Readying Michigan to Make Good Energy Decisions:

Comments to the Governor's Energy Listening Sessions from the Michigan Energy Innovation Business Council and Institute for Energy Innovation

MiEIBC
MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL

IEI
INSTITUTE FOR ENERGY INNOVATION

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I. Introduction

Just five years after the enactment of PA 286 and PA 295, the Michigan energy landscape has changed dramatically. At the time, the assumption was that new baseload capacity was needed and would be met with a combination of coal- and nuclear-fired power plants, with natural gas being too costly to play a significant role. Large-scale adoption of energy efficiency was unproven in Michigan, and concerns over balancing the costs of renewable energy with its economic and other benefits dominated the public policy discussion.

Five years later, policymakers begin the process of identifying the next phase of Michigan energy policy at a time of what the Edison Electric Institute calls "disruptive challenges." As a result of hydraulic fracturing and other technological advances, natural gas is at or near record low prices, and access to cheap gas is helping to boost American manufacturing, even while gas developers are scaling back exploration and production because low prices are making it difficult to economically produce in some cases. At the same time, the cost of renewable energy has dropped dramatically – and far faster than expected – creating a situation where distributed generation may soon reach cost parity with electricity from the grid, requiring new utility business models and creating new challenges for regulators. The combination of renewable energy, energy efficiency, and smart grid implementations largely erased the short-term need to construct costly new centralized baseload generation stations, and efficiency has proven to be highly cost effective, with each dollar invested under the state's Energy Optimization program producing approximately $3.50 in energy savings.

Against this backdrop, Michigan Governor Rick Snyder identified in his November 2012 address on energy and the environment four key criteria to consider in crafting the future of energy in Michigan. These criteria include reliability, cost, and environmental stewardship, all while maintaining the flexibility of energy policy to respond to market and technological changes.

Beginning in February of this year, the Michigan Public Service Commission (MPSC) and Michigan Energy Office hosted a series of seven listening sessions to collect public input on Michigan's energy future under the framework identified by Governor Snyder. Chaired by Michigan Public Service Commission Chair John Quackenbush and Steve Bakkal, director of the Michigan Energy Office, the purpose of these sessions was to allow the public to present information to assist policymakers and interested parties as they take a comprehensive look at Michigan energy policy.

Relying on research produced by the Institute for Energy Innovation (IEI), the Michigan Energy Innovation Business Council (Mi-EIBC) participated and provided input throughout the listening sessions. This white paper highlights the key issues raised by Mi-EIBC during this process and outlines a strategy for the state to maintain reliability, strengthen Michigan's economic opportunities and enhance flexibility while keeping energy costs in check for Michigan ratepayers.

II. About Mi-EIBC/ IEI

Mi-EIBC is a business trade association representing companies in Michigan's growing advanced energy sector. Mi-EIBC's mission is to grow Michigan's advanced energy economy by fostering opportunities for innovation and business growth and offering a unified voice in creating a business-friendly environment for the advanced energy industry in Michigan.

IEI is the not-for-profit partner organization of the Michigan Energy Innovation Business Council. The mission of IEI is to promote greater public understanding of advanced energy and its economic potential for Michigan, and to inform the public and policy discussion on Michigan's energy challenges and opportunities. IEI provides independent and unbiased research, organizes informational and networking events, and develops recommendations to spur public debate.

III. Overview of Mi-EIBC Participation in the Energy Listening Sessions

Mi-EIBC participated in all seven of the energy listening sessions, providing direct comment in Grand Rapids and Detroit and also attending the sessions in Lansing, Bay City, Kalamazoo, Marquette and Traverse City. During the Grand Rapids forum, Mi-EIBC presented information on the costs and economic development issues relating to the renewable energy standard and the energy optimization standard. During the Detroit listening session Mi-EIBC's public comments focused on how advanced energy increases overall system reliability and reduces risk to ratepayers.

In addition to Mi-EIBC, a large number of advanced energy businesses participated over the course of the energy listening sessions. These businesses include Astraeus Wind Energy, Barton Malow, Building Science Academy, CLEAResult/ Efficiency United, Contractors Building Supply, Dillon Energy Services, Dowding Industries, DwellTech Solutions, E3, Inc., Ecotelligent Homes, Energetx Composites, Four Elements Energy, Harding Energy, Heat Transfer International, Hemlock Semiconductor, Helios Solar, Illume Media, Keen Technical Solutions, Leelanau Community Energy LLC, Leelanau Solar, Midland Solar Applications, Novi Energy, Paradigm Energy Services, Parker-Arntz Plumbing and Heating, PiSAT Solar, Power by Sun, Shepherd Advisors, Solar Winds Power Systems, Sunsiaray, Sustainable Partners LLC, Ventower Industries, Voltage Electric, and WellHome. Additionally, a number of other companies, utilities, and electric cooperatives for whom advanced energy is a key part of their business – including Cone Drive, Consumers Energy, DTE Energy, Ford Motor Company, ITC Holdings, Lansing Board of Water and Light, and Traverse City Light and Power – also participated in the listening sessions, as well as advanced energy organizations including the Great Lakes Renewable Energy Association, the Great Lakes Wind Collaborative, the Michigan Alternative and Renewable Energy Center (MAREC) at Grand Valley State University, Michigan Biomass, Michigan Saves, the Midwest Energy Efficiency Alliance, the West Michigan Jobs Group, and Wind on the Wires. Those advanced energy businesses and organizations provided a broad range of information to assist policymakers in developing Michigan's energy roadmap.

IV. Key Elements for Michigan Policymakers to Consider in Making Good Energy Decisions

All modern economies depend upon economical, reliable, and resilient energy supplies. Whether investing in new capacity in meeting future anticipated demand or replacing aging, inefficient infrastructure, the process for evaluating capital expenditures, fuel and operating costs, future regulatory constraints and investment risk is critical to assuring that these investments are reasonable and prudent. Evaluating these concerns is the responsibility of the MPSC. However, while Michigan's regulatory process for making energy decisions is sound, there are significant deficiencies that need to be addressed.

For example, while in specific circumstances the MPSC and interveners are able to review and examine comprehensive analyses commonly referred to as Integrated Resource Plans, these Integrated Resource Plans are required only for large utility investments and are not available as context for legislative policy analysis, decisions to maintain or retire existing plants, or evaluation of energy efficiency programs. Transforming the utility planning process from a reactive requirement attached to a Certificate of Need application to a proactive tool would allow for greater consideration of a range of factors in setting energy policy. At present, transmission planners and utilities engage in resource planning, but their activities and actions are not necessarily made public and if they are made public they are not always presented in forms that make them easily understandable. Having access to this information would allow policymakers and the MPSC to review the ability of energy efficiency, demand response, smart grid technologies and distributed generation to meet Michigan's energy needs – as well as centralized baseload generation –and how these technologies and approaches might best be balanced to ensure reliability at the lowest cost to ratepayers.

Second, the MPSC lacks independent analytical capacity for integrated resource planning, generally depending on information submitted by regulated utilities. While Commission staff has considerable experience and expertise in energy issues and the Utility Consumer Participation Fund, overseen by the Utility Consumer Participation Board, provides funding for stakeholder intervention in MPSC proceedings, interveners generally do not have the information or wherewithal to develop independent analyses of alternative scenarios not provided voluntarily by utilities. A lack of transparency in the information submitted by the utilities only exacerbates this challenge. Furthermore, the Utility Consumer Participation Fund may only be used for intervention on behalf of residential ratepayers; it cannot, for example, provide funds for small electricity generators to oppose anti-competitive behavior by utilities. Addressing each of these issues would help to balance the information asymmetry that inherently leads to a state energy policy that favors the current utility business model over new approaches that better reflect the priorities of ratepayers and the state as a whole.

A. Overview of Key Considerations

In crafting energy policy for the state, Michigan policymakers should seek out a broad range of independent information to inform the decision-making process. Some of the

specific data that needs to be collected, reported, and assimilated by policy makers includes:

1. Reliable data on and best practices for facilitating and achieving the technical, economic, and market-ready potential for customer demand response in reducing peak loads;
2. A thorough understanding of and best practices for removing existing barriers and obstacles to the installation and operation of combined heat and power (CHP) systems and micro grids capable of intentional islanding as well as incentives for industrial energy efficiency;
3. Thorough understanding of barriers and obstacles and best practices for providing low-cost financing for distributed resources, including distributed generation;
4. Best practices in identifying, planning, and modeling cost effective non-transmission alternatives;
5. Best practices in coordinating energy planning with water and wastewater utilities; and,
6. Best practices in coordinating amongst the development and implementation of utility smart-grid investments with progress in "smart city" development and implementation.

It is also critical that policy makers understand that energy markets are seriously distorted by long-standing subsidies for traditional fossil fuels. Policymakers should also consider the risk of changes to the underlying fuel costs associated with each type of generation; the prospect of federal legislation or regulation to address global climate change (regardless of anyone's views as to the desirability of such federal action); innovation advances that have the prospect of changing the market fundamentals of different types of generation (including a dispassionate analysis of where innovation is happening most rapidly); regional transmission planning processes and national reliability and transmission siting developments and their impacts on the Michigan electricity markets; the development of demand side management procedures within the MISO territory and continued development of DSM procedures within PJM; and the prospect of other economic, legislative or regulatory changes that have the potential to impact energy markets.

B. Comparison of Michigan Advanced Energy Standards to Other States

The development of Michigan energy policy is happening within a rapidly changing context of state policy development throughout the country. Michigan, like other states, has used a combination of mandates and incentives in its utility policies. Policymakers should therefore avail themselves of the comprehensive data available for comparing Michigan's energy optimization and renewable energy standards to that of other states.

The best source of comprehensive comparative information about state policies and experience with utility energy efficiency programs is the American Council for an Energy Efficiency Economy (ACEEE) and the Database of State Incentives for Renewables and

Efficiency managed by North Carolina State University. These resources provide a broad range of data that should be examined deeply in any comparison of jurisdictional energy efficiency programs.

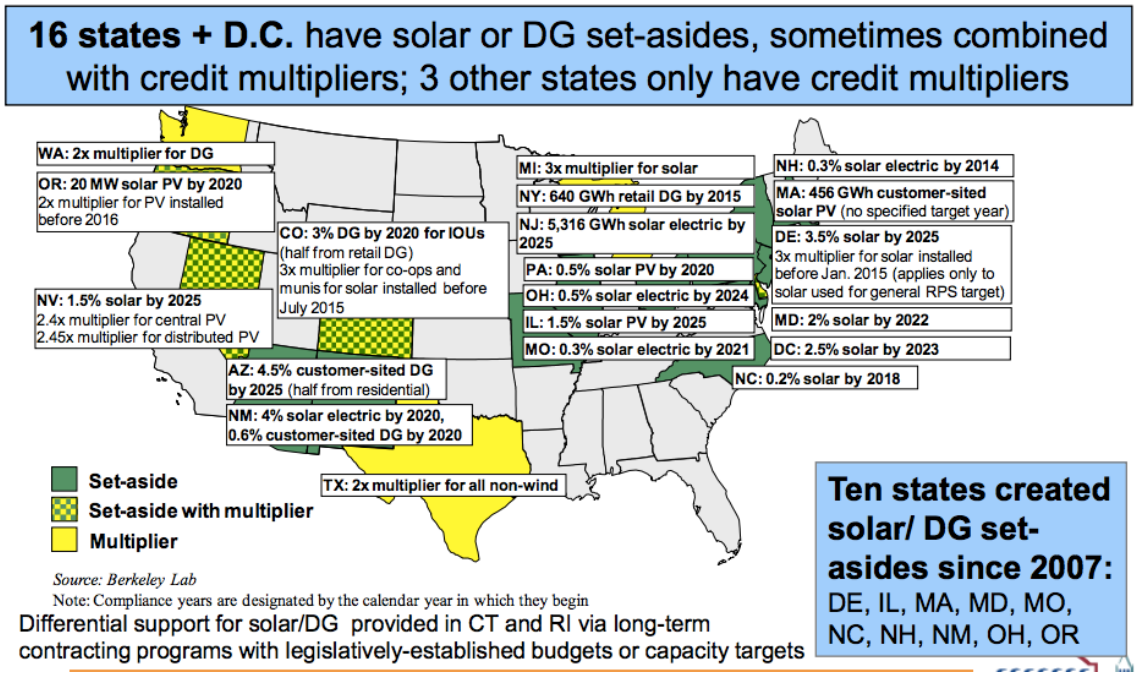
Michigan's energy efficiency resource standard, known as the Energy Optimization Standard, is mandated for all energy utilities. In addition, investor-owned electric utilities have been offered incentive payments for exceeding the mandated standards. This approach has been very successful for Michigan, and Michigan was recognized as one of two "most improved states" in the 2011 ACEEE Scorecard, and this annual report provides a particularly accessible and comprehensive perspective on state energy efficiency programs from around the country.

Michigan has placed the obligation for providing energy efficiency programs on the distribution utilities. This is the prevalent model, regardless of whether states have "restructured" to allow customer choice or not. A few states have created government or non-profit entities to administer the energy efficiency programs, using revenues provided by the utility companies. No states have placed the energy efficiency requirement on independent energy suppliers.

Michigan is somewhat unique in that in addition to utility administration, the state also provides an opportunity for utilities (particularly for smaller utilities and municipal utilities and electric cooperatives) to simply turn over the revenues to an independent administrator selected by the MPSC. Michigan's combined approach has worked very well, as the annual reports by the MPSC have clearly demonstrated.

