Roadmap to Implementing

Michigan's New Energy Policy

Final Grant Report

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List of Terms

AC – Air conditioning

CPP – Critical peak pricing

CPR – Critical peak rebate

CON – Certificate of Necessity

DER – Distributed energy resources

DLC – Direct load control

DOE – U.S. Department of Energy

DR – Demand response

DTE – DTE Energy

EWR – Energy waste reduction

FERC – Federal Energy Regulatory Commission

IRP – Integrated resource plan

kW – Kilowatt

kWh – Kilowatt hour

MAE – Michigan Agency for Energy

MCL – Michigan Common Law

MEO – Michigan Energy Office

MISO – Midcontinent Independent System Operator

MPSC – Michigan Public Service Commission

MW – Megawatt

MWh – Megawatt hour

PA – Public Act

PBR – Performance based rates

RAP – The Regulatory Assistance Project

ROA – Retail open access

RTO – Regional Transmission Operator

TOU – Time-of-use

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Disclaimer

Section One. Roadmap Purpose

When the Michigan Energy Office (MEO) sought funding from the U.S. Department of Energy (DOE) in 2014, Michigan was in the process of overhauling its energy policies. The revision process to the state's energy policies began in November 2012 when Governor Rick Snyder—recognizing the changing landscape for electric utilities and state regulators—called on policymakers, business leaders, and other stakeholders to establish a "no regrets" energy policy that would enable the state to meet its energy needs, while ensuring adaptability, affordability, reliability, and environmental protection. The governor outlined his vision in the special message "Ensuring our Future: Energy and the Environment." In this address, Governor Snyder directed the MEO and Michigan Public Service Commission (MPSC) to facilitate a review of Michigan's current energy landscape through a comprehensive stakeholder engagement process called "Readying Michigan to Make Good Energy Decisions." As part of this process, the MEO and the MPSC conducted seven public meetings across the state and collected input from dozens of stakeholders throughout 2013. At the end of the process, the MEO and the MPSC published four reports: one on renewable energy, one on electric choice, one on energy efficiency, and one on other issues such as reliability and rates. After the conclusion of the Readying Michigan process in 2015, Governor Snyder second energy message—called for action,: "Now it is time to propose a plan that will see Michigan through at least the next 10 years of energy decision-making".[1]

Recognizing the potential challenges to successfully implement a new energy policy, the MEO proposed the creation of a stakeholder-focused and research-driven roadmap to enhance coordination, provide thoughtful planning, and ensure appropriate implementation of regulatory and utility ratemaking models, all while working to align electric utility business interests and customer behavior with stated public policy goals. The framework for this project was based on the theory that when the state's energy interests—utilities, regulators, policymakers, advocates, and consumers—combine robust, structured dialogue with high-quality research, data, and ideas, they can jointly develop an implementation plan for policy goals that have been established by the state and federal government through 2025 and beyond. To this end, the MEO outlined the following objectives for the roadmap process:

- Develop a baseline assessment that builds off existing data collected as part of the 2013 "Readying Michigan to Make Good Energy Decisions" process and further examine the risks and opportunities facing the electric industry in Michigan as new policies are implemented.
- Review goals, standards, and mandates set by state and federal governments for the 2015–2025 time frame, as applicable, related to energy waste, renewable energy, and overall power generation fleet diversity and performance.
- Create a common vision and guiding principles for the "utility of the future" based on goals, emerging trends, and opportunities.
- Explore innovative models and options for utility regulation and ratemaking that would promote the utility business model vision and related energy policy goals.
- Assess the potential application and impacts of such models in Michigan, including alignment with state and federal policies and regulations. Modeling and other analyses will be used to flesh out potential impacts (e.g., peak load reductions, annual energy savings, avoided costs) and unintended consequences.
- Identify barriers to change and develop an implementation plan, including monitoring processes and communication protocols among state agencies, utilities, and other stakeholders, after the initial project period.
- Document lessons learned and best practices and share through peer groups and networks.

[1] Governor Snyder's The Governor's address "Ensuring Affordable, Reliable, and Environmentally Protective Energy for Michigan's Future" is available at the following link: http://www.michigan.gov/documents/150313_Energy_Message_FINAL_484033_7.pdf.

Other long-term roadmap impacts and outcomes included the following:

- Clear definition and awareness of Michigan's current energy situation and future goals.
- Alignment of state and federal policies with regulatory framework and utility business models.
- More effective, cohesive, and efficient implementation due to planning, analysis, and stakeholder engagement (avoided litigation, etc.).
- New pilots and, where appropriate, full-scale utility rate designs/programs implementation that will increase customer engagement in reducing energy waste and shave peak demand.

Section Two. Roadmap Governance Structure—Steering Committee and Stakeholder Group

Steering Committee

The first step in the roadmap process was to form the project's steering committee. The MEO established a multiagency steering committee with representatives from the Department of Environmental Quality, MPSC, and Michigan Agency for Energy (MAE). The steering committee's composition is outlined in the roadmap "Who's Who" document available in Appendix 1.[2] The steering committee was assisted by external and internal support staff who together made up the project team. See Exhibit 1.

Exhibit 1. Project Team Roles

Organization	Roles
Michigan Energy Office	❖ Principal investigator, grant administration, and compliance ❖ Oversight of the third-party facilitator, Public Sector Consultants (PSC) ❖ Chair of steering committee ❖ Member of project team
Michigan Public Service Commission	❖ Steering committee member ❖ Technical support provider, including research, modeling, and rate analysis
Michigan Department of Environmental Quality	❖ Steering committee member ❖ Lead adviser on environmental compliance issues and options
Michigan Department of the Attorney General	❖ Chair the stakeholder group ❖ Ex-officio member of the stakeholder group
Public Sector Consultants	❖ Project manager ❖ Third-party facilitator ❖ Lead researcher and report writer ❖ Oversight of the technical assistance contractor
The Regulatory Assistance Project	❖ Technical assistance contractor ❖ Baseline research support ❖ Advice and counsel on performance-based regulation and rate design development and implementation

Steering Committee Roles and Meeting Process

At the steering committee's initial meeting, the MEO provided members with an overview of the roadmap grant, their roles, and the planned meeting process. The steering committee's roles included the following:

- ❖ Solicit participation from a diverse set of representatives to serve on the roadmap stakeholder group
- ❖ Select participants
- ❖ Oversee the project scope and budget

[2] The MAE was formed in May 2015. Upon its creation, the MEO, which formerly resided in the Michigan Economic Development Corporation, was transferred to MAE.

- Provide technical support to the project's research efforts
- Review and report on stakeholders' actions and roadmap outcomes

The roadmap process was divided into the three phases outlined below in Exhibit 2.

Exhibit 2. Project Approach by Phase

The meeting process for the steering committee is available in Appendix 2, which provides meeting dates, the meeting focus, and resources provided. Actual steering committee and stakeholder meeting dates are available in Appendix 3.

Stakeholder Group

One of the first priorities for the steering committee was to form the roadmap stakeholder group. The steering committee designed an open process to solicit participation for the stakeholder group via an online posting. Prospective stakeholders were asked to submit a nomination form describing their relevant experience and ability to participate over the course of the project. The steering committee's aim was to ensure that the stakeholder group's membership represented a diverse array of interests. The following criteria were used to select among those nominated:

- The individual represents his or her respective stakeholder interests, as reflected by his or her leadership position within organizations and/or support of industry peers. Note: Represented stakeholders must be greatly impacted by energy availability, pricing, reliability, etc.
- The interest that this individual represents is not over-represented within the group, ensuring representation of a broad diversity of interests.
- The individual has experience with and knowledge of topics and regulatory processes.
- The individual can work well with other stakeholder group members.
- The individual should have a minimum of three years working experience with public and private sector energy issues. Priority will be given to individuals with affiliations and/or a member organization that will advance the implementation of the Roadmap for Michigan's New Energy Policy project objectives.

The steering committee received 50 nominations for stakeholder participation. After reviewing the list of potential participants, the steering committee made their final selections. The final list of stakeholders is available in Appendix 1.[3]

Stakeholder Responsibilities

After the steering committee finalized stakeholder group participation, they provided stakeholders group members with an overview of the responsibilities, operating procedures, and guidelines for participation. Stakeholders' primary responsibilities include the following:

- **Review Background Research:** Develop a foundational baseline report to ensure that all stakeholders have a mutual understanding of issues and information relevant to the project before beginning to explore and develop recommendations. The report summarizes Michigan's current energy policy landscape and regulatory framework; Michigan electric utilities' performance on key and relevant indicators; factors, risks, and opportunities that could impact implementation of such policy goals and requirements; and potential innovative regulatory and rate design options to policy implementation by aligning utilities and customers with the policy goals and requirements.
- **Develop a Vision and Guiding Principles:** Stakeholders will develop vision and guiding principles for any changes to the regulatory model or ratemaking approaches that can serve as a "yardstick" as they debate, design, and implement any changes. The vision and guiding principles will be reviewed by the steering committee before being finalized.
- **Recommend Regulatory and Rate Design Changes:** Using the background research and direction provided by the approved vision and guiding principles, the stakeholder group will explore and define the details of different regulatory approaches and rate designs that could assist with implementation of new energy policy goals in Michigan. These recommendations will be made to the steering committee, following a process outlined at the end of this document.

The complete "Stakeholder Group Responsibilities and Procedures" document is available in Appendix 4.

[3] The list of stakeholders approved initially by the steering committee differs from the final list of stakeholders in the "Who's Who" document. During the roadmap process, the steering committee modified the list of participants to reflect the shifting nature of events throughout the project.

Section Three. Phase One—Baselining

Baseline Assessment

Before engaging stakeholders in discussions related to Michigan's new energy policy, the steering committee sought to establish a common understanding of key elements related to the goals of this project. To this end, the steering committee directed the project team to conduct research to answer the following questions:

- Where does Michigan stand with respect to any recently adopted and proposed state and federal energy and environmental policy goals and requirements applicable to the energy industry in Michigan in the 2015–2025 time frame?
- What are the factors, risks, and opportunities that could impact implementation of such policy goals and requirements?
- What are potential innovative regulatory and rate design options that could support policy implementation by aligning utilities and customers with policy goals and requirements?

The answers to these questions were documented in two reports. The first report built off the groundwork provided by the Readying Michigan process and presented the current state of regulation, policy, and industry characteristics. The second report tackled potential regulatory and rate design options.

The project team, with support from MPSC staff and 5 Lakes Energy, developed the first report titled *Roadmap to Implementing Michigan's New Energy Policy: Baseline Research Report.* This report was designed to serve as a critical foundation for the roadmap process by providing an overview of Michigan's energy policy goals, how Michigan utilities perform on key indicators, and current relevant research related to changing economic and environmental conditions impacting the energy sector. The report presented a thorough assessment of where we are—that is, where Michigan stood with respect to any recently adopted and proposed energy and environmental policy goals and requirements applicable to the energy industry in Michigan in the 2015–2025 time frame. It also documented Michigan's existing utility regulatory framework and available data on historical, current, and projected utility industry performance on key indicators (e.g., reliability, environmental performance, efficiency, resource adequacy, and diversity). The report also laid out where we are going—that is, what should be expected in the next five to ten years (2020; 2025) in terms of new laws and requirements affecting the energy industry (e.g., energy waste, environmental performance, and resource diversity).

The report also reviews factors, risks, and opportunities that could potentially affect implementation of Michigan's overarching policy goals and requirements. The project team engaged subject matter experts and stakeholders to identify and assess factors, risks, and opportunities that could impact the successful implementation of new policies, such as expected investment needs in the energy industry in light of advanced metering infrastructure (also referred to as smart meters) and smart grid deployment, power plant retirements, retrofitting, new construction, and upgrades to transmission import/export capability; risk factors (e.g., fuel prices, capital costs, early plant retirements, technology advancements); and regional planning, compliance approaches, and implications for policy implementation within the state.

The second baseline report, "Roadmap for Implementing Michigan's New Energy Policy: Paths to the Future" was produced in concert with the project team's technical support contractor, The Regulatory Assistance Project (RAP). The report provided a review of innovative regulatory and rate design options to support sound policy implementation by aligning utilities and customers with state and federal policy goals. The report also included information related to what other states are doing in terms of regulatory and ratemaking models. This report compiles five sections covering the following topics: codes of conduct for the future, performance-based ratemaking, rate design, decoupling, and infrastructure planning analysis and review.

The baselining phase of the project took more time than originally proposed, because the steering committee did not want to divert stakeholders' attention from legislative energy policy activity happening

concurrently with the proposed stakeholder kick-off date (which was not anticipated at the time this grant was proposed). The baseline research report was reviewed and approved by the steering committee in June 2015. The steering committee shared the completed baseline report with stakeholders before the August 2015 stakeholder group convening in order to provide a collective understanding of issues and information relevant to the project before they explore policy issues and develop recommendations. Both reports are available on the roadmap website hosted by the MEO.

Baseline for Stakeholders

After submitting their application for the stakeholder group, members were asked to participate in an online survey. The survey had three open-ended questions and three rating scale questions designed to gauge what issues were important to them and stakeholders' familiarity with the subject matter. The steering committee reviewed the survey results and used the responses to determine how well-versed stakeholders were on topics related to roadmap discussions. A compiled list of the survey responses is available in the document titled "Detailed Survey Responses" in Appendix 5.

Using the input received, the project team was able to tailor the amount and type of information presented during the initial grounding meetings. These presentations are available on the roadmap website.

The project team dedicated the first two stakeholder group meetings to grounding stakeholders in the baseline research.

Section Four. Shifting Focus to Demand Response

It was assumed when the roadmap process was in development that Michigan would have new energy policies in place in 2015, and that the roadmap grant could be used to help implement aspects of these policies. This timeline was supported by Governor Snyder who, in his 2015 energy message, called on the state legislature to enact policy reforms prior to their summer recess. Unfortunately, the legislature's timing did not align with the roadmap process, and the energy policy discussions stalled at the capitol. To avoid jeopardizing the progress already underway, the steering committee met to discuss next steps for the roadmap stakeholder group.

Due to uncertainty surrounding the direction of Michigan's energy policy, the steering committee—in consultation with members of the project team—determined that stakeholders should focus their attention on a subject not embroiled in the legislative debate. The steering committee determined that stakeholders could begin their work by tackling demand response (DR).[4] The steering committee preferred this approach, because they believed the state would be able to later replicate the roadmap process with other energy policy topics once there was more certainty about the direction of the state's new energy policy.

In light of this change, the steering committee prepared a revised charge to the stakeholder group. The steering committee's charge to stakeholders consisted of the following five questions:

- Would it be valuable for the MPSC to conduct a potential study for DR programs in Michigan? If so, what questions should be explored in this study?
- How should customers be compensated for participation in DR programs, and what should the penalties or other approaches be to ensure adequate performance?
- How should utilities be compensated for delivering DR programs?
- What type of measurement and verification methodology should be used for DR performance?
- What changes to Michigan's regulatory framework should be made to make it easier and more useful for customers to take advantage of DR and for utilities to offer DR options?

The complete "Charge to the Stakeholder Group for Demand Response" is available in Appendix 6.

Studying DR Potential

During the initial stages of stakeholders' DR discussions, several stakeholders noted that there has not been a comprehensive potential study of DR for several years and that establishing a statewide baseline could be useful for energy providers and the state in the future. Participants noted that a statewide potential study would need to account for differences among utilities and across customer classes. The group generally agreed that a potential study for DR programs in Michigan could be an important aspect of completing an integrated resource plan should such a plan be required by pending energy legislation.

Phase Two—Vision for Future Ratemaking and Rate Design Approaches

After completing the baselining phase of the roadmap project, stakeholders were tasked with developing a DR vision statement. The vision statement described the desired end-state and long-term change the stakeholder group sought as a result of its work. The purpose of having a collective vision is to enable

[4] The Federal Energy Regulatory Commission (FERC) defines DR as "changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized" (FERC n.d.).

stakeholder group members to put personal preferences aside and make recommendations based on clearly defined objectives and criteria.

Before stakeholders could begin work on their vision for DR, the steering committee determined that the group needed more background information about the status of DR programs in Michigan and other states. To this end, the steering committee directed the MPSC's dedicated internal DR team to prepare an overview of current DR programs in the state for stakeholders; this presentation is available on the roadmap website. In addition to the presentation from MPSC staff, the steering committee invited two companies, EnerNoc and Opower, which provide innovative DR programs for customers and utilities, to present stakeholders with information about the types of DR programs they offer. These presentations are available on the roadmap website. These three presentations served to bolster the baseline research conducted earlier in the roadmap process by providing stakeholders with DR-specific information.

Stakeholder Group Vision for Promoting DR

To help jumpstart stakeholders' thinking about a DR vision, the project team, with assistance from the steering committee, developed a set of visioning questions for stakeholders. These questions are outlined in the stakeholder visioning worksheet in Appendix 7. Armed with stakeholders' questionnaire responses, the baseline for DR programs in the state, and examples of DR programs, the project team worked with stakeholders to develop their vision for DR programs in Michigan through a small group exercise. It was at this point that stakeholders determined that their work should focus on DR programs for residential customers.

The stakeholders' vision describes the desired end state or long-term change the group is seeking as a result of its DR work. The stakeholder group's vision for DR programs is that the following be accomplished in a cost-effective manner that is consistent with MPSC's legislative authority:

- Embrace new enabling technologies and leverage their full potential to cost-effectively deliver public benefits through innovative program designs.
- Be voluntary, allowing customers the opportunity to choose whether or not to participate in DR programs.
- Be simple, easy, and transparent for customers to understand and access.
- Improve the reliability of the electric power system.
- Reduce peak load and associated costs, serving as a cost-effective and reliable way to relieve peak demand, and improve system stability without needing to increase supply-side capacity.
- Meet capacity, energy, and ancillary service resource needs where DR is more economic and reliable than alternative supply-side options.
- Provide financial benefits for consumers and utilities.
- Provide flexibility to accommodate customers of all sizes; specifically, programs should permit larger customers to make individual agreements with their utility.
- Be a trusted resource with accurate measurement and verification—it is important that resources can be counted on when they are needed and that their calculated benefits are realized.
- Meet the resource adequacy requirements of the relevant regional transmission organization (RTO).

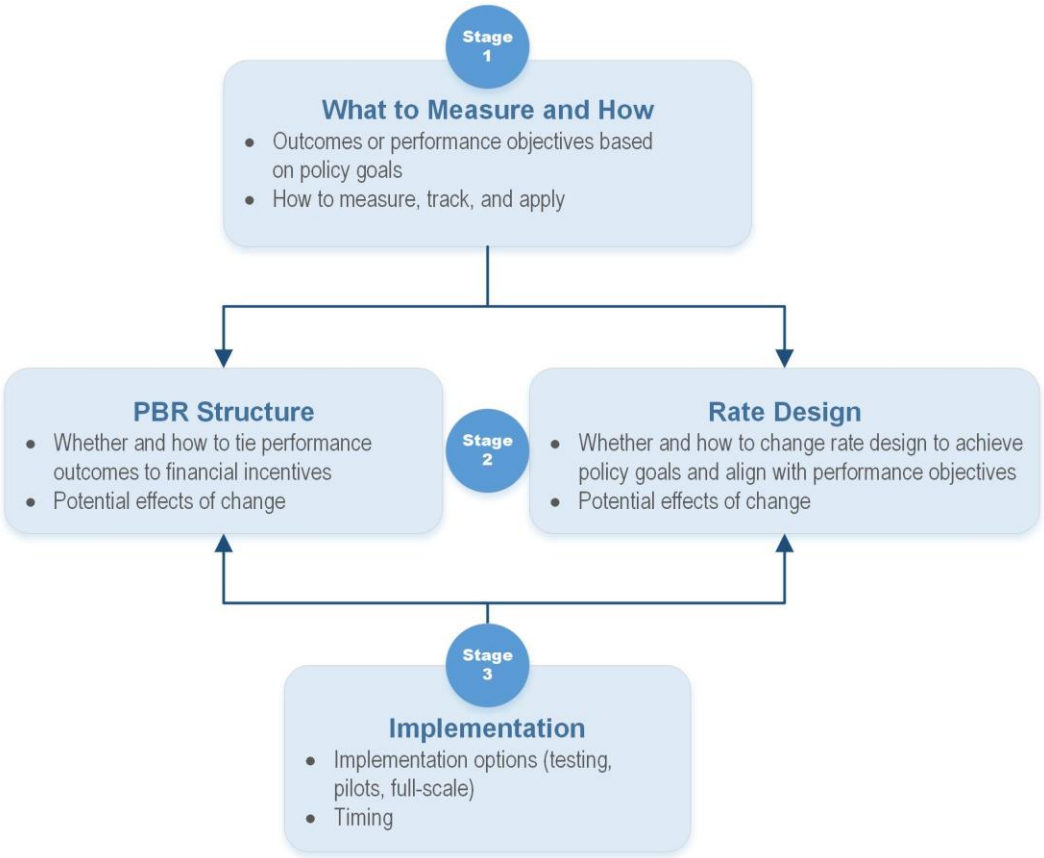
After stakeholders agreed on their final visions for DR, the vision statement was delivered to the steering committee for approval. The approved vision statement is available on the roadmap website and in Appendix 8. It provides clear parameters for accepting or rejecting recommendations.

Phase Three—Implementation

The next step for the stakeholder group, was to determine how to structure customer participation, performance objectives, and outcomes for utilities that align with their DR vision. This effort focused on identifying and addressing key issues and desired outcomes associated with potential changes in the

regulatory model and rate design. The project team worked through the process of exploring and defining the details of a performance-based regulation system and innovative rate designs that could be implemented in Michigan to achieve stakeholders' DR vision. This effort was intended to help ensure that utility regulation is not a barrier to implementation and to identify approaches that can support the energy industry's ability to adapt to rapid changes. The process for developing the implementation plan is described below in Exhibit 3.

Exhibit 3. Roadmap to Implementing Michigan's New Energy Policies



Stage One: What to Measure and How

To tackle the first stage of developing an implementation plan, the project team created a small group exercise to help stakeholders explore various elements of DR programs and the types of performance metrics to be used in designing and evaluating DR programs. Before the first meeting, stakeholders were provided with examples of performance metrics, available in Appendix 9, that could be used to evaluate progress. Stakeholders were asked to come prepared to respond to the following questions:

- Are these the right metrics to show whether or not we are achieving our vision? Should any be removed? Should any be added? Should the metric be utility specific or statewide? Of these metrics, what data are the utilities already collecting and reporting? What new data would have to be tracked and reported? How feasible is that? In light of this discussion, what performance metrics should be tracked and reported?
- What methodologies should we use for measurement, and what are the key assumptions for making calculations? What do the utilities already do to measure program performance?
- How are the metrics and results tracked and reported? Should utilities self-report with the opportunity for audit? What about simple correspondence to the commission or a public "report card" (e.g., a

presentation which translates metrics into something the public can understand)? To whom should the report be communicated (whether the news is good or bad)? Newspapers? Elected officials who are part of making the process effective? How should the commission respond?

- How are the metrics verified and by whom—a third party hired by the MPSC, or a third party hired by utilities? When should verification occur? What data are needed?

Stakeholders worked intently to refine their performance metrics for DR over the course of the November and December 2015 stakeholder meetings. The steering committee reviewed and approved the stakeholders' recommendations outlined below related to measuring, tracking, and applying performance objectives for DR.

- **Measuring program performance:** To measure progress toward achieving the stakeholder group's vision for DR programs in Michigan, the level and type of customer participation in cost-effective programs should be tracked. To that end, the stakeholder group recommends using the percentage of load per customer class participating in DR programs, as well as the net system savings through the use of DR ($/MW cost of DR relative to the $/MW cost of traditional investment) as the types of metric to be used to evaluate whether or not the DR vision is being achieved. These metrics should be specific for utilities and customer classes (as opposed to establishing a single, statewide target metric). Utilities are already collecting the necessary data to be able to evaluate progress toward these metrics, so the group thought these were not only the most important metrics, but also the most feasible to track. Utility-proposed targets should be founded in the currently known, cost-effective potential, as well as the anticipated need as determined by an integrated resource plan.
- **Measuring program cost-effectiveness:** The stakeholder group recommended using either the utility-cost test or total-resource-cost test, or a combination of the two, to measure program cost-effectiveness**.** The utilities already use this methodology, so it is both appropriate and feasible. This method compares the $/MW for the utility to implement a DR program to the $/MW saved by avoiding capacity generation. The group thought it was important that the costs and benefits be delineated by time (season and time of day) and location (local and regional effects) and normalized for variations in weather and regional economic conditions.
- **Program reporting:** The stakeholder group thought both prospective and retrospective reporting should be done. Utilities may submit a prospective DR plan to the MPSC—or include it in the integrated resource planning process, if appropriate—to ensure program costs are just and reasonable. Costs of a prospective plan preapproved by the MPSC should be deemed eligible for recovery. This can be done as part of a utility's regular rate proceedings or separately. If an RTO has already determined a utility's DR program is an eligible capacity resource, then there is an accelerated review and approval process. The utilities should then be required to annually submit a retrospective performance report on what was accomplished so that the reward can be approved. The group stressed the importance of transparency, so these reports should be shared by the MPSC publicly. However, individual customers should be treated as private.
- **Integrating DR with energy-efficiency plans:** The MPSC should be willing to consider integrated plans that include DR, energy efficiency, and other measures.
- **Third-party verification:** Findings from the retrospective performance reports should be verified annually by a third party hired by the utility. Identification of third-party verification contractor, or the process and qualifications for securing the third-party verifier, should be included in the prospective DR plan noted in a preceding bullet. Both the utilities proposing DR programs as well as DR providers should be monitored to ensure they are delivering intended results.
- **RTO verification:** An RTO's approval of DR programs used by a utility to meet its resource adequacy requirement should be sufficient to meet the requirement for third-party verification.

