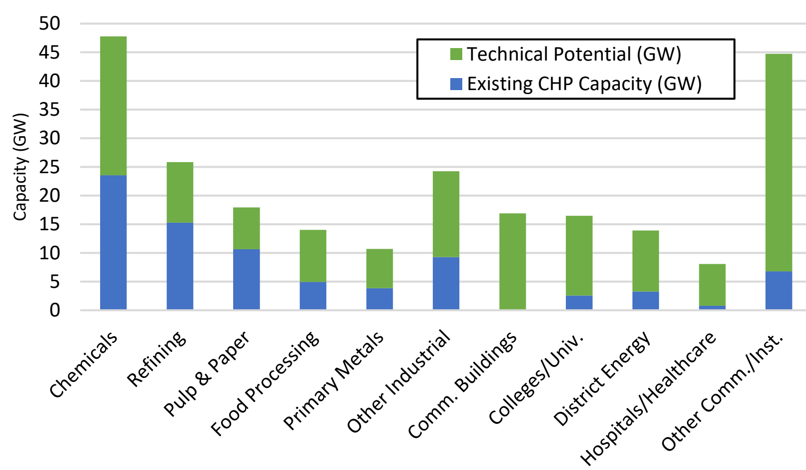


Figure 1. Existing CHP Compared to On-Site Technical Potential by Sector. (Source: DOE 2019a, DOE 2016)

New installations are trending toward "packaged" CHP systems, which are standardized and pre-engineered systems that reduce both the time and expense involved in installing CHP compared to systems that involve custom engineering and design.[5] The rise in packaged CHP corresponds with continued growth in installations in the commercial and institutional sectors, including systems at multi-family buildings, hotels, retail sites, hospitals, and wastewater treatment plants. In integrated resource planning, utilities can assess a range of CHP technologies

[3] *Ibid.*
[4] 149 GW is the additional, within the fence (i.e., no export of power to the grid) technical potential for CHP at existing industrial, commercial and institutional facilities; the technical potential for additional CHP including export (i.e., CHP system sized to site thermal and any excess power generated above site demand is exported to grid) is 241 GW (DOE 2016). This 92 GW of export potential can provide energy to the utility grid at locations or during times when it is needed most to address capacity constraints and increase grid resilience.
[5] For more information about packaged CHP, visit the DOE Packaged CHP Accelerator: https://betterbuildingsinitiative.energy.gov/accelerators/packaged-chp, and the CHP eCatalog: https://chp.ecatalog.lbl.gov/.

and applications, and model the potential energy and cost savings that could be derived from incorporating different types and sizes of CHP into its future resource mix. Figure 2 shows technical potential for packaged CHP systems less than 500 kW in commercial and institutional sectors by market segment.

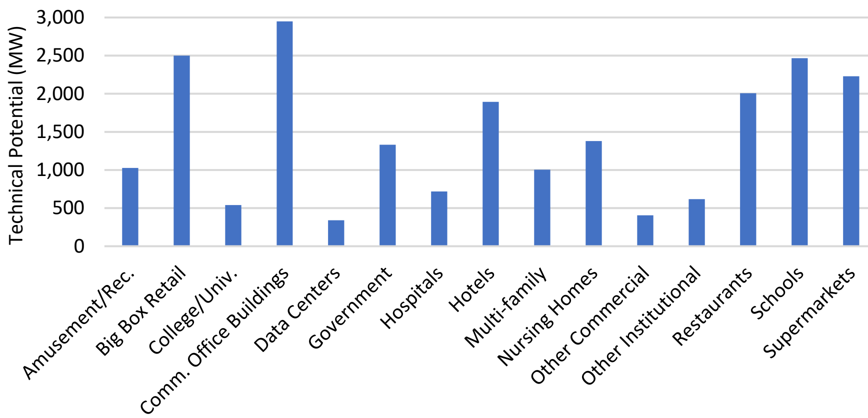
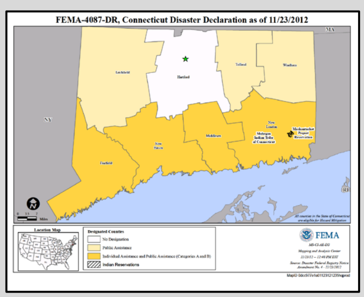


Figure 2. Existing CHP Compared to On-Site Technical Potential by Sector. (Source: DOE 2019a, DOE 2016)

CHP MICROGRIDS DELIVERY RESILIENT POWER TO CRITICAL FACILITIES



After Fairfield, Connecticut suffered significant energy outages during Superstorm Sandy, the town invested in a CHP-based microgrid supporting its critical facilities.

Credit: FEMA, Connecticut Hurricane Sandy (DR-4087), available at [*https://www.fema.gov/disaster/4087*](https://www.fema.gov/disaster/4087)

The microgrid features a 300 kW natural gas-fired generator, 47 kW of solar PV, and a 60 kW natural gas-fired CHP reciprocating engine as the microgrid anchor. It serves the fire station, police station, an emergency communications center, a public shelter, and a cell phone tower.

Source: U.S. Department of Energy - Better Buildings Initiative, Distributed Generation (DG) for Resilience Planning Guide (January 2019).

1.2. Current Trends in CHP

Looking forward, as states and utilities explore pathways to a low carbon future, CHP can continue to provide value and help balance key priorities.[6] Some examples of high-value applications for CHP today and in the future include (1) providing efficient and reliable electricity and thermal energy to the U.S. industrial sector, (2) delivering resilient power to our nation's critical infrastructure, (3) supporting the integration of renewable energy, and (4) providing an affordable, energy-efficient pathway to a low/no carbon energy supply. Heightened awareness of these benefits of CHP, along with evolving utility planning frameworks and state policy actions to encourage evaluation of CHP, are key drivers in increasing consideration of CHP in integrated resource planning.

Providing Efficient Electricity and Thermal Energy to the U.S. Industrial Sector

The industrial sector consumes nearly one-third of all total energy consumption in the United States (EIA 2019a). For industrial customers with large continuous thermal loads and complex process integration, CHP is the most energy-efficient method of producing electricity and high-temperature steam that is required to drive many manufacturing processes. Support for CHP at industrial sites is often an important economic development tool for states and utilities to retain industrial companies and attract new manufacturers, while also supporting companies in achieving their resilience and sustainability goals.

Increasing Energy Resilience of the Nation's Critical Infrastructure

Critical infrastructure refers to systems and assets so vital to the United States that the incapacity or destruction of these assets would have a debilitating impact on national security, national economic security, or national public health or safety.

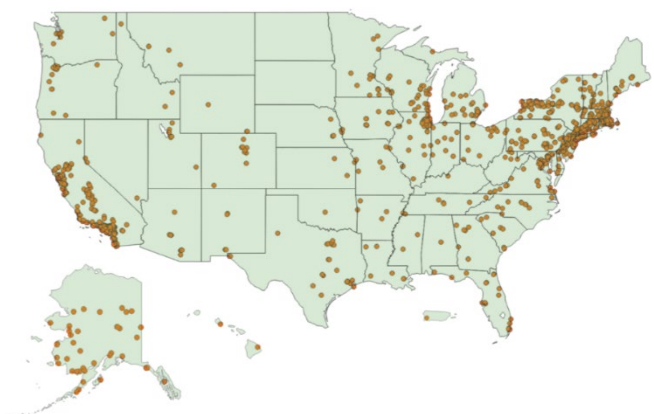


Figure 3. CHP Installations at Critical Infrastructure Facilities throughout the U.S. (Source: DOE 2019b)

Civilian critical infrastructure applications can include hospitals, water and wastewater treatment facilities, financial institutions, police and security services, and areas of refuge.[7] CHP provides resilient power capable of withstanding long, multi-day grid outages to protect and keep communities habitable and safe in disasters or other emergencies. Multifamily housing and campuses with CHP microgrids can reduce stress on shelters and emergency services by permitting shelter-in-place. Policymakers and planners are increasingly aware of the need to protect and reduce stress on critical infrastructure, and CHP systems can be configured to allow operations and delivery of essential services to continue uninterrupted at critical facilities, even during unexpected grid outages. More than

[6] *See* U.S. Department of Energy (DOE) and U.S. Environmental Protection Agency (EPA), State and Local Energy Efficiency Action (SEE Action) Network, Guide to the Successful Implementation of State Combined Heat and Power Policies (March 2013), *available at* https://www4.eere.energy.gov/seeaction/system/files/documents/see_action_chp_policies_guide.pdf

[7] Critical infrastructures protection, 42 U.S.C.§ 5195c (2011). https://www.law.cornell.edu/uscode/text/42/5195c

15 GW of CHP is currently installed at over 2,000 sites identified as critical infrastructure, shown in Figure 3 (DOE 2018b).

Defense applications can include any military installations where both thermal and electric loads are needed. For example, the U.S. Army sees opportunities for CHP deployment at large barracks, dining halls, hospitals, hangars, labs, manufacturing and maintenance facilities. The Army recognizes benefits of CHP systems – such as black start capability – as mission-sustaining technologies that can help the military improve resilience and reduce vulnerability to potential power disruptions caused by cyber and physical attacks, and severe weather events. A key need is to ensure the availability, reliability and quality of power (and water) to continuously sustain all missions.

In pursuit of energy security and energy resilience as required by the 2018 National Defense Authorization Act, the Army's Energy Security and Sustainability Strategy, and the Installation Energy and Water Security Policy (Army Directive 2017-07), which requires the capability of providing necessary energy and water to installations for a minimum of 14 days, the Army Office of Energy Initiatives is reviewing opportunities for installations across the enterprise to have assured energy – specifically, through islandable capabilities, sufficient on-site generation, energy storage and energy controls to allow generating assets to provide a direct power feed to the installation in the event of an extended grid disruption. A wide range of technology solutions, including CHP and microgrids, are undergoing feasibility assessments and several projects are already in operation. For example, a 2 MW CHP system recently began operation in 2017 at Picatinny Arsenal, a military research and ammunition manufacturing facility located in New Jersey. In another example, a 4 MW CHP system is planned at Fort Huachuca, home to intelligence and technology command units and a major installation in Arizona.[8]

Supporting the Integration of Variable Renewable Energy

Growing markets for CHP include hybrid installations and microgrids that integrate CHP with other distributed energy resources, including solar and storage. In these configurations, CHP can ramp up and down[9] to balance variable generation as part of an on-site microgrid or in support of the local distribution grid, increasing the capacity to accommodate more renewable energy. CHP installations can also be powered by renewable fuels, with approximately 23% of today's CHP sites using waste, wood, and biomass fuels, with potential for expanded use of renewable fuels in the future (DOE 2018a).

RENEWABLE-FUELED CHP AT WASTEWATER MANAGEMENT FACILITY

CHP installations can be powered by natural gas as well as renewable fuels; today, roughly 23% of existing CHP sites use waste, wood, and biomass fuels. For example, the McAlpine Creek Wastewater Management Facility in Charlotte, NC uses anaerobic digester gas to power a 1 MW CHP system. Advances in alternative fuels, including renewable natural gas and hydrogen, may in the future allow customers to benefit from a zero carbon source of electricity and thermal energy from CHP.

McAlpine Creek Wastewater Management Facility CHP System. Photo credit: US DOE Southeast CHP Technical Assistance Partnership

[8] https://www.army.mil/article/212756/the_us_armys_pivot_to_energy_and_water_resilience
[9] CHP systems designed for flexible operation or paired with thermal storage can avoid efficiency losses that might otherwise occur due to ramping.

PRINCETON UNIVERSITY INTEGRATES CHP, SOLAR PV, AND THERMAL STORAGE TO PROVIDE GRID SERVICES

In hybrid installations and microgrids that integrate CHP with other distributed energy resources, CHP can ramp up and down to balance variable generation as part of an on-site microgrid or in support of the local distribution grid. For example, Princeton University's CHP-based district energy system integrates 15 MW of CHP, a 4.5 MW solar array, and a large thermal energy storage system. The university operates its assets as dispatchable resources, responsive to market prices as well as onsite needs.

Princeton University CHP-based district energy system with solar array. Photo credit: Princeton University

Providing an Affordable, Energy-Efficient Pathway to a Low/No Carbon Future

Utilities use integrated resource planning as a framework for evaluating the reliability, costs and environmental impacts of future energy investment scenarios needed to meet system-wide energy capacity objectives. Comparing the levelized cost of electricity and the emissions profiles of CHP with the cost and emissions of other resource options in the plan, including new central station natural gas plants, can be a useful exercise, as conventional CHP inherently provides system-wide energy and emissions savings over state-of-the-art natural gas combined cycle or simple cycle peaking plants.

2. The Role of CHP in Utility Resource Planning

To determine if CHP is a cost-effective alternative to a traditional investment, utility system planners must have a method for evaluating and comparing it to other investment options. This exercise is undertaken through an integrated resource plan (IRP). An IRP is a utility plan for meeting forecasted annual peak and energy demand, including some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period (Wilson and Biewald 2013).[10]

Integrated resource planning is primarily used by utilities in vertically integrated states where utilities own generation assets and are the entity responsible for planning for and developing future resource needs. In these types of plans, a utility may evaluate CHP as a resource on both the supply-side and the demand-side as an alternative to an investment in a more traditional generating resource. Therefore, the scope of this report focuses in on integrated resource planning undertaken by electric utilities in vertically integrated markets.[11]

States can evaluate CHP in these procurements plans and other utility planning efforts that are separate from traditional integrated resource planning. Utilities may use other planning approaches such as long-term procurement plans that cover shorter planning horizons and evaluate purchases of capacity and energy in wholesale markets, as well as energy efficiency and other demand-side management resources. For example,

[10] Wilson and Biewald 2013 provides a detailed summary of how utility resource planning efforts have evolved and describes best practices in IRP processes. This section relies on their description for much of the background included.

[11] While CHP is relevant in both electric and gas utility planning, utilities tend to plan for the provision of gas and electric services separately. By contrast, many state energy offices undertake more comprehensive planning efforts that may encourage consideration of CHP. According to the EPA CHP Policies and Incentives Database, 29 states reference CHP as a strategy for achieving objectives laid out in state energy plans (EPA 2020). Interestingly, the energy office in Connecticut -- Connecticut Department of Energy and Environmental Protection (DEEP) – also prepares a statewide IRP, and the 2014 plan highlighted CHP as a key resource strategy: "The Department estimates that there is another 170 MW of cost-effective CHP potential in the state. DEEP proposes to revitalize incentive programs to help deploy this CHP potential, recognizing that CHP systems can provide special value in locations where it can power microgrids and/or avoid costly upgrades to the utilities' electric distribution systems" (Connecticut DEEP 2014).

investments in CHP can be evaluated in transmission or distribution system planning (*e.g.,* CHP as a non-wires solutions, also called non-wires alternative), as part of grid modernization plans, energy efficiency plans, resilience plans, state energy plans, or other state planning processes.

While these other planning processes are beyond the scope of this report,[12] insights gained from other types of utility planning, such as distribution system planning, can help capture the full range of benefits of CHP. Data on the locational benefits of specific CHP projects are immediately relevant to distribution system planning, and can also help assess the potential value of CHP as both a supply-side and demand-side resource in integrated resource planning. Similarly, rate design approaches can impact the use of CHP, which in turn impacts the consideration of CHP in a utility's various planning processes. Some leading states are developing more comprehensive approaches to planning that allow these separate processes to inform one another, and these efforts can result in valuable data to inform future integrated resource planning.[13]

According to Synapse Energy Economics, 34 states have or are developing an IRP rule and/or filing requirement, as shown in Figure 4 (Wilson 2018). In recent years, some states have updated their IRP rules to ensure utilities give consideration to specific resources with benefits in addition to cost-effective service, such as renewable energy and energy efficiency.[14] While most utilities do not yet have experience including CHP in resource plans, rules in the following states either require or at least mention CHP as an option to consider in a plan: Connecticut, Georgia, Iowa, Indiana, Kentucky, Nebraska, Nevada, New Mexico, Oregon, Massachusetts, Minnesota, Utah, Washington, and most recently, Michigan and Virginia (NASEO 2013). However, the majority of these rules do not provide detailed guidance about how utilities should evaluate CHP in their IRPs.

[12] Distribution system planning has emerged to help utilities plan for integrating more DERs on the grid and to address aging infrastructure and utility investments. Because CHP is a highly flexible grid asset, it can play a pivotal role in helping utilities balance the grid, especially with greater penetrations of variable resources. Utilities that prepare these types of plans could apply their cost-benefit frameworks to CHP to evaluate its ability to meet specific needs on the distribution system. An analysis of the treatment of CHP in distribution system planning is an area for further research that could reveal useful models for estimating the value of CHP to the system.
[13] *See* National Association of Regulatory Commissioners (NARUC) Task Force on Comprehensive Electricity Planning, encouraging greater alignment of resource and distribution system planning, *available at* https://www.naruc.org/taskforce/."
[14] *See* Frick, N., T. Eckman, A. Sanstad, G. Leventis, P. Peterson, J. Kallay and A. Hopkins. 2019. Treating Energy Efficiency as a Resource in Electricity System Planning. Berkeley Lab.

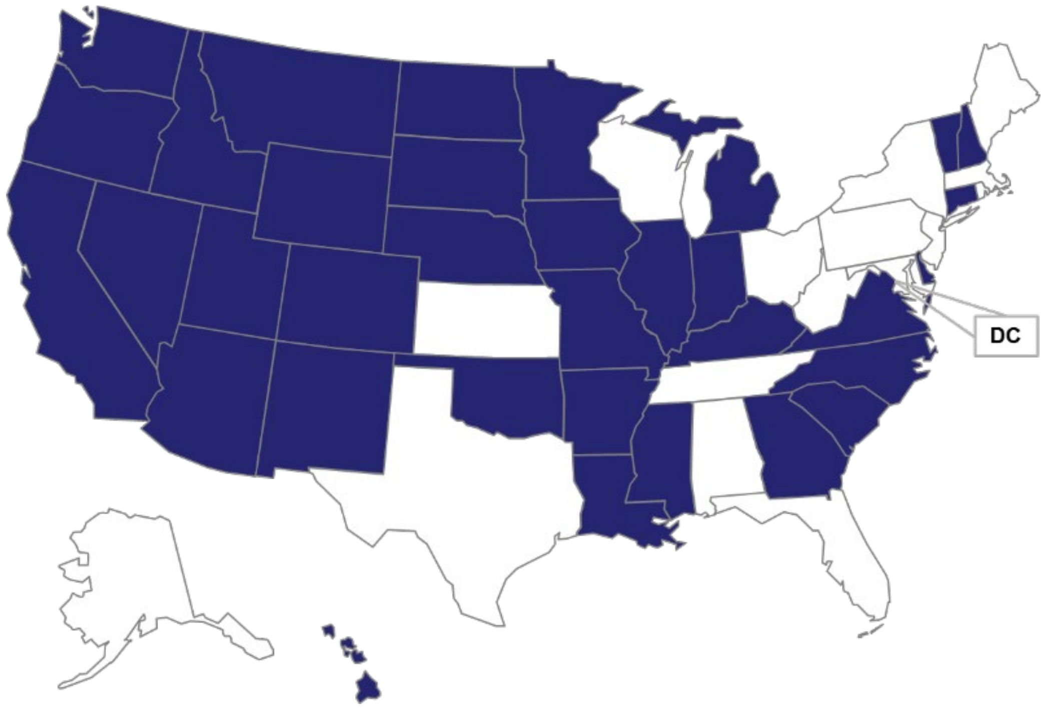


Figure 4. States with (or developing) an IRP rule and/or filing requirement. (Source: Wilson 2018)

As state policymakers and utilities explore options for building a more modern grid, several have recently recognized the value of evaluating CHP as a resource for achieving broad planning objectives. When developing plans for future resource options, utilities can gain value from evaluating CHP as a grid resource on the supply side, or as an energy efficiency resource on the demand side. On the supply side, CHP is often a least-cost resource compared to other generation options, and CHP plants can be deployed at strategic locations and in a shorter timeframe than large utility power plants. On the demand side, CHP delivers significant electric and thermal savings that utilities need to meet energy efficiency targets or other demand management needs. Whether CHP is considered as a supply-side or demand-side resource or an overall resource solution, consistent thermal energy demand is essential to reaching optimal economic efficiencies in resource planning.

2.1. Key State Policy Activity Related to CHP in Integrated Resource Planning

A handful of recent state policy activities encouraging the consideration of CHP in utility IRPs may also contribute to a growing role of CHP in utility planning. For example, policymakers in some states have updated statutory requirements or other rules to explicitly require consideration of CHP in future integrated resource plans. In other states, stakeholders have intervened in utility commission proceedings to discuss consideration of CHP and ensure utilities conduct an adequate review of CHP as a resource.

Updates to Integrated Resource Planning Rules Related to CHP

While the concept of integrated resource planning is not new, state requirements for utility IRPs are constantly evolving. This section describes recent examples from three states – Michigan, Virginia, and Mississippi – where policymakers have updated rules or are considering updates to rules related to CHP in integrated resource planning. Experience in these states demonstrates a range of ways in which state policymakers and regulators can ensure that CHP is evaluated alongside other potential resources in utility planning.

Michigan

In 2016, the Michigan Legislature passed PA 341, which requires all rate-regulated utilities to file IRPs with the Michigan Public Service Commission (PSC). The law also sets criteria for utilities to consider in their IRP filing. Among other requirements, an IRP must include the projected energy and capacity purchased or produced by the utility from a CHP resource (Michigan 2016).

In implementing PA 341, the Michigan PSC clarified how CHP should be taken into account during the IRP modeling process: "Prior to and during the modeling process, the utilities shall take into account resources that include, but are not limited to: small qualifying facilities (20 MW and under), renewable energy independent power producers, large combined heat and power plants, and self-generation facilities such as behind-the-meter-generation (BTMG)."(Michigan 2016; Michigan 2017).

IS CHP A SUPPLY SIDE OR DEMAND SIDE RESOURCE?

On the **supply side** (or "utility side of the meter"), the electric and thermal generation from CHP can contribute to a utility's supply-side portfolio, adding to the company's generation resource mix. Utilities may plan for increased use of CHP as a utility-owned, regulated asset, or through other competitive procurement strategies.

On the **demand side** (or "customer side of the meter"), CHP lowers demand and increases flexibility by providing energy efficiency and load management services. Utilities may plan for increased use of CHP as a demand resource via customer-focused programs, including energy efficiency portfolios.

As energy efficiency and demand response are increasingly treated as resource solutions rather than merely reductions in demand, the importance of the distinction between supply side and demand side resources in utility planning may eventually diminish, which could further enable utilities in the consideration of the full benefits of CHP in resource planning. This approach aligns with the increasing prevalence of all-source solicitation, in which a utility considers all resources (*i.e.*, demand and supply are bid together) in response to an RFP.

Virginia

A 2018 law in the Commonwealth of Virginia requires consideration of a specific CHP deployment scenario as part of the IRP process. Senate Bill 966 directs Dominion Energy to consider the deployment of 200 MW of CHP or waste heat to power (WHP) by 2024 in its next IRP (Virginia 2018). According to the 2018 Virginia Energy Plan, "a number of stakeholders recommended that increasing Virginia's focus on CHP to even a fraction of Virginia's 4,308 MW potential could position the Commonwealth to effectively achieve other public-policy strategies such as energy efficiency and resiliency."

Mississippi

In late 2019, the Mississippi PSC finalized a rule amendment requiring evaluation of CHP and other distributed energy resources as either a supply side resource a demand side resource: "For incremental capacity additions, reasonably useful, commercially-proven, and economic supply-side and demand-side resources that may be available to an electric utility should be considered, including but not limited to energy efficiency, demand response, and distributed energy resources (DER)." The amended rule defines DER to include both supply side and demand side resources:

> Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles, microgrids, and energy efficiency (EE). For purposes of this Rule, DER also includes utility-owned or controlled equipment (i.e. physical assets) used to generate, adjust, store, or sometimes deliver energy performed by a variety of devices at the distribution system-level. (Mississippi 2019)

The amended rule also requires utilities to identify, evaluate and discuss in their IRPs all existing supply-side resources, including but not limited to cogeneration (Mississippi 2019).

Interventions in Integrated Resource Planning Proceedings Related to CHP

This section describes recent examples from three states – Georgia, Missouri, and Michigan – where parties have intervened in IRP proceedings to request improved consideration of CHP. In some states, participants that aim to encourage consideration of CHP in utility resource plans may initially participate in utility-sponsored stakeholder engagement opportunities offered during the IRP development phase. Some utilities are encouraged by regulators to host workshops with interested participants to seek input, share information, and discuss assumptions, scenarios, and sensitivities used in the company's IRP modeling. After a utility has filed its IRP, parties may consider more formal intervention in IRP proceedings at state regulatory commissions.

Georgia

In response to Georgia Power's proposed 2019 IRP, Emory University intervened in support of a CHP-based microgrid that could provide ratepayers with a generation source at a lower cost than traditional utility resources (Maloney 2019). In addition to highlighting the benefits of CHP, Emory University's testimony pointed to other utilities, including Duke Energy, DTE Energy, AEP, and Florida Public Utilities that demonstrated supply-side or utility-owned CHP generation was "more beneficial to rate payers than having a large load leaving the utility's system by developing CHP behind their meter" (Kowal 2019).[15] While the proposed microgrid was ultimately not approved in the IRP settlement, the intervention initiated a dialogue between the utility, a large customer, and state regulators on the role of CHP in IRP and allowed for a future review and approval by the commission if the economics show no additional cost to Georgia Power's ratepayers (Georgia 2019).

Missouri

When Ameren Missouri filed its 2017 IRP before the Missouri PSC, the Missouri Division of Energy intervened and filed testimony in response to the company's filing.[16] The Division argued, among other things, that "Ameren Missouri should fully consider facilitating CHP deployment as an element of providing safe and adequate service and based on the state policy of pursuing all cost-effective demand-side savings" (Missouri 2018a). This concern was resolved in a settlement in which Ameren Missouri indicated it was "willing to work with interested stakeholders to develop an agreeable cost effectiveness model of CHP that reflects using CHP as a load management and/or demand response resource…" according to the Missouri Energy Efficiency Investment Act

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[15] See Kowal 2019, p.5. To view live testimony about the proposed project at Emory University before the Georgia Public Service Commission, visit https://youtu.be/Twl2DD3HCkA.
[16] Missouri's Division of Energy is the state's energy office.

(MEEIA), and specified that "symmetric treatment of costs and benefits will be explicitly discussed during the development of the cost effectiveness model." (Missouri 2018b).

Michigan

In Michigan, there was active interest in response to DTE Energy's proposed 2019 IRP, both during the utility's stakeholder engagement efforts prior to filing and during the more formal regulatory proceeding before the Michigan Public Service Commission. Some intervenors expressed a desire for the utility to consider CHP more thoroughly in its resource plan (Michigan 2019). Participants highlighted the ability of CHP to protect customers from a grid failure, which provides continuity of critical services and frees up power restoration efforts to focus on other facilities during emergencies, resulting in electricity cost savings, reduced losses due to power outages, and increased reliability.

3. Examples of Evaluation of CHP as a Resource in IRPs

In the previous section, discussion of experience gained in Michigan, Virginia, Mississippi, Georgia and Missouri demonstrates a range of ways in which state leaders and other interested parties can encourage the consideration of CHP in integrated resource planning. Historically, evaluation of CHP in integrated resource planning has not been widespread. According to a review of IRPs conducted by the American Council for an Energy-Efficient Economy (ACEEE) in 2017, the vast majority of plans at that time had no meaningful discussion of CHP.[17] While some plans defined or mentioned CHP, its benefits as a resource were not commonly evaluated.[18] CHP was considered in only a handful of utility IRPs reviewed, including examples from utilities operating in three states – North Carolina, South Carolina, and Indiana – that explicitly evaluate CHP as a supply resource option in their plans. A brief discussion of Idaho Power's evaluation of CHP in its 2017 IRP is also included below. Some of the utilities that evaluated CHP in their plans indicated a preference for owning the assets themselves, such as Duke Energy, but others do not take a position on ownership and simply consider the costs and benefits of CHP in the context of their resource needs.

The following section provides three examples from utilities that included CHP in their planning exercises and selected a clearly defined amount of installed capacity (MW) to pursue during the period covered by the plan. The case studies describe how Duke Energy Carolinas, Duke Energy Indiana, and Indiana Michigan Power approach CHP in their IRP. They are listed in Table 1 and summarized below. Some additional noteworthy examples of plans that did not select a defined amount of CHP but offer useful insights on approaches for pursuing CHP as a resource, are also discussed at the end of the section.

Table 1. Utility plans that select CHP as a resource

	Amount of CHP Included (MW)	Installed by (Year)
Duke Energy Carolinas	44	2021
Duke Energy Indiana	15*	2020
I&M	27	2035

*Duke Energy Indiana selected 29 MW in 2016-2020 and 15 MW in 2021-2025, for a total of 44 MW in its no-carbon regulation portfolio. 15 MW were selected in its carbon tax scenario and in the recommended plan for 2015 – 2035. Sources: Duke Energy Carolinas 2018; Duke Energy Indiana 2015; I&M 2015.

[17] ACEEE reviewed a sample of 29 publicly-available IRPs or similar planning documents published between 2014 and 2017 to see whether and how utilities evaluate CHP as a resource. See Appendix A, "ACEEE Review of Integrated Resource Plans," for more information.
[18] Some of these plans may include a forecast of customer-adoption of CHP for the purpose of adjusting future demand curves, without evaluating CHP as a resource option on the supply-side.

3.1. Duke Energy Carolinas

Duke Energy serves 3.3 million electric customers in North Carolina and 740,000 customers in South Carolina. The company began evaluating the interest of its customers in hosting utility-owned CHP in 2015 and included projections for 44 MW of CHP as a capacity and energy resource in its 2018 IRP (Duke Energy Carolinas 2018). These 44 MW are also included in the company's Short-Term Action Plan, which identifies actions to be taken over the next five years.

The company identified numerous potential customer sites with continuous steam loads in its service territory and is currently constructing a 15 MW system at Clemson University. Using the base plan scenario in the IRP, the Clemson University CHP project is a cost competitive generation resource addition compared to traditional generation.[19]

3.2. Duke Energy Indiana

Duke Energy Indiana serves 840,000 electric customers. In its 2018 IRP, Duke Energy Indiana modeled as a baseload resource a 16 MW combustion turbine CHP installation.[20] The company selected the Moderate Transition Portfolio, which was designed to gradually diversify the resource mix without steeply increasing cost to customers over a short period. The Moderate Transition Portfolio accelerated coal unit retirements, replacing that coal capacity with a mix of resources summarized in Table 2, including 56 MW of CHP added between 2021 and 2026.[21]

[19] In integrated resource planning modeling, the base plan scenario is the expected scenario, determined by using assumptions that the utility considers most likely to occur. For further reading, see Regulatory Assistance Project, Best Practices in Electric Utility Integrated Resource Planning (June 2013), *available at* https://www.raponline.org/wp-content/uploads/2016/05/rapsynapse-wilsonbiewald-bestpracticesinirp-2013-jun-21.pdf
[20] Duke Energy Indiana 2018 IRP (Vol. 1) , p. 130.
[21] Ibid.

Table 2. Capacity Nameplate Additions (MW) for Moderate Transition Portfolio (2018 IRP)

	Net Additions (MW)*							
Year	CC	CT	Solar	Wind	Cogen	Storage	DR	EE
2018	0	0	0	0	0	0	74	5
2019	0	(8)	6	0	0	10	13	26
2020	0	0	2	0	0	5	28	22
2021	0	0	0	0	16	0	23	24
2022	0	50	0	0	0	0	22	24
2023	0	0	100	0	0	0	21	24
2024	0	0	150	50	20	0	(1)	27
2025	0	0	150	50	0	0	0	29
2026	0	0	150	50	20	0	1	23
2027	0	0	100	50	0	0	0	26
2028	1240	0	100	(50)	0	0	0	19
2029	0	0	100	50	0	0	0	15
2030	0	0	100	50	0	0	0	6
2031	0	0	100	50	0	0	1	1
2032	0	0	100	50	0	0	0	7
2033	0	0	100	50	0	0	0	8
2034	1240	0	100	50	0	0	0	1
2035	0	0	100	50	0	0	1	(5)
2036	0	0	79	50	0	0	0	(4)
2037	0	0	100	50	0	0	0	(2)

Source: Duke Energy Indiana 2018 IRP

3.3. Indiana Michigan Power (I&M)

Indiana Michigan Power (I&M) is a unit of American Electric Power (AEP) serving approximately 587,000 customers in Indiana and Michigan. In its 2015 IRP, CHP was not originally included as a resource option, but I&M began modeling it after receiving stakeholder input. Ultimately, 27 MW of CHP at two customer sites were included over the planning period of the Preferred Portfolio. I&M indicated the locations of the two projects were unknown at the time, but planned to work with customers to identify a good fit (I&M 2015).

In its 2018 IRP, I&M again included CHP in its resource evaluation, modeling CHP as a 15 MW facility utilizing a natural gas fired combustion turbine, Heat Recovery Steam Generator (HRSG) and selective catalytic reduction (SCR) to control NOx emissions, assuming all of the steam was taken by the host and the efficiency of the modeled CHP resource was credited for the value of the steam provided to the host. The overnight installed cost was estimated to be $2,300/kW and the assumed modeled full load heat rate was approximately 4,800 Btu/kWh, and the assumed capacity factor was 90%.[22] I&M's 2015 and 2018 IRPs stand out for the transparency of their assumptions, all of which are documented in the plans.

3.4. Other Noteworthy Examples

Other utilities conducted meaningful exercises to evaluate or consider CHP, but did not set an explicit target for acquiring a defined amount of CHP or clearly define an approach for pursuing CHP as a resource. These noteworthy examples are summarized below.

Indianapolis Power & Light Company (IPL)

IPL provides retail electric service to 480,000 customers in Indianapolis and other central Indiana communities. IPL commissioned the engineering firm Burns & McDonnell to prepare a report detailing cost and performance assumptions for CHP in their 2016 IRP.[23] These parameters had not been included in previous planning studies.

IPL modeling, summarized below in Table 3, "reflects attributes of these resource[s] regardless of ownership" and selected CHP in two of four scenarios. 225 MW is included in the Distributed Generation Portfolio, which reflects high customer adoption of DERs, and in the Hybrid Preferred Resource Portfolio, which reflects public pressure to reduce emissions, customer adoption of DERs, additional environmental costs, and the possibility that technology costs decline more quickly than modeled.[24] Ultimately, IPL described the Hybrid Preferred Resource Portfolio as "the right mix of resource types that minimizes cost and risk for the customer, allows for flexibility in the response to future market changes, and provides balance to the portfolio in terms of cost, environmental impact, and risk."

Table 3. IPL Summary of Resources in MW (Cumulative changes 2017-2036)

	Final base case	Strengthened environmental	Distributed generation	Hybrid
Coal	1,078	0	1,078	1,078
Natural gas	1,565	2,732	1,565	1,565
Petroleum	11	11	11	0
DSM and DR	208	218	208	212
Solar	196	645	352	398
Wind with ES*	1,300	4,400	2,830	1,300
Battery	500	0	50	283
CHP	0	0	225	225
Totals	4,858	8,006	6,319	5,060

Source: IPL 2016. *Energy storage

Vectren

Vectren Energy Delivery of Indiana, Inc. (Vectren) provides natural gas and electricity to customers in Indiana, with 144,000 electricity customers in a 7-county region. According to Vectren's 2016 IRP, "CHP technical and operating

[22] A power plant's capacity factor is the ratio of its actual output over a period of time, usually a year, to its output if it were to operate at full nameplate capacity continuously over the same period of time.
[23] As of November 2019, IPL's 2019 IRP stakeholder process was still ongoing, with an IRP expected to be filed at the conclusion of public advisory meetings scheduled through December 2019.
[24] See IPL 2016, p. 208.

considerations should include the following: customer electric load and thermal requirements inclusive of a detailed engineering and feasibility review. The matching of high load factor thermal load is key to CHP success." The company also indicated it was monitoring developments in customer-owned CHP and including CHP as a supply-side resource option.

For its cost-effectiveness screening, Vectren modeled several different size CHP systems (1 MW, 3 MW, 5 MW, 10 MW, 15 MW) and assumed it would own the facility. The technical and operating assumptions used for the screening are published in the plan.[25] Of the different size CHP systems modeled, only the largest – a generic 15 MW CHP system – emerged as a cost-effective alternative to construction of new conventional generation resources. The company also conducted a review of potential CHP host sites and identified a market potential for customer-sited CHP of approximately 30 MW in the Vectren South service territory.

As of November 2019, the stakeholder process for Vectren's 2019 integrated resource planning process was ongoing, with public meetings scheduled through May 2020. During the second stakeholder meeting held in October 2019, Vectren provided examples of candidate CHP gas generation to be modeled in its 2019 IRP, as shown in Table 4.[26]

Table 4. Candidate Gas CHP Generation to be modeled in Vectren 2019 IRP

Gas Combined Heat and Power*	2 x 10 MW Recip Engines	20 MW Combustion Turbine
Net Plant Electrical Output (MW)	17.9 MW	21.7 MW
Fixed O & M (2019 $/kW-yr)	$42	$35
Total Project Costs (2019 $/kW)	~$2,800	~$4,600
**Utility owned and sited at a customer facility*		

3.4.1. Idaho Power

Idaho Power, headquartered in Boise, Idaho, serves more than 560,000 customers in a 24,000 square mile service territory. In its 2017 IRP, Idaho Power modeled CHP using a capital cost of $2,213 per kW and a 40-year levelized cost of energy of $71 per MWh, assuming an annual capacity factor of 80% (Idaho Power 2017). The company recognized the actual cost of a CHP resource varies and noted that CHP can be challenging to model in an IRP setting, although the company "is committed to working with individual customers to design operating schemes that allow power to be produced when it is most valuable, while still meeting the needs of the steam host's production process."

4. Characterizing CHP as a Resource Option

Utilities with experience evaluating distributed generation should already be well-positioned to include CHP in their planning exercises from a technical perspective. No additional analytic tools are needed. It can be useful to collect some basic data as a starting point for modeling and conducting cost-effectiveness screenings. The following section reviews the assumptions needed to characterize CHP in an IRP and provides specific examples of how two utilities compared the cost-effectiveness of CHP to other resources. It concludes with a brief discussion of additional benefits of CHP that could be included in cost screenings, but are not currently captured well by traditional frameworks.

[25] See Vectren 2016, Figure 5.7.
[26] Vectren 2019 IRP, Vectren Stakeholder Meeting #2 (PDF), p. 80, *available at* https://www.vectren.com/assets/downloads/planning/irp/IRP-2019-Vectren-Stakeholder-Meeting-2.pdf

4.1. Modeling Parameters and Other Assumptions

The modeling parameters and assumptions described in this section are inputs that would be a good starting point for including CHP in modeling used for IRPs.

Resource Potential

A CHP potential study could help estimate how much CHP capacity (MW) would be reasonable to model in a planning scenario. One initial step is to review the state-specific estimates of CHP technical potential in the 2016 DOE study (DOE 2016). Note that the projections of potential can vary significantly by service territory, depending on the availability of customer sites with consistent thermal loads. Sites that usually have consistent thermal loads are manufacturing facilities, hospitals, campuses and universities, hotels and casinos, and large commercial or multifamily buildings.

Customer Thermal Loads

Significant, and consistent thermal energy demand is essential to reaching the economic efficiencies that utilities can achieve by incorporating CHP in IRPs. CHP provides maximum benefits when a system is sized to meet all of the thermal demand of a given facility. In this way, the thermal load at the customer site influences the size of the system, and in order to maximize both energy efficiency and economic efficiency, the CHP system should be designed for high annual operating hours and maximum use of the thermal output and operated accordingly.

CHP System Characteristics

Additional assumptions about the performance, operating and cost characteristics of CHP systems are also needed. Planners can obtain cost and performance data for various types of CHP technologies of different size ranges from sources such as the US Department of Energy's (DOE's) CHP technology Fact Sheets (DOE n.d.), the EPA Combined Heat and Power Partnership (EPA n.d.) and the DOE CHP Technical Assistance Partnerships (TAPs). DOE's Technology Fact Sheets include typical CHP system cost and performance characteristics by technology (i.e., reciprocating engines, microturbines, gas turbines, fuel cells and steam turbines) and by size that can be the basis for IRP modeling parameters. For example, when the Michigan Energy Office completed its IRP modeling for the CHP Roadmap for Michigan using the open-source STEER Model, it "incorporated CHP technologies for inclusion in Michigan's generation portfolio based on the performance characteristics and costs published by EPA with potential deployment numbers and capacities published by DOE." (MEO 2018)

States may also work with their affiliated DOE CHP TAP or private consultants to develop state-specific estimates of market potential and CHP operating characteristics, and make other assumptions needed to compare the cost of generating electricity from CHP with other resources.

4.2. Comparing Cost-Effectiveness of CHP with Other Resources

Because of the substantially increased fuel efficiency and high capacity factor of most CHP, well-sited and properly designed systems can be a least cost resource compared to other baseload resource options available.[27] Many of the additional, unique features of CHP are more challenging to capture and value in a traditional cost-benefit framework, such as increased reliability and energy resilience including on a locational basis, lower emissions, or state economic development. CHP provides additional reliability because it does not rely on transmission lines, and is more efficient in light of lower transmission losses. States and utilities that develop planning frameworks

[27] For utility-owned CHP on the supply-side, utilities may apply the revenue from steam sales by the CHP system back to the cost of fuel for generating electricity. Crediting steam sales from CHP back to fuel costs covered by all customers is an important part of the equation for evaluating CHP as a least-cost generating option.

that carefully consider these beneficial attributes of CHP are likely to find CHP can be a useful solution that minimizes system costs and maximizes customer benefits.

Levelized cost of electricity (LCOE) is a common metric for comparing the utility's cost of different generating resources. It represents the cost per kWh of building and operating a plant over its expected lifetime. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate (or capacity factor) for each plant type. However, note that LCOE does not include avoided transmission and distribution costs. Because of the substantially increased fuel efficiency and high capacity factor of most CHP projects, well-sited and properly designed systems can be more cost-effective than other baseload resource options available. The following graphs, excerpted from IRPs prepared by Duke Energy Indiana and I&M in 2015, demonstrate actual cost comparisons that account for these factors.

Figure 5 shows Duke Energy Indiana's baseload screening analysis from its 2015 IRP, which evaluates a range of baseload technologies using different fuels including CHP under a variety of scenarios. The scenario shown in Figure 5 is the core "no carbon regulation" scenario that assumes no carbon regulation or renewable energy portfolio standard and rewards low capital cost portfolios.[28] The screening indicates that CHP (the purple line) is competitive with combined cycle generation as a least-cost resource throughout the capacity range and is lower cost than combined cycle at capacity factors above 50%. Note that the Energy Information Administration estimates that the national average capacity factor for natural gas combined cycle power plants in 2017 was 51.3% (EIA 2019b).

[28] For more information on scenario assumptions, see Duke Energy Indiana 2015 p. 136 – 137.

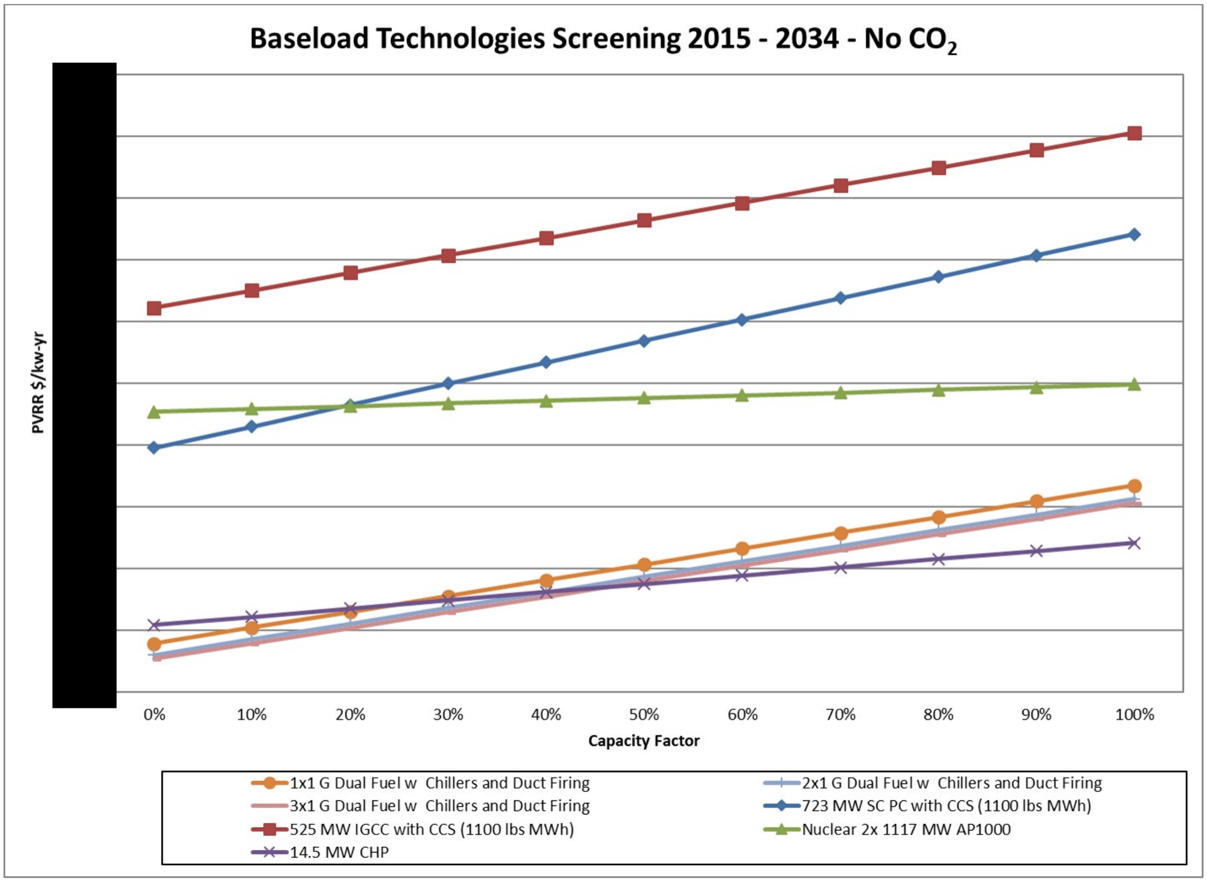

Figure 5. Duke Energy Indiana's supply-side resource screening analysis. (Source: Duke Energy Indiana 2015)

Figure 6 shows Indiana Michigan Power Company's (I&M) comparison of the cost of CHP with other natural gas-based resource options, relative to capacity factor, in its 2015 IRP (I&M 2015). I&M estimates that CHP operating at a capacity factor of about 65% or higher has a lower LCOE than a combustion turbine (CT) but higher LCOE than a combined cycle (CC) until the costs converge at around 95% capacity factor.

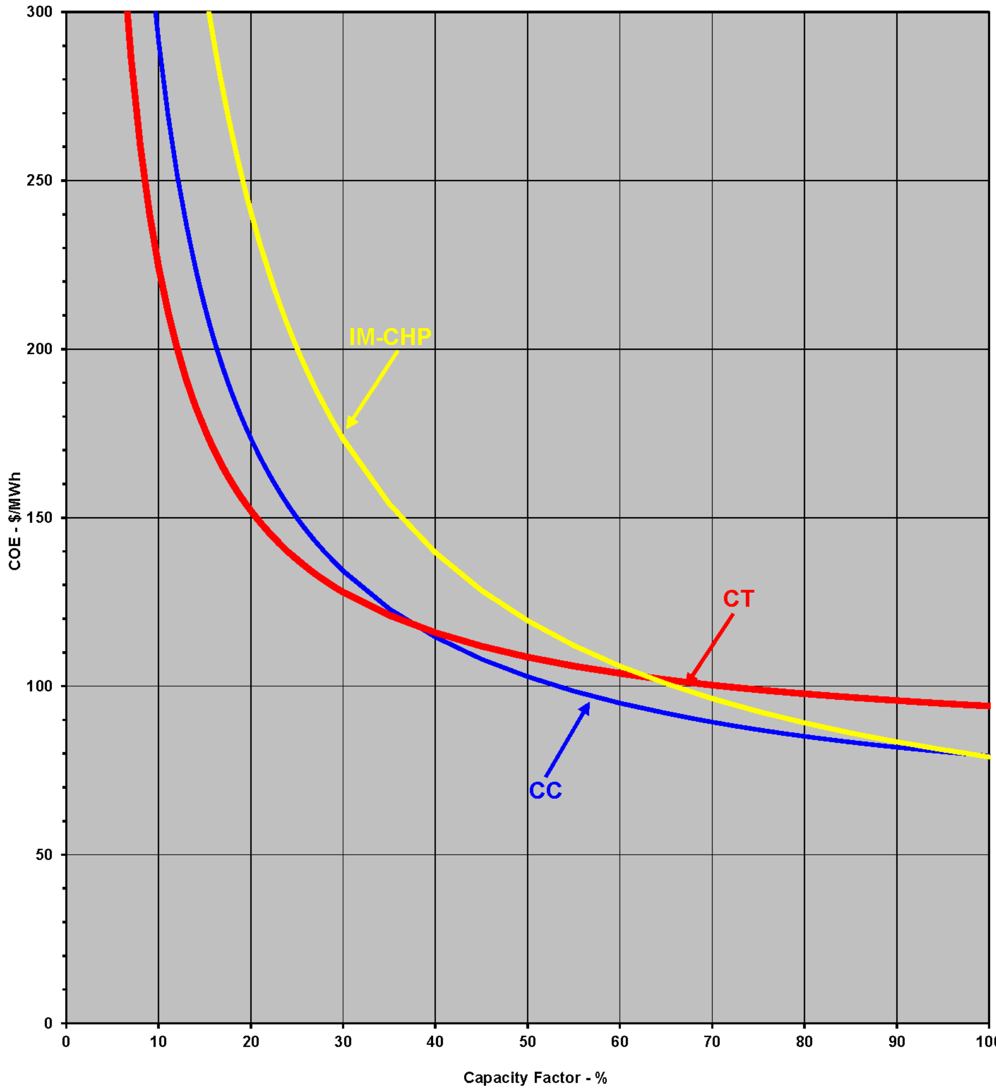

Figure 6. CHP cost of electricity ($/MWh) vs. capacity factor (%). (Source: I&M 2015)

The above examples are two variations on comparing CHP systems with other types of supply side resources within a utility resource portfolio. One consideration for such comparisons is whether the CHP system(s) in multiple configurations are compared on an equal basis on a cost per MW basis with comparative inputs as the other resource options within a resource plan.

4.3. Additional Benefits of CHP to Consider

In addition to the cost of capital, operations and maintenance (O&M), and fuel, which are commonly used, well-known variables that are relatively simple to evaluate, there are additional benefits of CHP to consider in utility resource planning.

The locational value of CHP is another important feature to consider, since the benefits can be greater depending on where CHP is located and how it is deployed. CHP is often thought about as providing baseload capacity, generating electricity and thermal energy consistently throughout the day. In addition to providing an always-on source of power, modern CHP systems are capable of acting as a more flexible resource, offering key grid-supporting services needed to maintain operations and help balance the distribution system. CHP's ability to defer or avoid the need for substation or switchgear investments, provide back-up power, deliver black start capability, or offer other ancillary services are additional features that are not usually factored in to these cost screenings.

As a growing number of states and utilities contemplate the benefits and costs of distributed energy resources, new approaches to benefit cost analyses will be needed to optimize value from ratepayer investments.[29] Supplemental types of plans, such as the distribution system plans, could play an important role in augmenting or becoming integrated with existing IRP and IRP-like activities. Some states are using this time of profound change within the electric industry to reassess what their energy resource planning and cost-effectiveness tests are accomplishing.

5. Considerations and Next Steps for States and Utilities

With an understanding of the role CHP can play in future resource planning and how it can support a least-cost utility resource portfolio, states and utilities may benefit from the following considerations to further explore the integration of CHP in their planning processes.

5.1. Considerations for States

Evaluate and Clarify How CHP is Treated in State Planning Rules

The interplay between a state's energy laws can be confusing and uncertainty may prevent a utility from trying something new, such as CHP, in its integrated resource plan. For example, in Ameren Missouri's 2017 IRP proceeding, uncertainty over how CHP may be classified as an eligible measure for energy efficiency programs complicated efforts by a utility to consider the benefits of CHP in its IRP process, either as a demand-side or supply-side resource (Missouri 2018a, 2-3). Clarifying the eligibility of CHP in these programs while encouraging the meaningful and comprehensive consideration of CHP in integrated resource planning could help to keep all options on the table.

Explore and Study the Role of CHP in Electric Utility Planning

Utility commissions can initiate efforts such as technical workshops, opportunities for stakeholder input, or studies to explore the role of CHP in the IRPs of their regulated electric utilities. See, for example, the Washington Utilities and Transportation Commission's policy statement on the role of energy storage in utility planning, which provides a good example of procedural activities and policy guidance that could similarly be undertaken for CHP (Washington 2017).

Provide Guidance on Utility Ownership of CHP as a Component of the Rate Base

In most states, existing guidance does not discuss how the utility commission views utility-ownership of CHP. Commissions could add guidance to clarify an approach for considering proposals for utility-owned, customer-sited CHP as a component of the rate base. Such guidance would provide utilities with more certainty in seeking regulatory approval.[30]

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[29] For example, the National Standard Practice Manual, a publication of the National Efficiency Screening Project coordinated by E4TheFuture, provides a comprehensive framework for cost-effectiveness assessment of energy resources, with a focus on energy efficiency. The Project is developing an expansion to include other DERs.

[30] Regulators may also consider whether to adopt rules to prevent cross-subsidization and preferential treatment between a utility's regulated and unregulated arms, including the utility's affiliated entities that may be providing CHP. For example, in 2018 the Michigan Public Service Commission adopted updated code of conduct rules, including affiliate transaction guidelines, for all utilities and alternative electric suppliers. *See* Michigan Public Service Commission, Case No. U-18361, Order dated December 20, 2018.

Revise IRP Rules to Ensure Inclusion of CHP

Regulatory commissions can review existing resource planning rules to ensure they reflect current state priorities and initiate rulemaking procedures to revise them if not. In order to optimize and enable non-utility solutions, states may consider whether to require consideration of customer-owned CHP in integrated resource planning. In recent years, several states have amended IRP rules to require utilities to specifically address certain technologies. In 2018, more than 15 states considered changes to the integrated resource planning process, with an emphasis on ensuring that complete consideration of all the costs and benefits of alternative resources are being evaluated (NC CETC 2018). Recent state policy actions in Michigan (Michigan 2016) and Virginia (Virginia 2018, 34) show that CHP is an important consideration in integrated resource planning in those states, while other states consider similar actions (Mississippi 2019a, 4-5).

Issue Guidance and Support Modeling Frameworks that Value the Benefits of CHP

Provide input in the IRP or other planning process to help set modeling parameters and assist with assumptions for utility system planners. This can include resilience benefits when serving critical facilities or critical areas of the distribution system, avoided investment costs when CHP systems are targeted to areas of the grid that need immediate capacity increases, and the value of ancillary services a CHP system may be able to provide.

Encourage Collaboration and Inclusion Across State Agencies

State leaders in various agencies may have expertise and valuable perspectives to contribute to discussions on the role of CHP in resource planning. For example, a state energy office may participate in regulatory discussions, including IRP proceedings. Missouri's state energy office, the Missouri Division of Energy (MDE), has participated in utility rate cases and IRP dockets before the Missouri Public Service Commission, and in 2017 requested more robust consideration of CHP in Ameren's IRP proceeding (Missouri 2018a, 2-3).

Require Utilities to Perform Outreach and Solicit Stakeholder Input in Developing Resource Plans

Effective stakeholder engagement increases accessibility and transparency, can build trust, and enhance cooperation and collaboration. Two-way knowledge sharing throughout the development of an IRP, from forecasting to modeling to the issuance of requests for proposals (RFPs), benefits all parties. By requiring, or strongly encouraging utilities to seek stakeholder input, state leaders can help to ensure a rigorous process with stakeholder buy-in. For example, under Indiana Code § 8-1-8.5-3(e)(2), electric utilities are required to submit IRPs every three years, with the plans subject to a rigorous stakeholder process.[31]

5.2. Considerations for Utilities

Identify Potential for CHP to Meet System Energy and Reliability Needs in Service Areas

Before launching a new CHP acquisition strategy, it is important to know whether there is the technical potential for CHP to provide the electricity needs of a service territory. Utilities and their key account representatives are aware of their largest electricity customers and can identify users that also have a demand for thermal energy as potential candidates for CHP. A rough-cut analysis of technical potential for CHP can be compared to known electric system needs and constraints to identify whether there are areas of the system that might be well-suited to CHP. The DOE CHP Technical Assistance Partnerships (TAPs) are also available to assist utilities in identifying CHP potential in their service area.

[31] *See* Indiana Utility Regulatory Commission, Integrated Resource Plans, *available at* https://www.in.gov/iurc/2630.htm

Evaluate Customer Hosts/Assess Interest in Service Territory

Through key account managers and energy efficiency program staff, it may be possible to understand where if any customer/host interest in CHP is present in a service territory. Key account managers and others with intimate knowledge of larger customers' energy needs and future growth plans are well-equipped to identify specific locations where a large thermal demand may coincide with a need for near term equipment upgrades, concerns about reliability or other conditions that lend themselves well to CHP. Surveying customers ahead of the development of an IRP can help provide appropriate projections for deployed CHP in utility plans.

Conduct Feasibility Assessments

Once potential locations are identified, a simple feasibility assessment can take into account facility energy use patterns and evaluate whether it makes sense to move forward with a more detailed investment-grade analysis of a CHP system. This is also an opportunity to identify whether a given facility already has dedicated staff onsite who might help move the project forward internally within the host company. The DOE CHP Technical Assistance Partnerships (TAPs) are available to provide high-level screenings to help assess feasibility for CHP.[32]

Issue a Request for Proposals (RFPs) for CHP Projects

An RFP for CHP projects can initiate partnerships between CHP developers and potential customers that can present concrete proposals to a utility. These proposals, in turn, can be evaluated in a utility's IRP modeling. For example, as part of its 2019 integrated resource planning process, Vectren issued an all-source RFP targeting 10 to 700 MW of capacity and unit-contingent energy, stating that "[m]arket information gathered from this RFP will be utilized within the IRP to inform the outcome of the 2019/2020 IRP."[33]

PUTTING IRPS INTO ACTION: DUKE ENERGY PLANS FOR NEW CHP AT UNIVERSITIES

Duke Energy Carolinas began evaluating the interest of its customers in hosting utility-owned CHP in 2015 and incorporated projections for 44 MW of CHP in its 2018 IRP, including a new CHP plant at Clemson University to be owned and operated by Duke. The system is currently under construction and expected to be operational in 2020. It will provide the university with 15 MW of electricity and 100,000 pounds/hour of steam, allowing the university to island from the grid to keep critical loads operational.

Conceptual rendering of Clemson University CHP System. Source: Burns & McDonnell

Similarly, Duke Energy Indiana included in its 2018 IRP a plan to build, own and operate a new 16 MW CHP project with planned completion in 2021. The proposed system CHP facility would serve as a baseload steam supply resource for Purdue University and baseload electricity supply for Duke Energy Indiana customers. It would consist of a natural gas fired turbine generator with a single heat recovery steam generator and a duct burner, capable of providing additional steam at Purdue's discretion.

For more information see, Duke Energy Indiana's petition to the IURC for the project (IURC 2019).

[32] For more information about the CHP Technical Assistance Partnerships (CHP TAPS), visit https://betterbuildingssolutioncenter.energy.gov/chp/chp-taps
[33] *See* Vectren, Integrated Resource Plan, All-Source RFP, *available at* https://www.vectren.com/irp

Develop Project Priority Pipeline

Once feasibility assessments are conducted, the potential projects can be prioritized based on known timelines (e.g. when a boiler replacement is planned) or distribution infrastructure needs. These potential projects can be evaluated in IRPs.

Measure Long-Term Benefits

Because there are so few utility-owned CHP systems sited at customer sites, there is little information on how contractual arrangements are updated, how and when major retrofits take place, and how CHP system features are affected when stakeholder interests change. By continuing to measure and evaluate the benefits and costs that were included in the original cost-benefit framework, utilities and other stakeholders can have a much clearer view of how CHP can fit into their resource landscape in the future.

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Appendix 1. ACEEE Review of Integrated Resource Plans

A sample of 30 publicly-available IRPs or similar planning documents were reviewed to see whether and how utilities evaluate CHP as a resource.[34] The selection includes plans that were most readily available and covers almost half of the US states.[35] These plans are the most recent of their kind from each utility and were published between 2014 and 2017. Table 5 provides a list of utilities, states, and the year the planning study was conducted. With limited exceptions, the focus of this research by ACEEE was on IOUs; further research may be warranted with regard to resource planning by consumer-owned utilities.

Table 5. List of utilities, states, and year of planning studies reviewed

Utility	State	Year
Alabama Power	AL	2016
Ameren	MO	2016
Appalachian Power	VA	2016
Arizona Public Service Company	AZ	2017
Cleco Power	LA	2015
Dominion	VA, NC	2016
Duke Energy Carolinas	NC, SC	2018
Duke Energy Indiana	IN	2015
Entergy Arkansas	AR	2015
Entergy Louisiana	LA	2015
Eversource	NH	2015
Georgia Power	GA	2016
Idaho Power	ID	2017
Indiana Michigan Power Company (I&M)	IN, MI	2015
Indianapolis Power & Light Company (IPL)	IN	2016
Los Angeles Department of Water & Power (LADWP)	CA	2016
Northern Indiana Public Service Company (NIPSCO)	IN	2016
NV Energy	NV	2016
Oklahoma Gas & Electric Company (OG&E)	OK	2014
Pacificorp	OR, ID, WY, CA, UT	2017

[34] ACEEE reviewed a sample of 29 publicly-available IRPs or similar planning documents published between 2014 and 2017 to see whether and how utilities evaluate CHP as a resource. Idaho Power's 2017 IRP was subsequently added to this summary.
[35] Note some states do not have requirements for utilities to file IRPs. See earlier discussion.

Portland General Electric (PGE)	OR	2016
Puget Sound Energy (PSE)	WA	2015
Salt River Project (SRP)	AZ	2014
South Carolina Electric & Gas Company (SCE&G)	SC	2016
Southwestern Electric Power Company (SWEPCO)	LA	2015
Southwestern Public Service Company (SPS)	NM	2015
Tennessee Valley Authority (TVA)	TN, AL, GA, KY, MS, NC, VA	2015
Tucson Electric Power (TEP)	AZ	2017
Wisconsin Power & Light (WPL)	WI	2014
Vectren	IN	2016

5.3. Analysis of Treatment of CHP

Utilities typically analyze multiple scenarios within integrated resource planning, each with a different mix of resources and different assumptions about load forecast; fuel prices; capital costs of generation, transmission, and distribution equipment; future regulation, and other anticipated conditions. In this assessment, the review first looked for any discussion of CHP in a plan. Second, if CHP was included, the review evaluated how utility planners treated CHP in general, and specifically looked for whether it was characterized as a resource option. Third, the review looked for the inclusion of CHP in the mix of resources modeled and reviewed how it was treated in cost-effectiveness screenings.

Utilities were grouped into four categories related to treatment of CHP in their IRP: no mention, little discussion, some treatment, or substantial treatment. Of the plans reviewed, six had no mention of CHP at all. Table 6 provides an overview of how plans were grouped in the assessment.

Table 6. Overview of treatment of CHP in resource planning

Category	Resource plan
No mention	Ameren Missouri, Eversource, NV Energy, OG&E, SRP, SPS
Little discussion	Appalachian Power, APS, Cleco Power, Dominion, Entergy Louisiana, Entergy Arkansas, Georgia Power, PacifiCorp, PSE, SCG&E, SWEPCO, TEP, TVA, WPL
Some analysis	Alabama Power, PGE
Explicit evaluation	Duke Energy Carolinas, Duke Energy Indiana, Idaho Power, I&M, LADWP, IPL, NIPSCO, Vectren

Fourteen plans had little discussion of CHP, meaning CHP is defined or mentioned in some way, but its benefits as a resource are not carefully evaluated. This category also includes those plans that forecast customer-adoption of CHP for the purpose of adjusting future demand, without evaluating CHP as a resource option on the supply-side.

Two plans had some progress toward treating CHP as a resource, meaning they indicate some interest in CHP as a supply-side resource or include a discussion of the adoption of utility-owned distributed generation technologies. For example, Portland General Electric's (PGE's) 2016 IRP included a study assessing CHP potential in Oregon, which showed 90.4 MW of CHP potential with a payback of less than 10 years. PGE suggests it will further evaluate

CHP in future IRPs and includes a discussion about the general benefits of utility resource ownership.[36] PGE explicitly does not add CHP to portfolios evaluated in the plan, though it does include a study of non-solar distributed generation. The study evaluated fuel cells and microturbines, but does not consider the configuration of these technologies in CHP operation; it evaluates them in electricity-only mode.

Eight plans offered more substantial treatment, meaning they explicitly evaluate CHP as a supply resource option in the plan. They were Duke Energy Carolinas, four utilities in Indiana (Duke Energy Indiana, I&M, IPL, NIPSCO, and Vectren), Idaho Power, and LADWP.

[36] See Section 7.7 of PGE 2016 for discussion on utility-ownership.

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CHP ROADMAP FOR MICHIGAN

Prepared for the Michigan Energy Office on behalf of the Michigan Agency for Energy and the US Department of Energy

February 2018

Project Team

The **Michigan Energy Office** (MEO) is within the **Michigan Agency for Energy** (MAE). MAE is a government agency within the Michigan Department of Licensing and Regulatory Affairs. MAE coordinates, analyzes, advises on, and advocates for the state's policies, programs, and proposals related to energy. The MEO is a recognized State Energy Office by the federal Department of Energy. MEO encourages and informs energy policy and technology and program development by facilitating partnerships, administering grant funds, and providing statewide education, outreach opportunities and stakeholder collaboratives.

5 Lakes Energy (5LE) is a Michigan-based policy consulting firm dedicated to advancing policies and programs that promote clean energy, sustainability and the environment. The team has decades of experience in research, modeling and analysis. From public policy design to reviewing policy implementation around the country and world, 5 Lakes Energy has the deep knowledge base necessary to review, analyze, and recommend models for optimizing the deployment of clean energy.

Sustainable Partners LLC (SPART) was formed in 2011 to develop and finance alternative and renewable energy projects and provide related consulting services to major industrial and commercial energy users. SPART excels at building consensus among stakeholders, leading cross-functional teams, and ensuring accountability, while helping clients thoroughly evaluate energy options and implement sustainable projects through advisory services and direct capital investment.

The **Energy Resources Center** (ERC), established in 1973 at the University of Illinois at Chicago, is an interdisciplinary public research center bringing experts from across the fields of electric, mechanical and environmental engineering, in addition to economics, public policy, and bioenergy. The ERC manages the U.S. Department of Energy's Midwest CHP Technical Assistance Partnership (TAP), which provides services to twelve Midwest states, including Michigan.

NextEnergy is one of the nation's leading accelerators of advanced energy and transportation technologies, businesses and industries. NextEnergy drives technology demonstration and commercialization, delivers industry and venture development services, and provides an authoritative voice in the public sector. Founded in 2002 as 501(c)(3) nonprofit organization, NextEnergy has helped attract more than $1.6 billion of new investment, including programs in excess of $160 million in which NextEnergy has directly participated.

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About the Report

The Combined Heat and Power (CHP) Roadmap for Michigan is a collaborative effort to accelerate the adoption of CHP in Michigan through three objectives:

1. Identify and evaluate CHP technologies and applications with a potential for adoption in Michigan;
2. Assess, measure, and determine the cost and value of CHP in Michigan's future energy mix;
3. Listen, educate, and advocate for the inclusion of CHP based upon economic, environmental, and system benefits.

Project partners worked to identify strategies to remove transactional, market, finance and policy barriers to CHP deployment. Project partners also worked to leverage proven methodology to map and engage the Michigan-specific CHP supply chain. This report shares results and recommendations that can be utilized to accelerate the adoption of CHP in Michigan and achieve the resulting economic benefits.

Acknowledgements

This report and the work described were supported by the U.S. Department of Energy and the Michigan Agency for Energy through the Michigan Energy Office under Award No. DE-EE0006226.

The authors gratefully acknowledge the assistance of the stakeholders in the CHP ecosystem who generously shared their time and expertise in completing surveys, participating in interviews, attending events, and providing other related information.