Another tool that other states use is the renewable portfolio standard (RPS), which is a requirement that a certain percentage of the electricity used in a state is generated from renewable resources. The following map highlights the state of renewable energy standards across the country:

Half of the states with a Renewable Portfolio Standard also allow retail choice competition and require the competitive suppliers to meet the Renewable Portfolio Standard. A number of states require that a portion of the renewable generation used to meet their Renewable Portfolio Standard include significant amounts of distributed generation. Generally, distributed generation is owned by utility customers or by third-party lessors rather than by utilities, so these requirements also serve to significantly diversify ownership. The following map shows distributed generation or solar carve outs around the country:



C. Advanced Energy is Already Cost-Competitive with Traditional Generation

Data provided by the MPSC shows that the costs for renewable energy and energy efficiency are already cost competitive with traditional generation sources, and the costs for renewable generation have been rapidly declining – and falling far faster than expected when PA 295 was enacted just five years ago.

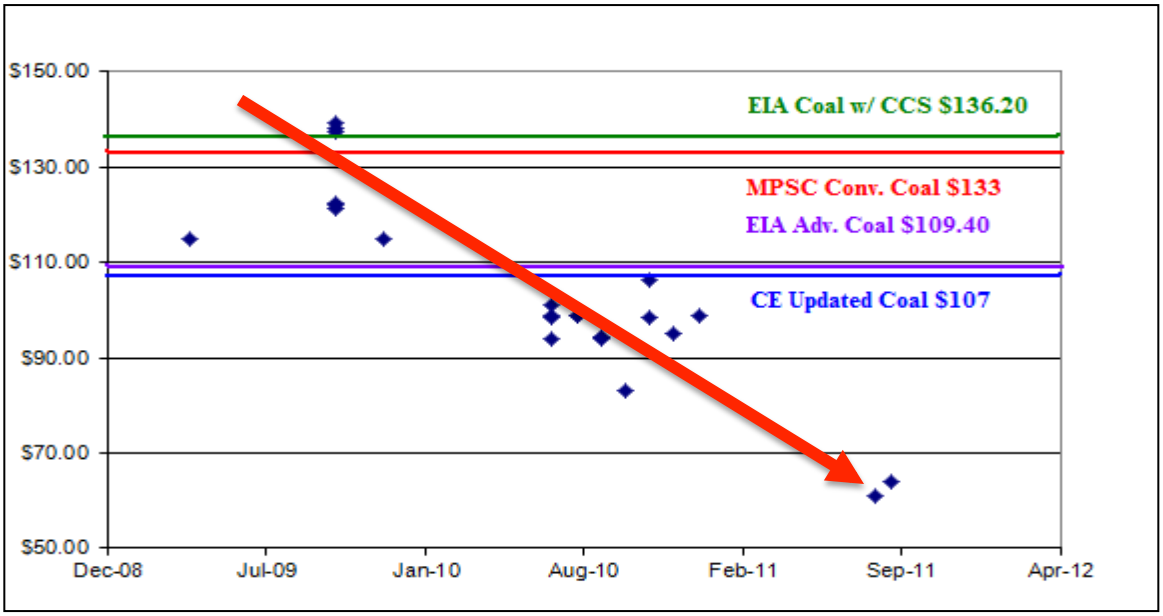
1. Renewable energy costs are declining far faster than anticipated

The costs of renewable energy continue to decline and are already cost-competitive with traditional generation. An MPSC report on the implementation of RPS released earlier this year shows a clear downward trend in cost for renewable energy projects, with new renewable energy generation costing $82.54 per MWh, while new coal fired generation costs $133 per MWh. More recent wind generation power purchase agreements are significantly less costly still, with the most recent contract signed at $47/

MWh, compared to the first contract signed under the RPS at $116/ MWh. Importantly, these are not speculative costs of estimates; rather, they represent actual, signed, long-term contracts for the purchase of electricity.

Furthermore, the weighted average cost of the renewable energy and energy optimization standards is $45.98 per MWh, which is lower than the cost of all new fossil fuel generation regardless of technology type, including new natural gas generation. The MPSC concluded that "[b]ased on contract pricing trends and the January 2013 announcement that federal legislation extended the eligibility of the Production Tax Credit for projects that begin construction by December 31, 2013, Commission Staff anticipates that the cost of renewable energy will continue to decline, while the benefits from energy optimization savings and emission reductions from offset generation will continue to increase."

The following chart highlights the rapid decline in cost for renewable generation in Michigan. Each of the dots represents an actual signed power purchase agreement for new renewable electricity generation, while the various bars represent estimates by different parties (the U.S. Energy Information Administration (EIA), the MPSC and Consumers Energy (CE) for new coal-fired generation (including that utilizing carbon capture and sequestration (CCS):



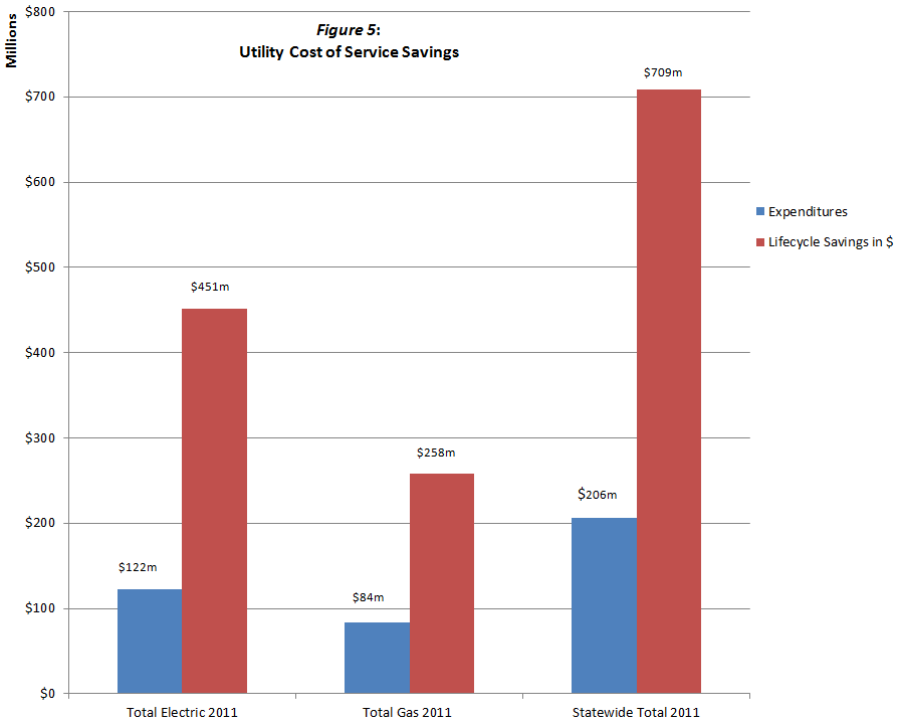
As the chart shows, the cost of new renewable generation is significantly lower than even industry projections on the cost of coal-fired generation, and less than half the cost of the projects used by the MPSC.

2. Energy efficiency provides significant savings to ratepayers

Energy efficiency also provides significant economic savings to ratepayers and the state. Broadly, energy efficiency investments are evaluated two ways. To determine

compliance with the Energy Optimization Standard (now 1% of load per year for electric utilities and 0.75% of deliveries per year for natural gas utilities), only first year savings are considered. For purposes of determining total benefits in the cost tests and for reporting net benefits of the programs, the investments are evaluated over the expected useful life of the measure. Even under this more limited standard, the energy optimization standard is projected to net more than $2.5 billion in savings to ratepayers between 2011-15, and generated more than $500 million in net savings in 2011 alone. In 2011, the last year for which MPSC data is available, ratepayers saved $3.55 for every $1.00 in energy optimization expenditures, and the cost of electricity use avoided was $0.02/ kWh – one-third of the wholesale cost of current generation and less than one-fifth the retail cost of electricity!

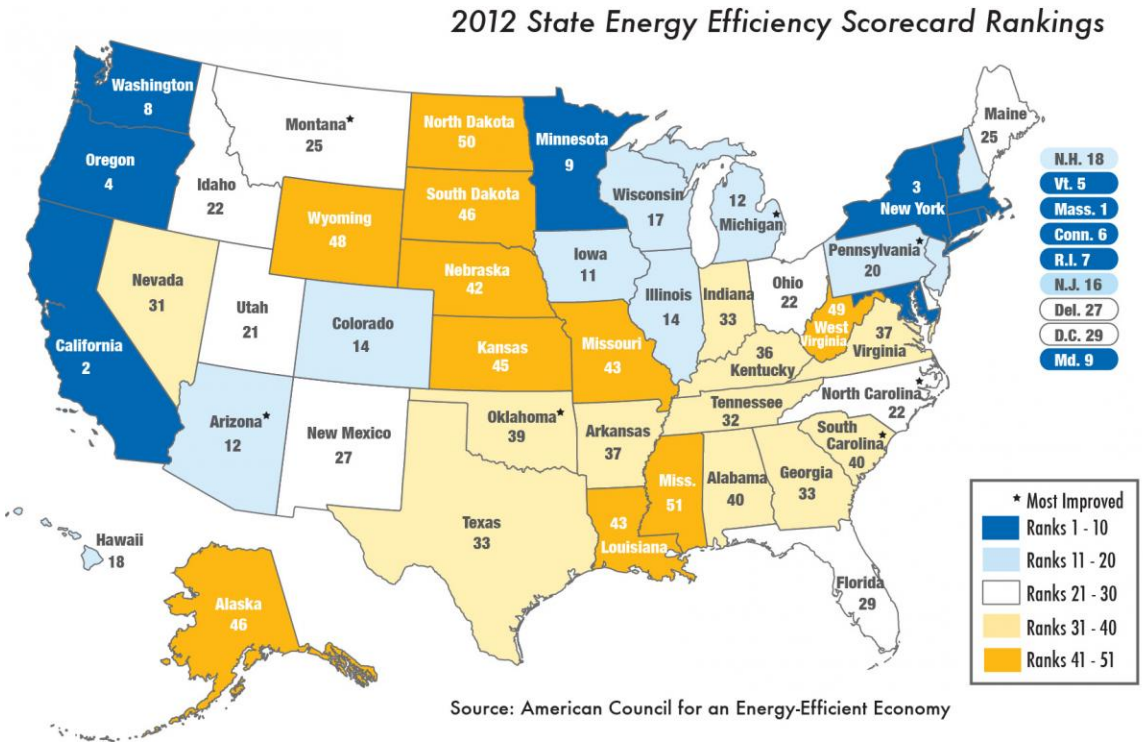
The following MPSC chart highlights the 2011 energy optimization program savings:



Because energy efficiency programs provide significant system peak savings, and because marginal resistive line losses reach very high levels during system peak, energy efficiency investments have the added benefit of reducing marginal line losses, thereby improving overall system reliability. When both electricity demand and line losses are reduced at peak, the utility can spend significantly less to ensure adequate capacity reserves and efficiency programs can defer or eliminate the need for expensive upgrades in transmission and distribution (T&D) infrastructure. For example, between 2003 and 2010, Con Ed in New York netted $300 million in customer savings by using energy efficiency to reduce load in geographically targeted areas that would have otherwise needed T&D upgrades. In other words, the savings attributed to the energy optimization standard likely substantially underestimates the economic benefits of

deferred or avoided upgrades to the transmission and distribution system as a result of reduced demand at peak times.

Finally, while some critics of the energy optimization program claim that after just four years the state has likely obtained the majority of cost-effective benefits, the reality is that a number of states have energy efficiency programs with substantially higher efficiency requirements and/or have had their programs in place for much longer time periods than the EO standard in Michigan and these programs continue to deliver value to ratepayers while in some cases led to additional rounds of innovation and market transformation. The following chart shows the energy efficiency programs from around the country:



D. Other Key Issues Relating to Integration of Advanced Energy

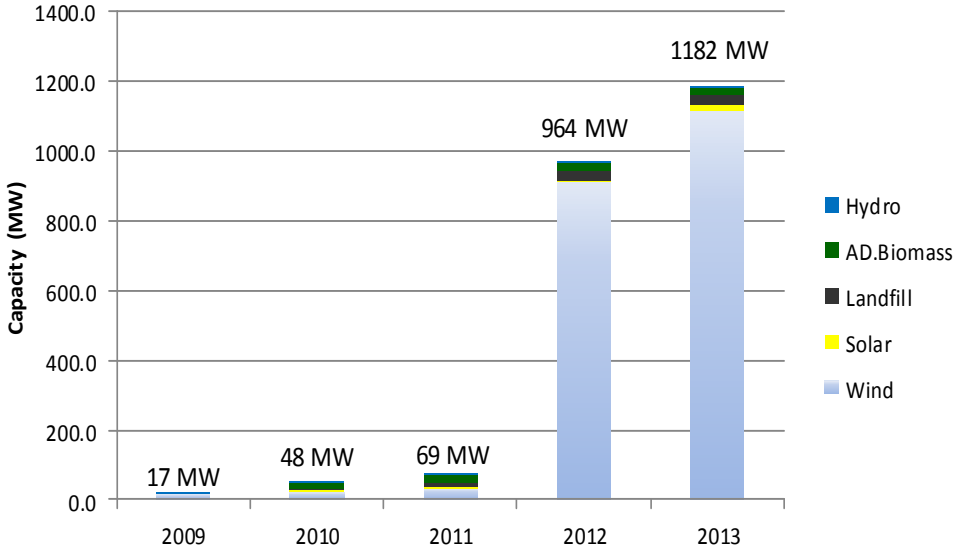
One issue repeatedly raised in the energy listening sessions relates to the variability of renewable energy resources. Critics often assert that because “the wind doesn’t always blow and the sun doesn’t always shine,” renewable resources are inherently unreliable. However, a review of data and independently verified research suggests that such concerns are overblown. A recent study published in the Journal of Power Sciences, for example, finds that by optimizing the mix of generation and storage technologies, “the electric system can be powered 90%–99.9% of hours entirely on renewable electricity [by 2030], at costs comparable to today's.” This reinforces a 2012 report from the National Renewable Energy Laboratory, which demonstrated that despite the variability of individual renewable sources, reliable electricity supply can be provided with a mix of

90% renewables. Other states and countries that have obtained far greater shares of their electricity mix from renewable resources than is called for under Michigan law with zero decrease in system reliability, proving the efficacy of greater reliance on renewable generation, and ongoing technical improvements in generation and storage technologies will only serve to reinforce this truth.