Stage Two: Performance-based Regulation Structure and Rate Design Recommendations

After stakeholders defined the metrics for DR programs, the group shifted focus to the second stage of the roadmap implementation plan: developing performance-based regulations and rate designs for DR (as

outlined in Exhibit 3 above). Stage two encompassed two separate elements related to DR program design. The first element focused on the utility regulatory framework (e.g., what changes to Michigan's regulatory framework should be made to make it more advantageous for utilities to offer DR programs). The second focused on how customers should be compensated for participation in DR programs.

To aid stakeholders in the development of their recommendations for DR program design, the steering committee asked the project team to provide stakeholders with more information related to how regulation can motivate utilities to offer and customers to participate in DR programs. The presentation also provided stakeholders with some common performance metrics used to measure the success of DR programs. This presentation is available on the roadmap website.

Performance-based Regulation: Structuring Utility Compensation and Measuring Performance

Stakeholders' work to develop recommendations for DR program design was carried out in two stages. The group started by working to develop recommendations for structuring utility compensation. The project team designed a small group exercise for stakeholders to facilitate the group's discussion. The small group exercise is described in Appendix 9. Stakeholders developed the following recommendations for performance-based regulation of DR programs:

- **Utility compensation:** Utility Compensation for delivering DR programs should be based on a combination of cost recovery and an opportunity to earn a performance-based return as follows:
  - **Full cost recovery of prudent program expenditures:** The costs of implementing DR programs can include capital (communication infrastructure, load control devices) and noncapital (marketing, administration, incentives) expenditures. Recovery of these costs could occur as an expense—for example, through a reconcilable surcharge—or through rate base. If cost recovery is done through rate base, both capital and noncapital DR program expenditures should be included, and utilities should be allowed the opportunity to earn a rate of return on their program investments.
  - **Performance reward:** Utilities that operate DR programs effectively and generate net system savings should be eligible for a performance incentive. The incentive should be tied to achievement of agreed-upon performance metrics (e.g., participation, threshold peak demand reduction, program cost-effectiveness, or minimum net system savings). The performance incentive could be structured as a percentage of program spending, as a share of net system savings, or as a premium rate of return on their program investment. Utilities should be awarded performance incentives only if they meet or exceed threshold performance levels and the incentives should not exceed the net system savings generated through the DR programs. A portion of net system savings should be used to lower system costs/rates for all customers. In addition to these benefits, participating customers should also be eligible to receive incentives.

Rate Design: Structuring Customer Compensation and Ensuring Adequate DR Performance

The second portion of the stakeholders' work, focused on rate design options; specifically, how to design rates that drive customer participation and incentives and ensure adequate performance. To help stakeholders tackle this important question, the steering committee tasked the MPSC staff DR Team with describing the current and—to the extent possible—best practices for DR rate design. Building on staff's initial research, the project team expanded the scope of this report to include a national overview of DR programs and incorporated additional references to recent studies of DR program effectiveness. The report focused on common practices for the two types of residential DR program mechanisms: 1) sending quantity (curtailment) signals to customers—direct load control (DLC) programs—and 2) sending price signals to customers to alter their consumption habits (time-varying rates), specifically time-of-use (TOU) pricing and critical-peak pricing (CPP) or critical-peak rebate (CPR) rates. In addition to reporting on common DR practices, MPSC staff also produced a sample DR rate tariff—based on current practices—to be used as a model in discussions of future DR programs in Michigan. This report is available on the roadmap website.

Using this report as a basis, stakeholders worked to define the parameters for designing TOU rates, CPP and CPR rates, and rates for DLC programs. The project team provided stakeholders with a worksheet,

available in Appendix 10, to complete prior to the group meeting so that participants were prepared to discuss specific elements of DR rate design.

To facilitate stakeholders' dialogue, the project team divided them into two groups and tasked each group with discussing how the state should address the following elements of DR rate design:

- Pricing/interruption period (frequency and timing)
- Opt-in/out provision
- Notification method and timing
- On-/off-peak price ratio
- Incentive offered
- Contract term

Based on the common practices identified by the MPSC, as well as stakeholders' experience/expertise, the group worked to define the parameters for designing TOU rates, CPP and CPR rates, and rates for DLC programs. These recommendations were focused solely on design for residential programs. Stakeholders' recommendations for each parameter are as follows:

TOU Pricing: This rate typically applies to usage over broad blocks of hours (e.g., on-peak=six hours for summer weekday afternoon; off-peak=all other hours in the summer months) where the price for each period is predetermined and constant.

- **Pricing/interruption period (frequency and timing)**: Stakeholders believe that there could be two approaches for designing residential TOU rates—a simple and a complex approach. Stakeholders described that a two-tier TOU rate may prove to be simpler for customers to understand and potentially increase customer participation. This approach would employ a single, longer peak period from 2 PM–7 PM. Stakeholders also saw value in the three-tier TOU rate because this structure better reflects the cost of providing service, provides for stronger price differential signals, and may make it easier for participants to avoid energy use during shorter on-peak periods. Any program design should be specific to a utility's load profile and seasonal weather patterns.
- **Opt-in/out provision:** During early stages, participation in TOU rates should be based on opt-in enrollment. Stakeholders commented that utilities should, where possible, provide standard-service to customers with a comparison of what their bill would have been had they participated in a TOU rate. As programs mature and savings are demonstrated, stakeholders expressed that an opt-out approach could feasibly replace the opt-in provision. There was also the suggestion from some participants that, when applicable, utilities should automatically enroll customers in the rate class that best suits a customer's consumption habits based on 12 months of energy use data.
- **Notification method and timing:** TOU rates make clear the different price levels associated with energy use at various times of the day. Notification is not necessary in TOU rates.
- **On-/off-peak price ratio:** Stakeholders noted that the on-/off-peak price ratio for utility TOU rates should—similarly to peak periods—reflect the nature of a utility's load profile and season weather patterns. Stakeholders generally agreed that a range of on-/off-peak price ratios between 3 and 4.5 would be a good place to set initial rates. As utilities' experience with TOU rates matures, these price ratios should reflect experiences with customer participation and actual savings in avoided energy and capacity costs.
- **Incentive offered:** Incentives should reflect the amount that produces the desired level of participation in and savings from these rates. Stakeholders commented that the appropriate level of incentives could be learned through utility experience over time. In TOU rates, the incentive should reflect the value of the avoided cost of energy consumption during peak periods and avoided costs of capacity otherwise needed to meet peak demands.
- **Contract term:** The typical length of time for customers to participate in a time-varying rate programs is one year. However, utilities should be allowed some flexibility with their individual programs in order to align with RTO requirements and customer preferences. A customer's individual commitment should not imply that utilities' time-varying rate programs are unavailable after a customers' individual

commitment. This point is important for customers whose participation in time-varying rate programs brings them to make investments in communicating devices or smart appliances.

Critical-Peak Pricing and Critical-Peak Rebates: When utilities observe or anticipate high wholesale market prices or power system emergency conditions, they may call critical events during a specified time, and the price for electricity during these time periods is substantially raised. Two variants of this type of rate design exist: one in which the time and duration of the price increase are predetermined when events are called and another in which the time and duration of the price increase may vary based on the electric grid's need for reduced loads.

- **Notification method and timing:** Residential customers should receive notification for a critical-peak event at least one day in advance. Stakeholders also noted that customers should be given the option to select the type of notification they receive (e.g., a text, a phone call, or an e-mail). Customers should also be given the option to have a notification delivered directly to a communicating thermostat or smart appliance. This practice could encourage participation by removing an obstacle for customers.
- **Critical-peak/off-peak price ratio:** Stakeholders noted that the critical-peal/off-peak price ratio should—similarly to TOU peak periods—reflect the nature of a utility's load profile and season weather patterns. As utilities' experience with critical-peak rates matures, these price ratios should reflect experiences with customer participation and actual savings. Utility participants noted that their peak pricing programs use critical-peak prices set at $0.95.
- **Price vs. rebate:** Utilities should provide access to both CPP and CPR programs, at least in pilot projects, until the best program results are determined. Stakeholders believe that participation would be higher in CPR programs but noted that these programs add an extra administrative and accounting step that could lead to higher program operating costs.
- **Incentive offered:** Incentives should reflect the amount that produces the desired level of participation in and savings from these rates in avoided energy and capacity costs associated with the customer response. Stakeholders commented that the appropriate level of incentives could be learned through utility experience over time.
- **Contract term:** Same as contract term for TOU pricing

Direct Load Control Programs: When utilities observe or anticipate high wholesale market prices or power system emergency conditions, they may call critical events during prespecified time periods. The price for electricity during these time periods remains the same but the customer is refunded at a single, predetermined value for any reduction in consumption relative to what the utility expected the customer to consume.

- **Opt-in/out provision:** Participation in Direct Loan Control (DLC) programs should be on an opt-in basis. Once enrolled in a DLC program, residential customers would not be able to opt out of any cycling events for the duration of their contract commitment. Stakeholders commented that allowing customers to opt out of a DLC event would place the utilities' capacity commitments with their regional transmission operator (RTO) at risk. Stakeholders noted that if customers were able to opt out of an event, a penalty requisite with the potential penalty the utility would face for nonperformance from the RTO would be required. Some utilities currently offer the option for a customer to opt out of one event per year, as long as the utility is given sufficient notice. This provides customers with some flexibility.
- **Notification method and timing:** Notification for DLC or air conditioning (AC) cycling programs should not be a requirement. However, customers should be able to determine whether their AC is being cycled through their utility account online, via an opt-in communication from their utility, or directly from their appliance. This would ensure customers can determine whether they are experiencing mechanical difficulties with their appliance or if their experience is the result of DLC.
- **Pricing/interruption period (frequency and timing):** DLC programs may vary depending on what appliances are being controlled. Michigan has years of successful utility AC cycling programs on which to model new programs. AC cycling programs should run from June through September and cover up to eight hours each day at a cycling rate of 15-30 minutes out of every hour.

- **Price vs. rebate:** Residential customers participating in DLC programs should receive a payment for their participation. Payments could potentially be in the form of a monthly bill credit, but utilities should have the flexibility to design payments so that they align with customer interest.
- **Incentive offered:** The level of incentive offered to participating DLC program customers should be correlated with the cost savings such programs produce. The amount of incentive should also be set at a level that is enough to drive customer participation in DLC programs. This determination would be made based on utility experience.
- **Contract term:** The typical length of time for customers to participate in a DLC programs is one year. However, utilities should be allowed some flexibility with their individual programs in order to align with RTO requirements and customer preferences. If participating in a DLC program requires a customer to make an investment in a communicating device or smart appliance, then a customer should have assurance that the program will be in place for longer than their individual commitment and that they will be given the opportunity to continue participation as they choose.

Stakeholders' completed recommendations are also available on the project website and in Appendix 8.

Stage Three: Implementation

The final stage of the roadmap process was to develop and execute an implementation plan for new DR policies based on stakeholders' recommendations. See stage three of Exhibit 3 above. Upon receipt of stakeholders' recommendations for performance-based regulation and rate design, the steering committee directed the MPSC DR team to lead implementation activities.

Implementation Plan

At the direction of the roadmap steering committee, the MPSC's DR team took on the task of implementing stakeholders' recommendations. The MPSC kicked off implementation efforts on March 29, 2016, in Commission Order U-17936, which solicited public comments on DR programs administered by the state's two largest utilities, Consumers Energy and DTE Energy, and the feasibility of conducting a statewide DR potential study. MPSC Chairman, Sally Talberg, highlighted the importance of DR in the Commission's announcement on March 29, 2016: "The MPSC is committed to exploring demand response programs to shift when customers use electricity—such as high-usage summer days—as an alternative to new power plants or out-of-state purchases. The Commission invites interested parties to submit comments on this important topic." The public was given until May 12, 2016, to submit comments. The steering committee asked that the MPSC's DR team provide periodic updates on implementation activities.

Monitor DR Implementation

The MPSC received more than 100 comments responding to their request for feedback. Comments were submitted by 16 different organizations, including utilities, advocacy organizations, businesses, and residents. The MPSC summarized feedback in their November 7, 2016, order in case number U-17936. Building on the feedback received, the MPSC DR team drafted a report titled, "Demand Response Potential Study Report," which detailed potential funding options, cost estimates, timing, and scope of preparing a statewide study of DR potential in Michigan. This report is available in case number U-17936 on the MPSC website at the following link.

In addition to MPSC's efforts, described in case number U-17936, the DR team monitored and tracked implementation activities related to the roadmap stakeholder group's other recommendations. During the implementation period of the roadmap process, Governor Snyder reached a final agreement with the state legislature to finalize Michigan's long-awaited new energy policy. Senate Bills 437 and 438 were signed into law by the Governor on December 21, 2016, capping off more than four years of work. Additional discussion of Michigan's new energy policies follows in section five of this report, beginning on page 28. However, it is important to mention here as elements of stakeholders' recommendations for DR were included in the legislation.

Progress on implementation activities was reported to the roadmap project team in March 2017. The steering committee reviewed the progress on implementing stakeholders' DR recommendations and asked

the project team to convene stakeholders to update them on the status of implementation. The progress report, delivered to stakeholders in March 2017, is available in Appendix 11. A complete summary of implementation actions is available below in Exhibit 4.

The MPSC DR team will continue their efforts toward implementing DR in Michigan. As a part of the Commission's overall energy law implementation efforts, the DR team is heading up a stakeholder workgroup to meet the legislation's requirement that the MPSC promote voluntary load management programs, such as DR programs, TOU and peak pricing, and remote shut off of air conditioning, which requires certain utility companies to offer MPSC-approved DR programs. Provisions of the new energy law related to DR, compiled by the MPSC, are available in Appendix 12. Updates on the MPSC's DR implementation efforts can be found at the MPSC's energy law implementation website.

Exhibit 4. Demand Response (DR) Implementation Status

Studying DR Potential

Recommendation	Implementation Status
Stakeholders noted that there has not been a comprehensive potential study of DR for several years and that a baseline study could be useful for energy providers and the state. Participants also noted that a potential statewide study would need to account for differences among utilities and across customer classes. The group generally agreed that a study for DR programs in Michigan could be an important aspect of completing an integrated resource plan (IRP) should such a plan be required by pending energy legislation.	Public Act 341 of 2016, section 6(t), requires regulated electric utilities to file an IRP. A requirement in the same section of PA 341 directs the commission to conduct an assessment for the use of DR programs in the state. The results of the statewide DR assessment will then be used to establish IRP modelling scenarios and assumptions for use by the utilities in their required filings.

Structuring Customer Compensation and Ensuring Adequate DR Performance

The stakeholder group made the following recommendations for designing the three most common types of DR rates.

TIME-OF-USE PRICING (TOU): Typically applies to usage over broad blocks of hours (e.g., on peak=six hours for summer weekday afternoon; off peak=all other hours in the summer months) where the price for each period is predetermined and constant.		
Parameter	**Recommendations**	**Implementation Status**
Pricing/interruption period (frequency and timing)	Stakeholders believe that there could be two approaches for designing residential TOU rates—a simple and a complex approach. Stakeholders described that a two-tier TOU rate may prove to be simpler for customers to understand and potentially increase customer participation. This approach would employ a single, longer peak period from 2 PM–7 PM. Stakeholders also saw value in the three-tier TOU rate because this structure better reflects the cost of providing service, provides for stronger price differential signals, and may make it easier for participants to avoid energy use during shorter on-peak periods. Any program design should be specific to a utility's load profile and seasonal weather patterns.	**Implemented.** The state's two largest electric utilities DTE Energy and Consumers Energy have instituted two-tier and three-tier TOU rates. These rates were designed in accordance with stakeholders' recommendations. Per stakeholders' recommendation, the two-tier rate includes one long on-peak period and the three-tier rates have higher price differentials. The utilities' three-tier rates are no longer labeled experimental, and there are no limits on the number of participants. The Michigan Public Service Commission (MPSC) approved these rates in the utilities' most recent general rate cases (Cases U-17990 and U-18014).
Opt-in/out provision	During early stages, participation in TOU rates should be based on opt-in enrollment. Stakeholders commented that utilities should, where possible, provide standard-service customers with a comparison of what their bill would have been had they participated in a TOU rate. As programs mature and savings are demonstrated, stakeholders expressed that an opt-out approach could feasibly replace the opt-in provision. There was also the suggestion from some participants that, when applicable, utilities should automatically	**Implemented.** The commission-approved TOU rates are opt-in only. In recent rate case orders, the commission rejected utilities' proposals to use three-tier rates as the default for new customers, commenting that "[the rate] is too complex to be set

	enroll customers in the rate class that best suits a customer's consumption habits based on 12 months of energy use data.	as the default rate for new residential and secondary commercial customers" (Case U-18014).
Notification method and timing	TOU rates make clear the different price levels associated with energy use at various times of the day. Notification is not necessary in TOU rates.	**Implemented.** Current two-tier TOU rates do not require customer notification.
On-/off-peak price ratio	Stakeholders noted that the on-/off-peak price ratio for utility TOU rates should—similarly to peak periods—reflect the nature of a utility's load profile and seasonal weather patterns. Stakeholders generally agreed that a range of on-/off-peak price ratios between three and 4.5 would be a good place to set initial rates. As utilities' experience with TOU rates matures, these price ratios should reflect experiences with customer participation and actual savings in avoided energy and capacity costs.	**Partially implemented.** The commission's recent orders established the following price differentials for TOU rates: DTE's two- and three-tier TOU rates feature on-/off-peak price ratios of approximately three. Consumers' TOU rates' price differentials are slightly lower, with 1.5 for their two-tier and 1.8 for their three-tier rates.
Incentive offered	Incentives should reflect the amount that produces the desired level of participation in and savings from these rates. Stakeholders commented that the appropriate level of incentives could be learned through utility experience over time. In TOU rates, the incentive should reflect the value of the avoided cost of energy consumption during peak periods and avoided costs of capacity otherwise needed to meet peak demands.	**In progress.** As utilities gain more experience with and customer feedback on their new TOU rates, they will be able to better optimize incentives to produce desired results.
Contract term	The typical length of time for customers to participate in a time-varying rate programs is one year. However, utilities should be allowed some flexibility with their individual programs in order to align with regional transmission operator (RTO) requirements and customer preferences. A customer's individual commitment should not imply that utilities' time-varying rate programs are unavailable after a customers' individual commitment. This point is important for customers whose participation in time-varying rate programs brings them to make investments in communicating devices or smart appliances.	**Implemented.** Stakeholders' recommendation was codified into Michigan law by Public Act 342 of 2016 Sec 95 (1) (a), which states "To participate in a [load management] program, a customer shall agree to remain in the program for at least one year."

CRITICAL-PEAK PRICING AND CRITICAL-PEAK REBATES (CPP and CPR): When utilities observe or anticipate high wholesale market prices or power system emergency conditions, they may call critical events during a specified time, and the price for electricity during these time periods is substantially raised. Two variants of this type of rate design exist: one in which the time and duration of the price increase are predetermined when events are called and another in which the time and duration of the price increase may vary based on the electric grid's need for reduced loads.		
Parameter	**Recommendations**	**Implementation Status**
Notification method and timing	Residential customers should receive notification for a critical-peak event at least one day in advance. Stakeholders also noted that customers should be given the option to select the type of notification they receive (e.g., text, phone call, email). Customers should also be given the option to have a notification delivered directly to a communicating thermostat or smart appliance. This practice could encourage participation by removing an obstacle for customers.	**Implemented.** Current utility programs require notification to be given a day in advance of critical-peak events. DTE's approved tariff specifies that notification may be made via telephone, text message, email, or in-home device.
Critical-peak/off-peak price ratio	Stakeholders noted that the critical-/off-peak price ratio should—similarly to TOU peak periods—reflect the nature of a utility's load profile and seasonal weather patterns. As utilities' experience with critical-peak rates matures, these price ratios should reflect experiences with customer participation and actual savings. Utility participants noted that their peak pricing programs use critical-peak prices set at $0.95.	**In progress.** More experience with and expanded participation in TOU rates will enable utilities' to further optimize critical-/off-peak price differentials. Currently, Consumers and DTE continue to use critical-peak prices of $0.95.
Price vs. rebate	Utilities should provide access to both CPP and CPR programs, at least in pilot projects, until the best program results are determined. Stakeholders believe that participation would be higher in CPR programs but noted that these programs add an extra administrative and accounting step that could lead to higher program operating costs.	**In progress.** Only Consumers offers CPP and CPR programs. New and expanded program offerings are expected as utilities garner more experience in offering CPP and CPR programs.
Incentive offered	Incentives should reflect the amount that produces the desired level of participation in and savings from these rates in avoided energy and capacity costs associated with the customer response. Stakeholders commented that the appropriate level of incentives could be learned through utility experience over time.	**In progress.** Incentives offered will be further refined as utilities gain more experience in offering critical-peak rates and learn from customer participation and feedback.
Contract term	The typical length of time for customers to participate in critical-peak programs is one year. However, utilities should be allowed some flexibility with their individual programs in order to align with RTO requirements and customer preferences. A customer's individual commitment should not imply that utilities' critical-peak programs are unavailable after a customer's individual commitment. This point is important for customers whose participation in critical-peak programs brings them to make investments in communicating devices or smart appliances.	**Implemented.** Stakeholders' recommendation was codified into Michigan law by Public Act 342 of 2016 Sec 95 (1) (a), which states, "To participate in a [load management] program, a customer shall agree to remain in the program for at least one year."

DIRECT LOAD CONTROL (DLC) PROGRAMS: When utilities observe or anticipate high wholesale market prices or power system emergency conditions, they may call critical events during prespecified time periods, the price for electricity during these time periods remains the same but the customer is refunded at a single, predetermined value for any reduction in consumption relative to what the utility deemed the customer was expected to consume.		
Parameter	**Recommendations**	**Implementation Status**
Opt-in/out provision	Participation in DLC programs should be on an opt-in basis. Once enrolled in a DLC program, residential customers would not be able to opt out of any cycling events for the duration of their contract commitment. Stakeholders commented that allowing customers to opt out of a DLC event would place the utilities' capacity commitments with their RTO at risk. Stakeholders noted that if customers were able to opt out of an event, a penalty requisite with the potential penalty the utility would face for nonperformance from the RTO would be required. Some utilities currently offer the option for a customer to opt out of one event per year, as long as the utility is given sufficient notice. This provides a customer with some flexibility.	Implemented. Currently DLC programs require a customer to opt-in. Consumers' DLC program allows the customer to opt-out of one load control event per summer. Additional opt-outs granted by Consumers may result in the customer's bill credit being forfeited.
Notification method and timing	Notification for DLC or air conditioning (AC)-cycling programs should not be a requirement. However, customers should be able to determine whether they are being cycled through their utility account online, via an opt-in communication from their utility, or directly from their appliance. This would ensure customers can determine whether they are experiencing mechanical difficulties with their appliance or if their experience is the result of DLC.	Implemented. Stakeholders' recommendation is reflected in Consumers and DTE's DLC programs.
Pricing/interruption period (frequency and timing)	DLC programs may vary depending on what appliances are being controlled. Michigan has years of successful utility AC-cycling programs on which to model new programs. AC-cycling programs should run from June through September and cover up to eight hours each day at a cycling rate of 15–30 minutes out of every hour.	Implemented. Stakeholders' recommendation is reflected in Consumers and DTE's DLC programs.
Price vs. rebate	Residential customers participating in DLC programs should receive a payment for their participation. Payments could potentially be in the form of a monthly bill credit, but utilities should have the flexibility to design payments so that they align with customer interest.	Implemented. DTE offers customers a discounted rate for their participation in DLC programs. Consumers offers a monthly bill credit.
Incentive offered	The level of incentive offered to participating DLC program customers should be correlated with the cost savings such programs produce. The amount of incentive should also be set at a level that is enough to drive customer participation in DLC programs. This determination would be made based on utility experience.	In progress. With more experience and participants on DLC rates, utilities will further optimize incentives. The monthly bill credit offered by Consumers is based on the summer incremental capacity costs as outlined in their general rate case.
Contract term	The typical length of time for customers to participate in a DLC programs is one year. However, utilities should be allowed some flexibility with their individual programs in order to align with RTO requirements and customer preferences. If participating in a DLC program requires a customer to make an investment in a communicating device or smart appliance, then a customer should have assurance that the program will be in place for longer than their individual commitment and that they will be given the opportunity to continue participation as they choose.	Implemented. Stakeholders' recommendation was codified into Michigan law by Public Act 342 of 2016 Sec 95 (1) (a), which states, "To participate in a [load management] program, a customer shall agree to remain in the program for at least one year."