Glossary of Acronyms

5LE – 5 Lakes Energy, LLC

CHP – Combined heat and power

CI – Commercial/industrial

CIBO – Council of Industrial Boiler Owners

CODE2 – Cogeneration Observatory and Dissemination Europe

CPM – Continuous process manufacturing

CPP – Clean Power Plan

DE – Digital economy

DOE – United States Department of Energy

DTE – DTE Electric Company (formerly Detroit Edison)

EIA – United States Energy Information Administration

EPA – United States Environmental Protection Agency

EPRI – Electric Power Research Institute

ERC – Energy Resources Center

EWR – Energy Waste Reduction

F&ES – Fabrication and essential services

GDP – Gross domestic product

GW – Gigawatt

HHV – Higher heating value

IEI – Institute for Energy Innovation

IRP – Integrated Resource Plan

ITC – Investment tax credit

kW – Kilowatt

kWh – Kilowatt-hour

LHV – Lower heating value

Michigan EIBC – Michigan Energy Innovation Business Council

MISO – Midcontinent Independent System Operator

MMBtu – Million British thermal units

MPSC – Michigan Public Service Commission

MW – Megawatt

MWh – Megawatt-hour

NEP – New Energy Policy

NREL – National Renewable Energy Laboratory

NYSERDA – New York State Energy Research and Development Authority

PACE – Property Assessed Clean Energy

PURPA – Public Utilities Regulatory Policies Act

RAP – The Regulatory Assistance Project

REC – Renewable energy credit

RPS – Renewable Portfolio Standard

SPART – Sustainable Partners, LLC

STEER – State Tool for Electricity Emissions Reduction

TAP – Technical Assistance Partnership

WHP – Waste heat to power

WMAEE – West Michigan Association of Energy Engineers

Contents

Executive Summary

Michigan has the opportunity to capture enormous benefits by embracing optimal levels of combined heat and power (CHP) generation in its future energy mix. CHP provides a path to make Michigan businesses more competitive by lowering and stabilizing energy costs, reducing strain on the electric grid, improving on-site reliability and resiliency, and lowering harmful greenhouse gas emissions. Yet many studies have shown that CHP is a vastly underutilized energy resource across the country due to a combination of policy barriers, market impediments, and other factors. Michigan intends to be a leader in advancing CHP deployment and this CHP Roadmap is a significant initial step in that effort.

CHP is *the* most fuel-efficient way to produce and utilize both electric and thermal energy from a single fuel source. CHP adoption across Michigan offers a low-cost approach to new electricity generation and uses highly skilled Michigan labor and technology to develop, implement, and operate projects.

Governor Snyder has made smart energy policy a top priority for Michigan, emphasizing the need to reduce energy waste and increase reliability. A confluence of executive and legislative interest in energy policy, coupled with recognition of the potential of CHP to participate in meeting Michigan's energy needs, means the time is right to accelerate CHP deployment in Michigan.

The CHP Roadmap for Michigan differs from previous projects by applying a cutting-edge integrated resource modeling tool to determine least-cost deployment of CHP resources. This model – the State Tool for Electricity Emissions Reduction (STEER) – calculates the least-cost resource portfolio to satisfy electricity demand and various reliability and environmental constraints based on projections of demand, fuel prices, technology price and performance, taxes, and other factors. Depending on natural gas prices and the availability of renewable energy resources, STEER recommended an optimal level of additional CHP deployment in Michigan ranging from 722 MW to 1,014 MW by 2030.

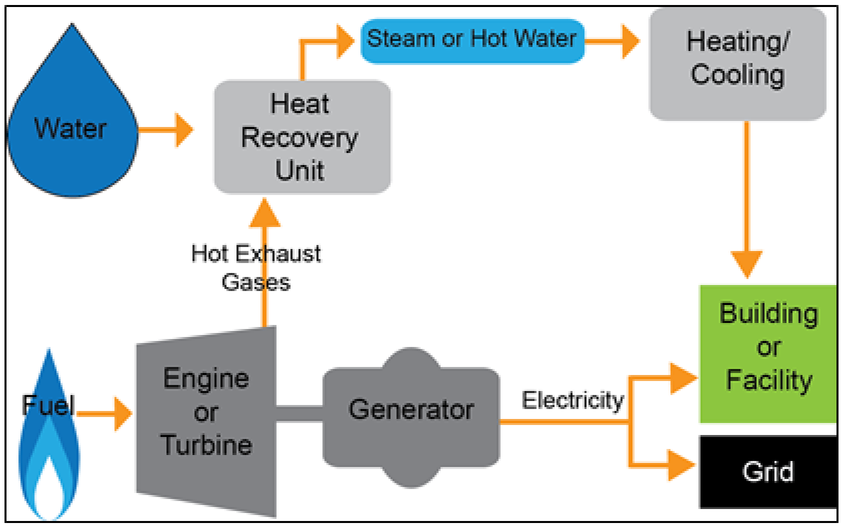
Parallel to this modeling effort, an intensive analysis of Michigan's CHP-related supply and value chains provides insight to support state-level policy analyses and recommendations. Michigan firms have a robust ability to participate throughout the CHP value chain with the majority of economic impact being realized by using the pool of talent based in Michigan companies to design and implement CHP projects.

Finally, the Michigan CHP Roadmap provides a series of prioritized public policy recommendations that will put Michigan on a path to a CHP-friendly future, including recommendations to:

- Offer financing and incentives for CHP in order to reduce the payback period for CHP projects;
- Promote Property Assessed Clean Energy (PACE) financing and on-bill financing for CHP;
- Consider best practices in utility standby rates and PURPA avoided cost/buyback rates;
- Fully value CHP when considering the costs and benefits of distributed energy resources;
- Update interconnection standards to better align with new technologies and best practices;
- Incorporate CHP as a resource in Michigan utility energy waste reduction (EWR) plans;
- Require utility integrated resource plans (IRPs) to consider CHP as both a supply-side and demand-side resource;
- Collaborate closely with expert organizations, such as the Midwest CHP Technical Assistance Program (TAP), to promote CHP assistance.

Background

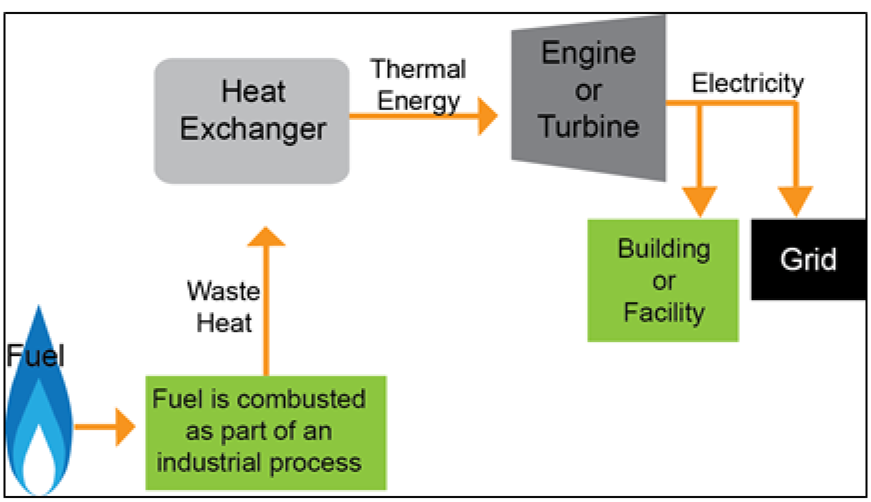
CHP is the simultaneous generation of electricity and useful thermal energy from a single source of fuel, located at or near the point of energy use. Electricity is primarily used on site as a substitute for utility-provided power, with any excess generation potentially sold onto the grid. The thermal energy can be used to support process applications or human comfort through the production of steam, hot water, hot air, refrigeration, or chilled water.



CHP Topping Cycle

Installed CHP systems typically achieve total energy efficiencies of 65% to 80%, compared to a weighted average of only about 45% to 60% for conventional separate heat (via boilers/furnaces) and power generation (via central utility plants). By avoiding electric line losses and utilizing much of the thermal energy normally wasted in power generation, CHP significantly reduces the total primary fuel needed to supply energy services, reducing greenhouse gas emissions and saving fuel and money. CHP systems can range in size from 5 kilowatts (kW; the demand of a typical single-family home) to several hundred Megawatts (MW; the demand of a very large industrial plant).

CHP technology can be deployed quickly, with few geographic limitations, and can utilize a variety of fuels, both fossil and renewable. CHP may not be widely recognized outside industrial, commercial, institutional, and utility circles, but it has quietly been providing highly efficient electricity and process heat throughout the United States for decades to vital industries, large employers, urban centers, critical infrastructure like hospitals and wastewater treatment plants, and university campuses.



CHP Bottoming Cycle: Waste Heat to Power (WHP)

Methodology

The methodology employed throughout the Roadmap was developed with the objective of replicability in other states. To achieve this objective, project partners relied on:

- U.S. Department of Energy (DOE) state-by-state CHP technical potential projections,
- U.S. Environmental Protection Agency (EPA) data on CHP economics and performance across a range of technologies and generating capacities, and
- U.S. Energy Information Administration (EIA) data for Michigan's existing power plant portfolio

According to DOE, Michigan has nearly 5 GW of CHP technical potential at more than 10,000 sites across 17 industrial and 24 commercial sectors. This potential, on a capacity basis, is roughly evenly split between industrial candidates in the transportation equipment, chemicals, primary metals, paper and food sectors; and commercial candidates in the commercial office building, higher education, hospital, retail location, and multifamily housing sectors.

The EPA provides cost and performance data for the five CHP technologies which comprise 99% of existing installations: reciprocating engines, steam turbines, combustion turbines, microturbines and fuel cells. Data from DOE, EPA and EIA serve as a major proportion of the input required for the STEER model to dynamically identify which CHP configurations are economically viable across a wide variety of scenarios. This analysis narrows the scope of Michigan's technical potential to only include those projects that are economically viable given Michigan's overall power generation portfolio.

Mapping of the Michigan CHP supply and value chain utilized methodology previously developed to support creation of the Michigan "Clean Energy Roadmap." Boundaries for supply and value chain mapping were determined through market research and market analysis based on likely economic impact to the state of Michigan arising from deployment of CHP projects. Market segments where Michigan companies are currently participating in the CHP supply or value chain were given principal consideration for surveys and interviews. A directory of Michigan supply and value chain firms has been created and will be distributed to foster collaboration and promote CHP deployment.

In customizing and prioritizing proposed solutions for Michigan, project partners considered the estimated proportion of potential projects affected, perception of barrier magnitude by stakeholders, and the ease/practicality of achieving change in the short term. Focus was placed on those barriers that are most significant to restricting deployment of CHP across Michigan and to which attainable solutions exist. These include 1) a lack of access to low-cost capital; 2) prohibitive utility rates; 3) failure to fully embrace CHP in energy waste reduction and integrated resource planning; and (4) a lack of awareness or familiarity with CHP. For the most part, solutions take the form of legislative change or regulatory relief, modification of utility rate structures, and financial incentives.

Finally, deployment of the Roadmap involves the ongoing effort to educate CHP stakeholders, and especially end-users, on the merits of CHP. Project partners engaged with over 300 individuals through outreach and education efforts related to the development of the Roadmap. Project partners are working with the Michigan Agency for Energy to expand outreach and assistance over the next several years as a critical step toward achieving the goal of accelerating the deployment of CHP in Michigan.

State Tool for Electricity Emissions Reduction (STEER)

The STEER model was used to assess, measure, and determine the cost and value of CHP as one of multiple resources in Michigan's future energy mix. In our primary application of STEER, we considered the net value of CHP to the economy by considering the cost of installing and operating various CHP systems, the value of the heat produced by CHP measured as the cost of supplying heat in the least-cost way other than CHP, and the value of electricity produced by the CHP system measured as the marginal cost of producing electricity absent the CHP system.

Because we determined that standby rates are one of the principal barriers to CHP adoption and may be amenable to policy adjustments, we also used STEER to evaluate the effect of standby rates on the economic potential for CHP in Michigan. Further, because resilience of CHP site host operations is an important benefit of CHP that is not reflected in standard electric power system evaluations, we also used STEER to evaluate the additional economic potential for CHP in Michigan if site hosts would not otherwise choose to build CHP but sufficiently valued resilience to enable them to build CHP. Consideration of resilience value increases the potential deployment of CHP in sectors where loss of power is most consequential and can significantly increase CHP potential beyond the levels that would be supported only by power sector value. Based on our analysis of Michigan potential, resilience value could increase CHP potential by around 60%. Standby rates, on the other hand, substantially reduce the profitability of CHP ownership and thereby reduce potential CHP deployment by 50% or more.

STEER modeling indicates that steam turbines, gas combustion turbines, and reciprocating engines appear profitable above some size threshold size in each scenario. Conversely, microturbines and fuel cells do not appear economically viable.

Scenarios with higher natural gas prices and higher cost of renewable resources in the future both tend to lower the minimum size threshold for the more viable CHP technologies, thereby expanding the number of potential installation sites in Michigan.

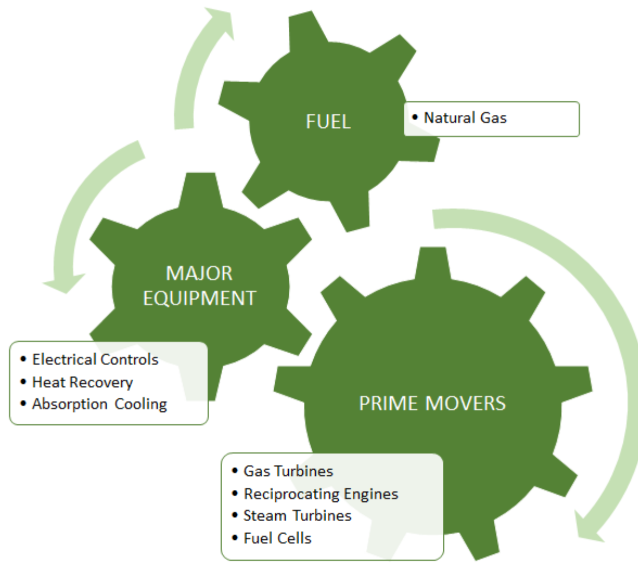
About half the sites where steam turbines are economically feasible are colleges and universities, confirming that this sector should be an important part of end-user outreach and education. We also note that this result does not necessarily mean that combustion turbines and reciprocating engines would not be suitable for many of these applications.

In our reference scenario, economic potential for CHP in Michigan is about 1,014 MW electric generation capacity with direct investment of about $865.6 million, annual direct O&M activity of about $67.6 million, annual economic profit of about $109.5 million, annual fuel cost savings of $94.7 million, and annual air emissions reductions of 662 tons CO_2 per year, 379 tons NO_x per year, and 39 tons SO_x per year.

In various scenarios, assuming various fuel and technology costs, the economic potential for new installed CHP in Michigan varies from 722 MW to 2,360 MW.

Michigan Supply and Value Chain

Demand for CHP projects in both the private and public sector is primarily driven by an economic comparison of the costs and benefits of CHP versus the costs and benefits of current operations. This status quo typically entails electric generation at a utility-owned power plant and thermal energy generation on-site by end-user-owned boilers or furnaces.

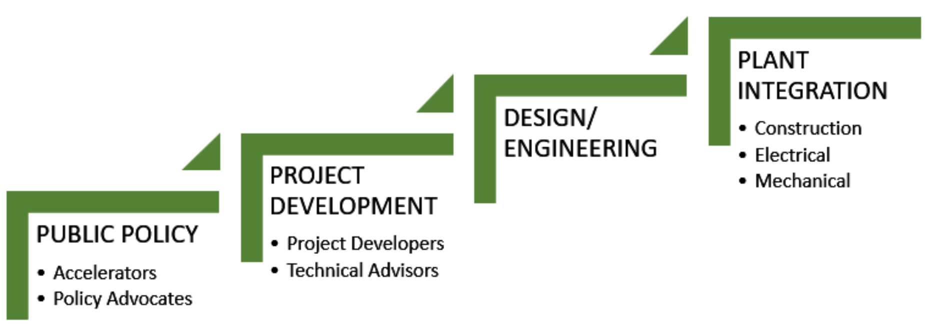


The **CHP supply chain** consists of the physical equipment and fuel required for the CHP system to operate. The major sectors of the CHP supply chain include CHP end-user applications, prime mover manufacturers and distributors, major equipment manufacturers and distributors, and fuel suppliers and brokers.

While Michigan manufacturers cannot realistically tap into prime mover manufacturing, there are a handful of Michigan companies that manufacture some of the major ancillary equipment that may be found in CHP projects but are not part of the prime mover systems. And manufacturers of both prime movers and other equipment execute sales, engineering, and service functions through Micihgan-based distributors.

Fuel supply and price can be controlled via 5 to 10 year contracts in most industrial and commercial locations, with costs currently near historic lows. This ability to control commodity costs significantly mitigates investment risk. In some regions of the state, particularly rural areas and the Upper Peninsula, the infrastructure for handling large volumes of natural gas is inadequate or nonexistent. Biomass-based fuel sources may be utilized but require significant additional effort on the part of the project developer. In the Upper Peninsula, unless a potential CHP project is located in one of the few major cities or along the east-west natural gas transmission corridor, fuel supply may be an impossible hurdle to overcome.

Michigan firms have a robust ability to participate throughout the **CHP value chain**, which consists of the intellectual capital and skilled trades required to develop, design, engineer, finance, install, and integrate CHP systems. The major sectors of the value chain include policy advocates and accelerators, project developers and technical advisors, design/engineering firms, and plant integration contractors. The majority of the economic impact of CHP will be realized by using this pool of talent based in Michigan companies to design and implement projects.



Barriers to CHP in Michigan

CHP has the potential to be a significant, reliable, cost-effective, and environmentally protective contributor to Michigan's energy mix. However, those interested in installing CHP projects face a number of obstacles. In order to fulfill the promise of energy waste reduction (EWR) in Michigan through optimal deployment of CHP, these barriers should be examined and understood in general, and in light of the unique circumstances facing Michigan energy users.

While CHP can save a system owner money in the long run, there are a few economic barriers that could prevent a CHP project from moving forward in the first place. The relatively high upfront cost of installing a CHP system can be a barrier in itself. Additionally, a lack of sufficient access to financing options can prevent otherwise cost-effective installations. CHP developers must navigate a complex landscape of project financing alternatives and provide detailed project information in order to attract investors. Inadequate information can cause project delays, leading investors to offer less favorable financial terms, or even decline a CHP investment opportunity all together.

Regulatory barriers can dramatically affect a CHP project's bottom line and projected payback period. An overarching barrier that affects the valuation of CHP throughout regulatory and policy discussions stems from the failure to account for the full value of CHP, including qualities such as resilience. Ignoring grid-wide and societal benefits affects how CHP is portrayed in standby rates, avoided cost rates, energy waste reduction standards and integrated resource planning. Standby rates, or charges a utility customer pays for the utility to provide backup service in case of a scheduled or unscheduled CHP system outage, can be so high as to completely undermine the economic viability of a proposed CHP system. Beyond standby rates, avoided cost or buyback rates under the Public Utility Regulatory Policies Act of 1978 (PURPA) may be insufficient to make a CHP project worthwhile. Interconnection processes can be lengthy, cumbersome and costly. Where states have embraced energy waste reduction (EWR) goals or standards, a failure to incorporate CHP, or to properly calculate energy savings from participating CHP systems, will lead to less than ideal deployment numbers. Finally, even as regulators and utilities embrace a longer-term resource planning approach, integrated resource planning (IRP) models often fail to recognize the value of CHP as both a supply side and demand side resource, resulting in CHP being overlooked in utility long-range resource plans.

Each of these barriers – which are often dependent on geography, project size and technology, utility constraints, and the prevailing regulatory climate – adds to the risk and cost associated with a potential CHP project. And since CHP is not regarded as part of most end-users' core business focus, it is often subject to higher investment hurdle rates than competing internal options.

Given the substantial capital investment involved in developing a CHP project, and in light of the benefits offered by more robust deployment of CHP, it is vitally important that these risks and costs be mitigated through thoughtful policies and incentives to avoid preventing CHP projects that would otherwise make good sense for Michigan businesses and the state's future energy mix.

Michigan businesses interested in CHP have access to the U.S. DOE's Midwest CHP Technical Assistance Partnership (TAP), managed by the Energy Resources Center and based in Chicago, Illinois. The Midwest CHP TAP promotes greater adoption of clean and efficient energy generation and use through CHP, district energy, and waste heat recovery. The Midwest CHP TAP provides a number of resources to potential CHP end-users including free or low-cost technical advisory services.

Roadmap for CHP Deployment

There is strong interest and capability for Michigan to move closer to optimal levels of CHP deployment. Currently, Michigan is home to over 3,300 MW of installed CHP capacity, and STEER indicates that ideal levels of CHP in Michigan include between 722 MW to 2,360 MW of new installed capacity. In order to pursue a greater role for CHP in Michigan's future energy mix, these recommendations reflect lessons learned from stakeholder surveys, interviews, Midwest CHP TAP experience and expertise, and best practices from other states.

1. **Offer financial incentives for CHP.** Payback period is critical to the development of a CHP project. Efforts to reduce the payback period of CHP by either defraying some of the initial upfront cost through a grant or offering a production incentive would be beneficial in addressing this barrier.
2. **Promote Property Assessed Clean Energy (PACE) financing and On-Bill Financing (OBF) for CHP.** PACE financing eliminates the high upfront cost and spreads the repayment over a long enough term that the annual savings generated from the CHP project exceed the PACE payments starting in the very first year. With OBF, the customer's costs of energy waste reduction retrofits or equipment are amortized and added to savings resulting from the measures on the customer's utility bill.
3. **Consider best practices in utility standby rates and PURPA avoided cost/buyback rates.** Standby rates are difficult are to interpret and navigate and negatively impact a CHP project's bottom line. The need for a revised approach to standby rates in Michigan stands as a prime example of a barrier to CHP that can be readily reduced or eliminated.
4. **Fully value CHP when considering the costs and benefits of distributed energy resources.** Michigan's current distributed generation program is targeted at small installations and does not include CHP. Future consideration of the costs and benefits of distributed energy resources should include CHP and attempt to capture its full value, including the value of resilience.
5. **Update interconnection standards to better align with new technologies and best practices.** Michigan's new energy law (passed in December 2016, PA341 and PA342) gives the MPSC authority to revisit and update the interconnection technical standards. Other states in the Midwest have recently revised their interconnection standards for small electrical generations to follow best practices and reflect the proposed standards in FERC Orders 792 and 792-A.
6. **Incorporate CHP as a resource in Michigan utility energy waste reduction (EWR) plans.** When allowed as an eligible measure, CHP can improve a utility's ability to meet energy reduction goals and further increase CHP deployment.
7. **Require utility IRP's to consider CHP as both a supply-side and demand-side resource.** This would help ensure that these complicated projects are allotted equivalent analyses as other resources.
8. **Collaborate closely with expert organizations (e.g. the Midwest CHP TAP) to promote CHP assistance.** These resources can be enormously helpful for those interested in developing CHP projects.

Moving Michigan Forward

Michigan is poised to move forward toward optimal levels of CHP development. According to the U.S. DOE, Michigan has nearly 5 GW of CHP technical potential at more than 10,000 sites across 17 industrial and 24 commercial sectors. STEER model results indicate that ideal levels of new CHP in Michigan, as a least-cost resource option, range between 722 MW to 2,360 MW.

This increase in CHP deployment will enhance Michigan's efforts to lead on energy waste reduction among other states. Currently, Michigan ranks 7th in the nation for potential annual CO_2 reductions from industrial energy efficiency and CHP and waste heat to power (WHP). In the 2017 American Council for an Energy Efficient Economy (ACEEE)Energy Efficiency Scorecard, Michigan was ranked 14th (tied with Arizona, Delaware, Iowa, New Jersey, New Mexico, Ohio, Texas, and Wisconsin) in the CHP category, slightly lower than its overall energy efficiency rank of 11th.

Demonstrating leadership in CHP development will serve to both reinforce and grow Michigan's demonstrated commitment to energy waste reduction. According to the Michigan Public Service Commission, regarding energy waste reduction overall, "For 2015, Michigan utility providers successfully complied with the energy savings targets laid out in PA 295. Providers met a combined average of 121 percent of their electric energy savings targets and 117 percent of their natural gas energy savings targets – one percent of retail sales for electric providers, and 0.75 percent of retail sales for gas providers. Energy Optimization programs across the state accounted for electric savings totaling over 1.1 million MWh (megawatt hours) and natural gas savings totaling over 4.58 million Mcf (thousand cubic feet) for program year 2015." CHP could be key to continuing to meet strong energy savings targets in the future. A single CHP system can offer the efficiency savings of many smaller energy efficiency projects. Given that some utilities are reporting a lower availability of cheap ("low hanging") energy efficiency savings opportunities in the commercial and industrial sector, CHP can offer deep savings at a very low cost, enhancing the overall cost-effectiveness of energy efficiency portfolios.

Execution of the Michigan CHP Roadmap will likely have significant impacts on the levels of CHP deployed in Michigan. For example, by addressing the CHP barrier of standby rates, STEER results using the EIA Reference Case indicate that Michigan could see an increase of 345 MW of CHP capacity built.

Additionally, CHP incentive programs in other states have seen dramatic results in additional CHP capacity coming online. The NYSERDA CHP incentive program has had an enormous market impact in New York. Between 2013 and 2016, the NYSERDA program has provided incentives to over 150 sites with a cumulative total capacity of over 70 MW. Similarly, in Illinois, the impact of the public sector CHP incentive was immediately felt, with the incentive program receiving 17 applications providing 31 MW of capacity. Through implementation of the Michigan CHP Roadmap, well-crafted CHP incentive programs could have similar positive effects on CHP development in Michigan.

Building on its strong commitment to energy waste reduction, Michigan is well-positioned to take advantage of the opportunities offered by increased CHP development in the state. By implementing the Michigan CHP Roadmap, the state can expand its energy waste reduction vision to include the many benefits of CHP, helping businesses to achieve their cost-savings and energy reliability goals. With key revisions to programs and policy, CHP has the potential to be a significant, reliable, cost-effective, and environmentally protective contributor to Michigan's energy mix.

1 Introduction

Michigan has the opportunity to capture enormous benefits by embracing optimal levels of combined heat and power (CHP) generation in the state's future energy mix. CHP provides a path to make Michigan businesses more competitive by lowering and stabilizing energy costs, reducing strain on the electric grid, improving on-site reliability and resiliency, and lowering harmful greenhouse gas emissions. Yet many studies have shown that CHP is a vastly underutilized energy resource across the country due to a combination of policy barriers, market impediments, and other factors. Michigan intends to be a leader in advancing CHP deployment and this Roadmap is a significant initial step in that effort.

Also known as cogeneration, CHP involves using one power system to generate both electricity and heat simultaneously from a single fuel source, and is the most fuel-efficient way to produce and utilize both electric and thermal energy. CHP systems typically reach fuel efficiencies of 65% to 80%, while the average efficiency of utility-scale electric generation has remained near 35% percent since the 1960s.[1]

CHP adoption across Michigan offers a low-cost approach to new electricity generation and uses highly skilled Michigan labor and technology to develop, implement, and operate projects. CHP is likely to enhance the competitiveness of Michigan's manufacturing, commercial, and institutional sectors, while lessening the need for new investments in utility transmission and distribution infrastructure.

Governor Snyder has made smart energy policy a top priority for Michigan, emphasizing the need to reduce energy waste and increase reliability. Through his leadership, the state remains focused on meeting its energy needs while protecting the environment and reducing customers' energy bills. Late in 2016, Governor Snyder signed into law an important package of energy legislation (MCL 460.6t(5)(g)), which accomplishes the following:

- Reduces energy waste by providing incentives for utilities to enhance current energy waste reduction programs;
- Ensures a reliable energy supply by requiring all electric providers to have adequate resources, using a market-driven approach;
- Allows customers to finance energy waste reduction projects through an itemized charge on utility bills; and
- Requires utilities' Integrated Resource Plans (IRPs) to include the projected energy and capacity purchased or produced by the utility from CHP resources, ensuring the use of reliable, cost-effective, and environmentally friendly energy.

This confluence of executive and legislative interest in formulating new energy policy, coupled with recognition of the potential of CHP to participate in meeting Michigan's energy needs, means the time is right to optimize and accelerate the deployment of CHP in Michigan.

This project differs from previous projects by applying cutting-edge integrated resource modeling tools to determine least-cost deployment options for CHP resources. The project team quantitatively modeled

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[1] U.S. EPA. 2017. *Methods for Calculating CHP Efficiency*. https://www.epa.gov/chp/methods-calculating-chp-efficiency.

the optimized deployment of CHP in Michigan using a modified version of the State Tool for Electricity Emissions Reduction (STEER) model. STEER is an integrated resource planning model that calculates the least-cost resource portfolio to satisfy electricity demand and various reliability and environmental constraints based on projections of demand, fuel prices, technology price and performance, taxes, and other factors. STEER was used to assess, measure, and determine the cost and value of CHP as one of multiple resources in Michigan's future energy mix. Depending on natural gas prices and the availability of renewable energy resources, STEER recommended an optimal level of additional CHP deployment in Michigan ranging from 722 Megawatts (MW) to 1.014 Gigawatts (GW) by 2030.

In developing the Michigan CHP Roadmap, the STEER model was also customized to consider the impact of the value of resilience and standby rates on projected CHP deployment. Results showed that consideration of CHP's resilience value increases the potential deployment of CHP in sectors where loss of power is most consequential and can significantly increase CHP potential beyond the levels that would be supported by only the power sector value. According to STEER, resilience value could increase CHP potential by around 60%. On the other hand, standby rates, which apply to most grid-connected CHP projects, substantially reduce the profitability of CHP ownership and thereby reduce potential CHP deployment by 50% or more.

Parallel to this modeling effort, an intensive analysis of Michigan's CHP-related supply and value chains provides insight to support policy analyses and recommendations. Evaluation of the CHP supply and value chains in Michigan indicates a robust ability by Michigan firms to participate throughout the CHP value chain, with the majority of the economic impact of CHP being realized by using this pool of talent based in Michigan companies to design and implement CHP projects.

Finally, the Michigan CHP Roadmap provides a series of prioritized public policy recommendations that will put Michigan on a path to a CHP-friendly future, including recommendations to:

- Offer financial incentives for CHP in order to reduce the payback period for CHP projects;
- Promote Property Assessed Clean Energy (PACE) financing and encourage local communities to adopt PACE programs;
- Include CHP as eligible for on-bill financing;
- Include the full value of CHP (including the value of resilience) when considering the costs and benefits of distributed energy resources (DER), such as in a "Value of DER Study;"
- Consider best practices in utility standby rates and PURPA avoided cost/buyback rates;
- Update interconnection standards to better align with new technologies and best practices;
- Incorporate CHP as a resource in Michigan utility energy waste reduction (EWR) plans;
- Use a societal cost test for calculating energy savings from CHP in EWR plans;
- Require utilities to consider in integrated resource planning (IRP) the demand-side savings from utility-owned CHP and on-site CHP as both a supply-side and demand-side resource;
- Enable commercial and industrial property owners to utilize shared CHP assets under flexible terms;
- Collaborate closely with expert organizations, such as the Midwest CHP Technical Assistance Program (TAP), to promote CHP outreach and education in Michigan.

1.1 Project Goal

The goal of this project was to create a multifaceted, cohesive, replicable program that will help drive the adoption and deployment of CHP in Michigan. To do this, the project assessed the full range of CHP technologies and applications and used recently developed analytical capabilities to model the energy and cost savings derived from integrating CHP technologies into Michigan's power system. This project enlisted and mobilized the primary CHP supply and value chain constituencies – engineering, procurement, construction, and supply– to educate policymakers, legislators, utilities, and potential industrial and commercial end-users on the economic and environmental benefits of CHP technologies.

The actions steps completed during 2016 and 2017 to achieve this goal were:

- Model least-cost, optimized deployment of CHP as a clean, reliable, and fuel efficient energy resource in Michigan;
- Conduct field research, surveys and interviews, to obtain a complete picture of the economic development opportunity of CHP in Michigan, mapping both the supply and value chains;
- Use modeling results to explore and prioritize gaps and opportunities in the supply and value chains, while also using case studies and other data obtained from supply and value chain mapping effort to further refine data in modeling scenarios;
- Employ modeling results and supply and value chain maps to tell the complete story of CHP in Michigan, including key opportunities for how policymakers can eliminate barriers to help achieve the ideal level of cost-effective CHP deployment for the state;
- Engage with stakeholders throughout the state to build education and awareness among potential CHP end-users and value chain members who would be active during CHP project design, development, engineering, and construction stages.

2 Background

2.1 Combined Heat and Power (CHP)

CHP is the simultaneous generation of electricity and useful thermal energy from a single source of fuel, located at or near the point of energy use. Electricity is primarily used on-site as a substitute for utility-provided power. The thermal energy can be used to support process applications or human comfort through the production of steam, hot water, hot air, refrigeration, or chilled water.

Installed CHP systems typically achieve total energy efficiencies of 65% to 80%, compared to a weighted average of only about 45% to 60% for conventional separate heat (via boilers/furnaces) and power generation (via central utility plants).[2] By avoiding electric line losses and capturing much of the thermal energy normally wasted in power generation to provide heating and cooling to factories and businesses, CHP significantly reduces the total primary fuel needed to supply energy services, reducing air emissions and saving fuel and money.

[2] U.S. EPA. 2017. *Methods for Calculating CHP Efficiency*. https://www.epa.gov/chp/methods-calculating-chp-efficiency.

CHP systems can range in size from 5 kilowatts (kW; the demand of a typical single-family home) to several hundred MW (the demand of a very large industrial plant).[3] In general, the more efficiently the thermal energy can be utilized, the greater the net overall efficiency of the CHP system. Because fuel costs are the primary expenses for operational CHP systems, the more efficient the system is, the less fuel it consumes, and in turn, the less money the end-user likely spends on energy.

CHP technology can be deployed quickly, with few geographic limitations, and can be powered using a variety of fossil fuels and renewable resources. CHP may not be widely recognized outside industrial, commercial, institutional, and utility circles, but it has quietly been providing highly efficient electricity and process heat throughout the United States for decades to vital industries, large employers, urban centers, critical infrastructure like hospitals and wastewater treatment plants, and university campuses.

2.2 CHP Processes: Topping and Bottoming Cycle

There are two types of CHP processes -- topping cycle and bottoming cycle.[4] In a topping cycle CHP system, as depicted in **Figure 1**, fuel is consumed by a prime mover such as a gas turbine or reciprocating engine, generating electricity or mechanical power. Energy normally lost in the prime mover's hot exhaust or cooling systems is recovered to provide process heat, hot water, space heating, and/or cooling for the facility. Optimal topping CHP systems are typically designed and sized to meet a facility's baseload thermal demand. Heat production may offset energy requirements previously met with water heaters and steam boilers. The electric requirements of on-site air conditioning and refrigeration units may be offset by using absorption chiller technology to produce cold water or refrigerant.

[3] Cuttica, J. J. and Haefke C. May 14, 2009. U.S. DOE Industrial Technologies Program. *Combined Heat and Power: Is It Right For Your Facility?* Webcast Series. https://energy.gov/sites/prod/files/2013/11/f4/webcast_2009-0514_chp_in_facilities_2.pdf.
[4] U.S EPA. 2016. *What is CHP?* https://www.epa.gov/chp/what-chp.

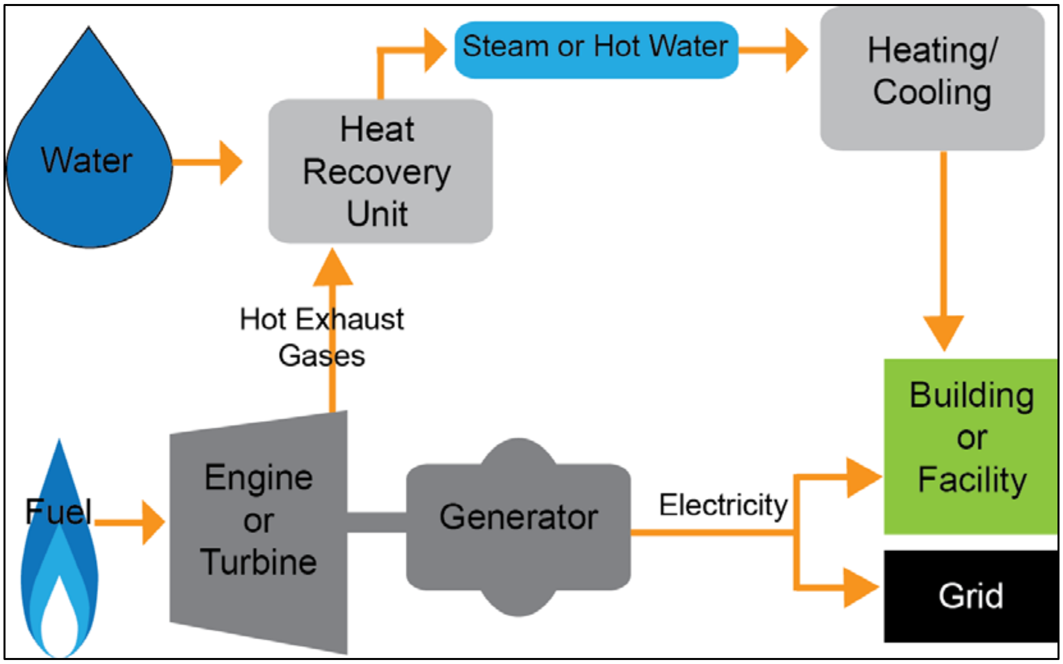

Figure 1: CHP Topping Cycle: Gas Turbine or Reciprocating Engine with Heat Recovery[5]

The bottoming cycle CHP process, which is alternatively known as waste heat to power (WHP), is depicted in **Figure 2**. In WHP, fuel is first used to provide thermal input to a furnace or other high temperature industrial process, and a portion of the heat rejected from the process is then recovered and used for power production, typically in a waste heat boiler/steam turbine system. WHP systems are a particularly beneficial form of CHP in that they utilize heat that would otherwise be wasted from an existing thermal process to produce electricity, without directly consuming additional fuel.

[5] Ibid.

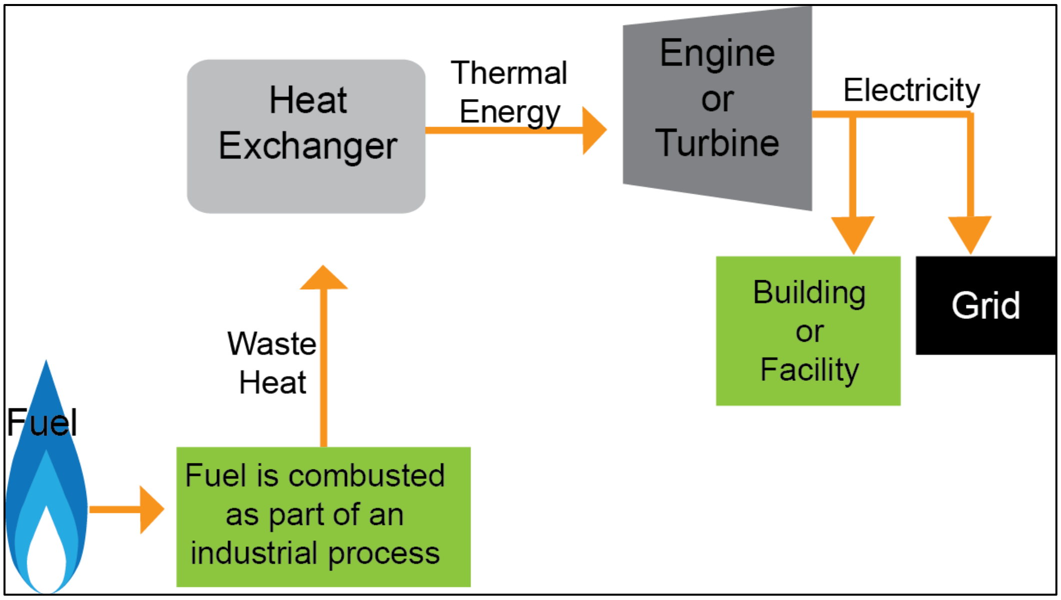

Figure 2: CHP Bottoming Cycle: Waste Heat to Power[6]

Topping cycle CHP installations may provide the local source of power generation around which microgrids can be designed. A microgrid is a group of interconnected power loads and distributed energy resources (DERs) such as CHP systems, solar panels, and batteries within clearly defined electrical boundaries that acts as a single controllable entity (micro-utility) with respect to the grid. A microgrid can connect and disconnect from the macro-utility grid to enable it to operate in both grid-connected or island-mode, providing distinct performance, resiliency, and economic benefits to energy users if managed and coordinated efficiently. Increased deployment of CHP in Michigan could present more opportunities for the development of microgrids, particularly in industrial parks or similar business clusters.[7]

[6] U.S EPA. 2016. *What is CHP?* https://www.epa.gov/chp/what-chp.
[7] Jones, D. and Tidball, R. ICF. 2016. *CHP for Microgrids: Resiliency Opportunities Through Locational Analysis*. https://www.icf.com/-/media/files/icf/white-papers/2016/energy-chp-microgrids.pdf.

2.3 Prime Mover Technologies

The United States Environmental Protection Agency (EPA) published a report in March 2015, which catalogs the various types of CHP technology.[8] According to the EPA, the five most common prime movers are fuel cells, gas turbines, micro gas turbines (microturbines), reciprocating engines, and steam turbines. Combined, these technologies comprised 97% of installations and 99% of CHP capacity installed in the U.S in 2016. **Table 1** provides a summary of the breakdown of prime movers for units under 100 MW – encompassing greater than 99.9% of all potential projects.

Fuel cells are the most recent of these innovations, and the least adopted, while steam turbines have been commonplace for over a century. Reciprocating engines, gas turbines, and microturbines comprise the bulk of new CHP installations.[9]

Prime Mover	Sites	Share of Sites	Capacity (MW)	Share of Capacity
Reciprocating Engine	2,194	51.9%	2,288	2.7%
Gas Turbine*	667	15.8%	53,320	64.0%
Boiler/Steam Turbine	734	17.4%	26,741	32.1%
Microturbine	355	8.4%	78	0.1%
Fuel Cell	155	3.7%	84	0.1%
Other	121	2.9%	806	1.0%
Total	**4,226**	**100.0%**	**83,317**	**100.0%**

Table 1: Economic Potential for CHP Units Less than 100 MW[10]

Installed capital costs for these technologies vary significantly depending on the scope of the plant equipment, geographical area, competitive market conditions, special site requirements, emissions control requirements, and prevailing labor rates. Prime mover packages themselves decline in cost, on an electrical capacity basis, only slightly as systems increase in scale. However, ancillary equipment such heat recovery steam generators (HRSG), gas compressors, water treatment systems, and electrical equipment achieve much lower costs per unit of electrical output as the systems become larger.

The description of each prime mover technology provided below is a summary of information provided in the EPA Catalog of CHP Technologies.[11] The U.S. Department of Energy (DOE) Midwest CHP TAP also describes the five prime mover technologies in additional detail.[12]

[8] U.S. EPA. 2017. *Catalog of CHP Technologies*.
http://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf.
[9] Ibid.
[10] Ibid.
[11] Ibid.
[12] U.S. DOE Midwest CHP Technical Assistance Partnerships (TAP). http://www.midwestchptap.org.

Reciprocating Engines

Reciprocating internal combustion engines are the most widespread technology for power generation up to 5 MW. These engines start quickly, follow electric load well, and generally are highly reliable. They are effective in applications that require hot water or low-pressure steam as the heat carrier. Natural gas is the typical fuel, but propane, landfill gas, or biogas can also be used.

There are nearly 2,400 reciprocating engine CHP installations in the United States, accounting for 54% of the total number of installed CHP systems and nearly 2.4 GW, or 3%, of total capacity. Individual engine units range in size from less than 50 kW up to 10 MW. In Michigan, 30 sites utilize reciprocating engine technology, accounting for nearly 60 MW of capacity. Common applications for reciprocating engine CHP systems include universities, hospitals, water treatment facilities, industrial facilities, commercial buildings, and multi-family dwellings.

Routine maintenance of reciprocating engines is required after approximately 2,000 hours of operation to ensure optimal engine performance. Engine overhauls are required every 32,000 to 64,000 hours of operation, depending on service, and typically include a complete inspection and rebuild of components to restore the reciprocating engine to nearly original or current (upgraded) performance standards. Engine maintenance costs can vary significantly depending on the quality and diligence of the preventative maintenance program and operating conditions.

Gas Combustion Turbines

Gas combustion turbines (also referred to simply as gas turbines or combustion turbines) are available in sizes ranging from 1 MW to more than 300 MW. They produce high-quality heat that can be used to generate steam for on-site use. In large applications, typically above 40 MW, the steam can be used to drive a steam turbine, generating additional electricity, in an arrangement known as “combined cycle.”

In CHP applications, gas turbines typically have favorable economics for system sizes greater than 5 MW. Gas turbines account for 52 GW of installed CHP capacity in the United States, representing 64% of the total installed CHP capacity. Michigan features 19 gas turbine installations and an aggregate installed capacity of 2.8 GW, which represents over 80% of Michigan’s 3.4 GW of installed CHP capacity. Gas turbines are well suited for industrial CHP applications because the high temperature gas turbine exhaust can either be used to generate high pressure steam or used directly for heating or drying.

Routine maintenance practices include predictive maintenance, plotting trends, performance testing, vibration analysis, and preventive maintenance procedures. Typically, routine inspections are required every 4,000 hours of operation to ensure that the turbine is free of excessive vibration due to worn bearings and rotors or damaged blade tips. A gas turbine overhaul is needed every 25,000 to 50,000 hours of operation, depending on service, and typically includes a complete inspection and rebuild of components to restore the gas turbine to nearly original or current (upgraded) performance standards. Gas turbine maintenance costs can vary significantly depending on the quality and diligence of the preventative maintenance program and operating conditions and reliance on the turbine distributor to supply the required labor.

Steam Turbines

Steam turbines are a mature technology and have been used since the 1880s for electricity production. These systems burn fuel in a boiler to generate high-pressure steam that is transferred to a turbine that powers a generator. Steam turbine-based CHP systems are most often used in medium- and large-scale industrial or institutional facilities with high thermal loads, and where solid or waste fuels are readily available for combustion in the boiler.

Most of the electricity generated in the United States is produced by steam turbines in central station power plants. Steam turbines are also commonly used for CHP installations, of which there are 699 sites in the United States. These steam turbine CHP installations have an average capacity of 37 MW and a combined capacity of 26 GW, representing 32% of total installed CHP capacity. In Michigan, steam turbines are installed at 31 sites, accounting for 500 MW of capacity. The majority of these CHP steam turbines are at industrial plants, commercial buildings with high thermal loads, and district heating sites.

Microturbines

Microturbines are relatively small combustion turbines that can use gaseous or liquid fuels. They produce hot water or low-pressure steam for a variety of applications, including potable water heating, absorption chillers and desiccant dehumidification equipment, space heating, process heating, and other building uses.

Microturbines emerged as a CHP option in the 1990s, evolving from the technology used in turbochargers and auxiliary power units which are lightweight and have few moving parts. Individual microturbines range in size from 30 to 330 kW and can be integrated to provide modular packages with capacities exceeding 1,000 kW. There are over 360 sites in the United States that currently use microturbines for CHP, accounting for over 8% of the total number of CHP sites and 92 MW, or 0.1%, of aggregate capacity. In Michigan, 5 sites utilize an aggregate 1.6 MW of microturbine CHP technology.

Fuel Cells

Fuel cells use an electrochemical process similar to a battery to convert the chemical energy of hydrogen into water and electricity. In CHP applications, heat is generally recovered in the form of hot water or low-pressure steam.[13] The hydrogen can be obtained from natural gas, coal gas, methanol, and other hydrocarbon fuels. Fuel cells are highly efficient, quiet, and clean running.

There are 126 fuel cells installed in the United States that are configured for CHP operation, accounting for a combined capacity of 67 MW, or less than 0.1% of total US CHP capacity. None are currently installed in Michigan. The majority of these fuel cells are used in commercial and institutional buildings (such as universities, hospitals, nursing homes, hotels, and office buildings) where there is a relatively

[13] Rajalakshmi, N. and Dhathathreyan, K. S. 2008. *Present Trends in Fuel Cell Technology Development*. Nova Publishers, p. 104.

high coincident demand for electricity and thermal energy. Fuel cell capital costs have decreased in recent years, leading to an increase in the adoption of this technology in CHP projects. As in any CHP application, thermal load displacement can improve operating economies of a fuel cell system.

2.4 Reliability and Resiliency Benefits

Aging U.S. electricity infrastructure presents a significant concern to commercial and industrial (CI) facilities in meeting their power needs, as grid outages become increasingly frequent. The Electric Power Research Institute (EPRI) estimates that over $150 billion per year is lost by U.S. industries due to electric network (reliability) problems.[14]

When properly configured to operate independently from the grid, CHP systems can provide critical power reliability for businesses and critical infrastructure facilities while providing electric and thermal energy to the sites on a continuous basis, resulting in daily operating cost savings.[15] A more resilient energy supply also prevents lost business productivity and decreases the likelihood of crippling power outages. By installing properly sized and configured CHP systems, Michigan facilities can effectively insulate themselves from a grid failure, providing continuity of critical services and freeing power restoration efforts to focus on other facilities in periods of emergency.

There are a number of ways in which CHP systems can be configured to meet the specific reliability needs and risk profiles of various customers, and to offset the capital cost investment for traditional backup power measures. Most CI facilities and even some non-CI facilities have backup generators on-site to supply electricity in the case of an outage. While the presence of a CHP system may not override the necessity, or in some sectors the legal requirement to have a backup generator, CHP systems provide regular benefits to their host facilities, rather than just during emergencies. Some advantages that CHP systems have over backup generators include:[16]

- Backup generators are seldom used and can often be poorly maintained. This can result in operational problems during an actual emergency. Most CHP systems run daily and are typically better maintained.
- Backup generators rely on a finite supply of fuel on site, generally enough supply to last only a few hours or days, after which fuel deliveries are required. Most CHP systems have a permanent source of fuel on demand. For example, in the case of CHP systems powered by natural gas, most natural gas infrastructure is underground and rarely impacted by severe weather events.
- Backup generators may take time to start up after a grid failure. This lag time, even though it may be brief, can result in the shutdown of critical systems. In some cases, backup generators not permanently located on-site must be delivered to the sites where they are needed, leading to further delays.

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[14] Rouse, G. and Kelly, J. Galvin Electricity Initiative. 2011. *Electric Reliability: Problems, Progress, and Policy Solutions.* http://www.galvinpower.org/sites/default/files/Electricity_Reliability_031611.pdf.
[15] Hampson, A., et al. ICF International. Prepared for Oak Ridge National Laboratory. 2013. *Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities.* https://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_critical_facilities.pdf.
[16] Ibid.

- Backup generators by and large typically rely on diesel fuel, a fuel which emits greater quantities of air pollutants compared to natural gas. The majority of CHP systems burn natural gas, thereby emitting less pollution in addition to significantly greater efficiencies and lower fuel costs.
- Backup generators only supply electricity; whereas, CHP systems supply thermal loads (heating, cooling, chilled water) as well as electricity to keep facilities operating as usual.

In a CHP system designed for reliability, the electric grid serves as the first level of backup to the CHP system. When the CHP system is down, the grid supplies the entire electricity load to the plant. In the unlikely event that both the CHP system and the grid are down at the same time, standby generators could be used to maintain critical loads. In certain applications, the value of this additional reliability can outweigh all other factors in the investment decision.

The requirements for a CHP system to deliver power reliability are straightforward. While CHP systems may or may not be designed to provide a facility's entire power demand, CHP can be configured to maintain critical loads in the event of a utility grid outage. To implement this capability, additional costs are often required including engineering, controls, labor and materials. The engineering required to analyze the existing electrical system, determine critical loads, provide a design and determine cost to provide back-up power from the system, may be extensive. A CHP system designed to supply the entire power needs of a facility during an outage may need to be oversized compared to the optimal design or require redundant units that would add to the cost.

2.5 CHP Market Summary

The DOE published a report in March 2016, which outlines the current status and technical potential for CHP for each state.[17] DOE data indicate that the U.S. currently has about 85 GW of CHP-based electric capacity installed, which represents nearly 9% of total installed electric capacity. Installed CHP systems generate about 505 million megawatt-hours (MWh) of electricity each year, or more than 12% of total U.S. 2016 generation. Compared to the average fossil-based electricity generation, this CHP portfolio eliminates 240 million metric tons of carbon dioxide emissions each year (equivalent to the emissions from 40 million cars).[18]

In Michigan, the total installed CHP capacity of 3.4 GW generates about 27 million MWh of electricity each year distributed among 87 locations and represents roughly 24% of total statewide generation. These CHP facilities provide power and thermal energy to users across a range of CI market sectors. The industrial chemicals sector is best represented, with 1,600+ MW of generation spread across 12 sites and is led by the state's largest CHP facility, Dow Corning's 1,370 MW plant in Midland.[19] Beyond

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[17] U.S. DOE. 2016. *Combined Heat and Power (CHP) Technical Potential in the United States*. https://www.energy.gov/eere/amo/downloads/new-release-us-doe-analysis-combined-heat-and-power-chp-technical-potential.

[18] State and Local Energy Efficiency Action Network. U.S. DOE. 2013. *Guide to the Successful Implementation of State Combined Heat and Power Policies*. p. 4. https://www4.eere.energy.gov/seeaction/system/files/documents/see_action_chp_policies_guide.pdf.

[19] We note that this facility is an extreme outlier in Michigan in terms of its size and scale.

industrial chemicals, the major users of CHP technology in Michigan are large public colleges and universities, pulp and paper mills, solid waste facilities, automotive factories, and agricultural processing plants.

The DOE Combined Heat and Power Installation Database, cataloging all operating CHP facilities in the nation, is publicly available online.[20] Nationwide investment in CHP declined in the early 2000s due to changes in the wholesale market for electricity and increasingly volatile natural gas prices. For example, in Michigan, from 2011 through 2015, only 10 CHP projects were commissioned, representing just 120 MW of capacity.

However, CHP's potential role as a clean energy source for the future is much greater than these recent market trends would indicate. Multiple factors point toward continued levels of CHP market penetration, including continued technological advancements reducing capital costs, new business and investment models, favorable incentives and policies, continued desire for low emissions profiles, and a recognition of the resiliency and reliability advantages of distributed energy.

Efficient on-site CHP represents a largely untapped resource that exists in a variety of energy-intensive industries and businesses. DOE estimates the technical potential for additional CHP at existing industrial facilities is slightly less than 65 GW and the technical potential for CHP at commercial and institutional facilities is slightly more than 65 GW, for a national total of about 130 GW.[21] A 2009 study by McKinsey & Company estimated that 50 GW of CHP in industrial and large commercial and institutional applications could be deployed at reasonable returns under then current equipment and energy prices.[22] These estimates of both technical and economic potential are likely greater today given the improved outlook in natural gas supply and pricing.

CHP deployment can also lead directly to greater deployment of renewable energy resources. Many renewable energy projects, such as biomass and solar, are often of an insufficient scale to be financially viable as stand-alone projects. Renewable fuels such as biogas or landfill gas can be co-fired with natural gas to enable larger scale, more cost-effective CHP installations than supply constraints of the renewable fuel might otherwise allow. A combined, larger-capacity solar/CHP project in some applications will yield an investment which is economically-viable, whereas neither solar nor CHP as smaller-capacity stand-alone projects are viable due to large fixed electrical grid interconnection costs.

The framework for a robust Michigan CHP industry is currently in place. As will be discussed in Section 5 of this Michigan CHP Roadmap, existing Michigan companies are well-positioned to supply the intellectual capital and skilled trades required to develop, design, finance, install/construct/integrate, operate, and maintain CHP systems. Economic value is primarily realized by employing the state's talent

[20] U.S. DOE. 2016. *Combined Heat and Power Installation Database*. https://doe.icfwebservices.com/chpdb/.
[21] State and Local Energy Efficiency Action Network. U.S. DOE. 2013. *Guide to the Successful Implementation of State Combined Heat and Power Policies*. p. 4.
https://www4.eere.energy.gov/seeaction/system/files/documents/see_action_chp_policies_guide.pdf.
[22] Granade, H. C., et al. McKinsey & Company. 2009. *Unlocking Energy Efficiency in the U.S. Economy*.
https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0ahUKEwipv7eB0-TYAhUEG6wKHet5DycQFggpMAA&url=https%3A%2F%2Fwww.mckinsey.com%2Fclient_service%2Felectric_power_and_natural_gas%2Flatest_thinking%2F~%2Fmedia%2F204463a4d27a419ba8d05a6c280a9.

pool and fuel suppliers throughout each project's 20- to 30-year useful lifecycle. Michigan companies are not particularly well-positioned to manufacture the principal energy equipment. But they will find opportunities in ancillary equipment manufacturing as well as in distribution and maintenance of both domestic and internationally-sourced CHP equipment.

2.6 Current Status of CHP Policy in Michigan

Historically, there have been a variety of policies and incentives in place to encourage the use of CHP. An enduring example is the DOE CHP TAPs, formerly called the Clean Energy Application Centers (CEACs), which promote and assist in transforming the market for CHP across the country. Services include market opportunity analyses, education and outreach, and technical assistance. Michigan is served by the Midwest CHP TAP, managed through the Energy Resources Center at the University of Illinois at Chicago.[23]

The federal Business Energy Investment Tax Credit (ITC) previously provided a non-refundable tax credit equal to 10% of expenditures related to CHP systems up to 50 MW in capacity that exceeded 60% energy efficiency. This credit expired at the end of 2016 and renewal is very unlikely.

At the state level, the Michigan legislature passed significant energy legislation at the end of 2016, including provisions affecting cogeneration. Public Act (PA) 341 of 2016 set criteria to be considered in an individual utility Integrated Resource Plan (IRP) filing with the Michigan Public Service Commission (MPSC). As of April 2017, CHP must be considered in a utility's IRP, which must be filed with the MPSC no later than April 2019. Specifically, a utility IRP must include the projected energy and capacity purchased or produced by the utility from a cogeneration resource (MCL 460.6t(5)(g)).

Also as part of this energy legislation, as of April 2017, renewable-fueled steam generation is included in the definition of "renewable energy."[24] However, PA 342 of 2016 also repealed Section 43 of PA 295, which provided that advanced cleaner energy credits could be created by cogeneration and Section 27, which provided the ability to substitute advanced cleaner energy credits for renewable energy credits. As a result, cogeneration does not qualify as renewable energy and can no longer be used to meet the requirements of the RPS under PA 342. [25] Despite their significance, these recent legislative changes are not expected to significantly affect the level of CHP deployment in Michigan.

One area of positive progress in Michigan is Property Assessed Clean Energy (PACE) financing, which is currently available in 23 Michigan counties and 2 large cities (Grand Rapids and Wyoming). PACE for CHP creates a system in which private sector loans are made to property owners to pay for up to 100% of

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[23] U.S. DOE. Office of Energy Efficiency and Renewable Energy. 2017. *CHP Technical Assistance Partnerships (CHP TAPs)*. https://www.energy.gov/eere/amo/chp-technical-assistance-partnerships-chp-taps.

[24] According to PA 342 of 2016, one Renewable Energy Credit (REC) will be issued for each MWh of electricity generated, including the steam equivalent of a MWh of electricity. RECs are the currency of the Michigan Renewable Portfolio Standard (RPS).

[25] PA 295 of 2008, Section 27 generally limits the combined use of energy optimization credits and advanced cleaner energy credits to 10% of an electric provider's renewable energy credit standard. However, this limitation does not appear to have impacted the development of cogeneration based on electric provider's responses to this question as part of their annual reporting to the MPSC.

CHP investments, with repayment of those loans occurring through a "special assessment" on the site's property taxes. This mechanism allows for CHP investments without any up-front capital investment by the property owner, substantially mitigating financial risk while leveraging the return on investment. If the property is sold, the special assessment remains with the property. Additional information on PACE program attributes and participating local governments can be found in **Attachment A**.

2.7 Recent Efforts to Examine Standby Rates for CHP

From January 2016 through February 2017, the MPSC staff hosted a working group on standby rates. The Association of Businesses Advocating for Tariff Equity (ABATE), Michigan Energy Innovation Business Council (Michigan EIBC), Alliance for Industrial Efficiency, Electricity Consumers Resource Council, Midwest Cogeneration Association, Consumers Energy Company and DTE Energy Company all submitted comments to the MPSC staff to inform the final working group report, issued in June 2017.

In the MPSC staff's first standby rate working group report, published in August 2016, the purpose of the workgroup was described as the following:

> Ensuring that utility standby service tariffs are appropriately recovering only the costs attributable to the self-generation customer can result in complex analysis and billing. There is some concern in the self-generation community that standby rates in Michigan may not be set appropriately – particularly for small-scale CHP and intermittent resources such as solar and wind generation, but also in some cases for large-scale CHP. With the burgeoning interest in these types of projects by potential self-generation customers and project developers, greater understanding of these complicated standby service tariffs is essential. It is an opportune time to determine whether the current standby service tariffs reflect the cost of serving self-generation customers with CHP or solar and address concerns of the self-generation community.[26]

As part of the working group process, Michigan utility standby rates for CHP sites were analyzed and compared to the standby rates of other utilities in the Midwest.[27] The analysis found that standby charges experienced in Michigan are relatively high, potentially posing a barrier to CHP deployment.[28] Further, the analysis found that standby tariffs in Michigan can be confusing and difficult for customers to navigate.[29] While no formal requirements came out of the working group process, the MPSC staff issued several recommendations related to standby rate best practices.[30]

Coming out of the MPSC staff standby rate working group, engagement in the overall discussion of standby rates continued, and some interested parties went on to pursue formal intervention in utility general rate cases as a means of continuing to raise concerns about the effect of standby rates on CHP installations. Outside of formal intervention, businesses and associations have expressed their support

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[26] Michigan Public Service Commission Staff. 2016. *Standby Rate Working Group August 19, 2016 Report*. http://www.michigan.gov/mpsc/0,4639,7-159-16377_47107-376753--,00.html.
[27] 5 Lakes Energy. 2016. *Consumers Energy: Standby Rate Tariff Scenarios*. http://www.michigan.gov/documents/mpsc/5LE_Standby_Rate_Scenarios_10182016_538289_7.pdf.
[28] Ibid.
[29] Ibid.
[30] Michigan Public Service Commission Staff. 2017. *Standby Rate Working Group Supplemental Report June 2017*. http://www.michigan.gov/mpsc/0,4639,7-159-16377_47107-376753--,00.html.

for standby rate reform through comments and sign-on letters submitted to the MPSC.[31] As utilities continue to refine and develop the ways in which they interact with customers with CHP projects, there will likely continue to be attention paid to aligning standby rates with best practices, and making sure these rates reflect a utility's cost of service.

2.8 Roadmap Purpose

The purpose of the CHP Roadmap is to help drive the adoption and deployment of CHP in Michigan through an assessment of CHP technologies and applications, use of integrated resource planning (IRP) modeling to determine the energy and cost savings derived from integrating CHP technologies into Michigan's power system, identification and cataloging of CHP business constituencies, and education of policymakers, legislators, utilities, business, and industrial nd-users on the economic and environmental benefits of CHP technologies.

Against the backdrop of Michigan's energy legislation passed in December 2016, renewed interest in distributed generation such as CHP, and recent efforts to examine elements of rate design affecting distributed generation resources, there is a desire to better understand the opportunities and barriers to CHP deployment in Michigan, and to identify a path forward. In order to examine how CHP can contribute to Michigan's future energy mix on a least-cost basis, the STEER model is utilized, with the benefit of an enhanced CHP suite of technologies and applications. The results of this modeling effort show that CHP can play an important, cost-effective role in Michigan's future energy mix. In parallel with this modeling effort, the policy and regulatory barriers to greater CHP penetration are identified, along with recommended solutions to address these barriers in Michigan.

A strong stakeholder engagement process is key to optimizing deployment of CHP in Michigan. The development of the CHP Roadmap has involved state energy, environmental, economic development, and regulatory agencies, as well as participation from utilities, universities, trade associations, project developers, equipment suppliers, engineering firms, and current and prospective CHP end-users. These stakeholders have helped to refine the barriers, identify potential solutions, and recommend best practices most suitable for Michigan. The process of working closely with stakeholders on policy development and education also represents an important first step in increasing education and outreach about the benefits and opportunities offered by CHP. Building on this foundation, and with the aid of the information contained in the CHP Roadmap, Michigan's CHP education and outreach effort can continue into the future, encouraging and supporting optimized CHP deployment in the years to come.

[31] Michigan Public Service Commission Staff. 2017. Public comments. http://www.michigan.gov/mpsc/0,4639,7-159-16377_47107-376753--,00.html.

2.9 Prior Studies

A number of important CHP studies have been conducted. According to the DOE, "states, utilities, and non-governmental organizations across the country have commissioned analyses over the years to identify potential energy savings (typically for electricity) available within their jurisdictions. These studies can be used to fulfill a variety of needs, including energy efficiency program planning, state goal setting, utility resource planning, and other priorities."[32]

Among the most useful in identifying opportunities for both energy savings and economic development have been studies of CHP potential. These studies quantify the size of particular resource, such as MW of CHP development, under different scenarios and within a specific geography. According to the American Gas Association (AGA), "estimates on the untapped potential of CHP in the United States vary considerably depending on how 'potential' is defined and calculated. While investment in CHP applications has remained low since 2005, recent market activity suggests the potential for a rebound in CHP development powered by three critical drivers: 1) the changing outlook for natural gas supply and price; 2) environmental regulatory pressures on power plants and industrial boilers, and 3) growing federal and state policymaker support."[33]

CHP potential studies can be viewed as a subset of energy efficiency potential studies, which according to the American Council for an Energy-Efficient Economy (ACEEE), fall into three categories:

- Technical potential studies, which describe an ideal scenario that sums all energy efficiency measures that are feasible given technology limitations;
- Economic potential studies, which describe the fraction of the technical potential that is cost-effective;
- Achievable potential studies, which describe the fraction of the economic potential that is attainable given actual program infrastructure and both societal and market limitations.[34]

Importantly, according to the Alliance for Industrial Efficiency (AIE), "technical potential provides an estimation of market size constrained only by technological limits – the ability of CHP technologies to fit customer energy needs. It does not include economic or other considerations relevant to a decision to invest in CHP."[35]

In terms of CHP potential in the state of Michigan, there have been an array of different estimates throughout the years. In 2007, "Michigan's 21st Century Electric Energy Plan" – a study modeling technical and economic potential of a number of different energy resources, with a view toward evaluation of policy initiatives – examined Michigan's short and long term electric needs through 2025. The Plan utilized extensive modeling to enhance the understanding of Michigan's energy needs and to verify policy initiatives, and sought to advance the goals of supporting economic development,

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[32] U.S. DOE. Office of Energy Efficiency and Renewable Energy. 2017. *Energy Efficiency Potential Studies Catalog*. https://www.energy.gov/eere/slsc/energy-efficiency-potential-studies-catalog.
[33] ICF International, Inc. Prepared for the American Gas Association (AGA). 2013. *The Opportunity for CHP in the United States*. p. ES-1. https://www.aga.org/research/reports/the-opportunity-for-chp-in-the-us---may-2013/.
[34] American Council for an Energy Efficient Economy (ACEEE). *Efficiency Potential and Market Analysis*. https://aceee.org/topics/efficiency-potential-and-market-analysis.
[35] Alliance for Industrial Efficiency (AIE). 2015. *Combined Heat and Power (CHP) as a Compliance Option under the Clean Power Plan*. https://alliance4industrialefficiency.org/resources/chp-as-a-compliance-option-under-the-clean-power-plan/.

improving environmental quality and promoting resource diversity, while ensuring reliable electric power.[36] With regard to CHP potential, The Plan stated:

> Modeling indicates a potential for at least 1,100 MW, and up to 2,700 MW, of new electric power capacity development in Michigan from renewable resources with another 180 MW available from combined heat and power, or CHP. Forecasting in this area is particularly problematic, in light of the rapid pace of technological advancements and policy changes that will affect renewables. It is thus important to revisit renewable resource modeling on a regular basis and to expand the renewable portfolio when appropriate.[37]

In May 2013, ICF International, Inc. (ICF) prepared for the AGA a study titled "The Opportunity for CHP in the United States."[38] Table 2 illustrates the state-by-state economic potential for CHP units less than 100 MW in size. The study found that there was 803 MW of CHP potential in Michigan in the 5-10 year payback range, and 3605 MW of CHP potential in the >10 year time frame.[39]

State	Technical Potential by Payback Range, MW			Total Technical Potential	State	Technical Potential by Payback Range, MW			Total Technical Potential
	Minimal Potential, Payback >10 yrs	Moderate Potential, Payback 5-10 yrs	Strong Potential, Payback <5yrs			Minimal Potential, Payback >10 yrs	Moderate Potential, Payback 5-10 yrs	Strong Potential, Payback <5yrs	
Alabama	1,512	416	0	1,928	Missouri	2,532	0	0	2,532
Alaska	0	52	130	181	Montana	343	0	0	343
Arizona	1,561	134	0	1,695	Nebraska	718	26	0	744
Arkansas	1,384	0	0	1,384	Nevada	999	0	0	999
California	2,807	8,283	735	11,826	New Hampshire	0	497	74	571
Colorado	1,211	208	0	1,419	New Jersey	1,159	2,301	341	3,801
Connecticut	0	796	621	1,417	New Mexico	493	76	0	569
Delaware	254	144	0	398	New York	0	5,993	3,367	9,360
Dist of Columbia	321	0	0	321	North Carolina	3,726	632	0	4,358
Florida	2,541	2,098	104	4,744	North Dakota	324	0	0	324
Georgia	3,256	555	0	3,811	Ohio	5,951	0	0	5,951
Hawaii	77	212	86	376	Oklahoma	1,295	0	0	1,295
Idaho	469	0	0	469	Oregon	1,472	0	0	1,472
Illinois	4,626	727	0	5,354	Pennsylvania	4,972	1,143	0	6,115
Indiana	2,705	0	0	2,705	Rhode Island	203	198	35	436
Iowa	1,573	0	0	1,573	South Carolina	1,962	386	0	2,348
Kansas	1,126	96	0	1,222	South Dakota	332	0	0	332
Kentucky	1,607	932	0	2,539	Tennessee	2,143	594	0	2,737
Louisiana	1,864	658	0	2,523	Texas	5,716	1,836	384	7,935
Maine	582	237	0	820	Utah	881	0	0	881
Maryland	1,450	306	0	1,756	Vermont	0	282	12	293
Massachusetts	282	2,078	466	2,826	Virginia	2,570	490	0	3,060
Michigan	3,605	803	0	4,408	Washington	2,201	0	0	2,201
Minnesota	2,230	327	0	2,557	West Virginia	545	244	0	789
Mississippi	1,086	274	0	1,360	Wisconsin	2,859	1,114	0	3,973
					Wyoming	166	110	0	275
					U.S. Total	81,691	35,257	6,355	123,303

Table 2: Economic Potential for CHP Units Less than 100 MW[40]

[36] Lark, P. J. Michigan Public Service Commission. 2007. *Michigan's 21st Century Electric Energy Pl*an. p. 1. https://www.michigan.gov/documents/mpsc/21stcenturyenergyplan_185274_7.pdf.
[37] Ibid., p. 26.
[38] ICF International, Inc. Prepared for the American Gas Association (AGA). 2013. *The Opportunity for CHP in the United States*. p. ES-1. https://www.aga.org/research/reports/the-opportunity-for-chp-in-the-us---may-2013/.
[39] Ibid.
[40] Ibid.