A second issues involves the current requirement that renewable generation facilities must be located in Michigan or the service territory of a Michigan utility to satisfy Michigan's renewable portfolio standard. This geographic requirement was not primarily intended to concentrate resulting economic activity in Michigan, but to have the renewable generation occur within the "balancing areas" of Michigan's electrical grid.

Renewable generation outside of Michigan's "balancing areas" would deliver power into the electrical grid in the location in which the renewable generator is located, and does not serve the purposes of diversifying energy resources to reliably meet energy needs of consumers in Michigan, providing energy security through use of indigenous resources, and improving air quality in Michigan. Furthermore, Michigan's unique geography as a peninsular state and the existence of significant load centers like the city of Chicago between Michigan's balancing areas and regions with higher wind and solar potential, means that, unlike most other states, it is not reasonable to conclude that generation elsewhere will ultimately flow to the benefit of Michigan electricity consumers. Maintaining the geographic requirement, then, should be a key part of any reconsideration of Michigan energy policy.

Finally, policymakers should be aware of the cost of delay, and that a significant time lag exists between when policymakers settle on an updated state energy policy and when investment relating to that new framework will flow into the state. The following chart demonstrates that, while Michigan's RPS has resulted in more than a gigawatt of new renewable energy generation capacity, it took several years between when PA 295 was enacted in 2008 and when significant new generation was brought online:



Policymakers should thus be aware of the cost of delay in establishing the next phase of Michigan energy policy. The current lack of a guiding policy framework beyond 2015 jeopardizes continued investment in the state's energy sector and could lead to a loss in cultivated talent and the destruction of businesses active in Michigan's energy sector. Furthermore, large investments in regulated central generation made prior to the establishment of an updated policy framework will foreclose options for more use of efficiency, renewable generation and competitive electricity supply, and could result in higher energy costs for ratepayers. Accelerating the process of identifying and establishing an undated state energy policy, therefore, is critical to managing risk and ensuring the "no regrets" energy policy called for by Governor Snyder.

V. Conclusion

The energy optimization and renewable energy provisions contained in PA 295 have worked better and at less cost than originally projected. Michigan's RPS has resulted in more than 1 GW of new renewable generation, generating more than $1.9 billion in economic activity and at lower-than-expected costs. Indeed, combined with energy savings under the energy optimization program, the renewable generation brought online as a result of PA 295 has to date avoided the need for any new baseload generation, and the costs of this renewable energy to ratepayers compare favorably with new fossil-fuel baseload generation, regardless of technology. The energy optimization program has also been effective, saving ratepayers more than $3.50 for every $1.00 in program expenditures, and providing savings at one-fifth the retail cost of current electricity generation.

At the same time, disruptive challenges are impacting electricity markets in Michigan and throughout the country. As policymakers embark on developing the next phase of Michigan energy policy, they would be wise to follow the policy framework articulated by Governor Snyder and embrace the Governor's priorities of a flexible electricity delivery systems that delivers reliable electricity to Michigan consumers at affordable costs.

Mi-EIBC and its membership of companies doing business in Michigan's advanced energy sector look forward to continuing to work with policymakers and regulators to develop and implement the next phase of energy policy in a way that lays the groundwork for a more prosperous Michigan.

APPENDIX A:
List of Questions Addressed by Mi-EIBC/ IEI

Overall

1. What information do energy policy makers need to consider in order to make good energy decisions?

Energy Efficiency

6. How does Michigan compare to other states / provinces / countries with respect to energy efficiency standards? Are the standards correlated with the cost of energy or excess generating capacity in such jurisdictions?

How does Michigan's efficiency standard compare given our cost of energy and generating capacity?

9. What have other jurisdictions' energy efficiency programs relied on: mandates, incentives, or both? What has the experience been with mandates and incentives?

15. How have energy efficiency programs in Michigan or other jurisdictions addressed non-traditional proposals for energy efficiency (e.g. digital metering, grid management technologies, or improvements on the utility side of the meter)?

20. What impact has Michigan's retail choice electricity market had upon energy optimization and compliance in Michigan? What has been the impact in other jurisdictions?

23. Over what lifecycle are energy efficiency investments in Michigan economically evaluated?

Renewable Energy

12. What methods have been used by other states or countries to set renewable targets?

13. What affect did Michigan's requirement that renewable energy be built in a defined geographic area have? What job growth is attributable to that requirement? What cost, reliability, and environmental impacts are attributable?

16. How has Michigan, and how have other jurisdictions limited the rate impact of renewable energy mandates on the residential, commercial, and industrial sector, if at all? What effect have such rate limitations had on other areas?

17. How has Michigan chosen to reflect the costs of renewables on customer bills, and how have other jurisdictions treated the billing of renewable energy?

18. How has Michigan handled the decision regarding what entities should construct and own renewable energy (e.g. an incumbent utility, an independent developer, feed-in tariffs)? What has been the practice in other jurisdictions? Has the type of project, cost of project, etc. varied depending on the entity constructing or owning the project?

26. Has Michigan, or have other jurisdictions, incentivized energy storage technologies or included energy storage in a renewable or clean energy standard? Why or why not?

30. How has the current law regarding the electric market structure (i.e. electric choice) dealt with renewable energy compliance? How have other states with deregulated and regulated systems addressed compliance?

31. What impact has Michigan's retail market structure had on compliance with the renewable energy standard?

32. How has Michigan or other jurisdictions designed their renewable standards to adapt to unforeseen circumstances, or proposed to do so? What methods beyond legislative changes have been considered or implemented?

34. How many states with RPS standards have a) achieved the standard, b) modified the standard, or c) frozen compliance due to cost or other factors?

36. To what extent is distributed generation supplying the energy needs of Michigan customers?

39. Over what lifecycle are renewable energy projects in Michigan economically evaluated?

APPENDIX B:
Full Text of Answers as Submitted

Overall

1. What information do energy policy makers need to consider in order to make good energy decisions?

   As with all-important decisions, energy policy-makers need to understand the uncertainties and the consequences of their decisions. Energy is an essential ingredient in a modern economy and way of living, so its relative cost is important to the sustainability of businesses and the prosperity of households. Traditional energy supply technologies have large economies of scale, so energy policy has tended to involve relatively few decisions but with each having large consequences. Because the distribution of energy, especially of electricity and natural gas, is a natural monopoly within each geographical area, simple market mechanisms are not expected to produce optimal economic outcomes. Energy supply technologies also have substantial effects on human health and the environment, which are not accounted for in energy markets but must be considered in making decisions that most benefit all members of our society. Most energy investments are long-lived, so some of their consequences are often far in the future and therefore significantly uncertain. Energy decisions are also technical, requiring significant expertise in engineering, economics, and ecology to adequately project the consequences of decisions.

   Michigan's basic set of institutions for making energy decisions is sound but needs to be refurbished. The Public Service Commission provides a venue for adjudicating most energy decisions. The Commission's procedures provide the opportunity for stakeholder engagement in those decisions. Commission staff have considerable experience and expertise in energy issues. The Utility Consumer Participation Fund, overseen by the Utility Consumer Participation Board, provides funding for stakeholder intervention in Public Service Commission proceedings. In specific circumstances, the Commission and interveners are able to review and examine comprehensive analyses commonly referred to as Integrated Resource Plans. However, there are significant deficiencies that need to be addressed:

   1) Integrated Resource Plans are required only for large utility investments and are not available as context for legislative policy analysis, decisions to maintain or retire existing plants, evaluation of energy efficiency programs, and the like.
   2) The Commission lacks independent analytical capacity for integrated resource planning, generally depending on information submitted by regulated utilities.

3) Intervenors generally do not have the information or wherewithal to develop independent analyses of alternative scenarios not provided voluntarily by utilities and utility analyses are not transparent.
4) The Utility Consumer Participation Fund may only be used for intervention on behalf of residential ratepayers; it cannot, for example, provide funds for small electricity generators to oppose anti-competitive behavior by utilities.
5) The Commission generally lacks the capacity and does not require utilities to adequately forecast the health effects, environmental effects, household sustainability effects or employment and income effects of its decisions.

Policy makers will need access to a great deal of objectively curated data, compiled and reported in appropriate forms to support decision making. The most pressing need is for publicly available, up-to-date, integrated resource planning (IRP) at several levels of detail (e.g., multi-state region or RTO territory, state, sub-state region or group of counties or utility service territory, substation, distribution feeder). At present, transmission planners and utilities engage in resource planning, but their activities and actions are not necessarily made public and if they are made public they are not always presented in forms that make them easily understandable to anyone who is not intimately well versed in the particular modeling tools used, including policy makers. Ideally, the planning process should include local governments and utility customers and invite the most broadly democratic and customer-centric means of planning and decision-making. Achieving this ideal will not be easy, because of the difficulty in understanding the utility infrastructure planning process. In order to overcome this problem, state level policy makers should work diligently to bridge this knowledge gap. Michigan could also play a leading role in making IRP modeling readily accessible to all interested parties. This effort requires much more than the occasional publishing of a reports like the 2007 *Michigan 21st Century (Electric) Energy Plan* or the 2006 *Capacity Needs Forum*. What is needed is a sophisticated and capable, GIS enabled mapping and modeling capability, similar to but even more complete than what has been developed thus far by the U.S. National Energy Laboratories for the Eastern Interstates Planning Council (EISPC) EZ Mapping Tool (https://eispctools.anl.gov/).

Some of the specific data that needs to be collected, reported, and assimilated by policy makers includes:

1. Reliable data on and best practices for facilitating achieving the technical, economic, and market-ready potential for customer demand response in reducing peak loads;

2. A thorough understanding of and best practices for removing existing barriers and obstacles to the installation and operation of combined heat and power (CHP) systems and microgrids capable of intentional islanding;

3. Thorough understanding of barriers and obstacles and best practices for providing low-cost financing for distributed resources, including distributed generation;

4. Best practices in identifying, planning, and modeling cost effective non-transmission alternatives;

5. Best practices in coordinating energy planning with water and wastewater utilities; and,

6. Best practices in coordinating amongst the development and implementation of utility smart-grid investments with progress in "smart city" development and implementation.

It is also absolutely important that policy makers understand the folly of depending on markets for making critically important decisions about energy production and use, when those markets are seriously distorted by long-standing subsidies for traditional fossil fuels. (See answer to Question 4.) In addition, current market prices do not reflect ecological negative externalities, leading to conclusions and decisions that fail to fully consider the total economic and non-economic costs involved.

Also, irrespective of anybody's personal views about global climate change science, a very substantial portion of all Michigan greenhouse gas emissions can be prevented by procuring rapidly all already-fully-cost-effective energy efficiency and renewable resources. The best available assessment, published in the *Michigan Climate Action Plan* (http://www.michigan.gov/deq/0,1607,7-135-50990-213752--,00.html), concludes that approximately 1/3 of all greenhouse gas production is already avoidable not at an incremental cost but for a savings. In other words, even if one rejects the science underlying the global climate change debate, taking steps to reduce greenhouse gas emissions in Michigan should still be undertaken from a purely economic perspective. Furthermore, the *Climate Action* study concludes that if some of those cost savings would be used to purchase even more gains, as much as 40% to 50% of all Michigan greenhouse gas emissions could be avoided at net zero cost.

Finally, it would be irresponsible not to include in any analysis of how best to meet Michigan's future energy needs the risk of changes to the underlying fuel costs associated with each type of generation; the prospect of federal legislation or regulation to address global climate change (regardless of anyone's views as to the desirability of such federal action); innovation advances that have the prospect of changing the market fundamentals of different types of generation (including a dispassionate analysis of where innovation is happening most rapidly); regional transmission planning processes and national reliability and transmission siting developments and their impacts on the Michigan electricity markets; the development of demand side management procedures within the MISO territory and continued development of DSM procedures within PJM; and the prospect of other economic, legislative or regulatory changes that have the potential to impact energy markets.

Energy Efficiency

6. How does Michigan compare to other states / provinces / countries with respect to energy efficiency standards? Are the standards correlated with the cost of energy or excess generating capacity in such jurisdictions? How does Michigan's efficiency standard compare given our cost of energy and generating capacity?

Cost of energy is included in most energy efficiency standards through a requirement that efficiency investments meet a "cost effectiveness" test. The test examines the cost of the efficiency measure over the life of the measure vs. the levelized cost of the generation it is reducing. Since cost effectiveness is required, consumers, regulators and legislators can be assured that any investment in energy efficiency will lead to a reduction in cost for consumers.