Structuring Utility Compensation and Measuring Performance

The stakeholder group made the following recommendations for compensating utilities for delivering DR programs and measuring program performance.

Recommendation Category	Recommendations	Implementation Status
Measuring program performance	To measure progress toward achieving the stakeholder group's vision for DR programs in Michigan, the level and type of customer participation in cost-effective programs should be tracked. To that end, the stakeholder group recommends using the percentage of load per customer class participating in DR programs, as well as the net system savings through the use of DR (dollars per megawatt [$/MW]) cost of DR relative to the $/MW cost of traditional investment) as the types of metric to be used to evaluate whether or not the DR vision is being achieved. These metrics should be specific for utilities and customer classes (as opposed to establishing a single, statewide target metric). Utilities are already collecting the necessary data to be able to evaluate progress toward these metrics, so the group thought these were not only the most important metrics, but also the most feasible to track. Utility-proposed targets should be grounded in the understood, cost-effective potential, as well as the anticipated need as determined by an IRP.	Implemented. The MPSC's orders in cases U-17936 and U-18013 require DTE and Consumers to file monthly and annual reports containing the data necessary to determine program performance on recommended metrics. These metrics are specific to individual utilities and differentiated by customer class and program. Targets or goals for these metrics will be developed as part of the utilities' separate IRPs. Modelling scenarios for utilities' IRPs, including the use of DR, are currently being drafted through a statewide stakeholder process.
Utility compensation	Utility compensation for delivering DR programs should be based on a combination of cost recovery and an opportunity to earn a performance-based return as follows: Full cost recovery of prudent program expenditures: The costs of implementing DR programs can include capital (communication infrastructure, load control devices) and noncapital (marketing, administration, incentives) expenditures. Recovery of these costs could occur as an expense—for example, through a reconcilable surcharge—or through rate base. If cost recovery is done through rate base, both capital and noncapital DR program expenditures should be included, and utilities should be allowed the opportunity to earn a rate of return on their program investments. Performance reward: Utilities that operate DR programs effectively and generate net system savings should be eligible for a performance incentive. The incentive should be tied to achievement of agreed-upon performance metrics (e.g., participation, threshold peak demand reduction, program cost effectiveness, or minimum net system savings). The performance incentive could be structured as a percentage of program spending, as a share of net system savings, or as a premium rate of return on their program investment. Utilities should be awarded performance incentives only if they meet or exceed threshold performance levels and the incentives should not exceed the net system savings generated through the DR programs. A portion of net system savings should be used to lower system costs/rates for all customers.	Cost Recovery: Implemented. Stakeholders' recommendation was codified into Michigan law by Public Act 342 of 2016 Sec 95 (3) which states, "The commission may allow a provider whose rates are regulated by the commission to recover costs for load management through base rates as part of a proceeding under section 6a of 1939 PA 3, MCL 460.6a, if the costs are reasonable and prudent and meet the utility systems resource cost test." Performance Reward: In progress. Stakeholders' recommendation was codified into Michigan law by Public Acts 341 and 342 of 2016 which include the financial incentive mechanism which could be extended to DR program spending. PA 341 also includes a provision allowing the use of a shared savings mechanism in utilities' IRPs. Utilities may also propose alternative performance reward mechanisms in cases before the commission. A stakeholder group will be discussing the framework for evaluating and rewarding DR programs throughout 2017.

	In addition to these benefits, participating customers should also be eligible to receive incentives.	
Measuring program cost effectiveness	The stakeholder group recommended using either the utility-cost test or total-resource-cost test, or a combination of the two, to measure program cost effectiveness. The utilities already use this methodology, so it is both appropriate and feasible. This method compares the $/MW for the utility to implement a DR program to the $/MW saved by avoiding capacity generation. The group thought it was important that the costs and benefits be delineated by time (season and time of day) and location (local and regional effects) and normalized for variations in weather and regional economic conditions.	Implemented. Stakeholders' recommendation was codified into Michigan law by Public Act 342 Sec 95 (3) which states, "The commission may allow a provider whose rates are regulated by the commission to recover costs for load management through base rates as part of a proceeding under section 6a of 1939 PA 3, MCL 460.6a, if the costs are reasonable and prudent and meet the utility systems resource cost test."
Program reporting	The stakeholder group thought both prospective and retrospective reporting should be done. Utilities may submit a prospective DR plan to the MPSC—or include it in the integrated resource planning process, if appropriate—to ensure program costs are just and reasonable. Costs of a prospective plan preapproved by the MPSC should be deemed eligible for recovery. This can be done as part of a utility's regular rate proceedings or separately. If an RTO has already determined a utility's DR program is an eligible capacity resource, then there is an accelerated review and approval process. The utilities should then be required to annually submit a retrospective performance report on what was accomplished so that the reward can be approved. The group stressed the importance of transparency, so these reports should be shared by the MPSC publicly. However, individual customers should be treated as private.	Implemented. The MPSC's orders in cases U-17936 and U-18013 require DTE and Consumers to file monthly and annual DR reports. These reports must include detailed accounts of participation in DR programs, available MW of demand reduction, resource capacity reported to the RTO, energy savings, and program spending. The data provided in these reports will allow stakeholders to develop performance measures to evaluate the effectiveness of utility DR programs. Forward-looking DR plans will be featured in utility IRPs.
Integrating DR with energy-efficiency plans	MPSC should be willing to consider integrated plans that include DR, energy efficiency, and other measures.	In progress. DR is included, to some extent, in the portions of PA 342 related to energy waste reduction (EWR) plans. MPSC will be hosting a stakeholder group to discuss the framework for evaluating and rewarding DR programs throughout 2017, including integration with EWR.
Third-party verification	Findings from the retrospective performance reports should be verified annually by a third party hired by the utility. Identification of third-party verification contractor, or the process and qualifications for securing the third-party verifier, should be included in the prospective DR plan noted in a preceding bullet. Both the utilities proposing DR programs as well as DR providers should be monitored to ensure they are delivering intended results.	Not implemented.
RTO verification	An RTO's approval of DR programs used by a utility to meet its resource adequacy requirement should be sufficient to meet the requirement for third-party verification.	Not implemented.

Section Five. Focus Returns to New Law Implementation

More than four years after Governor Snyder first called for changes to Michigan's energy policies, after countless hours of stakeholder engagement, legislative posturing, and a final all-night push, the Michigan Legislature moved to enact new energy policies. The final bipartisan legislation was signed by Governor Snyder on December 21, 2016. In an announcement, the governor praised the policy: "This legislation will make it easier for our state to meet its energy needs while protecting our environment and saving Michiganders millions on their energy bills...these bills that will help ensure a better and brighter future for all Michiganders." Both acts went into effect on April 20, 2017.

Elements of Michigan's New Energy Laws

Michigan's new energy policies address a wide variety of topics; the highlights of the legislation are as follows:

Public Act 341 of 2016

- Creates an Integrated Resource Planning (IRP) process applicable to all rate-regulated electric utilities and allows for MPSC pre-approval of costs for projects approved in an IRP.
- Establishes a new construct for electric generation capacity reliability that allows MPSC to evaluate whether to use a three-year forward auction or Prevailing State Compensation Mechanism (if implemented by MISO) or a backstop State Reliability Mechanism to ensure adequate capacity is available to serve customer load.
- Lowers cost threshold for a utility to file a certificate of necessity (CON) to $100 million and requires that all projects greater than 225 MW, included in a utility's IRP, to go through the CON application.
- Requires the MPSC to conduct a study to determine the cost of services for net metering and distributed generation and to create a tariff to be included in all electric rate cases after June 1, 2018.
- Enables the MPSC to approve revenue decoupling mechanisms for small electric utilities.
- Establishes the ability to use shared savings mechanisms to provide incentives for energy waste reduction activities.
- Relaxes electric utility code of conduct provisions.
- Includes provisions to expand the use of performance-based regulation in Michigan.
- Increases funding for the Utility Consumer Representation Fund and allows the utility consumer participation board and attorney general to participate in rate cases, CON proceedings, and the IRP process on behalf of residential customers.

Public Act 342 of 2016

- Maintains Michigan's standards for Energy Waste Reduction (EWR) for electric and natural gas providers through 2021. Natural gas EWR standards apply beyond 2022.
- Increases the state's Renewable Energy Portfolio Standard to 15 percent by 2021.
- Includes the goal that Michigan meet 35 percent of its electric needs through a combination of EWR and renewable energy by 2025.
- Eliminates current net metering program and establishes a new distributed generation program.
- Maintains existing participation caps and system, allowing behind the meter generation and crediting customers for excess generation placed onto the grid.
- Ensures that any grid charge established by the MPSC may not be reduced by any credit or other ratemaking mechanism.
- Allows current net metering customers to be grandfathered in at current terms of service ten years from enrollment date.

- Allows rate-regulated utilities to implement on-bill programs to allow customers to finance and repay the costs of residential energy projects on their utility bills.
- Requires rate-regulated electric utilities to offer customers voluntary "green-pricing" programs.

Implementation Efforts

Implementing Michigan's new energy policies continues to be a major undertaking. The MPSC has created a series of staff-led workgroups to tackle specific elements of the legislation. These workgroups cover the following topics:

- Rate case and CON
  - Rate case filing requirements
  - CON filing requirements
- IRP process
  - Statewide parameter setting/modeling
  - Plan filing requirements/schedule
  - DR potential study
  - EWR potential study
- Resource adequacy
  - Capacity demonstration
  - State reliability mechanism
- Electric choice
- Renewable energy
  - Renewable energy plan cases
  - Green pricing programs
- Distributed generation
- Energy waste reduction
  - EWR program updates
  - On-bill program implementation/ rulemaking
- DR implementation
- Public Utilities Regulatory Policies Act avoided cost review
- Performance-based regulation
- Code of conduct/value added programs

Implementation Plan

The implementation process for Michigan's new energy legislation kicked off on March 10, 2017. The MPSC convened stakeholders to provide them with an overview of the implementation process and to explain how they can participate in implementation plan activities. To this end, MPSC developed a website dedicated to the implementation plan for the state's new energy legislation and was designed to facilitate stakeholder engagement and timely dissemination of information related to the plan. The website hosts information regarding planned stakeholder meetings, background research, MPSC staff contacts, and more. The MPSC's energy legislation website is available at the following link. The 18 staff-led workgroups have been meeting regularly since the March kickoff meeting. Complete updates on workgroup activities are available on MPSC's website.

Implementing On-bill Program

When the Roadmap for Implementing Michigan's New Energy Policy started in 2015, the project team and steering committee expected to have enough time to work with stakeholders on implementing several aspects of the state's new energy policy. However, the timing of legislation did not coincide with the grant period. Despite this fact, the project team utilized the roadmap process to engage stakeholders about DR. When legislation was finally enacted in December 2016, the project team communicated with the roadmap steering committee to see if there was an opportunity to use remaining grant resources to help with implementing aspects of the new law. Thanks to a grant extension from DOE and the leadership of the steering committee, the project team was able to reconvene stakeholders to begin discussions related to on-bill programs.

Under the new energy law, rate-regulated utilities may offer residential customers the option to finance home energy improvement projects and the ability to pay off the costs of those projects on their utility bill. The legislation also requires the MPSC to promulgate rules to implement on-bill programs by April 20, 2018. Using the roadmap process as a model for stakeholder engagement, the project team, with MPSC and

MAE, worked with utilities and other interested parties to create a framework for an on-bill financing program in Michigan. The process used and outcomes achieved are described below.

Stakeholder Group

To form the on-bill program stakeholder group, the project team used an open nomination process to identify candidates. See Appendix 13 for the criteria used to select individuals for the stakeholder group. Twenty-two candidates, representing different utilities, utility associations, contractors, and community advocates, were invited to participate in a stakeholder group, which would ultimately identify goals for an on-bill program and determine program design structures that support the goals. A list of stakeholder participants is available in Appendix 14.

Phase One—Baseline Assessment

The project team's experience with the roadmap's DR efforts affirmed the importance of stakeholders having a common understanding of a topic from the outset of the process. Given this experience, the steering committee provided stakeholders with a baseline assessment titled "Program Design Considerations for Developing an On-bill Financing Program: A Primer for Utilities in Michigan." This report provided essential information meant to offer a better understanding of on-bill program goals, key program design decisions, and strategies for best meeting the needs of customers. Within the baseline assessment were five case studies from existing on-bill programs, run by utilities around the country that offer lessons learned, program design considerations, and inspiration. As part of this project, the project team updated this baseline assessment with new information, including additional capital options, new policies/provisions from PA 342 of 2017, and new case studies.

In addition to providing the baseline research, the project team also invited subject matter experts to present to stakeholders. Information related to stakeholders' implementation efforts and roadmap process are available on the On-bill Financing section of the MPSC's energy legislation website.

Phase Two—Visioning

Prior to the initial stakeholder group meeting, the project created an online survey for stakeholders. The purpose of the survey was to obtain stakeholder input on program goals and on-bill program design elements. The survey results were summarized and presented to the stakeholder group on April 24, 2017. A summary of the survey results can be found in Appendix 15.

At the first stakeholder meeting, the group worked to identify goals for an on-bill program that would be consistent statewide. To provide proper background and context for the meeting, attendees received an overview of the enabling legislation for on-bill programs, which discussed lessons learned from other on-bill programs and reviewed stakeholder survey results. The focal point of the meeting was to facilitate a discussion on goal setting, during which the stakeholders reached consensus on the following goals for an on-bill program that is consistent statewide:

- Increase the number of participating customers making energy improvements through the following measures:
  - Maximize the long-term reduction in energy use/demand per household.
  - Expand access to financing for individuals who may not qualify for financial products currently in the marketplace.
  - Make energy improvements more affordable for customers.

Stakeholders' completed list of goals for on-bill programs are available in Appendix 16.

Following stakeholders' goal setting, the project team drafted key program design elements to reflect an initial model proposal for an on-bill program. Stakeholders used the following guiding principles to evaluate the importance and efficacy of different program design elements:

- Provides uniformity and simplicity in processes
- Addresses gaps in coverage with existing available financing programs
- Is viable for capital providers
- Ensures reasonable participation costs for utility participants
- Leverages existing statewide resources
- Allows program goals to be met

Key program design elements, and the reasons for including a specific design element in an on-bill program, were presented to the stakeholder group during a second group meeting on May 19, 2017. Stakeholder feedback and discussion was necessary to further refine these design elements to ensure that an on-bill program meets the needs of the program partners. To facilitate discussion, the program design elements were compiled into three areas based on the level of decision making needed by the workgroup:

- Design elements that are either mandated by statute or require little or no discussion from the workgroup.
- Design elements that may require some discussion from the work group to reach consensus.
- Design elements that require discussion and consensus building.

A description of all the program design elements, reviewed by the stakeholder group, and a summary of stakeholders' discussion are shown below. See Exhibit 5.

Exhibit 5. On-bill Program Design Elements Agreed Upon by Stakeholders

Program Design Element	Description	Discussion
Eligible utilities	❖ Utilities regulated by the Michigan Public Service Commission (Public Act 342) ❖ Municipal utilities (Public Act 408) ❖ Rural electric cooperative utilities	❖ Municipal utility and regulated utilities can participate per statute ❖ Rural electric cooperatives are not governed by either statute, but have organizational characteristics that are conducive to an on-bill program
Home energy audit and diagnostic testing	❖ PA 408 requires compliance with American National Standards Institute home energy audit standards ❖ PA 342 requires compliance with American National Standards Institute home energy audit standards ❖ Statute allows eligible regulated utilities to propose alternative home energy audit standard, if desired	❖ Required by statute for municipal utilities ❖ Supports maximization of long-term reduction in energy use ❖ Subject to discussions with regulated utilities, as some may want to propose an alternative home energy audit standard
Loan type	❖ Unsecured loan ❖ Multiple loans per customer allowed if total amount financed does not exceed maximum allowable loan amount	❖ Eases administrative duties ❖ Supports maximization of long-term reduction in energy use
Interest rates	❖ Interest rate to be no greater than adjusted prime rate plus 4 percent	❖ If capital provider is a nonprofit corporation, then the interest rate cap is mandated by statute ❖ Support making energy improvements more affordable ❖ Subject to discussions with the capital provider
Loan term	❖ Maximum loan term is 180 months (15 years), not to exceed the useful life of the installed measures	❖ Supports making energy improvements more affordable ❖ Subject to discussion with the capital provider
Capital provider	❖ Single capital provider	❖ Ease of administration ❖ Subject to discussion with capital provider. Several capital providers may be required to satisfy some program design elements and to allow on-bill program to reach scale
Originator	❖ Capital provider to accept loan application and originate loan	❖ When capital provider accepts loan applications and originates loans, it is less costly and requires less data coordination with utility participants and loan servicer(s) ❖ Subject to discussion with capital provider. If capital provider cannot originate loans, then an alternative structure with third-party originator will be explored ❖ If several capital providers are required, a single originator would be preferred to reduce administrative burden and simplify contractor and customer use

Servicer	❖ Capital provider to service the loans	❖ If capital provider services loans, it is less costly and requires less data coordination with utility participants ❖ Subject to discussion with capital provider. If capital provider cannot service loans, then an alternative structure with a third-party loan servicer will be explored ❖ If several capital providers are required, a single servicer would be preferred to reduce administrative burden and simplify contractor and customer use
Underwriting criteria	❖ Twelve months of consecutive, on-time utility bill payment history ❖ Any bankruptcies, foreclosures, or repossessions (greater than $1,000) must have been discharged at least 12 months prior to loan application ❖ No outstanding tax liens ❖ No outstanding collections (greater than $1,000)	❖ Supports expanding access to financing ❖ Expands or tightens customer access by adjusting required number of consecutive months or by allowing delinquent payments ❖ Credit bureau data collected for future data review (FICO score not used in credit review) ❖ “On-time” defined by stakeholders as “payments without late fees” ❖ Subject to discussion with capital providers
Credit enhancement	❖ Potentially offer a loan loss or debt service reserve	❖ Capital providers may not offer a loan with a 15-year term and alternative underwriting without a credit enhancement ❖ Support making energy improvements more affordable and expanding access ❖ Subject to discussions with capital provider and, if required, determine source of funding for loan loss reserve or debt service reserve
Billing cycle	❖ Each participating utility will be encouraged to move on-bill customers to a consistent billing cycle, within the utility, to simplify loan servicing ❖ Subject to each utility’s ability to implement	❖ Eases administrative tasks for utility, capital provider, and loan servicer (if different from the capital provider) ❖
Transferability	❖ Notice of loan filed with county register of deeds so that obligation to pay the loan installment charge stays with the property and is binding to future customers contracting for utility service at the property	❖ Supports maximization of long-term reduction in energy use ❖ Supports expanding access to financing ❖ Includes a disclosure statement where the buyer would inform the seller of what items were included in the loan obligation
Statewide program administrator	❖ Assists utility and capital providers with development and management of the on-bill program per the Residential Energy Project Program Plan ❖ Provides quality assurance ❖ Manages contractor network ❖ Partners with utilities to market and drive demand for the program ❖ Measures and reports program performance to program partners	❖ Ease of administration for program participants ❖ Provides uniformity and continuity among participating utilities and contractors ❖ Ensures a consistent application of program procedures

Quality assurance	❖ Documentation review for every project ❖ On-site inspections or phone calls to customers at a rate of 20 percent for each participating contractor's first ten projects. After ten projects, 5 percent of the contractor's projects will be inspected. ❖ Remedial action process to correct mistakes and provide for continuous program improvement	❖ Essential to ensuring customer satisfaction, verifying compliance with statutory requirements and program procedures, and providing for continuous program improvement ❖ Provides an opportunity to review workmanship of participating contractors ❖ Consistent quality assurance protocols could support cost savings and continuity with other financing programs and provide contractors with administrative consistency

Design Elements That Still Need to Be Determined		
Program Design Element	**Description**	**Discussion**
Eligible properties	❖ Single-family homes (one to four units) within the utility's service territory ❖ Rental properties permitted ● If tenant pays utility bill, property owner must authorize work and renter must sign agreement to accept loan payment	❖ Legislation explicitly supports residential properties ❖ Commercial properties may be considered in the future ❖ On-bill programs are potentially a more effective approach to serving rental market, which is difficult to serve through traditional financing programs ❖ Stakeholder group requested scan of other programs to determine how to address rental properties
Minimum/maximum loan amounts	❖ Minimum loan amount: $1,000 ❖ Maximum loan amount: $30,000	❖ Raising minimum loan amount optimizes long-term reduction in energy use, because it encourages comprehensive, multi-measure projects ❖ Lower minimum loan amount may expand access for lower-income customers to make efficiency improvements ❖ Stakeholder group requested scan of other programs and/or a pilot program to address question of whether minimum loan amount should be raised to $3,000 or $5,000 to encourage more comprehensive work to support goal of maximizing energy savings
Eligible improvements	❖ Homeowners could finance any of the following improvements through the on-bill program: ❖ Appliances (clothes dryers, dishwashers, refrigerators) ❖ Building envelope improvements (air sealing, automated control systems, doors, energy recovery systems, insulation, roofing, windows) ❖ Heating, ventilation, and air conditioning systems (air conditioning, boilers, furnaces, geothermal systems, heat pumps)	❖ A single measure "a la carte" approach does not maximize energy savings; a comprehensive, multi-measure approach would support the goal of maximizing the long-term energy use per household ❖ Allows customers to address many efficiency and comfort issues in their homes ❖ Allows property owner to finance building improvements that might otherwise prevent energy efficiency work ❖ Stakeholder group requested scan of other programs and/or a pilot program to determine best approach to encourage deeper,

	❖ Lighting (day lighting, LED lighting) ❖ Other measures (electric vehicle charging stations) ❖ Renewable energy improvements (solar PV, solar thermal) ❖ Nonenergy building performance improvements (asbestos abatement, attic fans/ventilation, bath fans, building code upgrades, building envelope repairs, chimney liners, duct sealing/repair, electric upgrades, lead abatement, mold abatement) ❖ Any measure approved as a utility cost-saving measure ❖ Whenever possible, measures should carry the ENERGY STAR® label and have documented energy savings in the Michigan Energy Measures Database	more comprehensive work to support goal of maximizing energy savings
Payment management	❖ Prepayments—customers who wish to make additional payments on the loan shall pay the loan servicer directly ❖ Partial payments—when a customer does not pay the full billing amount (energy charges and loan installment charges), the loan servicer will apply the payment to the energy charges first ❖ Delinquent payments—customers will be given a seven-day grace period, after the initial payment due date, before the payment is considered delinquent. Late fees will not be assessed on the loan installment charge. ❖ Defaults—a loan is considered in default if three consecutive billing cycles pass without full payment toward the loan installment charge ❖ Disconnection—PA 408 and PA 342 allow participating utilities to disconnect service for nonpayment of loan installment charge in the same manner as disconnection for failure to pay energy charges. Home heating assistance grants should not be applied towards loan payments, ❖ Statewide uniformity will aid in ease of adoption and administration.	❖ Eases administrative tasks for utility, capital provider, and loan servicer (if different from capital provider) ❖ Provides continuity to the loan servicer in program procedures between multiple utilities ❖ The threat of utility disconnection for nonpayment is an effective deterrent of loan defaults ❖ It is assumed a capital provider will agree to expanded underwriting criteria with this type of loan security ❖ Supports expanding access to financing ❖ Stakeholders agreed that prepayments should be made directly to loan servicer

Payments included for gas measures on electric bills or vice versa	❖ When a customer has different utility service providers for electricity and natural gas, the loan installment charge is placed on the utility bill that corresponds to the measures providing the majority of the energy savings (e.g., if the majority of savings are coming from electric measures, then the loan installment charge will be placed on the electric utility bill)	❖ Supports maximization of long-term reduction in energy use ❖ Utility stakeholders suggested an administrative payment be provided to help defray the costs of providing payment collection services for another utility ❖ Utility stakeholders suggested that a credit toward their energy waste reduction goals be provided if they are offering payment collection services for another utility

Phase Three—Implementation

MPSC is currently working on updating customer billing rules, which are expected to be approved in October 2017. These new billing rules will accommodate the implementation of on-bill programs. MPSC plans to convene a broader group of stakeholders for a PA 342 rulemaking process. More conversations are expected to take place throughout 2017. This MPSC's rulemaking process is not expected to be completed until April 2018.