According to the study, projects with greater than 10 year projected payback periods have minimal potential; the range of 5-10 years for payback represents moderate potential; and a project payback of less than 5 years is considered to have strong potential.[41] This finding underscores a major barrier to CHP deployment in Michigan the payback period, which is further discussed in Sections 6 and 7 of this report.

More recently, the U.S. DOE estimated that "Michigan has 4,987 MW of CHP technical potential capacity identified at 10,370 sites."[42] The DOE Technical Potential study notes that "the outlook for increased CHP use is bright as policymakers at the federal and state level are recognizing the potential benefits and the role that this technology could play in providing clean, reliable, cost-effective energy services to industry and businesses."[43]

Internationally, there is a major CHP roadmapping effort underway throughout the European Union. Pursuant to Cogeneration Directive (2004/8/EC) European Union member states have "identified their cogeneration potential out to 2020 but many have failed or are failing to make progress on cogeneration despite the wide range of support measures which are in place."[44] The CODE2 project aims to support the development of 27 National Cogeneration Roadmaps[45] and one European Cogeneration Roadmap. The project will also "develop 'How-to' guides focused on understanding the cogeneration legislation and business case to simplify first steps for new users."[46] A major goal of the CODE2 project is to recommend policy measures to increase the deployment of CHP in participating nations.[47] For example, as part of the CODE2 project, a study titled "Final CHP Roadmap Ireland" was published in November 2014. This Final CHP Roadmap Ireland draws from a previous study called "Cogeneration Potential in Ireland" published in 2009 by Sustainable Energy Authority of Ireland. This earlier study estimated CHP potential in 2020 across multiple scenarios using historic patterns of deployment and the effects of various policies. The 2014 "Final CHP Roadmap Ireland" was further updated in 2016 by a study titled "Combined Heat and Power in Ireland: 2016 Update," which provided an update on Ireland's installed CHP capacity and associated energy savings and carbon reductions.[48]

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[41] Lark, P. J. Michigan Public Service Commission. 2007. *Michigan's 21st Century Electric Energy Pl*an. p. ES-2. https://www.michigan.gov/documents/mpsc/21stcenturyenergyplan_185274_7.pdf.
[42] U.S. DOE. 2016. *Combined Heat and Power (CHP) Technical Potential in the United States*. p. 56. https://www.energy.gov/eere/amo/downloads/new-release-us-doe-analysis-combined-heat-and-power-chp-technical-potential.
[43] Ibid., p. 1.
[44] Cogeneration Observatory and Dissemination Europe. 2014. http://www.code2-project.eu/about/.
[45] Countries covered by the CODE2 Project include Austria, Belgium, Bulgaria, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, United Kingdom. CHP Roadmaps are available at http://www.code2-project.eu/code-regions/.
[46] Cogeneration Observatory and Dissemination Europe. 2014. http://www.code2-project.eu/about/.
[47] Ibid.
[48] Howley, M. and Holland, M. Sustainable Energy Authority of Ireland. 2016. *Combined Heat and Power in Ireland: 2016 Updat*e. https://www.seai.ie/resources/publications/Combined%20Heat%20and%20Power%20in%20Ireland%20Update%202016.

The “Final CHP Roadmap Ireland” was developed to better understand market and policy factors affecting CHP penetration, map supply and value chain opportunities for manufacturers and project implementers, and determine ways to accelerate deployment. In this way, the “Final CHP Roadmap Ireland” is similar to this Michigan CHP Roadmap. A key difference, however, is that the Michigan CHP Roadmap benefits from the STEER model’s rigorous CHP technology and application suite, which allows for characterization of a range of CHP technologies and sizes, and dispatch of individual CHP units on an hourly basis. The Michigan CHP Roadmap also contains a substantial stakeholder outreach and education component.

Overall, the Michigan CHP Roadmap project builds upon these prior studies by adding a perspective that is specific to the challenges and opportunities of Michigan. The Michigan CHP Roadmap methodology makes use of the market-based perspective of private-sector project developers, and has the benefit of a quantitative modeling capability that differentiates among CHP technologies. Finally, the Michigan CHP Roadmap also makes initial strides toward educating a diverse array of stakeholders in order to effect long-term change, and lays the groundwork for this education and outreach to continue.

3 Methodology

The methodology employed throughout this study was developed with the objective of being replicable by other states. To achieve this objective, project partners relied on economic data provided by the U.S. EPA[49] and on technical potential data provided by the U.S. DOE[50] to evaluate CHP technologies and applications. Analytical modeling of this data within Michigan’s overall energy portfolio was achieved by leveraging the STEER model, which can be adapted by other states or developed independently. Mapping of the Michigan CHP supply and value chain utilized methodology previously developed to support creation of the Michigan “Clean Energy Roadmap.”[51] Recommendations to mitigate solutions are based on a quantitative assessment of the impact on CHP deployment under a variety of utility rate and public incentive scenarios. Finally, deployment of the CHP Roadmap involves the ongoing effort to educate CHP stakeholders, and especially end-users, on the merits of CHP, and to provide them with a directory of firms operating in the CHP space to facilitate project development with local partners. (A directory of Michigan CHP Supply/Value Chain Participants is contained in **Attachment B**.)

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[49] U.S. EPA. 2017. *Catalog of CHP Technologies*. http://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf.

[50] U.S. DOE. 2016. *Combined Heat and Power (CHP) Technical Potential in the United States*. https://www.energy.gov/eere/amo/downloads/new-release-us-doe-analysis-combined-heat-and-power-chp-technical-potential.

[51] Michigan Agency for Energy. 2016. Clean Energy Roadmap. http://www.michigan.gov/documents/energy/2016-03-09_CER_Full_526941_7.pdf.

3.1 Technology Roadmapping

STEER can dynamically model Michigan's electricity system on an hourly basis by dispatching electricity resources based on lowest marginal cost, and has the advantage of representing a range of supply-side and demand-side resource options at the level of individual electric generating units (see Section 4). This modeling, which we will alternatively refer to as "technology roadmapping," provides a rigorous capability to quantify the optimal cost CHP potential in Michigan.

STEER is populated with U.S. Energy Information Administration (EIA) data of Michigan's existing portfolio of power plants and various modules of fossil-fueled and renewable generating units that can be deployed as needed to meet hourly energy and capacity requirements out to the year 2030. Modifications were made to include an expanded, more detailed suite of CHP prime mover technologies, system sizes, and operating characteristics.

STEER modifications required the establishment of criteria to evaluate prime mover technologies for the suite of CHP options. As discussed in Section 2.3, because 99% of total installed CHP capacity is comprised of reciprocating engines, combustion turbines, microturbines, steam turbines and fuel cells, the project team decided to limit its focus to just these five technologies.

Project partners identified and evaluated CHP technologies and applications as a prelude to modifying the STEER model in order to achieve the following goals:

- Quantify Michigan CHP technical potential by prime mover type;
- Quantify industry average cost and performance data for each prime mover type;
- Extrapolate these data to Michigan prime mover technical potential.

U.S. DOE defines technical potential as "an estimation of market size constrained only by technological limits – the ability of CHP technologies to fit customer energy needs without regard to economic or market factors." This provides a valid upper boundary of CHP deployment in Michigan, with actual deployment levels being lower due to economic factors that can be represented as inputs to the STEER model that act to constrain deployment below technical potential.

According to DOE, Michigan has nearly 5 GW of CHP technical potential at more than 10,000 sites across 17 industrial and 24 commercial sectors (specific identifying data for each of the 10,000 sites is not available from DOE).[52] This potential, on a capacity basis, is roughly evenly split between 17 industrial sectors and 24 commercial sectors, as depicted in **Figure 3**. However, nearly 80% of the 10,000 sites are commercial locations, which tend to have much lower CHP capacity potential than industrial sites.

According to DOE, there are 2.2 GW of industrial on-site CHP potential primarily in the transportation equipment, chemicals, primary metals, paper, and food sectors. Another 2.0 GW of commercial CHP technical potential exists primarily at commercial office buildings, colleges and universities, hospitals, retail locations, and multifamily housing sectors. Michigan also has 700 MW of CHP potential

[52] U.S. DOE. 2016. *Combined Heat and Power (CHP) Technical Potential in the United States*. https://www.energy.gov/eere/amo/downloads/new-release-us-doe-analysis-combined-heat-and-power-chp-technical-potential.

deployment at 2 district energy sites and 150 MW of waste heat to power (WHP) potential identified at 36 sites primarily in the oil and gas extraction, refining, stone/clay/glass, and primary metals sectors.[53]

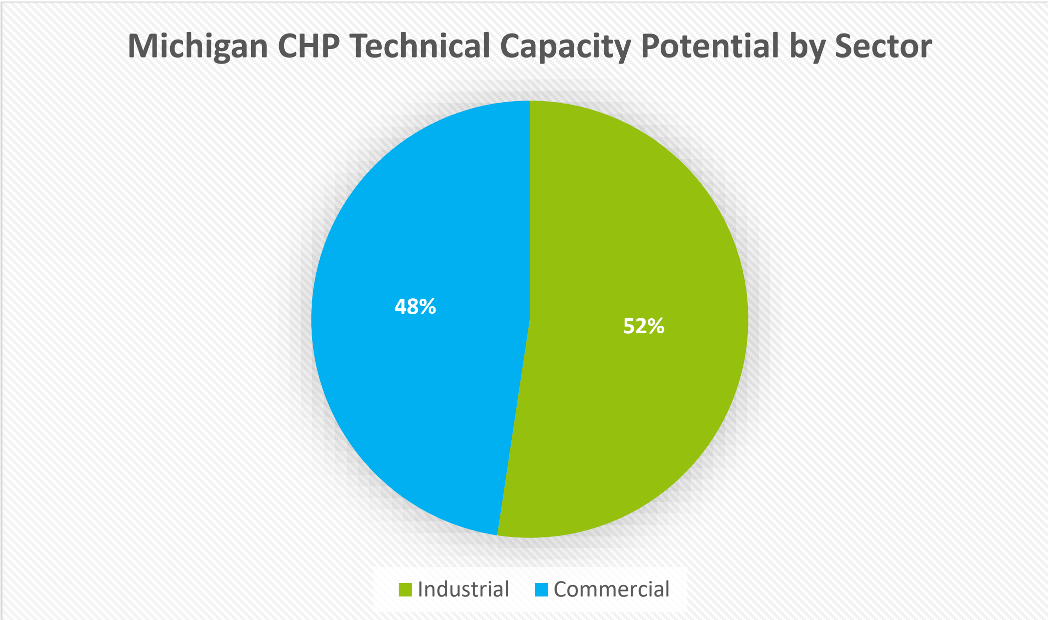

Figure 3: Michigan CHP Technical Capacity Potential by Sector[54]

Beyond commercial and industrial business types, the DOE database also quantifies the technical CHP potential in Michigan, by number of sites and capacity potential, according to annual operating hours (7,500 hours/full-time versus 4,500 hours/part-time) and project size classification (50 to 500 kW, 500 kW to 1 MW, 1 MW to 5 MW, 5 MW to 20 MW, and 20+ MW).[55]

For STEER customization, the DOE's CHP technical potential data for Michigan needed to be broken down one level further, from the total number of CHP sites and capacity (per project size range), to differentiate among the five prime mover types. To complete this task, the project team relied on EPA CHP cost and performance data for the prime movers across the spectrum of available capacities, along with project members' collective experience with public and private-sector CHP projects as necessary to make assumptions about market and pricing trends. Table 3 summarizes which prime movers were considered for CHP systems of various scale.

[53] Ibid.
[54] Ibid.
[55] Ibid.

Table 3: Prime Mover Technologies by System Capacity[56]

Capacity	Fuel Cell	Microturbine	Reciprocating Engine	Combustion Turbine	Steam Turbine
50 kW – 500 KW	X	X	X		
500 kW – 1 MW		X	X		
1 MW – 5 MW		X	X	X	
5 MW – 20 MW			X	X	X
> 20 MW				X	X

In their "Catalog of CHP Technologies,"[57] the EPA compiled cost and performance data for twenty-four CHP technology and size combinations as indicated in Table 4.

Table 4. EPA Technology and System Size Combinations[58]

Prime Mover Technology	System Sizes (kW)	EPA Catalog Reference
Fuel Cell	0.7, 1.5, 300, 400, 1400	Table 6-3
Microturbine	30, 65, 200, 250, 333, 1000	Table 5-2
Reciprocating Engine	100, 633, 1121, 3326, 9341	Table 2-2
Combustion Turbine	3510, 7520, 10680, 21730, 45607	Table 3-5
Steam Turbine	500, 3000, 15000	Table 4-2

Project partners extrapolated, via simple regression modeling, the cost and performance data for the EPA's 24 technology/size combinations indicated in Table 4, to include an additional 33 technology/size combinations. These 33 reflect the average CHP system size based on DOE technical potential in Michigan, across each of the five technologies and five capacity categories indicated in Table 3.

Table 5 lists all 57 resource options that are now available in the STEER model's CHP suite. The extrapolated data in combination with the EPA provided data provide the basis for technical analysis of CHP in the STEER model.

[56] Ibid.
[57] U.S. EPA. 2017. *Catalog of CHP Technologies*.
http://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf.
[58] Ibid.

Table 5. STEER Model CHP Resource Options

Prime Mover Technology	**System Sizes (kW)**
Fuel Cell	0.7, 1.5, 78, 124, 179, 300, 400, 1400
Microturbine	30, 65, 78, 124, 179, 200, 250, 333, 427, 597, 710, 1000, 1083
Reciprocating Engine	78, 100, 124, 179, 427, 597, 633, 710, 1083, 1121, 1800, 2093, 3326, 8000, 8758, 9341
Combustion Turbine	2093, 3510, 5000, 7520, 8000, 8758, 10680, 21730, 31000, 35867, 45607
Steam Turbine	500, 3000, 8000, 8758, 9091, 15000, 25000, 31000, 35867

Since STEER is a model of the electrical system and CHP provides heat-related benefits to the site host, STEER assumes that CHP systems will be sized to meet host thermal requirements. STEER treats the required capital and fuel costs for production of heat as the same with or without CHP. Thus, it can use the incremental capital and fuel costs associated with adding electricity production as the marginal cost of CHP generation of electricity.

This modified version of STEER containing these 57 CHP options can now dynamically identify which CHP configurations are economically viable across a wide variety of scenarios, narrowing the scope of Michigan's 5 GW/10,000 site technical potential to only include those projects that should be implemented based on economics and in consideration of Michigan's overall electricity generation portfolio.

3.2 Valuing Reliability and Resiliency

There have been many attempts to assess the cost of unreliable electricity. Reports by EPRI and DOE have estimated the cost of electricity outages at $30 to $400 billion per year.[59] According to the Lawrence Berkeley National Laboratory (LBNL), economic losses from unreliable electricity and power outages total approximately $80 billion per year.[60] However, even this figure is disputed as too low because it does not include the cost of food spoilage, dispatching police and fire personnel, evacuating and securing senior citizens and ancillary damage, such as the kind caused by sump pump failure.[61] While difficult to quantify, the full extent of power outage costs are undoubtedly quite large.

While everyone understands the value of power reliability and infrastructure resiliency, there are few, if any, proposed methodologies for monetizing that value. The data that exist regarding outage costs are largely aggregated between all customer classes among a wide geography and include economic loses as

[59] Primen. Submitted to the Electric Power Research Institute. 2001. *The Cost of Power Disturbances to Industrial and Digital Economy Companies*. http://www.energycollection.us/Energy-Reliability/Cost-Power-Disturbances.pdf.
[60] LaCommare, K. H., and Eto, J. H. Lawrence Berkeley National Laboratory. 2004. *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers*. https://emp.lbl.gov/sites/all/files/lbnl-55718.pdf.
[61] Rouse, G. and Kelly, J. Galvin Electricity Initiative. 2011. *Electric Reliability: Problems, Progress, and Policy Solutions.* http://www.galvinpower.org/sites/default/files/Electricity_Reliability_031611.pdf.

well as personal loses. Further complicating this effort is the fact that power resiliency creates both private and public benefits. In fact, there are three important categories when discussing resiliency costs and benefits:

- Private Resiliency for Private Benefit;
- Public Resiliency for Public Benefit;
- Private Resiliency for Public Benefit.

Public resiliency benefits are important specifically because of their relationship to maintaining critical infrastructure and the public well-being. However, it is difficult to monetize the value of resiliency in critical infrastructure where an outage may lead to human harm and even death. On the other hand, private benefits, such as reduced or eliminated economic loss can be easier and more ethical to monetize. Though public resiliency, especially as it relates to critical infrastructure, is very important, it was out of the scope of this project to attempt to create a methodology to monetize the value of public resiliency. Using existing research and literature, however, it is feasible to monetize the value of private benefits from private resiliency.

In 2001 and 2013, EPRI published studies that quantified the cost of power disturbances to industrial and digital economy firms using direct surveys. This report, titled "The Cost of Power Disturbances to Industrial & Digital Economy Companies," provides the best available data to quantify the value of electric resiliency for private benefit. The report focuses on three economic sectors particularly sensitive to power outages within the U.S. economy:[62]

- **The digital economy (DE).** This sector includes firms that rely heavily on data storage and retrieval, data processing, or research and development operations. Specific industries include telecommunications, data storage and retrieval services (including collocation facilities or Internet hotels), biotechnology, electronics manufacturing, and the financial industry.
- **Continuous process manufacturing (CPM).** This sector includes manufacturing facilities that continuously feed raw materials, often at high temperatures, through an industrial process. Specific industries include paper, chemicals, petroleum, rubber and plastic, stone, clay, and glass, and primary metals.
- **Fabrication and essential services (F&ES).** This sector includes all other manufacturing industries, plus utilities and transportation facilities such as railroads and mass transit, water and wastewater treatment, and gas utilities and pipelines.

These three sectors account for roughly 2 million business establishments in the U.S. While this comprises only 17 percent of U.S. businesses by establishment, these same sectors comprise approximately 40 percent of U.S. gross domestic product (GDP). Disruptions in each of these sectors – but especially DE and F&ES – have an almost immediate effect on other sectors that depend on the services they provide. According to the EPRI report, the U.S. economy is losing between $104 billion and $164 billion a year to outages and another $15 billion to $24 billion to power quality phenomena.[63]

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[62] Primen. Submitted to the Electric Power Research Institute. 2001. *The Cost of Power Disturbances to Industrial and Digital Economy Companies*. http://www.energycollection.us/Energy-Reliability/Cost-Power-Disturbances.pdf.
[63] Ibid.

Michigan is estimated to be losing between $3.765 billion and $5.971 billion per year in annual outage costs for all sectors.

However, in relation to the total economic losses stemming from power outages these figures are most likely on the low end of the spectrum because they do not include the loses stemming from outages to critical infrastructure. These data only include business losses, which in general, do not include the cost of potential loss of life, loss of communications, loss of critical infrastructure, and loss of evacuation routes. No doubt the cost of these aspects would outweigh those from the business sector, but as previously stated, there is no data available monetizing the value of public resiliency benefits.

While it is relatively easy to approximate the annual outage cost by state or economic sector it is much more difficult to translate that monetary loss into a resiliency value. Certainly, DE, F&ES and CPM businesses with on-site generation such as CHP would benefit from the increased resiliency provided by such applications. Difficulty arises, however, when monetizing individual resiliency benefits using nationwide, aggregate numbers.

In order to include the benefits of CHP resiliency into the STEER model it was necessary to calculate a dollar value per kilowatt of CHP installed for power resiliency. Using the data provided in the EPRI report and summarized in Figure 4, an average annual cost was assigned to all businesses within the DE, CPM and F&ES sectors. It was only necessary, however, to consider the Standard Industrial Classification (SIC) codes within each economic category with any CHP technical potential. CHP technical potential was assigned to each SIC code using DOE data discussed in Section 2.5. This aggregate CHP potential was then divided by potential CHP sites per SIC code to arrive at the average capacity per potential site. Using average CHP capacity by SIC code it was possible to assign a technology type and corresponding duration before a major maintenance overhaul based on the EPA Catalog of CHP Technologies.[64] This lifespan duration is not equal to the equipment lifespan but, rather, the average duration before a major overhaul is required. Because the equipment overhaul costs are not included in the STEER model, we felt it best to calculate resiliency benefits over the average timespan before any major overhaul is required. Resiliency benefits beyond this original duration could be calculated using the cost of the overhaul and the anticipated longevity of the CHP system at that point.

[64] U.S. EPA. 2017. *Catalog of CHP Technologies*.
http://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf.

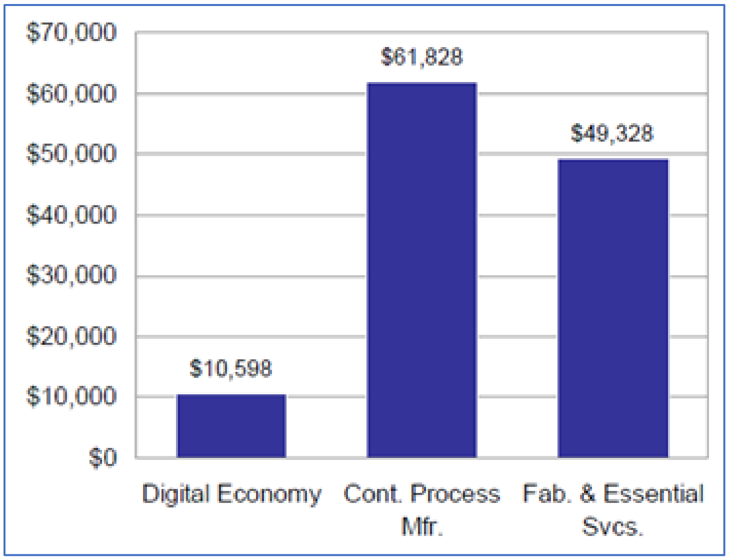


Figure 4: Average Annual Per-Establishment Cost of Outage by Sector

The value of resiliency was calculated by summing the annual outage costs over each CHP lifespan and using an 8% weighted average cost of capital[65] to determine the net present cost of outages. This net present cost was divided by the average CHP capacity per SIC code to arrive at a gross value of resiliency on a dollar per kW installed basis. As the CHP installed costs within the STEER model do not include additional costs related to resiliency (black start, islanding mode, etc.), an estimation of those costs was required. According to Oak Ridge National Laboratory, adding resiliency features to CHP installations costs approximately 10% of the total installed costs.[66]

The difference between these two figures is the net value of resiliency on a dollar per kW installed. Technically, this does not capture the value of resiliency, *per se.* Nevertheless, it does capture the costs of power outages per kW of CHP installed capacity on a net present value basis. However, absent other methodologies or guidelines, this approach best reflects an accurate monetization of the private resiliency benefits necessary to avoid costly power outages. The final results are presented in Table 6.

[65] While each SIC code might have an average weighted average cost of capital, 8% was used for simplicity.
[66] Hampson, A., et al. ICF International. Prepared for Oak Ridge National Laboratory. 2013. *Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities.* https://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_critical_facilities.pdf.

Table 6. Value of CHP Resiliency

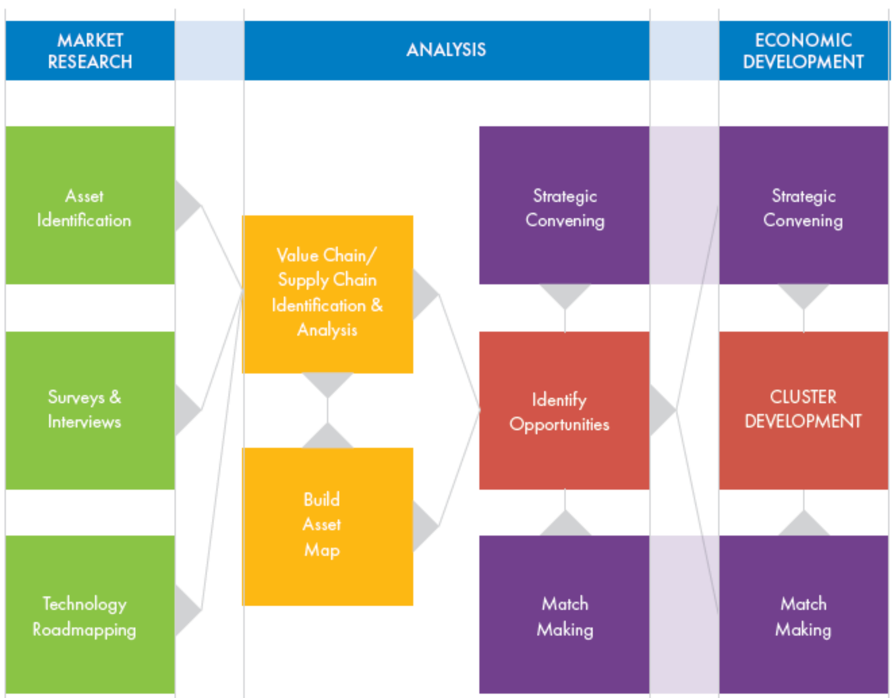
Sectors by SIC Code	Average Annual Outage Costs	CHP Technical Potential (kW)	CHP Technical Potential (Sites)	Average kW per Site	Technology Type	Average CHP Lifespan	Present Value of Outage costs per CHP lifespan	Gross value of resiliency $/kW Installed	Costs of Resiliency Equipment $/kW Installed	Net Value of Resiliency $/kW installed
Digital Economy	$ 10,598.00									
7374		27,948 kW	70	399 kW	RECIP	9	$66,204.52	$ 165.82	$ 230.00	$ (64.18)
38		915 kW	5	183 kW	MT	5	$42,314.74	$ 231.28	$ 230.00	$ 1.28
8051		42,672 kW	313	136 kW	MT	5	$42,314.74	$ 310.38	$ 230.00	$ 80.38
8062		193,064 kW	171	1,129 kW	RECIP	9	$66,204.52	$ 58.64	$ 160.00	$ (101.36)
Continuous Process Manufacturing	$ 61,828.00									
26		211,885 kW	104	2,037 kW	CT	6.25	$295,104.35	$ 144.85	$ 300.00	$ (155.15)
28		572,452 kW	284	2,016 kW	CT	6.25	$295,104.35	$ 146.40	$ 300.00	$ (153.60)
29		69,484 kW	20	3,474 kW	CT	6.25	$295,104.35	$ 84.94	$ 300.00	$ (215.06)
30		88,300 kW	333	265 kW	RECIP	9	$386,232.59	$ 1,456.57	$ 230.00	$ 1,226.57
32		16,923 kW	4	4,231 kW	CT	6.25	$295,104.35	$ 69.75	$ 300.00	$ (230.25)
33		255,213 kW	169	1,510 kW	CT	6.25	$295,104.35	$ 195.42	$ 300.00	$ (104.58)
Fabrication and Essential Services	$ 49,328.00									
43		2,344 kW	24	98 kW	MT	5	$196,952.40	$ 2,016.63	$ 230.00	$ 1,786.63
4581		6,977 kW	11	634 kW	RECIP	9	$308,146.49	$ 485.86	$ 180.00	$ 305.86
49		8,283 kW	16	518 kW	RECIP	9	$308,146.49	$ 595.20	$ 230.00	$ 365.20
20		186,019 kW	273	681 kW	RECIP	9	$308,146.49	$ 452.23	$ 180.00	$ 272.23
22		6,406 kW	23	279 kW	RECIP	9	$308,146.49	$ 1,106.40	$ 230.00	$ 876.40
25		662 kW	7	95 kW	MT	5	$196,952.40	$ 2,081.30	$ 230.00	$ 1,851.30
27		5,526 kW	38	145 kW	MT	5	$196,952.40	$ 1,354.34	$ 230.00	$ 1,124.34
34		18,129 kW	149	122 kW	MT	5	$196,952.40	$ 1,618.71	$ 230.00	$ 1,388.71
35		15,673 kW	17	922 kW	RECIP	9	$308,146.49	$ 334.25	$ 180.00	$ 154.25
37		618,436 kW	529	1,169 kW	RECIP	9	$308,146.49	$ 263.58	$ 160.00	$ 103.58
39		490 kW	6	82 kW	MT	5	$196,952.40	$ 2,411.02	$ 230.00	$ 2,181.02

3.3 Supply and Value Chain Mapping

Boundaries for the supply and value chain mapping component of this Michigan CHP Roadmap were determined through a combination of market research and market analysis. The primary criteria for setting boundaries were the significance to the state of Michigan in terms of economic activity arising from deployment of CHP projects and feasibility given the resources and timeframe of this project. Any market segments where Michigan companies are currently participating in the CHP supply or value chain were given principal consideration for surveys, interviews, and database development. Segments where Michigan companies are not competing but perhaps could compete, under the right value proposition, were also analyzed.

The supply and value chain mapping methodology was adapted from the approach used in developing the Michigan Agency for Energy's (MAE) "Clean Energy Roadmap" published in 2016.[67] That effort, focused on Michigan and Northeast Ohio, developed strategies for accelerating energy efficient or energy waste reduction technologies and developing technology roadmaps for several energy intensive, clean energy manufacturing processes to reduce the energy cost of these processes. The project was split into three components: market research, market analysis, and economic development, as depicted in **Figure 5**.

Figure 5: Clean Energy Roadmap Methodology[68]



[67] Michigan Agency for Energy. 2016. Clean Energy Roadmap. http://www.michigan.gov/documents/energy/2016-03-09_CER_Full_526941_7.pdf.
[68] Ibid.

Market Research

The first step of the mapping methodology -- market research -- included asset identification, surveying and interviewing market participants, and technology roadmapping.

Michigan companies – “assets” – that could potentially participate in the CHP supply and value chain, through a clear supply or value proposition, were identified by project partners through internet research, project partners’ knowledge base, and aggregation of attendance lists from the 2015, 2016 and 2017 Michigan CHP Conferences, as well as via additional contacts obtained through Institute for Energy Innovation (IEI) industrial energy efficiency (IEE) roundtables. This baseline asset list was supplemented by attendee lists from other CHP-related events, such as the Smart Solutions for the Upper Peninsula event (July 14, 2016), the Combined Heat and Power Opportunities for Michigan Healthcare Providers Detroit Event (August 22, 2016), and referrals from those in the supply and value chain.

Survey and interview questions were developed by project partners based on prior survey and interview work that had been completed to support the MAE’s “Clean Energy Roadmap.” The project team conducted 21 detailed interviews with representatives of firms active in the various sectors of Michigan’s CHP supply and value chain, and received detailed survey results from 107 individuals working at firms throughout these sectors. Many more information gathering conversations were conducted with supply and value chain participants by members of the project team throughout the course of this study.

Participants in the Michigan CHP supply and value chain who volunteered for interviews include the following, with their principal role in the CHP supply and value chain indicated:

- Michigan Caterpillar (prime mover distributor)
- W.W. Williams (prime mover distributor)
- Solar Turbines (prime mover distributor)
- Varnum Law (legal)
- CMS Enterprises (investor)
- Petros PACE Finance (investor)
- Ford Dearborn campus (end-user)
- Dow Chemical (end-user)
- Scenic View and Brook View dairy farms (end-user)
- Midland Cogeneration Venture (end-user)
- Opterra Energy (developer)
- Cogen Consultants (developer)
- DTE Gas (fuel supplier)
- Michigan Public Service Commission (regulators/policymakers)
- GEM Energy (design/engineering)
- Ghafari & Associates (design/engineering)
- Fishbeck, Thomson, Carr & Huber (design/engineering)
- Newkirk Electric/Theka (engineering/component supplier)

- Kendall Electric/Eaton (component supplier)
- Waukesha-Pierce (component supplier)
- EMP Corp (component supplier)

The project team also received 68 detailed survey responses from firm representatives who attended the annual Michigan CHP Conference in either 2015, 2016, or 2017. The survey was deployed on the following dates:

1. 9/14/2016 – First deployment sent to attendees of 2015 and 2016 CHP Conferences
2. 9/22/2016 – Survey reminder sent
3. 10/26/2016 – Survey link was shared with Michigan's New Energy Policy (NEP) stakeholder group
4. 7/24/2017 – Survey sent to attendees of 2015, 2016 and 2017 CHP Conferences
5. 8/14/2017 – Survey reminder sent

Digging deeper into potential opportunities for Michigan manufacturers to produce the high-value CHP equipment and/or prime mover components, further research was completed to ascertain whether there are any realistic economic opportunities for Michigan companies. This was pursued through:

1. Qualifying the market opportunity for a typical Michigan manufacturing firm;
2. Interviewing procurement gatekeepers at prime mover and major component manufacturers;
3. Identifying and qualifying the legal, regulatory, and financial barriers to market entry;
4. Assessing what Michigan could potentially do through state incentives or other mitigating strategies to help Michigan's manufacturing firms enter and compete in this market.

In aggregate, these market research efforts enabled the project team to better understand the full spectrum of challenges and opportunities facing CHP deployment in Michigan from a supply and value chain perspective and qualify the economic opportunities for Michigan businesses to participate.

Market Analysis

To identify likely gaps and opportunities for Michigan companies, the second step of the mapping methodology -- market analysis -- entailed identification of the specific industry segments within the CHP supply and value chains and classification of the Michigan CHP market participants into those sectors.

Project partners defined the **CHP supply chain** as the physical equipment and fuel required for the CHP system to operate. The CHP supply chain contains four major sectors of participants:

- CHP end-user applications;
- Prime mover manufacturers and distributors;
- Major equipment manufacturers and distributors;
- Fuel suppliers and brokers.

Project partners defined the **CHP value chain** as the intellectual capital and skilled trades required to develop, design, engineer, finance, install, and integrate CHP systems. The CHP value chain contains four major sectors of participants:

- Public policy advocates and accelerators;
- Project developers and technical advisors;
- Design/engineering firms;
- Plant integration contractors.

All firms identified as participating in the Michigan CHP supply and value chains were classified by project partners into one of these major sectors. Where a firm might participate across multiple sectors, preference was given to the sector in which it was deemed that the greatest impact would likely be realized for the business.

Economic Development

In the case of the MAE's "Clean Energy Roadmap," economic development was the third and final step of the mapping methodology and entailed strategic convening and match-making of Michigan companies who participate in the supply and value chains for the purpose of manufacturing new products. However, this approach is not well-suited for increasing the deployment of CHP energy projects, which are driven primarily by individual end-user interest, understanding, and their financial and technical ability to implement projects with the support of local and regional supply and value chain participants. For this reason, project partners expanded upon the economic development methodology used previously by MAE. For the Michigan CHP Roadmap, economic development includes not only the matchmaking component, which is accomplished through compiling, distributing, and periodically updating the directory of Michigan supply and value chain participants, but also proactive outreach to potential CHP end-users and their industry associations to discuss the merits of CHP.

End-users typically focus on their core business and take energy for granted. In project partners' experience, few have a clear understanding of CHP on both its technical and economic merits. End-users must be educated and engaged to explore CHP opportunities for their facilities, as it is their ultimate interest (or lack of interest) in the technology, coupled with their expectations for economic benefit that will drive (or stall) CHP project deployment.

The task of education has historically fallen on CHP equipment distributors who understand the technology well. However, these equipment distributors are often unable to accurately assess the economic impact of CHP systems on the end-user in an unbiased fashion. By helping prospective end-users fully recognize the range of benefits afforded by CHP, including implementation of projects and reinvestment of end-users' energy savings into growth or expansion of their core businesses, will create opportunities for economic development.

3.4 Barrier Identification

Project partners collected data through three approaches In order to recommend targeted solutions to mitigate barriers to CHP deployment:

1. The project team conducted detailed research to understand the barriers and market impediments, which in most cases are well-documented by prior studies;
2. The project team aggregated in-house data acquired through public- and private-sector technical assistance activities and project development experience;
3. The project team surveyed and interviewed the major market participants including CHP developers, equipment manufacturers, end-users, regulatory officials, and other invested stakeholders.

Throughout 2016 and 2017, Michigan stakeholders interested in CHP development were surveyed and interviewed as to their perceptions of the major barriers facing CHP in the state. As was described in Section 3.3, a comprehensive survey was deployed at five separate intervals between September 14, 2016 and August 14, 2017 to over 200 recipients. There were 107 survey respondents in total, representing the full spectrum of stakeholders including utilities, government officials, economic development specialists, CHP developers, engineering firms, advocates and end-users. Additionally, more than two dozen in-depth interviews took place with representatives from government, utilities, law firms, finance experts, CHP developers, engineering/design firms, and major energy users. Results from these survey and interview responses shed light on stakeholder perceptions regarding the major barriers impeding CHP development in Michigan. **Attachment C** contains survey and interview data reflecting respondents' perceptions as to the magnitude of potential barriers to CHP in Michigan.

Upon review of the survey and interview responses received from a broad array of Michigan stakeholders, key barriers to deployment of CHP in Michigan have been identified as: 1) a lack of access to low-cost capital; 2) utility rates; 3) failure by the electric utilities to fully embrace CHP in EWR and IRP programs; and (4) a lack of awareness/familiarity with CHP.

Identifying solutions to the barriers and market impediments of CHP adoption will help to enlarge the pool of CHP projects that meet minimum criteria for technical and economic viability within STEER, which models CHP as a least-cost resource in Michigan's future energy mix, and thereby enable increased CHP deployment. In customizing and prioritizing proposed solutions for Michigan, project partners considered the estimated proportion of potential projects affected, perception of barrier magnitude by stakeholders, and the ease/practicality of achieving change in the short term. Focus was placed on those barriers which are most significant to restricting deployment of CHP across Michigan and to which attainable solutions exist. For the most part, solutions take the form of legislative change or regulatory relief, modification of utility rate structures, and financial incentives.

3.5 Stakeholder Engagement in Roadmap Deployment

Project partners have engaged policymakers, utilities, state agencies, the MPSC, business and industrial trade associations, non-governmental organizations (NGOs), and end-users with regard to the development of this CHP roadmap, through presentations and engagement with, among others: the state's New Energy Policy (NEP) Stakeholder Group, the Michigan CHP Conferences at Oakland University (2016) and Grand Valley State University (2017), IEE roundtables hosted by IEI in Marquette, Kalamazoo, and Ann Arbor, an event focusing on CHP in healthcare in Detroit, and outreach to the state's Collaborative Development Council.

The 2016 Michigan CHP Conference took place at Oakland University on May 10, 2016. There were over 120 attendees representing component manufacturers, developers, end-users and potential end-users, and governmental leaders. This followed-up on the success of the first ever Michigan CHP Conference, held in Lansing in 2015, which drew nearly 200 attendees. Panel discussions at the 2016 conference focused on technology, case studies, project development, financing and policy.

On June 20, 2016, project partners presented at the NEP Stakeholder Group Meeting in Lansing. Stakeholders were asked to engage around the following questions: "What barriers are impeding the adoption of CHP technology in Michigan?" and "Where do you see the greatest opportunity for distributed CHP energy production?" A follow-up webinar was conducted on October 24, 2016 to gain further feedback on the project.

IEI hosted two roundtables focused on IEE and CHP: one in Marquette on July 15, 2016 and the other in Kalamazoo on August 22, 2016. These roundtables provided an opportunity for project partners to engage with current and potential end-users and policymakers, and provided a productive forum for education around a variety of aspects affecting CHP implementation in the state.

In August 2016, the Energy Resources Center organized an event focused on CHP in healthcare in Detroit. The workshop, titled "Combined Heat and Power Opportunities for Michigan Healthcare Providers," highlighted the steps necessary for end-users to implement a successful CHP project, from initial screening to equipment installation. The workshop also outlined the complimentary technical assistance provided by DOE CHP TAP to end-users interested in CHP solutions.

In December 2016, team members from Sustainable Partners, LLC (SPART) led a CHP presentation before the Collaborative Development Council, a group comprised of 18 economic development practitioners representing regions across the state. The purpose of the presentation was to provide general education about CHP, and also enlist the group's assistance in facilitating end-user outreach in 2017. Additionally, Douglas Jester of 5 Lakes Energy (5LE) presented to the Council of Industrial Boiler Owners (CIBO) on the potential challenges and opportunities surrounding CHP. The Energy Resource Center also presented on CHP to DTE Gas in November 2016, and to the West Michigan Association of Energy Engineers (WMAEE) in December 2016.

Proactive stakeholder engagement continued through year two of the project. On February 23, 2017 and April 25, 2017, Jamie Scripps of 5LE presented to the Alliance for Industrial Efficiency (AIE) and to the American Forest & Paper Association (AF&PA) on standby rates as a potential barrier to CHP deployment. In May 2017, project partners presented to MAE on the supply/value chain mapping aspects of the project. In the summer, project partners engaged with stakeholders through the 2017 Michigan CHP Conference held on June 28, 2017 in Grand Rapids.

In September 2017, Greg Northrup of SPART participated as an exhibitor on behalf of the CHP Roadmap Project at the Michigan Society for Healthcare Engineering (Mi-SHE) annual meeting in Traverse City. Also in September 2017, Jamie Scripps of 5LE presented to the Electricity Consumers Resource Council (ELCON) on standby rates as a potential barrier to CHP deployment. Additionally, in partnership with IEI, project partners presented on the CHP Roadmap and solicited feedback from stakeholders at a UP Energy Roundtable in Marquette on September 19, 2017, and at a CHP Roundtable in Ann Arbor on December 11, 2017.

Project partners engaged with over 300 unique individuals through outreach and education efforts related to the development of the CHP Roadmap.[69] Through this outreach process, in addition to receiving valuable insight, the project team has increased awareness in CHP and built a network of stakeholders interested in participating the future of CHP in Michigan.

4 State Tool for Electricity Emissions Reduction (STEER)

One objective of this project was to identify and evaluate CHP technologies and applications with a potential for adoption in Michigan. In support of this objective, the project team quantitatively modeled the optimized deployment of CHP in Michigan using a modified version of the STEER model. Because CHP simultaneously provides heat and power, the potential for CHP adoption is partly determined by the number and size of sites that have heat requirements that can be met by CHP.

STEER was used to assess, measure, and determine the cost and value of CHP as one of multiple resources in Michigan's future energy mix. In the primary application of STEER, the model considered the net value of CHP in the economy by considering the cost of installing and operating various CHP systems, the value of the heat produced by CHP measured as the cost of supplying heat in the least-cost way other than CHP, and the value of electricity produced by the CHP system measured as the marginal cost of producing electricity absent the CHP system. Determining the value of CHP in the electric power system is the province of STEER. Thus, the selection of CHP technologies by STEER is a projection of the economic potential for CHP in Michigan. The actual division of costs and benefits amongst CHP site hosts and utilities depends on policy and particularly on utility rates as applied to customers with CHP.

Because we determined that standby rates are one of the principal barriers to CHP adoption that may be amenable to policy adjustments, STEER was used to evaluate the effect of standby rates on the economic potential for CHP in Michigan. Further, because resilience of CHP site host operations is an important benefit of CHP that is not reflected in standard electric power system evaluations, STEER was used to evaluate the additional economic potential for CHP in Michigan if site hosts would not otherwise choose to build CHP but sufficiently valued resilience to do so. Consideration of resilience value increases the potential deployment of CHP in sectors where loss of power is most consequential and can significantly increase CHP potential beyond the levels that would be supported only by power sector value. Based on STEER analysis of Michigan potential, resilience value could increase CHP potential by

[69] Total calculated through aggregation and removal of duplicates from attendance lists for 2015, 2016 and 2017 Michigan CHP Conferences, and 2016 and 2017 IEI roundtables. This total is conservative and does not include anonymous survey respondents.

around 60%. Standby rates, on the other hand, substantially reduce the profitability of CHP ownership and thereby reduce potential CHP deployment by 50% or more.

As described in detail in the following sections, STEER modeling indicates that steam turbines, gas combustion turbines, and reciprocating engines appear profitable above some size threshold size in each scenario. Conversely, microturbines and fuel cells do not appear economically viable. In addition, STEER indicates that higher natural gas prices and higher cost of renewable resources in the future both tend to lower the minimum size threshold for the more viable CHP technologies, thereby expanding the number of potential installation sites in Michigan.

Furthermore, approximately half of sites where steam turbines are economically feasible are on college and university campuses, confirming that this sector should be an important part of end-user outreach and education. However, this result does not necessarily mean that combustion turbines and reciprocating engines would also not be suitable for these facilities.

In the STEEER reference scenario, economic potential for CHP in Michigan is about 1,014 MW electric generation capacity with direct investment of about $865.6 million, annual direct O&M activity of about $67.6 million, annual economic profit of about $109.5 million, annual fuel cost savings of $94.7 million, and annual air emissions reductions of 662 tons carbon dioxide (CO_2) per year, 379 tons nitrous oxide (NO_x) per year, and 39 tons sulfur oxide (SO_x) per year. In other STEER scenarios, assuming different fuel and technology costs, the economic potential for CHP in Michigan varies from 722 MW to 1,014 MW.

4.1 Model Overview

STEER is an integrated resource planning model that calculates the least-cost resource portfolio to satisfy electricity demand and various reliability and environmental constraints based on projections of demand, fuel prices, technology price and performance, taxes, and other factors.

To give state lawmakers, regulators, and stakeholders the ability to evaluate Clean Power Plan compliance approaches with the benefit of reliable integrated resource planning data, 5LE, in collaboration with the University of Michigan, originally developed the STEER model with funding from the Energy Foundation and Advanced Energy Economy Institute. The principal purpose of theSTEER model is to facilitate stakeholder access to data and integrated resource planning analysis. The STEER model automatically calculates the least-cost compliance and implementation strategies to serve forecast demand and comply with reliability and environmental standards, along with projected cost to electricity users, given certain policy options and electricity demand and price forecasts. All data, inputs, and formulae are visible to and changeable by the user. The Michigan version of the STEER model is available for download online.[70]

STEER is based on hourly load data for 24 representative days of the year and forecasts future loads out to 2030, considering changes in load profile that result from selected energy efficiency/EWR programs.

[70] Advanced Energy Economy. 2017. *State Tool for Electricity Reduction (*STEER). https://info.aee.net/steer.

STEER builds on a trend forecast of load with adjustments to accommodate forecasted adoption of electric vehicles and demand response, storage, and smart grid programs.

STEER contains performance data for each utility-scale electric generating unit in Michigan, including the multiple units in each power plant, and for aggregated small-scale generation either "behind-the meter" or integrated to the distribution system. It calculates the least-cost dispatch of these generating units to satisfy load for each hour, then calculates coal usage, natural gas usage, variable costs, carbon emissions, sulfur oxide emissions, nitrous oxide emissions, and mercury emissions based on that dispatch plan.

The STEER dispatch model also derives locational marginal prices for selection of least-cost resource additions. These locational marginal prices have been verified by comparisons to historical data. If an environmental policy (such as annual CO_2 emissions limits or NO_x limits to reduce summer ozone levels) is applied to dispatch, the model calculates dispatch, locational marginal price, and incremental cost of operating the power system accordingly.

STEER adds generation resources when needed to satisfy load, meet capacity reserve margin standards, or to satisfy a constraint on emissions. When adding generation resources, the STEER model considers technologies including natural gas combustion turbines and combined cycle plants, nuclear electricity generation, biomass co-firing in existing coal plants, hydropower, wind power, utility-scale and distributed solar photovoltaic generation, biomass combustion, and cogeneration. Required revenue to recover investment costs and operating expenses, as well as capacity and energy value of new generation resources is considered when those are chosen for addition to the generation portfolio. STEER follows the standard utility planning practice of valuing capacity at the cost of new entry of a natural gas combustion turbine, when capacity is needed. In utility operations, energy production is planned from a generating unit only when the output from all units that are cheaper to operate is insufficient to meet demand. The value of energy from each generating unit is the cost of electricity from the marginal generating unit at each time a generating unit operates.

To address capacity limitations, if the model finds that capacity requirements to satisfy the forecasted load, plus necessary reserve requirements, are not being met based on economic selection of another resource, it adds new natural gas combustion turbine capacity to the generation fleet. This occurs because, of the available generation technologies, such combustion turbines require the lowest capital investment per unit capacity. Economic selection of another technology occurs when the higher investment in the technology is offset by lower operating costs or emissions compliance. This method assures adequate capacity at least-cost even if the combustion turbine capacity itself is not "profitable" as a power system resource.

STEER allows for improvements in the fuel efficiency of existing generation plants, often referred to as "heat rate improvements." Costs and effects of heat rate improvements at existing plants default to the assumptions made by EPA in developing the draft Clean Power Plan. However, a STEER user is free to make plant-specific assumptions.

STEER does not automatically retire power plants, but allows the user to specify plant retirements and to attribute these retirements as due to compliance with environmental regulations or as retirements that would occur anyway. STEER facilitates user decisions about plant retirements by providing the capacity factors, dispatch order, air pollutant emissions, and other information that a user might consider in making retirement decisions. Upon retirement, the STEER model reflects the avoided fixed and variable cost of plant operations and the costs of replacement capacity and energy. Remaining book value is assumed to be securitized and accounted for in utility revenue and rate forecasts.

Since utility practices and regulation rarely lead to capacity additions based purely on economic value, if additional capacity is not needed, STEER does not add capacity unless capacity is needed. However, a user can quickly determine such economic additions by retiring plants that do not "earn" their fixed and operating costs and allowing STEER to select the best available demand-side or generation option.

Renewable resource options are based on inventories of renewable resource potentials developed by the National Renewable Energy Laboratory (NREL). Wind and solar generation are based on hourly site-specific data from NREL's Eastern Wind Integration Transmission Study and System Advisory Model, respectively. Capacity factors, capacity credits, and hence power system value of wind and solar generation are the result of calculations using site-specific data rather than general assumptions. Hydropower resources are representative of small hydropower facilities operated run-of-river using typical Michigan streamflow. Biomass resources are grouped into eight categories running from municipal waste and landfill gas through timber residuals.

Energy efficiency or energy waste reduction measures included in the model, their costs, and their achievable potential are taken from the Michigan Energy Efficiency Potential Study performed by GDS Associates in 2013 and released as part of Governor Snyder's "Ensuring Michigan's Future" report series in November 2013.[71] These measures include 190 applications used by residential, commercial, and industrial customers. For purposes of modeling effects on load profiles, we classified each measure as affecting all load or peak load. In STEER, the user can specify whether the model should consider all achievable cost-effective energy efficiency or constrain these programs to a spending cap of 2% of utility revenues, as was evaluated by GDS.

In addition to these features of Michigan's power system, the STEER model also incorporates the operation of the Ludington Pumped Storage Plant and the possibility of power imports and exports subject to current transmission limitations established by the regional transmission organizations. A STEER user can make changes to the import and export capacity limits.

4.2 Strengths and Weaknesses

By utilizing STEER, the project team was able to take advantage of an existing, Excel-based tool designed for use by anyone with a standard laptop or desktop computer. Also, STEER provides an appropriate granularity of analysis for this project because it represents Michigan's electricity system at the level of individual generating units dispatched hourly. This level of detail is well suited for capturing the different

[71] GDS Associates, Inc. Prepared for the Michigan Public Service Commission. 2013. *Michigan Electric and Natural Gas Energy Efficiency Potential Study*. http://www.michigan.gov/documents/mpsc/mi_ee_potential_study_rep_v29_439270_7.pdf.

sizes, operating characteristics, and costs of a range of CHP technologies. Finally, STEER's existing suite of cogeneration units provided a framework that could be readily expanded to include multiple prime mover technologies and system sizes to yield a more realistic set of CHP options for the model to deploy.

As with any model, simplifications have been made. STEER assumes there are no binding transmission constraints within Michigan. The model might replace generation from a fossil fuel plant with, for example, renewables located in an area that lacks adequate transmission interconnections, requiring additional transmission. New natural gas and biomass plants are not assigned to specific locations, so their locations can also reflect transmission availability and support requirements. That said, model results do not appear to be distorted as a result of this simplification.

In addition, the model calculates the least-cost plan for the single year, chosen by the user, and does not aggregate year-by-year results over a period of time. For example, the model might calculate that the least-cost plan uses a new natural gas combined cycle plant based on projected conditions in 2020. However, based on projected conditions in 2030, the model may calculate that a combination of wind generation and cogeneration is more cost-effective. The model does not attempt to resolve these differences by solving the dynamic programming problem of how best to act over the full life-cycle of each generator although that analysis can be performed by using the model to analyze results year-by-year and evaluating the life-cycle results. As such, the results of the model from any given year should be viewed in the context of long-term utility and regulatory planning, including underlying changes in the cost of fossil fuels used for generation and the desirability of hedging against volatility in fossil fuel prices.

With these simplifications in mind, STEER represents a useful strategic planning tool for regulators and stakeholders alike, enabling consideration of a wide range of alternatives and providing transparency as to the model's calculations in a particular scenario. STEER users may rely on the existing publicly available data that is included in the model or the data can be replaced with more granular information if desired. Stakeholders can use this tool for analysis and comparison with analyses produced by utility companies and other stakeholders.

4.3 Model Adaptation

The original version of STEER already included a limited selection of natural gas-fired, combustion turbine cogeneration systems available for deployment. As described in Section 3.1, for this project, this existing suite of CHP options was expanded to reflect a wider range of prime mover technologies, system sizes, and fuel types. This enables the ability to run more sophisticated modeling scenarios that consider the characteristics of different types of CHP applications. The result is a more realistic picture of the scale of CHP deployment that is possible in Michigan, subject to various factors such as future fuel prices, policy decisions such as the structure of standby rates, and other elements that affect the overall cost of building and operating CHP systems. The results presented throughout this report are based on the modified version of STEER.

During activities related to the customization of the STEER Model as described in detail within the technology roadmapping methodology in Section 3.1, project partners incorporated CHP technologies for inclusion in Michigan's generation portfolio based on the performance characteristics and costs published by EPA with potential deployment numbers and capacities published by DOE. These included various sizes of reciprocating engines, gas turbines, steam turbines, microturbines and fuel cells. In order to evaluate CHP's value to the electric power system, we found the "electric-only" costs of each CHP application by subtracting from both the investment cost and the operating cost of CHP the cost of producing a comparable amount of heat from an efficient natural gas boiler.

STEER evaluates the potential deployment of each CHP technology in the same way that it evaluates all new generation options. First, it computes the required annual revenue for investment per unit of the technology based on the investment cost, depreciation schedule, cost and shares of debt and equity, property and use taxation, and income taxation using rates that are representative of Michigan utilities. Second, STEER calculates the capacity and energy value of each generation option when placed into dispatch competition with all existing or previously selected generation resources. This allows calculation of "unmet required revenue," which is the required annual revenue for investment less the capacity and energy value the resource would provide if built. In principle, this is the same as determining whether the new resource would be profitable in a wholesale power supply market. If "unmet required revenue" is negative, then the plant would be profitable based solely on wholesale power market revenues and capacity values. If "unmet required revenue" is positive, then it would fail to recover its costs with a reasonable return on investment from its power output and would only be built if it provided additional value, such as resilience benefits to its host. Third, STEER calculates avoided emissions of CO_2, NO_x and SO_x by calculating the reduced use of the marginal generating unit in each hour due to deployment of a potential new resource and the consequent reduction of emissions from that marginal unit, offset by any emissions from the potential new resource. Finally, STEER chooses which generation resources to deploy by ranking them in order from the lowest to highest "unmet required revenue" per unit environmental mitigation and going as far down this list as necessary to both meet required load and satisfy the aggregate statewide environmental constraints established by the user. If the environmental constraints are lax, this produces essentially the same result as ranking them from lowest to highest "unmet required revenue" per unit of power generation.

Because new generation resources are only added when needed, in deference to the existing generation resources, it is possible that options with a negative (profitable) "unmet revenue requirement" will not be chosen by STEER. STEER might choose a resource that has a positive (unprofitable) "unmet revenue requirement" if necessary to meet the emissions constraints. For purposes of CHP deployment, any technology with a negative "unmet revenue requirement" would be viable in the marketplace absent discriminatory utility policy and without an emissions constraint.

4.4 Assumptions

As with all integrated resource planning, assumptions or projections about future conditions are the bases for analysis. The STEER model provides means to determine an optimum course of action given those projections, but the projections of future conditions are determined external to the model. Projections of conditions such as load growth, fuel prices, and technology prices are provided to the model as independent parameters but are not actually independent. Best practice when using a model is therefore to use multiple scenarios reflecting possible "states of the world" in order to understand the variation of modeling results and the risks associated with a potential course of action. Because of the large number of parameters that are incorporated into STEER, it is possible to construct many scenarios.

Because any investment in CHP will need to be viable for an extended period, we evaluated the role of CHP in 2030. For purposes of preliminary evaluation of the viability of CHP technologies in Michigan, we constructed and used several scenarios. In each case, we assume current law including Michigan's EWR resource standard and Renewable Portfolio Standard (RPS), the availability of federal production or investment tax credits, tax rates, etc. We also assumed announced plans to retire power plants, consistent with the retirements used by MAE in its modeling of Clean Power Plan compliance.[72]

"Spark spread" – the difference between the price of electricity and the cost of fuel to produce electricity – is widely understood to be one of the most critical factors in the economic viability of CHP projects. In order to evaluate this factor in a logically consistent way, we used natural gas price forecasts from three scenarios provided in the U.S. DOE Energy Information Administration (EIA) 2016 Annual Energy Outlook.[73]

In preparing the annual outlook, EIA uses econometric models that statistically identify the "linkages between the prices of various fuels." Their scenarios, designed principally to identify the effects of variation in natural gas supply, are the Reference Case, the High Oil and Gas Resource Case ("High Resource Case"), and the Low Oil and Gas Resource Case ("Low Resource Case"). The High Resource Case produces lower fuel price forecasts and the Low Resource Case produces higher fuel price forecasts than the Reference Case. These forecasts, in 2016 dollars per Million British thermal units (MMBtu) of heat content, are shown through 2030 in Table 7.

The other principal non-policy factor besides fuel prices that would be likely to materially affect "spark spread" and hence CHP project economics, is the price of electricity. STEER forecasts the hourly wholesale price of electricity given fuel prices, existing generation resources, and the least-cost selection of new generation resources. STEER projects the price of electricity using the embedded costs of legacy generation, projected costs of new generation resources, and projected costs of fuel used in either existing or new generation resources. The assumptions used in STEER, other than fuel prices, that are most likely to affect the future price of electricity are the costs of renewable generation technologies. In order to assess the effects of these projections, we used each of the fuel price scenarios noted above in combination with two alternative assumptions about renewable technology. One alternative assumes that renewable generation costs continue to decline at the rates that have occurred over the last five years, while the second alternative simply excludes new renewables from the STEER analysis, simulating that they are not economically competitive. This range of scenarios provides a corresponding range of CHP deployment outcomes, reflecting appropriate uncertainty about the future.

[72] These retirements were not based on requirements of the Clean Power Plan. Rather they reflected the knowledge and opinions of staff of the Michigan Public Service Commission and Michigan Agency for Energy about expected retirements of existing generating units based on age and other environmental requirements.
[73] U.S. EIA. 2016. *Annual Energy Outlook 2016 with projections to 2040*. https://www.eia.gov/outlooks/aeo/pdf/0383(2016).pdf.

Table 7. EIA Price Forecasts through 2030[74]

	Reference Case Fuel Forecast (2016$/MMBtu)				High Gas and Oil Resource Case Fuel Forecast (2016$/MMBtu)				Low Oil and Gas Resource Case Fuel Forecast (2016$/MMBtu)			
Year	Distillate Fuel Oil	Residual Fuel Oil	Natural Gas	Steam Coal	Distillate Fuel Oil	Residual Fuel Oil	Natural Gas	Steam Coal	Distillate Fuel Oil	Residual Fuel Oil	Natural Gas	Steam Coal
2014	$ 23.19	$ 20.00	$ 5.04	$ 2.27	$ 23.19	$ 20.01	$ 4.93	$ 2.27	$ 23.19	$ 20.01	$ 5.00	$ 2.27
2015	$ 15.26	$ 10.13	$ 3.29	$ 2.28	$ 15.26	$ 10.13	$ 3.29	$ 2.28	$ 15.26	$ 10.13	$ 3.29	$ 2.28
2016	$ 11.95	$ 8.09	$ 3.02	$ 2.14	$ 11.95	$ 8.09	$ 2.93	$ 2.15	$ 11.95	$ 8.09	$ 3.05	$ 2.13
2017	$ 14.33	$ 9.30	$ 3.53	$ 2.18	$ 14.58	$ 9.39	$ 3.32	$ 2.18	$ 14.17	$ 9.20	$ 3.65	$ 2.17
2018	$ 16.22	$ 10.57	$ 3.81	$ 2.23	$ 15.94	$ 10.40	$ 3.58	$ 2.20	$ 15.81	$ 9.89	$ 4.03	$ 2.26
2019	$ 17.26	$ 12.65	$ 4.18	$ 2.28	$ 16.96	$ 12.47	$ 3.81	$ 2.23	$ 17.22	$ 12.40	$ 4.55	$ 2.31
2020	$ 17.75	$ 13.25	$ 4.54	$ 2.31	$ 17.44	$ 13.00	$ 3.83	$ 2.24	$ 17.86	$ 13.14	$ 5.15	$ 2.36
2021	$ 18.10	$ 13.74	$ 4.57	$ 2.31	$ 17.76	$ 13.44	$ 3.68	$ 2.22	$ 18.52	$ 13.94	$ 5.48	$ 2.38
2022	$ 18.36	$ 14.12	$ 4.53	$ 2.32	$ 18.06	$ 13.93	$ 3.58	$ 2.23	$ 18.87	$ 14.45	$ 5.99	$ 2.39
2023	$ 18.69	$ 14.52	$ 4.56	$ 2.33	$ 18.55	$ 14.39	$ 3.60	$ 2.23	$ 19.27	$ 14.83	$ 6.32	$ 2.40
2024	$ 19.00	$ 14.78	$ 4.68	$ 2.33	$ 19.08	$ 14.87	$ 3.69	$ 2.24	$ 19.60	$ 15.22	$ 6.82	$ 2.40
2025	$ 19.48	$ 15.41	$ 4.81	$ 2.33	$ 19.47	$ 15.48	$ 3.76	$ 2.24	$ 20.07	$ 15.86	$ 7.34	$ 2.41
2026	$ 19.84	$ 15.95	$ 4.93	$ 2.33	$ 20.06	$ 16.41	$ 3.85	$ 2.25	$ 20.52	$ 16.49	$ 7.69	$ 2.41
2027	$ 20.04	$ 16.05	$ 5.05	$ 2.32	$ 20.07	$ 16.24	$ 3.97	$ 2.24	$ 20.74	$ 16.62	$ 8.00	$ 2.41
2028	$ 20.06	$ 16.09	$ 5.16	$ 2.31	$ 20.30	$ 16.60	$ 4.10	$ 2.23	$ 20.95	$ 16.77	$ 8.17	$ 2.42
2029	$ 20.31	$ 16.32	$ 5.25	$ 2.30	$ 20.64	$ 17.11	$ 4.14	$ 2.23	$ 21.28	$ 17.01	$ 8.33	$ 2.42
2030	$ 20.75	$ 16.63	$ 5.29	$ 2.30	$ 21.25	$ 17.42	$ 4.07	$ 2.22	$ 21.77	$ 17.41	$ 8.37	$ 2.42

[74] U.S. EIA. 2016. *Annual Energy Outlook 2016 with projections to 2040.* https://www.eia.gov/outlooks/aeo/pdf/0383(2016).pdf.

4.5 Power System Modeling Results

Using the EIA 2016 Annual Energy Outlook Reference Case and allowing STEER to choose renewables to meet generation requirements, STEER produced the results for the various CHP technologies that are shown in **Attachment D**. In this scenario, steam turbines of any size, combustion turbines larger than 20 MW capacity, and reciprocating engines larger than 3 MW capacity are profitable. Michigan technical potential for these CHP technologies totals 1.014 GW but only 722 MW at 70 sites are built because the additional capacity was not required.

Using the EIA 2016 Annual Energy Outlook Reference Case without allowing STEER to choose renewables to meet generation requirements, STEER produced the results for the various CHP technologies that are shown in **Attachment E**. In this scenario, the same CHP technologies as in the scenario with renewables are profitable, but because renewable capacity was not allowed to be chosen by STEER, all 1.014 GW of profitable CHP technologies at 103 sites are chosen.

Using the EIA 2016 Annual Energy Outlook High Resource Case and allowing STEER to choose renewables to meet generation requirements, STEER produced the results for the various CHP technologies that are shown in **Attachment F**. Natural gas prices are lower in this scenario, but CHP is generally competing with combined cycle natural gas in the dispatch order, so that the price of electricity is also lower. As a result, the same technologies are profitable as in the Reference Case: steam turbines of any size, combustion turbines larger than 20 MW capacity, and reciprocating engines larger than 3 MW capacity. However, because the price of natural gas is lower in this scenario, fewer renewables are selected and more of the profitable CHP capacity is built. Just like the Reference case, the profitable CHP technologies have Michigan potential totaling 1.014 GW at 103 sites, but in this case all 1.014 GW are chosen.

Using the EIA 2016 Annual Energy Outlook High Resource Case without allowing STEER to choose renewables to meet generation requirements, STEER produced the results for the various CHP technologies that are shown in **Attachment G**. In this scenario, the same CHP technologies are profitable as in the preceding scenario and are chosen as in the High Resource Case but with renewables excluded, primarily because with the low natural gas prices projected in this case, incremental renewables are not chosen.

Using the EIA 2016 Annual Energy Outlook Low Resource Case and allowing STEER to choose renewables to meet generation requirements, STEER Michigan CHP produced the results for the various CHP technologies that are shown in **Attachment H**. With the higher natural gas prices used in this scenario, the relative fuel efficiency of CHP generation as compared to combined cycle and electricity-only combustion turbines causes a wider range of CHP technologies to be profitable, including steam turbines of any size, combustion turbines 8 MW capacity and larger, and reciprocating engines 1 MW capacity and larger. Michigan technical potential for these profitable technologies totals 2.36 GW at 816 sites. However, with higher natural gas prices, substantial renewables are chosen and the selected amount of cogeneration is still only 1.014 GW.

Using the EIA 2016 Annual Energy Outlook Low Resource Case without allowing STEER to choose renewables to meet generation requirements, STEER produced the results for the various CHP technologies that are shown in **Attachment I**. As is generally true, the same set of CHP technologies is profitable in this scenario as in the previous scenario. Without renewables available in this scenario, STEER builds the entire 2.36 GW of profitable CHP generation technologies at 816 sites. This scenario results in the most amount of CHP being chosen by the STEER model.

Across a fairly broad range of scenarios, neither microturbines nor fuel cells appear economically viable for broad application in Michigan. Steam turbines, combustion turbines, and reciprocating engines above some threshold size appear profitable in each scenario with the minimum size threshold being lower under higher natural gas pricing and when renewables aren't available.

The CHP technologies that appear viable based on STEER modeling results based solely on their value to the power system have potential in specific economic sectors. Table 8 summarizes the number of sites in each sector for which there appear to be viable technologies, where a range reflects the results in the various scenarios described above.