The measurements of costs and benefits should be clearly articulated by the legislature with flexibility for implementation by the utility commission. There are numerous methods of quantifying costs including the "total resource cost" (TRC) and the Utility Cost Test (or Program Administrator Cost Test) – the primary difference between the two is that the TRC uses the total cost of a measure including what a consumer spends and the utility cost test just looks at what the utility spends. Since the evaluation is on the cost effectiveness of the utility investment vs the benefit to the system for the ratepayers, it is recommended that the state use a utility cost test. A consumer may be investing in energy efficiency for a number of reasons that have little to do with energy (design, comfort, sound dampening, etc…). Also, by looking at the utility cost rather than the consumer cost, the utility can benefit from private leverage of their limited incentive dollars for the greatest effect.

9. What have other jurisdictions' energy efficiency programs relied on: mandates, incentives, or both? What has the experience been with mandates and incentives?

One level at which this question can be considered is in terms of the use by states of policy mandates or incentives for utilities to provide customer energy efficiency programs. The best source of comprehensive comparative information about state policies and experience with utility energy efficiency programs is the American Council for an Energy Efficiency Economy (www.aceee.org) and the Database of State Incentives for Renewables and Efficiency (DSIREUSA) managed by North Carolina State University (www.dsireusa.org). These resources provide a broad range of data that should be examined deeply in any comparison of jurisdictional energy efficiency programs. A particularly accessible but comprehensive perspective can be found in the ACEEE's). ACEEE regularly reviews and reports data on state policies and achievements. Their most recent report is "The 2012 State Energy Efficiency

Scorecard" which can be downloaded from http://www.aceee.org/sites/default/files/publications/researchreports/e12c.pdf.

The data published by ACEEE shows that a total of 24 states (including Michigan) have established "Energy Efficiency Resource Standards" (EERS), whereby specific energy efficiency savings requirements are established for utility companies (http://www.aceee.org/files/pdf/policy-brief/state-eers-summary-0912.pdf). An additional two states have "voluntary" EERS goals, but those states rank fairly low (21st and 37th)in ACEEE's 2012 state Scorecard.

One lesson that has been learned over the three decades of experience with utility energy efficiency programs is that providing some type of incentive to utilities for energy efficiency accomplishments helps encourage them to perform well in delivering customer energy efficiency programs. This practice has become fairly widespread, such that 19 of the 24 states with mandatory EERS requirements for utilities also provide some type of mechanism for utilities to earn financial incentives for good performance with their energy efficiency programs (http://www.aceee.org/sites/default/files/publications/researchreports/e12c.pdf).

In fact, all six of the highest ranked states in the ACEEE 2012 Scorecard have both a mandatory EERS and some type of incentive to the utility for good performance, as do 11 of the top 15 states (http://www.aceee.org/sites/default/files/publications/researchreports/e12c.pdf). Overall, utilities tend to be doing very well in meeting their EERS requirements, with a majority actually exceeding their EERS targets (http://www.aceee.org/files/pdf/policy-brief/state-eers-summary-0912.pdf .)

In contrast, five states (OK, KY, LA, SD, and SC) have a mechanism for utilities to earn financial incentives for energy efficiency achievements, but no EERS savings requirement. That approach of "incentives available but no mandate" does not appear to be very successful, as none of those five states are in the top 30 in terms of the percent of their annual kWh sales that are saved by energy efficiency programs (http://www.aceee.org/sites/default/files/publications/researchreports/e12c.pdf).

Michigan has used a combination of mandates and incentives in its utility policies. An energy efficiency resource standard, known in Michigan as the Energy Optimization Standard, is mandated for all energy utilities. In addition, investor-owned electric utilities have been offered incentive payments for exceeding the mandated standards. This approach has been very successful for Michigan, and Michigan was recognized as one of two "most improved states" in the 2011 ACEEE Scorecard.

Another level at which this question can be considered is with regard to the types of approaches that states are using in their energy efficiency programs for customers.

Both mandates and incentives have been used effectively to achieve energy efficiency goals, however usually in different applications. For example, mandates might include adoption of the latest IECC (International Energy Conservation Code) in building standards to ensure that new buildings are being constructed to high efficiency standards. Mandates might also include requirements that a utility meet a certain percentage of their sales through energy efficiency, but the utility may meet those mandates by offering customers incentives to encourage participation. It should also be considered that our prevailing utility business model actually punishes a utility for achieving energy efficiency goals because they are selling less of the commodity from which they earn money (kWhs or BTUs). As a result, many states have adopted one of two mechanisms for providing a utility with cost recovery for their investments 1) decoupling or 2) energy efficiency incentive payments. With decoupling, a utility's sales are "decoupled" from their revenues – meaning if they sell fewer kWh, rates are adjusted so they are held harmless in their revenues. As a result, there is an incentive for a utility to find the greatest efficiencies in their system and implement those efficiencies because it will mean a greater return for their company. Notably, Michigan lawmakers included language in PA 295 to allow for such a decoupling mechanism. However, in a case brought by the Michigan Attorney General and industrial electricity consumers, the Michigan Court of Appeals struck down the Commission's decoupling program. One obvious corrective measure would be to reinstate the legislature's intent in the 2008 legislation to once again allow the Commission to develop and implement a rate decoupling program.

In an incentive payment structure, legislation can specifically state that energy efficiency and lost revenue from sales should be compensated so that efficiency has the highest rate of return for the business. In Colorado, this system has been implemented to great success – the utility receives an incentive once they achieve 80% of the goal and have higher incentives for exceeding the goal.

There is also an important third way to advance energy efficiency, which normally requires support in state policy but differs from directly mandating energy efficiency performance or steps but also doesn't offer financial incentives. This class of policies are often called "market transformation" and are focused on changes in institutional arrangements or transactions rules to enable and encourage energy efficiency. Market transformation efforts include such practices as labeling (Energy Star, for example), revising mortgage practices so that energy-efficient buildings are eligible for either better interest rates due to their reduced risk of default or enlarged borrowing limits reflecting the combined financial burden of mortgage and energy costs in less efficient buildings. Governor Snyder is to be commended for proposing that energy ratings be incorporated into real estate transactions in Michigan. The top-rated states in the nation

on energy efficiency all use a combination of the three types of approaches described above. http://www.aceee.org/sites/default/files/publications/researchreports/e12c.pdf

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A quick overview of state energy efficiency rules, regulations, and policies (mandates) is available at DSIREUSA (http://www.dsireusa.org/summarytables/rrpee.cfm) . Most states have adopted energy standards for public buildings as well as building energy codes, though they vary in stringency. Some states have adopted appliance and equipment standards, though most have relied on Federal standards for this purpose. Some states also have public benefits funds that are used by third-party organizations to implement energy efficiency projects or market transformation efforts. Michigan's defunct LIEEF fund made small contributions of this kind, although it was mostly devoted to low-income assistance.

In addition, many states have adopted rebate programs for energy-efficient programs, usually through utility energy efficiency resource programs mandated by the states. Many have also adopted some form of advantageous loan program for energy efficiency programs, like Michigan SAVES. Less commonly, states have adopted tax credits, expedited permit processing for green buildings, or discounted permit fees.

15. How have energy efficiency programs in Michigan or other jurisdictions addressed non-traditional proposals for energy efficiency (e.g. digital metering, grid management technologies, or improvements on the utility side of the meter)?

Most policies identified as "energy efficiency programs" have directed utilities to assist their customers in achieving energy efficiency and have neglected these additional options. There is a background assumption that utilities will optimize their own operations as a matter of good business practice. However, utilities that are regulated on the basis that they may recover "costs of service" are not generally incented for maximum performance. As a result, there are usually ample opportunities for energy efficiency within utility operations. Utilities have recently given attention to these opportunities largely as a result of Federal funding and advocacy for "smart grid"' investments.

Smart metering potentially provides detailed measurements of electricity consumption for each customer. If such data are made available and usable by customers and third-party analysts, there often are significant energy efficiency opportunities that can be identified and acted upon but about which there would be considerable uncertainty absent these data. Further, smart metering data can be used as the basis for

performance contracts that might otherwise be difficult for non-utility parties to enforce. Most utilities have resisted making full data available, or at least have failed to make it convenient. A White House initiative organized through the National Institute of Standards and Technology has produced an industry effort called the “Green Button Initiative”. Under this program, each participating utility provides a “Green Button” on their website from which the utility customer can obtain their data in a standardized format. At this time, while a number of utilities across the country have at least committed to participating in the “Green Button Initiative, no Michigan utility has announced that they will participate.

Another non-traditional opportunity for energy efficiency that has arisen from the advent of “smart grid” technologies is the use of dynamic volt-VAR control to reduce line losses. Alternating current wave forms are distorted by end-use devices that include capacitance or inductance in their operation. These distorted wave forms cause “back and forth” flows of power that both use line capacity and increase line losses of power in the distribution grid. They also reduce the performance of some customer devices and accelerate wearing-out of some equipment. Using real-time sensors and controls in the distribution grid to accurate control voltage and reactive power (VAR) can reduce line losses. In addition, when voltage and reactive power are dynamically controlled, the utility is enabled to use conservation voltage regulation which is reducing the target voltage on the distribution system below the nominal target during periods of high load, thereby both reducing line losses and peak generation capacity requirements. A description of these technologies and practices and results to date can be found at http://www.smartgrid.gov/sites/default/files/doc/files/VVO%20Report%20-%20Final.pdf . The results vary with the aggressiveness of conservation voltage regulation, but clearly demonstrate potential benefits of at least 1.5% reduction in annual energy consumption and approximately 2.5% reduction in peak load. Theoretically, energy consumption reduction could average as high as 4-5%. It should also be noted that dynamic volt-VAR control also increases the expected life of some distribution grid equipment, reduces outage frequency due to distribution equipment failure, and facilitates high penetration of distributed solar generation.

There are also significant opportunities for energy efficiency in power generating stations. The premier example is the use of combined heat and power, in which the heat produced to generate electricity is then used either for building heat or industrial process heat. In Michigan, some municipal utilities operate in this fashion with heat provided to customers through a district heating system. There are also a few industrial implementations, but these are relatively rare. Chapter 5 of the ACEEE’s “The 2012 State Energy Efficiency Scorecard” (http://www.aceee.org/sites/default/files/publications/researchreports/e12c.pdf) thoroughly compares the programs and results of combined heat and power policies in

the various states. According to the Michigan Public Service Commission's 21st Century Energy Plan, Appendix II (available at http://www.michigan.gov/documents/mpsc/energyplan_appendix2_185279_7.pdf) which was the last comprehensive assessment, Michigan has unused combined heat and power potential of more than 675 MW electricity generation capacity.

Efficiency in utility-owned power generation plants is largely determined by the generation technology installed when the plant was built of in major component replacement projects. It is also possible to improve the efficiency of plants through targeted investments. The overall results can be evaluated by considering the "heat rate" of the plant in comparison to other plants using similar fuel. Heat rate measures the heat content of fuel consumed per unit electricity generated. Perusal of heat rate of the power plants of Michigan's investor owned utilities as reported by them in annual reports to the Michigan Public Service Commission (available at http://michigan.gov/mpsc/0,4639,7-159-16377_17104-214349--,00.html) shows most of their plants to have heat rates at or above the national averages reported by the Energy Information Administration. A high heat rate indicates that the plant is inefficient.

20. What impact has Michigan's retail choice electricity market had upon energy optimization and compliance in Michigan? What has been the impact in other jurisdictions?

Michigan has followed a practice, which is nearly universal among states with active utility energy efficiency programs, which is to place the obligation for providing energy efficiency programs on the distribution utilities. This is the prevalent model, regardless of whether states have "restructured" to allow customer choice or not. A few states have created government or non-profit entities to administer the energy efficiency programs, using revenues provided by the utility companies. No states have placed the energy efficiency requirement on independent energy suppliers, for several reasons, including the facts that they are unregulated entities and there is no way to enforce such a requirement, and that there is considerable turnover in that independent supplier industry.

Michigan is somewhat unique in that in addition to utility administration, the state also provides an opportunity for utilities (particularly for smaller utilities and municipal utilities and electric cooperatives) to simply turn over the revenues to an independent administrator selected by the MPSC. Michigan's combined approach has worked very well, as the annual reports by the MPSC have clearly demonstrated.

Nationally, fifteen states have active retail choice programs, according to the US Energy Information Administration (see www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html). The following

table lists those states along with ACEEE's ranking of those states in "The 2012 State Energy Efficiency Scorecard", the level of the Energy Efficiency Resource Standard established as of 2012, and the level of electricity savings accomplished in 2010 through the State's programs. Estimated incremental electricity savings are not yet available for 2012. Some programs increased their standards since 2010, hence the difference between the 2012 resource standard and the 2010 actual savings.

State	ACEEE 2012 Scorecard Rank	2012 Energy Efficiency Resource Standard	2010 Net Incremental Electricity Savings
Massachusetts	1	1.91%	1.1%
New York	3	2.14%	0.84%
Oregon	4	0.98%	1.11%
Connecticut	6	No	`1.39%
Rhode Island	7	2.10%	1.04%
Maryland	9	2.44%	0.48%
Michigan	12	1.00%	0.72%
Illinois	14	1.67%	0.46%
New Jersey	16	No	0.40%
New Hampshire	18	No	0.62%
Pennsylvania	20	0.87%	0.23%
Ohio	22	1.19%	0.47%
Maine	25	No	0.73%
Delaware	27	No	0.15%
Texas	33	0.14%	0.19%

Since all but two of these are above median of the nation, it is apparent that there is not a fundamental conflict between retail choice and energy efficiency policy. Further, most of these retail choice states have specific energy efficiency resource standards, similar to Michigan's Energy Optimization Standard.