To continue the implementation plan for an on-bill program, the following actions are required:

- Finalize program design elements.
  - Provide additional research on rental property eligibility. Review other on-bill programs to determine how those programs incorporate rental properties. Test any changes to the program design element in a pilot project.
  - Come to an agreement on the types of eligible improvements that will be allowed in an on-bill program. The types of eligible improvements are tied to the discussion on minimum loan amounts as well as the extent to which a home energy audit will be required. More clarity on eligible improvements will likely come after discussions with capital providers.
- Identify several capital providers and begin discussions with these providers about participating in an on-bill program. Through these discussions, the team will seek solutions on the following questions:
  - Can the capital provider provide both loan origination and loan servicing?
  - How comfortable is the capital provider with alternative underwriting criteria that does not consider credit scoring? Would the underwriting criteria need to be changed for capital to be provided? If so, what changes would be necessary?
  - Would the capital provider require a credit enhancement to participate? If so, what type of credit enhancement would be desired?
  - How would the payment management design elements need to be adjusted to accommodate the capital provider? Could the loan installment payment be subordinate to the utility charges? Would a credit enhancement ease payment management concerns? How would loan collection procedures occur in the event of a default?
  - What interest rate would the capital provider propose? What loan term would the capital provider be comfortable with? Does the capital provider have any requirements for minimum and maximum loan amounts?
- Contact several utilities to determine their interest in participating in an on-bill pilot program.
  - The pilot program could be used to test different program design elements, such as a multi-measures approach, minimum/maximum loan amounts, the appropriate home energy audit level and payment procedures.
- Develop a draft program implementation guide and share with stakeholders.
  - The guide will include a summary of the on-bill program; lending requirements; eligible improvements; contractor requirements; billing and payment process; quality assurance requirements; evaluation, measurement, and verification process; and marketing efforts. The draft program implementation guide is available in Appendix 17.

References

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Appendix 1. Who's Who

STEERING COMMITTEE MEMBERS

Robert Jackson, Michigan Agency for Energy—Chair
Valerie Brader, Michigan Agency for Energy
Mary Maupin, Michigan Department of Environmental Quality
Sally Talberg, Michigan Public Service Commission
Norm Saari, Michigan Public Service Commission

STAKEHOLDER GROUP

Lauren Donofrio, Michigan Department of the Attorney General—Co-chair, ex-officio
Michael Moody, Michigan Department of the Attorney General—Co-chair, ex-officio
Kwafo Adarkwa, ITC Holdings
George Andraos, Ford Motor Company
Jim Ault, Michigan Electric and Gas Association
Chrissy Beckwith, Semco Energy
Mathias Bell, Opower
Greg Bergtold, Dow Chemical Company
Craig Borr, Wolverine Power Cooperative
Laura Chappelle, Energy Michigan
Greg Clark, Indiana Michigan Power
Liesl Clark, Michigan Energy Innovation Business Council
James Clift. Michigan Environmental Council
Dan Dundas, Senate Majority Policy Office
Anand Gangadharan, NOVI Energy
Jason Geer, Michigan Chamber of Commerce
Brandon Hofmeister, Consumers Energy
John LaMacchia, Michigan Municipal League
Greg Poulos, EnerNOC
Jean Redfield, NextEnergy
Don Stanczak, DTE Energy
Jill Steiner, The Cadmus Group
Andrew Vermeesch, Michigan Farm Bureau
Jim Weeks, Michigan Municipal Electric Association
Jeffrey Wiggins, House Republican Policy Office

INTERNAL SUPPORT STAFF

Lauren Donofrio, Michigan Department of the Attorney General
Michael Moody, Michigan Department of the Attorney General
Terri Novak, Michigan Agency for Energy
Dave Isakson, Michigan Public Service Commission
Bill Stosik, Michigan Public Service Commission

EXTERNAL SUPPORT STAFF

Julie Metty Bennett, Public Sector Consultants – *Project Manager*
Eric Pardini, Public Sector Consultants
Rich Sedano, The Regulatory Assistance Project

Appendix 2. Steering Committee Process

MEETING DATES	MAJOR FOCUS OF MEETING	RESOURCE MATERIALS PROVIDED
April 24	**Introductory Meeting** • Review project scope and timeline • Review and approve stakeholder list • Review invitation materials/process	• Purpose and process summaries • Baseline report outline • Draft stakeholder list • Draft invitation materials (letter, project summary, process flowchart, meeting schedule)
May 18–22	**Prepare for first stakeholder meeting** • Review and approve baseline research report • Review and approve stakeholder meeting agenda and materials	• Draft baseline research report • Draft meeting agenda • Draft presentations
June 8–12	**Prepare for next stakeholder meeting** • Review and approve Paths to the Future report • Review survey #1 results • Review and approve stakeholder meeting agenda and materials	• Paths to the Future report • Survey (#1) results on key regulatory issues, risks, and solutions • Draft meeting agenda • Draft presentations
July 13–17	**Prepare for next stakeholder meeting** • Review survey #2 results • Refine draft guiding principles • Review and approve stakeholder meeting agenda and materials	• Draft guiding principles • Survey (#2) results on importance and urgency of guiding principles • Draft meeting agenda
Aug 3–7	**Prepare for next stakeholder meeting** • Review revised guiding principles • Review draft vision • Review and approve stakeholder meeting agenda and materials	• Revised guiding principles • Draft vision • Draft meeting agenda
Aug 31–Sept 4	**Review and approve vision and guiding principles, prepare for next stakeholder meeting** • Finalize common vision for new regulatory framework based on key principles recommended by stakeholders • Review and approve stakeholder meeting agenda and materials	• Recommended principles and vision • Draft meeting agenda
Oct 5–9 Nov 2–6 Nov 30–Dec 4	**Prepare for next stakeholder meeting** • Review and approve stakeholder meeting agenda and materials	• Draft meeting agenda

Appendix 3. Steering Committee and Stakeholder Meeting Dates

Steering Committee Meetings

- **Meeting 1:** December 22, 2014
- **Meeting 2:** April 24, 2015
- **Meeting 3:** May 22, 2015
- **Meeting 4:** July 16, 2015
- **Meeting 5:** August 12, 2015
- **Meeting 6:** September 2, 2015
- **Meeting 7:** October 6, 2015
- **Meeting 8:** November 2, 2015
- **Meeting 9:** December 4, 2015
- **Meeting 10:** January 11, 2016
- **Meeting 11*:** March 24, 2016
- **Meeting 12:** July 23, 2017

Stakeholder Group Meetings

- **Meeting 1:** August 3, 2015
- **Meeting 2:** August 24, 2015
- **Meeting 3:** September 21, 2015
- **Meeting 4:** October 19, 2015
- **Meeting 5:** November 16, 2015
- **Meeting 6:** December 14, 2015
- **Meeting 7:** February 22, 2016
- **Meeting 8:** March 15, 2017
- **Meeting 9*:** April 24, 2017
- **Meeting 10*:** May 19, 2017

* On-bill financing meetings

Appendix 4. Roles and Responsibilities

Roadmap for Implementing Michigan's New Energy Policy:

Stakeholder Group Responsibilities and Procedures

The Michigan Energy Office, with grant support from the U.S. Department of Energy, is working to create a stakeholder- and research-driven roadmap that aligns electric utility business interests and customer behavior with public policy goals. The project is directed by a multiagency steering committee, including representatives from the Michigan Public Service Commission, the Michigan Agency for Energy, and the Michigan Department of Environmental Quality.

The steering committee appointed a stakeholder group to make recommendations on new and innovative electric utility ratemaking and rate design approaches to achieve Michigan's energy policy goals. The group's membership represents a diversity of interests and perspectives, including individuals that adequately represent their respective stakeholder interests as reflected by their leadership position within organizations and/or support of industry peers, experience with and knowledge of topics and regulatory processes, and ability to work well with other stakeholder group members.

The Michigan Energy Office has partnered with Public Sector Consultants Inc. (PSC) to manage the project and facilitate the work of the stakeholder group, provide logistical support for meetings, and prepare written documents and distribute materials. PSC has retained the services of the Regulatory Assistance Project and 5 Lakes Energy to provide technical assistance.

Responsibilities

- ***Review Background Research*:** At the direction of the steering committee, PSC, with contributions from the Michigan Public Service Commission, the Regulatory Assistance Project, and 5 Lakes Energy, has developed a foundational baseline report. The purpose of the report is to ensure that all stakeholders have a common understanding of issues and information relevant to the project before beginning to explore and develop recommendations. The report summarizes Michigan's current energy policy landscape and regulatory framework; Michigan electric utilities' performance on key and relevant indicators; factors, risks, and opportunities that could impact implementation of such policy goals and requirements; and potential innovative regulatory and rate design options to policy implementation by aligning utilities and customers with the policy goals and requirements.
- ***Develop a Vision and Guiding Principles*:** Stakeholders will develop vision and guiding principles for any changes to the regulatory model or ratemaking approaches that can serve as a "yardstick" for committee members as they debate, design, and implement any changes. The vision and guiding principles will be reviewed by the steering committee before being finalized.
- ***Recommend Regulatory and Rate Design Changes:*** Using background research and direction provided by the approved vision and guiding principles, the stakeholder group will explore and define the details of different regulatory approaches and innovative rate designs that could be implemented in Michigan in order to assist with implementation of new energy policy goals. These recommendations will be made to the steering committee. The process for adopting a consensus report and recommendations to the steering committee by the stakeholder group are outlined at the end of this document.

Operating Procedures

- All members should plan to be present at the beginning and participate until the end of each scheduled meeting to assure continuity and to optimize available time. Alternates, unless prearranged, are not allowed. Teleconferencing will be an option for participation in meetings, and may be utilized between meetings to expedite discussion at scheduled meetings.

- Meeting materials, schedules, and summaries will be available electronically, and an e-mail will be sent to members following the first meeting with instructions on accessing this information.
- Meeting summaries will be prepared and distributed to members. Individuals' comments will not be attributed in the summaries.
- Meetings are not open to the public. Members are, however, encouraged to solicit input from others between meetings to assist in the discussions during the meetings.
- Members who have materials they wish to share are encouraged to provide electronic copies to PSC for distribution to all members.
- E-mail will be the primary means of communications to members.

Discussion Guidelines

- Acknowledge one another as equals in the discussion.
- Stay open to each other's perspectives.
- Do not criticize the ideas of another, but offer your own ideas that might be different.
- Slow down so we have time to think and reflect.
- Remember that this process allows everyone to think together. Expect the process to be messy at times, particularly given the controversial nature of the issues with which the members will be grappling.
- Stay focused on the written charge set forth by the director that is attached.

Guidelines for Finalizing Stakeholder Group Recommendations

- The stakeholder group should strive for consensus recommendations. A supermajority of those members (i.e., at least one more than a simple majority) will constitute the level of agreement necessary for a consensus recommendation to the steering committee.
- The steering committee intends to give great weight to the recommendations of the stakeholder group, but must assume the ultimate responsibility for any proposed regulatory or rate design changes. A policy call will be made by state decision-makers on whether to implement recommended changes to ratemaking and rate design and, if so, when and how to make this transition.
- Agency staff members, although involved in the discussions with the stakeholder group, have alternative means to express their opinions; therefore, only appointed stakeholder members will participate in determining recommendations to the steering committee.
- The written recommendations of the stakeholder group will be prepared by PSC and finalized following review and approval by members.
- In the event that an individual member determines he or she cannot support a specific consensus recommendation, he or she will have the opportunity to record the reservation.
- In the event that a consensus cannot be reached among the members on a specific recommendation (e.g., a supermajority of stakeholder members do not concur and/or there are multiple alternatives still under discussion at the end of the process), PSC will summarize, with the help of those members advocating for a specific recommendation, the different alternatives and the potential consequences in a written report that will be shared with all members for review before being sent to the steering committee.
- When the final recommendations to the steering committee are prepared, the stakeholder group will be asked to agree that the report accurately describes the process, and that the process provided adequate opportunities for members to provide input into the final recommendations and for individual members to record reservations on certain specific recommendations.

Appendix 5. Detailed Survey Results

Responses to Stakeholder Survey Question 1: What are the current challenges with the existing regulatory and rate design structure?

Pressures on energy sector, resulting in reliability and affordability concerns

- Flat and even declining electric and gas load growth at the same time major new investments in generation and grid enhancements are needed—this puts increased upward pressure on rates
- Continued robust utility energy-efficiency programs lower average bills, but increase average rates
- Utilities are being used as tax collectors for social policy goals at a time when many customers say the costs are too high
- For economic development, Michigan needs the ability to offer competitive electric rates for energy intensive businesses that make siting decisions based on energy costs
- The existing infrastructure is aging
- Legacy fossil plant retirements and construction of new generation plants
- Challenges meeting capacity requirements and EPA 111d regulations

Roadblocks for distributed generation, alternative suppliers, and efficient technology

- Utilities incented to build and own, as opposed to identifying more flexible, adaptable options involving PPAs, energy service agreements (ESAs)
- Onsite renewables, such as solar or anaerobic digesters, owned by residents or commercial energy users can be costly to invest in; if we are to encourage this practice, it is important that these users get an equitable rate for access energy if they sell it back to the grid
- Cost/pricing structures that make self-generation and distributed generation options too expensive for customers
- No standardized PPA pricing/provisions for renewable resources, such as wind, hydro, and solar (similar to regulatory laws and commission rules in states like Oregon—although the transfer price schedule has been very useful and effective)
- Community renewables
- LED lighting rates

Challenges with hybrid market structure

- The current partially deregulated system puts generation resource adequacy at risk and unfairly allocates the fixed costs of generation among customers who pay in unequally
- The hybrid choice market creates political strife
- There are asymmetrical duties among providers—utilities with regulated rates have a duty to serve, while AES providers can pick who to serve and are not regulated
- Mix of very limited customer choice and regulated rates is "worst of both worlds"
- Lack of competition to help temper costs
- Physical limits of the systems may not be compatible with the regulatory models (e.g. choice loophole in the U.P.)

Challenges with the legislative process

- There is too much rate design and structure being proposed at the statutory level, limiting the impact of regulators. The cyclical revisions to the statutory structure create situations where the commission's broad regulatory authority conferred in PA 3 is limited, usually through legal actions appealing commission decisions. Thus, legislators with little experience in regulation may be asked to vote on very technical, difficult issues that are narrowly tailored to meet a specific need, to the detriment of the broad legal authority of the commission.
- Cost allocation among classes has been elevated to the legislature, with political influence affecting the result.
- Policymakers that are willing to design structures to appease interest groups lose focus of what is best for the whole
- Many groups wish to change rate design structure to incent their narrow interests rather than focusing on what is economically good for the whole

Litigious and costly regulatory process

- The current system is often very litigious, resulting in additional costs of discovery and unnecessary relitigation of similar issues
- Regulatory preapproval is required for capacity contracts that exceed six months, which poses a significant barrier to contracting for capacity; many sellers refuse to enter into negotiations with utilities because of regulatory delay and risks
- MPSC process is generally way too slow, particularly for smaller utilities such as co-ops and municipals

No incentive for cost containment

- Lack of alignment between utility business model and ratepayer interests; this doesn't line up with best options for ratepayers
- Cost declines when utility return is calculated on total project cost; leads to the highest cost that can still be deemed reasonable and prudent by regulators
- 2. File and use provisions provide upsides/certainty to utilities, but have not resulted in savings or efficiencies for ratepayers

Technology outpacing regulation

- Technology is moving faster than regulators and the industry as a whole; innovation is occurring outside the current regulatory model (Encouraging adaptation without destroying the current process in the short term will be paramount.)
- Ability for new technologies and new business models to be deployed in Michigan
- Many actors seek financial guarantees through the regulatory structure, which halts innovation (rent-seeking).

Grid performance not prioritized

- Regulatory framework encourages specific activities (building generation) as opposed to overall grid performance. This is, at best, a clumsy proxy for what we ultimately want to see; at worst, it encourages utilities to emphasize the wrong things
- Inherent tensions exist between utility as distribution grid operator (which is a natural monopoly, at least today) and the financial incentives to supply generation (not necessarily a natural monopoly)—the result is that utilities understandably de-emphasize distribution grid operations (which are less attractive to shareholders) in comparison to generation operations (which are more attractive).

Inadequate or threatened mechanisms for protection of public health and environment

- Public health and natural resource impacts of different generation sources are not considered as part of the regulatory structure
- Current mechanisms for including clean energy resources are effective, but subject to change under the current legislature

Encouraging distributed energy resources erodes economies of scale and threatens death spiral

- Economies of scale provide advantages that are being eroded with all the subsidization and encouragement of grid alternatives, threatening a death spiral

Lack of willingness to challenge assumptions about rate design

- There seems to be a feeling that the current paradigm is the only option. For example, many consider the "one in ten" basis for grid reliability to be the standard. But as many point out—at what cost? Is one in eight reasonable *and* cost-effective? How can we achieve maximum outcomes for ratepayers without impacting reliability and the environment? These points should be discussed and debated.

Lack of transparency in the planning process

- The planning process is dominated by utility interests, as that is where the information lies. Information dissymmetry makes it more difficult for regulators to fully evaluate efficacy of utility proposals and makes it very costly and difficult for third parties and ratepayer advocates to meaningfully participate.

Unfair rates for agricultural businesses

- In some situations, small businesses such as farms are caught in the middle of residential and commercial rates. For agriculture, most farms are on a residential rate structure for they do not meet the criteria to make commercial rate cost effective. This creates a challenge when residential rates increase during peak hours to disincentives use. Farms and other businesses are often required to pay this additional cost without the option to reduce usage of their operation. This can lead to a financial burden for many small businesses.

Responses to Stakeholder Survey Question 2: What do you see on the horizon that may pose new challenges to our current regulatory and rate design structure?

Lack of planning for impact of breakthrough technologies

- Declining costs of distributed generation and storage solutions may disrupt the overall electricity delivery system. While the issue of distributed generation gets most of the press, it's actually generation *plus* cost-effective storage that poses the real threat. Worse, utilities that seek short-term gain from limiting or disincentivizing distributed generation may ultimately lack the ability to change when generation storage costs less than grid-supplied power, offers greater reliability, and offers greater long-term hedge values on the price of power. The changes happening now in electricity delivery are evolutionary, but they will shortly become revolutionary; those utilities that do not position themselves to provide value within the emerging realities of the electricity system may find themselves unable to recover as trends accelerate. The long-term question of who pays the costs of the grid when other realistic options become available is a real one, but failing to anticipate changes may make this transition more difficult for utility shareholders and ratepayers alike.
- Lack of a coherent federal strategy regarding grid integration
- Planning poorly now, and limiting the options of consumers in the future, because current rate design has locked us into certain costs to meet federal, capacity, or energy demands
- If the costs of distributed generation continue to decline and more customers begin to install distributed generation, the existing net metering policy will need to be reexamined to ensure that all customers pay their fair share of the costs of the grid and backup generation.
- The existing electric code of conduct is a barrier to innovation in the value-added products and services that utilities might offer customers to promote customer value and ensure utilities continue to have financial security in the future.
- Breakthrough technology may call for an entirely new approach or end to regulation
- New technologies and efficiencies to make distributed and self-generation options more competitive
- Need for more flexibility for users in choosing options for power supply (renewables, market, self-generation).
- Advancing technology, distributed generation, storage, etc.
- The grid infrastructure is growing increasingly older and is based on generation and use patterns that have changed over time; there is no good decision-making process on what portions should be upgraded and how quickly

Existing and proposed environmental regulations causing dramatic fuel shift

- Federal mandates, and the shifting sands of regulation
- Environmental regulation can be disruptive due to sudden impact on generation versus a phased approach
- The anticipated baseload shutdown due to environmental regulation presents a potential crisis
- Climate legislation will place additional burden on aging infrastructure
- The use of fossil fuel is directly tied to changing the ecology of the planet—creating an energy environment that transitions away from fossil fuel before its price becomes prohibitive is one of the greater challenges facing global leaders.

- Changes in carbon pricing and/or shifts in price and availability of fossil fuels for electricity generation
- Cost increases due to new plants
- The EPA's proposed GHG rules

Potential for customer engagement

- Technological changes that provide new options to customers (however, customers that lack access to new technology may unduly bear the cost of the existing system)
- Existing metering and communications capabilities will not support customer needs for information.
- While the governor has expressed a strong preference to address "energy waste" in the state, Michigan does not have any state-level demand response programs.
- Net metering
- On-bill financing
- Dynamic pricing

Loss of expertise

- Ability to have well-educated and experienced people staffing regulatory bodies—loss of industry and government expertise due to retirements

Allocating costs for infrastructure upgrades due to increased demand

- As business and residential increase demand in certain areas, who pays for infrastructure upgrades—current customers or new customers looking to connect with the system?

Responses to Stakeholder Survey Question 3: What regulatory and rate design structures could address the current and future challenges you identified in the previous questions?

Rate design to address impacts of distributed energy resources

- New earnings recovery model that takes away from commodity sales volume
- Ability to better price services based on the cost of service and value delivered as well as provide better price signals to customers to make choices about their energy use
- Increase the use of nonvolumetric demand charges and fixed charges based on voltage level of the customer's connection to the distribution system to recover the fixed costs of generation capacity and distribution grid investments
- Implement revenue adjustment mechanisms (e.g., decoupling) to ensure fixed cost recovery in periods of sales declines
- Reevaluate how standby charges are calculated, or open standby options up to competition
- Net metering regulation that enables producers to sell excess generated power back to utilities at an equitable rate
- Reform the existing "true net metering" system by providing appropriate compensation for distributed generation that fairly values the energy produced by distributed generation and utilizes fair standby charges
- Improved net metering program
- Rate design needs to better encourage behavior that reduces systemwide costs and reduces public health and natural resource impacts from power generation. Time-of-day pricing can address the cost issue. The structure needs to incorporate harmful emissions in way that allows cleaner sources to compete on a level playing field.
- Educational and policy programs to promote energy conservation during peak hours

Changes to retail open access

- Divesting utilities of generation assets to remove tension between their role in distribution grid oversight and their role in providing generation (similar to what was successfully done with transmission assets more than a decade ago and which has been done in other leading states, including New York)
- Complete deregulation
- Less regulatory costs/restrictions on customers exercising electric choice
- Clarity regarding who pays for new generation
- Eliminate partial deregulation
- Clarity regarding who pays for new generation
- Need way to transition to broader market-based pricing, broader customer choices in fuel source and service levels, while ensuring universal access for low-income/limited choice customers

Regulatory roles and processes

- Remove the requirement of regulatory preapproval for capacity contracts that exceed six months
- Consider enhanced use of alternative dispute resolution and settlement early in the regulatory process

- Keeping regulators away from the role of promoting products like renewables when they are also the economic regulator (e.g., Michigan Renewable Energy Program, which is housed at the MPSC)
- A stronger commission presence in pushing incumbent utilities to innovate

Performance-based regulation

- Performance-based regulation (including both incentives and penalties)
- Offer utility investors performance-based financial incentives for both energy efficiency and demand response programs, such as a shared savings approach that values incentives at a portion of the net savings these programs provide to customers
- Benchmarking some industrial rates to an average in the region, with possible equity return incentive/disincentive based on the benchmark targets

Rate design to encourage economic development

- Give authority to offer temporary economic development prices where there is a net benefit to the state economy
- Allowance for seasonal inactivity to reduce occurrence of non-use monthly charges.
- Establishment of an agricultural rate or other business rate for certain industries that use consistent amounts of energy

Rate design to encourage conservation and peak shaving

Role of the utility

- Clarify that the existing code of conduct applies only to competition between electric utilities and alternative electric suppliers. Authorize utilities to offer value-added products and services to their customers in a manner similar to the existing Appliance Service Program. The revenues and costs directly associated with these offerings should be accounted for separately from the rest of the utility's business to ensure that utility customers are not unfairly subsidizing other businesses. The profits from these additional programs should be shared by utility customers (in form of reduced utility rates) and utility investors (to provide appropriate motivation to grow these businesses).
- Divesting utilities of generation assets to remove tension between their roles in distribution grid oversight and in providing generation (similar to what was successfully done with transmission assets more than a decade ago and which has been done in other leading states, including New York)

Access to energy information

- Ensuring meaningful access to grid data to allow third-party service providers to develop and offer value-added services, as opposed to allowing private utilities sole access to public energy data

Integrated resource planning

- Authorize longer-term investment programs for capital projects over multiple years to ensure holistic long-term planning, and include tracking mechanisms to ensure appropriate spending

Michigan GHG Plan

- Michigan GHG Plan

Properly allocating costs

- Properly allocating costs so as to not provide unwarranted cost advantages

Other

- More flexibility for homeowners, business owners, municipalities, schools

Appendix 6. Charge for Demand Response

The Michigan Energy Office, with grant support from the U.S. Department of Energy, is working to create a stakeholder- and research-driven roadmap that aligns electric utility business interests and customer behavior with public policy goals. The project is directed by a multiagency steering committee, informed by a multisector stakeholder group, and supported with internal agency staff and external partners.