Table 8. STEER CHP Evaluation Results

Sector	Steam Turbine		Combustion Turbine		Reciprocating Engine	
	MW	Sites	MW	Sites	MW	Sites
Food/Beverages	8	1	25	3	24-90	3-36
Lumber/Wood	-	-	7	1	6-36	1-16
Paper/Pulp	40	1	79-87	2-3	8-50	1-21
Chemicals	64	3	88-194	2-13	108-244	11-66
Petroleum Refining	-	-	-	-	0-16	0-8
Rubber/Plastics	-	-	-	-	0-17	0-9
Stone/Clay/Glass	-	-	5	1	5-12	1-3
Primary Metals	39	1	58-71	2-3	13-67	1-26
Machinery/Comp Equip	-	-	-	-	0-3	0-2
Transportation Equip	25	3	101-182	4-14	80-231	10-87
Gas Processing	-	-	-	-	0-6	0-2
Refrigerated Warehouses	-	-	-	-	1	1
Wastewater Treatment	-	-	-	-	2	1
Commercial Office Bldgs	-	-	-	-	0-172	0-284
Multifamily Housing	-	-	-	-	0-17	0-16
Hotels	-	-	-	-	0-24	0-15
Data Centers	-	-	-	-	0-13	0-8
Hospitals	-	-	0-21	0-3	7-131	1-57
Colleges/Universities	101	8	31-70	1-6	41-128	5-37
Prisons	-	-	-	-	0-50	0-34
Military Facilities	-	-	-	-	0-7	0-3
Airports	-	-	-	-	0-4	0-2
Museums	-	-	-	-	0-2	0-1
Government Buildings	-	-	5	1	0-30	0-16

4.6 Resilience

The preceding analysis using STEER does not assign any value to the potential contribution of CHP to site or community resilience in case of an extended grid outage, nor to the avoidance of costs related to outages of any length. For some CHP host sites, this resilience value can be decisive. We therefore extended STEER to account for the additional CHP potential associated with the resilience value of CHP.

Resilience value does not lead to increased deployment of a CHP technology that would be developed anyway based on only its power system value. Thus incremental CHP potential due to resilience value will result when CHP is not profitable based purely on the avoided cost of electricity. In these cases, the profitability gap is overcome by the value of resilience to the CHP host. Since resilience value varies amongst potential hosts, our extension of STEER to address resilience value was conducted primarily to include calculations of the minimum resilience value that would lead a potential CHP host to build a CHP resource that is otherwise not profitable, identify the application sectors likely to have resilience value at least as large as the threshold, and estimate the additional potential for CHP in those sectors.

The results of resilience calculations based on the EIA 2016 Annual Energy Outlook Reference Case fuel prices and considering additional use of renewables in the power system (corresponding to the assumptions in Attachment D) are shown in **Attachment J**. Consideration of CHP resilience value enables the potential use of smaller combustion turbines and reciprocating engines than would be profitable based solely on heat and power system value, and also enables the potential use of some microturbines.

Under the assumptions of Attachments D and J, consideration of resilience value increases CHP potential by 591 MW above the 1,014 MW that would be profitable without consideration of resilience value.

4.7 Standby Rates

The primary analysis using STEER examined the fundamental value of CHP in Michigan's power supply. Host decisions to adopt CHP, however, are often determined by the terms of utility tariffs rather than by power system value. The principal difference between these is the application of standby rates, which is one of the primary barriers to CHP adoption. We therefore extended our analysis using STEER to examine the effect of standby rate tariffs on CHP potential.

In order to incorporate the economic effects of standby rates on CHP potential, it was necessary to model the avoided costs as created by Michigan standby rates. The avoided cost assesses the financial relationship between the aggregate price of electricity before and after the installation of customer-sited CHP.

As a metric for evaluation, we used the guidelines and methodology presented by the EPA CHP partnership in the paper "Standby Rates for Customer-sited Resources: Issues, Considerations, and the Elements of Model Tariffs"; specifically, the EPA's concept and application of the avoided rate.[75] This

[75] Regulatory Assistance Project. Prepared for the U.S. EPA. Office of Atmospheric Programs, Climate Protection Partnerships Division. 2009. *Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs*. https://www.epa.gov/sites/production/files/2015-10/documents/standby_rates.pdf.

metric is useful because it reduces the economic and financial impact created by standby rates to a simple percentage figure that can easily be incorporated into the STEER model.

The concept of avoided rate evaluates the financial impacts of standby rates on distributed generation systems by comparing the per kWh cost of full-requirements customers to that of otherwise comparable standby customers. Ideally, a decrease in electricity purchased from the utility would be commensurate with a decrease in monthly electric costs. If a customer reduces their purchased electricity by 50% they would expect their bill to decrease by a similar amount. However, there are some utility system costs appropriately billed to the customer that are not reduced by the same percentage and limit the bill reduction. These manifest as standby charges and the question of whether or not they are reasonable is beginning to be the subject of rate cases before the MPSC.

Standby rates can increase electric demand charges even when a customer decreases overall electric consumption, thus negating many economic benefits to the customer. The avoided rate is a metric that measures the amount of savings per kWh a distributed generation customer receives when not purchasing electricity from the utility. In essence, it compares the value of a purchased kWh to the value of an avoided kWh. This rate requires the comparison between the electricity costs to a facility when on a full-requirements rate and the electricity costs to a facility when on a standby rate.

The avoided rate model analyzes the extent that standby rates allow distributed generation customers to avoid electric charges. After modeling each facility's usage during one year it is possible to aggregate all charges into a simple cost per kWh. This aggregate cost includes the cost of generation, transmission, distribution, demand, taxes and all applicable riders for both full-requirements and standby rates. The avoided rate is calculated by dividing the money not paid to the utility by the electricity not purchased from the utility. When the avoided rate closely matches the full-requirements rate, the user experiences increased savings.

For example, if a hypothetical facility purchases 1,000,000 kWh of electricity per year from the utility at an aggregate cost of $0.10 per kWh, the facility will pay a total cost of $100,000. If this same facility installs a CHP system that reduces their need for purchased electricity to 500,000 kWh per year, in an ideal economic situation, the annual bill would be half the normal bill, or $50,000. Under this ideally constructed scenario, the avoided rate from the 500,000 kWh *not* purchased would be $0.10 ($50,000/500,000 kWh). Thus, this situation would have an avoided rate equivalent to the full requirement rate.

There are limitations in using the avoided rate metric, however. Though simple to calculate and communicate, the avoided rate metric can over-simplify situations. The economic effect of standby rates is largely related to the specific attributes and operating schedules of a customer's generator. Given the diversity of potential CHP hosts in Michigan, the avoided rate represents a simplified generalization for these actual CHP hosts. A more specific calculation would be needed to assess an individual CHP project.

Project partners modeled the avoided rates of Consumers Energy and DTE Energy using energy usage data provided during a March 14, 2016 workshop on standby rates. Based on these data, Consumers Energy's standby rate results in an avoided rate between 81%-85% depending on the size of the CHP customer while DTE Energy's standby rate results in an avoided rate between 71%-77%. According to the EPA, avoided rates below 90% may pose an economic barrier to otherwise financially feasible CHP implementation. The results of this modelling are shown in Table 9.

Since standby rates primarily apply to the capacity of the CHP system, the ratio of the cost of standby rates to CHP system capacity is an appropriate measure of the effect of standby rates on the profitability of a CHP system. Based on the avoided rates of DTE Energy and Consumers Energy, STEER projected that standby rates in 2030 would impose costs of about $88,000 per MW capacity of a CHP system. In STEER, this additional cost of capacity reduced the profitability of all CHP technologies. Some CHP technologies were still profitable, despite the standby rate cost, while more marginal CHP technologies became unprofitable. The technologies that became unprofitable in the face of standby rates depend on the scenario under which they are evaluated.

The effect of standby rates on STEER Michigan CHP potential results using the EIA 2016 Annual Energy Outlook Reference Case and allowing STEER to choose renewables to meet generation requirements (corresponding to the assumptions of Attachment D) is shown in **Attachment K**. Standby charges had the effect of making combustion turbines below 40 MW and reciprocating engines below 9 MW unprofitable, thereby reducing CHP potential by 669 MW from the 1,014 MW that would be available under the same scenario but without standby charges.

Table 9. Utility Standby Rate Impact

Utility	Site Peak Load	CHP Capacity	Total Required kWh	Generated kWh	Full Requirements Bill	Standby Bill	Full Requirements $/kWh	Avoided Rate $/kWh	Avoided Rate Percentage
Consumers	7,000 kW	3,500 kW	44,623,000 kWh	27,594,000 kWh	$ 3,128,000.00	$ 1,489,000.00	$ 0.070	$ 0.059	85%
	1,000 kW	450 kW	5,889,000 kWh	3,548,000 kWh	$ 503,000.00	$ 259,000.00	$ 0.085	$ 0.069	81%
DTE Energy	8,000 kW	5,000 kW	51,544,000 kWh	30,926,400 kWh	$ 3,280,000.00	$ 1,756,000.00	$ 0.064	$ 0.049	77%
	1,000 kW	282 kW	3,917,000 kWh	2,350,200 kWh	$ 318,000.00	$ 183,000.00	$ 0.081	$ 0.057	71%

4.8 Analysis

As noted previously, STEER modeling indicated that steam turbines, gas combustion turbines, and reciprocating engines appear profitable above some size threshold size in each scenario. Conversely, microturbines and fuel cells do not appear economically viable. Assuming higher natural gas prices and higher cost of renewable resources in the future both tend to lower the minimum size threshold for the more viable CHP technologies, thereby expanding the number of potential installation sites in Michigan.

Consideration of resilience value increases the potential deployment of CHP in sectors where loss of power is most consequential and can significantly increase CHP potential beyond the levels that would be supported only by power sector value. Based on STEER analysis of Michigan potential, resilience value could increase CHP potential by around 60%. Standby rates, on the other hand, substantially reduce the profitability of CHP ownership and thereby reduce potential CHP deployment by 50% or more.

Developing CHP to its economic potential will provide a number of benefits to Michigan. Since economic potential varies with projections of technology and fuel costs, and other factors, STEER estimated the primary benefits using the EIA 2016 Annual Energy Outlook Reference Case for fuel prices and was allowed to choose renewables to meet generation requirements (corresponding to assumptions of Attachment D). If built, these CHP installations would produce about $109.5 million per year in profit above the level required to recover cost of capital. Such profit due to outperforming the marginal unit in the economy is considered a significant benefit to society and, if accruing to CHP hosts, increases the likelihood that they remain in their primary business in Michigan.

STEER estimates building 1,014 MW CHP of the types chosen in this scenario would require direct investment of about $865.7 million and annual non-fuel operations and maintenance of about $67.6 million. These expenditures are themselves costs to the site host but are income to suppliers and generate additional economic activity in Michigan. The amount of direct and indirect economic activity in Michigan and the consequent employment depends on the degree to which Michigan-based businesses are able to participate in the supply and value chains for CHP systems.

Fuel efficiency of CHP systems, in contrast to separately produced heat and electricity using natural gas as a fuel is a benefit to Michigan. STEER estimates building and operating 1,014 MW CHP of the types chosen in this scenario would save about 11.3 million MMBtus per year, representing a net cost savings to Michigan's economy of about $94.7 million per year. This reduction in fuel usage would also reduce air emissions by 662 tons of CO_2 per year, 379 tons of NO_x per year, and 39 tons of SO_x per year.

5 Michigan Supply and Value Chain

The primary objectives of mapping the Michigan CHP supply and value chains were to:

1. Identify the companies who are positioned to facilitate Michigan CHP projects – these firms are members of the Michigan supply and value chains;
2. Develop a digital directory of the identified companies and distribute to potential end-users to market CHP and expedite project discovery and implementation;
3. Evaluate segments of the supply and value chains where there may be barriers to CHP deployment due to a lack of Michigan firms operating in that space;
4. Assess the economic impact to Michigan arising from CHP deployment.

Mapping efforts built on the results of technology roadmapping presented in Section 3.1 and the conclusions of STEER modeling discussed in Section 4.8. Mapping utilized stakeholder engagement activities to assess end-user appetite for CHP and the supply and value chain enthusiasm for participating in CHP projects, with the goal of ultimately driving CHP education, project development, and implementation.

Demand for CHP projects in both the private and public sector is primarily driven by an economic comparison of the costs and benefits of CHP versus the costs and benefits of end-user current operations. This status quo typically entails electric generation at a utility-owned power plant and thermal energy generation on-site by end-user-owned boilers or furnaces. Thus, in order for demand for CHP to increase, the economics must become more favorable than the status quo. Market economics are affected by a number of factors, including:

- Delivered energy cost trends
- End-user energy efficiency or energy waste reduction targets
- Technological performance or cost improvements
- Fuel resource supply and pricing trends
- Utility regulations and incentives
- Government legislation and incentives

5.1 Supply Chain Mapping

As discussed in Section 3.4, project partners have defined the **CHP supply chain** as the physical equipment and fuel required for the CHP system to operate. The major sectors of the CHP supply chain include CHP end-user applications, prime mover manufacturers and distributors, major equipment manufacturers and distributors, and fuel suppliers and brokers.

Prime movers include gas turbines, reciprocating engines, steam turbines, and fuel cells. Project partners have confirmed that there are businesses operating in Michigan that manufacture, distribute, or provide maintenance services to each of these four types of prime movers.

Major equipment was grouped into three subsectors: electrical controls, heat recovery, and absorption cooling. Electrical controls and heat recovery are common to nearly all CHP applications, although the implementation may vary considerably. Absorption cooling is utilized in projects where there is demand for chilled water or refrigeration, but limited demand for heat.

Finally, natural gas was the only fuel identified to realistically supply most CHP projects. Although other types of fuel such as woody biomass, biogas, and landfill gas are available in some locations, unless a potential CHP user is located at an adjacent site, guaranteeing supply and transportation of these fuels is likely to be risky and cost prohibitive, respectively.

The major and minor sectors of the Michigan CHP supply chain are summarized in **Figure 6**.

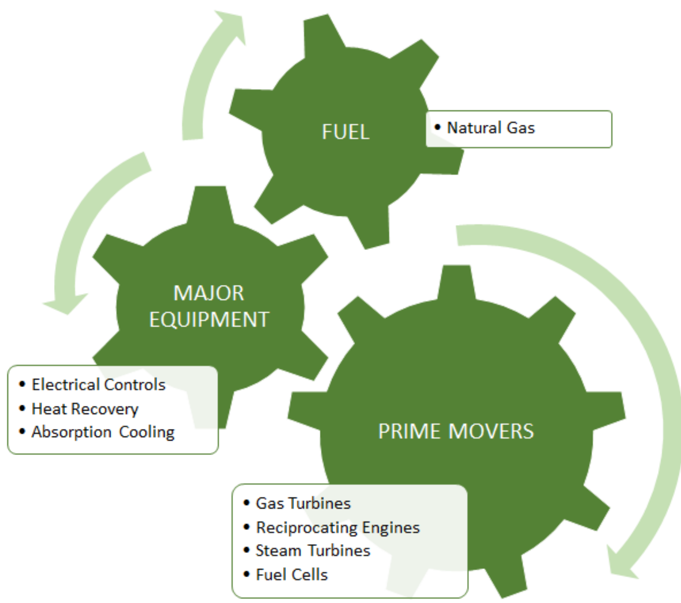


Figure 6: CHP Supply Chain (excluding end-users)

The majority of turbine and reciprocating engine prime movers – the highest value components in the supply chain – are designed and manufactured in a small geographic region in Germany and Austria. The firms operating in that region compete for the same engineering talent, which further encourages new CHP engineers to move there, much in the same manner as Silicon Valley has become the dominant location where computer engineers and their employees locate in the U.S.. Caterpillar is a notable exception as they manufacture reciprocating engines at a plant in Lafayette, Indiana and gas turbines at a plant in San Diego, California. Michigan prime mover manufacturers and distributors are identified in **Figure 7.**

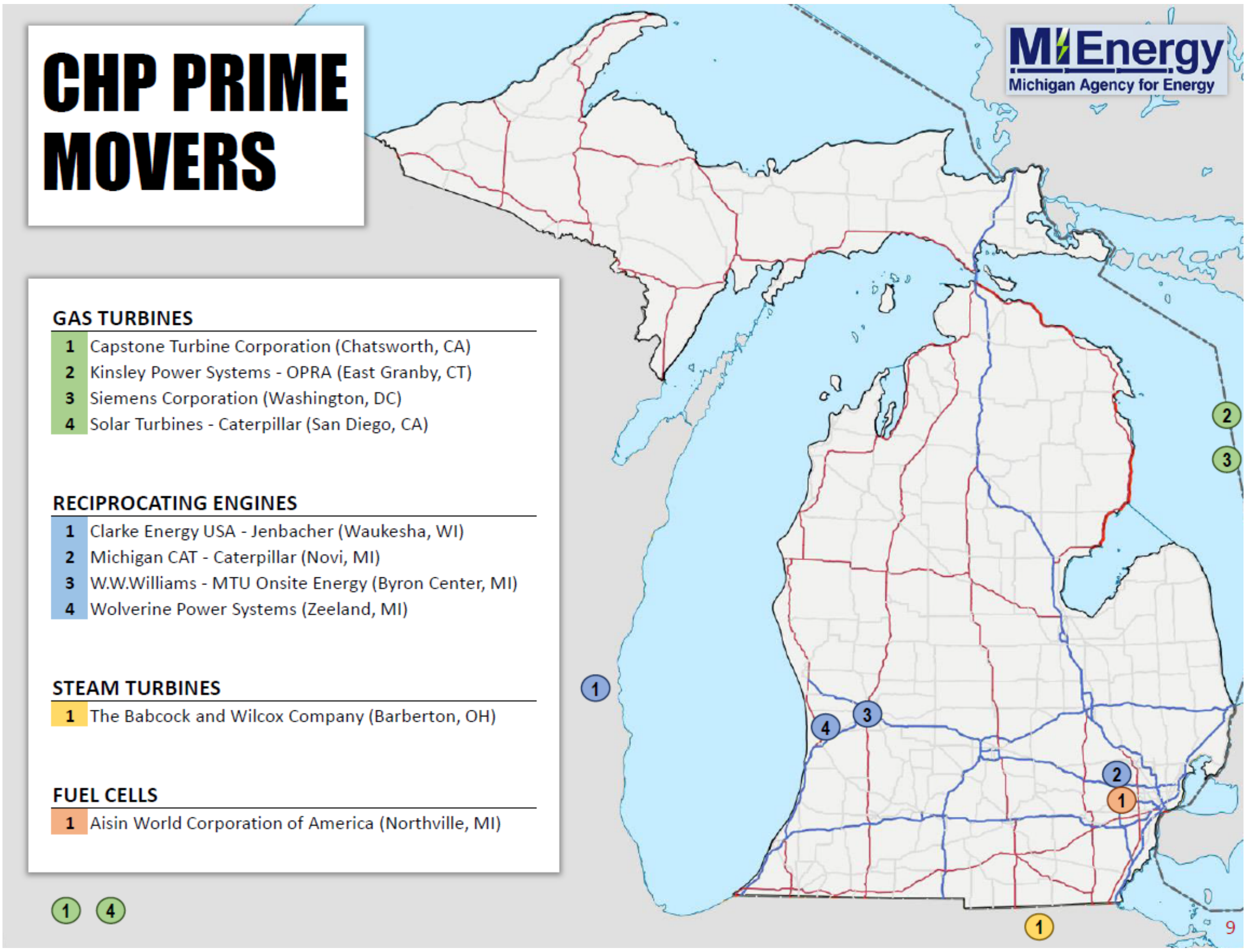


Figure 7: CHP Prime Movers

Project partners interviewed distributors from the companies MTU On-site Energy and Caterpillar serving the Michigan market. These distributors could not identify any companies in Michigan that currently manufacture any of the components found within the prime movers. These components are readily sourced from a well-developed domestic and international marketplace, with high economic, technical, and regulatory barriers to entry. Existing major equipment is sold based on decades of successful performance history which would be rendered invalid if any significant changes were made to the design of the equipment or sourcing of components. It is unlikely that Michigan manufacturers could someday tap into this market due to the unwillingness of prime mover and major component manufacturers to even entertain the possibility. From their perspective, sourcing components from Michigan manufacturers has insignificant upside potential and is fraught with considerable potential downside risks.

As identified in **Figure 8**, a handful of Michigan companies manufacture some of the major ancillary equipment that may be found in CHP projects but are not part of the prime mover systems. However, the vast majority of these firms' sales of these components are not to support CHP projects, but rather to support an array of traditional electric power and thermal energy processes. Broader deployment of

CHP would have a positive impact on the total economic activity generated by these firms, but the bulk of these firms' sales would still be expected to be for non-CHP purposes.

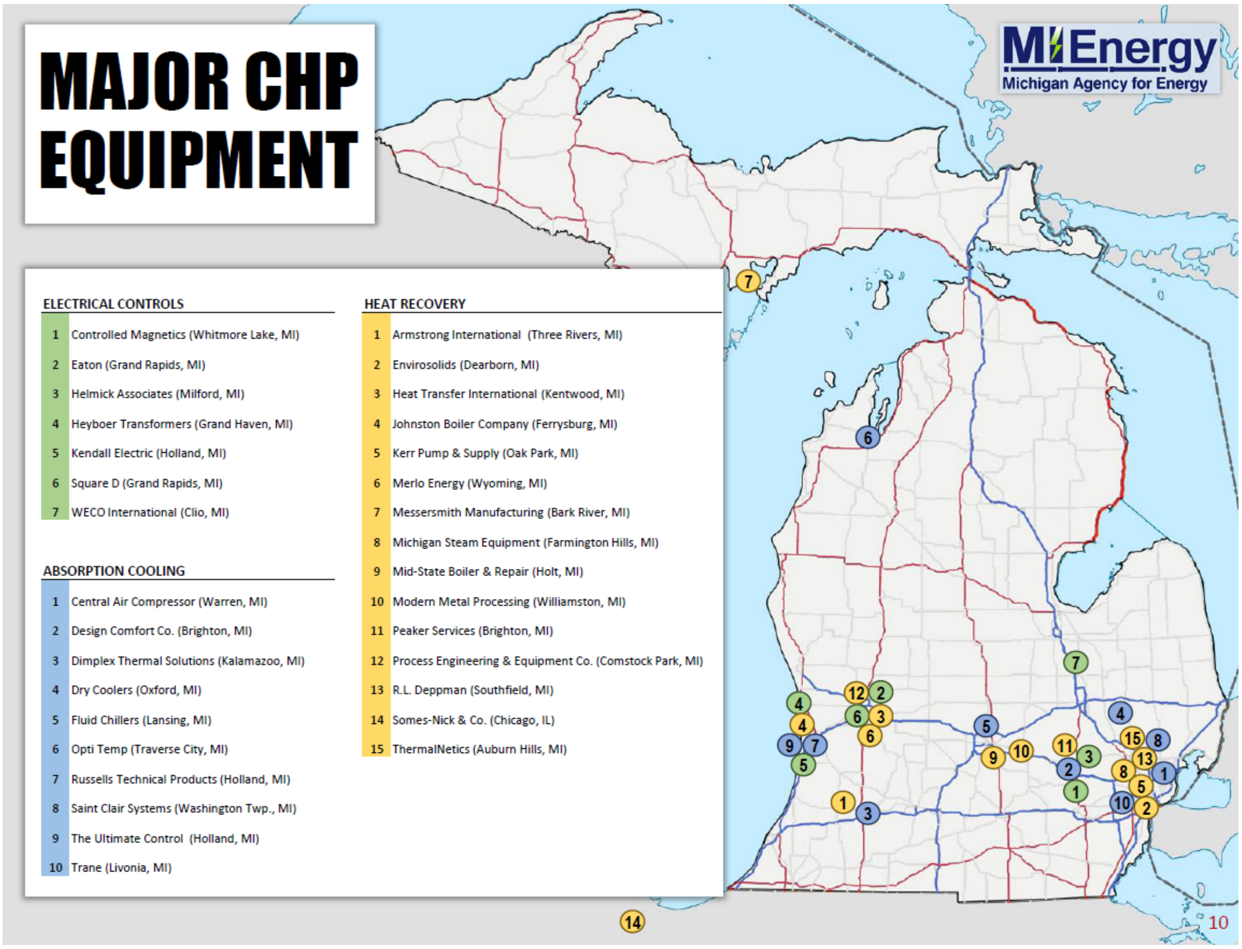


Figure 8: CHP Major Equipment

Fuel supply represents the largest ongoing expense for CHP projects. Natural gas, the most common fuel for CHP systems, is widely available in many parts of Michigan at cost near historical lows. Long-term contracts of 5 to 10 years are readily available through a large number of natural gas traders and brokers, allowing investors to control natural gas fuel supply and pricing during the project's payback period, significantly mitigating investment risk.

In some regions of the state, particularly rural areas and the Upper Peninsula, the infrastructure for transporting or receiving large volumes of natural gas is inadequate or nonexistent. Other fuel sources, such as woody biomass, biogas from anaerobic digesters, and landfill gas, may be utilized but are typically difficult to source, requiring significant additional effort on the part of the project developer to negotiate long-term project-specific supply agreements. Ultimately, this means that in the Upper Peninsula of Michigan, unless a potential CHP project is located in one of the few major cities or along the east-west gas pipeline corridor, fuel supply may be an impossible hurdle to overcome.

However, in general, and especially in the Lower Peninsula, instances where lack of access to appropriate fuel may prevent deployment of otherwise viable CHP projects will be rare. To be a candidate for CHP, one must have a significant existing thermal energy load, and in turn, existing access to a fuel source used to meet that load, which in most cases is natural gas which could be repurposed for a CHP application. Michigan natural gas suppliers and brokers are identified in **Figure 9**. A map of Michigan's natural gas transmission pipelines is available online.[76]

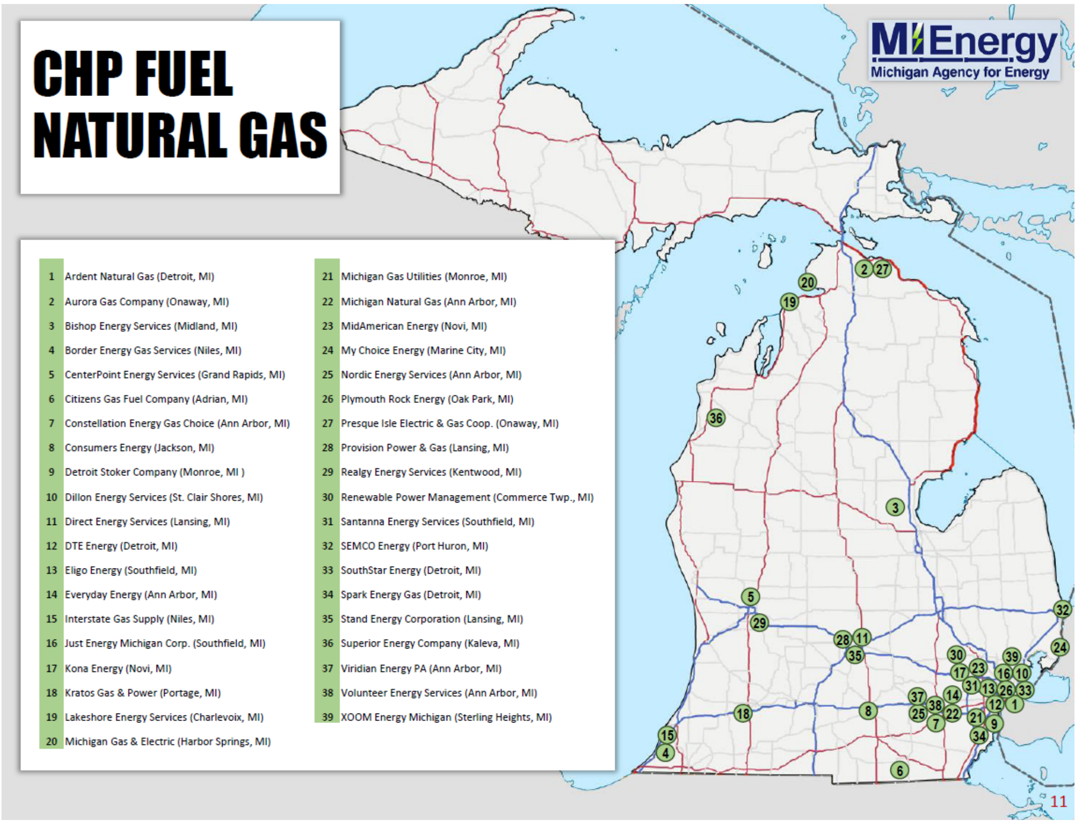


Figure 9: CHP Natural Gas Fuel Marketers

[76] Michigan Public Service Commission. 2002. *Natural Gas Transmission Pipeline and Storage Field Map*. http://www.michigan.gov/mpsc/0,4639,7-159-16385-413020--,00.html.

5.2 Value Chain Mapping

Limited opportunities for Michigan firms in the CHP supply chain are overcome by the robust ability of Michigan firms to participate throughout the value chain. As discussed in Section 3.4, project partners have defined the **CHP value chain** as the intellectual capital and skilled trades required to develop, design, engineer, finance, install, and integrate CHP systems. The major sectors of the value chain include public policy advocates and accelerators, project developers and technical advisors, design/engineering firms, and plant integration contractors.

CHP accelerators and public policy advocates play a critical role in developing the market for CHP applications through encouraging technological innovation, educating and lobbying policy-makers, and supporting end-users and industry organization. With the framework for CHP in place, project developers then identify and conceptually develop projects, assisted by valuable technical advisors and their specific expertise. Design/engineering firms bring the CHP projects from concept to a state of construction readiness. Finally, plant integration contractors, which may include construction management firms, electrical subcontractors, and mechanical subcontractors, install the CHP systems and ensure they operate as designed.

The major and minor sectors of the Michigan CHP value chain are summarized in **Figure 10.**

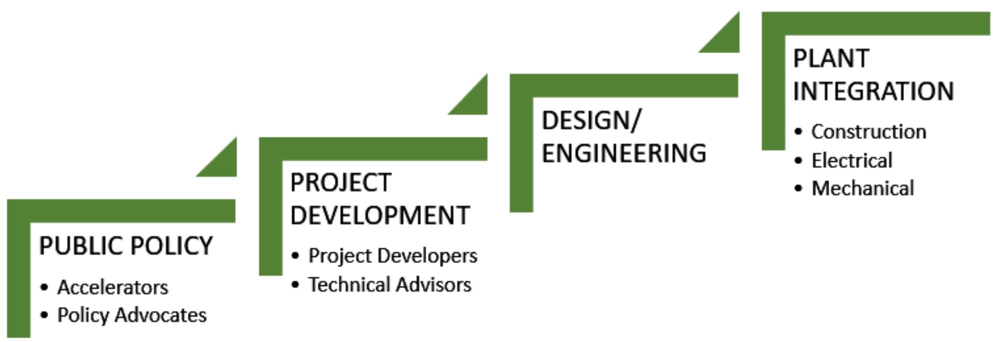


Figure 10: CHP Value Chain

The majority of the economic impact of CHP will be realized by using this pool of talent based in Michigan companies to design and implement projects. However, many value chain firms currently lack significant CHP experience due to the dearth of completed CHP projects in the state in recent years. This obstacle will be rapidly overcome as more projects are deployed throughout the state.

CHP accelerators and policy advocates in Michigan are identified in **Figure 11**. Not surprisingly, most of these firms are clustered around Lansing, Michigan and Washington, D.C., where regulatory policy and legislation are crafted at the statewide and national levels, respectively.

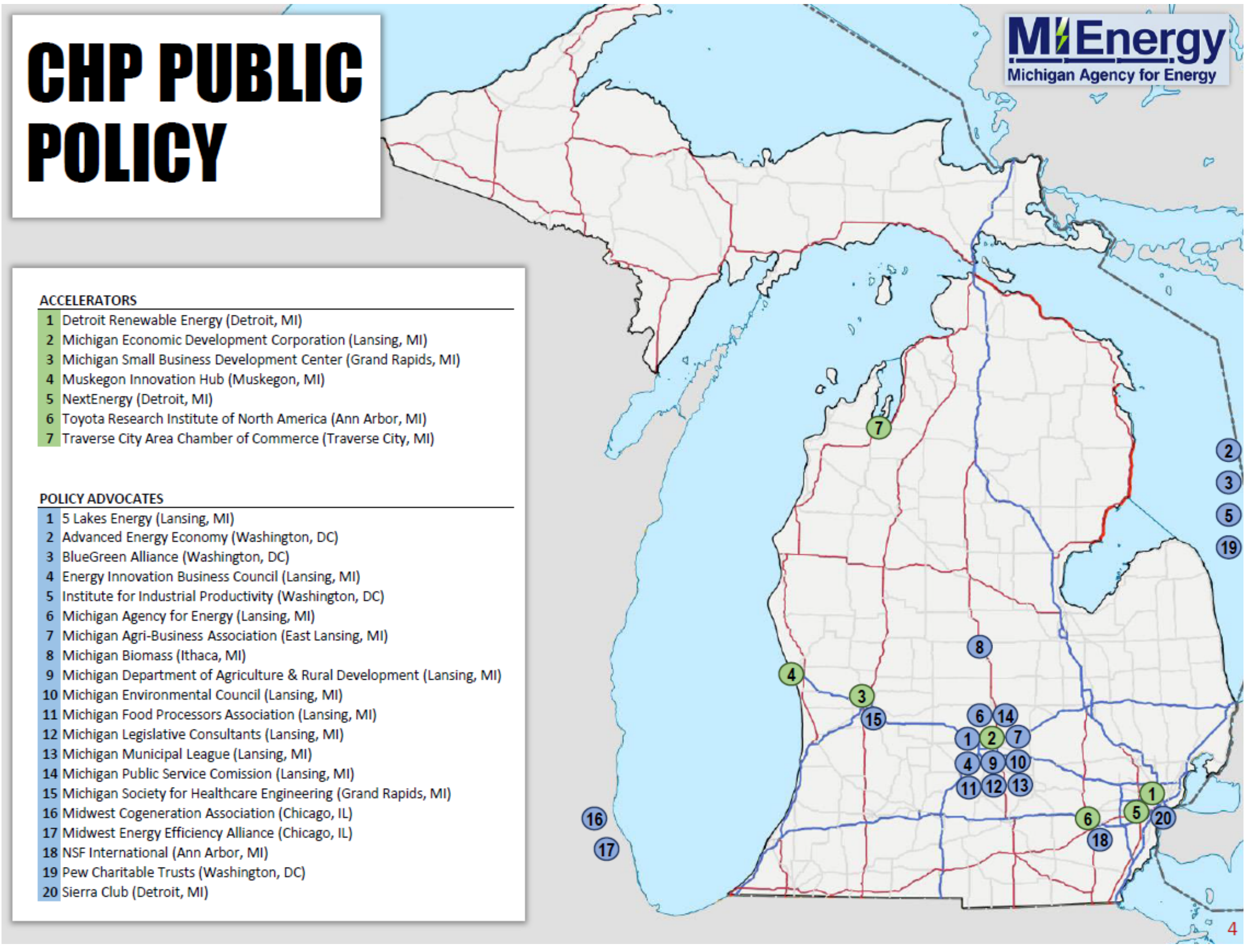


Figure 11: CHP Public Policy

CHP project developers and technical advisors are identified in **Figure 12**. In many cases, firms that principally develop projects also have some capabilities to provide technical expertise, and vice versa. One major difference may be in terms of the business model, where developers often take significant financial risk on developing and securing financing for projects, whereas technical advisors often have a clear fee structure and will only take minimal financial risk.

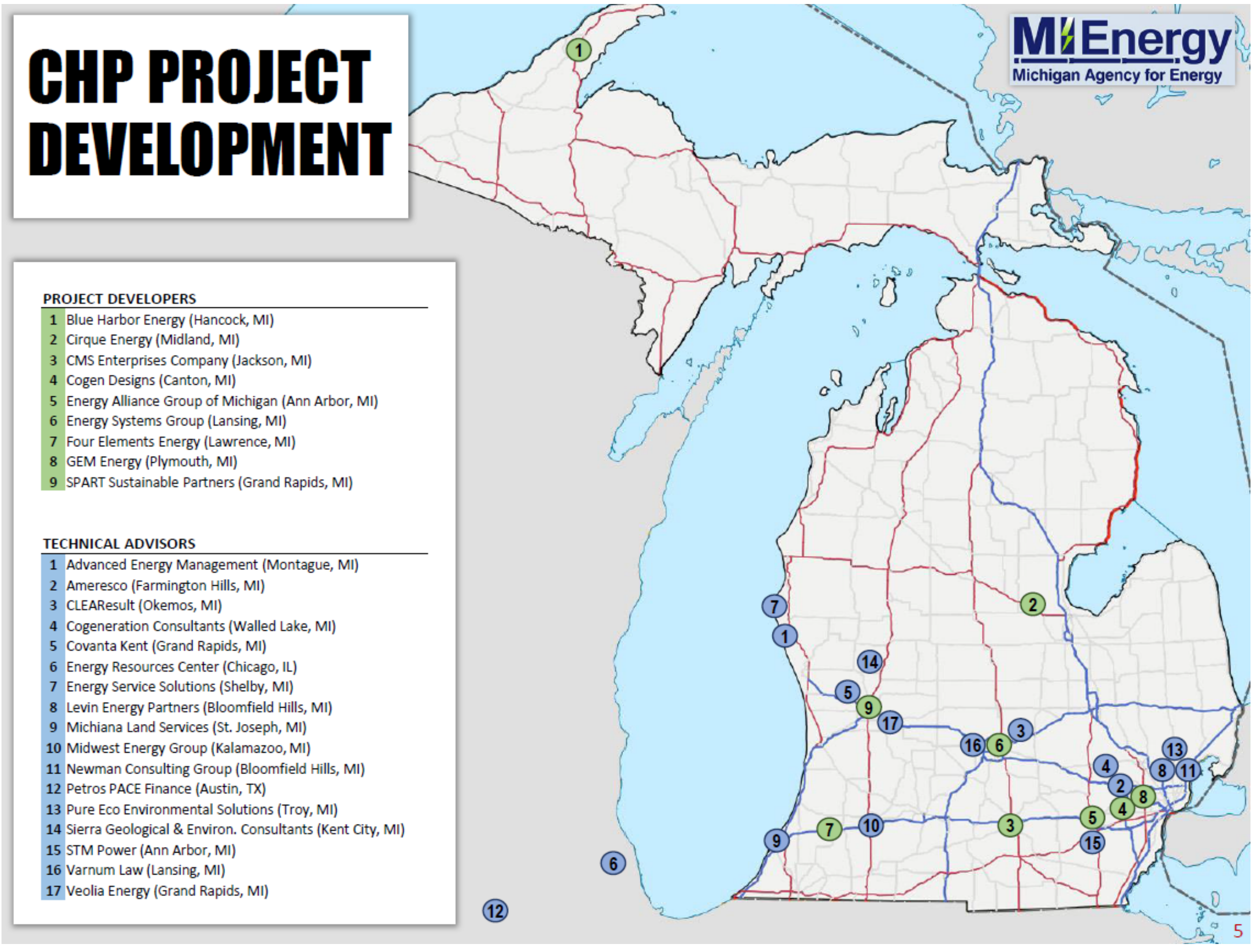


Figure 12: CHP Project Development

CHP design/engineering firms are identified in **Figure 13**. There are a great number of firms with the civil, electrical, and mechanical capabilities required to engineer CHP project in Michigan, and for simplicity many potential end-users may opt to work with the same firm that designed their existing electrical and thermal systems. Generally these firms are clustered around the state's major population centers.

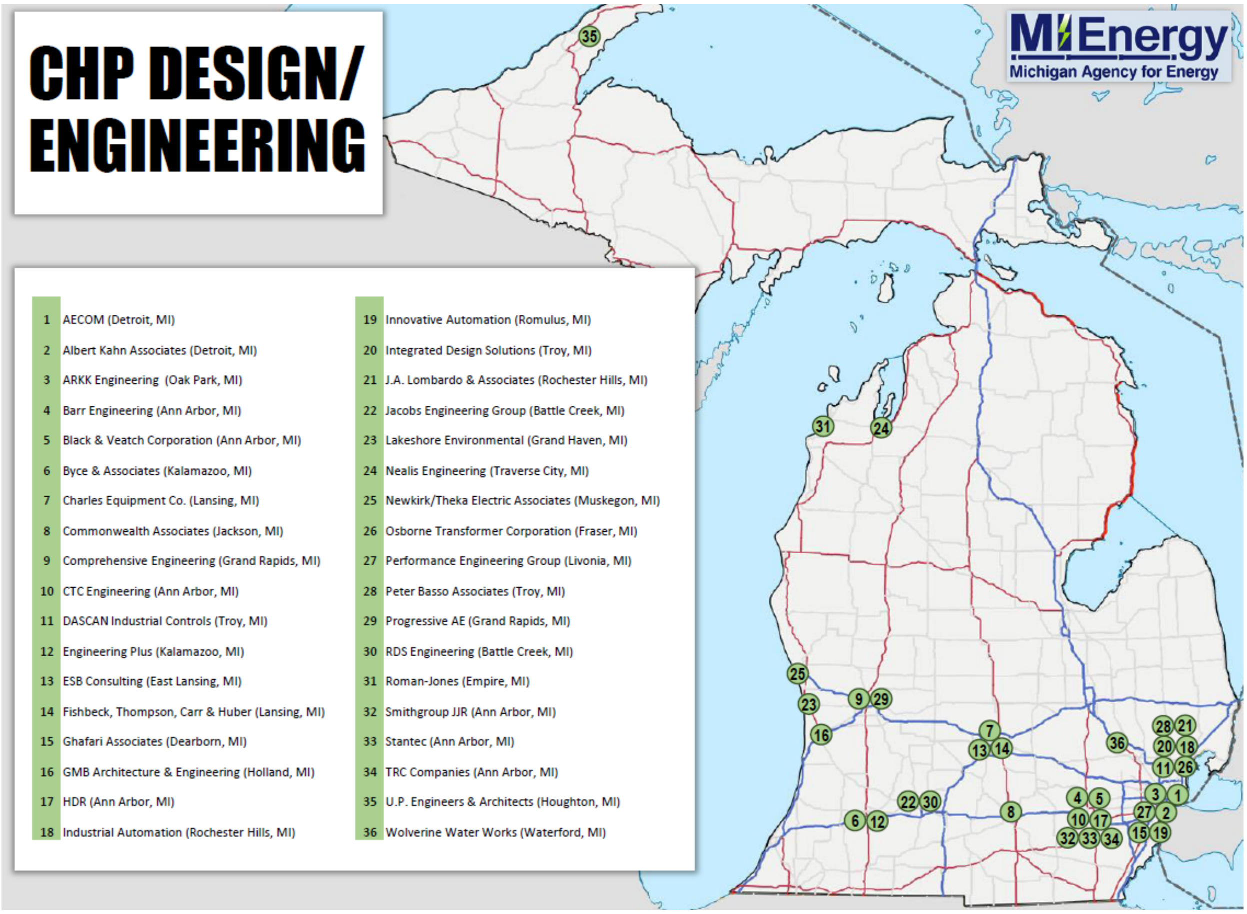


Figure 13: CHP Design/Engineering

CHP plant integration contractors are identified in **Figure 14**. These firms encompass the disciplines of construction management, electrical installation, and mechanical installation. Generally, these firms are clustered around the state's major population centers.

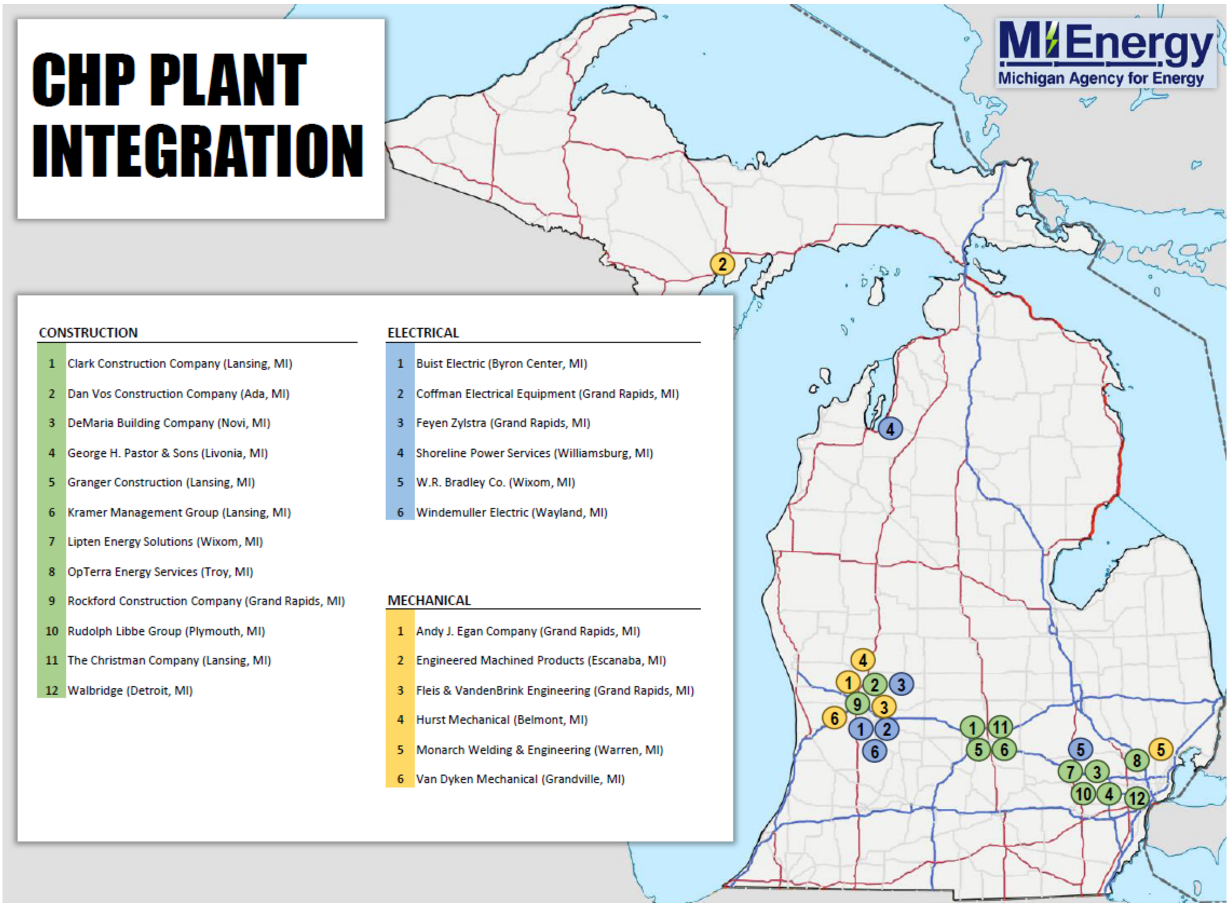


Figure 14: CHP Major Equipment

5.3 Michigan Economic Impact

Deployment of some portion of DOE's estimated 5 GW of Michigan CHP technical potential would generate significant economic activity throughout each project's lifecycle. However, the net economic impact on Michigan due to CHP deployment is quite difficult to discern. We can begin with the assumption that a business will spend less money on energy generation by implementing CHP than by maintaining the status quo, which must be true for a given project to be economically-viable. A business could use this saved money in many different ways. For example, if the business shifted this saved money, which it previously contributed to the Michigan economy, into dividends for company owners, there would be a negative impact on Michigan economic activity following CHP deployment. Alternatively, what is more likely is that widespread CHP deployment would actually be expected to significantly increase Michigan economic activity for a number of reasons:

- Businesses that save money on energy costs with CHP are likely to reinvest a significant portion or all of that savings into company growth;
- Electric utilities cannot simply scale back their generation and infrastructure investments proportionally to the loss of revenue due to CHP deployment. Incrementally, there will need to be more aggregate investments made in electric infrastructure in Michigan with CHP deployed than without, if there is the expectation to maintain an equivalent level of performance;
- Electric utilities will have additional capacity available, providing an opportunity to export to other power providers, or permitting a reduction in purchased power;
- Experience gained by Michigan-based participants in the CHP value chain could be deployed to other states, providing opportunities for many of these firms to bring new revenue streams into the Michigan economy.

Finally, there are factors that do not increase or reduce the economic impact on Michigan, but rather shift the economic impact from one market participant to another. For example, the public electric utilities will experience reduced revenues and likely spend less money on distribution system maintenance with widespread CHP deployment; but in turn, private sector developers, engineering firms, and project implementers will see increased revenues.

In Section 4.8, we determined through STEER modeling that optimal deployment of CHP in Michigan would require direct capital investment of about $865.7 million, annual non-fuel expenditures of about $67.6 million, and produce about $109.5 million per year in incremental profit. Optimal CHP deployment would also save Michigan's economy about $94.7 million per year in fuel costs.

Ultimately, the amount of direct and indirect economic activity in Michigan and the consequent employment (jobs) impact depends on the degree to which Michigan-based businesses are able to participate in the supply and value chains for CHP systems. A directory of Michigan CHP supply and value chain participants has been created and will be shared with potential end-users to foster the use of Michigan-based companies and resources when considering or implementing CHP projects. The database is ultimately envisioned as a tool that will continue to grow as the market for CHP in Michigan also expands. State policymakers could further encourage potential end-users to "Buy Michigan" and "Hire Michigan" through appropriate incentives.

6 Barriers to CHP in Michigan

CHP has the potential to be a significant, reliable, cost-effective, and environmentally protective contributor to Michigan's energy mix. Further, the Michigan CHP supply and value chain is well-positioned to deploy sustainable and cost-effective CHP projects for Michigan's largest energy users. However, those interested in installing CHP projects face a number of obstacles. In order to fulfill the promise of EWR in Michigan through optimal deployment of CHP, these barriers should be examined and understood in general, and in light of the unique circumstances facing Michigan energy users.

While CHP can save a system owner money in the long run, there are a few economic barriers that could prevent a CHP project from moving forward in the first place. The relatively high upfront cost of installing a CHP system can be a barrier in and of itself. Additionally, a lack of sufficient access to financing options can prevent otherwise cost-effective installations. According to the DOE's Advanced Manufacturing Office, "CHP developers must navigate a complex landscape of project financing alternatives and provide detailed project information in order to attract investors. Inadequate information can cause project delays, leading investors to offer less favorable financial terms, or even decline a CHP investment opportunity all together."[77]

Regulatory barriers can dramatically affect a CHP project's bottom line and projected payback period. An overarching barrier that affects the valuation of CHP throughout regulatory and policy discussions stems from the failure to account for the full value of CHP, including qualities such as resilience. Ignoring grid-wide and societal benefits affects how CHP is portrayed in standby rates, avoided cost rates, energy waste reduction standards and integrated resource planning.

Standby rates, or charges a utility customer pays for the utility to provide backup service in case of a scheduled or unscheduled CHP system outage, can be so high as to completely undermine the economic viability of a proposed CHP system. Beyond standby rates, avoided cost or buyback rates under the Public Utility Regulatory Policies Act of 1978 (PURPA) may be insufficient to make a CHP project worthwhile. Interconnection processes can be lengthy, cumbersome and costly. Whereas Michigan has embraced EWR goals through PA 341 and 342 of 2016, a failure to incorporate CHP, or to properly calculate energy savings from participating CHP systems, will lead to less than ideal deployment numbers. Finally, even as regulators and utilities embrace a longer-term resource planning approach, IRP models often fail to recognize the value of CHP as both a supply side and demand side resource, resulting in CHP being overlooked in utility long-range resource plans.

Each of these barriers – which are often dependent on geography, project size and technology, utility constraints, and the prevailing regulatory climate – adds to the risk and cost associated with a potential CHP project. Given the substantial capital investment involved in developing a CHP project, and in light of the benefits offered by more robust deployment of CHP, it is vitally important that these risks and costs be mitigated through thoughtful policies and incentives to avoid killing CHP projects that would otherwise make good sense for Michigan businesses, and good sense for the state's future energy mix.

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[77] ICF. Prepared for the U.S. DOE, Advanced Manufacturing Office. 2017. Combined Heat and Power (CHP) Financing Primer. p. ii. https://energy.gov/sites/prod/files/2017/06/f35/CHP%20Financing%20Primer%206-16-17%20Final.pdf.

6.1 Overview of Economic Barriers

One of the most commonly-cited barriers to CHP development is the upfront capital cost associated with the acquisition and installation of equipment. A potential CHP system owner encounters this barrier early in the planning process, as cash or financing is required to purchase components such as turbine or engine parts needed to generate the needed heat and electricity. With an installed cost of between $700 and $3,000 per kW,[78] a potential CHP installation competes for scarce investment capital within a firm. Decision-making structures within a company can pose an additional hurdle, with many business leaders lacking familiarity with the business's typical patterns of energy use, or different energy options, including CHP.

If a business lacks the cash on-hand to invest in CHP equipment, financing can be an option, but a lack of access to low-cost financing can present a major barrier long before a CHP project ever breaks ground. According to the DOE's Advanced Manufacturing Office, "Lenders and investors typically decide to invest in a CHP project based on its perceived level of risk and expected financial performance. These groups focus solely on the expected monetary benefits, and typically do not consider environmental or other non-energy benefits from the project that may be important to the end-user."[79] The size of a typical CHP system can pose a challenge to obtaining financing, with a typical CHP project being too small to interest banks or private equity firms without giving away massive equity stakes.[80] Financing with debt, although generally cheaper than equity financing, can be intimidating due to the high cost of CHP equipment, even if a company has good credit and rates are favorable.[81]

For owners of larger CHP projects intending to sell the power generated, a power purchase agreement (PPA) can be critical to securing CHP project financing (equity and debt). The PPA or off-take agreement typically provides the CHP project's owner with stable and sufficient revenue to pay its project debt obligation, covers the project's operating expenses, and provides a reasonable risk-adjusted return to investor(s). Lenders will look to whether or not there is a guaranteed revenue stream from a creditworthy purchaser that is sufficient to support the project's economics. The terms of the PPA determine whether equity investors and debt lenders view the project as financeable, and lenders are concerned with the length of the PPA term, with a strong preference for longer-term contracts of at least 10-15 years.[82]

Uncertainty about energy costs can pose an additional barrier to CHP development. Fluctuations in natural gas prices introduce a substantial level of risk and uncertainty into the economics of a potential CHP project. Even with natural gas prices perceived as relatively low, natural gas prices can vary widely if "(i) there are significant variations in weather-related factors, (ii) crude oil prices change significantly,

[78] Chittum, A., and Kaufman, N. American Council for an Energy-Efficient Economy. 2011. *Challenges Facing Combined Heat and Power Today: A State-by-State Assessment*. p. 6. http://aceee.org/sites/default/files/publications/researchreports/ie111.pdf.
[79] ICF. Prepared for the U.S. DOE, Advanced Manufacturing Office. 2017. Combined Heat and Power (CHP) Financing Primer. p. iii. https://energy.gov/sites/prod/files/2017/06/f35/CHP%20Financing%20Primer%206-16-17%20Final.pdf.
[80] Ibid., p. 10.
[81] Ibid., p. 10.
[82] ICF. Prepared for the U.S. DOE, Advanced Manufacturing Office. 2017. Combined Heat and Power (CHP) Financing Primer. https://energy.gov/sites/prod/files/2017/06/f35/CHP%20Financing%20Primer%206-16-17%20Final.pdf.

(iii) other substantial disruptions to the energy market occur, or (iv) certain cost-related assumptions are significantly different."[83]

In addition to natural gas prices, a potential CHP system owner must have a thorough understanding of projected local electricity prices. Any firm must compare the cost of installing and operating a CHP system to the cost of conducting business as usual, and the cost of purchasing power must be higher than the levelized costs of self-generation. Because the price of purchased power is utility-specific, the economic feasibility of CHP varies geographically; higher costs of purchased power make CHP more attractive than in places where electricity is comparatively cheap.[84] According to EIA, Michigan has the 12th highest electricity prices in the U.S.,[85] making it a relatively good candidate for locating CHP based on the cost of power alone.

6.2 Michigan Economic Barriers

Capital Cost, Financing, and Payback Period

Analysis of survey and interview responses showed that the most commonly-cited barrier was "Cost/payback period/value" of CHP. Of the 83 survey respondents that cited potential barriers to CHP in Michigan, 55 (66%) of these respondents identified "Cost/payback period/value" as a major barrier, and 23 (42%) of these respondents cited it as the largest barrier to CHP implementation. 32 respondents (58%) cited it as the first or second largest barrier overall, and 40 out of 55 (73%) put it in the top three.

In one interview response, an attorney with experience representing clients interested in CHP explained: "Companies are reluctant to make a 20-year bet that they will be in business. The horizon where these projects make economic sense, because of the uncertainty in the world economically, can be the 'Achilles heel' of CHP. Just staying in business long enough to really see the economic benefits." Ensuring a reasonable payback period is crucial to the success of CHP development.[86]

According to National Regulatory Research Institute (NRRI), "The simple payback of a CHP system is the number of years that it will take for the annual operating cost savings from CHP to pay back the upfront costs of installing the CHP system… Economic feasibility has no single definition. Some analysts refer to it in terms of the payback period, with one definition specifying the payback period of five years or less."[87] End-user expectations for investment payback are generally less than 10 years in the public and

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[83] Fujihara, R. U.S. EIA. Office of Technical and Regulatory Analysis. 2017. *Wholesale Natural Gas Market Assessment: Wholesale Natural Gas Futures Prices as of October 5, 2017*. https://www.dcpsc.org/PSCDC/media/PDFFiles/NaturalGas/NGAssessmenandinfo_current.pdf.

[84] Chittum, A., and Kaufman, N. American Council for an Energy-Efficient Economy. 2011. *Challenges Facing Combined Heat and Power Today: A State-by-State Assessment*. p. 8. http://aceee.org/sites/default/files/publications/researchreports/ie111.pdf.

[85] U.S. EIA. 2017. *Michigan State Profile and Energy Estimates.* https://www.eia.gov/state/?sid=MI.

[86] ICF International. Prepared for the American Gas Association (AGA). 2013. *The Opportunity for CHP in the United States*. p. ES-3. https://www.aga.org/research/reports/the-opportunity-for-chp-in-the-us---may-2013/.

[87] Costello, K. National Regulatory Research Institute (NRRI). 2014. *Gas-Fired Combined Heat and Power Going Forward: What Can State Utility Commissions Do?*. pp. vii, 18. http://energy.ky.gov/Programs/Documents/NRRI%20Report-What%20Can%20Commissions%20Do.pdf

institutional sectors, and less than 5 years in the private sector. Some end-users expect even shorter payback periods – 1 to 2 years – but this will never be realistic for CHP systems, which like utility power generation should be considered as a long-term investment. Ultimately when a CHP system's payback period or return on investment does not meet the end-users' internal requirements, the decision will often be to not implement the CHP project.[88]

Related to the payback period is a lack of low-cost financing to pay for the upfront cost of CHP equipment. As previously stated, the installed cost of CHP is between $700 and $3,000 per kW.[89] This means a relatively small CHP system of 2 MW in capacity could cost up to $6 million to install. Financing is critical for a project to move forward. Of those survey respondents citing potential barriers to CHP, a "lack [of] access to low cost capital" was listed by roughly a third of respondents as a major barrier to the development of CHP, with 20% of these individuals ranking it as the number one barrier to CHP in Michigan. In order to meet minimum equity investor expectations and investment requirements, projects must typically be financed such that the equity investor can achieve a leveraged, after-tax, payback on investment in less than 5 years, or the project will not move forward. To achieve this leveraged return on equity, a debt financing term of at least 7 to 10 years (best case), and often up to 15 or 20 years, typically must be negotiated with a long-term lender.[90]

Uncertain Energy Costs

"Spark spread" – the difference between the price of electricity and the cost of fuel to produce electricity – is widely understood to be one of the most critical factors in the economic viability of CHP projects. The price of natural gas can have a significant effect on spark spread. 31 survey respondents identified "natural gas price risk" as a top five barrier to the development of CHP in Michigan, with 17 respondents (55%) considering it to be either the fourth or fifth largest barrier, and 26 (84%) putting it in the bottom three of the five largest barriers.

Michigan residents and businesses enjoy natural gas choice, meaning they can transparently view competing offers from natural gas suppliers and "shop around." The Department of Licensing and Regulatory Affairs (LARA) provides a helpful website for consumers to easily "shop for gas for your home or business from a diverse market of natural gas suppliers."[91] This system provides flexibility for consumers to "choose an alternative gas supplier (AGS or supplier) that will invest in renewable products on their behalf while others are looking for other pricing options or value added services."[92] Despite the transparency and flexibility of being able to choose a natural gas supplier, Michigan businesses interested in exploring CHP will still be subject to risk from variations in natural gas prices overall. According to EIA, Michigan is currently ranked 40th in the U.S. for its natural gas prices, putting it on the relatively low side in the short term.[93]

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[88] ICF International. Prepared for the American Gas Association (AGA). 2013. *The Opportunity for CHP in the United States*. p. ES-3. https://www.aga.org/research/reports/the-opportunity-for-chp-in-the-us---may-2013/.
[89] Chittum, A., and Kaufman, N. American Council for an Energy-Efficient Economy. 2011. *Challenges Facing Combined Heat and Power Today: A State-by-State Assessment*. p. 6. http://aceee.org/sites/default/files/publications/researchreports/ie111.pdf.
[90] Feldman, D. National Renewable Energy Laboratory. 2016. *Put a Fence around It: Project Finance Explained*. https://financere.nrel.gov/finance/content/put-fence-around-it-project-finance-explained.
[91] State of Michigan. 2018. *Compare MI Gas*. https://w2.lara.state.mi.us/gaschoice/.
[92] Ibid.
[93] U.S. EIA. 2017. *Rankings: Natural Gas Residential Prices.* https://www.eia.gov/state/rankings/#/series/28.

According to the DOE's Midwest CHP TAP, "The risk of CHP projects can be reduced by utilizing available commodity price risk management tools."[94] Concerning uncertain natural gas prices, types of hedging include physical hedging and financial hedging. Physical hedging includes storing and withdrawing excess natural gas. Financial hedging includes:[95]

- Index Purchasing, in which natural gas is purchased month-by-month at a 'first of the month' index price;
- Fixed Price Purchase, in which all or a portion of natural gas needs are purchased at one time, with the vendor providing an average fixed price for the term of the contract;
- Cap, in which a fixed price for gas is set, but 'put' contracts are purchased to guarantee that when future market prices for gas settle below the fixed cost, the monthly price is adjusted downward;
- Collar, in which a series of 'put' and 'call' contracts are purchased to guarantee that monthly prices for natural gas will be contained within a defined price range regardless of market conditions;
- Hybrid Approach, in which a percentage of each month's natural gas needs are purchased at a fixed price, and the remainder purchased at an index price; and
- Winter Strip, in which November through March gas is purchased at a fixed price and all other months are purchased at an Index price.

Overall, long-term energy contracts allocate price risk between parties: the buyer faces price uncertainty in the upward direction, and the seller faces price risk resulting from the risk of decline.[96] As a result, longer-term energy contracts "can serve as a 'hedge' on price movements for consumers. Like other forms of hedges and price management tools, there are implications for parties entering into such contracts in terms of future obligations and liabilities."[97]

[94] University of Illinois at Chicago. Energy Resources Center. 2004. *CHP – Managing Commodity Price Risk: An Introduction to Combined Heat and Power*. http://www.midwestchptap.org/Archive/presentations/050518-IL/050518_Pruitt.pdf.
[95] Ibid.
[96] Ibid.
[97] Ibid.

6.3 Overview of Regulatory Barriers

Regulatory barriers to CHP deal with the legal framework around utilities and self-generation which can sometimes put up unintended roadblocks to CHP development. Often, the impact of the regulatory barriers to CHP manifest as negative impacts on project economics, similarly to the economic barriers discussed above. Because a variety of economic and regulatory barriers often intermingle in affecting the prospects of a potential CHP project, there is a critical need to use a holistic approach to achieving optimized CHP adoption. The following section builds upon the fundamental understanding of CHP project economics discussed above with a discussion of regulatory barriers to the optimal deployment of CHP.

Standby Rates

Standby rates are a type of electric tariff paid to utilities by customers with on-site distributed energy resources, such as CHP systems. Standby charges are intended to help the utility recover costs related to reserving such service and providing backup electricity during scheduled and unscheduled outages of the customer's CHP system. Although well-designed standby rates are clear and transparent to the customer, and based on cost of service principles, poorly designed standby rates are often based on erroneous assumptions about CHP reliability, and are frequently unclear and difficult to navigate. (As examples of existing standby tariffs, copies of Consumers Energy Rate GSG-2 and DTE Energy's Rider 3 are attached as **Attachment L.**)

As a result, standby rates can be a significant barrier to the development of otherwise economically viable CHP projects. When rates are too high, inflexible, unpredictable, or simply too difficult for customers to navigate, the economics of a CHP system will fail to provide the needed return on investment, and a potential project will not pencil out.

PURPA Buyback Rates

Owners of CHP projects intending to sell excess generation back to the grid rely on the Public Utility Regulatory Policies Act of 1978 (PURPA). This law, originally designed to encourage energy waste reduction and promote the use of distributed energy resources, such as CHP, requires utilities to purchase or "buy back" power at a rate equal to the utility's "avoided cost." The Federal Energy Regulatory Commission (FERC) has oversight over PURPA, and state utility commissions are in charge of regulating the particular avoided-cost calculation methodology applied by rate-regulated utilities in their state. If avoided cost or buyback rates are set too low, this can have a negative impact on the economics of a proposed CHP installation.

Failure to Recognize Value of Distributed Energy Resources

Until recently, whether in formulating standby rates, PURPA avoided cost/buyback rates, or utility distribution system plans, electric utilities have rarely accounted for the benefits of distributed generation. Many states, including Michigan, have similarly failed to embrace the full value of CHP as a DER in their energy policy development. This means that grid benefits, such as increased reliability and avoided built central-station generating capacity, are not compensated, even with regard to CHP, which can help to stabilize grids while decreasing transmission losses in times of increased electricity demand.[98] Resilience, in particular, is a major potential value of CHP that is often overlooked. When properly configured to operate independently from the grid, CHP systems can provide critical power reliability for businesses and critical infrastructure facilities while providing electric and thermal energy to the sites on a continuous basis, resulting in daily operating cost savings. There are a number of ways in which CHP systems can be configured to meet the specific reliability needs and risk profiles of various customers, and to offset the capital cost investment for traditional backup power measures such as diesel generators. By supporting critical infrastructure in Michigan, CHP can save lives. From reliability to avoided built central-station generating capacity, overlooking CHP's full value represents a missed opportunity, and can be a significant barrier to CHP development.

RE/EWR Standards and Integrated Resource Planning (IRP)

A lack of emphasis on CHP in state portfolio standards relating to renewable energy and EWR can be a major barrier to the deployment of CHP. While some states explicitly include CHP in the language of their RPS, other states' standards bundle CHP in with other energy efficiency measures, making other energy efficiency investments more cost effective in the short term.[99] Other states (including Michigan, discussed below) have tended to overlook CHP almost entirely when it comes to these standards, thus missing out on CHP's full potential for energy waste reduction.

Many states, including Michigan, require utilities to provide regular IRPs. The Regulatory Assistance Project (RAP) defines an IRP as "a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period."[100] A lack of emphasis on the consideration of CHP as a resource in a utility IRP could have a chilling effect on how CHP is viewed long-term. Alternatively, if a utility is required to consider CHP as a potential resource, CHP has a chance to compete on the merits. According to the National Association of State Energy Officials (NASEO), "By altering or broadening the scope of utility resource planning, state policymakers and regulators place CHP on a more equal playing field with traditional energy resources."[101]

Beyond the need to include CHP within an RPS or EWR standard, or within a utility IRP's scope, it is also important to view CHP as both a supply-side and demand-side resource. Current utility analyses of CHP often examine the costs and benefits of CHP from too narrow a perspective, treating CHP as either a supply-side option or a demand-side option. This ignores a major benefit of CHP – that it can supply cost-effective electricity and save energy. By analyzing CHP merely as an efficiency measure, it is not possible to account for its full benefits, which could include reductions in grid congestion, reduced transmission and distribution costs, and other supply benefits. In contrast, supply-side modeling of CHP

[98] Ibid.

[99] Chittum, A., and Kaufman, N. American Council for an Energy-Efficient Economy. 2011. *Challenges Facing Combined Heat and Power Today: A State-by-State Assessment*. p. 15. http://aceee.org/sites/default/files/publications/researchreports/ie111.pdf.

[100] Wilson, R. and Biewald, B. Regulatory Assistance Project (RAP). 2013. *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans*. p. 2. www.raponline.org/document/download/id/6608/.

[101] Friedman, J. and Otto, G. National Association of State Energy Officials (NASEO). 2013. *Combined Heat and Power: A Resource Guide for State Energy Officials*. p. 10. https://www.naseo.org/data/sites/1/documents/publications/CHP-for-State-Energy-Officials.pdf.

often only considers the capital cost of the CHP generation and does not take into account the benefits of the thermal energy. If a utility simultaneously considers CHP as a supply option and a demand/energy waste reduction option, it is much more likely to encourage development of the best CHP projects – projects that capture the full benefits for the utility, the site/host, and all utility ratepayers.