One key to the success of these programs in restructured states is that the rate charge to support these programs is "non-by-passable". In other words, all customers pay to support the energy efficiency programs through their distribution rates, regardless of whether they purchase their electricity commodity from a regulated utility or an independent supplier, and all distribution utility customers are eligible to participate in the energy efficiency programs.

23. Over what lifecycle are energy efficiency investments in Michigan economically evaluated?

Broadly, energy efficiency investments are evaluated two ways. To determine compliance with the Energy Optimization Standard (now 1% of load per year for electric utilities and 0.75% of deliveries per year for natural gas utilities), only first year savings are considered. For purposes of determining total benefits in the cost tests and for reporting net benefits of the programs, the investments are evaluated over the expected useful life of the measure.

Useful life is included in the Michigan Energy Measures Database (see www.michigan.gov/mpsc/0,4639,7-159-52495_55129---,00.html) that is used to score and evaluate utility program accomplishments. Useful life, like all other data included in the database, is determined using engineering data on the measures and validated by field studies where possible. Useful life for currently authorized measures range from 1 year for behavioral changes and temporary measures provided with an energy audit to 20 years for a solar water heater.

Also noteworthy is that for purposes of compliance with the spending cap, all utilities are treating energy efficiency programs as current expenses to be recovered in the current year rather than adding costs of long-lived measures to recoverable ratebase (capital) accounts. Current law allows either treatment, but ordinary business accounting practice would be to place expenditures on long-lived assets in capital accounts to be amortized over approximately the useful life of the item purchased. By definition, such a change to this ordinary method of business accounting would have the effect of reducing year one incurred costs and relaxing the program spending cap, which would enable implementation of more costly but longer-lasting energy efficiency measures.

Renewable Energy

12. What methods have been used by other states or countries to set renewable targets?

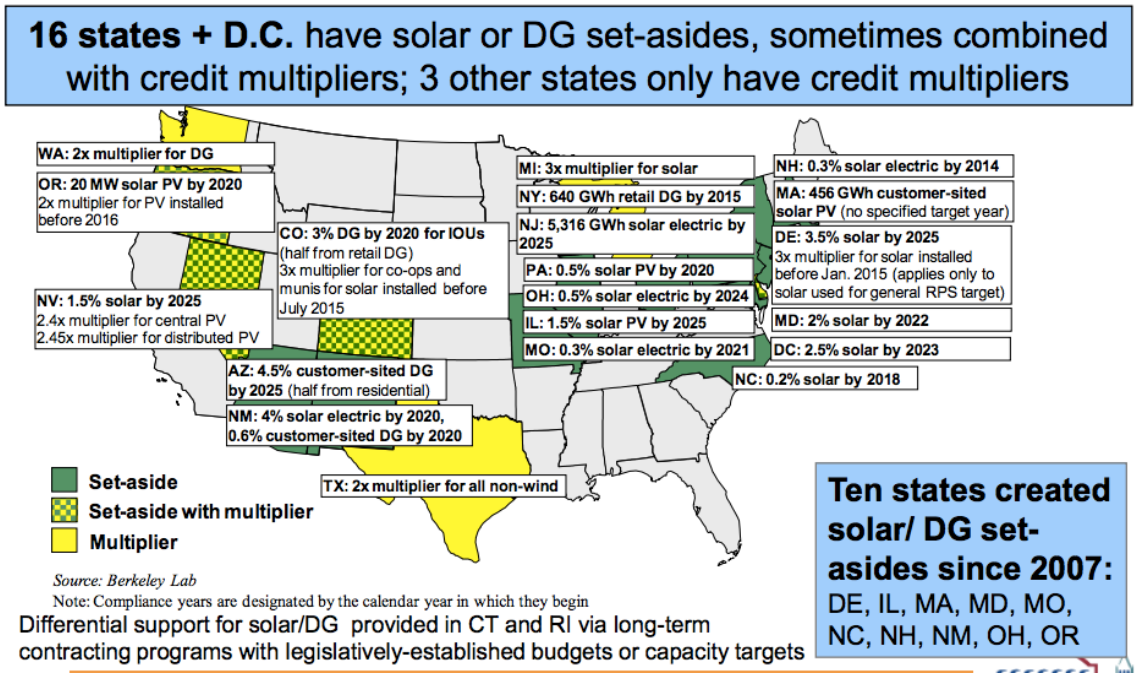
There is an excellent document that was produced by the Clean Energy States Alliance looking at some of the different ways of structuring RPS. See Warren Leon, *Evaluating the Benefits and Costs of a Renewable Portfolio Standard: A Guide for State RPS Programs*, Clean Energy States Alliance 2012, *available at* http://www.cleanenergystates.org/assets/2012-Files/RPS/CESA-RPS-evaluation-report-final-5-22-12.pdf. A recent presentation by Ryan Wiser from LBNL demonstrates the potential impacts of RPS policies as well as where various states are in achieving their RPS goals.

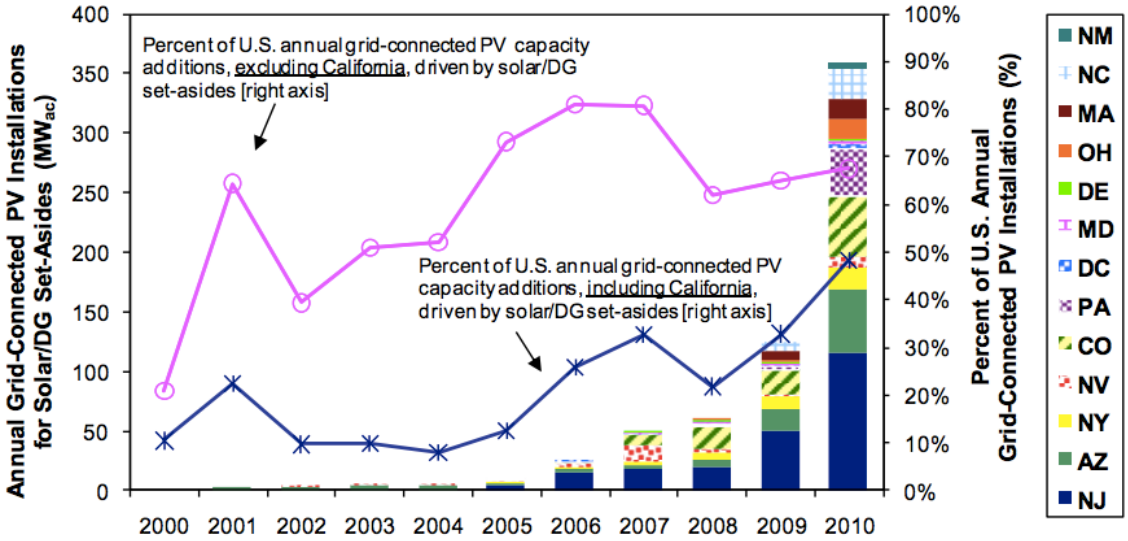
Generally states have goals based on a percentage of retail sales by a specified date. In some states there energy efficiency is an acceptable resource for meeting up to a portion of the RPS. In Ohio, utilities may use "alternative energy resources" which are defined in statute to meet up to 50% of the 25% standard.

Some lessons have been learned regarding RPS policies over time:

1. Set a standard that is designed to drive economic development – that is, set a standard that only applies to new generation. Many times there are efforts by interested parties to find ways in which they can qualify without any changes in their current portfolio, or without meeting the full standard. This isn't the point of the standard. One could always set a higher number and include existing resources, but the purpose of the RPS is to diversify the current portfolio, reduce risk within the current portfolio and increase environmental objectives relative to the current portfolio – as a result, the RPS should not include the current portfolio of resources. If the idea is to look at the entire portfolio of resources and their relative emissions, then perhaps an emissions standard across the portfolio would be a more appropriate mechanism for achieving that goal than an RPS.

2. Carve-outs can drive development of specific technologies or groups of technologies. Solar carve-outs within RPS goals have been very successful in building a robust solar market and driving down installation costs throughout the country. In other areas, distributed generation carve-outs that are technology neutral and based on a size of production have been successful. Generally, either of these options benefit from a statutory distinction that will promote diversity within the market place. These kinds of market segmentations may include residential vs. commercial and retail vs. wholesale markets ensuring a broad economic impact in the achievement of the standard.





3. Alternative Compliance Payments. ACP must be set high enough to be a less cost effective means of achieving compliance than the investment in resources the RPS is designed to achieve.

4. Utility ownership. In many states, there is a limitation on the percentage of resources that may be built by the utility without going out to the market for a competitive bid. Free market advocates will point to the ability to use the competitive marketplace to drive down the costs of resources for consumers, utilities may use the argument that Power Purchase Agreements are treated as imputed debt on their books and lead to a lowering of their credit rating and higher costs of capital across the investments of the utility – impacting the consumer. In recognition of both of these arguments, some states have put in place a cap (for example 25%) of utility owned resources. In other states, the cap is allowed to increase to a higher number (50%) if the utility can demonstrate an economic development benefit to the state.

5. In-State Multipliers. Some states have included in-state multipliers or generation requirements that generation be developed within the state. While the purpose of driving in-state economic development is understood, these provisions should be avoided. There is indication in recent legal challenges that these provisions could be perceived as un-constitutional due to a violation of the interstate commerce clause of the US Constitution. If a state includes an in-state multiplier, they should also include a severability clause that would indicate that if any portion of the standard is found to be unconstitutional, the act is found to be severable and just that provision would be removed by the courts. Alternatives to an in-state multiplier could be multipliers based on energy, economic or other reasons – but not on the geographic boundary of the state.

Geographic Eligibility and Delivery Requirements (Main Tier)	Examples
In-state generation requirement	HI, IA
In-region generation requirement	DC, MI, MN, OR, PA
Electricity delivery required to state or to LSE	
Direct transmission inter-tie between generators and state	TX
Broader delivery requirements to state or to LSE	AZ, CA, KS, MT, NM, NV, NY, OH, WI
Electricity delivery required to broader region	
Generators anywhere outside region must deliver electricity to region	DE, ME, NJ, WA
Generators in limited areas outside region must deliver electricity to region	CT, DC, MA, MD, NH, RI
In-state generation encouragement	
In-state multipliers	CO, MO
Cost-effectiveness test	IL
Limit on RECs from out-of-state generators	NC

6. Rate Caps – Rate caps have been very effective in limiting the potential cost impact of renewables. Further discussion in question #16.

7. REC Tracking and Vintage – Renewable Energy Credits are the general way in which compliance with an RPS is measured. One REC=1 MWh of renewable generation. There are mechanisms (for example WREGIS – the Western Renewable Energy Generation Information System) that are used by multiple states to track RECs and their retirements. The vintage of a REC is the year in which the REC is generated. Standards should be set on what vintages are acceptable for achieving RPS compliance. For example, RECs must be acquired in the same year they are generated, or within 3 years or 5 years…etc…

8. Scheduled compliance requirement. While overall requirements are set to a percentage by a certain year, legislation may include specific goals per year that

are used as an annual compliance requirement leading to the overall goal. Sometimes, the creation of this compliance schedule is left to the utility commission.

9. What utilities must comply with the standard. Some states exclude utilities that are below a certain number of meters. Other states may have one standard for IOUs and a different standard for public utilities. One common statewide standard with a meter size exclusion is recommended for simplicity.

13. What affect did Michigan's requirement that renewable energy be built in a defined geographic area have? What job growth is attributable to that requirement? What cost, reliability, and environmental impacts are attributable?

The requirement that renewable energy generation facilities be located in Michigan or the service territory of a Michigan utility to satisfy Michigan's renewable portfolio standard was an important element of 2008 PA 295. The act begins with the following language (MCL 460.1001):

"Section 1.

(1) This act shall be known and may be cited as the "clean, renewable, and efficient energy act".

(2) The purpose of this act is to promote the development of clean energy, renewable energy, and energy optimization through the implementation of a clean, renewable, and energy efficient standard that will cost-effectively do all of the following:

(a) Diversify the resources used to reliably meet the energy needs of consumers in this state.

(b) Provide greater energy security through the use of indigenous energy resources available within the state.

(c) Encourage private investment in renewable energy and energy efficiency.

(d) Provide improved air quality and other benefits to energy consumers and citizens of this state."

The geographical requirement (MCL 460.1029) is primarily that

" Sec. 29.

(1) Subject to subsection (2), a renewable energy system that is the source of renewable energy credits used to satisfy the renewable energy standards shall be either located outside of this state in the retail electric customer service

> territory of any provider that is not an alternative electric supplier or located anywhere in this state. For the purposes of this subsection, a retail electric customer service territory shall be considered to be the territory recognized by the commission on January 1, 2008 and any expansion of retail electric customer service territory recognized by the commission after January 1, 2008 under 1939 PA 3, MCL 460.1 to 460.10cc. The commission may also expand a service territory for the purposes of this subsection if a lack of transmission lines limits the ability to obtain sufficient renewable energy from renewable energy systems that meet the location requirement of this subsection."

This basic requirement is followed by certain exceptions that meet the spirit of this requirement but address special circumstances. This geographic requirement was not primarily intended to concentrate resulting economic activity in Michigan, but to have the renewable generation occur within the "balancing areas" of Michigan's electrical grid.