The project steering committee has decided to start with a focus on demand response (DR). This decision was based on initial stakeholder feedback (received through surveys and discussion), the potential these programs have for addressing pressures on the utility sector, and the current political environment (i.e., this is an aspect of energy policy that isn't expected to be significantly altered by new legislation and is within the commission's regulatory authority). The process we will use to explore this topic can be replicated on other topics once there is more legislative certainty.

Specifically, the charge to the stakeholder group is to provide the steering committee with answers to the following questions.

- Would it be valuable for the Michigan Public Service Commission to conduct a potential study for demand response programs in Michigan? If so, what questions should be explored in this study?
- How should customers be compensated for participation in DR programs, and what should the penalties or other approaches to ensure adequate performance be?
- How should utilities be compensated for delivering DR programs?
- What type of measurement and verification methodology should be used for DR performance?
- What changes to Michigan's regulatory framework should be made to make it easier and more advantageous for customers to take advantage of demand response and for utilities to offer demand response options?

Appendix 7. Visioning Questionnaire

During our next stakeholder group meeting, we are going to develop a collective vision for demand response programs in Michigan, as well as identify barriers to and opportunities for achieving that vision.

The Vision

A vision statement describes a desired end state or the long-term change the stakeholder group is seeking as a result of its work. It will be used to guide the stakeholder group in making recommendations regarding demand response. The purpose of having a collective vision is to enable stakeholder group members to put personal preferences aside and make recommendations based on clearly defined objectives and criteria. It provides clear parameters for accepting or rejecting future recommendations.

To assist in developing a collective vision, we will have a brainstorming session during our next stakeholder group meeting. To help prepare for the session, please answer the following question in advance of the meeting, and bring your work with you to the meeting:

- **What statements or words come to mind when you envision a successful demand response program in Michigan?**

_____

_____

_____

_____

_____

_____

To help you answer the overarching question above, below are some probing questions:

- Who should these programs serve?
- Where is there the most potential for success?
- What should be the benefit to customers for participating in a demand response program? What about non-participating customers?
- What should be the benefit to the utility for implementing a demand response program?
- If you were a demand response technology and/or service provider, what would you like demand response programs to look like in Michigan?

- How should demand response be evaluated vis a vis supply side options in the utility resource planning and acquisition processes?
- What else do you have to say regarding a future vision for demand response programs in Michigan?

Opportunities and Barriers

What changes are needed to the current regulatory framework and/or rate design to achieve your vision? How do we get from where we are now to where we want to be?

Appendix 8. Vision and Recommendations

Stakeholder Group Recommendations for Promoting Demand Response and Next Steps

The Michigan Energy Office, with grant support from the U.S. Department of Energy, is working to create a stakeholder- and research-driven roadmap that aligns electric utility business interests and customer behavior with public policy goals. The project is directed by a multiagency steering committee, informed by a multisector stakeholder group, and supported with internal agency staff and external partners.

In October 2015, the Roadmap for Implementing Michigan's New Energy Policy Steering Committee charged the stakeholder group with reviewing existing demand response (DR) efforts and devising recommendations for new models. This decision was based on initial stakeholder feedback (received through surveys and discussion), the potential these programs have for addressing pressures on the utility sector, and the current political environment. These feedback venues have added strength as this is an aspect of energy policy that is not expected to be significantly altered by new legislation and is within the commission's regulatory authority.

The steering committee's charge asked stakeholders to provide answers to the five following questions:

1. Would it be valuable for the Michigan Public Service Commission (MPSC) to conduct a potential study for DR programs in Michigan? If so, what questions should be explored in this study?
2. How should customers be compensated for participation in DR programs, and what should the penalties or other approaches to ensure adequate performance be?
3. How should utilities be compensated for delivering DR programs?
4. What type of measurement and verification methodology should be used for DR performance?
5. What changes to Michigan's regulatory framework would make it easier and more advantageous for customers to participate in DR programs and for utilities to offer them?

Stakeholder Group Vision for Promoting Demand Response

To guide their responses to the charge, the stakeholder group first created a vision for DR programs in Michigan. This vision describes the desired end-state or long-term change the group is seeking as a result of its DR work. The Federal Energy Regulatory Commission (FERC) defines demand response as "changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."

The stakeholder group's vision for DR programs is that the following be accomplished in a cost-effective manner that is consistent with the MPSC's legislative authority:

- Embrace new enabling technologies and leverage their full potential to cost-effectively deliver public benefits through innovative program designs
- Be voluntary, allowing customers the opportunity to choose whether or not to participate in DR programs
- Be simple, easy, and transparent for customers to understand and access

- Improve the reliability of the electric power system
- Reduce peak load and associated costs, serving as a cost-effective and reliable way to relieve peak demand and improve system stability without needing to increase supply-side capacity
- Meet capacity, energy, and ancillary service resource needs where DR is more economic and reliable than alternative supply-side options
- Provide financial benefits for consumers and utilities
- Provide flexibility in order to accommodate customers of all sizes; specifically, programs should permit larger customers to make individual agreements with their utility
- Be a trusted resource with accurate measurement and verification—it is important that resources can be counted on when they are needed and that their calculated benefits are realized
- Meet the resource adequacy requirements of the relevant regional transmission organization (RTO)

Stakeholder Group Recommendations for DR Response

After stakeholders' developed their vision for DR in response to the charge, the stakeholder group discussed the need for a potential study, developed a vision for demand response programs in Michigan, identified utility performance metrics based on this vision, and determined how to measure, track, and apply these metrics. Stakeholder responses to the charge can be found below.

Studying DR Potential

At the stakeholders' October, meeting, they discussed the first question of the steering committee's charge. Several stakeholders noted that there has not been a comprehensive potential study of DR for several years and that a baseline study could be useful for energy providers and the state. Participants also noted that a statewide potential study would need to account for differences among utilities and across customer classes. The group generally agreed that a potential study for DR programs in Michigan could be an important aspect of completing an integrated resource plan should such a plan be required by pending energy legislation.

Structuring Customer Compensation and Ensuring Adequate DR Performance

The steering committee asked, "How should customers be compensated for participation in DR programs, and what should the penalties or other approaches to ensure adequate performance be?" In an effort to help stakeholders tackle this important question, the steering committee tasked the MPSC staff Demand Response Team to prepare a report to describe current and best practices for demand response rate design. The report describes common practices for the two types of demand response program mechanisms: 1) sending quantity (curtailment) signals to customers (direct load control [DLC] programs) and 2) sending price signals to customers to alter their consumption habits (time-varying rates). There are many types of time-varying rates, but the two most common are time-of-use (TOU) pricing and critical-peak pricing (CPP) or critical-peak rebate (CPR) rates.

Based on the common practices identified by the MPSC, as well as stakeholders' experience/expertise, the group worked to define the parameters for designing TOU rates, CPP and CPR rates, and rates for DLC programs. These recommendations were focused solely on design for residential programs. Stakeholders' responses for each parameter have been summarized by the project management team and are available below.

Time-of-Use Pricing: This rate typically applies to usage over broad blocks of hours (e.g., on-peak=six hours for summer weekday afternoon; off-peak=all other hours in the summer months) where the price for each period is predetermined and constant.

- **Pricing/interruption period (frequency and timing)**: Stakeholders believe that there could be two approaches for designing residential TOU rates—a simple and a complex approach. Stakeholders described that a two-tier TOU rate may prove to be simpler for customers to understand and potentially increase customer participation. This approach would employ a single, longer peak period from 2 PM–

7PM. Stakeholders also saw value in the three-tier TOU rate because this structure better reflects the cost of providing service, provides for stronger price differential signals, and may make it easier for participants to avoid energy use during shorter on-peak periods. Any program design should be specific to a utility's load profile and seasonal weather patterns.

- **Opt-in/out provision:** During early stages, participation in TOU rates should be based on opt-in enrollment. Stakeholders commented that utilities should, where possible, provide standard-service customers with a comparison of what their bill would have been had they participated in a TOU rate. As programs mature and savings are demonstrated, stakeholders expressed that an opt-out approach could feasibly replace the opt-in provision. There was also the suggestion from some participants that, when applicable, utilities should automatically enroll customers in the rate class that best suits a customer's consumption habits based on 12 months of energy use data.
- **Notification method and timing:** TOU rates make clear the different price levels associated with energy use at various times of the day. Notification is not necessary in TOU rates.
- **On-/off-peak price ratio:** Stakeholders noted that the on-/off-peak price ratio for utility TOU rates should—similarly to peak periods—reflect the nature of a utility's load profile and season weather patterns. Stakeholders generally agreed that a range of on-/off-peak price ratios between 3 and 4.5 would be a good place to set initial rates. As utilities' experience with TOU rates matures, these price ratios should reflect experiences with customer participation and actual savings in avoided energy and capacity costs.
- **Incentive offered:** Incentives should reflect the amount that produces the desired level of participation in and savings from these rates. Stakeholders commented that the appropriate level of incentives could be learned through utility experience over time. In TOU rates, the incentive should reflect the value of the avoided cost of energy consumption during peak periods and avoided costs of capacity otherwise needed to meet peak demands.
- **Contract term:** The typical length of time for customers to participate in a time-varying rate programs is one year. However, utilities should be allowed some flexibility with their individual programs in order to align with RTO requirements and customer preferences. A customer's individual commitment should not imply that utilities' time-varying rate programs are unavailable after a customers' individual commitment. This point is important for customers whose participation in time-varying rate programs brings them to make investments in communicating devices or smart appliances.

Critical-Peak Pricing and Critical-Peak Rebates: When utilities observe or anticipate high wholesale market prices or power system emergency conditions, they may call critical events during a specified time, and the price for electricity during these time periods is substantially raised. Two variants of this type of rate design exist: one in which the time and duration of the price increase are predetermined when events are called and another in which the time and duration of the price increase may vary based on the electric grid's need for reduced loads.

- **Notification method and timing:** Residential customers should receive notification for a critical-peak event at least one day in advance. Stakeholders also noted that customers should be given the option to select the type of notification they receive (e.g., a text, a phone call, or an e-mail). Customers should also be given the option to have a notification delivered directly to a communicating thermostat or smart appliance. This practice could encourage participation by removing an obstacle for customers. **Critical-peak/off-peak price ratio:** Stakeholders noted that the critical-peal/off-peak price ratio should—similarly to TOU peak periods—reflect the nature of a utility's load profile and season weather patterns. As utilities' experience with critical-peak rates matures, these price ratios should reflect experiences with customer participation and actual savings. Utility participants noted that their peak pricing programs use critical-peak prices set at $0.95.
- **Price vs. rebate:** Utilities should provide access to both CPP and CPR programs, at least in pilot projects, until the best program results are determined. Stakeholders believe that participation would be higher in CPR programs but noted that these programs add an extra administrative and accounting step that could lead to higher program operating costs.
- **Incentive offered:** Incentives should reflect the amount that produces the desired level of participation in and savings from these rates in avoided energy and capacity costs associated with the customer

response. Stakeholders commented that the appropriate level of incentives could be learned through utility experience over time.

- **Contract term:** The typical length of time for customers to participate in a critical-peak programs is one year. However, utilities should be allowed some flexibility with their individual programs in order to align with RTO requirements and customer preferences. A customer's individual commitment should not imply that utilities' critical-peak programs are unavailable after a customer's individual commitment. This point is important for customers whose participation in critical-peak programs brings them to make investments in communicating devices or smart appliances.

Direct Load Control Programs: When utilities observe or anticipate high wholesale market prices or power system emergency conditions, they may call critical events during prespecified time periods, the price for electricity during these time periods remains the same but the customer is refunded at a single, predetermined value for any reduction in consumption relative to what the utility expected the customer to consume.

- **Opt-in/out provision:** Participation in DLC programs should be on an opt-in basis. Once enrolled in a DLC program, residential customers would not be able to opt out of any cycling events for the duration of their contract commitment. Stakeholders commented that allowing customers to opt out of a DLC event would place the utilities' capacity commitments with their regional transmission operator (RTO) at risk. Stakeholders noted that if customers were able to opt out of an event, a penalty requisite with the potential penalty the utility would face for nonperformance from the RTO would be required. Some utilities currently offer the option for a customer to opt out of one event per year, as long as the utility is given sufficient notice. This provides customers with some flexibility.
- **Notification method and timing:** Notification for DLC or air conditioning (AC) cycling programs should not be a requirement. However, customers should be able to determine whether they are being cycled through their utility account online, via an opt-in communication from their utility, or directly from their appliance. This would ensure customers can determine whether they are experiencing mechanical difficulties with their appliance or if their experience is the result of DLC.
- **Pricing/interruption period (frequency and timing):** DLC programs may vary depending on what appliances are being controlled. Michigan has years of successful utility AC cycling programs on which to model new programs. AC cycling programs should run from June through September and cover up to eight hours each day at a cycling rate of 15-30 minutes out of every hour.
- **Price vs. rebate:** Residential customers participating in DLC programs should receive a payment for their participation. Payments could potentially be in the form of a monthly bill credit, but utilities should have the flexibility to design payments so that they align with customer interest.
- **Incentive offered:** The level of incentive offered to participating DLC program customers should be correlated with the cost savings such programs produce. The amount of incentive should also be set at a level that is enough to drive customer participation in DLC programs. This determination would be made based on utility experience.
- **Contract term:** The typical length of time for customers to participate in a DLC programs is one year. However, utilities should be allowed some flexibility with their individual programs in order to align with RTO requirements and customer preferences. If participating in a DLC program requires a customer to make an investment in a communicating device or smart appliance, then a customer should have assurance that the program will be in place for longer than their individual commitment and that they will be given the opportunity to continue participation as they choose.

Structuring Utility Compensation and Measuring Performance

- **Measuring program performance:** To measure progress toward achieving the stakeholder group's vision for DR programs in Michigan, the level and type of customer participation in cost-effective programs should be tracked. To that end, the stakeholder group recommends using the percentage of load per customer class participating in DR programs, as well as the net system savings through the use of DR ($/MW cost of DR relative to the $/MW cost of traditional investment) as the types of metric to be used to evaluate whether or not the DR vision is being achieved. These metrics should be specific for utilities and customer classes (as opposed to establishing a single, statewide target metric). Utilities

Appendix 9. DR Small Group Exercise

Small Group Exercise Instructions: What to Measure and How

Group 1 Stakeholders:

Facilitator and scribe: **Rich Sedano**, Regulatory Assistance Project (RAP), and **Eric Pardini**, Public Sector Consultants (PSC)

George Andraos, Ford Motor Company
James Ault, Michigan Electric and Gas Association
Chrissy Beckwith, SEMCO Energy
James Clift, Michigan Environmental Council
John LaMacchia, Michigan Municipal League
Michael Moody, Michigan Department of Attorney General (AG)
Greg Poulos, EnerNOC
Jean Redfield, NextEnergy
Don Stanczak, DTE Energy
Andrew Vermeesch, Michigan Farm Bureau
Jim Weeks, Michigan Municipal Electric Association
Jeff Wiggins, House Republican Policy Office

Group 2 Stakeholders:

Facilitator and scribe: **Julie Metty Bennett**, PSC and **Dave Isakson**, Michigan Public Service Commission (MPSC)

Kwafo Adarkwa, ITC Holdings Corp.
Mathias Bell, Opower
Greg Bergtold, Dow Chemical
Craig Borr, Wolverine Power Cooperative
Laura Chappelle, Energy Michigan
Gregory Clark, Indiana Michigan Power
Lauren Donofrio, AG
Dan Dundas, Senate Majority Policy Office
Anand Gangadharan, NOVI Energy
Jason Geer, Michigan Chamber of Commerce
Brandon Hofmeister, Consumers Energy
Dan Scripps, MEIBC
Jill Steiner, Cadmus Group

Purpose: Before the last meeting, the Roadmap for Implementing Michigan's New Energy Policy Steering Committee issued a charge to the stakeholder group (see attached). Some elements of the charge focused on demand response (DR) program design (e.g., how customers should be compensated for participation in DR programs). Others focused on the utility regulatory framework (e.g., what changes to Michigan's regulatory framework should be made to make it more advantageous for utilities to offer DR programs). This small group discussion is focused on the latter. More specifically, stakeholders will be asked a series of questions to help shape recommendations regarding a new regulatory approach to promoting DR.

Agenda: Small groups will answer the following questions.

- The stakeholder group has developed a vision for DR programs in Michigan. Mapping **performance metrics** onto this vision will allow us to see whether or not we are making progress toward achieving our vision. In advance of the meeting, you were provided with some examples of performance metrics that could be used to evaluate progress (see attached). Are these are the right metrics to show whether or not we are achieving our vision? Should any be removed? Should any be added? Should the metric be utility specific or statewide? Of these metrics, what data are the utilities already collecting and reporting? What new data would have to be tracked and reported? How feasible is that? In light of this discussion, what performance metrics should be tracked and reported? (Please note that we are looking for types of metrics, not specific numerical targets. For example, X percent increase in customer participation is fine; no need to replace X with an actual numerical target.)
- Now that we know what performance metrics will be tracked, should the utility receive some type of **reward** (or penalty) for achieving the metric(s)? If so, what should the reward be? Something small? Recognition? Financial? Tied to utility financial earnings? Should the reward be tied to an individual utility achieving the metric or should all utilities have to achieve it statewide? How should the rewards be introduced? Should we conduct pilot programs to determine whether we have identified the right metrics (as opposed to ones that are impossible or too easy to achieve) before we put the reward system in place? Determine the appropriate pace, scope, and scale for rollout.
- What methodologies should we use for **measurement,** and what are the key assumptions for making calculations? What do the utilities already do to measure program performance?
- How are the metrics and results **tracked and reported**? Should utilities self-report with the opportunity for audit? What about simple correspondence to the commission or a public "report card" (e.g., a presentation which translates metrics into something the public can understand)? To whom should the report be communicated (whether the news is good or bad)? Newspapers? Elected officials who are part of making the process effective? How should the commission respond?
- How are the metrics **verified** and by whom—a third party hired by the MPSC, or a third party hired by utilities? When should verification occur? What data are needed?
- Decide what information from your deliberations you are going to share with the full group. There should be at least a couple of points per topic (performance metrics, rewards, measurement, tracking and reporting, penalties, and verification).

Limits: You have two hours to complete this exercise. If all of the questions are not answered by the end of the two hours, the group will either complete the questions during a conference call in advance of the next meeting, or during the next meeting (depending on how much work remains and the progress of the other small group). You will have ten minutes to report to the full group. No need to go into great detail; project staff will document the answers to the questions in writing and distribute to the group before the next meeting.

Performance Metrics: Knowing When We've Achieved Our Demand Response Vision

During our next stakeholder group meeting, we will develop metrics that will help us measure whether or not we are achieving our demand response (DR) vision. Below is the draft vision, which we will finalize during our next meeting, as well as examples of metrics that could be used to measure success (noted in italics). **Please come to the meeting prepared to share your thoughts on the example metrics and present additional and/or alternative metrics.**

- Embrace new enabling technologies and leverage their full potential to deliver positive public benefits through innovative program designs
  - *Example metric: Percentage increase in advanced metering infrastructure and/or automated meter reading deployment over time (e.g., year over year for a two to three year period)*
- Be voluntary, allowing customers the opportunity to choose to participate in DR programs
  - *Example metric: DR programs available to X percent of connected load*
- Be simple and easy for customers to understand and access
  - *Example metric: Percentage increase in customer participation over time*
- Improve the reliability of the electric power system
  - *Example metric: Percentage improvement in SAIDI, SAIFI, CAIDI, and MAIFI*
- Reduce peak load and associated costs, serving as a cost-effective, reliable way to relieve peak demand and improve system stability without needing to build excess supply-side infrastructure
  - *Example metric: Percentage kW peak demand reduction from baseline or X percent improvement in system load factor*
- Meet capacity, energy, and ancillary service resource needs where DR is more economic and reliable than alternative supply-side options, including upgrading transmission and/or distribution systems and buying or building generation assets.
  - *Example metric: Demonstration of net system savings through the use of DR ($/MW cost of DR relative to the $/MW cost of traditional investment)*
- Provide financial benefits for consumers and utilities
- Provide flexibility in order to accommodate customers of all sizes; specifically, programs should permit larger customers to make individual agreements with their utility
- Be a trusted alternative to supply-side resources, with accurate measurement and verification; it is important that resources can be counted on when they are needed, and that their calculated benefits are realized
  - *Example metric: Improvement in MWh of DR deployed relative to need*
- Meet the resource adequacy requirements of the relevant Regional Transmission Organization

List your suggested metrics on the next page and bring them with you to the next meeting. We are looking for types of metrics, not specific numerical targets (e.g., X percent increase in customer participation is fine; no need to replace X with an actual numerical target).

Appendix 10. DR Rate Design Worksheet

Demand Response Rate Design Recommendations

During our next stakeholder group meeting, we are going to develop recommendations for the steering committee criteria for effective demand response rate design. Stakeholders were provided a brief report entitled, "Common Demand Response Practices and Program Designs" to provide background on parameters most commonly used in the field. Based on that information and your experience, we would like you to define the parameters you would recommend.

TIME-VARYING RATES		
Parameter	**Common Practice**	**Recommendations**
Pricing/interruption period (frequency and timing)	TOU on-peak hours: 4 PM–7 PM TOU midpeak hours: Noon–4 PM and 7 PM–10 PM	
On/off price ratio	Average summer on/off peak ratio of 4.6 cents (max. = 16.7 min. = 1.2)	
Notification method and timing	At least one day in advance for critical peak.	
Opt in/out provision	Opt-out programs generally offer an overall benefit cost advantage.	
Price vs. rebate	Prices can yield higher demand reductions than rebate programs (without controlling technology). When controlling technology is introduced demand reductions are the same for prices and rebates.	
Incentive offered	Incentives are inherent in many time-varying rates. Additional rebate incentive for critical peak programs equal to 50 cents/kWh times the difference between a customers' baseline usage and kWh usage during the event.	
Contract term	One-year commitment	
DIRECT LOAD CONTROL PROGRAMS		
Parameter	**Common Practice**	**Recommendations**
Pricing/interruption period (frequency and timing)	Not to exceed three hours per day, interruptible season from June through September.	
Notification method and timing	One hour in advance.	
Opt in/out provision	Opt-in. Once enrolled, customers will have the opportunity to opt-out of two events per year.	
Price vs. rebate	Monthly bill credit	
Incentive offered	Monthly bill credit: half-time cycling—$4/month, full-time cycling—$8/month	
Contract term	One-year commitment	

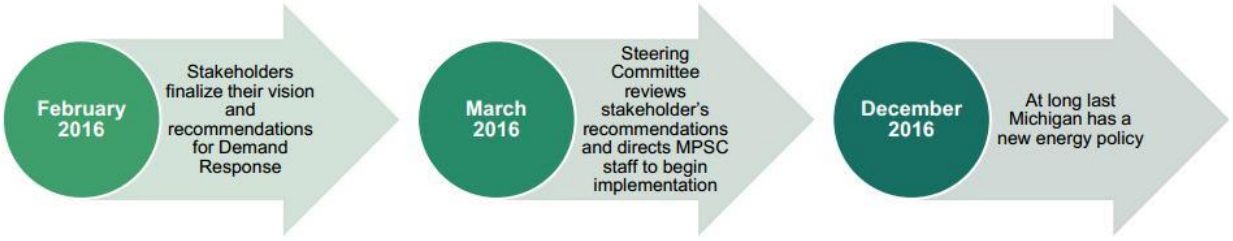
Appendix 11. Progress Report—DR

Roadmap to Implementing
Michigan's New Energy Policy

Progress Report – Demand Response

Wednesday, March 15, 2017
11:00 AM–12:00 PM

Where We Left Off



Michigan's New Energy Policy

- On December 21, 2016, Governor Rick Snyder signed historic energy policy reforms into law
- The bills update Michigan law to;
  - Reducing energy waste by providing incentives for utilities to enhance current programs
  - Requiring all electric providers to have adequate resources
  - Allowing regulated utilities to use on-bill financing programs
  - Requiring utilities to develop a long-term planning process

Vision for Demand Response

- **Embrace new enabling technologies** and leverage their full potential to cost-effectively deliver public benefits through innovative program designs
- **Be voluntary**, allowing customers the opportunity to choose whether or not to participate in DR programs
- **Be simple, easy, and transparent** for customers to understand and access
- **Improve reliability** of the electric power system
- **Reduce peak load and associated costs**, serving as a cost-effective and reliable way to relieve peak demand and improve system stability without needing to increase supply-side capacity

Vision for Demand Response

- **Meet capacity, energy, and ancillary service resource needs** where DR is more economic and reliable than alternative supply-side options
- **Provide financial benefits** for consumers and utilities
- **Provide flexibility** in order to accommodate customers of all sizes; specifically, programs should permit larger customers to make individual agreements with their utility
- **Be a trusted resource with accurate measurement and verification**—it is important that resources can be counted on when they are needed and that their calculated benefits are realized
- **Meet the resource adequacy requirements** of the relevant regional transmission organization

Recommendations for Promoting Demand Response

- Study Demand Response Potential
- Structure Customer Compensation and Ensure Adequate Demand Response Performance
- Structure Utility Compensation and Measure Performance

Link to Stakeholder Group Demand Response Recommendations

Implementing Recommendations

Studying Demand Response Potential

Demand Response Potential Study
Implementation Status
Implemented: Public Act 341 of 2016, section 6(t), requires regulated electric utilities to file an IRP. A requirement in the same section of PA 341 directs the commission to conduct an assessment for the use of demand response programs in the state. The results of the statewide DR assessment will then be used to establish IRP modelling scenarios and assumptions for use by the utilities in their required filings.