Interconnection Standards

Potential CHP system owners encounter the need to interconnect to the electric grid when they: 1) sign up for standby service from the utility to provide power in case of a CHP system outage; 2) desire to sell excess generation back to the utility; and/or 3) serve a utility customer behind the meter. The process of interconnecting a CHP system to the grid can be onerous and complex, posing a potential barrier to CHP deployment. According to ACEEE, "The lack of a consistent interconnection standard establishing parameters and procedures for connecting to the grid drives up both monetary and transaction costs for technology manufacturers and owners, discouraging CHP deployment."[102] Without standardized and streamlined interconnection processes and fees, potential CHP system owners face a confusing, costly task, which could stand in the way of a potentially beneficial CHP project.

6.4 Michigan Regulatory Barriers

Standby Rates

Among survey respondents, the third most commonly-cited barrier was "high cost standby rates," with 39 respondents naming this as a barrier to CHP development in Michigan. 20 of the 39 respondents (51%) named it as either the first or second largest barrier. The vast majority of the respondents (82%) identified standby rates in the top three. As described previously, in the context of growing stakeholder interest in distributed generation, and concern over standby rates as a potential barrier, the MPSC staff held workgroup discussions aimed at examining standby rates in Michigan.[103] As part of the working group process, Michigan utility standby rates for CHP sites were analyzed and compared to the standby rates of other utilities in the Midwest. The analysis found that standby charges experienced in Michigan are relatively high, potentially posing a barrier to CHP deployment. Further, the analysis found that standby tariffs in Michigan can be confusing and difficult for customers to navigate. While no formal requirements came out of the working group process, the MPSC staff issued several recommendations related to standby rate best practices.[104]

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[102] American Council for an Energy-Efficient Economy (ACEEE). *Interconnection Standards*. https://aceee.org/topics/interconnection-standards.
[103] Michigan Public Service Commission Staff. 2017. *Standby Rate Working Group Supplemental Report June 2017*. http://www.michigan.gov/mpsc/0,4639,7-159-16377_47107-376753--,00.html.
[104] 5 Lakes Energy. Prepared for the Michigan Public Service Commission. 2017. *"Apples to Apples" Standby Rate Analyses*.
http://www.michigan.gov/documents/mpsc/Copy_of_UPPCO_UMERC_jws_rev_03172017_rev2_568778_7.xlsx;
http://www.michigan.gov/documents/mpsc/UPPCO_UMERC_5Lakes_Analyses_03202017_568776_7.docx;
http://www.michigan.gov/documents/mpsc/mca_5_lakes_scenarios_545589_7.xlsx;
http://www.michigan.gov/documents/mpsc/5LE_Standby_Rate_Scenarios_10202016_538737_7.pdf

Coming out of the MPSC staff standby rate working group, engagement in the overall discussion of standby rates continued, and some interested parties went on to pursue formal intervention in utility general rate cases as a means of continuing to raise concerns about the effect of standby rates on CHP installations. Outside of formal intervention, businesses and associations have expressed their support for standby rate reform through comments and sign-on letters submitted to the MPSC.[105, 106]

PURPA Avoided Cost/Buyback Rates

Among survey respondents, the fourth most commonly-cited barrier was "lack of an adequate mechanism to sell excess generation to the grid." As discussed above, implementation of PURPA in Michigan is the legal mechanism by which utilities are required to buy back power generated by qualifying facilities. 38 respondents identified this as a top five barrier, with 19 of the 38 (50%) respondents naming this barrier as the first or second most significant barrier to CHP development in Michigan.

Similarly to standby rates, PURPA avoided cost/buyback rates have recently been a topic of interest at the MPSC. In October 2015, the Commission directed staff to form a technical advisory committee for the purpose of reviewing and considering its implementation of PURPA. "PURPA Technical Advisory Committee (PURPA TAC) participants provided a wide range of backgrounds and perspectives. Participation was welcomed from all who volunteered and included utilities, environmental groups, current and potential future qualifying facilities (QF), industry PURPA experts and MPSC Staff."[107] The PURPA TAC held a series of meetings and a report was issued by MPSC staff on April 8, 2016.[108] Afterwards, the Commission directed utilities to make avoided cost calculation filings in June 2016. While the results of some of these cases are still pending, the concern over an inadequate buyback rate remains, and continues to be a potential barrier to the development of CHP in Michigan. The MPSC has issued one order with new PURPA rates for Consumers Energy.[109]

In addition to its jurisdiction over the avoided cost methodology used in setting buyback rates, the Commission potentially also affects CHP deployment through approving other terms of power purchase agreements under PURPA, including the duration of and project size limitations included in utilities' proposed standard offer contracts. As discussed above, longer-term PPAs are more helpful to CHP

[105] Michigan Public Service Commission Staff. 2017. Public comments. http://www.michigan.gov/mpsc/0,4639,7-159-16377_47107-376753--,00.html.
[106] Alliance for Industrial Efficiency. 2017. *Signed Coalition Letters.* https://alliance4industrialefficiency.org/resources/type/signed-coalition-letters/.
[107] Michigan Public Service Commission staff. PURPA Technical Advisory Committee. 2016. *Report on the Continued Appropriateness of the Commission's Implementation of PURPA.* p. 2. https://www.eenews.net/assets/2017/06/12/document_ew_05.pdf.
[108] Ibid.
[109] Michigan Public Service Commission. November 21, 2017. *Order in Case No. U-18090.* https://mi-psc.force.com/s/filing/a00t0000005ppUqAAI/u180900273.

projects seeking financing. Allowing larger-sized projects to benefit from the ease of the standard offer contract can also reduce transaction costs related to proposed CHP projects.[110, 111]

Lack of Government and Utility Support for CHP

Survey respondents perceived a lack of support for CHP in Michigan in the form of government or utility incentives. The second most commonly-cited barrier was a "lack of government grants or incentives" for CHP. 22 respondents (51%) ranked this barrier in their top two, and 27 respondents (63%) placed it among the top three. Similarly, the fifth most commonly-cited barrier was "lack of utility incentives." 37 respondents named this in their top five, with 10 of 37 (27%) naming it in the top two most significant barriers to the deployment of CHP. The following discussion of EWR programs, integrated resource planning, and interconnection standards are all captured under the broad umbrella of government and utility incentives for CHP.

Energy Waste Reduction

Among the most important and impactful energy incentive programs in Michigan are the EWR programs run through the utilities.[112] PA 342 of 2016 requires utilities to achieve a specified amount of EWR savings. Electric and gas savings targets are based on prior years sales and are set at 1% per year for electric and 0.75% per year for gas utilities.[113] In order to achieve these savings, utilities conduct outreach and provide incentives to their customers to install energy waste reduction measures. The MPSC may authorize rate-regulated utilities to receive a financial incentive when they successfully meet the required savings reductions.

The law requires a "cost and benefit analysis and other justification for specific programs and measures included in a proposed energy waste reduction plan."[114] Michigan utilities rely on the utility system resource cost test, otherwise known as the Program Administrator Cost Test (PACT) approach, when assessing the cost/benefit ratio of each EWR measure. This approach compares the cost of program administration including incentive costs to supply-side resources. Unfortunately, the supply-side resources in question only refer to the avoided transmission, distribution and fuel costs, and not to the long-term avoided capacity costs as would be modelled under an IRP process. Further, the PACT method does not incorporate additional resource savings, such as natural gas savings, or any societal non-monetized benefits such as cleaner water or air.

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[110] Feldman, D. National Renewable Energy Laboratory. 2016. *Put a Fence around It: Project Finance Explained*. https://financere.nrel.gov/finance/content/put-fence-around-it-project-finance-explained.

[111] Parsons, J. E. Massachusetts Institute of Technology, Center for Energy and Environmental Policy Research, 2008. *The Value of Long Term Contracts for Investments in New Generation*, www.mit.edu/~jparsons/Presentations/Contract%20Value%20w%20Berger.pdf.

[112] Michigan's energy waste reduction standards in PA 342 maintain the energy efficiency goals established with the energy optimization standards developed in PA 295.

[113] Michigan Public Service Commission. 2018. *Energy Waste Reduction.* http://www.michigan.gov/mpsc/0,4639,7-159-52495---,00.html.

[114] Michigan Legislature. 2016. PA 342, Sec.201. http://www.legislature.mi.gov/(S(orha3tn1ppom5z5a11udqezd))/mileg.aspx?page=getObject&objectName=2015-SB-0438.

While CHP provides both electric and thermal energy at efficiency levels far above conventional methods, it is not currently included in the EWR plans of Michigan utilities, in part because it does not survive the PACT cost-benefit analysis. Part of what drives this barrier is the complex nature of CHP as a technology application. Unlike more traditional efficiency measures such as lighting improvements, CHP projects often result in greater energy usage on-site. In order to include CHP as an eligible resource in EWR plans, the proper methodology with which to calculate CHP energy savings must be assigned. Because CHP projects provide both thermal and electric supply at increased efficiencies, it is necessary to compare the fuel required under separate generation in order to assess total energy savings. Michigan utilities' reliance on the PACT method as required by law, and resulting failure to properly value the energy savings from CHP, pose an additional barrier to CHP development.

In addition to the reliance on the PACT method, concerns about fuel-switching and competition for customers among utilities pose an additional obstacle to fully encouraging CHP in EWR programs. These concerns will need to be addressed in order to obtain the full benefits of CHP as an energy waste reduction resource.

Integrated Resource Planning

Because CHP functions as both a supply and demand side technology, it is often overlooked in traditional load forecasts. Through an IRP, a utility is required to analyze the least-cost resource mix from both supply and demand-side options. Since EWR measures and CHP applications are often lower-cost resources compared to constructing new generation facilities, proper utilization of IRP can result in the incorporation of these measures as utility system resources, which may reduce the need for additional supply resources. For example, under the STEER model, which was designed to function similarly to IRP models, ideal levels of CHP in Michigan, as a least-cost resource option, range between 722 MW to 1,014 MW of new CHP built.

PA 341 of 2016 requires Michigan's electric utilities to file periodic IRPs with the Commission. While PA 341 requires a utility IRP to include the projected energy and capacity purchased or produced by the utility from a cogeneration resource, there is no requirement that the utility consider customer-sited CHP on the supply-side, or EWR from CHP on the demand-side. In order to realize the full benefit of CHP, IRP analyses should be updated to incorporate CHP as both a supply-side and demand-side measure. Formally requiring utilities to assess CHP on both the supply and demand-side in an IRP would help ensure that these complicated projects are allotted equivalent analysis as other resources. Further, including customer-sited CHP projects with other supply-side resources would signal an acceptance that these projects exist in the grey area between demand reduction and power generation.

Distributed Generation Program

Historically, CHP has not been included in Michigan's net metering program law. Additionally, the full value of CHP as a distributed energy resource has not been fully captured in utility rates or other energy policies and programs. This overarching barrier continues in the revised 2016 PA 342 net metering/distributed generation program currently in the implementation process. Pursuant to 2016 PA 342, the MPSC is in the process of establishing a new distributed generation program to reflect "equitable cost of service for utility revenue requirements for customers who participate in a net metering program or distributed generation program under the clean and renewable energy and energy waste reduction act."[115] Under the law, the distributed generation program is limited to customers who install certain on-site grid-connected, renewable generation. The size limitations of the program likely prevent participation from even renewably-fueled CHP systems (qualifying generation projects must be no larger than 150 kW).[116]

Interconnection Standards

In 2005, the Federal Energy Regulatory Commission (FERC) issued Order No. 2006 requiring all public utilities to adopt standard rules for interconnecting new sources of electricity less than or equal to 20 MW in size. The goal of this order was to decrease interconnection time, increase energy supply, lower wholesale electricity prices, and facilitate development of renewable resources. FERC Order No. 2006 established a "fast track" process based on technical screening criteria for generators under 2 MW.

In response FERC Order No. 2006, the MPSC began a process to revise the rules governing interconnection standards for small electrical generators (under 150 kW). The revised rules were approved by the Commission in March 2009. According to the MPSC, "Technical requirements (data, equipment, relaying, telemetry, metering) are defined according to type of generation, location of the interconnection, and mode of operation (Flow-back or Non-Flow-back). The process is designed to provide an expeditious interconnection to the Utility electric system that is both safe and reliable."[117] The MPSC interconnection standards are general interconnection procedures approved by the MPSC and are intended to be used for reference only. Each utility will has its own set of documents updated with the utility-specific interconnection requirements and all system owners, including CHP system owners excluded by the MPSC general standards due to system size, must work with each utility individually to navigate the complex interconnection process.

In 2013 and 2014, FERC issued Order Nos. 792 and 792-A, which expanded and revised the technical screening process adopted in Order No. 2006, and changed the fast track process to include differentiation by voltage and interconnection location and increased the maximum project size for the fast track process to 4 MW, which can now include many small to medium CHP projects. This technical screening process creates an efficient, expedited, and yet technically sound method to process applications without subjecting projects that do not significantly impact the grid to unnecessary review. Especially with increased demand for interconnection, it is critical to institute policies that avoid costly, time consuming reviews for projects that do not require such reviews. These Orders also established a process to allow developers/customers to request pre-application reports, enabling potential interconnection customers to identify issues that may delay or halt the interconnection process prior to investing significant time and capitol. Finally, Order Nos. 792 and 792-A created the opportunity for a "supplemental study" prior to conducting a full study if a project fails the initial fast track technical screens.

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[115] Michigan Public Service Commission. 2018. *Distributed Generation Program.* http://www.michigan.gov/mpsc/0,4639,7-159-80741_80743-406256--,00.html.
[116] Methane digester generation projects as large as 550 kW may also participate.
[117] Michigan Public Service Commission. 2018. *What is Interconnection?* http://www.michigan.gov/mpsc/0,4639,7-159-16393_48212_58223---,00.html.

The MPSC has not revisited these interconnection standards since FERC issued Order Nos. 792 and 792-A. Michigan's new energy law gives the MPSC authority to revisit and update the interconnection technical standards. As the MPSC considers revisions to the rules governing interconnection standards for electrical generators, it will be important to acknowledge the need for streamlining and expediting CHP system interconnection, where possible.

6.5 Lack of Expertise and Information

CHP is a well-established technology application and itis not new – it has been around for over a century. According to DOE, "CHP has been used in the United States for more than 100 years since Thomas Edison used it to power the world's first commercial power plant. Decentralized CHP systems located at industrial and municipal sites became the foundation of the U.S.'s early electric power industry."[118] Despite this long history, many businesses lack familiarity with CHP. This lack of awareness and need for further CHP education can be a barrier to optimal levels of CHP installations.

One reason for this lack of familiarity is that, according to a 2012 report from DOE and EPA, "CHP is not regarded as part of most end-users' core business focus and, as such, is sometimes subject to higher investment hurdle rates than competing internal options. In addition, many potential industrial project hosts are not fully aware of the full array of benefits provided by CHP, or are overly sensitive to perceived CHP investment risks."[119] As business leaders default to more familiar options, they miss out on the potential benefits of CHP.

For business leaders who are familiar with CHP, some may have longstanding negative expectations regarding the ease of CHP operations. This was confirmed directly via interviews with potential end-users, as many candidates for CHP either have direct negative past experience with CHP, or more commonly, have heard stories about the negative experiences of others with CHP systems. In many cases, these negative stories or rumors lead to CHP never being considered as a legitimate option.

Michigan businesses interested in CHP have access to the DOE Midwest CHP TAP, managed by the Energy Resources Center and based in Chicago, Illinois. The Midwest CHP TAP is one of seven regional CHP TAPs formed in 2003 "to promote greater adoption of clean and efficient energy generation and use through recycled energy. Recycled energy includes CHP, district energy, and WHP."[120] The Midwest CHP TAP educates prospective adopters of CHP and fosters CHP technologies as viable technical and economic options, providing businesses with free or reduced-cost CHP feasibility studies, among other resources. A number of private firms provide similar no-cost or low-cost services.

Despite Michigan's strong relationship with the Midwest CHP TAP, there is a lack of awareness and familiarity with CHP among end-users that is preventing businesses from reaching out for information. This lack of awareness of the potential benefits of CHP is preventing optimal levels of CHP development. In interviews with stakeholders, the need for increased education of end-users was mentioned as a barrier to CHP development in the state. According to a representative from an engineering firm

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[118] Department of Energy. 2013. *Top 10 Things You Didn't Know About Combined Heat and Power.* https://www.energy.gov/articles/top-10-things-you-didn-t-know-about-combined-heat-and-power.
[119] U.S. DOE and U.S. EPA. 2012. *Combined Heat and Power: A Clean Energy Solution.* p. 18. https://energy.gov/eere/amo/downloads/chp-clean-energy-solution-august-2012.
[120] U.S. DOE Midwest CHP Technical Assistance Partnerships. http://www.midwestchptap.org/about/.

specializing in CHP systems, "Michigan's CHP market is at the point of asking: how does CHP benefit my facility? How is it done? Michigan's potential CHP users need education on the technology and financial resources." A Michigan-based component distributor agrees. "The biggest challenge is getting people to understand CHP. Companies don't realize these opportunities are out there." Successful CHP projects in Michigan typically have a strong champion within the end-user organization providing leadership to build consensus for the project across engineering, sustainability, energy, and finance disciplines.

7 Roadmap for CHP Deployment

There is strong interest and capability on the part of participants in the Michigan CHP supply and value chain for Michigan to move closer to optimal levels of CHP deployment. Currently, Michigan is home to over 3,300 MW of installed CHP capacity.[121] STEER model results indicate that ideal levels of CHP in Michigan, as a least-cost resource option, range between 722 MW to 1,014 MW built, in addition to the 3,300 MW in CHP capacity already installed. In order to pursue a greater role for CHP in Michigan's future energy mix, the following roadmap is offered in an effort to outline concrete policy actions for consideration. The following recommendations reflect lessons learned from stakeholder surveys, interviews, Midwest CHP TAP experience and expertise, and best practices from other states. A case study on the impact of incentives on CHP economics is provided in Section 9.1.

7.1 Reduce the Payback Period

In light of the importance of the payback period to the development of a CHP project, efforts to reduce the payback period of CHP by either defraying some of the initial upfront cost through a grant or offering a production incentive would be beneficial in addressing this barrier. For example, AEP Ohio's Combined Heat and Power and Waste Energy Recovery Program (CHP/WER) "supports the installation of high efficiency, sustainable and cost effective projects in AEP Ohio's service territory as allowed by SB 315."[122] CHP projects are eligible for the incentive if they meet minimum efficiency requirements of 60% overall efficiency and 20% useful thermal energy. CHP incentive payments are based on production of kWh recovered by the project, and incentive rates for projects approved in 2017 are $0.035 per kWh recovered for systems >1000 kW. There is a yearly cap of $500,000.[123] This incentive is a critical aspect of AEP Ohio's EWR program. The company estimates that it will generate 600,000 MWh in incremental annual energy savings through its CHP/WER Program between 2015 and 2019.[124]

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[121] U.S. DOE. 2016. *Combined Heat and Power Installation Database*. https://doe.icfwebservices.com/chpdb/.
[122] AEP Ohio. *Combined Heat and Power and Waste Energy Recovery Program.* https://www.aepohio.com/save/business/programs/CombinedHeatandPower.aspx.
[123] Ibid.
[124] AEP Ohio. 2014. *Energy Efficiency/ Peak Demand Reduction Action Plan*. p. 118. https://aceee.org/files/pdf/aep-ohio-2015-2017-ee-pdr-plan.pdf.

7.2 Promote PACE and Other Financing Tools

For those citing a lack of low-cost financing as a barrier to CHP development in Michigan, PACE financing could be a solution. PACE financing is a long term financing tool for commercial property owners to pay for energy efficiency, water efficiency, and renewable energy upgrades, including CHP systems. According to Kyle Peczynski of Petros PACE Finance, "PACE financing eliminates the high upfront cost and spreads the repayment over a long enough term that the annual savings generated from the CHP project exceed the PACE payments starting in the very first year. In other words, PACE is a no-money-down, cash-flow-positive way to fund large CHP projects." Michigan's "Property Assessed Clean Energy" Act, or PA 270 of 2010, authorizes local governments to adopt PACE financing programs. This means PACE must first be adopted at the local level in order for PACE to be active in a particular county or city. PACE financing is currently available in 23 Michigan counties and 11 of the larger cities in non-participating counties. The adoption of local PACE authorization ordinances should be encouraged, and Michigan residents and businesses should be educated about this innovative financing tool.

On-Bill Financing (OBF) could also be helpful in facilitating CHP development. In OBF, the customer's costs of energy waste reduction retrofits or equipment are amortized and added to savings from the measures on the customer's utility bill. In Michigan's new energy legislation, PA 342, Part 7, Sec. 201-209 describes a framework for creating a residential OBF program. The new law invites utilities to file a residential OBF plan proposal for Commission approval. On April 24, 2017, the MPSC and MAE initiated a stakeholder meeting for the purposes of receiving feedback for OBF program goals. Currently, the OBF program is limited to residential energy installations, which would exclude industrial and commercial CHP installations. However, in the future, OBF programs could be revised to allow for commercial and industrial applications such as CHP projects.

7.3 Reform Standby Rates

Standby rates have a significant impact on whether a CHP project is developed. Both in terms of how difficult they are to interpret and navigate, and in terms of the negative impact on a project's bottom line, the need for a revised approach to standby rates in Michigan stands as a prime example of a barrier to CHP that can be readily reduced or eliminated. The MPSC Staff Standby Rate Working Group began a constructive conversation with stakeholders, with several important recommendations issued in the June 2017 Supplemental Report.[125] These include recommendations dealing with transparency and clarity of the published standby tariffs, the desire to encourage efficient use of the grid by incenting scheduled maintenance of CHP systems, and the overarching principle that standby rates should be based on cost of service principles.[126] A case study on the impact of standby rate mitigation is presented in Section 9.2.

The MPSC should continue to look to best practices in standby rate design as Michigan utilities further develop their approach to working with customers with CHP systems.

The RAP outlines best practices for standby rates,[127] including:

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[125] Michigan Public Service Commission Staff. 2017. *Standby Rate Working Group Supplemental Report June 2017*. http://www.michigan.gov/mpsc/0,4639,7-159-16377_47107-376753--,00.html.
[126] Ibid.
[127] Selecky, J., Iverson, K., and Al-Jabir, A. Regulatory Assistance Project (RAP). 2014. *Standby Rates for Combined Heat and Power Systems*. p. 5. http://www.raponline.org/knowledge-center/standby-rates-for-combined-heat-and-power-systems/?sf_data=results&_sf_s=standby+rates+for+combined+heat+and+power+systems.

- Reservation fees should be based on the utility's cost and the forced outage rate of the CHP system;
- Standby rate design should not assume that all forced outages of CHP systems occur simultaneously, or at the time of the utility system peak;
- Demand charges should be designed to recognize the scheduling of maintenance service during periods when the utility generation requirements are low.

With regard to clarity and transparency of standby rates, utilities should provide educational materials to help customers navigate complex standby rate structures. For example, AEP Ohio helpfully provides bill calculation spreadsheets on its website.[128]

Ameren Missouri, another example, provides a standby rate billing model to any inquiring customer. The purpose of the model is to simulate the annual bill for a customer on the new standby rate given standby contract capacity and generation output and to calculate the standby avoided rate. The model includes a customer's annual 15-minute interval consumption data. The customer, or a third party entity, would only need to enter anticipated generation, supplemental capacity, and standby capacity. Once entered, the model calculates the annual bill and the avoided rate percentage create by the standby tariff. This model provides important information on the financial impact that Ameren's standby rate has on CHP customers. Further, this model allows customers to assess the financial effect of different operating schedules, standby contract capacities, and outages durations.[129]

The transparency provided by AEP Ohio and Ameren Missouri should be emulated by Michigan's utilities, including Consumers Energy and DTE Energy.

7.4 Improve Distributed Generation Program

PA 341 of 2016 requires the MPSC to determine "an appropriate tariff reflecting equitable cost of service for utility revenue requirements for customers who participate in a net metering program or distributed generation program." While Michigan's current distributed generation program is targeted at small installations and does not include CHP, future consideration of the cost and benefits of distributed energy resources should include CHP and attempt to capture its full value, including the value of resilience. This analysis would build on the findings regarding the distributed generation program.

According to the National Association of Regulatory Utility Commissioners (NARUC), "...a growing number of parties involved in the [distributed energy resource] debate acknowledge DER can provide material benefits beyond just those enjoyed by the customer behind whose meter the DER is sited... Some jurisdictions, utilities, researchers, and advocates have also concluded or posited that responsible encouragement of other types of DER adoption leads to positive cost benefit results. In this respect, when using the traditional model for rate design, which does not compensate (or charge) particular customers for producing particular benefits (or costs) for the grid... a regulator would be missing that

[128] AEP Ohio. https://www.aepohio.com/account/bills/rates/AEPOhioRatesTariffsOH.aspx.
[129] Standby Service Rider - Ameren, March 8, 2017, *available at* https://www.ameren.com/-/media/rates/files/missouri/uecesheetno92riderssrstandbyservicerider.ashx.

portion of the cost benefit analysis for DER... At the very least, neglecting DER benefits could represent a lost opportunity to meet customer needs on a more cost-effective basis."[130]

For example, in New York, under the Reforming the Energy Vision (REV) process, New York Public Service Commission issued its Value of Distributed Energy Generation Phase One Decision[131] in March of 2017, and the Phase One Implementation Order was released September 14, 2017. The New York methodology moves beyond Net Energy Metering (NEM) "to a more accurate valuation and compensation of Distributed Energy Resources. [The new method's] factors include the price of the energy, the avoided carbon emissions, the cost savings to customers and utilities, and other savings from avoiding expensive capital investments."[132] New York is wrestling with the issue of how to consider non-metered technologies, such as CHP projects, in its valuation of distributed energy resources. "A number of existing tariffs and programs govern the treatment and compensation of projects that are not eligible for NEM. Inclusion of those projects in VDER tariffs will require a thorough analysis of how a transition from those tariffs and programs can best be achieved."[133]

Michigan will be required to undergo a similar transition and accompanying analysis of larger distributed energy resources, such as CHP, as it pursues its grid modernization objectives. As the full benefits of CHP are increasingly taken into account, this barrier to CHP development should be diminished.

7.5 Update Interconnection Standards

As previously discussed, the MPSC has not yet revisited the interconnection standards since FERC issued Orders 792 and 792-A. Michigan's new energy law (passed in December 2016, PA 341 and PA 342) gives the MPSC authority to revisit and update the interconnection technical standards. Other states in the Midwest have recently revised their interconnection standards for small electrical generations to follow best practices and reflect the proposed standards in FERC 792 and 792-A. Michigan should follow their lead and adopt the following revisions to the state's interconnection standards:

1. Require utilities to facilitate pre-application reports to enable early assessment of proposed interconnections, decrease utility interconnection queues, and streamline applications.
2. Develop and implement a technical screening process for projects based on size, voltage, and location to allow those projects with limited expected impact on the grid to avoid undergoing full distribution and engineering studies.
3. Develop and implement a supplemental review process for projects that do not meet the criteria for expedited approval based on the original technical screening process, but that are not likely to significantly impact the grid or require grid upgrades.

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

[131] New York Public Service Commission. 2017. *Order in Cases 15-E-0751 and 15-E-0082.* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b5B69628E-2928-44A9-B83E-65CEA7326428%7d.

[132] New York State Energy Research and Development Authority (NYSERDA). 2017. *Value of Distributed Energy Resources (VDER).* https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Project-Developers/Value-of-Distributed-Energy-Resources.

[133] New York Department of Public Service. 2016. *Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding*. p. 47. https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Project-Developers/Value-of-Distributed-Energy-Resources.

4. Address energy storage as an "electrical generator."
5. Require utilities to create and utilize dynamic electronic submittal and tracking portals.
6. Require utilities to create maps of the grid system to facilitate siting of proposed interconnections (including hosting capacity analysis, interconnection points).

With updated and streamlined interconnection processes in place, distributed energy resources such as CHP will have an easier path to connecting to, and providing benefits to, Michigan's electric grid.

7.6 Incorporate CHP as a Resource in Michigan Utility EWR Plans

The STEER model results indicate that ideal levels of CHP in Michigan, as a least-cost resource option, range between 722 MW to 1,014 MW built – in addition to the 3,300 MW in CHP capacity already installed. A key way to achieve this increase in CHP deployment is for Michigan utilities to embrace CHP as an EWR resource.

Michigan utilities have so far been extremely successful in setting and meeting their EWR goals, even without relying on CHP. "For the seven year period of 2009 through 2015, Energy Optimization program savings achieved for electric utility providers were 129 percent of the target… EO program savings achieved for natural gas utility providers were 127 percent of the required target."[134] There have been job creation benefits, as well. "The EO programs have led to the creation of new jobs in Michigan, by process contractors and by installation contractors. EO programs have also prompted the increasing availability of higher efficiency equipment such as LED lighting for homes and businesses."[135]

However, as more traditional energy efficiency measures become increasingly common in the market, utilities in other states are beginning to struggle to meet efficiency savings targets. When allowed as an eligible measure, CHP can improve a utility's ability to meet energy reduction goals and further increase CHP deployment. For example, in 2016, CHP was only responsible for 10% of AEP Ohio's efficiency portfolio savings; however, AEP Ohio's business plan aims to increase CHP contribution to efficiency savings targets to over 30% by 2020.[136] This proposed increase stems in part to the large energy savings that CHP applications can create, as well as the increased familiarity of their CHP incentives.

By failing to embrace the potential contribution of CHP as an EWR resource, Michigan is missing out on an opportunity to reap the full benefits of its EWR strategy. EWR program savings could be even higher with CHP and by deploying participants in the Michigan CHP supply and value chains, Michigan could experience increased job creation from CHP development, as well. According to ACEEE, which ranks states on progress towards energy efficiency metrics, "All of the highest-scoring states define CHP as an eligible resource in an energy efficiency resource standard, have implemented a standard for connecting CHP systems to the grid, and have a state-approved CHP production goal."

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[134] Michigan Public Service Commission. 2016. *2016 Report on the Implementation of P.A. 295 Utility Energy Optimization Programs*. p. 2. http://www.michigan.gov/documents/mpsc/2016_Energy_Optimization_Report_to_the_Legislature_with_Appendix_Nov_30_543919_7.pdf.
[135] Ibid., p. 10.
[136] AEP Ohio, Energy Efficiency, *available at* https://www.aep.com/about/IssuesAndPositions/Distribution/EnergyEfficiency/GeneralPolicy.aspx

There are two main approaches to creating utility CHP incentive programs: passive and active. The passive approach, employed in states like Illinois and Ohio, is to define EWR broadly enough as too include savings from CHP. Utilities in those states are thereby incented to create CHP incentive programs themselves once the technology is deemed eligible. In 2013, Illinois passed Public Act 98-0090, which redefined "Energy Efficiency Project" as a measure that reduces the total Btus of electricity and natural gas needed to meet the end use or uses.[137] This new definition removed any concerns over fuel switching for CHP projects and allowed for future CHP incentive programs such as the Illinois public sector CHP pilot program, the Commonwealth Edison CHP incentive program and the Nicor Gas CHP incentive program. The downside of such an approach is that there is no requirement to include CHP as eligible. Indeed utilities such as Ameren Illinois, North Shore Gas, Duke Energy and First Energy do not yet have CHP incentives, though they are allowed under state law.[138] However, this approach may be more feasible to accomplish in the short term, as it does not require a CHP-specific carve-out, but instead only a broad redefinition of efficiency as total energy savings.

The active approach, on the other hand, involves creating a mechanism with which to require utilities to achieve specific savings targets from CHP installations. This is the approach used in Massachusetts through the Green Communities Act (S.B. 2768) passed in 2008, which created the state's Alternative Energy Portfolio and Energy Efficiency First Fuel Requirement.[139] The efficiency requirement requires utilities to prioritize cost-effective energy efficiency and demand reduction over supply resource and specifically mentions CHP as an eligible technology. The Alternative Energy Portfolio Standard (AEPS) is similar to Michigan's EWR program, but instead of requiring a certain level of load from efficiency, the AEPS requires utilities to achieve a specific amount of load from "alternative energy generating sources," including CHP projects, flywheel energy storage, energy efficient steam technology and renewable technologies that generate useful thermal energy. From 2009 to 2014, roughly 99% of compliance was met using CHP technologies.[140]

Under either approach, the proper methodology with which to calculate CHP energy savings must be carefully chosen. As discussed above, Michigan utilities' reliance on PACT fails to accurately capture the full energy savings of a CHP system. As an alternative, the Illinois Technical Reference Manual (TRM) provides a potential methodology for calculating energy savings from CHP.[141] Strengths of the Illinois TRM include the fact that it accurately reflects the energy required from the grid and on-site boilers/furnaces to produce an equivalent amount of electricity and thermal energy. On the electricity side, the Illinois TRM divides CHP into two categories, those operating above 6,500 hours a year and those operating below 6,500 hours a year. For systems operating fewer than 6,500 hours per year, the

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[137] Illinois General Assembly. Illinois Compiled Statutes 3501/825-65 (a)(iii)(b). http://www.ilga.gov/legislation/ilcs/fulltext.asp?DocName=002035010K825-65.
[138] U.S. DOE. 2015. *Energy Incentive Programs, Illinois*. https://energy.gov/eere/femp/energy-incentive-programs-illinois.
[139] Massachusetts Legislature. 2008. Chapter 169. https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter169.
[140] Ballam, J. Massachusetts Department of Energy Resources. 2013. *Massachusetts Alternative Portfolio Standard for Combined Heat & Power (CHP): An Effective Program for Clean, Efficient Energy*. https://www.maeep.org/sites/default/files/CHP2013/MAEEP%20CHP%20061913%20(Ballam).pdf.
[141] *Illinois Statewide Technical Reference Manual for Energy Efficiency Version 6.0*. 2017. http://ilsagfiles.org/SAG_files/Technical_Reference_Manual/Version_6/Final/IL-TRM_Version_6.0_dated_February_8_2017_Final_Volumes_1-4_Compiled.pdf.

avoided grid energy calculations use the non-baseload heat rate provided by EPA eGRID for utility specific regions (RFC West region for ComEd territory and SERC Midwest region for Ameren territory) and includes any line losses.[142] For systems operating more than 6,500 hour per year, the avoided grid energy calculations use the All Fossil Average heat rate provided by EPA eGRID for utility specific regions.[143] The utilities then monetize the energy savings from CHP using utility-specific avoided cost data to calculate the cost and value of incentives as outlined in a resource cost test (and requiring some sort of evaluation measurement and verification protocol). These cost tests determine what costs and benefits may be incorporated when assessing energy savings and their respective implementation costs.

An efficiency threshold for CHP projects should be a required feature of incorporating CHP in the EWR program. A reasonable eligibility threshold for CHP systems is one that is set high enough that so that it is clear that the CHP is achieving energy savings compared to separate heat and power, but not so high as to prevent CHP systems considered to be "high efficiency" from eligibility.[144]

The New York State Energy Research and Development Authority (NYSERDA) CHP incentive program is commonly thought of as the gold standard for state supported CHP policies.[145, 146] Incentives levels are divided between geographies, system sizes, and technology types and are capped at $2.5 million per project. The NYSERDA CHP Program provides incentives through a catalog approach and a custom approach. According to NYSERDA, under the catalog approach, approved CHP vendors act as a single point of responsibility for the entire project and provide a minimum 5-year maintenance/warranty agreement on the CHP system.[147] Under the custom approach, NYSERDA accepts applications from the site owner, the CHP System owner, or any member of the project team takes responsibility for the proper design, integration, installation, commissioning and maintenance of the CHP System.[148] NYSERDA will contract only with the applicant. The Custom Approach is available for projects 1 MW and larger in size.[149]

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[142] Ibid.
[143] Ibid.
[144] U.S. EPA. 2017. *Methods for Calculating CHP Efficiency*. https://www.epa.gov/chp/methods-calculating-chp-efficiency.
[145] CleanEnergy States Alliance. 2015. *Clean Energy Champions: The Importance of State Programs and Policies*. p. 112. https://www.cesa.org/assets/2015-Files/Clean-Energy-Champions-LR.pdf.
[146] New York State Energy Research and Development Authority (NYSERDA). 2017. *Combined Heat and Power Program.* https://www.nyserda.ny.gov/All-Programs/Programs/Combined-Heat-and-Power-Program.
[147] Ibid.
[148] Ibid.
[149] The deadline for applications to the program is December 31, 2018 and projects are to be commissioned within 30 months of approval of application. Therefore, comprehensive program evaluation is expected to commence by June 2021. https://portal.nyserda.ny.gov/CORE_Solicitation_Document_Page?documentId=a0lt0000000kzvQAAQ.

7.7 Consider CHP Supply and Demand in IRP

Building upon Michigan's 2016 energy law's requirement that CHP must be considered in a utility's IRP, utilities should also be required to consider:

- the demand-side savings from CHP;
- on-site CHP as both a supply-side and demand-side resource.

IRP analysis should incorporate CHP as both a supply and demand-side measure. On the supply side analysis, CHP would be included as another generation resource similar to combined cycle generation. Unlike combined cycle plants, CHP requires a host facility capable of using the thermal output. Relatedly, the value of this thermal load would need to be accounted for either through a credit or another mechanism to account for the total cost of CHP to the utility. Formally requiring Michigan utilities to assess CHP on both the supply-side and demand-side in an IRP would help ensure that these complicated projects are allotted equivalent analyses as other resources. While the final proposed course of action might not include CHP, its required inclusion as a supply-side and demand-side resource would ensure a level playing field between all potential resources.

As one example of utility that has successfully included CHP in its IRP, Alabama Power includes more than 500 MW of company-owned and 1,500 MW of customer-owned CHP generation in its IRP. The plan states that the company aims to identify "CHP projects that are expected to bring benefits to all customers" and attributes its success in developing CHP resources to "a good working arrangement between all parties" and "an adaptive regulatory process."[150]

7.8 Promote Outreach and Technical Assistance

The DOE Midwest CHP TAP is an enormously helpful resource for those interested in developing CHP projects. Businesses in Michigan that are interested in CHP should work closely with the Midwest CHP TAP to utilize all available services and resources needed to better understand if CHP is right for them. Government leaders, along with trade associations and advocacy groups like the Midwest Cogeneration Association and the Michigan EIBC, should work in close collaboration with the Midwest CHP TAP to ensure their constituents and members are aware of the potential benefits of CHP and the resources provided by the Midwest CHP TAP. This can include assistance with navigating the complex array of financing options available for the development of CHP projects. Proactive engagement with technical assistance resources can also help to overcome structural organizational challenges necessitating education for energy and financial decision-makers within a company.

Targeted outreach to emergency management professionals are an additional key group that must be engaged in the effort, because they provide a gateway to their stakeholders who play an important role, at the local level, in developing emergency response plans and taking action when needed. Those involved with emergency planning and critical infrastructure are likely to be most interested in the resilience benefits of CHP. As discussed above, when properly configured to operate independently from the grid, CHP systems can provide critical power reliability for businesses and critical infrastructure facilities while providing electric and thermal energy to the sites on a continuous basis, resulting in daily

[150] Alabama Power. 2016. *2016 Integrated Resource Plan*. p. 34. https://www.alabamapower.com/our-company/how-we-operate/regulation/integrated-resource-plan.html.

operating cost savings. There are a number of ways in which CHP systems can be configured to meet the specific reliability needs and risk profiles of various customers, and to offset the capital cost investment for traditional backup power measures. In order to optimally deploy CHP for Michigan's critical facilities, outreach and education will need to be a high priority. "Successful application of CHP in critical infrastructure sectors will depend on overcoming institutional barriers, and engaging the support of decision-makers who build, manage, and operate these facilities. An element of 'out-of-the-box' thinking is also required as the needs of our infrastructure evolve to contend with growing and changing risks."[151]

8 Moving Michigan Forward

Michigan is poised to move forward toward optimal levels of CHP development. According to the DOE, Michigan has nearly 5 GW of CHP technical potential across more than 10,000 sites across 17 industrial and 24 commercial sectors. This potential, on a capacity basis, is roughly evenly split between 17 industrial sectors and 24 commercial sectors.[152] As discussed above, STEER model results indicate that ideal levels of CHP in Michigan, as a least-cost resource option, range between 722 MW and 1,014 MW built, in addition to the 3,300 MW in CHP capacity already installed.

This increase in CHP deployment will enhance Michigan's efforts to lead on EWR among other states. Currently, Michigan ranks 7th in the nation for potential annual CO_2 reductions from industrial energy efficiency and CHP/WHP.[153] In the 2017 ACEEE Energy Efficiency Scorecard, Michigan scored 14th (tied with Arizona, Delaware, Iowa, New Jersey, New Mexico, Ohio, Texas, and Wisconsin) in the CHP category, slightly lower than its overall energy efficiency rank of 11th.[154]

Demonstrating leadership in CHP development will serve to both reinforce and grow Michigan's demonstrated commitment to serious levels of energy waste reduction. According to the MPSC, regarding EWR overall, "For 2015, Michigan utility providers successfully complied with the energy savings targets laid out in PA 295. Providers met a combined average of 121 percent of their electric energy savings targets and 117 percent of their natural gas energy savings targets – one percent of retail sales for electric providers, and 0.75 percent of retail sales for gas providers. EO programs across the state accounted for electric savings totaling over 1.1 million MWh (megawatt hours) and natural gas savings totaling over 4.58 million Mcf (thousand cubic feet) for program year 2015."[155] CHP could be key

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[151] State and Local Energy Efficiency Action Network. U.S. DOE. 2013. *Guide to the Successful Implementation of State Combined Heat and Power Policies*. p. 4. https://www4.eere.energy.gov/seeaction/system/files/documents/see_action_chp_policies_guide.pdf.
[152] U.S. DOE. 2016. *Combined Heat and Power (CHP) Technical Potential in the United States*. https://www.energy.gov/eere/amo/downloads/new-release-us-doe-analysis-combined-heat-and-power-chp-technical-potential.
[153] Alliance for Industrial Efficiency. 2016. *State Ranking of Potential Carbon Dioxide Emission Reductions through Industrial Energy Efficiency*. https://alliance4industrialefficiency.org/wp-content/uploads/2016/09/FINAL-AIE-State-Industrial-Efficiency-Ranking-Report_9_15_16.pdf.
[154] Berg, W., et al. American Council for an Energy-Efficient Economy. 2017. *The 2017 State Energy Efficiency Scorecard*. http://aceee.org/research-report/u1710.
[155] Michigan Public Service Commission. 2016. *2016 Report on the Implementation of P.A. 295 Utility Energy Optimization Programs*. p. 1.

to continuing to meet strong energy savings targets in the future. According to the ACEEE, "In states with energy efficiency goals, CHP can offer a more cost-effective way to reach efficiency targets and earn performance incentives. A single CHP system can offer the efficiency savings of many smaller efficiency projects. In times when some utilities are reporting less low hanging efficiency fruit in the commercial and industrial sector, CHP can offer deep savings at a very low cost, enhancing the overall cost-effectiveness of energy efficiency portfolios."[156]

Execution of the Michigan CHP Roadmap will likely have significant impacts on the levels of CHP deployed in Michigan. For example, by addressing the CHP barrier of standby rates, STEER Model results using the EIA 2016 Annual Energy Outlook Reference Case indicate that Michigan could see an increase of 345 MW of CHP capacity built. In Missouri, this pattern has already been demonstrated. In 2016, the Missouri Energy Office and Ameren Missouri reached a settlement agreement on standby rate reform. The new standby rate was a significant improvement to the previous rate, which was modelled to have detrimental financial effects on CHP development. As a result, there has been a noticeable uptick in CHP qualification screenings requested and provided by the Midwest CHP TAP. In 2016, before the standby model was created, the Midwest TAP provided technical assistance to only 10 sites in Missouri. In 2017, this number jumped to 46 sites, including Mercy Hospital in St. Louis. The renewed interest in CHP by Mercy Hospital was due in large part to the new standby rate in conjunction with the Missouri Energy Office's outreach.

Additionally, CHP incentive programs in other states have seen dramatic results in additional CHP capacity coming online. The NYSERDA CHP incentive program has had an enormous market impact in New York. Between 2013 and 2016, the NYSERDA program has provided incentives to over 150 sites with a cumulative total capacity of over 70 MW. In New York City alone, the program is directly responsible for over 100 MW of new CHP capacity since 2003. Similarly, in Illinois, the impact of the public sector CHP incentive was immediately felt. When released in 2013, the public sector incentive program received 17 applications providing 31 MW of capacity. Of these applicants, seven were selected as finalists to receive incentives. Through implementing the Michigan CHP Roadmap, well-crafted CHP incentive programs could have similar positive effects on CHP development in Michigan.

Building on its strong commitment to EWR, Michigan is well-positioned to take advantage of the opportunities offered by increased CHP development in the state. By implementing the Michigan CHP Roadmap, the state can expand its energy waste reduction vision to include the many benefits of CHP, helping businesses to achieve their cost-savings and energy reliability goals. With key revisions to programs and policy, CHP has the potential to be a significant, reliable, cost-effective, and environmentally protective contributor to Michigan's energy mix.

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http://www.michigan.gov/documents/mpsc/2016_Energy_Optimization_Report_to_the_Legislature_with_Appendix_Nov_30_543919_7.pdf.

[156] Chittum, A. American Council for an Energy Efficient Economy (ACEEE). 2013. *How Electric Utilities Can Find Value in CHP*. p. 5. http://aceee.org/files/pdf/white-paper/chp-and-electric-utilities.pdf.

9 Case Studies

9.1 Impact of Incentives

Incentive programs help to improve the economics of proposed projects and can be an important consideration in the decision to move forward. Several models from other states exist for how such a CHP incentive program may be structured:

- Commonwealth Edison's (ComEd) Smart Ideas program provides CHP incentives for business customers in northern Illinois;
- Nicor Gas's (Nicor's) Energy Smart program provides natural gas incentives for CHP projects pursued by business customers in its in northern Illinois territories;
- The Illinois Energy Office, under its Illinois Energy Now program, provides incentives to public entities for CHP projects;
- Dayton Power and Light (DP&L) provides CHP incentives to public and private customers in its Ohio service territory;
- Baltimore Gas and Electric (BG&E) provides CHP incentives to public and private customers in its Maryland service territory.

Each of the five incentive programs has unique features, although they have some commonalities. All of the programs set a minimum efficiency level for eligibility – 60% for the Illinois-based programs and DP&L and 65% for BG&E.[157] The ComEd, Nicor, and DP&L programs provide incentives for feasibility assessments and the ComEd program further provides cost sharing for interconnection expenses. The Illinois Energy Now and BG&E programs offer a design incentive and these two programs along with DP&L provide incentive payments at the time of project commissioning. The design and commissioning incentives effectively act as up front capital cost buy downs.

All of the programs provide production incentives after a period of operation based on the electric generation and, in the case of Nicor, on the gas displaced from the existing on-site boilers. The production incentives are frequently structured to encourage higher efficiencies in the CHP systems. For example, DP&L's incentive ranges from 80% to 100% of $0.08/kWh depending on the system efficiency. For basic systems with a CHP efficiency of 60%, Illinois-based programs allow only 65% of generation to be eligible for incentives, but this percentage increases as the efficiency of the system increases. Some of the gas savings are also counted when CHP efficiencies exceed 65%. The BG&E program is not structured to incentivize higher efficiencies, but it sets the highest efficiency threshold for eligibility.

Table 10 summarizes the incentive structure for each of the five programs. Note that each of the programs has additional requirements that can be examined through the sources cited.[158] In northern

[157] The Illinois and BG&E programs calculate the CHP efficiency based on higher heating value (HHV), whereas the DP&L program uses Lower Heating Value (LHV). HHV and LHV are a measure of the range of expected energy content for a volume of fuel, typically natural gas for CHP applications. Therefore, the DP&L eligibility is a lower threshold.
[158] CHP Incentive Program Details:

Illinois, when a customer is shared by both ComEd and Nicor, the incentive programs operate in concert under rules for counting savings in the Illinois Technical Reference Manual.[159]

Table 10: Comparison of Five CHP Incentive Programs

Category	ComEd[1]/Nicor[2]	ComEd Only[1]	Illinois Energy Now[3]	DP&L[4]	BG&E[5]
Minimum CHP Efficiency	60% HHV	60% HHV	60% HHV	60% LHV	65% HHV
Feasibility Assessment	up to $25,000 or 50% of study cost	up to $25,000 or 50% of study cost		up to $10,000 for study cost	
	up to $12,500 or 25% of study cost				
Design incentive			up to $75/kW, max. 50% of design cost or $195,000		$75/kW
Installation/Commissioning Incentive			$175/kW, max. $650,000 including design incentive	$100/kW	$275/kW for <250 kW, $175 kW for ≥250 kW
Interconnection Incentive	up to $25,000 or 50% of interconnection cost				
Production incentive rate	$0.07/kWh @ 12 months	$0.07/kWh @ 12 months	$0.08/kWh @ 12 mos. if CHP eff ≥70% HHV	$0.08/kWh @ 12 months	$0.07/kWh @ 6, 12, & 18 months
	$1/therm @ 12 months		$0.06/kWh @ 12 mos. if CHP eff ≤60%<70% HHV		
Savings eligible for incentives	65% of kWh + 1% x each % CHP eff ≤60%<65% HHV	65% of kWh + 1% x each % CHP eff ≥60%	65% of kWh + 1% x each % CHP eff ≤60%<65% HHV	100% of kWh CHP eff ≥80% LHV	100% of kWh
	70% of kWh CHP eff ≥65% HHV		70% of kWh CHP eff ≥65% HHV	90% of kWh CHP eff ≤70%<80% LHV	
	2.5% of therms x each % CHP eff>65% HHV		2.5% of therms x each % CHP eff>65% HHV	80% of kWh CHP eff ≤60%<70% LHV	
Incentive Caps	$2,500,000 or 50% of project $2,000,000 elec, $500,000 gas	$2,000,000 or 50% of total project costs	$2,000,000 or 50% of total project costs	$500,000 or 50% of total project costs	$1.25 million design & installation $1.25 million production

To assess the impact of these incentives on a potential CHP project, we begin with the operating and financial data for a sample university as defined in Table 11.

Table 11: University Base Energy Load and Costs

Annual Operating Hours	8,760
Average Electric Demand (kW)	7585
Annual Electric Demand (kWh)	66,444,600
Average Thermal Demand (MMBtu/hr)	25
Annual Thermal Demand (MMBtu)	219,000
Annual Natural Gas Demand (therms)	2,737,500

(1) ComEd. 2017. https://www.comed.com/SiteCollectionDocuments/WaysToSave/Business/PY9_CHP_flyer_v03.pdf.
(2) Nicor Gas. 2018. https://www.nicorgasrebates.com/your-business/custom-incentive/Combined-Heat-and-Power.
(3) Illinois Department of Commerce & Economic Opportunity. 2017. https://www.illinois.gov/dceo/whyillinois/TargetIndustries/Energy/Pages/CHPprogram.aspx.
(4) Dayton Power & Light. 2018. https://www.dpandl.com/save-money/business-government/custom-rebates/chp-rebates.
(5) Baltimore Gas and Electric. 2015. http://www.bgesmartenergy.com/business/chp.
[159] *Illinois Statewide Technical Reference Manual for Energy Efficiency Version 6.0*. 2017. http://ilsagfiles.org/SAG_files/Technical_Reference_Manual/Version_6/Final/IL-TRM_Version_6.0_dated_February_8_2017_Final_Volumes_1-4_Compiled.pdf.

Average electricity price ($/kWh)	$0.072
Average natural gas price ($/MMBtu)	$3.56

A feasibility evaluation had specified a gas turbine system with a net capacity of 4,324 kW and 25.2 MMBtu/hour of useful thermal output, as the optimal technical solution for this end-user. The specifications for this CHP project are sourced from a DOE factsheet[160] and summarized in Table 12.

Table 12: CHP Specifications

Nominal Electric Power (kW)	4,600
Net Electric Power (kW)	4,324
Fuel Input (MMBtu/hr)	59.1
Useful Thermal (MMBtu/hr)	25.2
Electric Efficiency	25%
CHP System Efficiency (HHV)	67.6%
CHP System Efficiency (LHV)	74.7%
Total Installed Cost ($/kW)	2,817
CHP O&M costs ($/kWh)	$0.013

[160] U.S. DOE. *Combined Heat and Power Basics.* http://energy.gov/eere/amo/combined-heat-and-power-basics#factsheet.

Using the specified gas turbine, and in the absence of incentives, the sample university would expect an implemented CHP project to achieve the metrics outlined in Table 13.

Table 13: Energy Savings and Payback

Energy Savings	
Net electric generation (kWh)	$35,984,328
Natural Gas Boiler Savings (therms)	$2,621,430
Energy in Btus	
Fuel total CHP (mmBtu) HHV	$491,830
Net CHP generation (mmBtu)	$122,779
Useful thermal (mmBtu)	$209,714
Costs and Payback	
Annual Operating Savings	$1,046,302
Total Installed Costs	$12,180,708
Incentives	$0
Simple Payback, Years, w/o incentives	11.6
Assumptions	
CHP up-time	95%
Thermal utilization	100%
Parasitic load	6%
Existing boiler efficiency	80%
% of electricity costs saved by CHP	90%

Table 14 summarizes what kind of incentives the hypothetical University project would be eligible for under these five utility programs. Note that 70-100% of the generation would be eligible for production incentives across the various programs, based on CHP system efficiency. In addition, 6.5% of the boiler natural gas displaced by the system would be eligible for incentives under the Nicor program.

Table 14: Electricity Generation and Natural Gas Savings Eligible for Incentives

Category	**ComEd/Nicor**	**ComEd Only**	**Ilinois Energy Now**	**DP&L**	**BG&E**
Electric (%)	70.0%	72.6%	70.0%	90.0%	100.0%
Natural gas %)	6.5%	0.0%	0.0%	0.0%	0.0%
Electricity (kWh)	25,189,030	26,125,771	25,189,030	32,385,895	35,984,328
Natural gas (therms)	170,602	-	-	-	-

Before applying any program caps on total incentives, the project would be eligible for incentives of $1.9 to $4.9 million under the various programs, as depicted in Table 15. However, given the size of the potential university CHP system, the program caps would apply under some of the programs. The Illinois Energy Now program would cap the incentives at $2 million, while the BG&E program would cap the production incentive portion of the incentive, resulting in a total incentive of about $2.3 million. The

DP&L program has the lowest cap – $500,000 – but DP&L encourages customers considering larger projects (over 500 kW) to contact the utility to discuss potential incentive levels that could be higher than this cap.

Table 15: Potential Incentives under the Various CHP Programs

Category	**ComEd/Nicor**	**ComEd Only**	**Illinois Energy Now**	**DP&L**	**BG&E**
Feasibility study	$37,500	$25,000		$10,000	
Design incentive			$195,000*		$324,300
Installation/Commissioning incentive			$455,000*	$432,400	$756,700
Interconnection Incentive	$25,000	$25,000	$0	$0	
Electric production incentive	$1,763,232	$1,828,804	$1,350,000*	$67,600*	$1,250,000*
Natural gas incentive	$170,602	$0	$0	$0	$0
Incentive (calculated w/o cap)	$1,996,334	$1,878,804	$2,592,342	$3,033,272	$4,859,354
TOTAL Incentive (with caps)	$1,996,334	$1,878,804	$2,000,000	$510,000	$2,331,000

**Cap applied to this portion of the incentive.*

The impact on total project costs and simple paybacks are summarized in Table 16. The combined incentives from ComEd and Nicor and the Illinois Energy Now incentive would reduce the payback period by nearly two years, whereas if the DP&L caps were applied the incentive would only reduce the payback by about one-half year. The BG&E program would provide the greatest benefit, offsetting nearly 20% of installation costs and reducing the payback period by over two years. Again, other rules and requirements may apply and utilities (as DP&L suggests) may negotiate different incentive levels in individual situations.

Table 16: Cost Reductions from Incentives

Category	**ComEd/Nicor**	**ComEd Only**	**Illinois Energy Now**	**DP&L**	**BG&E**
Installed Cost with incentive	$10,184,374	$10,301,904	$10,180,708	$11,670,708	$9,849,708
% of Project Offset	16.40%	15.40%	16.40%	4.20%	19.10%
Simple Payback (in years) w/o incentive	11.6	11.6	11.6	11.6	11.6
Simple Payback (in years) w/incentive	9.7	9.8	9.7	11.2	9.4
Reduction in Payback (in years)	1.9	1.8	1.9	0.5	2.2

9.2 Impact of Standby Rates

Using data from nine Michigan CHP project evaluations, completed by the Energy Resources Center from 2014 to 2017 to support potential new projects, project partners were able to model the effects of standby rate changes on system payback for each of the projects, as identified in Table 17 by their corresponding utility, market sector, estimated capacity, and estimated system payback. While two of these sites are viewed as economically viable under existing conditions (Consumers Casino and Consumers University), none of these nine sites are currently proceeding with a CHP installation. We consider economic viability to include a payback period of less than 10 years for the public and institutional sectors and less than 4 years for the private sector.

Table 17: Michigan Site Screening Results for CHP

Site	Utility	Capacity	Base Case Payback (years)
Office Building	DTE	613 kW	21.1
Waste Water Plant	Consumers	1,000 kW	14.4
Casino	DTE	600 kW	12.5
Waste Water Plant	DTE	9,800 kW	11.3
Auto Mfg.	DTE	9,400 kW	6.9
Metals Mfg.	DTE	9,000 kW	6.5
Food Mfg.	DTE	7,000 kW	6.2
University	Consumers	3,000 kW	5.3
Casino	Consumers	600 kW	3.5

Current standby rates are unfavorable to the financial viability of CHP applications in Michigan. Project partners used an avoided rate model to analyze the financial effects that standby rates have on CHP system payback. The concept of avoided rate evaluates the financial impacts of standby rates on distributed generation systems by comparing the per kilowatt-hour (kWh) cost of full-requirements customers to that of standby customers. Ideally, a decrease in electricity purchased from the utility would be commensurate with a decrease in monthly electric costs. However, many standby rates are created such that they increase capacity demand charges when a customer decreases energy consumption, thus negating much of the expected savings.

The avoided rate is a percentage that reflects the relationship between the aggregate cost of a kWh before and after CHP implementation. An avoided rate of 70% means that the savings for each kWh generated on-site will only equal 70% of the utility's aggregate kWh price. According to the EPA, avoided rates above 90% are not considered a significant barrier to CHP implementation. [161] With an avoided rate of 100%, standby rates are not considered a barrier at all.

Project partners have calculated that the standby rates of DTE Energy create avoided rates that range from 70% to 77%, while the avoided rates of Consumers Energy range from 81%-86%. These are both

[161] Regulatory Assistance Project. Prepared for the U.S. EPA. Office of Atmospheric Programs, Climate Protection Partnerships Division. 2009. *Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs*. https://www.epa.gov/sites/production/files/2015-10/documents/standby_rates.pdf.

considered major barriers to CHP implementation and significantly increase project payback periods as illustrated in **Figure 15**.

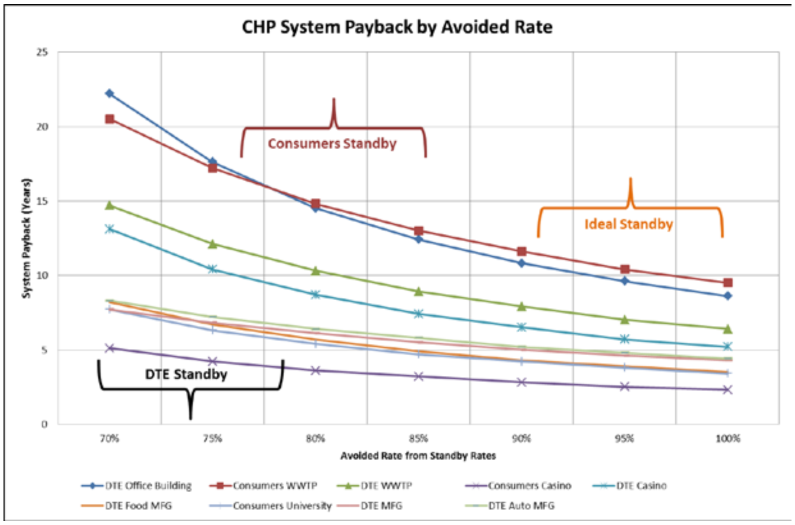

Figure 15: CHP System Payback by Avoided Rate

Project partners modeled the effects of standby rate improvement on system payback for each site, as depicted in **Figure 16**. Under ideal standby rates all sites would experience paybacks under ten years with a majority having paybacks less than five years. Compared to status quo, this change causes an additional two sites to become economically viable (Consumers Waste Water Plant and DTE WWP) while three sites are on the cusp of viability (DTE Food MFG, DTE MFG, DTE Auto MFG).

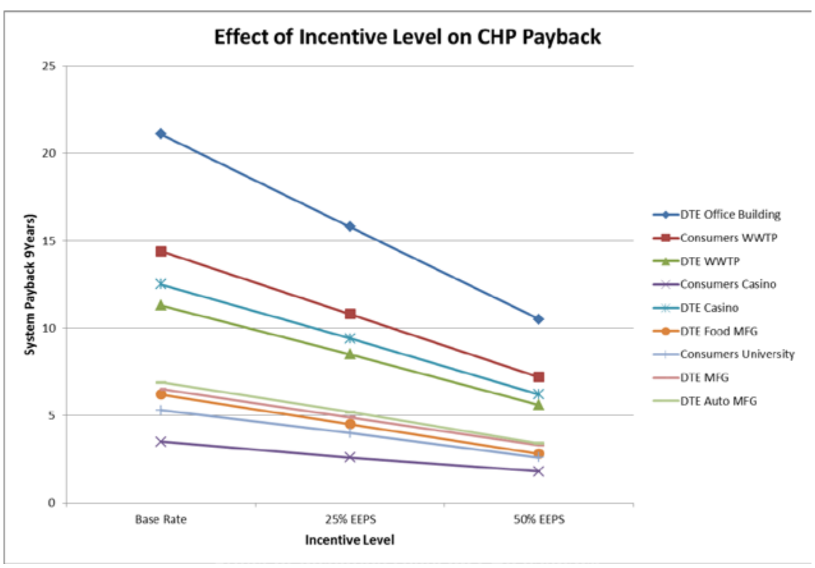

Figure 16: CHP System Payback by Incentive Level

Project partners also modeled the effects of EWR incentives (offered in the form of rebates) on system payback. Two levels were analyzed, 25% of installed costs and 50% of installed costs. Under a 25%

incentive level, one additional site becomes economically viable (DTE WWP), bringing the total to three viable projects. Under a 50% incentive an additional four sites become economically viable (Consumers WWP, DTE Food MFG, DTE MFG, DTE Auto MFG), bringing the total to six.

When both measures are implemented, eight of the nine sites become economically viable. Table 18 shows the revised system paybacks under each scenario. It is important to note that the one site not achieving economic viability was an office building located within DTE Energy's territory. Though the "Commercial Buildings" category contains 718 MW of CHP potential according to DOE estimates, most of this potential is very unlikely to be realized as these facilities do not operate enough hours per year or do not have large enough total energy requirements for CHP to be a reasonable economic fit.

Table 18: CHP Payback by Avoided Rate and Incentive Levels

Site	Utility	Capacity	Base Case Payback (years)	Ideal Standby Payback (Years)	Ideal Standby + 25% Incentive	Ideal Standby + 50% Incentive
Office Building	DTE	613 kW	21.1	8.6	6.5	4.3
Waste Water Plant	Consumers	1,000 kW	14.4	9.5	7.1	4.7
Casino	DTE	600 kW	12.5	5.2	3.9	2.6
Waste Water Plant	DTE	9,800 kW	11.3	6.4	4.8	3.2
Auto Mfg.	DTE	9,400 kW	6.9	4.4	3.3	2.2
Metals Mfg.	DTE	9,000 kW	6.5	4.3	3.2	2.1
Food Mfg.	DTE	7,000 kW	6.2	3.8	2.9	1.9
University	Consumers	3,000 kW	5.3	3.4	2.6	1.7
Casino	Consumers	600 kW	3.5	2.3	1.7	1.1

Attachments

List of Attachments

A. Property Assessed Clean Energy (PACE) Overview
B. Michigan CHP Directory of Supply/Value Chain Participants
C. CHP Survey and Interview Responses
D. STEER Results - EIA 2016 Annual Energy Outlook Reference Case w/ renewables
E. STEER Results - EIA 2016 Annual Energy Outlook Reference Case w/o renewables
F. STEER Results - EIA 2016 Annual Energy Outlook High Resource Case w/ renewables
G. STEER Results - EIA 2016 Annual Energy Outlook High Resource Case w/o renewables
H. STEER Results - EIA 2016 Annual Energy Outlook Low Resource Case w/ renewables
I. STEER Results - EIA 2016 Annual Energy Outlook Low Resource Case w/o renewables
J. STEER Results – Resilience Values and EIA 2016 Annual Energy Outlook Reference Case w/ renewables
K. STEER Results – Standby Rates and EIA 2016 Annual Energy Outlook Reference Case w/ renewables
L. Sample Standby Tariffs – Consumers Energy Rate GSG-2 and DTE Energy Rider 3

CATERPILLAR®

Press Release

For Worldwide Release: September 1, 2021
Release Number: EEPR1421

Caterpillar to Offer Power Solutions Operating on 100% Hydrogen to Customers in 2021

Commercial introduction of Cat® generator sets capable of 25% hydrogen blends to also commence later this year.

DEERFIELD, IL – Caterpillar Inc. today announced that the company will begin offering Cat® generator sets capable of operating on 100% hydrogen, including fully renewable green hydrogen, on a designed-to-order basis in the fourth quarter of 2021. Additionally, later this year Caterpillar will launch commercially available power generation solutions from 400 kW to 4.5 MW that can be configured to operate on natural gas blended with up to 25% hydrogen.

These market-focused innovations leverage power generation projects currently operating on natural gas blended with up to 80% hydrogen to help address customers' carbon-reduction goals with high-performing, cost-effective technologies that demonstrate the near-term viability of hydrogen as a fuel source. Building on 35 years of experience across multiple end markets, Caterpillar continues to improve the performance of hydrogen-fueled power technologies with minimal impacts on maintenance costs and schedules, availability and operations.

"The power solutions landscape is transforming as customers look to maximize the environmental and economic benefits of reducing their carbon intensities," said Bart Myers, general manager for Caterpillar Large Electric Power. "We're extending our leadership through numerous initiatives that demonstrate the viability of power solutions that can utilize many types of hydrogen, including fully renewable, in order to shorten the path to commercial availability."

New Caterpillar Hydrogen Fuel-Capable Electric Power Offerings

In the fourth quarter of 2021, Caterpillar will begin offering the Cat G3516H gas generator set specifically configured to use 100% hydrogen for fuel. Initially available as demonstrator units in North America and Europe with initial deliveries in late 2022, the Cat G3516H generator set will be offered with a rating of 1250 kW for 50 or 60 Hz continuous, prime, and load management applications.

Later this year, Caterpillar will also begin a staged roll-out of commercially available Cat CG132B, CG170B, G3500H, G3500 with Fast Response, and CG260 gas generator sets configured to enable operation on natural gas blended with up to 25% hydrogen for continuous, prime, and load management applications in North America and Europe. Additionally, the company will offer retrofit kits that provide hydrogen blending capabilities up to 25% hydrogen for select generator sets built on these engine platforms. Production of new natural gas generator sets and retrofit kits capable of 25% hydrogen will begin in the fourth quarter of 2022.

Plans for operating on 100% hydrogen include developing a range of commercially available products and upgrades for existing Cat gas generators. The development and launch of these solutions address potential customer demand growth as the hydrogen supply infrastructure matures, and these initiatives demonstrate Caterpillar's comprehensive, wide-ranging commitment to helping customers meet their climate-related objectives.

Caterpillar's Leadership in Sustainability

Caterpillar's hydrogen-capable reciprocating engines, gas turbines and renewable green hydrogen fuel cell projects are the latest examples of the company's commitment to power solutions that help customers utilize more sustainable energy sources:

- Solar® Turbines' gas turbines have run on high hydrogen blends for decades and are capable of operating on 100% hydrogen today. Solar has a large installed base of high hydrogen blend gas turbines.
- Caterpillar's hybrid energy solutions technology suite includes photovoltaic (PV) solar modules, bi-directional power (BDP) inverters, energy storage system (ESS) modules, advanced microgrid controllers and full digital monitoring.
- Cat cogeneration combined heat and power (CHP) systems simultaneously provide power for electrical loads as well as high-efficiency heating and cooling.

- Cat generator sets can be configured to operate on numerous biogas fuels, including fermentation biogas, landfill gas, and wastewater biogas.
- Cat diesel-fueled power solutions have enabled operation on various hydrotreated vegetable oil (HVO) fuel products for more than a decade, including a system for Microsoft data centers in Sweden that will use a co-processed synthetic diesel fuel containing more than 50% renewable raw materials.
- Caterpillar and Certarus Ltd. announced in April a memorandum of understanding to explore opportunities for bringing lower-carbon energy solutions to their combined customer base. The companies will work together to advance the use of lower-carbon fuels including hydrogen, as well as conventional and renewable natural gas.