Renewable generation outside of Michigan's "balancing areas" would deliver power into the electrical grid in the location in which the renewable generator is located. If the location was not in the North American electric power grid or is at great remove from Michigan, then it is clear that the only purpose of the act served would be "(c) Encourage private investment in renewable energy and energy efficiency". Diversifying energy resources to reliably meet energy needs of consumers in Michigan, providing energy security through use of indigenous resources, and improving air quality in Michigan are accomplished only to the extent that the renewable generation is close enough to Michigan to displace combustion of imported fossil fuel in Michigan.

Michigan's electricity providers mostly operate within the rules of the wholesale power market operated by the Midwest Independent System Operator (MISO). The core of MISO's market making is that each load serving entity forecasts its load and every generating unit bids a price at which it will operate, then MISO schedules generation from lowest to most expensive generation to meet the forecast load, subject to transmission capacity. Most renewable generators operate near zero variable cost, so are always dispatched under the MISO rules. As a result, higher-cost fossil fuel plants are not operated to the extent that renewable generation is available. But, which fossil fuel plants will be operated less? A bit of careful modeling of the dispatch process shows that the effect is generally to reduce the operation of those fossil fuel plants that are closest (within the transmission grid) to the renewable generator and between the renewable generator and the load center toward which energy flows from the region of the renewable generator.

Most people who advocate that relaxing Michigan's locational requirement will allow cheaper renewable generation are comparing the cost of wind generation in Michigan to the cost of wind generation in the Northern Plains states. But, wind generation in the

Northern Plains will not reduce fossil fuel generation in Michigan by any significant amount unless the wind generation in that region saturates the electricity loads of the Minnesota, Wisconsin, northern Illinois, and northern Indiana markets. Further, if those markets were saturated with wind generation from the Northern Plains, the residual flow of power past these markets would be divided between Michigan and areas to our southeast. The geographical area allowed to meet Michigan's Renewable Portfolio Standard approximates in definable territories the places in which the renewable generation will effectively compete with and displace Michigan-based fossil-fueled generation.

Finally, comparisons of the levelized cost of energy between locations are an inappropriate measure of the economic value of generation. Power is sold into the grid where it is generated and at the marginal price in that location at that time. Thus, the appropriate comparison is not the levelized cost of energy from a generator but the levelized cost of energy less the locational marginal price at the time of generation. Michigan has a persistently higher locational marginal price than do the Northern Plains states, averaging approximately $20 per MWH more (see the MISO Market Monitor reports at https://www.misoenergy.org/MarketsOperations/IndependentMarketMonitor/Pages/IndependentMarketMonitor.aspx). This persistent difference in locational marginal price reflects precisely the limitations on transmission capacity and the intervening generation locations that would prevent renewable generation in the Northern Plains from displacing Michigan-based fossil-fueled generation.

16. How has Michigan, and how have other jurisdictions limited the rate impact of renewable energy mandates on the residential, commercial, and industrial sector, if at all? What effect have such rate limitations had on other areas?

Most states create a percentage rate cap that serves as a limit on the incremental costs of renewable energy over the levelized costs of other traditional resources within the utility portfolio. Because renewable energy costs are largely capital expenditures and are constant over time, long-term power purchase agreements are critical to determining the relative cost of renewables and protecting the ratepayer from market changes as well as securing low cost capital for project investment. Projected costs of traditional resources are heavily dependent on fluctuations in resource costs of traditional energy. States may consider introducing a risk component to the valuation recognizing that the future impacts of traditional energy resources are largely unknown.

17. How has Michigan chosen to reflect the costs of renewables on customer bills, and how have other jurisdictions treated the billing of renewable energy?

Relevant law on this question may be found in Michigan Compiled Laws 460.1045.

Electric providers are required to recover incremental costs of renewable generation via a line-item per meter surcharge on the customer bill. Surcharges are required to be fixed for each customer class, subject to caps provided in law, by levelizing recovery of incremental costs of the electric provider comprehensive renewable energy plan over a period of 20 years. Non-incremental costs of renewable generation, reflecting the avoided costs of non-renewable generation, are recovered through power supply cost recovery lines on the bill along with costs of fossil fuels and wholesale power purchases.

In addition, electric providers are required to include in each bill an estimate of costs avoided by the combined renewable energy program and energy optimization program, computed as the costs of equivalent power from a new coal-fired power plant.

Notably, the Commission has concluded that the incremental costs of renewable generations are lower than anticipated, and falling far faster than anyone expected at the time PA 295 was enacted. In addition, the current estimate of avoided costs resulting from the combined renewable energy program and energy efficiency program far outweigh the additional assessed costs of the program.

No comprehensive summary of billing practices for renewables in other jurisdictions is currently available.

18. How has Michigan handled the decision regarding what entities should construct and own renewable energy (e.g. an incumbent utility, an independent developer, feed-in tariffs)? What has been the practice in other jurisdictions? Has the type of project, cost of project, etc. varied depending on the entity constructing or owning the project?

With the exception of electric providers that had more than one million retail customers in Michigan as of January 1, 2008 (effectively Consumers Energy and DTE Energy), Michigan allows the renewable portfolio credit standard to be met with any combination of utility-owned, power purchase agreement, or renewable energy credit purchases reasonably determined by the electricity provider.

In the cases of the two large electricity providers, Section 33 of 2008 PA295 (MCL 460.1033) essentially provides that not more than 50% of the required renewable energy credits may be obtained from projects owned by the electricity provider and at least 50% of the renewable energy credits must be obtained through renewable energy contracts or renewable energy credit contracts with independent producers. In this context, independent producers could be customers of the electricity provider engaging in cogeneration, net metering, or a feed-in tariff program.

As indicated in EIBC's answer to Renewable Energy Question 30, half of the states with a Renewable Portfolio Standard also allow retail choice competition and require the

competitive suppliers to meet the Renewable Portfolio Standard. In these cases, a requirement of third-party ownership is less significant since the various competing suppliers will inherently diversify ownership and create competition; consequently, those states with retail choice competition do not have similar requirements.

A number of states require that a portion of the renewable generation used to meet their Renewable Portfolio Standard include significant amounts of distributed generation. Generally, distributed generation is owned by utility customers or by third-party lessors rather than by utilities, so these requirements also serve to significantly diversify ownership.

Other states have competitive procurement provisions for electricity generation, some of which are directly tied to renewable requirements, but more commonly as general principles of utility regulation. In these states, diversity of ownership arises from the competitive process rather than from an overt requirement like the one in Michigan.

To a close approximation, Consumers Energy and DTE Energy have chosen to obtain close to 50% of their renewable energy credits from projects that they own, indicating that absent this requirement, they would have sought greater than 50% ownership share. Because the "fuel supply" for landfill gas and anaerobic digestion systems are controlled by independent parties, these kinds of projects would likely have been less likely absent the requirement of independent ownership. The limited amount of dam refurbishment for hydropower also has been done by dam owners and likely would not have been done by the large utilities absent this requirement. The predominance of utility-scale wind in meeting Michigan's Renewable Portfolio Standard is a result of fundamental economics and would not have changed absent the ownership requirement.

The effectiveness of the ownership limitations and competitive procurement provisions 2008 PA295 are addressed explicitly in the Michigan Public Service Commission's annual reports to the legislature on the Renewable Portfolio Standard, the most recent of which was issued in February 2013 (www.michigan.gov/documents/mpsc/implementation_of_PA295_renewable_energy_411615_7.pdf). Due to the predominance of wind generation in Michigan's portfolio, they based their analysis on wind projects only. The report summarizes their analysis as "The analysis shows that Company-owned projects have been three percent cheaper than similar competitively bid power purchase agreements." This conclusion, however, is based on a direct comparison of the levelized cost of electricity from the various power purchase agreements, company-built projects, and company-purchased projects without adjustments for differing conditions and timing. Power purchase contract terms are 20 years while company-owned projects are amortized over periods between 20 and 30 years; these longer terms favor the utility-owned contracts but the

independently-owned projects are unlikely to terminate operations at the end of the initial contract term. Company-owned projects have been developed somewhat later in time than those developed by independent developers and either sold to the companies or operated under power purchase agreements. The same report shows very rapid cost declines for wind developments, as Michigan developers and contractors have gained experience, so that the timing of projects has a significant effect on cost. Further, the companies report as renewable program costs certain expenditures that are not allocated to specific projects but treated as overhead, while those same activities by independent developers must be recovered through contract prices for delivered power. Some of the information that would be required to reanalyze this comparison is proprietary, so the analysis cannot be redone by an outside party. Therefore, it isn't possible at this time to reach a conclusion about the cost-effectiveness of company-built versus independently developed projects.

26. Has Michigan, or have other jurisdictions, incentivized energy storage technologies or included energy storage in a renewable or clean energy standard? Why or why not?

In California an energy storage standard has worked in a similar way to a renewable portfolio standard, but it is treated as a separate and distinct standard. One interface of a storage standard may be the maximizing of the DC value of multiple renewable technologies that may deliver power to one storage facility and undergo one DC/AC conversion for distribution to the grid. In this way, multiple conversions through multiple inverters can be avoided both increasing delivered power to the grid and decreasing the costs of renewable generation by avoiding DC/AC inverter costs.

30. How has the current law regarding the electric market structure (i.e. electric choice) dealt with renewable energy compliance? How have other states with deregulated and regulated systems addressed compliance?

As a general matter, while the presence of retail choice in a state will generally require that certain details of the renewable portfolio standard be tailored to that fact, there is no indication that retail choice has a bearing on the feasibility of adopting a renewable portfolio standard or of achieving a renewable portfolio standard if adopted.

The table on the following page summarizes state renewable portfolio standards as of March 2013, along with compliance information and status of retail choice. State renewable portfolio standards vary in many details, so the targets here are indicative rather than strictly comparable. All data are from the Database of State Incentives for Renewables and Efficiency (www.dsireusa.org).

Note that all fifteen retail choice states also have a renewable portfolio standard, while an equal fifteen states have a renewable portfolio standard but do not allow retail choice, and another twenty states have neither. The unweighted average ultimate

standard for the retail-choice states is 22.38% while the unweighted average ultimate standard for the non-retail-choice states is 21.1%, a difference which is likely unrelated to the state's choice decision but is driven by either the natural endowments of the state or the tenure of its renewable portfolio standard. Similarly, there a few states that have fallen short of achieving their 2010 requirements for renewable generation, but some are in states with retail choice and some are in states without retail choice.

State	Renewable Portfolio Standard	2010 RPS Obligation	2012 RPS Obligation	RPS Attainment % of Obligation	Retail Choice?
Arizona	15% by 2025	2.5%	3.5%	93%	
California	33% by 2020	20%	20%	86%	
Colorado	30% by 2020	5%	12%	100%	
Connecticut	27% by 2020	14%	16%	No data	Yes
Delaware	25% by 2026	3%	4%	99%	Yes
District of Columbia	20% by 2020	5.5%	7.5%	100%	
Hawaii	40% by 2030	10%	10%	100%	
Illinois	25% by 2025	4%	6%	100%	Yes
Iowa	105 MW by 2000	105 MW	105 MW	100%	
Kansas	20% by 2020	10%	10%	Not applicable	
Maine	40% by 2017	33%	35%	100%	Yes
Maryland	20% by 2022	5.25%	8.91%	100%	Yes
Massachusetts	32.1% by 2030	11.32%	12.937%	74%	Yes
Michigan	10% by 2015	0%	4.8%	Not applicable	10%
Minnesota	25% by 2025	12.5%	15.0%	100%	
Missouri	15% by 2021	0%	2%	Not applicable	
Montana	15% by 2015	10%	10%	98%	
New Hampshire	23.8% by 2025	7.54%	9.58%	90%	Yes
New Jersey	22.5% by 2021	7.406%	7.992%+442 GWH	100%	Yes
New Mexico	20% by 2020	6%	8.2%	100%	
Nevada	25% by 2025	12%	15%	100%	
New York	29% by 2015	21.935%	24.558%	96%	Yes
North Carolina	12.5% by 2021	0.02%	3%	100%	Yes
Ohio	12.5%/25% by 2025	0.5%	1.5%	100%	
Oregon	25% by 2025	0%	5%	Not applicable	Yes
Pennsylvania	18% by 2021	6.522%	9.721%	No data	Yes
Rhode Island	16% by 2020	4.5%	6.5%	100%	Yes
Texas	5880 by 2015	4264 MW	5256 MW	100%	Yes
Washington	15% by 2020	0%	3%	Not applicable	
Wisconsin	10% by 2015	5.57%	5.57%	100%	

31. What impact has Michigan's retail market structure had on compliance with the renewable energy standard?

There has been no apparent effect on compliance. Almost all alternative energy suppliers have chosen to comply through purchases of Renewable Energy Credits rather than through project development or power purchase agreements. The major investor-owned utilities have almost completely pursued either project development or power purchase agreements to meet their renewable energy obligations. (www.michigan.gov/documents/mpsc/implementation_of_PA295_renewable_energy_411615_7.pdf)

It is therefore likely that the structure of the renewable generation market in Michigan would be different if the State had a different policy concerning retail competition. However, as illustrated in Mi-EIBC's answer to Renewable Energy Question 30, there is no evidence that Renewable Portfolio Standards are less adaptable or effective in retail choice states as opposed to states with monopoly service territories.

32. How has Michigan or other jurisdictions designed their renewable standards to adapt to unforeseen circumstances, or proposed to do so? What methods beyond legislative changes have been considered or implemented?