Implementing Recommendations

Structuring Customer Compensation and Ensuring Adequate DR Performance

TIME-OF-USE PRICING (TOU)	
Parameter	**Implementation Status**
Pricing/interruption period (frequency and timing)	**Implemented.** DTE and Consumers have instituted two-tier and three-tier TOU rates. The Michigan Public Service Commission (MPSC) approved these rates in the utilities' most recent general rate cases (Cases U-17990 and U-18014).
Opt-in/out provision	**Implemented.** The commission-approved TOU rates are opt-in only. In recent rate case orders, the commission rejected utilities' proposals to use three-tier rates as the default for new customers(Case U-18014).
Notification method and timing	**Implemented.** Current two-tier TOU rates do not require customer notification.
On-/off-peak price ratio	**Partially implemented.** The commission has recently approved separate price differentials for DTE and Consumers' TOU rates.
Incentive offered	**In progress.** As utilities gain more experience with and customer feedback on their new TOU rates, they will be able to better optimize incentives to produce desired results.
Contract term	**Implemented.** PA 342 established that customers participating in load management programs will be required to stay for at leas one year

Implementing Recommendations

Structuring Customer Compensation and Ensuring Adequate DR Performance

CRITICAL-PEAK PRICING AND CRITICAL-PEAK REBATES (CPP and CPR)	
Parameter	**Implementation Status**
Notification method and timing	**Implemented.** Current utility programs require notification to be given a day in advance of critical-peak events. DTE's approved tariff specifies that notification may be made via telephone, text message, email, or in-home device.
Critical-peak/off-peak price ratio	**In progress.** More experience with and expanded participation in TOU rates will enable utilities' to further optimize critical-/off-peak price differentials. Currently, Consumers and DTE continue to use critical-peak prices of $0.95.
Price vs. rebate	**In progress.** Only Consumers offers CPP and CPR programs. New and expanded program offerings are expected as utilities garner more experience in offering CPP and CPR programs.
Incentive offered	**In progress.** Incentives offered will be further refined as utilities gain more experience in offering critical-peak rates and learn from customer participation and feedback.
Contract term	**Implemented.** PA 342 established that customers participating in load management programs will be required to stay for at leas one year

Implementing Recommendations

Structuring Customer Compensation and Ensuring Adequate DR Performance

DIRECT LOAD CONTROL (DLC) PROGRAMS	
Parameter	**Implementation Status**
Opt-in/-out provision	**Implemented.** Currently DLC programs require a customer to opt-in. Consumers' DLC program allows the customer to opt-out of one load control event per summer. Additional opt-outs granted by Consumers may result in the customer's bill credit being forfeited.
Notification method and timing	**Implemented.** Stakeholders' recommendation is reflected in Consumers and DTE's DLC programs.
Pricing/interruption period (frequency and timing)	**Implemented.** Stakeholders' recommendation is reflected in Consumers and DTE's DLC programs.
Price vs. rebate	**Implemented.** DTE offers customers a discounted rate for their participation in DLC programs. Consumers offers a monthly bill credit.
Incentive offered	**In progress.** With more experience and participants on DLC rates, utilities will further optimize incentives. The monthly bill credit offered by Consumers is based on the summer incremental capacity costs as outlined in their general rate case.
Contract term	**Implemented.** PA 342 established that customers participating in load management programs will be required to stay for at leas one year

Implementing Recommendations

Structuring Utility Compensation and Measuring Performance

Recommendation Category	Implementation Status
Measuring program performance	**Implemented.** The MPSC's orders in cases U-17936 and U-18013 require DTE and Consumers to file monthly and annual reports containing the data necessary to determine program performance on recommended metrics. The data provided in these reports will allow stakeholders to develop performance measures to evaluate the effectiveness of utility DR programs.
Utility compensation: Cost Recovery	**Implemented.** PA 342 established that utilities can recover costs for load management through base rates, if the costs are reasonable and prudent and meet the utility systems resource cost test.
Utility compensation: Performance Reward	**In progress.** Public Acts 341 and 342 allowed utilities' to use a financial incentive mechanism for DR program spending. PA 341 also included a provision allowing the use of a shared savings mechanism in utilities' IRPs.
Measuring program cost effectiveness	**Implemented.** PA 342 established that load management program costs must meet the utility systems resource cost test.
Program reporting	**Implemented.** The MPSC's orders in cases U-17936 and U-18013 require DTE and Consumers to file monthly and annual demand response reports. These reports must include detailed accounts of participation in DR programs, available MW of demand reduction, resource capacity reported to the RTO, energy savings, and program spending.
Integrating DR with energy-efficiency plans	**In progress**. Demand response is included, to some extent, in the portions of PA 342 related to energy waste reduction (EWR) plans. MPSC will be hosting a stakeholder group to discuss the framework for evaluating and rewarding demand response programs throughout 2017, including integration with EWR.
Third-party verification	**Not implemented.**
RTO verification	**Not implemented.**

Next Steps

- The Michigan Public Service Commission along with the Michigan Agency for Energy, and the Department of Environmental Quality are beginning the implementation of Michigan's new energy policy.
- PA 341 Section 6t requires the MPSC to establish modeling scenarios and assumptions utilities should include in developing their IRP. The MPSC has established a stakeholder process to work through these scenarios and assumptions including subgroups devoted to different aspects of the IRP. One of these subgroups will be devoted to Demand Response.
- The **Demand Response Workgroup** will meet **Friday, March 17 at 9:00 am.**

Appendix 12. Overview of DR in PA 341 and 342

Overview of Demand Response in PA 341 and PA 342

PA 341

Consideration of Aggregate Revenues

MCL 460.6a
(13) The commission shall consider the aggregate revenues attributable to revenue decoupling mechanisms, financial incentives, and shared savings mechanisms the commission has approved for an electric utility relative to energy waste reduction, conservation, demand-side programs, peak load reduction, and other waste reduction measures. The commission may approve an alternative methodology for a revenue decoupling mechanism authorized under subsection (12), a financial incentive authorized under section 75 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1075, or a shared savings mechanism authorized under section 6x if the commission determines that the resulting aggregate revenues from those mechanisms would not result in a reasonable and cost-effective method to ensure that investments in energy waste reduction, demand-side programs, peak load reduction, and other waste reduction measures are not disfavored when compared to utility supply-side investments. The commission's consideration of an alternative methodology under this subsection shall be conducted as a contested case pursuant to chapter 4 of the administrative procedures act of 1969, 1969 PA 306, MCL 24.271 to 24.287

DR in IRP Filings

MCL 460.6s
(11) The commission shall establish standards for an integrated resource plan that shall be filed by an electric utility requesting a certificate of necessity under this section. This subsection does not apply to an electric utility that has an approved integrated resource plan under section 6t. An integrated resource plan shall include all of the following:
…
(e) Projected load management and demand response savings for the electric utility and the projected costs for those programs.

MCL 460.6t
(1) The commission shall, within 120 days of the effective date of the amendatory act that added this section and every 5 years thereafter, commence a proceeding and, in consultation with the Michigan agency for energy, the department of environmental quality, and other interested parties, do all of the following as part of the proceeding:
…
(b) Conduct an assessment for the use of demand response programs in this state, based on what is economically and technologically feasible, as well as what is reasonably achievable. The assessment shall expressly account for advanced metering infrastructure that has already been installed in this state and seek to fully maximize potential benefits to ratepayers in lowering utility bills

(5) An integrated resource plan shall include all of the following:
…
(f) Projected load management and demand response savings for the electric utility and the projected costs for those programs.
…

(n) A forecast of the utility's peak demand and details regarding the amount of peak demand reduction the utility expects to achieve and the actions the utility proposes to take in order to achieve that peak demand reduction

(8) The commission shall approve the integrated resource plan under subsection (7) if the commission determines all of the following:

(a) The proposed integrated resource plan represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. To determine whether the integrated resource plan is the most reasonable and prudent means of meeting energy and capacity needs, the commission shall consider whether the plan appropriately balances all of the following factors:

…

(vii) Whether the proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective. Exceeding the renewable energy resources and energy waste reduction goal in section 1 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001, by a utility shall not, in and of itself, be grounds for determining that the proposed levels of peak load reduction, renewable energy, and energy waste reduction are not reasonable and cost effective.

Shared Savings Mechanism

MCL 460.6x

(1) Subject to section 6 a (13), in order to ensure equivalent consideration of energy waste reduction resources within the integrated resource planning process, the commission shall by January 1, 2021 authorize a shared savings mechanism for an electric utility to the extent that the electric utility has not otherwise capitalized the costs of the energy waste reduction, conservation, demand reduction, and other waste reduction measures.

(2) For an electric utility that achieves annual electric energy savings of at least 1% but not greater than 1.25% of its total annual weather-adjusted retail sales in megawatt hours in the previous calendar year, the shared savings incentive shall be 25% of the net benefits validated as a result of the programs implemented by the electric utility related to energy waste reduction, conservation, demand reduction, and other waste reduction. A shared savings mechanism authorized under this subsection shall not exceed 15% of the electric utility's expenditures associated with implementing energy waste reduction programs for the calendar year in which the shared savings mechanism was authorized. The commission shall determine net benefits by calculating the net present value of the lifetime avoided utility costs that are projected from the utility's energy waste reduction programs implemented in a calendar year less the utility expenditures associated with implementing the energy waste reduction program in that calendar year,

[1](3) 1.25%-1.5% energy savings gets 27.5% of net benefits, not to exceed 17.5% of ERW program costs

[1](4) >1.5% energy savings gets 30% of net benefits, not to exceed 20% of ERW program costs

[1] Paraphrased. These shared savings provisions contain the same language as 1%-1.25%

Overview of Demand Response in PA 341 and PA 342

PA 342

Definitions

MCL 460.1005 (f):
"Energy waste reduction", subject to subdivision (g), means all of the following:
(i) Energy efficiency.
(ii) Load management, to the extent that the load management reduces provider costs

460.1007 (g):
"Load management" means measures or programs that target equipment or behavior to result in decreased peak electricity demand such as by shifting demand from a peak to an off-peak period.

Financial Incentive Mechanism— see section 89 for DR program costs

MCL 460.1075
(1) An energy waste reduction plan of a provider whose rates are regulated by the commission may authorize a commensurate financial incentive for the provider for exceeding the energy waste reduction standard. Payment of any financial incentive authorized in the energy waste reduction plan is subject to the approval of the commission.
(2) The total amount of a financial incentive for an electric provider that achieves annual incremental savings of greater than 1.5% of its total annual retail electricity sales in megawatt hours in the preceding year… shall not exceed the lesser of the following amounts:
(a) 30% of the net present value of life-cycle cost reductions experienced by the provider's customers as a result of implementation, during the year for which the financial incentive is paid, of the energy waste reduction plan.
(b) 20% of the provider's actual energy waste reduction program expenditures for the year.
[2](3) Between 1.25% and 1.5%:
(a) 27.5% of the net present value of life-cycle cost reductions
(b) 17.5% of the provider's actual energy waste reduction program expenditures
[2](4) Between 1.0% and 1.25%:
(a) 25% of the net present value of life-cycle cost reductions
(b) 15% of the provider's actual energy waste reduction program expenditures

DR in EWR Plan

MCL 460.1077
(2) If an electric provider uses load management to achieve energy savings under its energy waste reduction plan, the minimum energy savings required under subsection (1) *[1% per year]* shall be adjusted by an amount such that the ratio of the minimum energy savings to the sum of actual expenditures for implementing its approved energy waste reduction plan and the load management expenditures remains constant

[2] Paraphrased. These parts contain the same language as the incentive for >1.5%

(7) Renewable energy credits, load management that reduces overall energy usage, or a combination thereof shall not be used by a provider to meet more than 10% of the energy waste reduction standard. Substitutions for energy waste reduction credits shall be made at the rate of 1 renewable energy credit per energy waste reduction credit.

MCL 460.1089

(1) The commission shall allow a provider whose rates are regulated by the commission to recover the actual costs of implementing its approved energy waste reduction plan. However, costs exceeding the overall funding levels specified in the energy waste reduction plan are not recoverable unless those costs are reasonable and prudent and meet the utility system resource cost test. Furthermore, costs for load management undertaken by an electric provider pursuant to an energy waste reduction plan are not recoverable as energy waste reduction program costs under this section, but *may* be recovered as described in section 95.

MCL 460.1091:

(1) Except for section 89(5), sections 71 to 89 do not apply to a provider that each year pays not less than 2.0% of total utility sales revenues for the second year preceding, including electricity or natural gas commodity costs, to an independent energy waste reduction program administrator selected by the commission.

Promotion and Cost Recovery

MCL 460.1095

(1) Subject to subsection (2), the commission shall do all of the following:

(a) Promote load management in appropriate circumstances, including expansion of existing and establishment of new load management programs in which an electric provider may manage the operation of energy consuming devices and remotely shut down air conditioning or other energy intensive systems of participating customers, demand response programs that use time of day pricing and dynamic rate pricing, and similar programs, for utility customers that have advanced metering infrastructure. Electric provider participation and customer enrollment in such programs are voluntary. However, electric providers whose rates are regulated by the commission and whose rates include the cost of advanced metering infrastructure shall offer commission-approved demand response programs. The programs may provide incentives for customer participation and shall include customer protection provisions as required by the commission. To participate in a program, a customer shall agree to remain in the program for at least 1 year.

(b) Actively pursue increasing public awareness of load management techniques.

(c) Engage in regional load management efforts to reduce the annual demand for energy whenever possible.

(d) Work with residential, commercial, and industrial customers to reduce annual demand and conserve energy through load management techniques and other activities it considers appropriate.

(2) Subsection (1) shall not be construed to prevent an electric utility from doing any of the following:

Overview of Demand Response in PA 341 and PA 342

(a) Recovering the full cost associated with providing electric service and load management programs.
(b) Installing metering and retrieving metering data necessary to properly, accurately, and efficiently bill for the electric utility's services without manual intervention or manual calculation.

(3) The commission *may* allow a provider whose rates are regulated by the commission to recover costs for load management through base rates as part of a proceeding under section 6a of 1939 PA 3, MCL 460.6a, if the costs are reasonable and prudent and meet the utility systems resource cost test.

(5) This subpart does not limit the authority of the commission, following an integrated resource plan proceeding and as part of a rate-making process, to allow a provider whose rates are regulated by the commission to recover for additional prudent energy efficiency and energy conservation measures not included in the provider's energy waste reduction plan if the provider has met the requirements of the energy waste reduction program.

Category	Link
Total Revenues	460.6a(13)
IRP	460.6s(11)e
Potential Study	460.6t(1)b
IRP	460.6t(5)f
IRP	460.6t(5)n
IRP	460.6t(8)a
SSM	460.6x(1)
SSM	460.6x(2)
SSM	460.6x(3)
SSM	460.6x(4)
Definition	460.1005(f)
Definition	460.1007(g)
FIM	460.1075(1)
FIM	460.1075(2)
FIM	460.1075(3)
FIM	460.1075(4)
DR in EWR Plan	460.1077(2)
DR in EWR Plan	460.1089(1)
EWR Prog Admin	460.1091(1)
Promote DR	460.1095(1)
DR Cost Recovery	460.1095(2)
DR Cost Recovery	460.1095(3)
DR Cost Recovery	460.1095(5)

Appendix 13. On-bill Stakeholder Meeting

Statewide On-bill Program Stakeholder Group Meeting

Stakeholder Group Selection Criteria

The Michigan Energy Office, with grant support from the U.S. Department of Energy, is using a stakeholder-driven process to create goals and identify program design structures that support the goals of aon-bill program applicable statewide. The project is directed by a multiagency steering committee, including representatives from the Michigan Public Service Commission and the Michigan Agency for Energy.

Designing an on-bill program is complex and, therefore, time and resource intensive. Rather than each interested utility embarking on this alone, having a group of utilities—combined with technical assistance from experts and utilities that have already implemented programs—will decrease cost and complexity. Once designed, there is potential to share services—such as capital providers, loan originators, and loan servicers—thus reducing implementation costs. Finally, a program consistent statewide will help drive demand for the program, since the process and offering will be similar across utilities, allowing contractors and customers to easily learn about and take advantage of the program.

During an initial meeting, stakeholders will identify goals for an on-bill program consistent statewide. A second meeting will determine program design structures that support the goals. A final report will be made available in June 2017.

To receive stakeholder input, the steering committee formed a stakeholder group. An open nomination process was used to identify candidates, and the following criteria were used to select among those nominated:

- The individual adequately represents his or her respective stakeholder interests as reflected by his/her leadership position within organizations and/or support of industry peers.
- The interest that this individual represents is not overrepresented within the group, ensuring representation of a broad diversity of interests.
- The individual has experience with and knowledge of topics and regulatory processes.
- The individual can work well with other stakeholder group members.
- The individual has a minimum of three (3) years of working experience on public- and private-sector energy issues and/or financing programs.
- Priority will be given to individuals with affiliations and/or a member organization that will advance the implementation of a statewide on-bill program.

Appendix 14. On-bill Financing Stakeholder List

On-Bill Financing Stakeholder List, April 2017

A broad cross section of stakeholders interested in the establishment of a statewide on-bill financing program, were invited to a goal setting discussion at the Michigan Public Service Commission/Michigan Agency for Energy Offices on April 24.

The results of that goal setting discussion will be provided soon. If interested in being involved, please contact Patricia Poli or Madhu Anderson and a goal setting survey will be provided to you.

The next stakeholder meeting will be May 19, 2017.

On-bill Financing Stakeholders:

- Great Lakes Energy
- Holland Energy Fund
- Lansing Board of Water & Light
- National Association of State Energy Officials
- Consumers Energy
- DTE Energy
- Michigan Electric Cooperative Association
- Coldwater Board of Public Works
- Genisys Credit Union
- SEMCO Energy
- Franklin Energy
- Michigan Electric and Gas Association
- Traverse City Light & Power
- Midwest Energy
- Michigan Energy Efficiency Contractors Association
- Michigan Community Action Agency Association
- Michigan Public Service Commission
- Michigan Agency for Energy
- Michigan Saves
- Public Sector Consultants
- Harcourt, Brown & Carey

Appendix 15. On-bill Presentation

Agenda

- Review stakeholder survey results
- Learn about goal impact on program design and results
- Learn about tensions between goals
- Revisit survey goals and make changes, if any
- Conduct hot dot voting
- Discuss results
- Agree on goals

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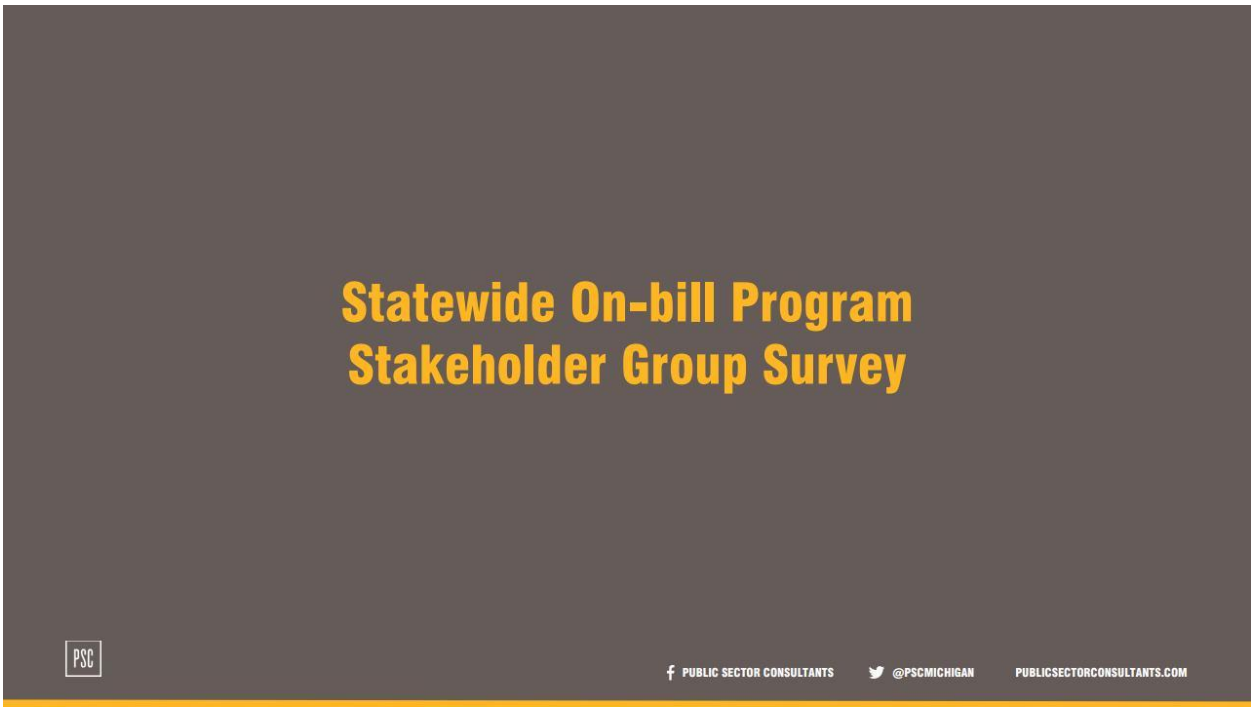

Purpose of Survey

- Obtain stakeholder input on program goals and design elements.
- Shape agenda for today's meeting.
- Learn more about who is participating in today's meeting.

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Survey Response

- Twenty-two recipients
- Fifteen responses submitted (68 percent response rate)

Respondent Distribution

Sector	Responses
Government/consumer group	3
Program implementation provider	1
Technology/energy service provider	3
Utility	8
Rural electric cooperative	*2*
Investor owned	*3*
Municipal	*3*

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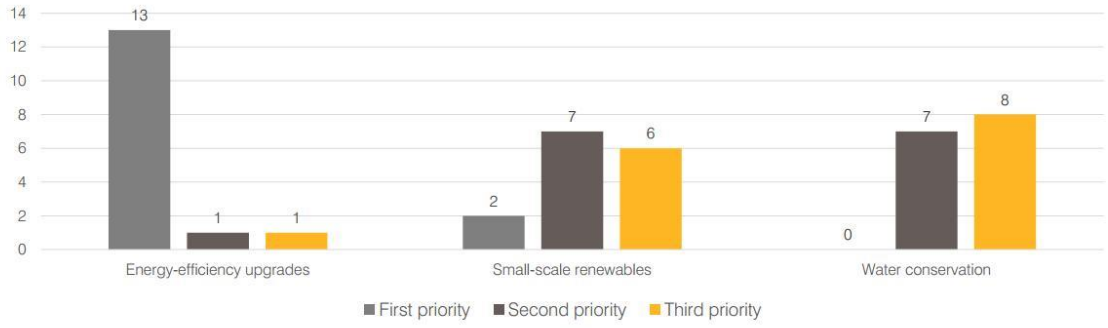
Question One

The Michigan law that authorizes on-bill financing programs stipulates that investment in energy efficiency, renewable energy systems, and water conservation are all eligible. Please rank these in terms of importance.



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Question Two

Please rank these goals in order of importance to you and your organization. Rank each set of goals from highest to lowest priority.

- Three goals ranked high priority
  - Lower customers' monthly energy bill.
  - Provide the most cost-effective way to encourage energy savings.
  - Make energy improvements more affordable for customers by providing lower interest rates and longer terms than are currently offered in the marketplace.
- Three goals ranked low priority:
  - Reduce the carbon footprint for participating utilities.
  - Stimulate the economy and create jobs.
  - Expand access to financing for individuals that have tarnished credit and, therefore, do not qualify for products currently in the marketplace.

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Question Two (cont.)

- No consensus on remaining goals
  - Maximize the reduction in energy use/demand per home.
  - Maximize the number of participating customers making energy improvements.
  - Provide motivation to landlords who don't want to take on financing energy improvements because the tenant pays the utility bill and, therefore, the landlord sees no financial benefit.
  - Provide motivation to renters and homeowners who don't want to take on financing energy improvements because the payback will take longer than they plan to stay in their home.

