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Readying Michigan to Make Good Energy Decisions: Electric Choice

November 20, 2013

Presented by

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Preface

The initial draft of the Electric Choice Report was released for comment on October 15, 2013. Comments on the draft report were accepted through November 1, 2013. A total of 17 comments and multiple attached documents commenting on or providing feedback to the draft report were received prior to the deadline. All of the comments were reviewed and considered in preparation of this final draft. Based upon the comments received, several revisions have been made throughout the report. Significant revisions that have been made are described below, and many of the other comments are addressed throughout the body of this report.

Several comments were received regarding choice participation, customer savings and the impact of the choice cap change on the financial stability of utilities. Some of these comments have been summarized in the Choice Participation section, or Section II of this report.

Comments were received regarding rate levels in deregulated versus regulated states, rate volatility and pricing stability. Various comments have been summarized in the Rates section, or Section VI, of this report. In addition, Figure 16 showing cumulative price changes of all rate classes from 1997-2013, and Figure 22 showing long-term price stability data have been summarized in this section.

Additionally, a number of comments were submitted regarding reliability and have been summarized throughout this report.

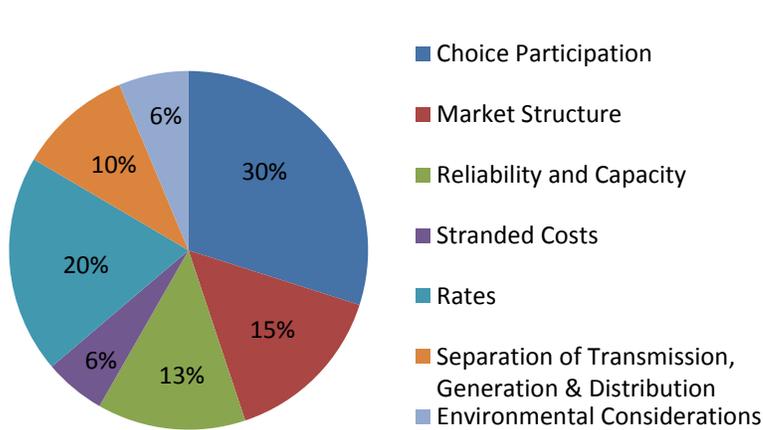
Many other less significant revisions concerning market structure, stranded costs, possible policy outcomes, etc. have been incorporated throughout the body of this report.

Readying Michigan to Make Good Energy Decisions – Electric Choice

Executive Summary

The 26 electric choice questions posted on the Ensuring Michigan’s Energy Future website garnered 114 responses. The comment summary pie chart presents an overview of comments received at the website.

**Please note, the number of responses used for the pie chart is slightly higher than 114 as some of the responses related to more than one section.*



Where Michigan Is

Today: PA 286 of 2008 provides that “no more than 10% of an electric utility’s average weather-adjusted retail sales for the preceding calendar year may take service from an alternative electric supplier at any time.” There is a single exception in the law that

allows an iron ore mining or processing facility to elect an alternative supplier of electricity. As a result of legislation (PA 141 of 2000 and PA 286 of 2008), Michigan currently exhibits characteristics of both a regulated and deregulated market and is commonly referred to as a hybrid structure. Transmission and distribution of electricity is not normally impacted by a customer’s choice of electric supplier; what the current Michigan system does is allow a minority of customers to select an alternative generation supplier.

Choice Participation

- From 2001 to 2008 choice participation was not limited (often referred to as a “full customer choice” system) as provided by 2000 PA 141 (PA 141). During this time, the level of choice participation ranged from three percent to 20 percent of utility load.
- Presently, five utilities experience active choice participation. With the exception of one of these five utilities, all are at the 10 percent choice participation cap implemented with 2008 PA 286 (PA 286).
- Although most states throughout the country operate under full regulation, the utilities cite a historically high level of customer choice participation at 12 percent of U.S customers and 22 percent of electric load, attributed to recent low wholesale power market prices. Additionally, they report that an increase in the choice cap would reduce the financial stability of utilities and therefore investors’ willingness to make long-term investments, including investments in new generation.

- Energy Choice Now comments that the actual record of utility financial solidity in restructured, competitive states stands in stark contrast to the Joint Utilities Response of allegations of financial challenges.

