Roadmap for Implementing
Michigan's New Energy Policy

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 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 integrated resource plan.

- **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.
- **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.