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Question Three

What issues, perspectives, and/or concerns do you want to make sure are considered?

- Program administration
  - Programs can be complex, staff intensive, and costly, while participation rates have been low, historically.
  - What privacy issues arise from outsourcing program functions?
  - There must be a clear path for customer services.
- Program design
  - Reduce complexity, expedite/streamline startup process, and maximize participation.
  - Follow best practices from other programs.

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Question Three (cont.)

- Handling Defaults
  - Utilities should not be responsible for credit reporting or paying defaults.
  - If there is a late/partial payment, does the amount go first to utility service or on-bill charge?
  - Who is responsible for collection?

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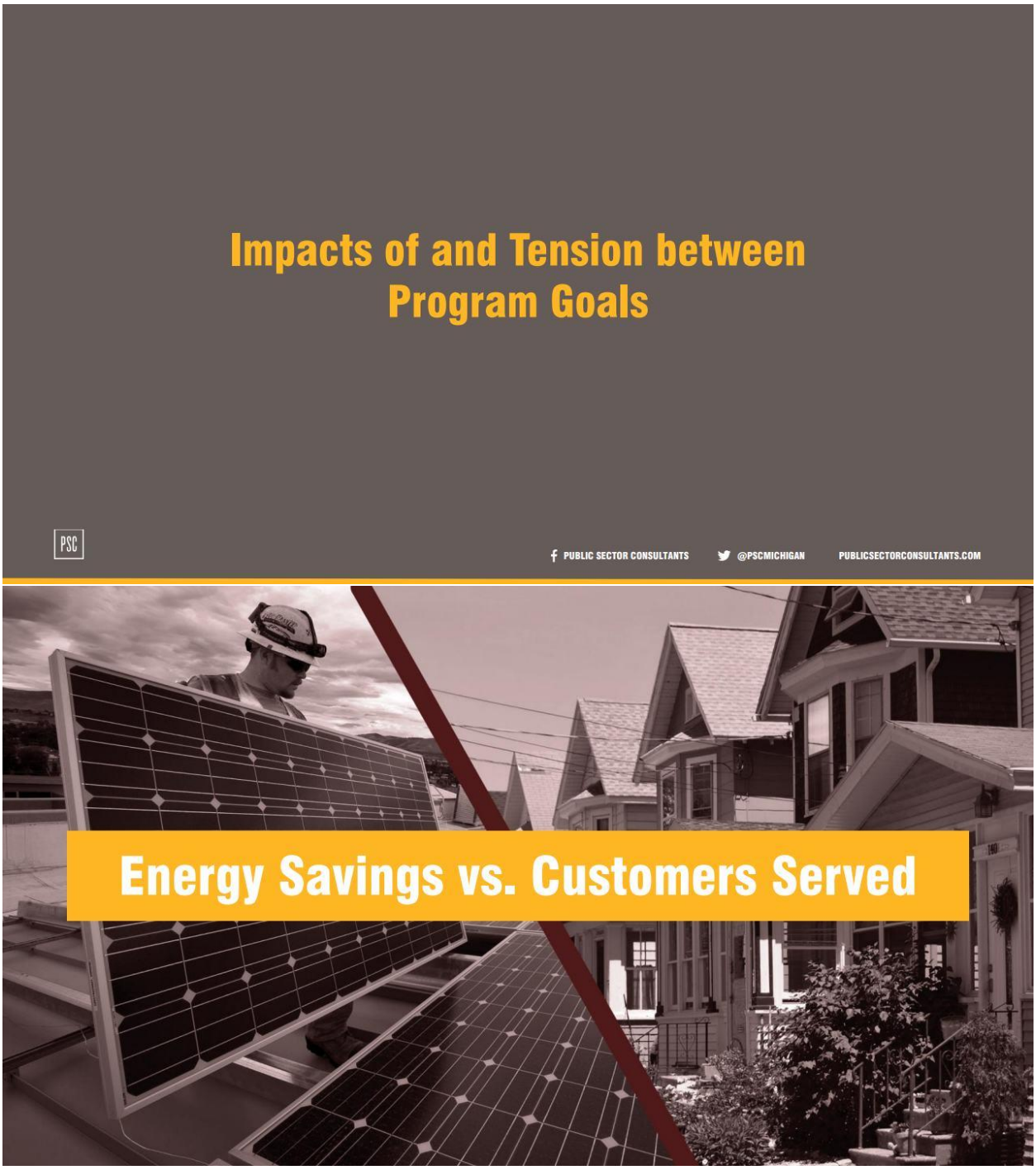
Impacts of and Tension between Program Goals
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Energy Savings vs. Customers Served

Transferability

- The tariff structure may entice people with **short time horizons** to invest in energy improvements, since the obligation will automatically transfer to the next occupant.
- The tariff structure may also entice **landlords to allow tenants** to invest in energy improvements.
- **Half of projects** that have transferability provisions **clear the tariff** when properties change hands.
- **Private capital** providers may hesitate to tie obligations to meters instead of the borrower.

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Based on everything you learned today, did your goal priority order change?

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Process for Identifying Goals

- Revisit original list of goals
  - Remove, add, or change existing goals
- Hot dot voting
  - Each person gets three dots
  - Place a dot next to the goals you think are most important
  - It is okay to use more than one dot per goal
  - Tally votes and discuss
- Determine group support for goals

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Goals

- Increase the number of participating customers making energy and/or water improvements through:
  - Maximizing the long-term reduction in energy and/or water use/demand per household;
  - Expanding access to financing for individuals who may not qualify for financial products currently in the marketplace; and
  - Making energy and/or water improvements more affordable for customers.

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Appendix 16. On-bill Program Goals

On-bill Program Goals

Increase the number of participating customers making energy and/or water improvements through the following measures:

- Maximizing the long-term reduction in energy and/or water use/demand per household
- Expanding access to financing for individuals who may not qualify for financial products currently in the marketplace
- Making energy and/or water improvements more affordable for customers

Guiding Principles for Program Design

The following guiding principles were used to evaluate the importance and efficacy of different program design elements:

- Provides uniformity and simplicity in processes
- Addresses gaps in coverage with existing available financing programs
- Is viable for capital providers
- Ensures reasonable participation costs for utility participants
- Leverages existing statewide resources
- Allows program goals to be met

On-Bill Program Design Elements

Key program design elements and the reasons for including a specific design element in an on-bill program that is consistent statewide are described in the tables below. These design elements reflect an initial model proposal for an on-bill program. Stakeholder feedback and discussion is necessary to further refine these design elements to ensure that an on-bill program meets the needs of the program partners.

To facilitate discussion, the program design elements have been compiled into three areas, based on the level of decision making needed by the workgroup. The first table lists the design elements that are either mandated by statute or require little or no discussion from the workgroup. The second table describes design elements that may require some discussion from the work group to reach consensus. The final table identifies the design elements that require discussion and consensus building.

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Design elements that are either mandated by statute or require little or no discussion from the workgroup		
Program Design Element	**Description**	**Discussion**
Eligible utilities	• Utilities regulated by the Michigan Public Service Commission (Public Act 342) • Municipal utilities (Public Act 408) • Rural electric cooperative utilities	• Required by statute • Rural electric cooperatives have a business model conducive to on-bill financing
Home energy audit and diagnostic testing	• Must comply with American National Standards Institute home energy audit standards	• Required by statute • Supports maximization of long-term reduction in energy/water use
Loan type	• Unsecured loan • Multiple loans per customer allowed if total amount financed does not exceed maximum allowable loan amount	• Eases administrative duties • Supports maximization of long-term reduction in energy/water use
Interest rates	• Interest rate to be no greater than adjusted prime rate plus 4 percent	• Required by statute • Support making energy/water improvements more affordable • Subject to discussions with the capital provider
Loan term	• Maximum loan term is 180 months (15 years), not to exceed the useful life of the installed measures	• Supports making energy/water improvements more affordable • Subject to discussion with the capital provider

Design elements that may require some discussion from the workgroup to reach consensus		
Program Design Element	**Description**	**Discussion**
Capital provider	• Single capital provider	• Ease of administration
Originator	• Capital provider to accept loan application and originate loan	• When capital provider accepts loan applications and originates loans, it is less costly and requires less data coordination with utility and loan servicer(s) • Subject to discussion with capital provider. If capital provider cannot originate loans, then an alternative structure with third party originator will be explored

Servicer	• Capital provider to service the loans	• If capital provider services loans, it is less costly and requires less data coordination with utility servicer • Subject to discussion with capital provider. If capital provider cannot service loans, then an alternative structure with a third-party loan servicer will be explored
Eligible properties	• Single-family homes (one to four units) within the utility's service territory o Rental properties permitted ▪ If tenant pays utility bill, property owner must authorize work and renter must sign agreement to accept loan payment	• Legislation explicitly supports residential properties • Commercial properties may be considered in the future • On-bill programs are potentially a more effective approach to serving rental market, which is difficult to serve through traditional financing programs
Underwriting criteria	• Twelve months of consecutive, on-time utility bill payment history • Any bankruptcies, foreclosures, or repossessions (greater than $1,000) must have been discharged at least 12 months prior to loan application • No outstanding tax liens • No outstanding collections (greater than $1,000)	• Supports expanding access to financing • Expands or tightens customer access by adjusting required number of consecutive months or by allowing delinquent payments • Credit bureau data collected for future data review (FICO score not used in credit review)
Credit enhancement	• Potentially offer a loan loss or debt service reserve	• Subject to discussions with capital provider • Assumption is that capital providers will not offer a 15-year term and alternative underwriting without a loss reserve • Supports making energy/water improvements more affordable and expanding access

Design elements that require discussion and consensus building		
Program Design Element	**Description**	**Discussion**
Statewide program administrator	• Assists utility and capital providers with development and management of the on-bill program per the Residential Energy Project Program Plan • Provides quality assurance • Manages contractor network • Partners with utilities to market and drive demand for the program • Measures and reports program performance to program partners	• Ease of administration for program participants • Provides uniformity and continuity among participating utilities and contractors • Ensures a consistent application of program procedures

Minimum/maximum loan amounts	• Minimum loan amount: $1,000 • Maximum loan amount: $30,000	• Raising minimum loan amount optimizes long-term reduction in energy/water use, because it encourages comprehensive, multi-measure projects • Lower minimum loan amount may expand access for lower-income customers to make efficiency improvements
Billing cycle	• Each participating utility will move on-bill customers to the same monthly billing cycle to simplify loan servicing	• Ease of administration for utility, capital provider, and loan servicer (if different from the capital provider)
Payment management	• Prepayments—customers who wish to make additional payments on the loan shall pay the loan servicer directly • Partial payments—when a customer does not pay the full billing amount (energy charges and loan installment charges), the loan servicer will apply the payment to the energy charges first • Delinquent payments—customers will be given a seven-day grace period, after the initial payment due date, before the payment is considered delinquent. Late fees will not be assessed on the loan installment charge. • Defaults—a loan is considered in default if three consecutive billing cycles pass without full payment toward the loan installment charge • Disconnection—PA 408 and PA 342 allow participating utilities to disconnect service for nonpayment of loan installment charge, in the same manner as disconnection for failure to pay energy charges. Home heating assistance grants should not be applied towards loan payments, • Uniform statewide will aid in ease of adoption and administration.	• Eases administrative tasks for utility, capital provider, and loan servicer (if different from capital provider) • Provides continuity to the loan servicer in program procedures between multiple utilities • The threat of utility disconnection for nonpayment is an effective deterrent of loan defaults • It is assumed a capital provider will agree to expanded underwriting criteria with this type of loan security • Supports expanding access to financing
Payments included for gas measures on electric bills or vice versa	• When a customer has different utility service providers for electricity and natural gas, the loan installment charge is placed on the utility bill that corresponds to the measures providing the majority of the energy savings (e.g., if the majority of savings are coming from electric measures, then the loan installment charge will be placed on the electric utility bill)	• Supports maximization of long-term reduction in energy/water use
Transferability	• Notice of loan filed with county register of deeds so that obligation to pay the loan installment charge runs with the land and is binding to future customers contracting for utility service at the property	• Supports maximization of long-term reduction in energy/water use • Supports expanding access to financing

Quality assurance	○ Documentation review for every project ○ On-site inspections or phone calls to customers at a rate of 20 percent for each participating contractor's first ten projects. After ten projects, five percent of the contractor's projects will be inspected. ○ Remedial action process to correct mistakes and provide for continuous program improvement	• Essential to ensuring customer satisfaction, verifying compliance with statutory requirements and program procedures, and providing for continuous program improvement • Provides an opportunity to review workmanship of participating contractors • Consistent quality assurance protocols could provide cost savings and continuity with other financing programs, and provides contractors with administrative consistency
Eligible improvements	• Homeowners could finance any of the following improvements through the on-bill program: ○ Appliances (clothes dryers, dishwashers, refrigerators) ○ Building envelope improvements (air sealing, automated control systems, doors, energy recovery systems, insulation, roofing, windows) ○ Heating, ventilation, and air conditioning systems (air conditioning, boilers, furnaces, geothermal systems, heat pumps, water heaters) ○ Lighting (day lighting, LED lighting) ○ Other measures (electric vehicle charging stations) ○ Renewable energy improvements (solar PV, solar thermal) ○ Measures that reduce water usage ○ Nonenergy building performance improvements (asbestos abatement, attic fans/ventilation, bath fans, building code upgrades, building envelope repairs, chimney liners, duct sealing/repair, electric upgrades, lead abatement, mold abatement) ○ Any measure approved as a utility cost-saving measure • Whenever possible, measures should carry the ENERGY STAR® label and have documented energy savings in the Michigan Energy Measures Database	• A single measure, 'a la carte' approach, does not maximize energy savings; a comprehensive, multi-measure approach would support the goal of maximizing the long-term energy/water use per household. • Allows customers to address many efficiency and comfort issues in their homes • Allows property owner to finance building improvements that might otherwise prevent energy efficiency work

Appendix 17. Draft Implementation Guide

Michigan On-bill Loan Program

Implementation Guide
Version 1.0 [draft]
June 2017

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Document History

Version	Date	Nature of Revisions
1.0	June 1, 2017	Initial Implementation Guide

Introduction

Purpose

This implementation guide outlines the details and requirements of the Michigan On-bill Loan Program, which provides easy, affordable loans to Michigan homeowners for qualifying energy efficiency, water efficiency, and renewable energy improvements. Customers pay back the loan through a per-meter charge on their utility bill for electric or gas services. The loan payment is considered part of the charges for electric or gas services to the property. The guide serves as a reference for anyone who wants to learn more about the On-bill Loan Program, including customers and contractors.

Why On-bill Programs?

Many homeowners lack the funds to make investments in clean energy or water efficiency improvements, especially for bigger ticket items that can produce the greatest savings. High up-front costs and a lack of easily accessible financing are commonly cited as key barriers to investments in residential energy efficiency, water efficiency, or renewable energy improvements. Rebate programs do not significantly lower this barrier. A residential energy efficiency upgrade that includes insulation; building envelope upgrades; and heating, ventilation, and air conditioning (HVAC) improvements will often cost thousands of dollars, and installing a renewable energy system is even more costly. Access to financing is essential for reaching large numbers of homeowners and unlocking the many benefits of energy efficiency, water efficiency, and renewable energy.

Over the past several decades, a range of clean energy financing tools have been developed with the goal of reducing the up-front costs for clean energy improvements. An on-bill program is a common energy efficiency and renewable energy financing tool. As of 2015, 32 states have legislation related to on-bill programs or utilities that have implemented (or are currently developing) on-bill programs.

While existing options add diversity to the financing tools available, in each case there is something unique about on-bill programs that help fill a gap. For example, on-bill programs can do the following:

1. Expand access: Existing clean energy financing tools active in Michigan use traditional underwriting criteria and may not be available or attractive to all customers, such as those with tarnished credit. Those who don't qualify for these programs may qualify using utility repayment history.
2. Provide greater affordability: On-bill programs typically allow for terms of up to 15 years, which make comprehensive energy efficiency, water efficiency, and renewable energy improvements more affordable for homeowners. Extended-term financing is beneficial for low- to moderate- and fixed-income individuals who need low, fixed monthly payments.
3. Provide solutions for tenants and other short-term occupants: On-bill programs can be structured to allow the debt obligation to be transferred to subsequent occupants. This is an enticing option for those who are interested in making improvements but expect to move soon.
4. Increase customer ease: In addition to high up-front costs for making energy or water improvements, lack of information and transaction costs can hold projects back. On-bill programs can address these barriers by integrating the improvement and payment process into customers' existing billing and customer services relationship with their energy provider.

About the Michigan On-bill Loan Program

Designing an on-bill program is complex and, therefore, time and resource intensive. Rather than each interested utility embarking on this alone, having a single program available to utilities statewide—combined with technical assistance from experts and utilities that have already implemented programs—will decrease cost and complexity. Once designed, there is potential to share services—such as capital providers, loan originators, and loan servicers—thus reducing implementation costs. Finally, an on-bill program that is consistent statewide will help drive consumer demand, because the process and financial offering will be similar across utilities, allowing contractors and customers to easily learn about and take advantage of the program.

The Michigan Energy Office (MEO), with grant support from the U.S. Department of Energy, implemented a stakeholder-driven process to create goals and identify program design structures that support the goals of an on-bill program that is applicable statewide. The work was directed by a multiagency steering committee, including representatives from the Michigan Public Service Commission and the Michigan Agency for Energy.

In May and June of 2017, the MEO convened a group of stakeholders to identify on-bill program goals and determine program design structures that support those goals. Participants came to consensus around the following goals for an on-bill program that is consistent statewide:

- Increase the number of participating customers making energy and/or water improvements through the following measures:
  - Maximizing the long-term reduction in energy and/or water use/demand per household
  - Expanding access to financing for individuals who may not qualify for financial products currently in the marketplace
  - Making energy and/or water improvements more affordable for customers

Using this Program Implementation Guide

This guide is written in a conversational way, reflecting the way industry professionals refer to efficiency measures or efficiency programs. As a result, there are instances where terms are used interchangeably, such as "audit" and "assessment."

This guide represents the best and most accurate information on the On-bill Loan Program **as of the date on the front cover**. A summary of changes to each version of this guide is recorded after the table of contents.

Summary of the On-bill Loan Program

Program Overview

Under the Michigan On-bill Loan Program, owners of residential buildings (four units or fewer), within the service territory of a participating utility, can finance any eligible energy efficiency, water efficiency, or renewable energy improvement. Eligible improvements include any measure or piece of equipment that has energy savings documented in the Michigan Energy Measures Database (MEMD)—such as air conditioners, air sealing, air source heat pumps, appliances, boilers, doors, furnaces, geothermal systems, insulation, roofs, skylights, water heaters, and windows; water efficiency improvements, as specified on the eligible measures list; and renewable energy measures like solar photovoltaic (PV) systems and solar thermal systems. (See Appendix A for a sample list of eligible measures.)

Homeowners may also finance the remediation of pre-existing environmental hazards or the repair of physical and structural defects that create health and safety issues, so long as the remediation or repairs necessary to allow for an appropriate efficiency measure and the cause(s) of the environmental hazard or physical defect are addressed. All improvements must be implemented by an authorized contractor following the completion of a comprehensive, whole-home energy audit.

Loans under this program are secured loans for amounts of $5,000–$30,000 at a fixed-rate interest with terms of up to 180 months (15 years). (Details are provided in Table 1.)

Table 1. Loan Product Details

Program Element	Definition
Eligible properties	Single-family (one to four unit) homes within the service territory of a participating utility.
Loan type	Unsecured loan.
	Notice of the loan is recorded with the register of deeds for the county in which the property is located, allowing the loan obligation to stay with the property and become binding for future customers contracting electric service to the property.
	Multiple loans per customer are allowed if the total amount financed does not exceed the maximum allowable loan amount (below). Multiple loans will be consolidated into one loan at the interest rate(s) in the effect at the time of issuing the additional loan.
Repayment mechanism	Customers will pay back the loan through a per-meter charge on their monthly utility bill. The payment is considered part of the charges for electric or gas services to the property. Participating utilities have the authority to disconnect the customer's utility service for nonpayment of the loan.
Loan amounts	$5,000–$30,000.
Loan term	15 years or useful life of the improvement, whichever is less.
Loan rates	Not to exceed prime plus 4 percent. Fixed rate with no prepayment penalty. Final APR is dependent on loan amount and length of loan.
Key underwriting criteria	Twelve consecutive months of utility bill payments without any late charges.
	No delinquent taxes, bankruptcies, foreclosures, or repossessions greater than $1,000 within the last three years (from discharge).
	No unsatisfied money judgement.
Loan agreement	Loans are made directly by the authorized lender to the customer.

Participant Roles and Responsibilities

Numerous organizations are involved in this program—from the program's marketing to the installation and financing of improvements and program monitoring. Roles of key entities, which are referenced in this guide, are summarized in Table 2.

Table 2. Role and Responsibilities of Program Participants

Program Participant	Responsibilities
Program administrator	❖ Recruit utility participants and capital providers; arrange for loan origination and servicing; create onboarding materials for new utilities and capital providers; manage and oversee provider contracts (lender, originator, servicer, etc.). ❖ Work with capital provider, loan originator, and utility to develop underwriting criteria. ❖ Work with the capital provider and loan originator to develop the loan application. ❖ Research data needs and requirements; develop and/or coordinate the data exchange protocols. ❖ Establish quality assurance criteria and procedures. ❖ Develop metrics and reporting requirements. ❖ Finalize program structure; create all program documents; and develop a program implementation guide. ❖ Coordinate the legal review of program structure and documents. ❖ Recruit, register, and oversee authorized installation contractors and energy auditors that provide services and promote financing under the program. ❖ Develop contractor training materials and conduct contractor training. ❖ Develop and implement an outreach plan and a branding/marketing strategy. ❖ Create marketing collateral to be used by participating utilities and contractors. ❖ Develop and maintain systems for capturing project data. ❖ Conduct customer satisfaction surveys and quality assurance inspections. ❖ Monitor program results and impacts; create monthly and annual program performance reports.
Utility provider	❖ Promote loan program to customers and provide support (e.g., ❖ customer service, contractor outreach). ❖ Collect loan payments. ❖ Bill customers. ❖ Offer utility energy optimization programs with customer incentives.
Capital provider	❖ Provide loan capital. ❖ Pay installation contractor upon completion of work. ❖ Hold loan agreements with customers. ❖ Record notice of loan with register of deeds with county where ❖ property is located. ❖ Discharge loan from register of deeds upon notification of full repayment.

Loan originator	❖ Accept loan applications from customers. ❖ Review underwriting criteria to determine loan eligibility. ❖ Create and distribute loan packet to customer. ❖ Provide signed loan packet to capital provider. ❖ Send new loan information to servicer. ❖ Maintain license per federal and state laws; follow legal ❖ guidelines in the lending and decision-making processes.
Loan servicer	❖ Process loan payments. ❖ Keep track of principal and interest paid. ❖ Monitor delinquencies. ❖ Notify utility of monthly loan payment amounts to be collected on utility bill. ❖ Notify customer, utility, and capital provider upon full repayment of loan.
Customer/homeowner	❖ Select authorized contractor for energy audit and improvements; apply for loan.
Residential energy auditor	❖ Conduct comprehensive whole-home energy assessments. ❖ Promote financing to customers.
Installation contractor	❖ Install energy-saving, water-saving, or renewable energy improvements under contract with the customer. ❖ Promote financing to customers (can be the same company as ❖ energy auditor).

Lending Requirements

Overview of Lending Requirements

The authorized lender provides loans to customers whose residential property is located within the service area of the participating utility. The loans comply with all applicable consumer lending laws. Customers will repay the loan monthly through a per-meter charge on their utility bill. The payment is considered part of the charges for electric or gas services to the property. Consequences for nonpayment are the same as other utility service charges; the balance owed could be enforced in the same way that delinquency with utility service payments is handled.

Customer Eligibility

Eligibility requirements for the Michigan On-bill Loan Program include the following:

- Property must be located within the service area of the participating utility.
- The customer must have at least 12 consecutive months of utility bill payments without any late charges.
- The name of the loan applicant must be the name on the utility account.
- Applicant must meet underwriting criteria. (For details, see Table 1 above.)
- Applicant must complete a home energy audit. (See the Comprehensive Energy Assessment below.)
- Rental properties are eligible (single family; one to four units).

Customers who qualify for free or lower-cost weatherization or retrofit programs are encouraged to take advantage of those programs before seeking loans through the program. Examples of such programs include the following:

- Weatherization Assistance Program, administered by the state and local community action agencies.
- Michigan State Housing Development Authority Property Improvement Program.
- Utility income-qualified weatherization programs.
- U.S. Department of Agriculture loan and grant programs.
- Customers are encouraged to contact individual programs for detailed eligibility requirements and current program information.