These initiatives illustrate Caterpillar's contribution to a reduced-carbon future through a continued investment in new products, technologies and services. Caterpillar helps customers achieve their climate-related goals by providing products that facilitate fuel transition, increased operational efficiency and reduced emissions. In addition to enabling the increased use of reduced-carbon fuels, Caterpillar's advanced power innovations include a battery-powered switcher locomotive and underground loader, battery-powered construction machines, electric and hybrid powertrains, and microgrids.

Caterpillar delivers innovative power systems engineered for exceptional durability, reliability and value. The company offers worldwide product support, with parts and service available globally through the Cat authorized service and dealer network. In addition, dealer technicians are trained to service every aspect of Cat equipment.

For more information, visit www.cat.com/sustainablepower or e-mail Electric_Power@cat.com.

# # #

About Caterpillar

Since 1925, Caterpillar Inc. has been helping our customers build a better world – making sustainable progress possible and driving positive change on every continent. With 2020 sales and revenues of $41.7 billion, Caterpillar is the world's leading manufacturer of construction and mining equipment, diesel and natural gas engines, industrial gas turbines and diesel-electric locomotives. Services offered throughout the product life cycle, cutting-edge technology and decades of product expertise set Caterpillar apart, providing exceptional value to help our customers succeed. The company principally operates through three primary segments - Construction Industries, Resource Industries and Energy & Transportation - and provides financing and related services through its Financial Products segment. For more information, visit caterpillar.com. To connect on social media, visit caterpillar.com/social-media.

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Download here or contact Bob Chase at bchase@gelia.com

Hydrogen-fueled Cat® power solutions	

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Question:

1. Please describe how front-of-the-meter ("FTM") cogeneration/combined heat and power ("CHP") applications were considered in the Company's integrated resource planning process.

a. If FTM CHP applications were considered, please list the configurations considered including size/nameplate capacity and prime mover type(s)?

b. If FTM CHP applications were considered, were they considered during an initial screening phase?

i. If so, please describe the FTM CHP applications that were considered during an initial screening phase.
ii. Please describe the results of such screening.
iii. If not, please provide an explanation why FTM CHP applications were not considered during an initial screening phase.

c. Were any FTM CHP applications modeled and evaluated beyond an initial screen?

i. If so, please describe the FTM CHP applications that were evaluated.
ii. Please describe the results of such evaluation.
iii. If not, please provide an explanation why FTM CHP applications were not modeled and evaluated beyond an initial screen.

Response:

a. As part of the initial screening process for prospective gas-fired generation technologies, a 2x1 Combined Heat and Power (CHP) Plant was investigated. The proposed CHP plant consists of two (2) GE LM6000 aeroderivative DLE (50) Spirit gas turbines with evaporative cooling and generators, two (2) - two-pressure heat recovery steam generators, one (1) condensing steam turbine with high-pressure and low-pressure rotor sections and a generator, as well as a mechanical draft (wet) cooling tower.

   The proposed CHP plant is equipped with a high-pressure extraction and is capable of providing process steam with an energy flow of 65.79 MBtu/h. The plant's estimated summer time capacity is 114 MW, with a corresponding heat rate of 7,323 Btu/kWh. The 2021 overnight cost, in 2017 real dollars, is $1,507/kW.

b. Yes.
   i. Please see the response to part (a).
   ii. The CHP technologies were not selected in the initial screening phase.
   iii. N/A
c. No.
   i. N/A

ii. Combined heat and power resources were thoroughly investigated. Costs of these installations can be highly variable and site-specific. Furthermore, capital, and fixed operating and maintenance costs for CHP were identified at values significantly higher than all other natural gas technologies considered. For these reasons, the CHP was not selected past the initial screening phase.

iii. Please see the response to the above part (c)(ii).

Sara T. Walz

Sara T Walz
August 26, 2021

Electric Supply Planning

U21090-MEIBC-CE-132

Question:

2. Please describe how behind-the-meter ("BTM") cogeneration/combined heat and power ("CHP") applications were considered in the Company's integrated resource planning process.

a. If BTM CHP applications were considered, please list the configurations considered including size/nameplate capacity and prime mover type(s)?

b. If BTM CHP applications were considered, were they considered during an initial screening phase?

i. If so, please describe the BTM CHP applications that were considered during an initial screening phase.
ii. Please describe the results of such screening.
iii. If not, please provide an explanation why BTM CHP applications were not considered during an initial screening phase.

c. Were any BTM CHP applications modeled and evaluated beyond an initial screen?

i. If so, please describe the BTM CHP applications that were evaluated.
ii. Please describe the results of such evaluation.
iii. If not, please provide an explanation why BTM CHP applications were not modeled and evaluated beyond an initial screen.

Response:

1. No behind-the-meter combined heat and power options were considered in the IRP model.
    a. N/A
    b. N/A
        i. N/A
        ii. N/A
        iii. While the resource screening is a highly comprehensive process, not all technologies are included. In this IRP, front-of-the meter CHP technology was considered.
    c. No.
        i. N/A
        ii. N/A
        iii. Please see the response to part (b)(iii).

Sara T. Walz

Sara T Walz
August 26, 2021

Electric Supply Planning

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MEMO

TO: Michigan Energy Innovation Business Council

FROM: Laura Chappelle & Tim Lundgren, Varnum LLP

RE: Distributed Generation and Electric Interconnection

DATE: March 5, 2020

I. Executive Summary

At recent Senate Energy and Technology Committee ("Committee") hearings, questions have arisen regarding whether there is clear state statutory authority requiring electric interconnection ("interconnection") of residential and commercial solar systems (<100 kW). In part, the Committee received testimony on March 3, 2020, from Peninsula Solar, stating that when the solar Distributed Generation ("DG") cap[1] was reached in Upper Peninsula Power Company's ("UPPCO") service territory, the utility denied all interconnection applications until the cap was increased in a subsequent Michigan Public Service Commission ("MPSC" or the "Commission") electric rate case settlement (Case No. U-20350).

You have asked whether state law specifically requires an interconnection within the DG statutory requirements or otherwise once the DG cap is met. To answer this question, we conducted a legal review and analysis of current federal and state statutes and regulations. Our analysis found that there are no state statutes in Michigan which specifically require investor-owned utilities to interconnect residential and small commercial solar systems (<100 kW) to the utility grid once the distributed generation cap for that utility is reached. Interconnection of these systems may be required under federal law (i.e., PURPA[2]), but this has not yet been legally tested in Michigan, as no MPSC complaint case has been brought by a customer denied interconnection (e.g., in UPPCO's territory after the initial residential solar cap was reached in 2016). Highlights of our findings include the following:

- There has been no comprehensive review by the Legislature of the interconnection statutory requirements, despite interconnection having been addressed in several specific regulatory categories on occasion. It appears this has resulted in a regulatory gap now being potentially faced by customers who wish to interconnect once the utilities have met their net metering/DG caps.

- "Self-service" customers with on-site generators are, by definition, not interconnected with the grid, so their relationship to the utility is different than

[1] MCL 460.1173(3).
[2] The Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 824a-3; MCL 460.6v ("PURPA").

that of a net metering/DG customer with an interconnected generator. Under Michigan's law, a customer can always install a solar system for "self-service" if the customer is not grid connected.

- The merchant generation statute guaranteeing interconnection only applies to generators larger than 100 kW in size. Smaller generators would need to access the interconnection standards under another regulatory category (e.g., the DG program).

- Under current MPSC rules, a utility must provide notice to the MPSC and its customers when the cap is reached and that its DG program is closed and that no new applications will be accepted. The language of the rule is mandatory ("the electric provider … **shall** provide notice…"). A utility may voluntarily obligate itself to do additional interconnections, but customers may not then be able to rely on the protections of the timelines and expense limitations provided by the existing rules.

- Customers can likely obtain and use PURPA QF status with the Federal Energy Regulatory Commission ("FERC") to gain access to the MPSC's interconnection rules, but, to our knowledge, this has not yet been used to provide interconnection access in Michigan for small solar systems. Additionally, this will not ensure that customers are able to be fairly paid for power sent to the grid, in the same way the DG program does.

- While some utilities have apparently given verbal assurances that DG systems will continue to be interconnected once the statutory DG cap is met, such as those provided in recent testimony before the Senate Energy and Technology Committee,[3] we have found nothing in state law or Commission orders that would require such interconnections.

II. Introduction

Recent concerns about Consumers Energy Company ("Consumers Energy"), UPPCO, DTE Electric Company ("DTE Electric"), and other electric utilities hitting their statutory caps[4] for residential and commercial solar in their net metering/DG programs have raised two particular questions: (1) whether customers will be able to continue to install and interconnect their home and small commercial solar systems once the cap is reached, and if so, under what terms, and (2) what rate would be paid for excess power sent to the utility under those circumstances, assuming customers were still allowed to interconnect.

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[3] Video available at: https://misenate.viebit.com/player.php?hash=AkTDMtmQhY66

[4] Section 173(3) of 2016 PA 342 provides, in part, that: "(3) An electric utility or alternative electric supplier is not required to allow for a distributed generation program that is greater than 1% of its average in-state peak load for the preceding 5 calendar years. The electric utility or alternative electric supplier shall notify the commission if its distributed generation program reaches the 1% limit under this subsection. . . "

This memo provides a high-level review of the current electric interconnection regulations and how those might apply to net metering/DG customers after the cap is met. The memo also examines possible rate impacts for customers interested in the DG program once the solar DG caps are met. The first section below addresses the regulations, in general, applying to interconnection, and the second section addresses what rate might apply for power delivered to the utility once the DG cap has been met.

A. Interconnection

With respect to interconnection, the major concerns customers traditionally face are the willingness of the utility to interconnect, the timeliness of utility responses during the process, and the costs of the interconnection. All of these concerns are addressed by the Commission's current interconnection standards. The development of those standards is discussed briefly below, as is a cursory review of how they apply to customers who have various types of on-site generation – in the context of each regulatory category.

As discussed below, it appears that once the net metering/DG cap is reached, only the federal PURPA law offers a certain path to interconnection rights for small renewable projects. Although the PURPA law applies to all of the states, in 2016, the Michigan Legislature affirmatively adopted the law's protections into state law. *See* MCL 460.6v.

1. <u>Self-Service Power</u>

As a clarifying matter, we should distinguish this category from the start. Utility customers have a right to self-generate that is probably inherent and needs no specific legislative grant, but in any event is reinforced in two places by statute: MCL 460.10a(4) and MCL 460.1185. The latter of these only applies to industrial customers. The former applies to residential and small commercial customers as well, and states in relevant part:

> This act does not prohibit or limit the right of a person to obtain self-service power and does not impose a transition, implementation, exit fee, or any other similar charge on self-service power. A person using self-service power is not an electric supplier, electric utility, or a person conducting an electric utility business. As used in this subsection, "self-service power" means any of the following: (a) Electricity generated and consumed at an industrial site or contiguous industrial site or single commercial establishment or single residence without the use of an electric utility's transmission and distribution system. [MCL 460.10a(4)(a)]

Thus, <u>the statute requires that the generator is not interconnected with the grid</u> (it does not rely on utility transmission or distribution lines) and purely serves the load behind the meter ("generated and consumed at … [a] single commercial establishment or single residence"). Thus, by definition, it cannot be fed back to the grid, nor can it be distributed to another site. This is, therefore, a different kind of installation and relationship with the grid for the homeowner than a DG installation would be and raises different technical and economic challenges and issues. It is not a simple substitute.

The "self-service" provision was passed as part of the Customer Choice and Electricity Reliability Act, PA 141 of 2000, where it was intended to clarify that by allowing customers to shop for their electric power from third-party suppliers (Alternative Electric Suppliers)[5] the Legislature did not intend to also restrict those customers' ability to supply their own power, if they so choose.

2. Merchant Generation

Another statutory provision added by PA 141 of 2000 in an effort to spur competition in Michigan's electric market was MCL 460.10e, which ensured that merchant plants would be interconnected by the utilities in a timely manner. A "merchant plant" is defined in MCL 460.10g(e) as an in-state, non-utility generator with a capacity of more than 100 kW. While this provision addresses projects too large to apply to the categories of concern here, it is nevertheless of interest because it drove the creation of the MPSC's interconnection rules, as discussed below.

The MPSC's Interconnection and Net Metering Standards ("Interconnection Standards"), R 460.601a – R 460.656, were first promulgated in response to the requirement in MCL 460.10e that reads as follows:

> (1) An electric utility shall take all necessary steps to ensure that merchant plants are connected to the transmission and distribution systems within their operational control. If the commission finds, after notice and hearing, that an electric utility has prevented or unduly delayed the ability of the plant to connect to the facilities of the utility, the commission shall order remedies designed to make whole the merchant plant, including, but not limited to, reasonable attorney fees. The commission may also order fines of not more than $50,000.00 per day that the electric utility is in violation of this subsection.
>
> (2) A merchant plant may sell its capacity to alternative electric suppliers, electric utilities, municipal electric utilities, retail customers, or other persons. A merchant plant making sales to retail customers is an alternative electric supplier and shall obtain a license under section 10(2).
>
> (3) The commission shall establish standards for the interconnection of merchant plants with the transmission and distribution systems of electric utilities. The standards shall not require an electric utility to interconnect with generating facilities with a capacity of less than 100 kilowatts for parallel operations. The standards shall be consistent with generally accepted industry practices and guidelines and shall be established to ensure the reliability of electric service and the safety of customers, utility

[5] This pre-dated the imposition of the 10% market cap that was imposed in 2008 on the Electric Choice market.

> employees, and the general public. The merchant plant will be responsible for all costs associated with the interconnection unless the commission has otherwise allocated the costs and provided for cost recovery.
> (4) this section does not apply to interconnections or transaction that are subject to the jurisdiction of the federal energy regulatory commission.

In 2001, the Commission made the following observations about this Section 10e when it began the process of promulgating new interconnection standards in response to Section 10e(3).

> Section 10e was enacted, in part, in response to concern that the interconnection process could be manipulated to impede competitors trying to enter the generation market. <u>The Commission fully endorses the Legislature's policy determination that the interconnection process should not constitute a barrier to market entry</u>.[6]

Later in that same Order, the Commission examined the timelines under which interconnections were being made in the absence of Commission-established standards, and observed:

> The Commission <u>finds that the concern expressed by developers regarding the existing procedures has merit</u>. Section 10e(1) of Act 141 empowers the Commission to sanction interconnections that are "unduly delayed." Without more definite standards regarding the time that a utility may take to process an application, <u>project developers will continue to face uncertainties and delays</u> that could frustrate development of a competitive market in this state. Accordingly, the Commission agrees with the Staff that standards should be adopted for the processing of applications that expedite the review process, provide greater certainty to developers, and take into account the varying sizes and complexities of merchant plants.[7]

In a follow-on Order issued on March 26, 2003, the Commission elaborated on its concerns about utility delays and indefinite timelines:

> The Commission agrees with the commenting parties that the entire interconnection process, from the filing of the application to the physical interconnection with the utility's system, should be subject to definite time deadlines, with specific periods provided for meeting major milestones. <u>The Commission will not permit utilities to set open-ended timeframes that invite delay. Each utility should be accountable for missed deadlines that are not attributable to the applicant</u>.[8]

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[6] February 5, 2001 Order in Case No. U-12485, p. 6 (emphasis added).
[7] *Id.*, p. 10 (emphasis added).
[8] March 26, 2003 Order and Notice of Hearing in Case Nos. U-12485 and 13745, p. 10 (emphasis added).

It is thus plain that the Commission's Interconnection Standards were first established in the early 2000s in response to the statutory directive that merchant plants be interconnected to the utility without undue delay, and that the Commission shared the Legislature's concerns about utility delays and indefinite timelines that developers were then experiencing in the absence of such rules.

3. Net Metering/DG

The initial interconnection rules established in 2003 were revised in 2009 to accommodate the net metering program required under the Clean and Renewable Energy and Waste Reduction Act, PA 295 of 2008, which was itself subsequently amended in 2016, resulting in the current "distributed generation" program. The size of an "eligible electric generator" is limited to 150 kW at a single site.[9] Many of the key provisions can be found at MCL 460.1173, including requirements for "[s]tatewide uniform interconnection requirements for all eligible electric generators. … designed to protect electric utility workers and equipment and the general public."[10] The MPSC is in the process of updating its interconnection rules,[11] but in the meantime, the current rules remain in effect and controlling.

Under the current MPSC rules, if a utility reaches the program cap, it must provide notice to the MPSC and its customers that its program is closed and that no new applications will be accepted. See Rule 44 (R 460.644). The language used there is mandatory ("the electric provider … **shall** provide notice…"). Presumably, a utility can voluntarily obligate itself to do additional interconnections, but, as noted above, under such circumstances, customers may not be able to rely on the protections of the timelines and expense limitations provided by the existing rules.

As discussed further below, in its rate case filed on February 27, 2020 (U-20697), Consumers Energy has suggested that customers could be interconnected as PURPA QFs.

4. PURPA Qualifying Facilities

PURPA grants certain rights to certain renewable and highly efficient facilities that are able to meet certain criteria – these are known as "Qualifying Facilities" or "QFs." Among the rights granted under the FERC's rules are a right to interconnect with the local utility: "any electric utility shall make such interconnection with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart. The obligation to pay for any interconnection costs shall be determined in accordance with § 292.306." 18 CFR 292.303(c). FERC's rules explicitly assign to the State the task of determining how the obligations to pay interconnection costs are to be assigned. See 18 CFR 292.306. What PURPA does not do is to mandate the setting of specific timelines by the State, which is left to the State to implement. Michigan has handled PURPA QF interconnection through the same interconnection standards that it handles merchant plants and distributed generation. Being certified as a QF (which is

[9] See MCL 460.1005(b).
[10] MCL 460.1173(6)(a)
[11] See https://www.michigan.gov/mpsc/0,9535,7-395-93307_93312_93320_94834-482690--,00.html

relatively simple[12]) can thus provide another means to require the utility to interconnect a project under existing rules.

5. Terms of Interconnection

Before moving on to discuss rates, we should note that net metering/DG customers have some benefits – as required by the Legislature -- in their terms of interconnection that other customers do not have. Thus, once the program cap is met, those rules that apply only to net metering/DG customers will not apply to other similar customers of the same size who are outside of the cap. We have not done an exhaustive review of the various rules to determine all the differences between the sets of rules that might apply, but there appear to be some shortened timelines under the net metering rules of which customers would lose the benefit. If a customer is able to interconnect as a PURPA QF after the cap is reached, costs and fees would appear to remain approximately the same for Category 1 projects (those of 20 kW or less), while Categories 2 and 3 projects (*i.e.*, those between 20 kW and 150 kW, and methane digesters greater than 150 kW but not more than 550 kW, respectively) would face potential cost increases for interconnection due to an increase in the application fee costs, and an increased obligation to pay for utility testing and inspection.[13] So, even if such customers were able to effectively gain access to the interconnection rules via PURPA, in doing so they lose some of the benefits the Legislature granted to net metering /DG customers.

B. Rates for Purchases

Once interconnected, the customer must consider the rate that the utility will pay for energy provided to the utility through the interconnection. Once the cap is exceeded, the utility no longer is obligated to pay under the net metering or DG tariff, as the case may be. As Mike Byrne, COO of the Commission, testified on March 3, 2020, the Commission determined a cost-of-service based outflow credit rate for DG customers in the DTE rate case last year.[14] In their February 25, 2020 testimony before the Senate Energy and Technology Committee, both Brandon Hofmeister, Senior VP of Governmental, Regulatory and Public Affairs for CMS Energy Corporation and Consumers Energy Company, and Renze Hoeksema, VP of Corporate and Governmental Affairs for DTE Energy, stated that their companies would continue to purchase power from customers who wanted to install solar projects and interconnect them after the caps had been exceeded for their respective companies. Mr. Hofmeister stated that Consumers proposed to do so at the customer's choice of either the latest competitive bid price for solar, or the MISO wholesale energy market price.[15] Mr. Hoeksema simply stated that a rate would have to be set that would reflect the proper costs and benefits, and noted that DTE believes that the current inflow/outflow model is inequitable because, in his opinion, it both underpays the utility for the customer's use of the grid, and overpays the customer for the energy provided. On further questioning, Mr. Hoeksema also admitted that before any rate could be put

[12] See: https://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp
[13] See the fee chart in MPSC's interconnection rules, at R 460.618, Rule 18.
[14] DTE Electric Company, Case No. U-20162, dated May 2, 2019.
[15] As discussed below, Consumers' filed tariff does not provide such a choice, but only the market rate.

into place to pay such customers, it would have to be reviewed and approved by the Commission.

In its rate case filed on February 27, 2020 (U-20697), Consumers Energy has suggested that customers could be interconnected as PURPA QFs, and is proposing tariff modifications to enable the utility to pay such customers the real-time market (LMP) MISO energy price for the power delivered. This is a rate well below that offered to current net metering/DG customers. It is also a controversial rate that has been criticized by intervening parties in MPSC PURPA cases, and is also criticized as part of FERC Commissioner Richard Glick's dissent in the current FERC PURPA NOPR.[16] If the Commission approves these tariff changes, then it is also worth noting that Consumers has proposed in its tariff that the utility "has the right to refuse to contract for the purchase of energy," and so can refuse to contract with any customer. Such a proposal is not consistent with Consumers' current obligations under the settlement agreement in U-20165, where it must give a contract to all QFs at or below 150 kW.

III. Summary and Conclusion

Up until 2000, customers seeking to interconnect with the utility had no statutory or regulatory right to do so under Michigan law that we are aware of. They had to negotiate such interconnections with the utilities, leading to complaints over uncertain timelines and delays. In 2003, under the authority of MCL 460.10e, the MPSC promulgated interconnection rules for merchant plants that were later expanded to include rules for net metering/DG customers. These rules have also been applied to PURPA QF projects seeking interconnection. The interconnection rules are currently under review at the MPSC and will undergo a new rulemaking process in order to be updated following the 2016 Acts 341 and 342.

Meanwhile, there has not been a comprehensive review by the Legislature of the interconnection statutory requirements, despite interconnection having been addressed in several specific regulatory categories on occasion. It appears this has resulted in a regulatory gap now being potentially faced by customers who wish to interconnect once the utilities have met their net metering/DG caps.

Once the net metering/DG cap is exceeded and customers are no longer eligible to access the interconnection rules under those provisions, the only other category which might apply to projects of that size is a PURPA QF. While being a PURPA QF may allow access to the benefits of the interconnection rules, customers would lose the timeline and price requirements of the net metering/DG program, and would be subject to a new pricing mechanism, which would need to be approved by the Commission.

[16] Dissent in Part of Commissioner Richard Glick Regarding FERC's Notice of Proposed Rulemaking to Update PURPA Regulations, Docket Nos. RM19-15-000, AD16-16-000, dated September 19, 2019. https://www.ferc.gov/media/statements-speeches/glick/2019/09-19-19-glick-E-1.asp#.XmEqtiFKi71

There is at present no clear tariff rate structure that would apply to DG/net metering customers seeking to interconnect after the cap is exceeded. Consumers Energy has now proposed a new tariff based on moving these customers to PURPA and a MISO market energy rate. DTE would have to seek a similar new rate structure which will have to be approved first through a 10-month MPSC proceeding. This means that the time and expense of an administrative rate case before the MPSC pursuant to the Michigan Administrative Procedures Act will likely be required before such customers will be able to be paid by the utility. Given this past history, and this apparent regulatory gap, it is not unreasonable, therefore, for customers to have concerns that mere general verbal assurances from utility executives that DG systems will continue to be interconnected, such as those provided in recent testimony before the Senate Energy and Technology Committee,[17] may not be sufficient to ensure timely interconnection under reasonable terms once the cap has been exceeded, and payment of a reasonable rate for power delivered to the utility.

[17] Video available at: https://misenate.viebit.com/player.php?hash=AkTDMtmQhY66

Question:

13. Please see the testimony of Keith Troyer.
a. Please detail what options the Company gave to customers who submitted applications for the DG program when the DG program cap was reached and the Company notified the Commission that the program was full in November 2020.
i. Please provide sample emails (appropriately redacted) to customers describing those options.
b. Please describe what tariff or program options would be available for customers who wish to install rooftop solar in Consumers' territory once the new 2% cap is reached.
i. Please describe in detail how these future tariff or program options are currently communicated to customers.
ii. Please describe in detail how the Company plans to communicate these tariff or program options to customers once the new 2% cap is reached.

Response:

a. Consumers Energy posted the message below on both the residential and business versions of the renewable energy and net metering pages:

> "**Net Metering Reaches Capacity:** Consumers Energy **stopped accepting** new applications for its net metering program on Nov. 19, 2020. To learn more, send an email to EnergyPurchase@cmsenergy.com."

A similar message was posted in a banner on our PowerClerk web application website and included in our application receipt email for net metering applications received in PowerClerk. A redacted version of the receipt email is provided as U21090-MEIBC-CE-143 Attachment 2. A media statement was also released on November 19, 2020 addressing the closure and is provided as U21090-MEIBC-CE-143 Attachment 3.

At that time, customers were welcome connect to our system ahead of joining our DG program as space became available depending upon their annual energy consumption and the size of their solar systems. They joined a short-term waiting list while we awaited a regulatory decision on the DG program and tariff in Case No. U-20697. Customers were also able to execute PURPA Standard Offer or "energy-only" contracts for their surplus generation during this period. A sample letter provided to Net Metering solar installers is provided as U21090-MEIBC-CE-143 Attachment 1.

b. Consumers Energy cannot predict exactly when the 2% cap will be reached or what tariff options would be available at that time. That said, the Company has PURPA Standard Offer and "energy only" tariff options in place today.

   At this time, it is premature to state how Consumers Energy will communicate options when the new 2% cap is reached.

KEITH G. TROYER
August 27, 2021

EGI Contracts & Settlements

Consumers Energy
Count on Us®

November 30, 2020

Dear Michigan solar installer,

We're writing to share important news:

We plan to consider doubling our limited distributed generation (DG) incentive program for customers who want to install rooftop solar generation in Michigan starting Jan. 1, 2021. Expanding our DG program's participation limit to 2 percent of average peak load is an exciting step on Michigan's journey to a permanent rooftop solar program.

Transitioning to a DG model requires regulatory approval. It also means our successful net metering program has reached capacity and we stopped accepting new applications on Nov. 19, 2020.

Here are answers to key questions about what the change means for your customers:

Q: How are current net metering program participants impacted?

A: We support customers who want to install rooftop solar generation and can help them connect to our system and be paid for excess energy generated.

- Existing net metering customers will transition to the DG program at the end of their 10-year commitment (if tariff approved) on Jan. 1, 2021.
- New customers who apply after Nov. 19, 2020, can still connect to our system ahead of joining our DG program as space is available depending upon their annual energy consumption and the size of their solar systems. They will join a short-term waiting list while we await a regulatory decision on the DG program and tariff.

Q: If some customers withdraw, can new applicants still enroll in the net metering program before the new DG program becomes effective?

A: No. Consumers Energy factored potential attrition into its decision to stop accepting new applications for the net metering program.

Q: When and how can customers apply for the DG program?

A: All applications received after Nov. 19, 2020 will be reviewed and considered for the DG program if and when space becomes available. In the interim, customers can continue to apply to and receive permission to interconnect their solar systems regardless of program availability or participation. Customers can apply for the DG program via PowerClerk at https://consumersenergy.powerclerk.com.

We're committed to developing solar as a key component in our Clean Energy Plan while providing our customers with maximum value for their energy dollars.

Please contact me directly at (517) 788-0363 with questions.

Sincerely,

Nicholas Tenney, PE

Distribution Agreements & Programs

Date Printed: Mon Aug 23 2021 15:17:23 GMT-0400 (Eastern Daylight Time)

Sent by: Jennifer Gardiner on 12/22/2020 at 10:48 AM
From: DoNotReply@PowerClerk.com
To: [redacted]
Reply-To Email Address:
Reply-To Display Name:
Cc: miohpa.icr@powerhome.com
Bcc:
Subject: Interconnection Application Receipt & Assignment
Attachments:

Dear [redacted]

Thank you for your interest in Interconnection.

This message is to provide notification that the **Net Metering program is now closed for new applicants**. [redacted] will still undergo review and will be considered for the available program starting January 1, 2021.

*****Please disregard if this is an existing application that was submitted before November 19, 2020.**

This email confirms that Consumers Energy has received your Interconnection application and has assigned it to the appropriate coordinators. Per your application you have agreed to mail a check in the amount of $100.00. Upon receipt of the payment, the assigned team(s) will begin reviewing your application. **If you are resubmitting this application and payment has already been received, we will begin reviewing at our earliest opportunity.** You will receive an email notification indicating the results of the review. Thank you for your patience as we complete this process.

Please mail the check and include a copy of this letter to:
Interconnection Coordinator
1945 West Parnall Road (Room P14-206)
Jackson, MI 49201

Sincerely,

Interconnection Coordinators

This is an automated email. For additional questions, please contact the appropriate program coordinator
Net Metering: net_metering@cmsenergy.com or website
Interconnecton: customergeneration@cmsenergy.com or website

Question:

10. For Category 1 (residential distributed generation systems < 20kW) of the current distributed generation program, please determine the following values. Please include all calculations to determine these values.
a. Total kW available for Category 1 under the program (given voluntary soft cap of 1% of average in-state peak load).
b. Current amount of installed/operational kW in Category 1.
c. Remaining amount of kW available for installation under Category 1 program based on total installed/operational kW (given total kW available as determined in a. and current amount of kW installed/operational in b.).
d. Remaining percentage available in the Category 1 program currently based on installed/operational distributed generation systems.
e. Current amount of kW of pending applications for Category 1.
f. Total current amount of installed/operational kW in Category 1 plus current amount of kW of pending applications for Category 1.
g. Remaining amount of kW that would be available for installation under Category 1 program given all installed/operational systems and assuming all pending applications were completed and operational.
h. Remaining percentage available in the Category 1 program given all installed/operational systems and assuming all pending applications were completed and operational.
i. Given historical trends in installations over the last five years, expected time period when the Category 1 soft cap will be reached based on:
i. Average installations per year over the five-year period.
ii. Maximum growth in installations per year from the years with the greatest growth in installations.

Response:

Consumers Energy's category 1 distributed generation participant numbers are as follows as of August 23, 2021:

- **a.** The voluntary cap of 1% of our 5-year average in-state peak load is 74,822 kW.
- **b.** There are presently 39,890 kW of active category 1 program participants.
- **c.** The remaining capacity equates to a total cap of 74,822 kW minus the 39,890 kW of space already allocated. Therefore, there is 34,932 kW of capacity available in the program.
- **d.** The calculation for the remaining percentage available for category 1 systems is similar to the answer in part c. above: the remaining capacity, 34,932 kW, divided by the total cap, 74,822 kW. Therefore, 46.7% of our voluntary cap is remaining for new category 1 program participants.
- **e.** There are 6,327 kW of pending category 1 applications.

f. The total number of pending (6,327 kW) plus active (39,890 kW) category 1 customers is 46,217 kW.

g. The remaining capacity, given all pending applicants become active, equates to a total cap of 74,822 kW minus the 46,217 kW of space that would be already allocated. There is 28,605 kW of capacity available in the program

h. The remaining percentage available for category 1 systems is calculated similar to the answer above: the remaining capacity, given all pending applicants become active, 28,605 kW, divided by the total cap, 74,822 kW. Therefore, 38.2% of our voluntary cap would be remaining for new category 1 program participants.

i. Consumers Energy does not have the data requested readily available. The Company has created an internal forecast that is currently projecting the category 1 cap to be reached in 2023.

KEITH G. TROYER
August 27, 2021

EGI Contracts & Settlements

Question:

11. For Category 2 (distributed generation systems 20kW-150kW) of the current distributed generation program, please determine the following values. Please include all calculations to determine these values.
a. Total kW available for Category 2 under the program (given voluntary soft cap of 0.5% of average in-state peak load).
b. Current amount of installed/operational kW in Category 2.
c. Remaining amount of kW available for installation under Category 2 program based on total installed/operational kW (given total kW available as determined in a. and current amount of kW installed/operational in b.).
d. Remaining percentage available in the Category 2 program currently based on installed/operational distributed generation systems.
e. Current amount of kW of pending applications for Category 2.
f. Total current amount of installed/operational kW in Category 2 plus current amount of kW of pending applications for Category 2.
g. Remaining amount of kW that would be available for installation under Category 2 program given all installed/operational systems and assuming all pending applications were completed and operational.
h. Remaining percentage available in the Category 2 program given all installed/operational systems and assuming all pending applications were completed and operational.
i. Given historical trends in installations over the last five years, expected time period when the Category 2 soft cap will be reached based on:
i. Average installations per year over the five-year period.
ii. Maximum growth in installations per year from the years with the greatest growth in installations.

Response:

Consumers Energy's Category 2 distributed generation participant numbers are as follows as of August 23, 2021:

a. The voluntary cap of 0.5% of our 5-year average in-state peak load is 37,411 kW.
b. There are presently 16,603 kW of active category 2 program participants.
c. The remaining capacity equates to a total cap of 37,411 kW minus the 16,603 kW of space already allocated. Therefore, there is 20,808 kW of capacity available in the program.
d. The calculation for the remaining percentage available for category 2 systems is similar to the answer in part c. above: the remaining capacity, 20,808 kW, divided by the total cap, 37,411 kW. Therefore, 55.6% of our voluntary cap is remaining for new category 2 program participants.
e. There are 4,042 kW of pending Category 2 applications.

f. The total number of pending (4,042 kW) plus active (16,603 kW) category 2 customers is 20,645 kW.
g. The remaining capacity, given all pending applicants become active, equates to a total cap of 37,411 kW minus the 20,645 kW of space that would be already allocated. There is 16,766 kW of capacity available in the program
h. The remaining percentage available for Category 2 systems is calculated similar to the answer above: the remaining capacity, given all pending applicants become active, 16,766 kW, divided by the total cap, 37,411 kW. Therefore, 44.8% of our voluntary cap would be remaining for new category 2 program participants.
i. Consumers Energy does not have the data requested readily available. The Company has created an internal forecast that is currently projecting the Category 1 cap to be reached in 2023.

KEITH G. TROYER
August 27, 2021

Question:

15. Please detail the number of QFs in each of the following size categories who have been awarded a contract as a result of a Company competitive solicitation process for any program (e.g., IRP, RE plan, VGP, etc):
a. Less than 20kW.
b. Greater than 20kW, up to 150 kW.
c. Greater than 150 kW, up to 500 kW.
d. Greater than 500 kW, up to 1 MW.
e. Greater than 1 MW, up to 2 MW.
f. Greater than 2 MW, up to 5 MW.
g. Greater than 5 MW, up to 10 MW.
h. Greater than 10 MW.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request to the extent it is irrelevant and overly broad. Furthermore, by seeking "any" and "all" documents, the request is not narrowly tailored and not proportional to the needs of this case. Subject to that objection, and without waiving it, the Company provides the following response:

The Company has issued two competitive solicitations, in 2019 and 2020, for IRP solar resources. The Company cannot confirm if any QFs have been awarded a contract as a result of its IRP solar competitive solicitation process; however the 30 MW Healthlands Solar, LLC project filed for Commission approval on July 6, 2021 in Case No. U-20165 from the 2020 solicitation could be registered as a QF with FERC, and the Company has offered the 10 MW remaining from the 2019 solicitation to PURPA QFs.

KEITH G. TROYER
August 27, 2021

Question:

17. Please see the testimony of Keith Troyer, pg. 23. Please describe in detail the manner in which "distributed energy resources 100 kW and larger can participate in the wholesale market" through FERC Order 2222. Specifically, please detail:
a. Existing Midcontinent Independent System Operator ("MISO") rules or proceedings which enable such participation under Federal Energy Regulatory Commission ("FERC") Order No. 2222.
b. Existing Michigan Public Service Commission ("MPSC") rules supporting this participation.
c. Any barriers to such participation that have been removed by MISO.
d. Any barriers to such participation that have been removed by the MPSC.

Response:

In September of 2020, FERC issued Order No. 2222, which requires Regional Transmission Organization ("RTOs"), like MISO, to adopt rules and procedures to enable the participation of distributed energy resources 100 kW and larger in wholesale markets. It set a summer 2021 deadline for RTOs to submit tariff revisions, but subsequently extended MISO's compliance deadline to April 2022. This means that there have been no ways in which distributed energy resources 100 kW and larger can participate in the wholesale market as a result of FERC Order No. 2222 at this time.

However, the Company's IRP covers a very long time-horizon (from now until 2040) and a final ruling by FERC on MISO's Order No. 2222 compliance filing is expected soon after the April 2022 compliance deadline, within the very early years of this IRP time-horizon. So, while FERC Order No. 2222 does not currently enable distributed energy resources 100 kW and larger to participate in the wholesale market, the above referenced testimony correctly assumes that it will in the very near future, and will cover the vast majority of the time-horizon anticipated by the Company's IRP filing (approximately 2024 – 2040).

a. MISO is using several existing processes as the basis for a framework for FERC Order No. 2222 implementation. Discussion and development of the MISO compliance filing began in 2020 and will continue until MISO's planned compliance filing submission in April 2022.

b. The State of Michigan allows for Aggregator of Retail Choice (ARC) participation. Rules for ARC participation are serving as a starting point at MISO for discussions regarding FERC Order No. 2222 implementation. Furthermore, FERC Order 841 seeks to remove participation barriers to Energy Storage Resources (ESRs) in the capacity, energy, and ancillary service markets.

c. By definition, MISO's compliance with FERC Order No. 2222 will remove barriers to participation. The latest information regarding MISO's FERC Order No. 2222 efforts can be found by attending MISO's Distributed Energy Resource Task Force Stakeholder Meetings, other related MISO stakeholder meetings and at https://www.misoenergy.org/stakeholder-engagement/committees/DERTF/.

d. MPSC Staff are actively involved in MISO's FERC Order No. 2222 efforts via the aforementioned MISO Stakeholder process. The MPSC's MISO Sector, the Organization of MISO States (OMS), has also been actively engaged in MISO's FERC Order No. 2222 compliance filing implementation efforts.

KEITH G. TROYER
August 27, 2021

EGI Contracts & Settlements

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of CONSUMERS ENERGY COMPANY for approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	)))))	**Case No. U-21090**

TESTIMONY OF EDWARD BURGESS

ON BEHALF OF

THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,

INSTITUTE FOR ENERGY INNOVATION,

AND

CLEAN GRID ALLIANCE

TABLE OF CONTENTS

I. <u>Summary of Findings and Recommendations</u>

Q. Please provide a summary of your testimony.

A. My testimony examines Consumers Energy Company's ("Consumers" or the "Company") Integrated Resource Plan ("IRP") with a particular focus on the role of energy storage. I analyze the key drivers that led to Consumers' decision about whether or not to include new energy storage resources over the next 10 years and discuss its reasonableness. I critique Consumers' recent solicitation process that focused solely on existing gas resources, and I discuss the Company's modeling choices that likely contributed to the absence of energy storage from its Proposed Course of Action ("PCA") for nearly a decade.

Q. Please provide a summary of your key findings.

A. My key findings are summarized as follows:

(1) Consumers' recent unilateral gas procurement decisions significantly disadvantaged other competitive resource options including energy storage.

(2) Consumers' Capacity Sufficiency Analysis ("CSA") contains numerous methodological flaws and paints an overly pessimistic picture of how non-gas resources (including storage) would contribute to Consumers' long-term reliability needs. Due to its myriad shortcomings, the Capacity Sufficiency Analysis was not a reasonable basis for Consumers to restrict its January 2021 procurement solely to gas resources.

(3) Consumers' IRP modeling process artificially limited the value that energy storage can deliver to its system.

(4) Consumers' lack of planned storage investments is out of step with peer utilities that are taking advantage of recent cost reductions in battery technologies to make serious investments in storage as a core part of their resource portfolios by 2025.

Q. Please provide a summary of your recommendations.

A. My primary recommendations are as follows:

(1) With respect to Consumers' proposed 2023-2025 resources additions, I recommend that the Michigan Public Service Commission ("MPSC" or the "Commission") should:

(a) not accept Consumers' proposed 2025 gas resource additions;

(b) direct Consumers to procure 80-230 MW of energy storage by 2025; and

(c) direct Consumers to immediately conduct a new "all-source" competitive solicitation ("all-source RFP") for the remainder of 2025 needs (~770 MW) that allows for all resource types, including energy storage, to participate. In addition to the technical needs of Consumers' system, the all-source RFP should consider additional criteria to prioritize resources that are better positioned to help meet the state's clean energy goals and/or advance the market in Michigan for more recently available technologies.

(2) For Consumers' Capacity Sufficiency Analysis, I recommend that the Commission disregard this analysis as a reasonable or sufficient basis for the Company's decision to pursue a gas-only RFP.

(3) Finally, with respect to the Company's IRP modeling, I believe the Commission should recognize the fact that Consumers' long-term IRP analysis may not reflect the full amount of cost-competitive energy storage due to both the gas procurement

issues and the storage modeling issues discussed in my testimony. Due to the practical reality of time limitations, I am recommending that the IRP modeling issues identified in my testimony be addressed in the next IRP cycle. However, the Commission's recognition of the factors artificially limiting storage's inclusion in the PCA are still reason enough to warrant accelerated storage procurement in the near term beyond what Consumers has proposed (i.e., 80-230 MW by 2025). This level of storage procurement would still be consistent with Consumers' own IRP analysis, even though I believe that analysis could be improved.

II. Introduction and Qualifications

Q. State your name, business name and address.

A. My name is Ed Burgess. I am a Senior Director at Strategen Consulting. My business address is 2150 Allston Way, Suite 400, Berkeley, California 94704.

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

A. I am appearing here as an expert witness on behalf of the Michigan Energy Innovation Business Council ("Michigan EIBC"), the Institute for Energy Innovation ("IEI"), and the Clean Grid Alliance ("CGA"), collectively referred to as "Michigan EIBC/IEI/CGA."

Q. Summarize your professional and educational background.

A. I am a leader on Strategen's consulting team and oversee much of the firm's utility-focused practice for governmental clients, non-governmental organizations, and trade associations. Strategen's team is globally recognized for its expertise in the electric power sector on issues relating to resource planning, transmission planning, renewable energy, energy storage, utility rate design and program design, and utility business models and strategy. During my time at Strategen, I have managed or supported projects for numerous client engagements related to these issues. Before joining Strategen in 2015, I worked as an independent consultant in Arizona and regularly appeared before the Arizona Corporation Commission. I also worked for Arizona State University where I helped launch their Utility of the Future initiative as well as the Energy Policy Innovation Council. I have a Professional Science Master's degree in Solar Energy Engineering and Commercialization from Arizona State University as well as a Master of Science in Sustainability, also from

Arizona State. I also have a Bachelor of Arts degree in Chemistry from Princeton University. A full resume is attached as Exhibit EIB-15 (EB-1).

Q. Have you ever testified before any other state regulatory body?

A. Yes. I have testified before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General's Office ("AGO") at the evidentiary hearings for D.P.U. 18-150 and D.P.U. 17-140. I have also supported the AGO as a technical consultant in other cases including D.P.U. 17-05, D.P.U. 17-13, D.P.U. 15-155, and D.P.U. 17-146. I have also testified before the South Carolina Public Service Commission on behalf of the South Carolina Solar Business Alliance in evidentiary hearings for 2019-186-E, 2019-185-E, and 2019-184-E. I provided written testimony to the Indiana Utility Regulatory Commission on behalf of the Citizens Action Coalition and Earthjustice on coal fuel costs in two proceedings related to Duke Energy's Fuel Adjustment Clause (IURC Cause No. 38707 FAC 123 S1 and FAC 125). I also recently provided testimony to the Nevada PUC on NV Energy's Integrated Resource Plan in (Docket No 20-07023). I have testified before the California Public Utilities Commission on behalf of Sierra Club in PacifiCorp's 2020 and 2021 Energy Cost Adjustment Clause proceedings (A.19-08-002 and A.20-08-002). Additionally, I have represented numerous clients by drafting written testimony, drafting written comments, presenting oral comments and participating in technical workshops on a wide range of proceedings at Public Utilities Commissions in Arizona, California, District of Columbia, Maryland, Minnesota, Nevada, New Hampshire, New York, North Carolina, Ohio, Oregon, Pennsylvania, at the Federal Energy Regulatory Commission, and at the California Independent System Operator.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to assess Consumers' IRP with a particular focus on the role of energy storage. I analyze the key drivers that led to Consumers' decision about whether or not to include energy storage resources over the next 10 years. I discuss the shortcomings of Consumers' recent solicitation process that focused solely on gas resources and did not consider viable alternatives such as storage. I also critique a variety of Consumers' modeling assumptions both in its Capacity Sufficiency Analysis and in its IRP analysis related to the role of storage.

Q. How is your testimony organized?

A. The remainder of my testimony is organized as follows:

- First, I review Consumers' gas procurement decision-making process;
- Second, I review Consumers' Capacity Sufficiency Analysis;
- Third, I discuss Consumers' assumptions for modeling storage in its IRP analysis; and
- Finally, I compare the storage resources in Consumers' IRP to those in the IRPs of other similar utilities.

I provide summary findings and recommendations throughout.

Q. Are you providing any exhibits?

A. Yes. My exhibits are as follows:

- Exhibit EIB-15 (EB-1): Resume of Edward Burgess
- Exhibit EIB-16 (EB-2): Competitive Bidding Workgroup, Staff Strawman

- Exhibit EIB-17 (EB-3): Discovery response AG-CE-388
- Exhibit EIB-18 (EB-4): Discovery response MEIBC-CE-307
- Exhibit EIB-19 (EB-5): Discovery response MEIBC-CE-299
- Exhibit EIB-20 (EB-6): WP-STW-7 2021 IRP Assumptions Book, tab 8d
- Exhibit EIB-21 (EB-7): Discovery response MEIBC-CE-308
- Exhibit EIB-22 (EB-8): Discovery response AG-CE-427
- Exhibit EIB-23 (EB-9): Discovery response MEIBC-CE-304
- Exhibit EIB-24 (EB-10): Discovery response MEIBC-CE-291
- Exhibit EIBC-25 (EB-11) : Discovery response MEIBC-CE-252
- Exhibit EIBC-26 (EB-12): Discovery response MEIBC-CE-290
- Exhibit EIBC-27 (EB-13) Loss of Load Analysis 1
- Exhibit EIB-28 (EB-14): Discovery response MEIBC-CE-288
- Exhibit EIB-29 (EB-15): Discovery response MEIBC-CE-289
- Exhibit EIB-30 (EB-16): Loss of Load Analysis 2
- Exhibit EIB-31 (EB-17): Discovery response MEIBC-CE-292
- Exhibit EIB-32 (EB-18): Discovery response MEIBC-CE-297
- Exhibit EIB-33 (EB-19): Discovery response MEIBC-CE-287
- Exhibit EIB-34 (EB-20): Discovery response MEIBC-CE-300
- Exhibit EIB-35 (EB-21): Discovery response MEIBC-CE-305
- Exhibit EIB-36 (EB-22): Discovery response MEIBC-CE-302c
- Exhibit EIB-37 (EB-23): Discovery response MEIBC-CE-303
- Exhibit EIB-38 (EB-24): Discovery response MEIBC-CE-302b
- Exhibit EIB-39 (EB-25): Discovery response MEIBC-CE-309

III. <u>Consumers' recent unilateral gas procurement decisions significantly disadvantage other competitive resource options including energy storage.</u>

A. Overview of gas additions within Consumers' IRP

Q. How would you characterize the Proposed Course of Action ("PCA") portfolio in Consumers' IRP over the next 5 to 10 years?

A. The PCA portfolio in Consumers' IRP is dominated by significant near-term (2021-2025) additions of utility-owned natural gas capacity, with 1,565 MW of natural gas being added by 2025. This represents more than 20% of Consumers' *total* Planning Reserve Margin Requirement ("PRMR") which is approximately ~7,500 MW, with most of the remainder being met by existing resources. Over the medium term (2026-2030), Consumers gradually adds in a significant amount of solar resources, and a modest amount of demand-side resources (i.e., energy waste reduction and new demand response ["DR"]). However, energy storage is conspicuously absent from any resource additions in the PCA until the year 2030, at which point only 55 MW of storage is added, representing less than 1% of the PRMR.

Q. What is the primary driver of the need to add resources in the 2023-2025 timeframe?

A. The primary driver appears to be the retirement of the Karn and Campbell coal facilities by 2023 and 2025, respectively.

B. Consumers' RFP for existing gas resources

Q. Were the proposed gas additions used to replace these coal resources procured through a competitive process that allowed for all resource types?

A. No. These proposed additions were the result of a Request for Proposals ("RFP") that only allowed existing gas resources to participate and excluded other viable alternatives.

Q. Are you familiar with the Competitive Bidding Guidelines adopted by this Commission through an Order on September 9, 2021, in Case No. U-20852?

A. I have reviewed several critical provisions of the guidelines that were included in the September 9, 2021 Order. Michigan EIBC/IEI/CGA witness Dr. Laura Sherman addresses these guidelines in greater detail in her testimony.

Q. Do you believe Consumers' procurement process in this instance (i.e., the gas-only RFP) reflects the September 9, 2021 Order's provisions?

A. No. In particular, it does not reflect the provision that competitive solicitations should be "technology neutral" rather than predetermining the outcome. For example, Guideline #1 states that "All Long-term Resources, including utility self-build projects, should be procured through Competitive Procurements. Competitive Procurement will be conducted in a manner which is <u>technology neutral</u> to the extent practical."[1] (Emphasis added).

[1] Commission Order in Case No. U-20852. September 9, 2021, Exhibit A.

Q. Although these guidelines were officially adopted in September 2021, would it have been reasonable for Consumers to anticipate the key provisions, including technology neutrality, prior to its January 2021 RFP?

A. Yes. The Competitive Bidding workgroup process began in September 2020 and the principle of technology neutrality was introduced as early as October 1, 2020 as part of the MPSC Staff's strawman draft. I've attached this draft as Exhibit EIB-16 (EB-2).

Q. In your opinion, did the RFP that Consumers conducted lead to robust competition?

A. No. As Consumers revealed in response to discovery request AG-CE-388, there were only 2 eligible bidders that participated in the recent RFP. EIB-17 (EB-3). Not only is this a very low number of bidders, it is also fewer than those participating in RFPs conducted by Consumers in prior years.[2] Additionally, it is the exact same number of bids that Consumers ultimately selected. Had Consumers allowed for additional technology categories, I am reasonably confident it would have received a greater number of bids, leading to more robust competition and potentially lower costs to Consumers' customers.

C. Consumers' modeling of existing gas purchases in the IRP

Q. Regardless of the procurement process Consumers followed, were these gas resource additions selected as part of an optimized least-cost portfolio through Consumers' IRP modeling process?

[2] Exhibit EIB-17 (EB-3).

A. No. As Company witness Walz stated, these additions were "determined outside the model."[3]

Q. So just for clarification, the gas resources Consumers is proposing to add were not economically selected through Consumers' IRP modeling process?

A. Yes, that's correct. When conducting IRP modeling, the gas resources were simply "forced in" as a starting condition of the PCA resource portfolio. Thus, the model did not have the flexibility to choose the gas resources or any other alternatives based on economic considerations.

Q. What was Consumers' justification for focusing solely on gas resource additions versus allowing other resource types to compete in the RFP or allowing them to be selected in the IRP model?

A. Consumers' rationale for this approach largely hinges upon its "Capacity Sufficiency Analysis," which incorrectly concludes that only the addition of gas resources would be able to meet Consumers' reliability needs. I discuss the shortcomings of the Capacity Sufficiency Analysis in greater detail in Section IV of my testimony below.

Q. What are the implications of such large resource additions being added in the near-term?

A. The implications of these additions are significant for several reasons. First, as mentioned above, these additions were selected through a solicitation process that was not technology

[3] Exhibit EIB-18 (EB-4): discovery response MEIBC-CE-307.

neutral, was limited only to gas resources, and did not allow other resource types to compete on a level playing field to meet Consumers' system reliability needs. Second, these additions effectively "crowd out" investments from other competitive technology categories, particularly storage, for the next 5-10 years. Practically speaking, there simply wouldn't be a need for incremental capacity from any resource and thus Consumers' plan effectively stifles the market for new investments, including clean energy investments. Finally, these gas additions represent significant resource choices that Consumers made on its own without the benefit of input from the Commission or other stakeholders through the IRP process. By making this decision unilaterally, Consumers' proposed resource plan defeats the purpose of several changes made to Michigan's IRP statute in 2016. My understanding is that these 2016 changes, which established the current the IRP process, were intended to ensure a more comprehensive planning process (versus the prior Certificate of Need process) that not only included more robust stakeholder input, but also allowed for a level playing field across technology categories. Unfortunately, that is not the case under Consumers' proposed plan due to the narrow focus on existing gas resource additions that were determined outside of the IRP's economic modeling process and without stakeholder input or robust competition.

Q. Can you elaborate on the timing of the gas resource additions versus potential energy storage additions in Consumers' final IRP analysis?

A. Yes. In Consumers' final IRP analysis used to support the PCA, it was assumed that energy storage additions could not occur prior to 2025. Notably this means that, under Consumers' proposal, storage resource additions could only occur after Consumers' pre-determined gas resources are added. Thus, Consumers' approach puts non-gas resources (including storage) at a systematic disadvantage since there is a significantly diminished overall resource need once the gas purchases are added to the system – a need that storage resources could potentially have fulfilled. In other words, if the gas resources are added first (and added outside of the modeling process), then the opportunity for adding storage or other resources -- whether done through IRP modeling or any other selection process -- becomes significantly diminished over the next decade.

Q. What was Consumers' rationale for limiting storage additions to 2025 or later?

A. According to Company witness Washburn, "2025 was selected to give time for the IRP proposed course of action to go through the regulatory process and then provide time for procuring the battery energy storage system asset."[4]

Q. Did Consumers equally apply these same limitations to all resources it included in the PCA?

A. No. In particular, the gas additions I described above did not presume any time was needed to "go through the regulatory process" or a subsequent procurement process. In fact, Consumers seems to have pursued these gas procurements without any regard for the IRP and related regulatory process (i.e., this proceeding). By doing so, Consumers put storage and other resources at a distinct disadvantage and did not allow them to compete on a level playing field.

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[4] Exhibit EIB-19 (EB-5): discovery response MEIBC-CE-299.

Q. Can you elaborate on the feasibility of storage to fulfill at least part of Consumers' resource needs in the 2023-2025 time horizon?

A. Yes. There are several factors that lead me to believe that storage could be a feasible replacement for at least some of the gas resources that Consumers is proposing in the near term (i.e., prior to 2025). These include the following:

a) Significant battery storage resources already exist in the Midcontinent Independent System Operator's ("MISO") interconnection queue, with over 2,300 MW in Michigan alone;

b) Large-scale battery resources can be developed on a short, 1 to 2-year time horizon;

c) Both MISO and the MPSC are already undertaking reforms to streamline their interconnection processes for transmission and distribution-connected storage, respectively. In MPSC's case, this includes specific references and rules for distribution-connected storage;[5]

d) Standalone storage can be flexibly sited at optimal grid locations, thereby significantly reducing interconnection timescales and costs;

e) Consumers' own modeling initially characterizes the earliest year in which energy storage could feasibly be added as 2023, but later restricts it to after 2025;[6] and

f) According to the sensitivity analysis in Consumers' IRP, which comprised over 116 different AURORA simulations, the first year that storage was added (on average) was in 2023. By 2025 the average storage additions were over 80 MW with some simulation runs exceeding 230 MW.[7] However, as I alluded to, any potential

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[5] See Case No. U-21116 and Case No. U-21117.

[6] See Exhibit EIB-20 (EB-6): WP-STW-7 2021 IRP Assumptions Book tab 8d, and Exhibit EIB-21 (EB-7): discovery response MEIBC-CE-308.

[7] Company Exhibit A-13 (STW-10).

storage additions during this timeframe were excluded from the PCA in favor of the gas additions.

For these reasons, I believe that 2023-2025 would be a more reasonable timeline for large-scale battery resource additions to be considered, rather than Consumers' seemingly arbitrary decision to limit storage additions until after 2025. This would especially be true if Consumers were to conduct another solicitation within the next few months. By delaying storage deployment to after 2025, Consumers is artificially constraining the resource options that could be considered in the near term. If storage resources were deployed sooner, they could potentially obviate the need for some of the gas resource procurements Consumers presumes are necessary in the 2023-2025 time horizon.

Q. Do you think a 2023 or 2024 date for new storage additions is still possible in light of the fact that Consumers failed to include storage as an option in its January 2021 RFP?

A. Yes. Consumers had the chance to include storage in its January 2021 RFP, but simply chose not to. Had they done so, there would have been much greater certainty a storage resource could come online in the 2023-2024 timeframe. Nevertheless, as of this filing, I think a 2023-2024 deployment date is still technically possible, however any further delay could begin to create significant uncertainties around the feasibility of 2023 deployments. If a 2025 date (or later) ultimately becomes reality, then it should be acknowledged that this result is at least partially linked to the unreasonable steps Consumers took when conducting its January 2021 RFP, as well as any subsequent delays in additional procurement activities.

Q. Do you believe the emphasis on gas procurement in Consumers' IRP is aligned with the state's clean energy goals?

A. No. In 2020, Governor Whitmer signed Executive Order ("EO") 2020-182, which established the Council on Climate Solutions. Part of the Council's charge is "Identifying and recommending opportunities for the development and effective implementation of emissions-reduction strategies."[8] Consumers' decision to procure natural gas generation, in lieu of cleaner resources, could potentially prolong the life of these emitting resources. Thus, it is at cross-purposes with the goal of EO 2020-182.

Q. Can you summarize the gas resource additions Consumers selected through the RFP process for which the Company is now seeking cost recovery?

A. Yes. The table below summarizes these additions.

Table 1: Gas Resource additions for which Consumers is seeking cost recovery[9]

<table>
<tr><th>Plant</th><th>Capacity (MW nameplate)</th><th>Technology</th><th>Date To Be Added</th><th>Current/Prior Owner</th><th>Purchase Price</th></tr>
<tr><td>Covert</td><td>1,176</td><td>Combined Cycle</td><td>2023</td><td>Segreto Power</td><td>$815 million</td></tr>
<tr><td>DIG</td><td>770</td><td>Combined Cycle</td><td>2025</td><td>CMS Energy</td><td rowspan="3">$530 million</td></tr>
<tr><td>Kalamazoo</td><td>75</td><td>Simple Cycle</td><td>2025</td><td>CMS Energy</td></tr>
<tr><td>Livingston</td><td>156</td><td>Simple Cycle</td><td>2025</td><td>CMS Energy</td></tr>
</table>

[8] Governor Whitmer. September 23, 2020. Available at https://www.michigan.gov/whitmer/0,9309,7-387-90501_90626-540284--,00.html.

[9] Table created using details provided in Direct Testimony of Jeffrey E. Battaglia.

Q. Based on the shortcomings of Consumers' solicitation process for gas resources vis-à-vis storage, do you have any recommendations for the Commission in this proceeding?

A. Yes. I recommend that the Commission should not accept the results of Consumers' gas-only solicitation process since it failed to consider the full range of technology options that could meet the same grid reliability needs. As such, these additions are counter to the Commission's Competitive Procurement Guidelines as discussed above.[10] I understand that Consumers has provided analysis that it believes shows that gas resources are essential for meeting reliability needs (i.e., the Capacity Sufficiency Analysis), however I dispute the validity and conclusions of this analysis in Section IV of my testimony.

As part of its action on this matter, I believe the Commission should also deny preapproval of costs associated with the gas resource procurements – particularly those resources added in 2025 (i.e., for the DIG/Kalamazoo/Livingston plants). Instead, the Commission should direct Consumers to do the following: a) conduct a new RFP that allows for participation of storage resources and other technologies to meet some (if not all) of the resource needs currently proposed to be met with gas purchases, and b) procure near-term storage resources more consistent with its IRP analysis for 2025. Even if the Commission is not inclined to reject all of Consumers' proposed gas resource additions, I suggest that at a minimum the proposed Kalamazoo and Livingston resource additions should be rejected now (approximately 230 MW of total nameplate capacity), in favor of accelerated storage

[10] Commission Order in Case No. U-20852. September 9, 2021.

deployment and a future all-source solicitation. I will discuss the specific recommendations for storage in greater detail below.

Q. Of the proposed gas resources additions, why do you think the Commission should not pre-approve cost recovery for the 2025 additions, and the Kalamazoo and Livingston plants in particular?

A. There are several reasons to apply additional scrutiny to the proposed 2025 plant additions:

- First, it is particularly noteworthy that the DIG, Kalamazoo, and Livingston plants are all owned by CMS Energy, which is the parent company of Consumers. Thus, there is a potential risk for self-dealing since Consumers/CMS has nothing to lose in this transaction and may have a vested interest in seeing this transaction realized even at the expense of other more competitive options. From CMS' perspective, the cost of these plants merely represents an internal transfer payment. Meanwhile, the Company is afforded the opportunity to convert its merchant generators that were exposed to substantial market risk, into regulated assets that earn a stable rate of return regardless of market performance. Additionally, Consumers provides no evidence to explain why such a transfer of ownership is necessary or beneficial to its customers in the first place. For instance, it would be possible for Consumers to execute a short-term contract (e.g., for < 5 years) for capacity from these same resources rather than acquiring them. This contractual arrangement would also have the added benefits of reducing ownership risk to ratepayers and not crowding out future competitive resource options, including energy storage.

- Second, the Commission has not yet determined if this purchase adheres to the Code of Conduct rules for affiliate transactions. However, Consumers has already acknowledged the potential need to seek a waiver for these Code of Conduct rules.[11]
- Third, the 2025 resource additions only provide a fraction of their potential value in the near term due to pre-existing energy and capacity commitments. As described in witness Battaglia's testimony, only a fraction of the resource capacity from these gas plants is available in 2025, with the available capacity ramping up in later years, reaching full value in 2035.[12] This means that the near-term value of these resources is significantly diminished, and as I will detail in Section III-D below, may be even lower than storage alternatives.
- Finally, the Kalamazoo and Livingston resources are particularly ideal candidates for replacement with alternatives such as energy storage due to their low efficiency and low capacity factors (often below <1% in recent years). This means that these plants are seldom operated and provide very little value in terms of energy or ancillary services. They operate essentially as "peaker plants," whose main function is to provide capacity during a limited number of peak hours. Energy storage is often well suited to replace inefficient peakers since it also serves as a capacity resource providing energy during a limited number of peak hours. This is in contrast to combined cycle plants that runs more frequently and may contribute relatively more energy value.

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[11] See Exhibit EIB-22 (EB-8): CE response to AG-CE-427, question 4d.

[12] Direct testimony of Jeffrey A. Battaglia, on behalf of Consumers Energy Company in Case No. U-21090. ("Battaglia Direct"). p. 43.

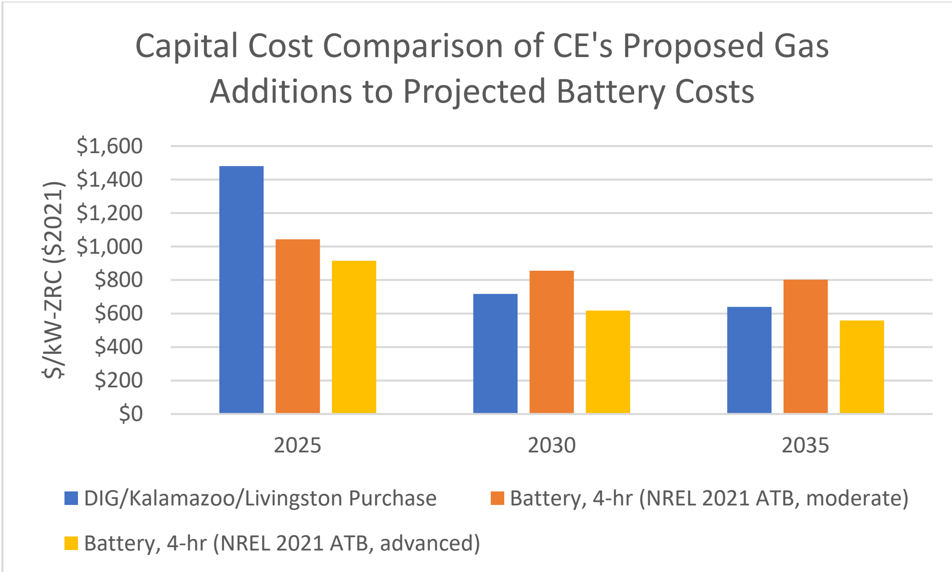
D. Comparison of gas purchase costs to other resources

Q. In your opinion, would the cost of new battery storage resources compare favorably to the proposed gas additions at DIG/Kalamazoo/Livingston?

A. Yes. As noted in opening testimony of Mr. Battaglia, Consumers estimates these gas additions to total $530 million in initial capital costs.[13] However, the initial value of the gas additions to Consumers' portfolio is relatively limited in the early years due to previously committed uses. For instance, the uncommitted capacity in 2025 only amounts to 358 MW, which equates to a per unit cost of $1,480/kW. In comparison, the most recent NREL 2021 ATB estimates show the capital cost of a 4-hr duration battery storage resource added in 2025 to be $1043/kW (ZRC adjusted) or about 30% less in the moderate case and $915/kW (ZRC adjusted) or about 38% less in the advanced case. This is illustrated in the chart below by comparing the three bars on the left side. Note that this does not even factor in the ancillary services credit that Consumers applied to certain storage resource types which could lower the relative cost of storage by another ~$80/kW.[14]

[13] *Ibid*., p 44.

[14] See Direct Testimony of Mr. Washburn page 18, lines 12-14 which discusses the Ancillary Services Market Prototype. As confirmed in Exhibit EIB-23 (EB-9): discovery response MEIBC-CE-304, the $80/kW value was incorporated as a reduction to the cost of this storage resource.



As the prior commitments of the gas resources roll off over time, more capacity becomes available to serve Consumers' customers, and the value of the DIG/Kalamazoo/Livingston resource increases (i.e., the blue bars on the graph decrease). However, the full value is not realized until 2035, at which point the total 828 MW ZRC becomes available. Even if this increasing value is accounted for, however, a new storage resource still appears to be cost-competitive, and possibly cheaper, than the gas purchases on a $/kW basis.

E. Recommendations

Q. Based on your findings and conclusions thus far, do you have any recommendations for the Commission at this time?

A. Yes. As I have explained, the Commission should not accept Consumers' 2025 gas resource additions as proposed. Additionally, as I stated earlier, the average result of Consumers' own IRP sensitivity analysis showed that at least 80 MW of energy storage should be added by 2025,[15] and some sensitivity cases showed optimal additions exceeding

[15] See Company Exhibit A-13 (STW-10).

230 MW. Thus, I believe 80-230 MW of new storage can be viewed as a bare minimum "no regret" option and could serve to offset a portion of the 2025 gas additions.

Q. How do these model results compare to Consumers' proposed gas resource additions?

A. 80 MW is roughly equal to the proposed Kalamazoo addition. Meanwhile, 230 MW is roughly equal to the Kalamazoo and Livingston additions combined.

Q. Do you think Consumers should pursue a different course of action that is informed by its own model results?

A. Yes, I think the Commission should direct Consumers to procure at least 80 MW to 230 MW of energy storage in lieu of the Kalamazoo and Livingston acquisitions. Additionally, for the remainder of the 2025 gas additions, I believe a new "all-source" competitive solicitation should be conducted that allows for other resource types including energy storage.

Q. How does this level of storage compare to other recommended industry best practices?

A. From the high-level storage policy perspective, the US Energy Storage Association recommends implementing near-term storage deployment targets equivalent to 3-7% of a utility's peak demand.[16] This range is based on what other states with deployment targets have adopted to date. I estimate that this would equate to a target for Consumers of approximately 230-537 MW. The lower end of this range would be consistent with the

[16] See https://energystorage.org/wp/wp-content/uploads/2021/02/Final-Policy-Position-on-State-Level-Energy-Storage-Target-Design_clean-and-uploaded-3.pdf

range of storage procurement that I am recommending for 2025 (i.e., 80-230 MW). Meanwhile even greater storage additions could be considered through the all-source RFP.

Q. Do you have any recommendations for additional criteria that this all-source RFP should include?

A. Yes. In addition to the technical needs of Consumers' system, I think it would be appropriate to consider some additional criteria for resources that are better positioned to help meet the state's clean energy goals. That is, there could be some additional weight given to "clean capacity" resources that meet reliability needs without direct contributions to emissions. Additionally, if emitting resources do participate (e.g., natural gas), I think it is necessary to evaluate their economics under a scenario whereby these resources need to retire early either due to state or federal policy.