Most RPS laws have components such as price caps to provide consumer protection against increased rates. Most RPS laws also have provisions that allow for the PUC to waive through a hearing process the utility's requirement of meeting the standard on an annual basis due to unforeseen circumstances. It is recommended that a transparent planning and reporting process be included with any RPS law so that these provisions aren't abused by a regulatory commission that may just be ideologically opposed to renewable energy.

34. How many states with RPS standards have a) achieved the standard, b) modified the standard, or c) frozen compliance due to cost or other factors?

Data in the following table are derived from www.dsireusa.org:

State	Renewable Portfolio Standard	2010 RPS Obligation	2012 RPS Obligation	2010 RPS Attainment as % of 2010 Obligation
Arizona	15% by 2025	2.5%	3.5%	93%
California	33% by 2020	20%	20%	86%
Colorado	30% by 2020	5%	12%	100%
Connecticut	27% by 2020	14%	16%	No data
Delaware	25% by 2026	3%	4%	99%
District of Columbia	20% by 2020	5.5%	7.5%	100%
Hawaii	40% by 2030	10%	10%	100%
Illinois	25% by 2025	4%	6%	100%
Iowa	105 MW by 2000	105 MW	105 MW	100%
Kansas	20% by 2020	10%	10%	Not applicable
Maine	40% by 2017	33%	35%	100%
Maryland	20% by 2022	5.25%	8.91%	100%
Massachusetts	32.1% by 2030	11.32%	12.937%	74%
Michigan	10% by 2015	0%	4.8%	Not applicable
Minnesota	25% by 2025	12.5%	15.0%	100%
Missouri	15% by 2021	0%	2%	Not applicable
Montana	15% by 2015	10%	10%	98%
Nevada	25% by 2025	12%	15%	100%
New Jersey	22.5% by 2021	7.406%	7.992%+442 GWH	100%
New Mexico	20% by 2020	6%	8.2%	100%
New York	29% by 2015	21.935%	24.558%	96%
North Carolina	12.5% by 2021	0.02%	3%	100%
Ohio	12.5%/25% by 2025	0.5%	1.5%	100%
Oregon	25% by 2025	0%	5%	Not applicable
Pennsylvania	18% by 2021	6.522%	9.721%	No data
Rhode Island	16% by 2020	4.5%	6.5%	100%
Texas	5880 MW by 2015	4264 MW	5256 MW	100%
Washington	15% by 2020	0%	3%	Not applicable
Wisconsin	10% by 2015	5.57%	5.57%	100%

The states that currently have an RPS are listed in the table on the preceding page. Most of these 30 states (including the District of Columbia) have renewable portfolio standards that reach their current horizon in the 2020s and thus have not attained the ultimate required level of renewable energy generation. However, most states have exceeded or are close to meeting interim standards and are on pace to meet their ultimate requirement.

Following are selections from background accounts provided by public service commission staff of the respective states to the Database of State Incentives for Renewables and Efficiency (www.dsireusa.org) for those sixteen states with Renewable Portfolio Standards that have modified or increased the standards.

Arizona

Prior to the 2006 rules, Arizona's original Environmental Portfolio Standard (EPS) required regulated utilities to generate 0.4% of their power from renewables in 2002, increasing to 1.1% in 2007-2012. Solar electric power was to make up 50% of total renewables in 2001, increasing to 60% in 2004-2012. The EPS was an update of repealed 1996 ACC rules for a solar portfolio standard, which set a goal of 0.2% from solar energy by 1999 and 1% by 2003.

California

Prior to the passage of SBX1-2 in April 2011, the RPS approved by the California Legislature stopped at 20% required in 2010 and all future years. Legislation that would have expanded the RPS beyond 20% failed to become law in 2009. In the absence of legislation, California's Governor signed Executive Order S-21-09 in September 2009, which required the California Air Resources Board to adopt a renewable energy program requiring 33% renewable energy by 2020. With SBX1-2 of 2011, the legislature has codified the 33% requirement in state law, requiring the CPUC and the CEC to implement the 33% RPS. SBX1-2 imparts some powers to the Air Resources Board to enforce the requirements on publicly-owned utilities, but the CPUC will be serving as the primary rule-making authority for carrying out the RPS.

Colorado

Colorado became the first U.S. state to create a renewable portfolio standard (RPS) by ballot initiative when voters approved Amendment 37 in November 2004. The original version of Colorado's RPS required utilities serving 40,000 or more customers to generate or purchase enough renewable energy to supply 10% of their retail electric sales by 2015. In March 2007, HB 1281 increased the RPS to 20% by 2020 and

extended a separate renewable-energy requirement to electric cooperatives, among other changes. HB 1001 of 2010 further expanded the RPS to 30% by 2020.

Connecticut

Established in 1998 and subsequently revised several times, Connecticut's renewables portfolio standard (RPS) requires each electric supplier and each electric distribution company wholesale supplier to obtain at least 23% of its retail load by using renewable energy by January 1, 2020. The RPS also requires each electric supplier and each electric distribution company wholesale supplier to obtain at least 4% of its retail load by using combined heat and power (CHP) systems and energy efficiency by 2010.

Delaware

In 2005, S.B. 74 established a renewables portfolio standard (RPS) requiring retail electricity suppliers to purchase 10% of the electricity sold in the state from renewable sources by 2019-2020 (the compliance year, or CY, runs from June - May). In 2007, S.B. 19 increased the RPS target to 20%, with 2.005% required to come from solar photovoltaics (PV). In July 2010 the general renewables target was revised yet again by S.S. 1 for S.B. 119 to 25% by CY 2025-2026, with at least 3.5% from PV. The 2010 amendments did not significantly alter the existing annual renewable energy benchmarks for CY 2010 -2011 through CY 2019 -2020. The annual PV benchmarks were accelerated for CY 2011-2012 through CY 2018-2019, although the existing CY 2019-2020 requirement of 2.005% PV was only slightly modified to the current level of 2.0%. In July of 2011, S.B. 124 was passed, allowing for qualified fuel cell projects to account for 1 REC per MWh of energy produced and 6 MWh of RECs per 1MWh of SRECs, capping out at a maximum of 30% of the SREC requirements. Qualified fuel cell projects in the state now have to be capable of operating off of renewable energy rather than being required to do so

District of Columbia

In January 2005, the District of Columbia Council enacted a Renewable Portfolio Standard (RPS) that applies to all retail electricity sales in the District. In October 2008 the RPS was amended by the Clean and Affordable Energy Act (CAEA) of 2008. Significantly, this legislation increased the percentage and number of benchmarks that utilities must meet, included solar water heating as an eligible technology, increased the alternative compliance payment and amended reporting requirements. In August of 2011, the RPS was further amended by both the Emergency Distributed Generation Amendment Act (B19-0384), and the Distributed Generation Amendment Act (B19-10), which increased the solar carve out from .4% to 2.50% by 2023. Following a Congressional Review Period, The Distributed Generation Amendment Act became D.C. Law 19-36 on October 20, 2011.

Subsequent to these major changes, more minor amendments clarifying the eligibility of solar thermal facilities located within the District, and geographic eligibility of renewable resources in general were made by D.C. Law 18-0223 in 2010. These changes are not yet reflected in the associated administrative regulations although the law states that the provisions of the law apply as of October 1, 2010. Further amendments were made by D.C. Law 18-0303 in March 2011 to clarify the certification requirements for non-residential solar thermal systems

Hawaii

Hawaii established a renewable portfolio goal in 2001. Hawaii's renewable portfolio goal was replaced with an enforceable renewable portfolio standard (RPS) upon the enactment of SB 2474 (Act 95, Session Laws of Hawaii 2004) in June 2004. Under Hawaii's original renewable portfolio goal, established by Act 272 (SLH 2001), each electric utility was required to establish goals to increase net renewable energy sales to 9% by December 31, 2010. The 2004 standard raised this target and required that 20% of electricity be generated from renewable resources by the end of 2020. Additional modifications were made to Hawaii's RPS law in June 2006 by SB 3185 (Act 162, SLH 2006). The 2006 amendments allowed electrical energy savings generated by renewables including solar water heating and seawater air-conditioning district cooling systems, among others, to count towards the RPS. The 2006 amendments also allowed electrical energy savings generated by certain energy efficiency technologies to count towards the RPS. In January 2008, the U.S. Department of Energy (DOE) and the State of Hawaii signed a Memorandum of Understanding (MOU) establishing the Hawaii Clean Energy Initiative. This agreement established an aggressive goal to help Hawaii greatly increase its renewable and clean energy production capabilities, and to transition exclusively to renewable energy use on the smaller islands. Although the MOU is not legally binding, it has the potential to help reduce oil consumption in Hawaii by 72% if implementation is successful. The expansion of Hawaii's RPS in 2009 formalized many of the goals established by the Hawaii Clean Energy Initiative in 2008. Hawaii's renewable portfolio standard was significantly expanded by legislation passed in 2009. HB 1464, signed by the governor in June 2009, increased the amount of renewable electrical energy generation required by utilities to 40% by 2030

Maine

Maine's original Renewable Resource Portfolio Requirement was passed as part of the state's 1997 electric-utility restructuring law. In 1999, Maine's Public Utility Commission (PUC) adopted rules requiring each electricity provider to supply at least 30% of their total electric sales using electricity generated by eligible renewable and certain energy efficiency resources. Actually, at the time of passage, the required percentage of renewables was actually lower than the existing percentage supplied.

Eligible facilities include those up to 100 megawatts (MW) in capacity that use fuel cells, tidal, solar, wind, geothermal, hydro, biomass or municipal solid waste in conjunction with recycling. Electricity generated by efficient combined heat and power (CHP) facilities and other systems that qualify as "small power production facilities" under the federal Public Utility Regulatory Policies Act of 1978 (PURPA) also are eligible.

Since 1999, the renewables portfolio standard (RPS) has been amended several times and two separate classes designated. Class II includes existing renewables, which are eligible to meet the 30% requirement described above. Class I is composed of new renewables that have come on-line after September 1, 2005. Unlike Class II, municipal solid waste facilities and CHP facilities are not eligible for Class I and there are more stringent hydropower qualifying requirements. In addition, new wind installations may exceed 100 MW

Maryland

Maryland's RPS was originally enacted in 2004, but has been revised on numerous occasions since that time. The 2004 enactment established a standard of 7.5% Tier 1 renewables by 2019 and 2.5% Tier 2 renewables by 2018 (sunsetting in 2019). Legislation enacted in April 2007 (S.B. 595) added a provision requiring electricity suppliers to derive 2% of electricity sales from solar energy in addition to the 7.5% renewables derived from other Tier 1 resources as outlined in the initial RPS law. The solar set-aside began at 0.005% of retail sales in 2008 and increases incrementally each year to reach 2% by 2020. The set-aside is projected to result in the development of more than 1,250 MW of solar capacity by 2020. In April 2008 H.B. 375 more than doubled the overall Tier 1 requirement and accelerated the compliance schedule. The Tier 2 and solar requirements were left unchanged at this time, but in May 2010 S.B. 277 accelerated the solar compliance schedule and increased solar alternative compliance payment levels for 2011 through 2016. Finally, Maryland enacted S.B. 717 allowing solar water heating systems commissioned on or after June 1, 2011 to qualify as eligible resources for the solar carve-out, effective January 1, 2012. In order to qualify for the standard solar water heating systems must: be commissioned on or after June 1, 2011; not be used solely to heat a pool or a hot tub; and use SRCC OG-100 certified equipment.

Also in May 2011, Maryland enacted S.B. 690 reclassifying waste-to-energy facilities connected to the Maryland distribution grid as Tier 1 resources. Formerly, all waste-to-energy facilities were considered Tier 2 facilities. The legislation also classifies facilities connected to the Maryland distribution grid that use refuse-derived fuel (formerly not specifically addressed) as Tier 1 resources, effective October 1, 2011.In May 2012 Maryland enacted a suite of bills affecting the RPS. The most significant bill, S.B. 791/H.B. 1187, accelerates the solar carve-out compliance requirements by varying

degrees beginning in 2013; pushes up the date for the ultimate 2% target from 2022 to 2020; and allows solar water heating energy production measurements for some systems to be estimated under a certification system other than SRCC OG-300 (subject to Public Service Commission approval). The changes also have the effect of reducing the minimum Tier I resource requirements from 2013 - 2021.

Apart from solar-related changes, in 2012 Maryland also enacted S.B. 652/H.B. 1186 allowing geothermal heating and cooling systems commissioned on or after January 1, 2013 that meet certain standards to qualify as a Tier I resource. Finally, in May 2012 the legislature also enacted S.B. 1004/H.B. 1339 allowing thermal energy associated with biomass systems that primarily use animal waste (possibly supplemented by other biomass resources) to qualify as Tier I resources, effective January 1, 2013.

Massachusetts

Massachusetts' 1997 electric-utility restructuring legislation created the framework for a renewable portfolio standard (RPS). In April 2002, the Massachusetts Department of Energy Resources (DOER) adopted RPS regulations that required all retail electricity providers in the state to utilize new renewable-energy sources for at least 1% of their power supply in 2003, increasing to 4% by 2009. The RPS was significantly expanded by legislation enacted in July 2008 (Green Communities Act S.B. 2768); this legislation established two separate renewable standards -- a standard for “Class I” renewables, and a standard for “Class II” renewables -- as well as an alternative portfolio standard.