Loan Application Process

We expect that many homeowners will learn about the Michigan On-bill Loan Program from contractors and outreach efforts of utility participants. In some cases, customers will seek authorized contractors via the Michigan Saves online searchable database. In other cases, contractors will promote their affiliation with the program through marketing materials. Regardless of the flow of contact between a customer and an authorized contractor, the enrollment process remains the same.

Step One: The customer identifies an authorized contractor to perform an energy assessment and identify potential energy or water improvements. (See the Eligible Improvements section below for details.) As part of the energy assessment, the contractor should perform "test-in" diagnostics, unless asbestos or other hazardous materials are present in the home. The contractor should provide the customer with a detailed work plan and the cost for the proposed improvements.

Step Two: The contractor provides information about the on-bill loan program to the customer. If the customer would like to apply for the on-bill loan, the contractor initiates the loan application process for the customer by accessing the loan application center via phone or internet. The customer completes the loan application or sends a paper copy by mail. The loan application includes a consent form, which authorizes the release of the customer's utility bill payment history to loan application center. In most cases, the customer will receive a decision within minutes. The customer will be notified, in writing, if their loan application is approved, conditionally approved, or denied. If the loan application is conditionally approved, the customer will be asked to provide additional documentation to complete the application process. (See Appendix B for a sample loan application.)

Step Three: If a customer's loan application has been approved, and they wish to move forward with the on-bill loan, the customer should sign the contractor's agreement, the loan documents, and schedule the project.

Step Four: The contractor installs the equipment according to the work plan and the contract with the customer. A "test out" procedure, such as a blower door test, may also be conducted to ensure that the improvements were installed properly. As necessary, the work plan could be modified to add or subtract energy efficiency, water efficiency, renewable energy, or nonenergy building performance improvements. If a change in the work plan caused the cost of the project to increase or decrease, the customer will have to sign new loan documentation that reflects the new project cost.

Step Five: After installation and the test-out procedure (as applicable), the contractor obtains the customer's signature on a certificate of completion (COC) and sends the COC to the lender. This triggers payment to the contractor. (See Loan Closing and Servicing section below for more detail.) Payments are made directly to the contractors, minus an administrative fee, and normally arrive within seven to ten days.

Step Six: The contractor logs into their account, created when the contractor became authorized to participate in the on-bill loan program, and creates a new specification sheet (also called spec sheet or project record). The contactor attaches the signed COC and other project documentation, such as the detailed work plan, energy assessment report, and cost-benefit analysis, to this spec sheet. Once the spec sheet is complete, the contractor submits it to the program administrator so that quality assurance procedures can be implemented and energy savings calculated.

Step Seven: The customer repays the loan via direct billing by the participating utility on their monthly utility bill.

Credit Enhancement

TBD

Loan Origination

The loan originator performs the following functions:

- Verifies that the contractor initiating the loan application and performing the work is authorized by the program administrator.
- Obtains consent from the applicant to pull credit history (according to underwriting criteria) and determines eligibility for loan.
- Obtains consent from the applicant for lender, contractor, and utility company to disclose customer-specific information about the improvements made, financing provided, and pre- and post-installation energy savings to the program administrator.
- Confirms compliance with program requirements.
- Communicates loan approval immediately (within minutes) upon receiving the loan application submission via web or phone.
- Facilitates the fulfillment of the loan requirements of the lender, including customer enrollment and generating loan agreements. (See Appendix C for sample loan agreement.)

Some of the sales that will be financed through the program will have been initiated by a contractor and, therefore, will be subject to the Michigan Home Solicitation Act. For these sales, the customer has a right to cancel any time prior to midnight of the third business day after the date of the sale. The loans are also subject to the Michigan Home Improvement Finance Act, which gives the customer the right to rescind the loan agreement no later than 5 PM on the business day following the date thereof.

Loan Closing and Servicing

The authorized lender is the TBD. The lender will comply with all consumer lending laws. Once loan origination is complete, the customer will sign the loan documents. If the scope of work changes after the loan documents are signed, but before project completion, the contractor will prepare a change order with the revised project cost and submit to the lender. The customer would then sign revised loan documents.

Payment to the contractor will not occur until the work is completed and the borrower has signed a COC, created a spec sheet, and uploaded all supporting project documentation. This COC certifies that the borrower is satisfied with the completed work and consents to share certain information with the program administrator. The contractor will submit the signed COC to the program administrator, who will transmit it to the lender, thereby affirming project completion and triggering payment to the contractor.

The participating utility will begin billing the customer on the customer's utility bill after the loan is closed in accordance with their established billing practices. Customers can make extra payment on the loan or pay off the loan early, without penalty, if they choose. Extra payments or payoffs should be sent directly to the lender.

Consequence for nonpayment will be the same as for other utility service charges: service can be shutoff for nonpayment, according to the terms of the participating utility's shut-off policy, as described in the utility's most recent Rate Book.

Notice of the loan will be recorded with the register of deeds for the county in which the property is located, and the obligation to pay the loan payment will stay with the property and be binding on future customers contracting for electric or gas service to the property. (See Appendix D for details.) When the property is sold (or rented), the property owner must disclose the loan to the prospective buyer or renter.

Fees

To maintain and monitor the network of contractors promoting the financing, the program administrator assesses authorized contractors a fee of 1.99 percent of the loan value upon loan closing. The lender withholds the 1.99 percent fee from the checks sent to contractors. The lender sends the fees to the program administrator monthly, along with a report that summarizes loan activity. The contractor agrees to the 1.99 percent fee when they join the on-bill loan program and sign the contractor agreement.

Eligible Improvements

Financing may only be used for qualifying energy efficiency, water efficiency, renewable energy, or nonenergy building performance improvements installed by authorized contractors. Measures installed by the homeowner—or by any other individual or company not authorized (or not acting as a sub-contractor for an authorized contractor)—are not eligible for financing. Additionally, improvements must save energy or water (no cosmetic improvements), unless the improvements are nonenergy building performance improvements related to energy efficiency, water efficiency, or renewable energy installations. A comprehensive energy assessment is required on every project. Due to this requirement, emergency equipment replacements are not eligible.

Comprehensive Energy Assessment

A comprehensive home energy audit (or assessment) by a certified home energy auditor must be completed before the customer applies for financing. A home energy audit is an evaluation of the energy performance of a residential structure—conducted by a qualified person using building performance diagnostic equipment and complying with American National Standards Institute approved home energy audit standards. The audit must meet both of the following requirements:

I. Determines how best to optimize energy performance while maintaining or improving human comfort, health, and safety, as well as the durability of the structure.

II. Includes a baseline energy model and cost-benefit analysis for recommending energy efficiency improvements.

With a comprehensive home energy assessment, homeowners are encouraged to implement multiple measures. Whenever recommended by the assessment, health and safety measures must be implemented for the project to be eligible for financing. Contractors must follow Section 802 of the Residential Energy Services Network standard for blower door test procedures when suspected asbestos or other hazardous materials are present.

Energy assessments must be conducted no more than 12 months prior to the loan application.

Customers can pay for the energy assessment up front or roll the cost into their loan. If a homeowner does not implement any improvement identified by the energy assessment, or is not approved for financing, the homeowner must pay the full cost of the energy assessment.

Rebates for energy audits may be available through some utilities. Customers should check with their electric and natural gas utility for the availability of assessment rebates.

Eligible Measures List

Homeowners can finance any eligible energy efficiency, water efficiency, renewable energy, or nonenergy building performance improvement that is implemented by an authorized contractor. Eligible improvements include any measure or piece of equipment that has energy savings documented in the MEMD—air conditioners, air sealing, air source heat pumps, appliances, boilers, doors, furnaces, geothermal systems, insulation, roofs, skylights, water heaters, and windows; water efficiency improvements, as specified on the eligible measures list; and renewable energy measures like solar PV systems and solar thermal systems. (See Appendix A for a sample list of eligible measures.)

The on-bill loan program also allows customers to finance the remediation of pre-existing environmental hazards or the repair of physical/structural defects that create health and safety issues (collectively known as nonenergy building performance improvements). The customer may only finance nonenergy building performance improvements if they are coupled with an appropriate efficiency measure, and if the cause(s) of the environmental hazard or physical defect are addressed. (See Nonenergy Building Performance Improvements below).

All appliances and other replaced equipment must be disabled and taken out of service permanently and must be either recycled or disposed of in accordance with local, state, and federal laws, codes, and ordinances. Appliances and other replaced equipment may not be re-used.

All work must be performed in accordance with all applicable federal, state, and local codes and standards, and contractors must obtain all required permits from local authorities.

Renewable Energy Improvements

Homeowners can use the on-bill loan program for renewable energy measures like solar PV systems and solar thermal systems. For all solar PV system installations, authorized contractors must also obtain appropriate city or municipal building permits. All solar PV installations must include a solar generation meter and meter enclosure. The solar PV system must comply with current Michigan Utility Generator Interconnection Requirements. Contractors must provide a copy of the interconnection agreement or of the authorization letter with the COC.

Solar PV systems must comply with the participating utility's net metering interconnection policies. Participating utilities have the right to prohibit renewable energy installations. Customers should check with the program administrator to determine which participating utilities allow solar PV systems.

Residential wind turbines are not eligible for financing.

Nonenergy Building Performance Improvements

The on-bill loan program also allows customers to finance the remediation of preexisting environmental hazards or the repair of physical/structural defects that create health and safety issues. The customer may only finance nonenergy building performance improvements if the improvements are coupled with an appropriate efficiency measure, and if the cause(s) of the environmental hazard or physical defect are addressed. Examples of this type of work include but are not limited to the following:

- Asbestos abatement with air sealing or when installing a new boiler system.
- Electric service upgrade, necessary when installing a new heating/cooling unit.
- Upgrade of knob and tube wiring to install insulation.
- Radon and lead abatement work.
- The cost of removing an oil tank when done with a heating system replacement.
- Repairs to the home due to water damage, molds or mildew, ice dams, or other symptoms of poor building performance if the cause(s) of building performance-related damage are addressed.

In each of these examples, the remediation of the environmental hazard is necessary to allow for the installation of an efficiency measure. Customers cannot finance the remediation work on their own. A customer must also install a related efficiency measure.

Any remediation work must be performed by a contractor who is qualified, and in many cases, licensed for the task. Contractors should not attempt to remediate environmental hazards or correct physical defects they are not trained or qualified to repair. Doing so will increase contractors' liability and jeopardize their participation in the program. Authorized contractors who can remediate environmental hazards should consider obtaining pollution occurrence (also called pollution liability) insurance to protect them from liability.

Authorized Contractors

All energy-saving, water efficiency, or renewable energy improvements that qualify for financing must be installed by an authorized contractor (i.e., energy auditors and contractors installing qualifying improvements to homes). The program administrator authorizes and manages the contractors. To be authorized, the contractor must meet certain minimum requirements, including appropriate insurance, licensure, and program training. (See Table 3 below for details.) These requirements are reflected in the contractor application that must be completed by the contractor to become an authorized contractor. Authorized contractors can implement any energy efficiency measure on the eligible measures list. (See Appendix A for details.) In all cases, a baseline home energy audit must be conducted before an energy project is undertaken. (See details about requirements for the audit in the Comprehensive Energy Assessment above.)

Table 3. Contractor Qualifications

Qualification	Description	Required Documentation
Business/Organization Financial/Ethical Stability		
Business registered with State of Michigan	Licensed to do business in the state	License # and business type (LLC, Inc, etc.) on application
Workers' compensation or self-insurance	Required for all contractors, unless a sole proprietor or limited partnership, which are exempt under state law, or a corporation or a limited liability company that has filed for an exclusion	Insurance certificate, proof of sole-proprietorship, or state exclusion form
Commercial general liability insurance	Required with minimum coverage of $1,000,000 per occurrence, $1,000,000 aggregate	Insurance certificate
Add as "Certificate Holder" and "Additional Insured" on commercial	Contractors must add Michigan Saves as an additional insured to their commercial general liability policy and list Michigan Saves as a certificate holder	Insurance certificate and copy of endorsement to insurance policies naming Michigan Saves as an additional insured and certificate holder
License/Certification		
Skilled trade license	Active license in applicable trade, as required by law with no pending actions against the	Copy of license; confirmation of no pending action on application form

Federal lead-safe certification*	Required for any contractor with a residential builders or maintenance and alterations license. Strongly suggested, but optional, for all other contractors	Proof of successful completion
Training/Education		
On-bill loan program training	Training session for on-bill loan program	Proof of participation

*As of April 22, 2010, the Environmental Protection Agency (EPA) requires that contractors performing renovation, repair, and painting projects that disturb lead-based paint in homes, child care facilities, and schools must be certified and follow specific work practices to prevent lead contamination if the structure was built before 1978. Firms can become certified by completing an application and sending in a fee payment. Applications may take up to 90 days to be approved by the EPA. Individual renovation contractors must complete an EPA-accredited training course to receive certification. More information is available at *http://www.epa.gov*.

Any installation contractor performing work in a trade that requires a state license must have a valid license specific to that trade. The relevant state licenses are listed in Table 4.

Table 4. Summary of State Licensing Requirements for Contractors

Skilled Trade	License	Special Designations
Boiler	Boiler Installation	None
Construction, including insulation, remodeling, and weatherization	Residential Builders or Maintenance and Alterations	For Maintenance and Alterations License • Insulation work • Screen and storm sash
Mechanical	Mechanical Contractor	1. Hydronic heating, cooling, and process piping 2. HVAC equipment† 3. Ductwork 4. Refrigeration 5. Limited heating service† 6. Unlimited heating service 7. Limited refrigeration and air conditioning service† 8. Unlimited refrigeration and air conditioning service 9. N/A for program 10. Specialty license a—Solar
Plumbing	Plumbing Contractor or Master Plumber	None
Solar PV††	Master Electrician or Electrical Contractor and Residential Builders License	None

†Minimum requirement for Mechanical Contractor's license. Strongly suggest classification # 1 (hydronic heating, cooling, and piping) and #3 (ductwork), but do not require. Classifications 7 and 8 are often waived for contractors in the Upper Peninsula.
††Additional requirements apply.

Because of the complex nature of solar PV systems, the program has additional requirements for solar PV installation contractors. These additional requirements reflect the program administrator's desire that only experienced contractors install these systems.

Contractors must provide documentation that they meet the following minimum requirements:

- Master Electricians license or Electrical Contractors license and a Residential Builders license

If a contractor does not hold the appropriate licenses, they should provide a copy of their sub-contractor's license.

Contractors should also meet one of the following requirements:

- North American Board of Certified Energy Practitioners (NABCEP) Solar PV Installer Certification; or
- NABCEP Solar PV Entry Level Program and two installations totaling 1 kWDC with at least 1 solar PV system that include an inverter and is subject to a complete electrical permitting and inspection process by local authorities. The contractor must have served as foreman, site supervisor, or site manager responsible for the quality of the installation—for both installations; or
- Installations of at least four solar PV systems with three that include an inverter and are subject to a complete electrical permitting and inspection process by local authorities. The contractor must have served as foreman, site supervisor, or site manager responsible for the quality of the installation for at least three of the installations.

Contractor Training

Authorized contractors must participate in training before performing any work under the on-bill loan program. At least one designated employee for each contractor must attend the training. That individual will serve as the contractor's point person to train other employees. While they are not required to do so, other employees having direct contact with customers, particularly those promoting the on-bill loan program, are strongly encouraged to attend the training.

The program training covers the following topics:

- Role of authorized contractors in the program
- Program guidelines, including eligible improvements
- Customer eligibility and enrollment process
- Use of forms
- Marketing and communications guidelines
- Quality assurance process

Administrative Fees Assessed to Contractors

Authorized contractors shall pay to the program administrator a fee of 1.99 percent of the loan amount for work completed under the program. The proceeds from collected fees are used by the program administrator to sustain the program's operations. The fee will be deducted from the amount sent by the lender to the contractor.

Billing and Payment

Contractor Payment

After the work is satisfactorily completed, the customer and contractor will sign a COC. The contractor is responsible for submitting this form, the spec sheet, and *all supporting documentation to the program administrator.* **Once the COC is received, the lender will pay the contractor**. The contractor will be paid within seven days of receipt of the signed COC.

Customer Rebates

The on-bill loan program is designed to complement utility rebates, state rebates, contractor incentives, and federal tax credits. For rebates offered by the State of Michigan or individual utilities, the customer should follow the redemption procedures outlined by those entities. While the contractor can help the customer complete the redemption form, the customer is responsible for submitting the rebate form. The customer is also responsible for claiming any applicable federal tax rebates. The contractor will provide all the necessary product information and costs for customers to include in their tax filing.

Because rebate amounts and availability can change quickly and without notice, the program administrator strongly suggests that contractors and customers review utility websites for up-to-date information prior to installing any efficiency measure. The program administrator has no control or influence over any rebate program and makes no assurances or guarantees as to rebate amounts or availability.

The program does not currently provide for a contractor buy-down of the interest rate on a loan. However, contractors may apply other types of incentives before or after the loan is finalized (rebates, cash back, etc.). The contractor shall report any incentives accepted by the customer on the *spec sheet.*

Customer Inquiries

Customer inquiries regarding loan-related questions should be directed to the lender. Customers should direct any billing questions to the participating utility. Customer complaints regarding services, equipment, or authorized contractors should be directed to the program administrator.

The program administrator oversees all aspects of the on-bill loan program, including program participants, processes, and external communications. In this role, the program administrator reviews certain credentials of the contractors. However, the program administrator does not "certify," "approve," or "qualify" contractors. The program administrator cannot endorse or make any warranties as to the work or business practices of a contractor. The program administrator encourages each customer to research the contractor's work through word of mouth, contractor ratings, customer networks (such as Angie's List), and the Better Business Bureau.

If a customer makes a complaint with the program administrator regarding a contractor's performance, workmanship, or professionalism, the program administrator will note the complaint in the contractor's permanent file and take appropriate action. Repeated customer complaints can result in a contractor's suspension or termination from the program.

Quality Assurance

Contractors promoting financing must provide high-quality work and comply with the requirements outlined in this implementation guide. The program administrator will perform certain quality assurance (QA) functions to confirm that—on a consistent basis—the financed measures qualify under program guidelines and were installed in accordance with applicable program requirements and industry standards, ensuring that energy savings can reasonably be achieved. Examples of QA procedures can be found in the Michigan Saves Quality Assurance Guide.

Metrics and Reporting

The program administrator will monitor the effectiveness and impacts of the on-bill loan program. Key metrics include the following:

- Number of loans
- Loan value (average and total)
- Energy savings (average and total)

The program administrator will have access to information on customer participation, measures installed, and utility savings in accordance with authorizations signed by participating customers. The program administrator and its officers, directors, and agents will take necessary precautions to protect the confidentiality of the customer and contractor information and will only use the information for evaluation and program management purposes.

Marketing

The program administrator will rely on two primary marketing efforts to promote the on-bill loan program. These two efforts will be spearheaded by the participating utilities and the program administrator.

Participating Utility Marketing Efforts

TBD

Program Administrator Marketing Efforts

The program administrator will provide authorized contractors with a contractor marketing tool kit that stipulates marketing guidelines and resources to help authorized contractors promote the on-bill loan program to customers. The tool kit includes information, such as permitted and required uses of logos and other branding requirements, contractor identification cards, and sample copies of marketing materials.

Contractors can also follow the on-bill loan program branding guidelines to develop their own customized marketing materials with the on-bill loan program logo.

The program administrator reserves the right to request changes to, or the termination of, any contractor-generated marketing materials that do not meet program or brand guidelines. The contractor bears all changes and associated costs. Contractors can request a review of draft materials, but this is not required.

At no time will the contractor represent its business as an agent or representative of the program administrator. Contractors may represent themselves as an authorized contractor. The program administrator does not "certify," "approve," or "qualify" contractors. Any contracts between the contractor and its customers, or any third parties, shall clearly and conspicuously express that no agency relationship exists between the contractor and the program administrator.

Process to Amend the On-bill Loan Program

The program administrator seeks to continuously improve the on-bill loan program. Suggestions may be sent to [insert contact person, address, email]. The suggested changes will be reviewed by program staff and may be presented to the program participants for consideration.

Participating utilities may change the conditions of their participation in the on-bill loan program, as allowed by PA 408 of 2014 and PA 342 of 2016.

Appendix A: Eligible Measures List

The Michigan Energy Measures Database contains the most recent and ruling version of the list of eligible measures. The following table has been inserted for reference.

Measure Description	Useful Life (yrs)
Appliances	
Clothes dryer	14
Clothes washer	11
Dehumidifier	12
Dishwasher	11
Freezer (chest)	21
Refrigerator/freezer	16
Building Envelope	
Air seal can lights	15
Attic/roof insulation	25
Attic hatch insulation	20
Basement wall insulation	25
Cool roofing	20
Crawlspace wall insulation	25
Door (exterior)	20
Door weatherstripping	5
Duct insulation	20
Floor insulation	25
Infiltration reduction (Any %)	13
Kneewall insulation	20
Pipe wrap	15
Rim joist insulation	25
Wall insulation	25
Windows	25
HVAC Improvements	
AC (package system)	15
AC (split system)	15
Air source heat pump (ASHP)	15
Boiler	20
Duct sealing	18
Electric water heater	15
Furnace with energy conservation motor (ECM)	15

Measure Description	Useful Life (yrs)
HVAC Improvements (cont.)	
Gas tanked water heater	13
Ground source heat pump (GSHP)	15
Heat pump water heater	10
Instant gas water heater	20
Room air conditioner	15
Thermostat	9
Renewable Energy Improvements	
Solar domestic hot water	20
Solar PV	20
Other Energy Improvements	
Ceiling fans	15
CFL bulbs	9
LED bulbs	15
Whole house fan	15
Water Efficiency Improvements	
Faucet aerators	10
Toilets (low flow)	
Showerheads (low flow)	10

Appendix B: Sample Credit Application

To be added once the capital provider/ lender is selected.

Appendix C: Sample Loan Application

To be added once the capital provider/ lender is selected.

Appendix D: Memorandum and Notice of On-bill Payment Agreement

MEMORANDUM AND NOTICE OF ON-BILL PAYMENT AGREEMENT

THIS MEMORANDUM AND NOTICE OF ON-BILL FINANCING AGREEMENT is made this ____ day of _____, ____ by and between _____, _____, of _____ (the "Owner") and the **[name of capital provider/lender]** of [address of capital provider/lender] (the "Fund").

WITNESSETH:

WHEREAS, the Fund and the Owner have entered into a Loan Agreement (the "Agreement") of even date herewith to finance energy and/or water improvements to the Property described below with payments billed as a per-meter charge on electric or gas utility bills for the property; and

WHEREAS, the parties desire to enter into this Memorandum to give record notice of existence of the Agreement pursuant to MCL 460.969 (5).

NOW THEREFORE, for other good and valuable consideration, the Owner and the Fund acknowledge, and the parties give notice that:

1. They have entered into a Loan Agreement to finance energy and/or water improvements for the property known as _____, [City, State, Zip], legally described as follows:

   _____

   Tax Parcel No.: _____

   (the "Property")

2. The Agreement provides for the monthly payments due under the Agreement to be billed on the electric or gas utility bill for the Property in the amount of $_____ per month with the last bill due on or before _____.
3. The on-bill payments are deemed part of the charges for electric or gas services to the property pursuant to MCL 460.969 and thus, are an obligation the runs with the land and the meter for the Property requiring payment in order to obtain electric or gas service to the property.
4. Nonpayment of the electric or gas bill and the loan payments can be enforced in the same manner as nonpayment of charges for electric or gas services to the property, i.e., by shut off of electric or gas service.
5. The Agreement provides that the Owner and Owner's successors must keep the electric or gas utility account in the owner's name may not file an affidavit of tenant responsibility for any unit of the Property while the Agreement has an outstanding balance.
6. This Memorandum will be discharged only when the Agreement has been paid in full. Information about the Agreement, its terms, or the amount owed can be obtained from the [name of capital provider/lender] at the address set forth above.

This instrument is exempt from transfer taxes, because this Memorandum and Notice is not an instrument of sale or transfer of the property but merely gives notice of the Agreement.

{Signatures on next page}

The parties hereto have executed this Memorandum and Notice on ___ day of _____, ____.

Owners:

_____ _____

By: _____, Owner By:_____, Owner

[name of capital provider/lender], Fund

_____

By: _____, its President

STATE OF MICHIGAN)
) ss.
COUNTY OF _____)

The foregoing instrument was acknowledged before me in _____County, State of Michigan, this ___ of _____, ____, by _____ and _____, Owners.

_____

Notary Public, _____ County, Michigan
My commission expires: _____
Acting in _____County, Michigan

STATE OF MICHIGAN)
) ss.
COUNTY OF _____)

The foregoing instrument was acknowledged before me in _____ County, State of Michigan, this ___ of _____, ____, by _____ as President of the [name of capital provider/lender].

_____

Notary Public, _____ County, Michigan
My commission expires: _____
Acting in Ottawa County, Michigan