Finally, I think it is also worth recognizing that Michigan utilities have relatively limited experience with deploying advanced, large-scale battery storage technologies in significant quantities. Over the course of my career, I have seen repeatedly that with the advent of any new technology, there is a significant need for utilities to gain experience with the technical issues and operating parameters of the technology (i.e., "learning by doing") in order for the technology to be successfully integrated and considered as an ongoing resource option. I do not believe that Consumers has had a robust experience with significant quantities of battery storage on its system to date beyond pilot projects. Additional experience with storage and other new technologies could be accomplished through an additional "market transformation" value-added criteria in the solicitation process to assist resources that are in an earlier stage of maturity for the region. The intent of this would be to better prepare Consumers resource planners and operators, through real-world experience, for a much more robust deployment of low-cost battery storage resources in the future.

IV. <u>Consumers' Capacity Sufficiency Analysis is flawed and paints an overly pessimistic picture of how non-gas resources (including storage) could contribute to Consumers' reliability needs. The CSA was not a reasonable basis for Consumers to have pursued a gas-only RFP.</u>

A. Overview of Consumers' Capacity Sufficiency Analysis

Q. What was the Company's primary rationale for conducting a gas-only RFP rather than allowing other types of resources to compete to meet Consumers' reliability needs?

A. The primary rationale for Consumers' decision to pursue a gas-only RFP, rather than conduct a more competitive solicitation open to all technologies, was an internal analysis the company conducted, which it has dubbed a "Capacity Sufficiency Analysis" ("CSA"). As Company witness Blumenstock explains in his testimony, "The capacity sufficiency assessment analysis, as discussed above, supported the Company's decision to issue an RFP for existing gas units."[17] As such, the CSA appears to underpin Consumers' choice to pursue gas resources at the exclusion of alternatives. Thus, it is critical that the Commission evaluate whether this analysis and its conclusions are sufficient to justify the Company's exclusionary and anti-competitive approach.

[17] Direct testimony of witness Richard Blumenstock, on behalf of Consumers Energy Company. Case No. U-21090. ("Blumenstock Direct"). p. 73.

Q. Please describe the Company's Capacity Sufficiency Analysis in general terms.

A. According to Company witness Walz, the goal of the CSA was to understand the sufficiency of a portfolio of resources to serve projected customer demand.[18] To achieve this, the Company conducted a series of simulations of its power system for two discrete and predetermined resource portfolios in a future year (2032) under a number of different scenarios. The two portfolios include the PCA, as well as an "alternate plan," the installed capacity of which is presented in Table 1 of the direct testimony of Company witness Walz.[19] Few details were provided by Consumers in testimony or through discovery about how the Company determined the "alternate plan;" however, it was briefly summarized as "a refresh of our approved 2018 IRP plan, containing high renewables and less controllable generation."[20] These two portfolios were stress tested under a high number of future scenarios to assess their ability to serve the Company's customers' projected demand in each hour. Specifically, the Company investigated the reliability of the PCA and the "alternate plan" by varying four discrete evaluation parameters: 1) the availability of thermal generating units, 2) the hourly demand profile, 3) the intermittency of solar and wind generation profiles, and 4) the responsiveness of DR programs. To evaluate the portfolios' ability to meet demand, the Company defines a "capacity insufficiency event" as occurring whenever supply or demand-side resources are insufficient to meet demand in a given hour, which can be thought of as the loss of load in that hour.[21]

[18] Direct testimony of witness Sara Walz, on behalf of Consumers Energy Company. Case No. U-21090. ("Walz Direct"). p. 72:4-18.
[19] *Id.*, p 76.
[20] Exhibit EIB-24 (EB-10): discovery response MEIBC-CE-291.
[21] Walz Direct, p. 73.:6-8

Q. Is Consumers' CSA a standard reliability planning analysis?

A. No. The CSA appears to be an analysis that Consumers conducted on its own without any consultation with MISO, other grid reliability experts, or other stakeholders. As such it deviates from the general MISO reliability framework, which typically includes loss-of-load expectation analysis ("LOLE") on a MISO-wide basis.

Q. Please summarize the Company's conclusions from conducting the CSA.

A. According to the Company, the 3,000 model iterations it performed showed a higher number of loss of load hours under the "alternate plan" when compared to the PCA.[22] Thus, Consumers concluded that a resource portfolio like the "alternate plan" has a greater chance of a potential loss of load event. Meanwhile, the Company also concluded that these loss of load events could be avoided under the PCA portfolio that includes the Company's proposed gas generation capacity purchases. This conclusion was then used to justify Consumers' choice to pursue gas resources at the exclusion of alternatives, without any consideration of the Company's subsequent IRP modeling.

Q. Do you generally agree with the conclusions the Company drew from its CSA?

A. No. I have serious concerns about the Company's methodology in conducting the CSA. I believe that methodology to have numerous flaws that may have skewed the results toward a predetermined outcome that included the gas purchases. Later in this section of my testimony, I outline four specific concerns I have with the methodology and describe each

[22] Walz Direct, pp. 87-89.

of these in much greater detail. I also have concerns about the overall transparency of the CSA modeling.

Q. Did the Company's CSA explore the use of energy storage as a form of dispatchable resource that could assist with reliability needs?

A. To some degree, yes. In fact, the CSA's "alternate plan" included ~760 MW more of incremental battery storage when compared to the PCA (i.e., in 2032 the PCA includes 61 MW of energy storage, while the alternate plan includes 820 MW). However, the Company ultimately drew the conclusion that this amount of storage, in combination with other resources, was insufficient to meet its reliability requirements. In support of this, Consumers specifically pointed to an example of two consecutively modeled days in September 2032 where loss of load events occurred under the "alternate plan."[23] In discussing the model results, Company witness Walz stated: "This example illustrates that storage resources may not be the solution to resolve electric reliability concerns, especially on consecutive days of high demand."[24]

Q. Do you have concerns about this conclusion as well?

A. Yes. I don't believe the Company's conclusions regarding storage are well founded. I will address this issue in greater detail in my testimony below.

B. Methodological flaws in Consumers' Capacity Sufficiency Analysis

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[23] Company Exhibit A-16, p. 4.
[24] Walz Direct, p. 85.

Q. Can you summarize your four primary concerns with the Company's CSA methodology?

A. Yes. While not necessarily exhaustive, the four main methodological concerns I have with the CSA are as follows:

(1) The CSA compared the PCA against an "alternate plan" whose development is not adequately justified or explained.

(2) While the CSA compared each portfolio over 3,000 scenarios, the development of these scenarios was fundamentally flawed. Specifically, the scenarios were flawed in the following respects:

   (a) lack of support for the high load scenarios;

   (b) incorrect pairing of wind, solar, and load profiles;

   (c) lack of correlation for thermal outages.

(3) The CSA modeling process included inappropriate assumptions for DR.

(4) The CSA assumed a lower Capacity Import Limit than is currently established by MISO (or would be reasonable to expect in 2032), which artificially creates more loss of load hours than is likely.

In addition to these discrete methodological issues, I also have some general concerns that the lack of transparency around the CSA results creates questions around the validity of conclusions.

1. Methodological Flaw #1: Selection of "Alternate Plan" portfolio

Q. Please explain your concerns with the selection of the Alternate Plan portfolio.

A. In the CSA, the Company compares the PCA portfolio against a hypothetical "alternate plan" that was different from any candidate portfolio considered in the Company's IRP analysis. It is not clear how the Company selected this "alternate plan" and when asked to provide the reasoning for this portfolio, the Company simply responded that it is a "refresh" of the 2018 approved IRP plan.[25] Additionally, it is not clear why other portfolios could not have been considered for the CSA. For example, the Company claims that the CSA analysis proves that energy storage is insufficient to meet its resource needs on a hypothetical extremely high load event in September 2032. However, it is possible that this hypothetical loss of load event could have been alleviated or avoided entirely by selecting a different resource portfolio that simply included more storage. Similarly, a different alternative could have been considered that included some, but not all, of the gas resource purchases being considered. For example, there could be a viable scenario that includes the Covert resource addition, but not the DIG/Kalamazoo/Livingston additions. Unfortunately, the "alternate plan" put forward by Consumers in its CSA essentially serves as a "straw man" designed to make the full suite of proposed gas purchases in the PCA seem like an inevitable outcome. In reality, there may be other viable alternatives that simply weren't considered in Consumers' CSA.

Moreover, it appears that Consumers did not actually attempt to develop any alternate portfolios for the CSA (other than the PCA) that were designed to meet even basic reliability criteria such as the PRMR. For instance, Consumers' response to a discovery

[25] Exhibit EIB-24 (EB-10) : discovery response MEIBC-CE-291.

request lists the resources included in the "alternate plan" in the CSA.[26] However, the resources in this portfolio only total 7,697 ZRCs in 2032, which is far less than the 7,796 MW the Company identifies as its PRMR needs for that year. The fact that the total ZRCs in the "alternate plan" are significantly less than the ZRCs in the PCA means that the two portfolios are basically "apples and oranges" from a reliability standpoint and really cannot be meaningfully compared at all. While Consumers has attempted to draw conclusions from such comparisons in its CSA, in my opinion such comparisons are fundamentally flawed and cannot be credibly used to draw any meaningful conclusions about relative reliability performance of the "alternate plan" with respect to the PCA.

Finally, Consumers' CSA analysis appears to have examined a portfolio that was inconsistent with the Alternate Plan studied in its subsequent IRP analysis. I address this inconsistency below in Section IV-D of my testimony on Transparency Concerns.

2. Methodological Flaw #2: Construction of scenarios used to test the PCA and Alternate Plan portfolios

Q. Please explain your concerns with the Company's scenarios under which the two portfolios were tested.

A. As already mentioned, the Company investigated the reliability of the PCA and the Alternate Plan by varying four evaluation parameters: 1) the availability of thermal generating units, 2) the hourly demand profile, 3) the intermittency of solar and wind

[26] Exhibit EIBC-25 (EB-11) : discovery response MEIBC-CE 252.

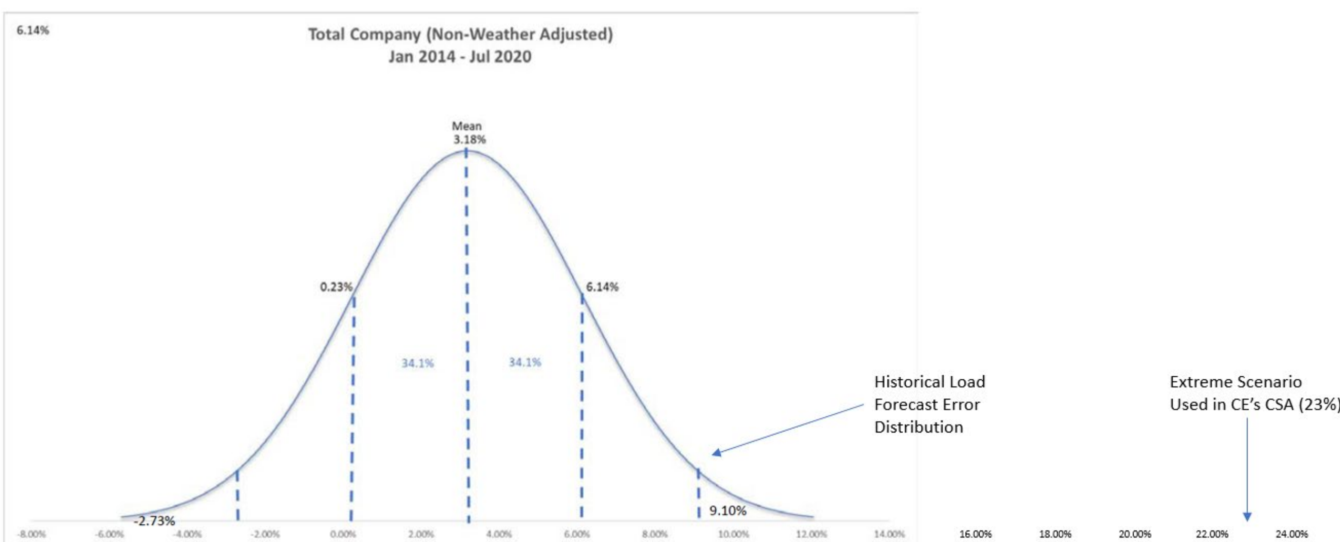
generation profiles, and 4) the responsiveness of demand response programs. These four evaluation parameters were used to generate 3,000 scenarios under which the two portfolios were tested. However, the development of those scenarios was based on random pairings of the load and generation profiles. This means that thermal outages, wind, solar and demand hourly profiles were not calibrated to reflect real-world conditions. Instead, they were incorrectly paired in a random way, thereby introducing errors in the process.

In reality, there are statistical correlations between the different generation and load profiles, meaning that they move in coordination with each other, either in a positive or a negative direction. For example, extreme cold weather can drive both load and thermal outages up. Instead, the Company paired the profiles randomly without accounting for these coordinated movements. This makes me question the probability of occurrence for any of the 3,000 scenarios since some of these pairings would be extremely unlikely if not impossible. I believe this also calls into question the validity of the CSA's overarching conclusions. In my testimony below, I present in greater detail on the flaws in Consumers' characterization of each of the CSA scenario parameters.

a) Load Scenarios

Q. Please explain your concerns with the CSA's increased load scenario.

The CSA appears to include highly exaggerated extreme load scenarios that are outside of the realm of normal planning assumptions. For example, Consumers draws much attention to the September 2032 case where storage (along with other resources) are supposedly insufficient to meet load over two consecutive days. Company witness Walz's testimony describes this scenario as including a 23% load increase. However, it is not explained why the assumed 23% load increase is appropriate for this analysis or whether such an increase is within the bounds of reasonable expectations. Notably, Consumers described parameters for variations in demand within its Aurora modeling as follows: "Hourly demand could shift upwards or downwards by a random percentage chosen by Aurora, within a standard deviation of +/- 9.1%." [27] This means that the 23% increased load scenario exceeds the upper bounds of Consumers' normal modeling parameters by over 2.5 times. Indeed, Consumers' own historical observations for load forecast uncertainty show the rarest and most extreme deviations to be in the 10-12% range, nowhere close to 23%.[28] The figure below illustrates just how extreme the 23% load scenario is. This figure was adapted from Figure 3 on page 14 of Direct Testimony of Anna K. Munie, which depicts the normal distribution of historical load forecast error. The extreme 23% value used in the CSA was included for scale.



[27] See Exhibit EIBC-26 (EB-12) : discovery response MEIBC-CE-290.
[28] See Figure 3 on page 14 of Direct Testimony of Anna K. Munie.

Additionally, the peak load hour in the 23% scenario is 8,490 MW,[29] which is well above Consumers' assumed PRMR value for 2032 of 7,796 MW.[30] The reserve margin should already be the result of a probabilistic, loss of load expectation risk analysis, and thus it is unclear why Consumers chose to pursue a more extreme risk analysis in this instance. If instead, the load was only increased by the standard deviation range of 9.1% (rather than 23%), then I estimate that there would be no loss of load event during this period. In fact, the load increase could be as high as 14% (i.e., 1.5 standard deviations) -- which is more reasonable than a 23% increase but still higher than Consumers' normal range – without causing a loss of load event. This is shown in the analysis I have included in Exhibit EIB-27 (EB-13). In other words, the only reason Consumers' CSA example identifies a reliability issue with the "alternate plan" is due to the extremely exaggerated load assumptions Consumers imposes. If those assumptions were made more reasonable, there would be no reliability issues.

b) Wind and Solar Output Scenarios

Q. Please explain your concerns with the lack of correlation for solar, wind, and load profiles.

A. As mentioned above, Consumers' CSA conducts iterative simulations that randomly pair solar profiles, wind profiles, and demand profiles.[31] However, this random paring approach is inappropriate because there are often correlations between these profiles. There are at least three distinct ways this would occur.

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[29] Company Exhibit A-16.
[30] Blumenstock Direct. Figure 9.
[31] Exhibit EIB-28 (EB-14): discovery response MEIBC-CE-288 and Exhibit EIB-29 (EB-15): discovery response MEIBC-CE-289.

First, the generation profiles could be correlated with the load profiles. For example, in the summer, cloudy days with lower solar output also generally have lower levels of system demand due to lower temperatures and, therefore, less use of air conditioning. While there may be days with low solar output, or days with high system demand, it is very unlikely, if not impossible, that the most extreme version of these two conditions would ever coexist. For this reason, a better approach would be to sample historical weather data that matches actual solar and load profiles as they coexist. Randomly pairing an extremely low solar output profile with an extremely high demand profile creates an arbitrary system condition that is not realistic and cannot be meaningfully used to inform the CSA.

Second, Consumers' CSA seems to incorrectly assume that simultaneous, uniform reductions in solar output across all solar generators on Consumers' system is a realistic possibility. In fact, the scenarios with reduced solar generation uniformly reduce generation from all solar generators in the portfolio. For example, the Company presents the results of a day that is characterized as "Winter Day with no Solar."[32] In this run and for this day, output at each solar generator on Consumers' system is reduced to 0 MW. This is not just improbable, but virtually impossible, due to the geographic diversity of variable resources like wind and solar. While weather events often do lead to decreased solar output, it is not appropriate to assume that the same weather will happen everywhere across Consumers' entire territory all at once. Thus, aggregate profiles (i.e., solar, wind, and load) over large areas tend to diminish the range of variation from each individual profile when looking at

[32] Company Exhibit A-16, p. 3.

the entire system. By applying a universal, simultaneous reduction to the entire solar or wind generation fleet, Consumers is artificially creating a virtually impossible scenario whose results should not be considered valid when compared to scenarios based on historical solar profiles. Even if reduced output could occur due to equipment at a single solar plant, a scenario with simultaneous and uniform reduction across all solar plants is still not plausible. Unlike a thermal generator, which can lose hundreds or even thousands of MWs of capacity to a single failure, the loss of capacity from the overall renewable resource portfolio tends to be smaller and more geographically dispersed.[33] Thus, instead of focusing on unrealistic "zero solar" generation events, the CSA should have focused on the likelihood and frequency of correlated events that are much smaller in magnitude.

Finally, wind and solar tend to have some inverse correlation and thus, their profiles should also not be paired randomly. The complementarity of wind and solar resources means that the combination of these resources results in a lower range of variation in net demand. By randomly pairing the profiles, the Company might again be artificially creating unrealistic loss of load events and misrepresenting the true reliability of a portfolio with variable generation and/or duration-limited resources (i.e., storage).

c) *Thermal Outage Scenarios*

Q. Please explain your concerns with the lack of correlation for thermal outages.

[33] Redefining Resource Adequacy Task Force. 2021. Redefining Resource Adequacy for Modern Power Systems. Reston, VA: Energy Systems Integration Group. Available at https://www.esig.energy/reports-briefs.

A. In the CSA, it seems that thermal resources are unavailable based on a single forced outage rate with no assessment of the probability of correlated outages. Recent events have clearly shown how fuel supply failure can become a key reliability risk and can result in correlated outages, especially during winter months when multiple thermal power plants might experience interrupted fuel supply simultaneously.[34] For a system relying heavily on natural gas, disruptions in the natural gas supply can result in significant capacity being unavailable, as was evident during the February 2021 outages in Texas. In addition to the correlation of thermal outages, these would also be positively correlated with load, as extreme cold weather could be driving both. This reliability risk seems to be absent from the Company's CSA even though it would become more salient due to the Company's proposed significant purchase of natural gas plants in the PCA. Overall, the CSA appears to underestimate the relative reliability risk of the PCA portfolio versus the Alternate Portfolio.

3. Methodological Flaw #3: Modeling of DR resources in the Alternate Plan portfolio

Q. Please explain your concerns with the modeling of DR.

According to Company witness Walz, within Aurora, DR is scheduled to dispatch economically during a predetermined number of hours per year that correspond to the highest demand hours in the year. As the Company acknowledges, if a loss of load hour falls outside of this predetermined set hours, then DR is unable to resolve the loss of load

[34] Redefining Resource Adequacy Task Force. 2021. Redefining Resource Adequacy for Modern Power Systems. Reston, VA: Energy Systems Integration Group. Available at https://www.esig.energy/reports-briefs.

event.[35] Additionally, Consumers' analysis considers three potential scenarios for the predetermined number of hours that DR can be dispatched: 40 hours, 10 hours, and 0 hours.[36] There are two main concerns I have with this approach. First, while loss of load events are more likely to occur during the highest demand hours, they may not correspond perfectly. For example, in the second example presented in Exhibit A-16 (i.e., "Summer Peak Day") the loss of load occurs during a single hour on a summer evening (Hour 21 or 8-9pm) after solar output declines. Thus, while this hour is not the highest total load hour of the day and may not even fall within the highest set of hours for the year, it still presents a reliability challenge that DR could readily resolve. Thus, a better modeling approach would be for DR to be dispatched during hours with an expectation of high *net* load (i.e., load net of variable resources like wind and solar), rather than high gross load. Had DR been modeled in this manner, it likely could have alleviated a significant portion of the capacity insufficiency events Consumers has identified. Consumers' testimony even acknowledges these issues by stating that "[w]hile in practice, DR need not be dispatched only during the highest demand hours, this example illustrates the fact that DR programs may be limited in nature."[37] It is worth noting that the limitations Consumers describes are not a function of DR's capabilities as a resource, but simply reflects Consumers' assumptions for how it will implement its own DR programs in the future. There is no reason to assume that Consumers could not reorient its future DR procurement, before 2032, to target net peak load hours. In fact, this would be consistent with evolving industry best practices.

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[35] Direct Testimony of Sara Walz, page 82.
[36] *Ibid*.
[37] Direct Testimony of Sara Walz, p. 85.

Second, it is not clear how the number of possible DR dispatch hours per year (i.e., 40, 10, or 0 hours) were selected, and how or when each scenario was applied in Consumers' CSA modeling. It is particularly concerning that a "zero hour" scenario was considered, which effectively means that for this scenario, DR was not treated as a real resource that could contribute at all to Consumers' reliability needs. In fact, DR is not dispatching during *any* hours in the "Winter Day with No Solar" capacity sufficiency event or the "Consecutive Days" capacity insufficiency event. This suggests to me that these examples may reflect the "zero hour" DR scenario, or at least a lower number of hours than is reasonable to assume. Had a more reasonable, higher number of DR dispatch hours been assumed, then I believe insufficiency events in these cases would have been substantially alleviated.

4. Methodological Flaw #4: Capacity Import Limit Assumptions

Q. Please explain your concerns with the level of Capacity Import Limit ("CIL") assumed by Consumers.

A. It is well understood by grid planners that capacity import limits can serve as a safeguard under extreme conditions, even if not relied upon during most daily conditions. Resource sharing can be a significant, low-cost alternative to procuring new resources for these less frequent events. In its CSA, the Company seems to underestimate the potential assistance it could receive from imports. Specifically, the CIL assumed was only 3,200 MW, whereas the company's own testimony acknowledge that recent MISO estimates placed this value at 4,888 MW.[38] If the 4,888 MW value were used instead, I estimate that this change, in

[38] Direct Testimony of Sara Walz, p. 79.

combination with dispatch of energy storage and other resources in the Alternative Portfolio, could effectively eliminate virtually all the loss of load hours Consumers predicted for September 2032. This is illustrated in my attached Exhibit EIB-30 (EB-16).

Q. Has MISO subsequently proposed any adjustments to the 4,888 MW CIL, and if so, how do you respond?

A. Yes. As Consumers explained in a discovery response, MISO determined the Zone 7 CIL to be 3,749 MW for Planning Year 2022/2023.[39] While this is less than the 4,888 MW value it is still much greater than the 3,200 MW assumption that Consumers used in its CSA analysis. This suggests to me that Consumers was overly conservative in its CIL assumptions for the CSA. Furthermore, it is worth noting that, while the CIL has decreased for one planning year this does not negate the fact that the current transmission system itself is technically capable of delivering at least 4,888 MW in imports to Zone 7 depending on other system factors. It is not unreasonable to believe that MISO's CIL designation would increase to 4,888 MW or higher by 2032. This would especially be true if Consumers actively pursued actions to increase the import limit as a means to enhance value and reduce costs to its customers.

Q. Are there any other factors that lead you to believe that a capacity import assumption closer to 4,888 MW is more appropriate for 2032 than either 3,200 MW Consumers assumed or the 2022/2023 MISO value?

[39] Exhibit EIB-31 (EB-17): discovery response MEIBC-CE-292.

A. Yes. In addition to the CIL for Zone 7, Consumers also has the ability to receive imports from other resources within Zone 7, such as those from DTE. This was confirmed in Consumers' direct testimony which stated: "there are tie lines within Zone 7, for example, between Consumers Energy and DTE, that provide additional import capability to Consumers Energy, in addition to the CIL."[40] This should effectively increase the import limit Consumers should assume for the CSA analysis beyond what is feasible from the Zone 7 CIL alone. Additionally, while the analysis I provide in Exhibit EIB-30 (EB16) primarily focuses on the CIL, if the modification therein were combined with a more reasonable load assumption as I explained above, then the scenario in question would undoubtedly indicate no capacity insufficiency for the alternate plan.

C. Transparency Concerns

Q. Beyond the methodological issues you described above, do you have any general concerns with the overall transparency of Consumers' results and conclusions from the CSA?

A. Yes. Unfortunately, in addition to these four methodological flaws, I find the CSA analysis to be significantly lacking in transparency. There are two primary shortcomings in this respect. The first is the lack of a clear and consistent explanation of which resource portfolios were actually analyzed, and the second is a lack of underlying data provided on the model results.

[40] Direct Testimony of Sara Walz, p. 80.

1. Lack of consistency on the analyzed portfolios

Q. Can you elaborate on the first of these transparency issues (i.e., the lack of a clear and consistent explanation of what portfolios were analyzed)?

Yes. As I explained earlier, the CSA focused on capacity insufficiency examples which were described in the direct testimony of Company witness Walz (pp. 82-87) and produced both as Exhibit A-16 and through a discovery response.[41] In at least ten places in Walz's direct testimony, Consumers makes reference to the CSA's evaluation of an "Alternate Plan" or "alternate plan"[42] which at first glance seems to be equivalent to the Alternate Plan Consumers studied in its subsequent IRP analysis. However, it appears that the "alternate plan" studied in the CSA actually represents a wholly different portfolio that is not exactly consistent with the Alternate Plan studied in the subsequent IRP analysis. In other places, Consumers' testimony and exhibits also refer to a "high renewables" portfolio that is different from the Alternate Plan and appears to be what Consumers actually analyzed in its CSA.[43] As Consumers stated in a discovery response, the CSA "compares a refresh of our approved 2018 IRP plan, containing high renewables and less controllable generation (the "alternate plan"), to the 2021 IRP PCA."[44] Thus, it remains unclear how this "high renewables" or "alternate plan" was derived or what relationship it has to the Alternate Plan later examined by Consumers in its IRP analysis. In any case, I find these descriptions of what was studied in the CSA to be confusing, opaque, and

[41] Exhibit EIBC-32 (EB-18): discovery response MEIBC-CE-297.
[42] See, for example, Direct Testimony of Sara Walz, pp. 75, 76, 77, 82, 83, 87, 88, and 89.
[43] Walz Direct., pp. 86, 87, 88, and Exhibit A-16.
[44] Exhibit EIB-24 (EB10).

counterproductive to stakeholders' ability to assess the reliability of the portfolios that were ultimately evaluated in the IRP.

2. Data provided

Q. Can you elaborate on the second of these transparency issues (i.e., the lack of data provided)?

A. Yes. Although the Company claims to have performed 3,000 iterations of model runs for its CSA analysis, the Company only provided the numerical results for a very limited number of hours during which loss of load events occurs. The set of numerical results I was able to review remained limited to the examples the Company chose to provide in Exhibits A-16 and A-17, which were nearly identical to the data provided in subsequent discovery responses.[45]

Q. Did Michigan EIBC/IEI/CGA seek access to additional hourly data through the discovery process?

A. Yes. In response to these inquiries, Consumers stated that hourly output was "not activated" and that it was not reasonable to store the amount of data generated through the sensitivity analysis.[46] Michigan EIBC/IEI/CGA subsequently attempted to narrow its request to Consumers in order to reduce the amount of data Consumers would need to generate. Consumers did provide an additional response to this modified request; however, this

[45] Exhibit EIB-33 (EB-19): discovery response MEIBC-CE-287 and Exhibit EIB-32 (EB-18): discovery response MEIBC-CE-297.
[46] Exhibit EIB-32 (EB-18): discovery response MEIBC-CE-297.

response did not result in any additional information on the CSA scenarios analyzed beyond the examples already provided in Exhibits A-16 and A-17.

D. Findings and Recommendations

Q. Do you have any summary findings and recommendations for the Commission based on your review of the Company's CSA?

A. Yes. I believe the Commission should disregard the CSA as a reasonable basis for the Company's decision to pursue a gas-only RFP. As I have explained, the CSA contained numerous methodological flaws that invalidate its conclusions. My analyses in Exhibits EIB-27 (EB-13) and EIB-30 (EB-16) show that correcting any one of these flaws could substantially alleviate the identified capacity insufficiency events. Applying more than one of these corrections together would only serve to further alleviate these reliability concerns altogether. These obvious shortcomings with Consumers' analysis demonstrate that the CSA does not reflect a sound analysis and should not serve as a basis to support Consumers' RFP. Thus, in lieu of Consumers' proposed gas resources – particularly those added in 2025 – I believe the Commission should require Consumers to conduct a truly competitive solicitation as I have outlined in the previous section.

V. <u>Consumers' IRP modeling process artificially limits the value that energy storage can deliver to its system.</u>

Q. Please describe the modeling process the Company followed in its IRP analysis to select its PCA.

A. The Company followed a nine-step process.[47] These nine steps mainly include the development of input assumptions for the Company's existing and future resources and load, portfolio modeling, and sensitivity analysis. In my testimony in this section, I discuss a number of flaws and biases that are included in this process and are impacting the energy storage deployment in the Company's PCA.

Q. Please summarize the biases you have identified in the Company's process.

A. First, during steps 1 and 2 of the process, the Company identifies all the viable resource options and develops input assumptions that will be used in the modeling, including the cost and performance characteristics of those resources. In these two steps, the Company identifies four storage prototypes. As I will discuss later, I do not believe these four prototypes fully capture the value that energy storage can deliver to Consumers' system.

Second, in step 5 of the nine-step process, the Company uses the AURORA software to identify the optimal portfolio under each scenario. According to Company witness Walz, "in capacity expansion mode, AURORA selects incremental capacity additions from a selection of various resource options according to technology, amount, and timing to arrive at a least-cost resource plan that is a co-optimization of meeting hourly energy requirements as well as ensuring that required capacity reserve margins are maintained."[48] However, I find that in this step, the Company has included several constraints that significantly limit the model's ability to select a truly optimal portfolio. Those constraints

[47] Direct Testimony of Sara Walz, p. 15.
[48] Direct testimony of Sara Walz, p. 24.

include annual resource limits, earliest years of operations for specific resource types, and forcing in resources that might not otherwise be selected by the model.

Third, in step 8, during the risk assessment of the different portfolios, the Company presents its CSA, which concludes that a portfolio with renewable resources and storage results in significant periods of time for which potential loss of load may occur. The analysis presented and concluding remarks have flaws that I have already discussed in Section VI of my testimony.

A. Energy Storage Resource Options Considered in the IRP do not reflect the technology's technical and cost performance.

Q. Beyond the issues regarding the gas resource additions and the CSA you have already described, are there additional shortcomings in Consumers' analysis of energy storage resources?

A. Yes. There are at least four (4) additional flaws in Consumers' IRP analysis that unfairly place energy storage at a competitive disadvantage. I will explain each of these shortcomings in this section of my testimony. These shortcomings can be categorized into a few areas as follows:

1. Lack of sub-hourly dispatch
2. Overly restrictive assumptions on market participation
3. Interconnection costs
4. Capital and O&M costs

I will describe each of these in greater detail below.

1. Lack of sub-hourly dispatch

Q. How quickly can battery resources respond to dispatch instructions for charging or discharging?

A. Almost instantaneously. The fact that batteries can effectively ramp up or down within seconds can provide significant value and flexibility to a utility's system operations.

Q. Does Consumers' modeling of storage resources in AURORA adequately capture the full value of this real-time flexibility batteries can provide?

A. No. Consumers' AURORA modeling was conducted using hourly timesteps and sub-hourly modeling was not performed.[49] Thus, the additional incremental value that energy storage resources can provide through sub-hourly dispatch was not adequately captured by the model. While the "Ancillary Services" prototype does approximate to a limited degree sub-hourly dispatch, it represents only a partial view of a storage resource's capability. Within the Ancillary Services prototype the battery is assumed to provide regulation reserves as a form of ancillary service. However, even if a battery is not providing regulation, it can still respond to real-time price signals for energy, which are updated by MISO every 5 minutes. Depending on system conditions, real-time energy prices can be quite volatile and present a significant opportunity to enhance the value that a battery can provide to Consumers' system. In fact, Strategen has conducted analyses showing that this real-time dispatch has the potential to increase the energy value of a storage system in some

[49] Exhibit EIB-34 (EB-20): discovery response MEIBC-CE-300.

markets by up to approximately 80%.[50] In theory, this enhanced value could apply to all of the storage resource prototypes, not just the Ancillary Services prototype.

2. Overly restrictive assumptions on market participation

Q. Does Consumers' IRP modeling consider the fact that standalone battery storage resources can provide multiple services at the same time (i.e., "value stacking")?

A. Yes. To its credit, Consumers has made an effort to capture the broad range of potential energy storage use cases and value streams. However, I still find that there are limitations in Consumers' approach that may not fully capture the total value that a storage resource could provide. I will explain these limitations in further detail below.

Q. Of the storage resource prototypes Consumers modeled, were there any that you believe best represented this value stacking?

A. Yes. I believe the Ancillary Services prototype best accomplishes this. This prototype is similar to the Energy and Capacity storage resource prototypes, but with the added provision of ancillary services in addition to energy and capacity. Since energy, capacity, and ancillary services are system-wide functions, I believe this is also representative of the largest universe of high-value storage resources that could potentially be procured by Consumers independent of location. While the distribution deferral prototype is also interesting, I believe it has more limited usefulness in the IRP context due to its more limited and location-constrained potential. Additionally, it is worth noting that the only storage resource included in Consumers' PCA prior to 2035 is the Ancillary Services

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[50] See p 65 of https://www.strategen.com/s/VirginiaEnergyStorageStudy-FinalReport2019.pdf

prototype, presumably due to the higher value it can provide versus the other resource types.[51]

Q. Regarding the Ancillary Services prototype, were there any limitations in how this resource was represented in the model that you are concerned about?

A. Yes. It is first worth noting that Consumers' modeling approach did not attempt to optimize how the storage resource was dispatched between energy and ancillary services. Instead, Consumers employed some simplifying assumptions about how often it could be used for each purpose. I recognize that this may have been a necessity due to limited time, resources, and modeling capabilities, but it also means that the results are not completely accurate. More importantly, the simplifying assumptions placed somewhat arbitrary time limits on the ability of the resource to be dispatched for each purpose without any attempt to quantify or prioritize which service would likely provide highest value.

Q. Can you elaborate on these arbitrary time limits and why you find them to be problematic?

A. Yes. First, Consumers assumed that the Ancillary Services prototype could only operate in the energy market on 50% of days throughout the year, while the other 50% were reserved for frequency regulation. Second, within the days that the storage resource was restricted to energy market services, Consumers assumed it was only able to provide 4 hours of charging and 4 hours of discharging. And third, within the days that the storage resource was restricted to ancillary services, Consumers assumed it would only receive a market

[51] Exhibit EIB-35 (EB-21): Discovery response MEIBC-CE-305.

award half of the time. I find each these assumptions to be problematic for a few different reasons:

1. First, there is no basis for the 50/50 split between days in which each service can be provided. It could very well be that it is more valuable to provide ancillary services on 100% of days, 0% of days, or some value other than 50%. In fact, Consumers acknowledged that a storage resource could participate in either the energy market or the ancillary services market for a greater number of days per year than 50%.[52] To my knowledge, Consumers conducted no analysis to support its assumption of a 50/50 split.

2. Second, on the days in which storage provides energy market services, there is no reason why the battery could not be utilized outside of the 4 hours of charging and 4 hours of discharging. By limiting dispatch to a total of 8 hours per day, the battery is being underutilized two thirds of the time (i.e., 16 hours). Practically speaking, a storage resource could still be dispatched during these hours to provide real-time energy services on a sub-hourly basis, or it could also provide ancillary services.

3. Third, while it is reasonable to assume that a storage resource might not receive a market award for ancillary services 100% of the time, Consumers' assumption of 50% is also unsupported. Witness Washburn even acknowledged that it is possible that a battery could participate in the ancillary services market for greater than 50% of the time.[53] In fact, since

[52] Exhibit EIB-36 (EB-22) : discovery response MEIBC-CE-302c.
[53] Exhibit EIB-37 (EB-23): discovery response MEIBC-CE-303.

battery resources have virtually no startup costs, there is good reason to believe they might provide ancillary services more often than other types of resources.

4. Fourth, it is not clear how Consumers selected the hours in which each service would be provided. As detailed in Consumers' response to a discovery request, an hourly profile was created but the details of how this profile was developed have not yet been provided, and no evidence has been provided explaining the specific pattern of hours selected.[54]

5. Fifth, it appears that the Ancillary Services prototype resource additions were arbitrarily limited to either 12 MW per year or a maximum of about 52 MW in the 2025 timeframe.[55]

3. Interconnection Costs

Q. What generation interconnection costs did Consumers assume for new resources in its IRP analysis?

A. According to Mr. Scott, "A transmission network upgrade cost assumption of $46,000 per megawatt ($/MW), equivalent to $46/kW of generation capacity, was used for all generation technologies located in Michigan."[56] Additionally, Mr. Scott went on to explain that a recent survey of network upgrade costs ranged from $5.30/kW to $172.30/kW.[57]

[54] Exhibit EIB-38 (EB-24): discovery response MIEIBC-CE-302b.
[55] See Exhibits EIB-20 (EB-6): WP-STW-7 2021 IRP Assumptions Book, tab 8d and EIB-39 (EB-25): discovery response -MEIBC-CE-309.
[56] Direct testimony of Benjamin T. Scott, on behalf of Consumers Energy Company. Case No. U-21090, p. 13.
[57] *Ibid.*

Q. Do you believe these interconnection cost assumptions are applicable to standalone storage resources?

A. No. As I've explained, standalone storage resources are very flexible in terms of siting and can be placed in locations that are most optimal from a grid interconnection standpoint. In fact, some storage developers specialize in identifying locations where these costs would be minimized.

Q. In light of this flexibility to optimally site storage resources, do you think it is appropriate for the Consumers IRP analysis to assume that new storage would typically incur a $46/kW network upgrade cost?

A. No. In fact, I would suggest that the Consumers IRP analyses should assume the lower end of the interconnection cost range for standalone storage resources. That is, I believe a $5.30/kW value would be more appropriate.

4. Capital and O&M Costs

Q. Do you think that the assumptions used by Consumers for capital and O&M costs and performance of storage resources in its IRP are appropriate?

A. I think that the assumptions used by Consumers are fairly reasonable. More specifically, Consumers relied upon the 2019 NREL ATB assumptions for storage costs in its analysis. In general, I believe the NREL ATB is an authoritative source of recent cost information and commend Consumers for using it in its IRP analysis. However, I would note that Consumers relies upon 2019 data, which are slightly outdated. As of its IRP filing in June 2021, Consumers would have had access to the 2020 NREL ATB data. Since then, NREL has also issued its 2021 ATB. Thus, while I think the use of the 2019 data was reasonable for Consumers to use in this case, it is worth considering in this proceeding how the IRP results might differ if the 2020 or 2021 data were used instead. In particular, I'm concerned about how some of Consumers' recent gas purchases might have been reevaluated given the lower cost estimates for battery storage in the 2025 timeframe according to the 2020 ATB, which were about 5% lower in terms of capital costs for the moderate case.

B. Consumers Energy's IRP modeling in AURORA included constraints that significantly limited the ability of the model to select storage resources

Q. Please explain how the AURORA capacity expansion model was used in the IRP process.

A. The Company followed a complex process that evaluated ten portfolio designs across eight future scenarios and multiple sensitivities. Ultimately, the Company's preferred portfolio -- the PCA -- seems to include a selection of resources that are not the direct result of any specific capacity expansion modeling run in AURORA, but stem from a post-modeling analysis that the Company conducted. Specifically, Company witness Blumenstock states that the Company "identified the demand-side management and supply resources most widely selected by the Company's AURORA software across the scenarios and sensitivities."[58] While I see merit in an approach where resource selection is informed by a wide range of scenarios and sensitivities, a close analysis shows that this is not actually what Consumers did. In fact, this otherwise commendable approach was superseded when it came to developing the PCA. More specifically, the gas resource additions (among

[58] Direct testimony of Richard T. Blumenstock, p 45.

others) were actually forced into the final PCA portfolio[59] in lieu of other resources that AURORA selected as part of an optimal portfolio. Despite these facts, the AURORA capacity expansion runs still indirectly inform important aspects of the PCA in the longer term. Thus, it is still worth trying to understand the modeling choices and constraints that might have led to such a low level of investment on energy storage.

Q. Please summarize the modeling choices you have identified in the capacity expansion modeling for the selection of a resource portfolio.

A. The two main constraints that seem to dictate the resources selected by AURORA are:

- Exogenously forced-in resources, and
- Annual limits on incremental additions by resource type.

The two constraint types combined with the timing of the coal retirements (which are the main drivers of the capacity need) largely dictate what is selected by AURORA.

Q. Which resources were exogenously forced in the model?

A. According to a discovery response from Consumers, several new resources were determined outside the model and added exogenously to the portfolios. Those resources include energy waste reduction, conservation voltage reduction, behind-the-meter generation, combustion turbines (in an MPSC-required sensitivity) and the Covert, DIG, Livingston and Kalamazoo units.[60]

[59] See Exhibit EIB-18 (EB-4) : discovery response MEIBC-CE-307.
[60] *Ibid.*

Q. What are the annual limits that the Company imposed on incremental capacity additions in AURORA?

A. The Company's capacity expansion modeling included limits on the incremental capacity additions per year for several resource options. Specifically:

1. Solar was constrained to 0 MW per year up to 2024 and 500 MW per year starting in 2025;
2. The "Energy and Capacity" storage resource was constrained to 0 MW per year up to 2024 and 500 MW per year starting in 2025;
3. The "Distribution Asset Upgrade Deferral" storage resources was constrained to 0 MW per year up to 2024 and one battery per year (2 MW/year) starting in 2025;
4. The "Ancillary Services Market" storage resources were constrained to 0 MW per year up to 2024 and had an upper limit of 12MW per year increasing to 58 MW (cumulative) in 2030; and
5. DR was constrained with varying levels per year per scenario.

Q. What was the rationale for limiting the first year that each energy storage prototype could be built to 2025?

A. According to the Company, 2025 was selected to give time for the IRP PCA to go through the regulatory process and then provide time for procuring battery energy storage system assets.[61]

[61] Exhibit EIB-19 (EB-5): discovery response MEIBC-CE-299.

Q. Do you agree with the Company's rationale for limiting the first year that energy storage can be built?

A. No. Large-scale battery resources can technically be deployed on a 1 to 2-year time horizon. As described previously, they could be deployed prior to 2025 and (partially) meet the capacity need from the Campbell retirement.

Q. What is the impact of those constraints in the selection of resources by AURORA and the level of energy storage in the different portfolios?

A. By forcing in the natural gas units, the Company essentially eliminates the capacity need from the retirement of the Campbell units. Forcing in resources means that their cost is not ever compared to those of alternative resources, but it is rather imposed on the model (and eventually ratepayers) without consideration of whether it compares favorably to other available options. Had the gas resources not been forced in and energy storage and renewables not been subject to annual limits, the least cost portfolio might have included more energy storage and less natural gas.

C. Findings and Recommendations

Q. What are your main conclusions regarding Consumers' modeling assumptions for energy storage?

A. As detailed in the earlier sections of my testimony, the primary factor limiting energy storage from being included in Consumers' IRP prior to 2030 is the significant gas resource purchases that crowd out potential alternatives such as storage. However, even in later years where additional resource needs arise (or if the gas purchases were removed), there are still inaccurate modeling assumptions that put storage at an unfair disadvantage.

Q. Are there modeling assumptions for storage that you believe are close to reasonable?

A. Yes. In general, I believe the performance characteristics and capital costs of battery storage assumed by Consumers are close to reasonable. However, one exception to this is that Consumers used the 2019 NREL ATB cost projections, rather than more recent projections that would have been available to Consumers during the development of its IRP. While the 2021 NREL ATB cost projections are now available, I recognize that Consumers would not have access to these at the time of developing its IRP, however the 2020 projections would have been available and could have been used.

Q. What other assumptions do you believe put storage at a disadvantage?

A. I believe the restrictions assumed for market services are potentially a significant disadvantage, as is the lack of sub-hourly modeling.

Q. How should the Commission act to remedy these issues?

A. First, I believe the Commission should recognize the fact that Consumers' IRP analysis may not reflect the full amount of cost-effective energy storage due to both the gas procurement issues, as well as the additional modeling issues discussed in this section. Ideally, there would be sufficient time and resources to rerun some of the IRP modeling exercises, with these changes incorporated, however I am not certain that is feasible within this proceeding. In light of this practical reality, I believe a recognition of the factors artificially limiting storage's inclusion in the PCA may be reason enough to warrant additional storage procurement in the near term (i.e., by 2025) beyond what Consumers has proposed. As such, I reiterate my recommendation of a near-term procurement of 80-230 MW of storage. Additionally, an all-source RFP should be conducted for any remaining resource need, in which storage could also participate. Finally, the Commission should direct Consumers to address the modeling limitations for storage I have described in this section in future IRP cycles.

VI. Comparison to other utility IRPs

Q. How do the energy storage additions in Consumers' IRP compare to those of other similarly sized utilities?

A. Other utilities have significantly more storage additions as determined by their IRPs. The table below shows a comparison of several other utilities' planned storage additions by 2025. While the durations each individual storage projects may vary to some degree, the MW reported in this table for resources that are typically around 4-hours in duration.

Utility	**2025 PRMR (MW)**	**Storage added by 2025 (MW)**	**Source**
Arizona Public Service	9,871	235	APS 2020 IRP[62]
PacifiCorp	11,162	697	PacifiCorp 2021 IRP[63]
NV Energy	9,326	1,488	NVE 2021 IRP[64]
Consumers Energy	7,435	0	CE 2021 IRP

[62] https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/2020IntegratedResourcePlan062620.ashx?la=en&hash=24B8E082028B6DD7338D1E8DA41A1563

[63] https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf

[64] http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2020_THRU_PRESENT/2021-6/10318.pdf

Q. What are some of the reasons why these utilities are including such significant amounts of storage investments in their plans?

A. Speaking generally, the most significant reason for these planned additions is to provide peaking capacity to support system reliability. It should also be noted that a significant share (though not all) of these storage resources are being paired with solar PV to take advantage of federal investment tax credit benefits.

Q. What does this comparison reveal in terms of Consumers' plans for energy storage?

A. Consumers' lack of storage investment appears to be out of step with peer utilities that are taking advantage of recent cost reductions in battery technology and making serious investments in storage as a core part of their resource portfolio.

Q. Does this conclude your testimony?

A. Yes.

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the Application of CONSUMERS ENERGY COMPANY for approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief	)))))	**Case No. U-21090**

EXHIBITS OF EDWARD BURGESS

ON BEHALF OF

MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL

AND

ENERGY INNOVATION

Edward Burgess

Senior Director

STRATEGEN

Ed leads the integrated resource planning practice at Strategen. Ed has served clients including consumer advocates, public interest organizations, Fortune 500 companies, energy project developers, trade associations, utilities, government agencies, universities, and foundations. He has led or contributed to expert testimony, formal comments, technical analyses, and strategic grid planning efforts for clients in over 25 states. These have focused on a range of topics including resource planning and procurement, utility system operations, transmission planning, energy storage, electric vehicles, utility rates and rate design, demand-side management, and distributed energy resources.

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Education

PSM
Solar Energy Engineering and Commercialization
Arizona State University
2012

MS
Sustainability
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BA
Chemistry
Princeton
2007

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Work Experience

Senior Director

Strategen / Berkeley, CA / 2015 - Present

+ Focuses on energy system planning via economic analysis, technical regulatory support, integrated resource planning and procurement, utility rates, and policy & program design.
+ Supports clients such as trade associations, project developers, public interest nonprofits, government agencies, consumer advocates, utilities commissions and more.

Senior Policy Director

Vehicle-Grid Integration Council / Berkeley, CA / 2019 - Present

+ Leads advocacy and regulatory policy for a group representing major auto OEMs and EVSEs
+ Advances state level policies and programs to ensure the value from EV deployments and flexible EV charging and discharging is recognized and compensated
+ Leads all policy development, education, outreach, and research efforts

Consultant

Kris Mayes Law Firm / Phoenix, AZ / 2012 - 2015

+ Consulted on policy and regulatory issues related to the electricity sector in the Western U.S.

Consultant

Schlegel & Associates / Phoenix, AZ / 2012 - 2015

+ Conducted analysis and helping draft legal testimony in support of energy efficiency for a utility rate case.

Edward Burgess

Senior Director

Selected Recent Publications

+ New York BEST, 2020. *Long Island Fossil Peaker Replacement Study.*
+ Ceres, 2020. *Arizona Renewable Energy Standard and Tariff: 2020 Progress Report.*
+ Virginia Department of Mines and Minerals, 2020. "*Commonwealth of Virginia Energy Storage Study.*
+ Sierra Club, 2019. *Arizona Coal Plant Valuation Study.*
+ Strategen, 2018. *Evolving the RPS: Implementing a Clean Peak Standard.*"
+ SunSpec Alliance for California Energy Commission.,2018. *Analysis Report of Wholesale Energy Market Participation by Distributed Energy Resources (DERs) in California.*

Domain Expertise

Vehicle Grid Integration

Distributed Energy Resources

Electric Vehicle Rates, Programs and Policies

Energy Resource Planning

Benefit Cost Analysis

Electricity Expert Testimony

Stakeholder Engagement

Energy Policy & Regulatory Strategy

Energy Product Development & Market Strategy

STRATEGEN.COM

Relevant Project Experience

Arizona Residential Utility Consumer Office (RUCO)

IRP Analysis and Impact Assessment / 2015 - 2018

+ Supported drafting of expert witness testimony on multiple rate cases regarding utility rate design, distributed solar PV, and energy efficiency.
+ Performed analytical assessments to advance consumer-oriented policy including rate design, resource procurement/planning, and distributed generation consumer protection.
+ Ed was the lead author on the white paper published by RUCO introducing the concept of a Clean Peak Standard.

Western Resource Advocates

Nevada Energy IRP Analysis / 2018 - 2019

+ Conducted a thorough technical analysis and report on the NV Energy IRP (Docket No. 18-06003)
+ Investigated resource mixes that included higher levels of demand side management, renewable energy, battery storage, and decreased reliance on existing and/or planned fossil fuel plants.

Massachusetts Office of the Attorney General

SMART Program / 2016 - 2017

+ Appeared as an expert witness and supported drafting of testimony on the implementation of the MA SMART program (D.P.U. 17-140), which is expected to deploy 1600 MW of solar PV (and PV + storage) resources over the next several years. Ed served as an expert consultant on multiple rate cases regarding utility rate design and implications for ratepayers and distributed energy resource deployment.

New Hampshire Office of Consumer Advocate

NEM Successor Tariff Design / 2016

+ Worked with the state's consumer advocate to develop expert testimony on a case reforming the state's market for distributed energy resources, developing a new methodology for designing retail electricity rates that is intended to support greater deployment of energy storage.

Edward Burgess

Senior Director

Relevant Project Experience (con't)

Southwest Energy Efficiency Project

IRP Technical Analysis and Modeling / 2018 - 2020

+ Provided critical analysis and alternatives to the 2020 integrated resource plans (IRPs) of the state's major utilities, Arizona Public Service (APS) and Tucson Electric Power (TEP).
+ Provided analysis on Salt River Project's resource plan as part of its 2035 planning process.
+ Evaluated different levels of renewable energy and energy efficiency and identify any changes to the resources needed to meet these requirements and ensure reliability.
+ Worked with Strategen technical team on utilizing a sophisticated capacity expansion model to optimize the clean energy portfolio used in the analysis of the IRPs.

California Energy Storage Alliance

California Hybridization Assessment / 2018 - 2019

+ Managed a special initiative of this leading industry trade group to conduct technical analysis and stakeholder outreach on the value of hybridizing existing gas peaker plants with energy storage

Portland General Electric

Energy Storage Strategy / 2016

+ Provided education and strategic guidance to a major investor-owned utility on the potential role of energy storage in their planning process in response to state legislation (HB 2193).
+ Participated in public workshop before the Oregon Public Utilities Commission on behalf of PGE.
+ Supported development of a competitive solicitation process for storage technology solution providers.

Xcel Energy

Time-of-use Rates / 2017 - 2018

+ Conducted analysis supporting the design of a new residential time-of-use rate for Northern States Power (Xcel Energy) in Minnesota.

Sierra Club

PacifiCorp 2021 IRP Technical Support / 2020 - 2021

+ Provided technical support for Sierra Club in analyzing issues of interest during Pacificorp's IRP stakeholder input process.
+ Prepared analysis, technical comments, discovery requests in advance of drafting formal comments to be submitted before the Oregon Public Utility Commission.

North Carolina, Office of the Attorney General

Duke Energy 2020 IRP Technical Support / 2020 - 2021

+ Provided technical support and analysis to the state's consumer advocate on utility integrated resource plans and their implications for customers and public policy goals.
+ Presented original analysis at multiple IRP-related technical workshops hosted by the NCUC

University of Minnesota

Energy Storage Stakeholder Workshops / 2016 - 2017

+ Facilitated multiple stakeholder workshops to understand and advance the appropriate role of energy storage as part of Minnesota's energy resource portfolio.
+ Conducted study on the use of storage as an alternative to natural gas peaker.
+ Presented workshop and study findings before the Minnesota Public Utilities Commission.

STRATEGEN

Edward Burgess

Senior Director

Expert Testimony

California Public Utilities Commission

- Pacific Power 2020 Energy Cost Adjustment Clause (Docket No. A.19-08-002)
- Pacific Power 2021 Energy Cost Adjustment Clause (Docket No. A.20-08-002)

Indiana Utility Regulatory Commission

- Duke Energy Fuel Adjustment Clause (Cause No. 38707 FAC 125)
- Duke Energy Fuel Adjustment Clause – Sub-docket Investigation (Cause No. 38707 FAC 123 S1)

Massachusetts Department of Public Utilities

- National Grid General Rate Case (D.P.U. 18-150)
- Eversource, National Grid, and Until SMART Tariff (D.P.U. 17-140)

Nevada Public Utilities Commission

- NV Energy's Integrated Resource Plan in (Docket No 20-07023)

Oregon Public Utilities Commission

- Pacific Power 2021 Transition Adjustment Mechanism (Docket No. UE-375)
- Pacific Power 2022 Transition Adjustment Mechanism (Docket No. UE-390)

South Carolina Public Service Commission

- Dominion Energy South Carolina 2019 Avoided Cost Methodologies (Docket No. 2019-184-E)
- Duke Energy Carolinas 2019 Avoided Cost Methodologies (Docket No. 2019-185-E)
- Dominion Energy Progress 2019 Avoided Cost Methodologies (Docket No. 2019-186-E)
- Dominion Energy South Carolina 2021 Avoided Cost Methodologies (Docket No. 2021-88-E)

Washington Utilities and Transportation Commission

- Avista Utilities General Rate Case (Docket No. UE-200900)

Questions for Stakeholder Input:

1. In addressing the draft guidelines below, please indicate your support, opposition, proposed modification, or request for clarification on specific items. Are there any additional guidelines that should be included?
2. Please identify topics that need additional research and/or discussion as part of the workgroup process (e.g., use of independent evaluator, sample scoring criteria or Request for Proposals (RFP)).
3. Are there additional experts or resources that we should consider as part of the workgroup process?
4. What processes should be instituted to ensure streamlined review of winning projects resulting from a procurement process that conforms to these guidelines?
5. With respect to Item 8, and the three options listed below, to address the implementation of MCL 460.6(t)6:
    1. For any of the three options presented, are there any legal constraints?
    2. For any of the three options presented, are there any timing concerns?
    3. For any of the three options presented, are there any concerns with usefulness of the information that would be obtained?
    4. For any of the three options presented, are there any other reasons why they should not be pursued? (Please explain)
    5. Are there additional options or variations to the three options presented that should be considered?

Responses due October 30, 2020.

DRAFT Competitive Procurement Guidelines for Investor-Owned Electric Utilities

Objective: Develop a final guidance document/rule set for use by the Commission to ensure strong, technology-neutral market response and value for ratepayers through transparency, non-discriminatory access, certainty, and fairness in bidding processes that also provides participants with confidence in the process.

Guiding Principles: When making determinations on the reasonableness and prudence of all utility energy resource arrangements, the following guidelines will be used in the Commission's evaluation of the process and resulting bids. This will include resources necessary for Voluntary Green Pricing Programs, for Renewable Portfolio Standards, to inform Integrated Resource Plans (IRP) or as a result of IRPs, etc. These guidelines do not apply to energy waste reduction or other demand-side programs administered by utilities.

Draft Guidelines:

1. All energy resources, including both short- and long-term supply and utility self-build projects, are arranged through competitive procurement. Bidding processes may be tailored based on the specific energy resource purpose or need.
2. Open, non-discriminatory treatment of resources:
    a. Conduct open, non-discriminatory procurement process that fairly considers different ownership structures, resource types, and locations with transparency on how they will be evaluated (see minimum requirements below)

   b. Bidding open to all resources and solutions that can meet system needs (e.g., energy, capacity, voltage support, ramping)
3. Comply with competitive bidding guidelines in FERC's PURPA order (July 2020), including referenced Allegheny case (*Allegheny Energy Supply Co, LLC*, 108 FERC 61082 at p 19 (2004))
4. Minimum RFP requirements and specification of evaluation criteria:
   a. Minimum eligibility requirements for bidders and resources
   b. Price and non-price factors and weighting to be used for project selection (RFP to include scoring sheets with applicable weighting of evaluation factors)
   c. Template PPA with terms and conditions
   d. Consideration of transmission and distribution availability and constraints, including treatment of transmission congestion costs and inter-zonal pricing risk
   e. As applicable, identify the parameters for inclusion of a financial compensation mechanism, terminal value analysis or any other adjustment factor for utility self-build or build/transfer projects.
   f. As applicable, assumptions for federal tax credit treatment for PPAs and utility self-build or build-transfer projects
5. Oversight and independence of bidding process:
   a. Separate staffing and information sharing between utility personnel or utility affiliate responding to RFP (submitting bids) and utility personnel conducting the RFP process (preparation of RFP, scoring/evaluation of results, and contract negotiation)
   b. Use independent evaluator to administer and oversee the competitive solicitation process (independent evaluator need not have final selection authority but should provide recommendations that could be considered for Commission review through audit process)
      i. Utility to provide access to all information for the independent evaluator to effectively carry out its roles and responsibilities
      ii. Independent evaluator will provide utility with sufficient information to conduct a thorough internal review without disclosing the bidder's identity
      iii. Independent evaluator available and responsive to the MPSC throughout the process
   c. At its sole discretion and as part of the Commission's regulatory review process, the Commission may hire its own independent evaluator in lieu of or in addition to the independent evaluator hired by the utility
6. Code of conduct compliance:
   a. All code of conduct rules shall be followed
   b. RFPs used to determine "market price" in affiliate transactions for resource supply pursuant to MPSC code of conduct rules
7. MPSC and Stakeholder Involvement:
   a. Build in time for Staff and stakeholder review and input on draft RFP, review/scoring processes, and PPA documents
   b. Review of actual bids will be limited to individuals or parties that do not participate directly in or have affiliations with organizations that have or will submit proposals responding to utility RFPs
   c. Parties wishing to review bid proposals will be subject to non-disclosure agreements and other requirements to ensure the integrity of the process at the discretion of the utility and Commission
   d. Continue to refine bidding processes over time based on feedback from bidders, the Commission, and stakeholders as well as experiences in other jurisdictions

8. Ensure bidding process aligns with resource planning and various project/contract approval processes, including requirements in MCL 460.6t(6) (see options below).

Options for Alignment with MCL 460.6t(6):

Option 1: Pre-IRP RFP functions as a Request for Information (RFI) and Post-IRP RFP is specific to resource need identified in IRP proceeding.

- Pre-IRP RFP would be an all-source RFP that would function more like an RFI
- Would allow for price and resource discovery to inform IRP
- Final RFP would take place post-IRP
    - Pros
        - Would be responsive to modeling and the contested process taking place in the IRP proceeding
    - Cons
        - MCL 460.6t(6) uses the wording "RFP"

Option 2: Pre-IRP RFP functions as an RFI, Post-IRP RFP is specific to resource need identified in IRP proceeding. RFP process/parameters specified in IRP with approval/modification by the Commission in the IRP proceeding.

- Process used would mimic process identified within Option 1, but any deviations from the process would be vetted through a contested case process.

Option 3: Pre-IRP RFP is a true all-source RFP which informs and drives the modeling and project selection in the IRP and will result in executable contracts following approval in IRP.

- No post-IRP RFPs unless needed.
    - Pros
        - Adheres to exact language in MCL 460.6t(6)
        - Relies on market response for resource acquisition vs. use of planning models/projections to identify resource needs
    - Cons
        - Long lead-time for developers (> one year) which may introduce risk for bidders/increase costs
        - Resource need identified in IRP may not match RFP results

Attachment: Sample Timelines for RFI/RFP Processes and Regulatory Approvals

Option 1 Timeline

Pre-Integrated Resource Plan RFP (Functions as an RFI)			**Post-Integrated Resource Plan RFP**		
Needs to be completed at least 6 months prior to IRP filing date. All-source bid.			RFP will solicit resources based on approved IRP (may utilize results of all source bidding presenting in IRP or selected through modeling and other information in the IRP proceeding).		
Ways to encourage participation in pre-IRP RFP could be included such as advanced notice of post-IRP RFP release, etc.			Need to determine methods to ensure respondent confidence with respect to confidentiality and interested party review.		
Activity	**Business Days**		**Activity**	**Business Days**	**Simultaneous Business Days**
RFP Review (Commission Staff and Interested Non-Competitive Parties)	14		RFP Review (Commission Staff and Interested Non-Competitive Parties)	14	
Utility Receives Feedback	7		Utility Receives Feedback	7	
Release RFP	30		Release RFP	30	
Response Review	30		Independent Evaluator Review	10	
IRP Incorporation	60		Utility Reviews Responses	30	
			Contract Negotiations	30	
			Utility Presentation, MPSC Staff Review		2
			Utility Presentation, Interested Non-Competitive Party Review		2
			Submit Contract(s) to Commission for Ex-Parte Review	45	
Total Business Days	141			166	

Option 3 Timeline

Pre-Integrated Resource Plan RFP		
Needs to be completed at least 6 months prior to IRP filing date. All-source bid.		
Need to determine methods to ensure respondent confidence with respect to confidentiality and interested party review.		
Activity	**Business Days**	**Simultaneous Business Days**
RFP Review (Commission Staff and Interested Non-Competitive Parties)	14	
Utility Receives Feedback	7	
Release RFP	30	
Independent Evaluator Review	10	
Utility Reviews Responses	30	
Contract Pre-Negotiations	30	
IRP Incorporation	60	
IRP Case Final Order	360 (non-business)	
Final Contract Negotiations	30	
Utility Presentation, MPSC Staff Review		2
Utility Presentation, Interested Non-Competitive Party Review		2
Submit Contract(s) to Commission for Ex-Parte Review	45	
Total Business Days	616	

Question:

33. Please address the following topics related to the RFP:

a. How did the Company select the RFP Administrator?

b. How were potential bidders notified of the RFP?

c. How were the types of products sought by the Company selected?

d. Has the Company or RFP Administrator received any complaints regarding the RFP process? If so, please explain.

e. How did the number of bidders in the current RFP compare to the number of bidders in each RFP conducted by the Company within the last 10 years?

Response:

a. The Company identified two organizations that met the needs of the Company and the parameters of the solicitation. After both were interviewed, the Company chose CRA based on several factors, including that CRA had previous experience facilitating Edgar/Allegheny compliant RFPs in which affiliates were permitted to participate. The other company the Company interviewed was not selected due in part to a conflict with a potential bidder(s).

b. As explained beginning on page 2 of Exhibit A-49 (KGT-5), a bidder outreach email was sent to potential respondents identified by the Company and CRA. Additionally, an advertisement was run in S&P Global Platts Megawatt Daily to capture any additional respondents.

c. The parameters of the Company's natural gas RFP are detailed in Witness Blumenstock's direct testimony Page 45 lines 12 through Page 46, lines 3, as well as my direct testimony, page 51, line 22 through page 52, line 19.

d. Neither the Company nor CRA have received any complaints regarding the RFP.

e. The Company has issued 4` RFPs for existing gas plants in the last 10 years. The following table details the number of bidders to each RFP:

RFP	# of Eligible Bidders
2012 Gas Plant RFP	5
2013 Gas Plant RFP	5
2017 Gas Plant RFP	2
2021 Gas Plant RFP	2

KEITH G. TROYER
October 20, 2021

EGI Contracts & Settlements

Question:

68. Please identify any and all generation resources that are exogenously added to the AURORA capacity expansion modeling.

Response:

New resources that were added as determined outside the model during long term capacity expansions in various sensitivities and optimization portfolios were energy waste reduction, conservation voltage reduction, behind-the-meter generation, combustion turbines (in an MPSC-required sensitivity) and the Covert, Dearborn, Livingston and Kalamazoo units.

Sara T. Walz

Sara T Walz
October 7, 2021

Electric Supply Planning

Question:

60. Please refer to the Direct Testimony of Mr. Washburn at page 4.

a. What was the rationale for limiting the first year that each energy storage prototype can be built to 2025?”

Response:

2025 was selected to give time for the IRP proposed course of action to go through the regulatory process and then provide time for procuring the battery energy storage system asset.

Nathan J. Washburn
October 7, 2021

DER/I&C Design

8. New generation technologies and options

d. New generation technologies - Storage (value stack revenues and operating parameters)

Battery Storage, Primary Service - Ancillary Services Market Prototype

Line			
1	Maximum Capacity[1]	(MW)	12
2	Minimum Capacity	(MW)	0
3	Effective Load Carrying Capability	(%)	95%
4	Round-trip efficiency	(%)	85.0%
5	Duration	(hrs)	4
	Cycles per day		1
6			
7	Operating Life	(yrs)	15
8	First Month / Year Available	-	Jan-23
9	Variable O&M (2020$)	($/MWh)	$0

Line			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
10	Fixed O&M ($\$/\text{MW}_{AC}$ nominal)	($/kW-yr)	$33	$31	$30	$28	$27	$25	$25	$24	$23	$23	$22	$22	$22	$22	$22	$22	$23	$23	$23	$23	$23
11	Primary Service Revenue (nominal)	($/kW-yr)		$80	$78	$76	$77	$77	$79	$82	$83	$85	$87	$89	$91	$93	$95	$97	$99	$101	$103	$105	$107
12	Capital Cost ($\$/\text{MW}_{AC}$ nominal)	($\$/\text{kW}_{AC}$)	$1,304	$1,253	$1,200	$1,141	$1,079	$1,011	$986	$960	$932	$903	$873	$879	$886	$891	$896	$901	$906	$911	$915	$919	$923
13	CE Market Cap	(MW)		11.91	24.38	37.42	51.04	52.20	53.39	54.58	55.80	57.04	58.29	59.57	60.86	62.17	63.50	64.86	66.23	67.62	69.03	70.47	71.92

Battery Storage, Primary Service - Distribution Asset Upgrade Deferral Prototype

Line			
14	Maximum Capacity	(MW)	2
15	Minimum Capacity	(MW)	0
16	Effective Load Carrying Capability	(%)	87%
17	Round-trip efficiency	(%)	85.0%
18	Duration	(hrs)	4
	Cycles per day		1
19			
20	Max installations per year		1
21	Operating Life	(yrs)	15
22	First Month / Year Available	-	Jan-23
23	Variable O&M (2020$)	($/MWh)	$0

Line			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
24	Fixed O&M ($\$/\text{MW}_{AC}$ nominal)	($/kW-yr)	$33	$31	$30	$28	$27	$25	$25	$24	$23	$23	$22	$22	$22	$22	$22	$22	$23	$23	$23	$23	$23
25	Primary Service Revenue (nominal)[6]	(lifetime $/kW)	$194	$198	$203	$208	$213	$218	$223	$228	$234	$239	$245	$250	$256	$262	$267	$273	$279	$285	$292	$298	$305
26	Capital Cost ($\$/\text{MW}_{AC}$ nominal)	($\$/\text{kW}_{AC}$)	$1,304	$1,253	$1,200	$1,141	$1,079	$1,011	$986	$960	$932	$903	$873	$879	$886	$891	$896	$901	$906	$911	$915	$919	$923
27	Modeling Constraints, if applicable	(FOR)	This prototype provides peak shifting/shaving, to defer an otherwise necessary upgrade at a distribution substation. Assume the battery is reserved to provide that service Jun 1 - Sep 30, Mon-Fri, 3pm-8pm and therefore unavailable to Aurora during those periods.																				