Minnesota

Minnesota enacted legislation (S.F. 4) in 2007 that created a renewable portfolio standard (RPS) for Xcel Energy, created a separate RPS for other electric utilities,* and modified the state's existing non-mandated renewable-energy objective. The definition of eligible biomass was refined slightly in 2008 by S.F. 2996 to include the organic components of wastewater effluent and sludge from public treatment plants, with the exception of waste sludge incineration. After January 1, 2010, hydrogen must be generated by other eligible renewables in order to be eligible. In May 2011, the legislature passed S.F. 1197, which requires utilities to submit a report to the commission and legislative committees estimating the rate impact of the activities necessary for compliance. The first report was due in October 2011, and subsequent reports are included as part of the utilities' resource plans.

Nevada

Nevada established a renewable portfolio standard (RPS) as part of its 1997 restructuring legislation. Under the standard, NV Energy (formerly Nevada Power and Sierra Pacific Power) must use eligible renewable energy resources to supply a

minimum percentage of the total electricity it sells. In 2001, the state increased the minimum requirement by 2% every two years, culminating in a 15% requirement by 2013. The portfolio requirement has been subsequently revised, most significantly by SB 358 of 2009, which increased the requirement to 25% by 2025. The 2009 amendments also raised the solar carve-out, requiring utilities to meet 6% of their portfolio requirement through solar energy beginning in calendar year 2016. The solar carve-out remains at 5% through the end of calendar year 2015.

AB 3 of 2005 allowed efficiency measures to be used to satisfy a portion of the requirement. To qualify as portfolio energy credits, efficiency measures must be: (1) implemented after January 1, 2005; (2) sited or implemented at a retail customer's location; and (3) partially or fully subsidized by the electric utility. The measure must also reduce the customer's energy demand (as opposed to shifting demand to off-peak hours). The contribution from energy efficiency measures to meet the portfolio standard is capped at one-quarter of the total standard in any particular year. AB1 of 2007 expanded the definition of efficiency resources to include district heating systems powered by geothermal hot water.

New Jersey

New Jersey's RPS was originally adopted in 1999 as part of the state's electricity restructuring legislation with initial renewables targets of 4.0% Class I and 2.5% Class I or Class II resources by 2012. In 2004 the BPU amended the standard to require the renewable energy targets be met by May 2008, and to add a requirement that at least 0.16% of sales come from solar electricity as part of the overall Class I target of 4.0%.

The New Jersey Board of Public Utilities (BPU) made even more extensive revisions to the RPS in April 2006, significantly increasing the required percentages of Class I, Class II, and solar resources towards an ultimate requirement of 22.5% renewables, including 2.12% solar, by May 2021. In December 2007 the BPU issued a far-reaching order (BPU Solar Transition Order) directing that further changes be made to many of the details of the RPS in an effort to increase the effectiveness and efficiency of New Jersey's solar energy policies. Formal rule amendments associated with many of these changes became effective in 2009, although the broader renewable energy targets were not affected. During 2010 the solar carve-out was redesigned and expanded and the offshore wind requirement was also added. In July 2012 New Jersey enacted S.B. 1925 substantially revising its solar carve-out.

New Mexico

In December 2002, the PRC unanimously approved a renewables portfolio standard (RPS) requiring investor-owned utilities to derive 5% of annual retail sales to New Mexico customers from renewable energy sources by 2006, rising to 10% by 2011. In

March of 2004, Senate Bill 43 codified the PRC rules and established additional requirements. New Mexico subsequently doubled its RPS for investor-owned utilities and created a separate standard for rural electric cooperatives in March 2007 (Senate Bill 418). The New Mexico Public Regulation Commission (PRC) passed an order in December 2012, making some significant changes to the state's Renewables Portfolio Standard. Notably, the order increased the carve-out for wind from 20% to 30% of the overall standard. It also increased the reasonable cost threshold for investor-owned utilities such that 3% of their total annual revenue must be spent procuring renewable energy. Cooperative utilities will also have to comply with a 5% reasonable cost threshold beginning in 2015.

Texas

In 1999 the Public Utility Commission of Texas (PUCT) adopted rules for the state's Renewable Energy Mandate, establishing a renewable portfolio standard (RPS), a renewable-energy credit (REC) trading program, and renewable-energy purchase requirements for competitive retailers in Texas. The 1999 standard called for 2,000 megawatts (MW) of new renewables to be installed in Texas by 2009, in addition to the 880 MW of existing renewables generation at the time. In August 2005, S.B. 20 increased the renewable-energy mandate to 5,880 MW by 2015 (about 5% of the state's electricity demand), including a target of 500 MW of renewable-energy capacity from resources other than wind. Wind accounts for nearly all of the current renewable-energy generation in Texas. The 2005 legislation also set a target of reaching 10,000 MW of renewable energy capacity by 2025.

In 2007 H.B. 1090 clarified that RECs retired for other purposes (e.g. sold through a voluntary green power program) could not be counted toward the RPS requirements. The law also permits large utility customers served by transmission voltage to opt out of the RPS requirements. Finally, H.B. 1090 empowers the PUCT to establish alternative compliance payments (ACP) for the RPS and for the non-wind target. To date, the PUCT has declined to set an ACP for either portion, although as noted above, an administrative penalty exists for providers that do not meet the general renewable energy obligation.

Wisconsin

In 1998 Wisconsin enacted Act 204, requiring regulated utilities in eastern Wisconsin to install to an aggregate total of 50 MW of new renewable-based electric capacity by December 31, 2000. In October 1999 Wisconsin enacted Act 9, becoming the first state to enact a renewable portfolio standard (RPS) without having restructured its electric-utility industry. Wisconsin's RPS originally required investor-owned utilities and electric cooperatives to obtain at least 2.2% of the electricity sold to customers from renewable-

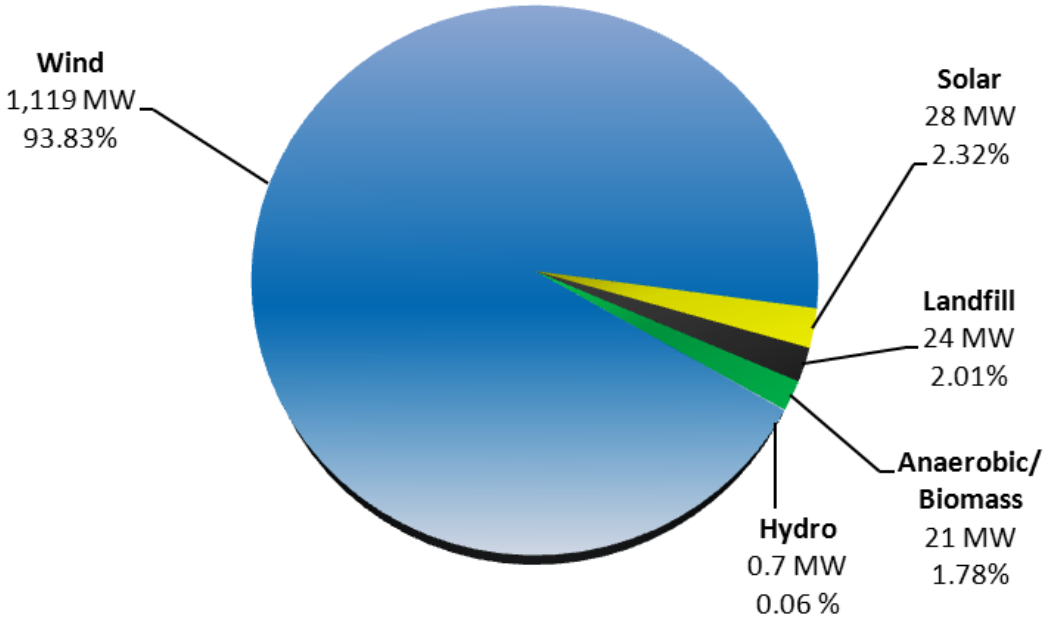
energy resources by 2012. Legislation enacted in March 2006 increased renewable energy requirements and established an overall statewide renewable energy goal of 10% by December 31, 2015.

36. To what extent is distributed generation supplying the energy needs of Michigan customers?

Based on the data available, distributed generation currently supplies approximately two-tenths of 1% of the electricity needs of Michigan consumers. Even this figure likely overstates the contribution of distributed energy, as it also includes all new solar generation, anaerobic digestion, landfill gas, and refurbished small hydropower facilities.

The Michigan Public Service Commission is required to report annually to the legislature on the implementation of Michigan's Renewable Portfolio Standard. This report provides official and definitive information that can be relied upon through its coverage period. The most recent report, presented in February 2013, includes Commission activity through 2012 as well as electricity provider renewable energy report information through calendar 2011. This report can be found at www.michigan.gov/documents/mpsc/implementation_of_PA295_renewable_energy_411615_7.pdf.

Figure 5 of this report summarizes the contracts and projects approved by the Commission, as follows:



This figure indicates that distributed generation technologies constitute 6.17% of the new renewable electricity generation capacity developed as a result of Michigan's Renewable Portfolio Standard, with a small amount of refurbished hydropower and the remainder roughly equally divided between landfill gas, anaerobic digestion, and solar. It is important to note that this figure includes some capacity, especially solar, that has been authorized by the Commission but will not be placed into commercial operation until 2013 or 2014. Even including the amount authorized but not yet built, generation from landfill gas, anaerobic digestion, refurbished hydro and solar amounts to approximately 72 MW of total distributed generation – or approximately 0.2% of the total 30,000 MW of total net summer generation capacity in Michigan.

Solar generation has been developed through two policies adopted by the State of Michigan in 2008 – the Renewable Portfolio Standard, and Net Metering. The Figure above does not include net metering systems. All electricity providers are required to meet the Renewable Portfolio Standard, but not all are required to include solar in their portfolio. All regulated utilities, Alternative Energy Suppliers, and Cooperative utilities are required to follow Net Metering policies and some municipal utilities have also chosen to allow net metering. Net metering is not limited to solar, but solar has been the dominant technology chosen by net metering customers with only a few choosing small-scale wind turbines. Net metering customers are widely distributed throughout the state but with a significant concentration in DTE's southeast Michigan territory.

Solar deployment associated with utility compliance with the Renewable Portfolio Standard has been modest compared to other technologies. Both programs are summarized through 2011 in a report of the Michigan Public Service Commission available at www.michigan.gov/documents/mpsc/NetMeteringReport_Aug2012_396259_7.pdf. Table 1 of that reports is duplicated below:

Table 1: Michigan Solar PV Totals (Estimate through 2011)

Program	Number of Installations	Total Participating Solar Capacity kW
Solar Net Metering (includes Detroit Edison SolarCurrents customer-owned projects)	784	5,193
Experimental Advanced Renewable Program (EARP) Consumers Energy	102	2,020
SolarCurrents (Detroit Edison-owned projects)	8	2,793
Total	894	10,006 kW
Net metering data is based on 2011 electric provider annual reports filed with the MPSC. Consumers Energy EARP and Detroit Edison SolarCurrents (both customer and company owned) data estimates were provided by the companies.		

Since the issuance of this report, Consumers Energy has been executing an additional tranche of solar contracts with its customers, under its Experimental Advanced Renewable Program, which provides a “feed-in tariff” for solar generation at a fixed tariff for a fixed period. Consumers Energy expects to support deployment of a total of 3,250 kW solar capacity in this tranche of their program. DTE has completed a total of 5,000 kW of customer-owned solar systems under their original Solar Currents program, which included about 500 kW that were not included in the Michigan Public Service Commission report referenced above. DTE’s agreed to an additional 2,000 kW of customer-owned solar systems as well as completion of a total of 15,000 kW of company-owned solar systems on customer premises.

Distributed generation in Michigan reflects varying levels of uptake of the technical potential as estimated by the National Renewable Energy Laboratory http://www.nrel.gov/docs/fy12osti/51946.pdf. Landfill gas already deployed is about two-thirds of the potential. Hydropower is about 60% of the potential (and this ignores river use and environmental conflicts). Solar deployed is less than one-thousandth of the rooftop potential and less than one in one-hundred-thousandth of total solar potential.

39. Over what lifecycle are renewable energy projects in Michigan economically evaluated?

Within utility programs, renewable energy projects are either developed by independent power-producers and the power is sold to the utility under a power purchase agreement, or the project is developed by the utility or purchased from an independent developer and the project then becomes part of the utility’s ratebase.

Power purchase agreement contract lengths are generally less than the expected useful life of the project assets, reflecting greater risks of changes in economic conditions, technology, or of increasing project maintenance expenses with increasing age. Contract duration for wind or landfill gas generation is almost universally for 20 years. Contract duration for solar is usually for 12 years. Contract duration for anaerobic digestion and for hydropower is usually for 7 years, though occasionally contracts are longer, up to 20 years. The independent power producers participating in these contracts may or may not have assumed residual value in the project at the end of the contract.

Projects owned by the utility company are depreciated over a period somewhat shorter than the expected useful life of the project, so to avoid an unpaid regulatory asset that doesn’t produce power. Depreciation rates for wind farms and solar systems are currently a matter of dispute before the Public Service Commission with a range of positions by the parties in which the shortest amortization period proposed is longer

than the typical contract lengths cited above and the longest amortization period proposed is approximately 50% longer than the typical contract periods cited above.

Within the assets that make up a wind farm or a solar system, different elements have different expected useful lives; for example, the civil works, concrete base, and tower of a wind turbine is expected to be useful for 50 years while the blades, nacelle, and generation equipment likely have useful life of about 25 years. In normal course, such turbines would be retrofitted with new equipment on the old towers and used for a second generation of investments. In this case, the levelized cost of energy from the wind turbine would be calculated over a 25 year period. This is similar to utility practices with respect to steam electric plants fueled with coal or natural gas.