Battery Storage, Primary Service - Energy and Capacity Prototype

Line			
28	Maximum Capacity[3]	(MW)	500
29	Minimum Capacity	(MW)	0
30	Effective Load Carrying Capability	(%)	95%
31	Round-trip efficiency	(%)	85.0%
32	Duration	(hrs)	4
33	Cycles per day		1
34	Operating Life	(yrs)	15
35	First Month / Year Available	-	Jan-23
36	Variable O&M (2020$)	($/MWh)	$0

Line			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
37	Fixed O&M ($\$/\text{MW}_{AC}$ nominal)	($/kW-yr)	$33	$31	$30	$28	$27	$25	$25	$24	$23	$23	$22	$22	$22	$22	$22	$22	$23	$23	$23	$23	$23
38	Primary Service Revenue (nominal)	($/kW-yr)	N/A[2]																				
39	Capital Cost ($\$/\text{MW}_{AC}$ nominal)[6]	($\$/\text{kW}_{AC}$)	$1,304	$1,253	$1,200	$1,141	$1,079	$1,011	$986	$960	$932	$903	$873	$879	$886	$891	$896	$901	$906	$911	$915	$919	$923

Battery Storage, Primary Service - Solar Plus Storage Prototype

Line			
40	Solar Capacity	(MW)	100
41	Storage Capacity	(MW)	30
42	Solar ELCC	(%)	50%
	Storage ELCC	(%)	95%
43	Storage Round-trip efficiency	(%)	85.0%
44	Storage Duration	(hrs)	4
45	Storage Cycles per day		1
46	Solar Capacity Factor	(%)	26%
47	Operating Life	(yrs)	30
48	First Month / Year Available	-	Jan-23
49	Variable O&M (2020$)	($/MWh)	$0

Line	Entered on solar unit:		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
50	Fixed O&M ($\$/\text{MW}_{AC}$ nominal)[4]	($/kW-yr)	$12	$12	$11	$11	$10	$10	$9	$9	$9	$9	$8	$8	$8	$8	$8	$8	$9	$9	$9	$9	$9
51	Primary Service Revenue (nominal)	($/kW-yr)	DC-coupled, ITC credit																				
52	ITC	(%)	30%	30%	30%	26%	22%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
53	Capital Cost ($\$/\text{MW}_{AC}$ nominal)[5]	($\$/\text{kW}_{AC}$)	$2,226	$2,181	$2,132	$2,077	$2,016	$1,949	$1,915	$1,881	$1,845	$1,808	$1,767	$1,778	$1,787	$1,795	$1,802	$1,808	$1,818	$1,826	$1,834	$1,842	$1,849
54	Modeling Constraints, if applicable	(Charging)	This prototype is DC-coupled and earns 75% investment tax credits; therefore, the storage unit must be charged at least 75% of the time from the solar unit.																				

[1]The maximum size listed here for the first year. See line 13 for annual maximum capacity expansion.

[2]Energy and capacity value are determined within Aurora and are therefore not input as an offset to costs on the prototype.

[3]The maximum size listed represents an annual upper bound of total capacity expansion and is used in conjunction with the "Allow Partial Build" option. The maximum capacity listed represents the maximum amount of storage capacity additions the company would consider in a single year. In reality, each storage installation project would smaller. For solar plus storage, Allow Partial Build will not be used.

[4]EIA reports Fixed O&M expenses for hybrid solar + storage systems at 26% higher than standalone storage; operating costs are entered onto the solar unit (at 100 MW, not the storage unit, at 30 MW).

[5]Capital costs ($/kW) for hybrid solar + storage systems are denominated based on solar capacity (100 MW)

[6]The distribution asset deferral primary service revenue is a one-time value, for realization of a deferred substation upgrade. The revenue is not credited annually, it should credited as a reduction to the capital expense.

Question:

69. Has the Company performed any AURORA modeling runs that had energy storage available as a resource prior to 2025? If yes, please provide any relevant workpapers.

Response:

Yes, there were modeling runs that had energy storage offered starting in 2023. Please see Exhibit A-13 (STW-10) and workpaper WP-STW-2 Glide Path Rainbow Chart Compiler v2 (Not Printed).xlsm

Sara T. Walz

Sara T Walz
October 7, 2021

Electric Supply Planning

Question:

4. For the purposes of this request, please refer to the Direct Testimony of Keith G. Troyer at page 55, lines 18 through 20, where he discusses required FERC approval under the FPA.
a. Confirm or Deny. Has the Company filed an application with FERC for approval of the proposed acquisition of the generation assets from the Company's affiliates?
b. To the extent the Company's response to (a) above is in the affirmative, please provide a complete reference to the FERC proceeding where the Company's application is being considered.
c. Please provide a detailed narrative explaining the Company's plans if FERC does not approve the proposed acquisition.
d. Please provide a detailed narrative explaining the Company's plans if the Commission does not approve the requested waiver of its Code of Conduct requirements.
e. Please provide a detailed narrative explaining the Company's plans if the Commission approves the proposed acquisition for ratepayer recovery at embedded book costs of the assets.
f. Please provide the requested documents in electronic form with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Response:

- **a.** The Company has not filed an application for FERC approval of the acquisition of generation assets at the time of this response.
- **b.** See my response to part a.
- **c.** The acquisition of the Covert, DIG, Kalamazoo, and Livingston gas plants is an integral part of the Company's IRP. The Company will reassess the options available that will allow it to reliably serve customers if FERC approval is not granted.
- **d.** As stated in c. above, the acquisition of the gas plants is an integral part of the Company's IRP. Again, the Company will reassess its options available in the event that the Commission does not approve the affiliate transaction. It should be noted that as explained on page 60, line 19 through page 62, line 20 of my direct testimony, it is the Company's position that the gas asset acquisition complies with the MPSC's Code of Conduct Rules. However, as explained on page 62, line 3 through page 64, line 15, in the event that the Commission

determines that the Company was not compliant with the MPSC's Code of Conduct Rules, the Company is alternatively seeking a waiver of the Code of Conduct Rules for the affiliate purchase.

e. CMS is not required to honor the transaction if the Company does not pay the full, negotiated sale price. As in responses d. and e., the Company would need to reassess its options in the event that this situation occurs. Please refer to Company witness Battaglia's Exhibit A-44 (JEB-4), pages 44 through 46, that address the conditions to close and rights to terminate the transaction.

KEITH G. TROYER
October 20, 2021

EGI Contracts & Settlements

Question:

65. Please refer to Direct Testimony of Mr. Washburn which discusses the Ancillary Services Market Prototype and page 18, lines 12-14 which state: “this yields an approximate value of $80/kW-year for the Ancillary Service Market prototype for 2021”

a. Please provide any workpapers used to calculate this value.

b. Please confirm that this value was applied as a cost reduction to the Ancillary Services Market Prototype.

c. Was the same value applied for storage resources in all years? If not, please provide the corresponding value for each year after 2021.

Response:

a. Please refer to workpaper WP-NJW-2, tab projection, column M which provides the maximum theoretical value which was reduced according to Washburn Direct Testimony page 18, lines 6-15.

b. Yes, this value was applied as a cost reduction to the Ancillary Services Market prototype.

c. The same value was not applied for storage resources in all years. Please refer to workpaper WP-STW-7 2021 IRP Assumptions Book, tab 8d, line 11 which shows the schedule of values for each year after 2021.

Nathan J. Washburn
October 7, 2021

Question:

52. Please explain the basis and rationale of selecting the alternate portfolio of the Capacity Sufficiency Analysis.

Response:

The Capacity Sufficiency Analysis (CSA) compares a refresh of our approved 2018 IRP plan, containing high renewables and less controllable generation (the “alternate plan”), to the 2021 IRP proposed course of action (PCA) that adds controllable generation to replace fossil-fueled capacity retirements. This alternate plan was compared against the PCA to determine the level of improvement to resource adequacy with the addition of controllable gas generation units. The CSA results are contained in Exhibit A-18 (STW-15) for both the alternate plan (page 1) and the PCA (page 2).

Sara T. Walz

Sara T Walz
October 7, 2021

Electric Supply Planning

Question:

31. On page 82 of Ms. Walz's direct testimony, its states "Exhibit A-16 correspond to a sensitivity that included high level of renewable resources and storage resources, similar to the alternate plan." Please:

a. explain why the Alternate Plan was not used for the analysis depicted by Exhibit A-16.

b. explain why a "portfolio of resources" similar to the Alternate Plan was used;

c. provide the nameplate capacity and the zonal resource credit per resource type, per year for the resource portfolio used for the analysis represented in Exh. A-16;

d. explain why the Alternate Plan resource portfolio be used for the Capacity Sufficiency Analysis represented in Exh. A-16;

e. explain why a "portfolio of resources" similar to the Alternate Plan was used for the Capacity Sufficiency Analysis (reflected in Exh. A-16) but used the Alternate Plan resource portfolio for the Capacity Sufficiency Analysis reflected in Exh. A-18.

Response:

a. When running the capacity sufficiency analysis (CSA), a total of 3,000 simulations are executed. Due to time and computer memory limitations, hourly output is not reported for all the 3,000 simulations. As noted in Walz testimony, the results from Exhibit A-16 are illustrative examples showcasing what a loss of load event may look like. The hourly outputs necessary to produce Exhibit A-16 were not available from the 3,000-simulation alternate plan but was available from a smaller subset of simulations (only 100 instead 3,000) that evaluated a portfolio of resources very similar to the alternate plan.

b. Please see response to part (a).

c. Please refer to attachment "U21090-MEIBC-CE-252-Walz_ATT_1".

d. The phrasing of the question is unclear.

e. As discussed in Walz testimony, Exhibit A-16 and Exhibit A-17 are <u>illustrative examples</u> that compare a portfolio of resources relying primarily on intermittent renewable resources to a portfolio of resources that includes the addition of controllable generation. On the other hand, Exhibit A-18 and Exhibit A-19 directly provide the <u>results</u> of the CSA that support the electric reliability analysis in the IRP filing.

Sara T. Walz

Sara T Walz
9/20/2021

Electric Supply Planning

Question:

51. Please explain how many demand profiles were modeled and how they were paired with the stochastic draws of thermal and renewable generation profiles.

Response:

Only a single demand profile was input to Aurora, but 100 variations of demand manipulations were created within Aurora's risk simulations. Hourly demand could shift upwards or downwards by a random percentage chosen by Aurora, within a standard deviation of +/- 9.1%. Likewise, thermal generation availability was randomly manipulated according to the range of historical outage rates. Ten renewable generation profiles were evaluated under each of the 100 random draws of demand and thermal generator availability. There was no pairing specified between demand and thermal and renewable generation profiles.

Please see the direct testimony of Anna Munie for additional information regarding the parameters and assumed deviations.

Sara T. Walz

Sara T Walz
October 7, 2021

Electric Supply Planning

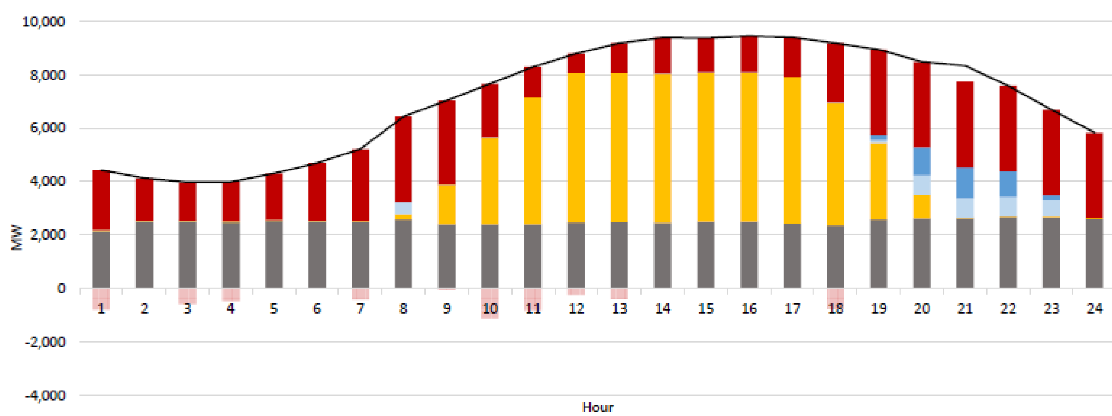
Modified "Summer Peak Day" Example

The two charts below were both constructed using data provided by CE, which CE also presented as part of its CSA in Exhibit A-16 (STW-13). The first chart is identical to the one provided in Exhibit A-16, page 2. According to CE, this purports to show the risk of capacity insufficiency in hour 21 of a summer peak day under a "High Renewables" portfolio that is similar to the Alternate Plan and under a scenario with a load increase of 23% and a Capacity Import Limit ("CIL") of 3,200 MW. The second table shows a modified "Summer Peak Day" example with only a 14% load increase instead of CE's assumed 23% increase. In this modified case, there is no capacity insufficiency during hour 21.

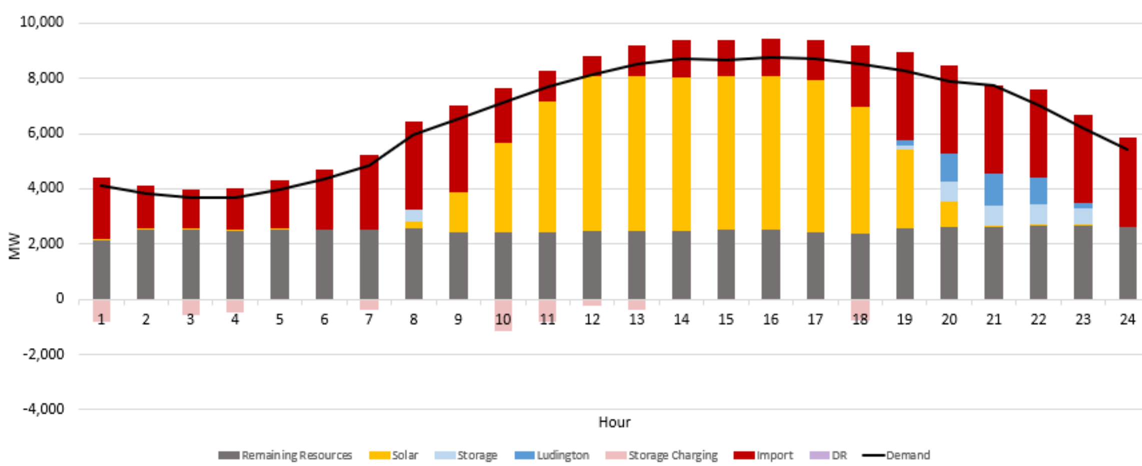
Original CE CSA Analysis (Example 2: Summer Peak Day)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capacity Sufficiency Analysis Loss of Load Event Examples: High Renewable
Summer Peak Day

Case No.: U-21090
Exhibit No.: A-16 (STW-13)
Page: 2 of 5
Witness: STWalz
Date: June 2021



Modified "Summer Peak Day" Example with a reduced load increase (14% versus 23%)



Question:

49. With respect to the CSA Evaluation parameters:

a. Please explain how the modeled outage rate of thermal resources compares to historical outage data for each unit and provide historical outage rates.

b. Please explain the process of selecting the demand, solar, and wind profiles.

i. Please explain whether the renewable energy profiles were developed based on historical data or taken from an AURORA or other database.

ii. Please explain whether the 10 pairings of wind and solar profiles were created randomly as indicated on Walz/75:3 or they are correlated based on weather or other factors.

Response:

a. Historical outage rates are used as inputs to develop the modeled outage rate of thermal resources in the Aurora model. Historical outage rate information can be found in the Company's most recent PSCR reconciliation case, U-21048, Exhibit A-12 (NJK-2), column (e).
b. Demand profiles are created within the Aurora risk simulation. See the response to U21090-MEIBC-CE-290 for additional explanation. Solar and wind profiles were developed based on a combination of historical profiles and profiles delivered with the Aurora model and data from Energy Exemplar.
    i. Both; there were two hourly wind profiles based on historical data at Lake Winds Energy farm and two hourly wind profiles based on Aurora data provided for Michigan wind. Four of the hourly solar profiles were based on Aurora data provided for Michigan solar, and two hourly solar profiles were based on historical data.
    ii. The profiles were randomly paired and not correlated based on weather or other factors.

Sara T. Walz

Sara T Walz
October 7, 2021

Electric Supply Planning

Question:

50. Please explain what the 100 stochastic draws on Walz/75:5 represent and how they differ from the 100 draws varying the duration and timing of unexpected generator outages (Walz/73:24).

Response:

The 100 draws referenced in the aforementioned sections of my testimony are not different. The capacity sufficiency analysis (CSA) includes a stochastic risk simulation that draws 100 iterations. Within these 100 iterations, all of the following variables are randomly manipulated by Aurora

- Customer demand
- Generator availability.

The 100 iterations vary the input data simultaneously (i.e. customer demand is manipulated simultaneously with manipulations to generator availability).

Sara T. Walz

Sara T Walz
October 7, 2021

Electric Supply Planning

<u>Modified "Consecutive Days" Example</u>

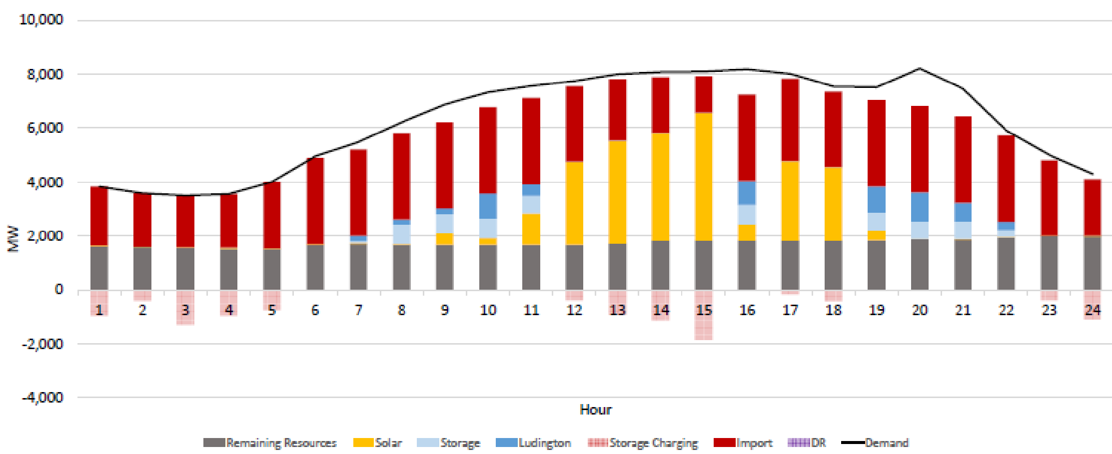
The two pairs of charts below were both constructed using data provided by Consumers Energy ("CE"), which CE also presented as part of its Capacity Sufficiency Analysis ("CSA") in Exhibit A-16 (STW-13). The first pair of charts is identical to the one provided in Exhibit A-16, page 4 labeled as the "Consecutive Days" example. According to CE, this example purports to show the risk of capacity insufficiency in several hours over a two-day period in September 2032 under a "High Renewables" portfolio that is similar to the Alternate Plan and under a scenario with a load increase of 23% and a Capacity Import Limit ("CIL") of 3,200 MW. The second pair shows a modified scenario that is identical to the "Consecutive Days" example except for the following two changes: 1) the Capacity Import Limit was increased to 4,888 MW consistent with MISO's recent assessment for the 2021/2022 planning year; 2) a small amount of storage discharge was shifted from hour 10 to 11, and from hour 13 to 14. In this second case, there is no capacity insufficiency.

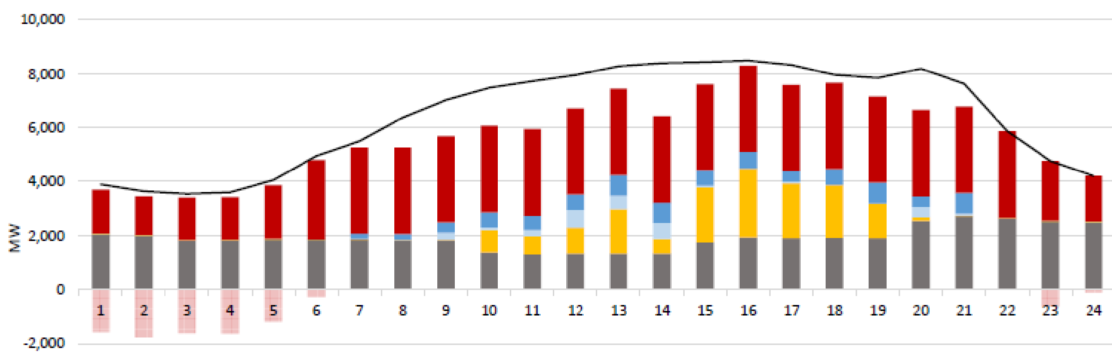
Original CE CSA Analysis (Example 4: "Consecutive Days")

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capacity Sufficiency Analysis Loss of Load Event Examples: High Renewable
Consecutive Days

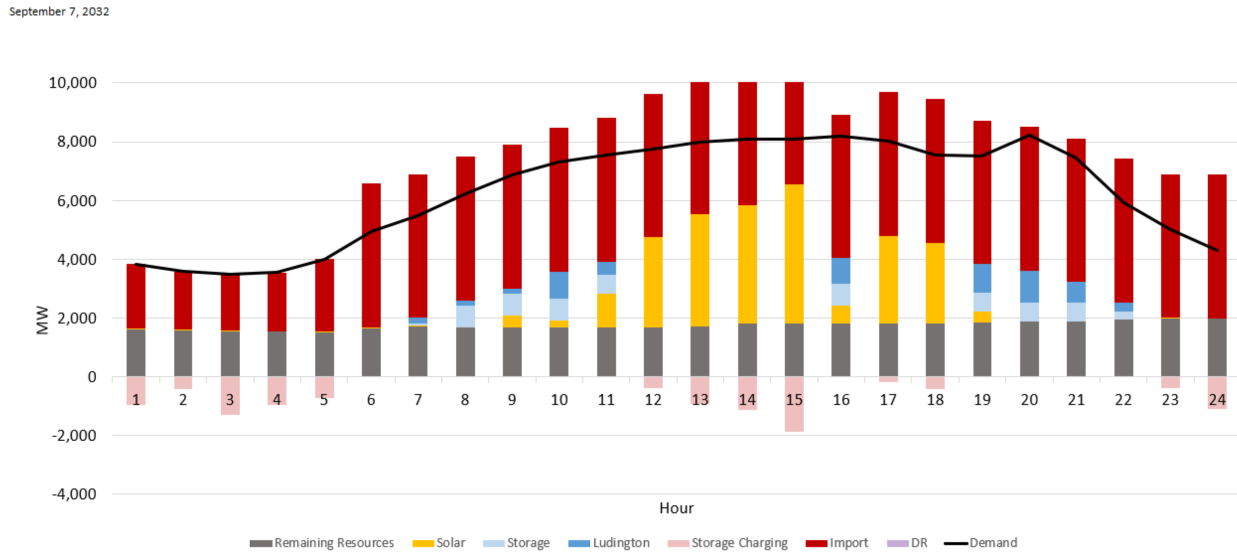
Case No.:	U-21090
Exhibit No.:	A-16 (STW-13)
Page:	4 of 5
Witness:	STWalz
Date:	June 2021

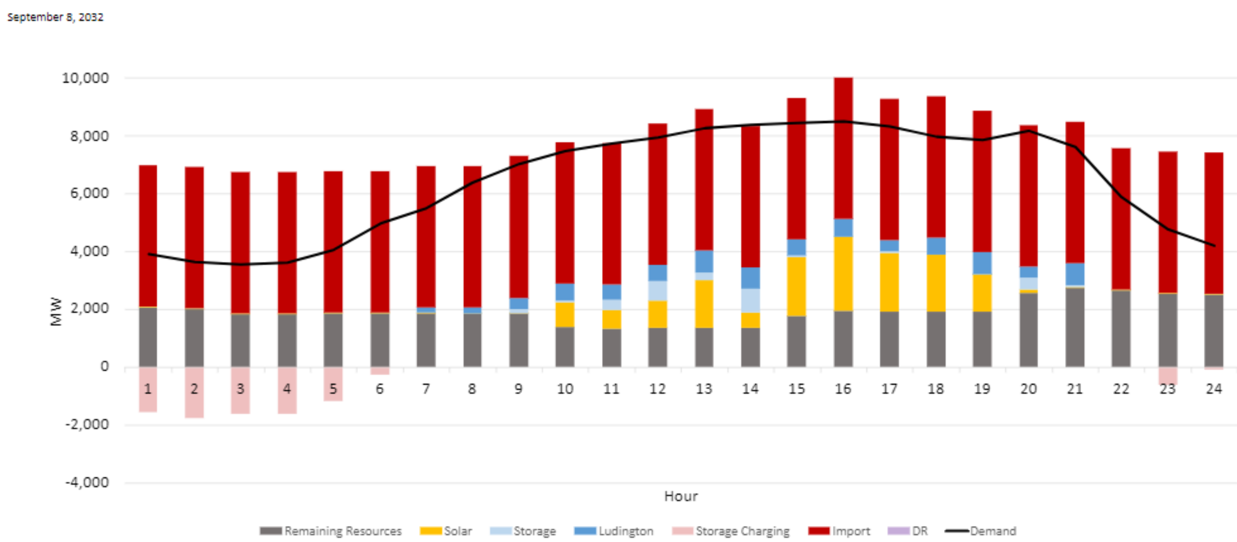
September 7, 2032





Modified "Consecutive Days" Example with an increased CIL (4,888 MW vs 3,200 MW)





Question:

53. Please provide any and all analyses and supporting documentation for reducing the Capacity Import Limit ("CIL") to 3200 MW, from the Midcontinent System Operator's ("MISO") determination of 4,888 MW.

Response:

Please refer to pages 18 and 19 of my Direct Testimony. MISO determined the LRZ7 CIL to be 3,200 MW in its Planning Year 2020/2021 Loss of Load Expectation Study Report. This was the most recent public report available from MISO at the start of the IRP modeling process. Subsequently, MISO published its Planning Year 2021/2022 Loss of Load Expectation Study Report in which MISO determined the LRZ7 CIL to be 4,888 MW. MISO plans to present the Planning Year 2022/2023 CIL/CEL results at the October 5, 2021 Loss of Load Working Group (LOLEWG) meeting. MISO determined the LRZ7 CIL to be 3,749 MW for Planning Year 2022/2023. MISO's presentation can be found at https://cdn.misoenergy.org/20211005%20LOLEWG%20Item%2003%20PY%202022-23%20Final%20CIL-CEL593917.pdf.

Ben Scott

Benjamin T. Scott
October 7, 2021

HVD Planning West & Transmission

Question:

58. For all the loss of load events presented in the testimony of Company Witness Sara Walz, please provide the 8760 generation and load by type. Please explain whether any of the thermal resources is unavailable during the identified loss of load events.

Response:

> **Objection of Counsel: Consumers Energy Company objects to this discovery request because it is overly broad, unduly burdensome, and not proportional to the needs of this case. Due to the size of the requested information in this discovery request, it cannot be reasonably provided. Subject to that objection, and without waiving it, the Company provides the following response:**

Hourly output reporting was not activated for the capacity sufficiency analysis (CSA) presented in Exhibit A-18 (STW-15), due to the volume of data that would be generated. As an example, the CSA includes 235 individual resources in the proposed course of action.

235 resources * 8,760 hours per year * 3,000 simulations = 6,175,800,000 records.

It is not reasonable to generate, store, nor query that amount of data for each sensitivity evaluated in the CSA.

Hourly data is available for the examples presented in Exhibits A-16 (STW-13) and A-17 (STW-14). See enclosed attached file that provides hourly output for all resources in Consumers Energy's system at the time a capacity sufficiency event occurs.

Sara T. Walz

Sara T Walz
October 12, 2021

Question:

48. Please provide any and all workpapers used in the preparation of the Capacity Sufficiency Analysis ("CSA").

Response:

Please see the Excel-based versions of Exhibits A-16, A-17, and A-18 included with the filing.

Sara T. Walz

Sara T Walz
October 7, 2021

Electric Supply Planning

Question:

61. Please refer to Direct Testimony of Mr. Washburn at page 5, lines 16-17: "Aurora models the energy time shifting and calculates the associated revenue."

a. For the Energy and Capacity prototype, did Consumers Energy's Aurora modeling allow for real-time, or sub-hourly, dispatch of energy storage?

b. If not, has Consumers Energy estimated any change in revenue from energy time-shifting that might occur under sub-hourly dispatch?

Response:

a. The Aurora model can generally be thought of as simulating commitment and dispatch decisions most closely aligned with a day-ahead type of market. Sub-hourly modeling was not performed in this IRP.

b. No, not for the prototype referenced in the aforementioned section of testimony.

Sara T. Walz

Sara T Walz
October 7, 2021

Electric Supply Planning

Question:

66. Of the 4 prototypes of energy storage considered, please explain how many MW of each type were added in each year of the Proposed Course of Action.

Response:

Below are the cumulative MW for all battery types added in the PCA:

ASM stands for batteries that participate in the ancillary services market; and DAUD stands for batteries that are intended as a distribution asset upgrade deferral resource.

	ASM	**DAD**	**Storage (Energy+Capacity)**	**Storage (Solar+Storage)**
2030	58	-	-	-
2031	60	-	-	-
2032	61	-	-	-
2033	62	-	-	-
2034	64	-	-	-
2035	65	2	79	-
2036	66	4	157	-
2037	68	6	236	-
2038	69	8	314	-
2039	70	10	393	-
2040	72	10	393	-

Sara T. Walz

Sara T Walz
October 7, 2021

Electric Supply Planning

Question:

63. Please refer to Direct Testimony of Mr. Washburn which discusses the Ancillary Services Market Prototype and page 17, line 23 which states: "50% was selected for participation in the energy market."

a. Does this mean that the battery resource's participation in the energy market was limited to 50% of days throughout the year?

b. For the IRP planning horizon, did Consumers Energy identify specific days and/or hours when the battery would be participating as an energy or capacity resources, and specific hours when it would be providing ancillary services?

c. Is it possible that a battery resource would participate in the energy market during a greater number of days per year than 50%?

d. Did Consumers Energy apply any limitations to the battery resource's participation in the capacity market?

Response:

a) Yes.
b) Yes, an hourly profile was created based on the assumption that 1460 hours will be allocated to serving the energy market and 3650 hours for frequency regulation (ancillary services). Additionally, the resource must be available for the entire MISO Planning Year to participate in the capacity market.
c) Yes.
d) No.

Nathan J. Washburn
October 7, 2021

Question:

64. Please refer to Direct Testimony of Mr. Washburn which discusses the Ancillary Services Market Prototype and page 18, lines 4-5 which state: “50% of the remaining available 7300 hours is 3650 hours of performing frequency regulation”

a. Is it possible that a battery resource would participate in the ancillary services market during a greater number of hours per year than 50%?

Response:

Yes, it is possible.

Nathan J. Washburn
October 7, 2021

DER/I&C Design

Question:

63. Please refer to Direct Testimony of Mr. Washburn which discusses the Ancillary Services Market Prototype and page 17, line 23 which states: “50% was selected for participation in the energy market.”

a. Does this mean that the battery resource’s participation in the energy market was limited to 50% of days throughout the year?

b. For the IRP planning horizon, did Consumers Energy identify specific days and/or hours when the battery would be participating as an energy or capacity resources, and specific hours when it would be providing ancillary services?

c. Is it possible that a battery resource would participate in the energy market during a greater number of days per year than 50%?

d. Did Consumers Energy apply any limitations to the battery resource’s participation in the capacity market?

Response:

a) Yes.
b) Yes, an hourly profile was created based on the assumption that 1460 hours will be allocated to serving the energy market and 3650 hours for frequency regulation (ancillary services). Additionally, the resource must be available for the entire MISO Planning Year to participate in the capacity market.
c) Yes.
d) No.

Nathan J. Washburn
October 7, 2021

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Page **1** of **1**

Question:

70. Please provide a list of all the annual deployment limits per resource type and year included in AURORA. Please provide the reasoning for these constraints.

Response:

For modeling in Aurora, the following annual constraints were applied:

- Solar was constrained to 500 MW per year starting in 2025, as described by Company witness Jeffrey E. Battaglia on page 13-14, lines 11-24 and 1-5;
- Energy and capacity storage was constrained to 500 MW per year starting in 2025 as described by Company witness Nathan J. Washburn on page 5, lines 8-13;
- Distribution asset upgrade deferral batteries were constrained to one per year as described by Company witness Nathan J. Washburn on pages 14-15, lines 8-22 and 1-3;
- Ancillary services market battery was constrained as described by Company witness Nathan J. Washburn on pages 17, lines 11-14. These cumulative MW amounts are shown below

2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
52	53	55	56	57	58	60	61	62	64	65	66	68	69	70	72

- Demand response was constrained as described by Company witness Emily A. McGraw on page 10, lines 12-16. These cumulative MW amounts in CE and MPSC scenarios are shown below:

	2023	2024	2025	2026	2027	2028	2029	2030	2031
CE	23	60	107	160	231	295	371	449	512
MPSC Medium	59	117	176	234	293	351	410	468	527
MPSC High	113	226	339	453	566	679	792	905	1,018

	2032	2033	2034	2035	2036	2037	2038	2039	2040
CE	512	512	512	512	512	512	512	512	512
MPSC Medium	536	546	556	565	575	585	594	604	614
MPSC High	1,037	1,055	1,074	1,093	1,111	1,130	1,148	1,167	1,185

Sara T. Walz

Sara T Walz
October 7, 2021

Electric Supply Planning

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of Consumers Energy Company for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and other relief	))))))	Case No. U-21090

TESTIMONY OF SEAN R. BRADY

ON BEHALF OF

THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,

INSTITUTE FOR ENERGY INNOVATION,

AND CLEAN GRID ALLIANCE

TABLE OF CONTENTS

I. INTRODUCTION and QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Sean R. Brady and I am Senior Counsel and Regional Policy Manager – East for Clean Grid Alliance ("CGA"). Our office is located at 570 Asbury Street, Suite 201, St. Paul, MN 55104.

Q. For whom are you testifying?

A. I am appearing on behalf of Michigan Energy Innovation Business Council ("Michigan EIBC"), the Institute for Energy Innovation ("IEI") and CGA, collectively referred to as "Michigan EIBC/IEI/CGA."

Q. Have you previously testified before the Michigan Public Service Commission?

A. I have not.

Q. What is your background and education?

A. I worked for nine years at the Illinois Commerce Commission in the general counsel's office and as a legal and policy advisor for two commissioners. Since 2009 I have been working at CGA on policies that promote the development of wind, solar and battery storage in the Midcontinent Independent System Operator, Inc. ("MISO") footprint. For ten years, on behalf of CGA, I provided technical and policy comments to MISO on its annual transmission expansion plan. For those ten years, I was the sector representative to the MISO Planning Advisory Committee for the Environmental/Other Sector. I have a law degree from Chicago/Kent College of Law, a masters degree in public administration from the University of Illinois at Chicago, and a bachelors of engineering degree from the University of Illinois at Urbana-Champaign.

Q. Have you previously analyzed and provided comments on integrated resource plans?

A. On behalf of CGA and its predecessor, Wind on the Wires, I have performed analyses of cost inputs used by utilities in developing their integrated resource plans ("IRP"). I have prepared and submitted comments on IRPs prepared by Ameren Missouri, Duke Energy-Indiana, Indiana & Michigan Power, Northern Indiana Public Service Company LLC, and in long-term renewable resource plans prepared on behalf of Illinois utilities by the Illinois Power Agency.

In addition, I have prepared comments for over ten years of MISO annual transmission expansion plans on a range of issues, including modeling inputs affecting costs.

Q. What is the purpose of your testimony?

A. My testimony reviews Consumers Energy Company's ("Consumers Energy" or "Company") IRP and Proposed Course of Action ("PCA") between 2022 and 2030 and recommends improvements upon the PCA.

Q. Please summarize your findings and recommendation.

A. There are several aspects of Company's methodology and assumptions that were reasonable. It was appropriate for the Company to evaluate an earlier retirement of its coal-fired units, given the increasingly challenging economics of burning coal. The Company's primary source of renewable and storage resource costs, the National Renewable Energy Laboratory's ("NREL") Annual Technology Baseline ("ATB"), is a reliable industry standard source for this data.

My review, however, found that there are many steps in the Company's methodology that stacked the deck against adding renewable and battery resources in its modeling. Key errors were made in the sensitivities that were run in the integrated resource plan modeling. In addition, inputs and assumptions result in barriers to proper consideration of a portfolio of utility-scale wind, utility-scale solar, battery storage, distributed energy resources and demand response. The flaws in the Company's modeling include:

(1) the Company's levelized cost of energy and capacity for renewable resources and battery storage is too high. If those costs are corrected, there is a reasonable likelihood the Aurora model would not select the existing gas plants;

(2) the sensitivities the Company presented in its filing do not demonstrate that the Company evaluated a renewable resources portfolio that could replace the plant retirement timeline in the PCA;

(3) the Alternative Scenario the Company presents is not a reasonable proxy for a renewable and battery resource portfolio that replaces the Karn and Campbell retirements proposed in the PCA;

These issues, coupled with the issues raised by Michigan EIBC/IEI/CGA witness Burgess, raise the question as to whether a portfolio of renewable resources, battery storage, distributed generation, and demand response could replace the Karn and Campbell Units at a cost lower than the natural gas plants proposed in the PCA. Together, these findings indicate that the Company's evaluation of potential resources was, at best, incomplete and at worst, not reasonable. As such, the Company's IRP arguably demonstrates a bias toward the purchase of natural gas plants in place of other, more cost-effective resources.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

- Exhibit EIB-40 (SRB-1) Résumé of Sean R. Brady.
- Exhibit EIB-41 (SRB-2) Discovery Response MEIBC-CE-241.

II. SUMMARY OF CONSUMERS ENERGY'S PCA and MODELING APPROACH

Q. Please summarize the Company's Proposed Course of Action.

A. The Company's PCA includes the following:[1]

i. The retirement of Karn Units 3 and 4 by May 31, 2023, and Campbell Units 1, 2, and 3 by May 31, 2025;

ii. The purchase of four existing gas units – New Covert Generating Facility ("Covert"), Dearborn Industrial Generation ("DIG"), the Livingston Generating Station (":Livingston") and the Kalamazoo River Generation Station ("Kalamazoo"). The Covert Plant is to be purchased on or about May 31, 2023, and the DIG/Livingston/Kalamazoo plants are to be purchased on or about May 31, 2025.

iii. Approval of the acquisition and purchase costs of the Covert, Livingston, Kalamazoo, and DIG plants in the manner set forth in the Company's application

[1] Direct Testimony of Richard T. Blumenstock, on behalf of Consumers Energy Company. Case No. U-21090. ("Blumenstock Direct") pp. 5-7.

filing, and proposed Energy Waste Reduction, Demand Response, and Conservation Voltage Reduction costs as reasonable and prudent for cost recovery purposes pursuant to MCL 460.6t;

iv. Approval of certain accounting treatments, which include: (i) regulatory asset treatment, with full return, to recover the remaining net book balances of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 through their current design lives; (ii) approval to defer employee retention costs; and (iii) approval to recover retirement transition costs through a regulatory asset;

v. Approval of the selection and proposed purchase of the DIG, Kalamazoo, and Livingston plants by Consumers Energy from its affiliate, CMS Enterprises Company ("CMS Enterprises");

vi. Changes to the Company's currently approved IRP competitive procurement process used to acquire the new supply-side resources in the Company's PCA which include greater flexibility in the amount of capacity ultimately acquired in each solicitation and greater certainty regarding the Commission approval process for the new resources selected;

vii. Continued use of the competitive procurement process to determine full PURPA avoided cost rates and the Company's capacity needs or sufficiency for the purposes of PURPA. In addition, the Company requests modifications to its currently approved PURPA avoided cost construct. Furthermore, the Company is requesting a continuation of the Commission's determination that the Company does not have a PURPA capacity need so long as it is implementing the PCA, with the competitive procurement approach proposed by the Company; and

vii. Continued recovery of a Financial Compensation Mechanism ("FCM") and application of that FCM on all new or newly modified PPAs. The Company is also proposing an adjustment to the methodology and level of FCM applied to PPAs, based on the FCM initially approved in Case No. U-20165.

Q. Please summarize the Company's modeling approach.

A. Company witness Walz describes the nine interrelated steps used to develop and evaluate potential resource portfolios. Those steps include:[2]

1. Determine capacity position and first year of need;
2. Identify viable resource options;
3. Develop production cost models including appropriate inputs and assumptions;
4. Construct resource portfolios for evaluation;
5. Perform portfolio capacity expansion and production cost simulation analysis;
6. Evaluate portfolios using quantitative and qualitative measures;
7. Evaluate portfolios through scenario and sensitivity analysis;
8. Complete a risk analysis; and
9. Determine the most reasonable and prudent plan that meets the MPSC and Company planning objectives, and consider stakeholder feedback.

Q. What is a portfolio?

[2] Direct Testimony of Sara T. Walz, on behalf of Consumers Energy Company. Case No. U-21090. ("Walz Direct"). p. 15.

A. A portfolio is a collection of resources (supply-side or demand-side) that can be used to fill a capacity need.[3]

Q. What were potential resource portfolios developed by the Company?

A. The Company developed ten portfolio designs.[4]

- Portfolio 1 purchases capacity on the wholesale market;
- Portfolio 2 selects lowest cost resource, either supply or demand side, to meet capacity requirements using overnight build costs;
- Portfolio 3 selects lowest cost resource, either supply or demand side, to meet capacity requirements and uses a glide path that gradually adds resources over a period of years (in contrast to Portfolio 2 which adds resources in the year before the capacity shortfall). The glide path accounts for factors that impact amount of time needed to develop a typical resource;
- Portfolio 4 is the Company's PCA;
- Portfolios 5 through 10 are the business as usual, emerging technology, and environmental policy scenarios analyzed under a glide path approach that meets either the Company's base capacity position ("BUACE," "ETCE," and "EPCE"), or the Commission's required scenarios ("BAUAEO," "EPAEO," and "EPAEO").

The capacity additions selected by Portfolios 1 through 3 vary based on the sensitivity analyzed. In contrast, resource additions in Portfolios 4 through 10 do not change because

[3] Walz Direct. p. 23.
[4] Walz Direct. pp. 46-48 and Company Exhibit A-11.

the Company fixed resource expansion amounts for all scenarios and sensitivities. The portfolios are graphically represented in Company Exhibit A-14.

Q. What scenarios and sensitivities were used in the IRP?

A. The Company evaluated the portfolios under eight scenarios and numerous sensitivities that represented external factors that could influence resource availability and selection. The eight scenarios are: business as usual ("BAU"), emerging technology ("ET"), environmental policy ("EP"), the same three scenarios with a natural gas price forecast developed by the Company ("BAUCE," "EPCE," and "ETCE"), advanced technology scenario, and a carbon reduction scenario.[5]

The Company used thirteen sensitivities and 39 retirement sensitivities.[6] The sensitivities evaluated changes in key assumptions, such as: energy waste reduction, conservation voltage reduction, behind-the-meter-generation levels, the effective load carrying capability, costs of transmissions network upgrades, and the assumed discount rate. Retirement sensitivities evaluate different years in which Karn and Campbell retire. These retirement sensitivities are included in the "Retirement Assumptions" tab of WP-STW-2.

Q. How were the portfolios analyzed?

---

[5] *In the Matter of the Application of Consumers Energy Company for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief*. dated June 30, 2021 ("Application"). Case No. U-21090 ¶9; Blumenstock Direct. pp. 42-45; Walz Direct. pp. 6-9.
[6] Walz Direct. pp. 7-8.

A. The portfolios were analyzed under the previously described scenarios and sensitivities.[7] Models are commonly allowed to select the optimal resource to add to a portfolio. The Company states that the graphs in Exhibit A-14 show that the gas units were optimally selected as part of a portfolio as replacements for the retirement of the Karn Units in 2023 and the three Campbell Units in 2025.[8]

Workpaper STW-2 provides the underlying content for Exhibit A-14 including spreadsheets for the sensitivities the Company used to evaluate the eight scenarios. The spreadsheets identify the resource types and capacity additions that were optimally selected for 133 different sensitivities, including resource selections in the event the Karn Units or the Campbell Units were retired on dates other than what is proposed in the PCA (i.e., retirement sensitivities).

III. CONSUMERS ENERGY DID NOT PROPERLY EVALUATE A PORTFOLIO OF RENEWABLE RESOURCES THAT COULD REPLACE THE KARN AND CAMPBELL UNITS BY 2025.

A. Updates and Corrections to Consumers Energy's Levelized Cost Model Shows That Renewable Resources and Battery Storage Would Likely be Lower in Price Than What Consumers Energy Used in its Model Runs.

[7] Blumenstock Direct. pp. 42-43.
[8] Walz Direct .p. 65.

Q. What Company materials have you reviewed regarding the inputs and assumptions for wind, solar and solar plus storage resources?

A. I have reviewed the testimony, exhibits, workpapers, model inputs, working models, and interrogatory responses of a number of Company witnesses, primarily those of Blumenstock, Walz, Scott, Battaglia, Troyer, and Washburn.

Q. Do you have concerns with the Company's modeling?

A. I have concerns with the levelized cost of energy ("LCOE") and capacity ("LCOC") calculations. The cost data needs to be updated and there are a few errors related to the calculation of wind, solar, and hybrid resources that need to be corrected. I will review the errors and then recommend changes to correct those errors.

Q. If the input changes and corrections you are proposing were incorporated into the Company's model, what would be the impact of those changes?

A. The LCOE and LCOC for renewable resources would be lower than what the Company forecasts.[9] Below is a table comparing the Company's LCOE to a recalculated LCOE based on my discussion below:

Comparison of Company 2023 LCOE to Michigan EIBC/IEI/CGA Updated 2023 LCOE		
Unit Type	Company	MEIBC/IEI/CGA
In State Wind	$ 71.00	$ 47.99
Out of State Wind	$ 51.00	$ 40.74
Transmission Solar	$ 62.00	$ 38.96
Battery - E&C	$ 162.00	$ 126.63
Solar + Storage	$ 80.00	$ 54.47

[9] Company Exhibit A-7.

This means that a renewable energy portfolio with solar plus storage and battery storage could be more cost effective than purchasing new gas plants.

Q. Please describe how the Company modeled wind, solar, solar plus storage and battery storage.

A. The Company's LCOE analysis for utility-scale renewable and battery storage resources mostly relied upon data from the NREL 2019 ATB ("2019 ATB") workbook. NREL has updated its ATB workbook twice since 2019, with the most recent workbook having been issued in 2021 ("2021 ATB workbook"). In addition, there is recent, publicly available price data from Indiana utilities that is informative, especially since the Company did not conduct a request for information or request for proposals for renewable energy resource price data. Using more recent data would improve the accuracy of the Company's analyses.

1. Changes to Levelized Cost of Energy Analysis for Wind Resources

Q. What is your opinion of Consumers Energy wind analysis?

A. I have two concerns with the wind analysis: (1) the method the Company proposes for calculating the capital cost for wind projects unreasonably inflates that cost; and (2) the Company used an improper capital cost curve for wind resources.

Q. What methodology does the Company propose for calculating capital costs?

A. The Company proposes that the capital cost for both in-state and out-of-state wind resources be based on the average of the low, mid and constant price forecasts in the 2019 ATB workbook.[10]

Q. What are your thoughts on the Company's approach?

A. This approach devalues the purpose of the NREL ATB workbook providing three cost scenarios – constant, mid and low. The constant cost scenario assumes no change in any aspect of the industry from 2017 to 2050. The mid cost scenario scales the costs based on NREL predicted turbine and plant technology being used in 2030, and it adjusts for construction contingencies. The low cost scenario scales the costs based on NREL predicted turbine and plant technology being used in 2030 and extends that adjustment out to 2050.

Averaging all three cost scenarios mutes the forecasted improvements in the industry. Instead of an average, I believe that the mid cost scenario should be used because it uses predictions from industry experts and cross checks those against bottoms-up engineering analysis from original equipment manufacturers.[11] The industry has seen a trend of decreasing costs for ten years, so input from industry experts on what changes will occur in the next ten years is valuable. The mid cost scenario methodology is a better way to account for future improvements in industry technology than to dampen the cost scenarios by taking an average.

Q. Please describe the capital cost curve the Company uses for its wind analysis.

---

[10] Direct Testimony of Jeffrey E. Battaglia, on behalf of Consumers Energy Company. Case No. U-21090 ("Battaglia Direct"). p. 21.

[11] U.S. Department of Energy's National Renewable Energy Laboratory's ("NREL") 2019 ATB workbook. Available at https://atb-archive.nrel.gov/electricity/2019/index.html?t=lw.

A. Company witness Battaglia prepared the wind capital cost curve using NREL's 2019 ATB workbook. He used the average of the year-over-year cost increase between 2019 and 2040 and applied that to each year,[12] which he incorrectly asserts to be an annual increase of 2.88%.

Q. What are your thoughts on the Company's approach?

A. An increasing capital cost curve for utility-scale wind resources is contrary to current market data, the market trend over the past ten years, and the 2021 ATB workbook forward forecast.[13] The Company's approach completely overlooks or devalues the trend over the last 10 years of decreasing capital costs due to advances in wind technology.

In addition, the 2019 ATB workbook overnight capital costs in 2017 dollars do not increase between 2019 and 2040, they actually decrease. For in-state wind, Technology Resource Group 7 ("TRG7") most closely reflects the 29% net capacity factor the Company is using. The mid-value overnight capital cost for TRG7 decreases from $1,521/kW (in 2019) to $1,119/kW (in 2040). Over 21 years, that is a 1.25% decrease per year in 2017 dollars – not an increase as Battaglia suggests.

The forward curve for out-of-state wind resources also supports a decreasing capital cost curve. For out-of-state wind, the Company used Iowa, with a 44% net capacity factor, as the representative out-of-state wind resource. In the 2019 ATB workbook, Iowa is predicted to

[12] Battaglia Direct. p. 21.
[13] U.S. Department of Energy's National Renewable Energy Laboratory's 2021 ATB workbook. Available at https://atb.nrel.gov/electricity/2021/land-based_wind.

have the same rate of decline in wind costs from 2019 to 2040 as Michigan wind resources because the 2019 ATB workbook held the capital costs constant for all TRGs. Therefore, the mid-value overnight capital cost for TRG-2 and TRG-3 in 2019 is also $1,521/kW, and the cost in 2040 is $1,119/kW.

Q. Previously you mentioned that the levelized cost analysis should be updated using NREL 2021 ATB workbook data. Does that data have an increasing capital cost curve?

A. No, the forward capital cost curves in the 2021 ATB workbook continue the same downward trend observed in the 2019 ATB workbook, only at a faster rate of 1.9% per year. Regardless of the ATB workbook that is used, the capital costs for wind are predicted to decline from 2019 through 2040. According to the 2021 ATB workbook, the moderate scenario overnight capital cost for every wind class decreases from $1,376/kW (in 2019) to $819/kW (in 2040).[14]

Q. What is the impact of using an increasing capital cost curve compared to a decreasing capital cost curve?

A. Using an increasing capital cost curve, which the Company proposes, instead of a decreasing cost of capital (as predicted by the NREL 2019 and 2021 ATB workbooks) increases the cost of wind resources and likely contributes to Aurora selecting no wind resources for the Company's IRP.

[14] Similar to the 2019 ATB workbook, in the 2021 ATB workbook, the capital costs in a year are the same for each wind class.

A more accurate approach would be to use a decreasing cost of capital and the updated 2021 ATB workbook for utility-scale wind capital costs, instead of the methodology the Company proposes.

2. Changes to Levelized Cost of Energy Analysis for Utility-Scale Solar

Q. What is your opinion of Consumers Energy's utility-scale solar analysis?

A. I have two concerns with the Company's utility-scale solar analysis, as follows: (1) the Company set a constraint that utility-scale solar cannot be selected as a resource until after 2024;[15] and (2) the Company set a constraint in the PCA that only 500 MW of utility-scale solar can be added annually.[16]

Q. What is your opinion regarding the modelling constraint that new utility-scale solar can only be added after 2024?

A. While I understand the Company is tying this constraint to what was agreed to in the 2018 IRP, from a modeling perspective, this constraint is arbitrary. It has the unreasonable, and impractical, effect of limiting the analysis of resources available as a replacement for the retirement of Karn and Campbell Units. The PCA has both the Karn and Campbell Units retiring by 2025, and the utility-scale modelling constraint sidelines solar as a potential replacement for these resources.

Q. What is your recommendation for resolving this issue?

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[15] Walz Direct. p. 36.
[16] Battaglia Direct. pp. 13-14.

A. The constraint should be removed and generation expansion modeled with utility-scale solar resources being available as early as 2023.

Q. What is your opinion regarding the annual constraint on new utility-scale solar resources to 500 MW?

A. This annual constraint seems arbitrary in light of the MISO generation interconnection queue, which has well over 2,500 MW of solar resources. The table below summarizes the amount of solar in the MISO queue by study cycle (year in which they applied for interconnection).[17] As of the filing of this testimony, MISO is anticipating it will finish its generation interconnection analysis for the projects in the 2019 study cycle and

	DPP 2018		DPP 2019		DPP 2020		DPP 2021	
	# of Projects	MW	# of Projects	MW	# of Projects	MW	# of Projects	MW
solar	4	430	21	2,985	18	3,105	31	5,183
solar+storage	0	-	0	-	1	499	8	1,425

execute generation interconnection agreements ("GIA") in September 2022. Similarly, MISO is anticipating it will finish its analysis of the 2022 study cycle and negotiate GIAs in May 2024.

Q. Should the Company also consider solar resources outside of Michigan?

A. Yes. To increase the pool of resources and range of options for the IRP, the Company should also evaluate solar projects in other neighboring states, such as Indiana and Illinois. Indiana

[17] Data from MISO's Interactive Queue portal. Available at https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/gi-interactive-queue/.

has over 16,000 MW of solar in development and Illinois has over 8,300 MW in development.[18]

3. Update Inputs and Assumptions for all Resources Relying on NREL Data

Q. Do you have any other changes that should be made to the Company's LCOE analysis?

A. Yes, the Company should update its data inputs from NREL. The Company largely relied on data from the NREL 2019 ATB workbook when calculating its levelized costs for wind,[19] utility-scale solar,[20] battery storage,[21] and solar plus storage hybrid resources,[22] and used it for developing forward capital cost curves for gas units.[23]

Q. Why should the cost inputs be updated?

A. NREL has updated the ATB workbook twice since 2019. The update since 2019 are fairly extensive. Upgrading the analysis to utilize current data will significantly reduce the levelized cost of renewable resources and battery storage, as reflected in the table at the beginning of this section. Some of the key changes include:

(1) the Technology Resource Group classification that was used for wind resources in the 2019 ATB workbook was updated to classes based on wind speed;

(2) wind data in 2021 was updated to coincide with wind speeds at 110 meters above the surface, which coincides with a common turbine design height in the Midwest;[24]

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[18] *Ibid.*
[19] Battaglia Direct. p. 20; Company Exhibit A-5.
[20] *Id*. pp. 6-7.
[21] *Id*. pp. 22-23.
[22] *Id*. p. 26.
[23] Company Exhibit A-41.
[24] U.S. Department of Energy. 2021. "Land-Based Wind Market Report: 2021 Editions," p. 26.

(3) solar resource designations were updated, replacing the city proxies (i.e., Chicago proxy) used in 2019 ATB workbook with horizontal global irradiance;

(4) expansion of battery storage facility options and modification of scenarios to be based on projected battery cost and performance over time;[25]

(5) a new spreadsheet for hybrid utility-scale solar plus storage projects whose classes are based on solar irradiance and are coordinated with battery operations.

(6) updated data to account for technology changes in wind, solar, battery storage, and solar plus storage hybrid resources. For example, 2021 ATB workbook has updated net capacity factors for solar due to improved tracking, use of bifacial panels, reduced system losses, improved system uptime and more efficient inverters.[26]

B. The Sensitivities the Company Studied Did Not Evaluate a Portfolio of Renewable Resources that Could Replace the Karn and Campbell Retirement Timeline Proposed in the PCA.

Q. Given all of the modeling the Company has done, why do you believe the Company failed to consider a portfolio of renewable resources to replace Karn and Campbell by 2025?

A. A review of Company witness Walz's workpapers STW-1 and STW-2[27] indicates an incomplete analysis of renewable resources. Workpaper STW-2 presents the spreadsheets

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[25] NREL. 2021 Annual Technology Baseline. "Utility-Scale Battery Storage." Available at https://atb.nrel.gov/electricity/2021/utility-scale_battery_storage.
[26] NREL. 2021 Annual Technology Baseline. "Utility-Scale PV." Available at https://atb.nrel.gov/electricity/2021/utility-scale_pv.
[27] Walz workpaper WP-STW-2, tab "Retirement Assumptions."

that describe the resources selected and the capacity that was optimally selected for 114 different sensitivities.

The spreadsheets in STW-2 do not include a sensitivity in which the Karn Units retire in 2023, the Campbell Units retire in 2025, and the model was allowed to optimally select resources *other than* the gas units the Company proposes to purchase (i.e., Covert, DIG, Kalamazoo, and Livingston). The "Retirement Assumptions" tab in STW-2 also supports this finding. Of the 161 sensitivities listed in the "Retirement Assumptions" spreadsheet, 45 reflect the PCA's retirement proposal -- the Campbell Units retire by 2025 and the Karn Units retire in 2023. All 45 of these sensitivities included the addition of Covert/DIG/Kalamazoo/Livingston. None of the 161 sensitivities evaluated whether a portfolio of renewable resources, battery storage, distributed energy resources, and demand response as a replacement for Karn and Campbell by 2025 without the addition of the gas units. To state this differently, it appears that there are no sensitivities presented in the filing in which the Aurora model was allowed to select renewable resources as a replacement to the PCA plant retirements.

C. The Alternative Scenario the Company Presents is not a Reasonable Proxy for a Renewable Resource Portfolio that Replaces the Karn and Campbell Retirement Timeline Proposed in the PCA.

Q. Did you ask Consumers Energy whether they analyzed a portfolio of wind/solar/battery storage/hybrid plants that would replace the zonal resource capacity or energy of the Campbell and Karn Units ?

A. Yes. In a discovery response (EIB-41 (SRB-2)) the Company responded:

> the [A]lternate [P]lan includes incremental levels of solar and battery storage capacity . . . that would replace the ZRCs [attributed to Campbell and Karn]. WP-STW-2 presents the schedule of capacity replacements.

Q. What is the Alternate Plan?

A. The Alternate Plan is a portfolio representing a refresh of the 2018 IRP[28] with Campbell Units 1 and 2 retiring in 2031, Campbell Unit 3 retiring in 2039, and Karn Units 3 and 4 retiring in 2025.

Q. Is the Alternate Plan an evaluation of renewable resources and battery storage that could replace the retirement of Karn and Campbell Units by the dates in the PCA?

A. No, the Alternate Plan is not a reasonable replacement for the PCA. It is not optimized for the same plant retirement dates as the PCA. As I described above, the Alternate Plan evaluates a portfolio with plant retirements much later than that of the PCA.

Q. Why is this significant?

A. The Company's decisions to not run sensitivities that allow for selection of other resources than natural gas plants to replace the Karn and Campbell Units, in conjunction with the Company's response that the Alternate Plan is intended to perform that function, indicates that the Company did not evaluate a portfolio of renewable and storage resources to replace the Karn and Campbell Units within the timeline proposed in the PCA.

[28] Blumenstock Direct. p. 42.

D. Availability of Supply-Side Resources Other Than the Existing Gas Units the Company Proposes to Purchase.

Q. If the Company were to replace the Karn and Campbell Units with a portfolio of renewable, battery storage, hybrid, distributed generation and demand response, what would you recommend?

A. I cannot recommend a specific portfolio of resources because Michigan EIBC/IEI/CGA did not have the ability to run the Aurora model, and the Company's filing did not present any sensitivities on that point that would help in the selection of such a portfolio, as discussed above. The Company, however, used the Alternate Plan as the portfolio for adding renewable resources replacing Karn and Campbell, but as I stated above, I believe that is insufficient and further analysis is needed.

Q. If the Company were to replace the Karn and Campbell Units on the timeline proposed in the PCA, what resources could be placed in service ?

A. The MISO queue is informative on this point. As of October 6, 2021, MISO's website shows that Michigan has more utility-scale solar and storage under development than the forecasted need in either the PCA or Alternate Plan resource expansion portfolios as illustrated in the table below.[29]

	MI (MW)	IN (MW)	IL (MW)	TOTAL (MW)
wind	2,175	1,900	4,323	8,398
solar	11,703	16,476	8,345	36,525
battery storage	2,347	2,546	1,777	6,671
solar+battery	1,924	3,252	1,123	6,299
wind+battery			900	900

[29] MISO Interactive Queue. Available at https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/gi-interactive-queue/.

solar + wind			412	412
nat gas	1,203		1,365	2,568
TOTAL:	19,354	24,175	18,246	

It is generally accepted that resources that are in the queue are looking to be placed in-service within five years, so by 2026. I have not evaluated which projects have entered into power purchase agreement or are looking for power purchase agreements. The table above also indicates that Illinois and Indiana have a significant amount of renewable resources currently in the MISO queue. These resources should also be considered in the analysis to meet near term needs as replacements for early retirement of the Karn and Campbell Units.

Q. What is your recommendation?

A. Michigan EIBC/IEI/CGA do not have access to the Aurora model to develop an alternative portfolio that provides sufficient energy and meets both the Local Reliability Requirement and PRMR. The shortcomings of the CSA analysis presented above and by Michigan EIBC/IEI/CGA witness Burgess indicate that the Company was premature in doing a gas-only RFP. The Company should have also collected information from all-resources through either an all-source RFP or request for information, so as to have better data on the costs and potential in service dates of alternatives.

The Commission should direct the Company to use the Aurora model to identify a resource expansion portfolio of renewable, battery, distributed energy, and demand response resources that is optimized to reasonably replace the energy and ZRCs lost with the retirement of Karn and Campbell. As described above in section III.A., the lower cost of renewable and battery storage resources than what was modeled by the Company increases the likelihood that an alternative portfolio exists that is more cost effective than the natural gas purchases proposed by the Company.

IV. CONCLUSION

Q. Please summarize your findings and recommendations.

A. The Company's decision to purchase natural gas plants (Covert/DIG/ Kalamazoo/Livingston) is based on a flawed CSA and flawed resource expansion modeling. Michigan EIBC/IEI/CGA witness Burgess details a number of technical flaws with the CSA.

The resource expansion modeling included a number of inaccurate modeling assumptions that inflated the levelized cost of renewable resources, battery storage, and hybrid projects.

In addition, the Company's filing did not present one sensitivity that evaluated a portfolio to replace the Karn and Campbell Units on the timeline proposed in the PCA that did not include the purchase of at least one existing gas plant. Sensitivities were run that evaluated various retirement dates for the Karn and Campbell Units and did not include the existing gas plant purchases, however, none of those sensitivities were presented in the case.

In addition, the Alternate Plan, which the Company has directed Michigan EIBC/IEI/CGA to as a portfolio of renewable and storage resources, does not have sufficient ZRCs to replace the retiring coal plants by the dates proposed in the PCA. These flawed analyses served as the Company's justification for an IRP heavily focused on portfolios that included the purchase of the aforementioned existing gas plants and provided an insufficient analysis of other portfolios that could replace the energy and capacity of Karn and Campbell by 2025.

Q. What are your recommendations?

A. Based on my analysis and findings, the Commission should find that:

(1) the cost of renewable resources and battery storage would likely be lower in price than what Consumers Energy modeled;

(2) it was unreasonable for the Company to not have renewable resource price and operation information comparable in quality to information collected through the natural gas RFP;

(3) the Company's resource evaluation was unreasonable because it did not present sensitivity's that evaluated portfolios to replace the Karn and Campbell Units on the timeline proposed in the PCA that did <u>not</u> include the purchase of at least one existing gas plant; and

(4) there are resources available in the MISO queue to replace the Karn and Campbell Units by 2025 or shortly thereafter, subject to refinement through further modeling.

The Commission should therefore direct the Company to:

(1) conduct an all-source RFP or RFI to collect price and operation data on resources, inclusive of renewable and battery storage; and

(2) evaluate portfolios of renewable resources, battery storage, distributed solar and demand response that could replace Karn and Campbell Units on the retirement timeline set forth in the PCA and evaluate various retirement assumptions in which

one or more of those plants retire prior to 2030. The range of retirement assumptions should include, but not be limited to, sensitivities in which Karn Units 3 and 4 retire on or before 2025, Campbell Units 1 and 2 retire on or before 2026, and Campbell Unit 3 retires on or before 2029.

Q. Does this conclude your testimony?

A. Yes it does.

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the Application of	)	
CONSUMERS ENERGY COMPANY	)	
for approval of an Integrated Resource Plan	)	**Case No. U-21090**
under MCL 460.6t, certain accounting	)	
approvals, and for other relief	)	

EXHIBITS OF SEAN BRADY

ON BEHALF OF

MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL

AND

ENERGY INNOVATION

SEAN R. BRADY

PROFESSIONAL EXPERIENCE:

Clean Grid Alliance — St. Paul, MN
Regional Policy Manager and Senior Counsel — 9/2009 – Current

- Develop and manage strategy, outreach, advocacy and lobbying of state regulators and legislators related to energy issues that increase demand for utility-scale wind, solar, and battery storage resources on issues such as: competitive procurement of new energy resources, tax policies, siting policies, green tariffs, long term resource plans, and transmission policies in IL, IN, MI and MO.
- Sector Representative to MISO's Planning Advisory Committee for 10 years.
- Lead and coordinate transmission planning and advocacy at MISO for multiple environmental NGOs and renewable energy developers.
- Work with MISO and other stakeholders in revising or adding new provisions to MISOs tariffs and business practice manuals.

State of Illinois -- Illinois Commerce Commission — Chicago, IL
Legal and Policy Advisor to Commissioners Lieberman & Elliott — 10/2006 – 9/2009

- Evaluated and recommended courses of action to Commissioners concerning complex policy and legal issues on energy and telecommunication matters at both state and federal level.
- Represented Commissioner(s) in meetings with Staff experts, federal regulators, generation companies or utilities on various matters.
- Drafted responses, on behalf of Commissioner, to questions from the U.S. House of Representatives Sub-Committee on Energy and Commerce, explaining Commissioner's position on advanced metering infrastructure and demand response.
- Worked with Commissioners from Ohio and representatives from Duke Energy and Ameren Illinois to develop a proposal to account for price responsive demand resources in the wholesale electric market.

State of Illinois -- Illinois Commerce Commission — Chicago, IL
Special Assistant Attorney General/Staff Counsel — 9/2000 – 10/2006

- Litigated and managed cases on behalf of state agency involving state and federal utility/telecommunication laws.

Other Professional Work Experience:

Crawford, Murphy & Tilly Inc., Aurora, IL
Senior Transportation Engineer — 1/1991 - 8/1997
Professional Engineer's License — 1996 - 2017

EDUCATION:

Chicago-Kent College of Law, Illinois Institute of Technology, — Chicago, IL
Juris Doctor — May 1999
University of Illinois, — Chicago & Urbana, IL
M.A. in Public Administration — May 1994
B.S. in Civil Engineering — Jan. 1991

- Areas of concentration were transportation facilities (analysis, planning, and design), construction management, and geotechnical engineering.

Question:

20. On page 42 of Mr. Blumenstock's direct testimony it states that the PCA was evaluated through all scenarios and sensitivities to understand its performance under all study conditions and was measured against an Alternate Plan. Has Consumers Energy analyzed a portfolio of wind/solar/battery storage/hybrid plants that would replace the zonal resource capacity or energy of Campbell Units 1, 2 and 3, and Karn Units 3 and 4? If yes, please provide such workpapers in an excel file or a format that can be converted to and manipulated by excel.

Response:

Yes. The alternate plan includes incremental levels of solar and battery storage capacity as well as energy waste reduction and demand response that would replace zonal resource capacity at the current assumed end of life of the aforementioned units. WP-STW-2 presents the schedule of capacity replacements.

Sara T. Walz

Sara T Walz
September 18, 2021

Electric Supply Planning

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the Application of	)	
CONSUMERS ENERGY COMPANY	)	
for approval of an Integrated Resource Plan	)	**Case No. U-21090**
under MCL 460.6t, certain accounting	)	
approvals, and for other relief	)	

PROOF OF SERVICE

STATE OF SOUTH CAROLINA)
) ss.
COUNTY OF BERKELEY)

Summer R. Dukes, the undersigned, being first duly sworn, deposes and says that she is a Paralegal at Potomac Law Group PLLC and that on the 28th day of October, 2021 she served a copy of the Testimony and Exhibits of Dr. Laura S. Sherman, Edward Burgess, and Sean Brady on behalf of The Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Clean Grid Alliance, via email, upon those individuals listed on the attached Service List via email.

Summer R. Dukes Digitally signed by Summer R. Dukes
Date: 2021.10.28 11:04:09 -04'00'

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