Upper Peninsula Developments

- Choice development in the Upper Peninsula was slow to develop, but has recently ramped up. The current choice law, (MCL 460.10a(1)(d)), provides that any customer operating an iron ore mining facility, iron ore processing facility, or both, located in the Upper Peninsula of this state shall be permitted to purchase all or any portion of its electricity from an alternative electric supplier, regardless of whether the sales exceed 10% of the serving electric utility's average weather-adjusted retail sales.
- As a result of a combination of customers including the iron ore mines selecting an alternative supplier in the summer of 2013, WEPCo immediately lost approximately 85% of its Michigan load.
- WEPCo recently requested to suspend operations at the Presque Isle Power Plant in Marquette in 2014. MISO analyzed the removal of the plant from the electric grid and reports that the plant must continue operating to maintain reliability of the power system on Michigan's Upper Peninsula. MISO and stakeholders will consider alternatives to the plant, and WEPCo is currently in discussions with MISO regarding compensation to keep the plant operating.

Market Structure

- Regardless of whether electric generation is regulated or deregulated, regulation continues for transmission and distribution services. For instance, transmission and distribution services remain monopolies, and the public risk involved in having a limited number of electricity providers typically leads states to continue to require oversight of the utility sector. For instance, PA 141 requires all alternative electric suppliers (AES) to be licensed by the Michigan Public Service Commission (MPSC).
- Broadly speaking, there is agreement that while there are a number of market forces that could impact the current market dynamic toward selection of incumbent or alternative energy providers (such as EPA regulations, renewables, shale gas production and high prices), regulatory policy is one of the main factors that could change the market dynamic for choice.
- In order to ensure that no one is "cut off" from service due to the inability to find a company that will take them as a customer, all states have a way of effectively forcing companies to serve. In regulated states or in Michigan's hybrid system, that role is served by the monopoly (or in Michigan's case, the incumbent) utilities. In states with fully deregulated generation, they have statutes requiring a provider of last resort, or a default supplier, or both. These alternatives vary in their operation.

- Similarly, all states have continued programs to assist low-income customers in some fashion. The utilities report that issues related to uncollectibles and low-income customers are present under both regulated and deregulated structures with additional challenges in serving low-income customers in a deregulated market. Some commenters suggest a purchase of receivables program in addressing uncollectibles and state that low-income customers should have equal opportunity to experience savings through a restructured electricity market.
- General comments suggest taking a look into markets where introducing competition has been successful.

Rates

- The utilities report that even in today's low natural gas price environment, electric rates are 30% higher on average in deregulated states than in regulated states. Because most of those states were higher-cost prior to selecting a deregulated structure, however, causation should not be inferred.
- Historically, Michigan's rates are usually at the national average or above it. The only time in recent history that Michigan's rates have been noticeably below the national average occurred from 2000-2008; that approximately matches the time Michigan's statute provided for 100% choice. However, for five years (2000-2005), there was a legislatively-mandated rate cap, and in the remaining years of that time (2005-2009), the rates rose sharply every year, a trend that continued after the 2008 energy package was passed that created the current system.
- Some commenters suggest that market mechanisms are the most efficient at addressing change in prices and that market systems, such as wholesale auctions, can help mitigate rate volatility. Other commenters suggest that a deregulated market results in increased price volatility. Because of the large number of factors that can affect utility rates and markets, and the limited universe of "experiments" (i.e. states), it is difficult to determine a causal relationship.
- The utilities report that a survey of residential and small-business customers in Michigan and other states indicate that they place the most value on price stability and predictability. Severstal North America (Severstal) points out that large industrial customers place a higher value on lower power costs.
- Additionally, the utilities report that the free option to switch to choice costs remaining utility customers approximately \$300 million per year. Other commenters report that it's impossible to comprehend the full extent to which a customer in Michigan has been economically burdened because of the 10 percent cap due to the fact that there are very few policies to ensure pricing visibility in Michigan, and that Michigan electric bills have become unduly complex.
- Some commenters report that fully competitive retail markets create lower electric bills that decrease the cost of doing business and cost of living, which eventually attracts new

businesses to Michigan, while the utilities report that new long-term supply investments will bring new jobs and expand the tax base in Michigan.

Reliability and Capacity

- As described in the “additional areas” report, sufficient generation is necessary to assure system reliability (keep the lights on for everyone).
- Some commenters argue that reliability is not negatively impacted by electric choice and electric choice suppliers may be better suited to respond to ever changing market conditions. Other commenters argue that regulated systems are more reliable because regulation is more conducive to new generation investment.
- MISO and utilities are jointly responsible for maintaining electric reliability and do this by establishing, following, and enforcing rules and procedures. Each utility and electric choice supplier must make a showing to MISO each year that it has sufficient supply to meet the peak demand for the upcoming year in order to comply with MISO’s tariff.

Stranded Costs

- In general, “stranded cost” refers to the decline in the value of an asset as a result of a change, such as a regulatory change or a market change. When there are fewer customers or no customers “guaranteed” to an incumbent utility, they may have stranded costs due to a now-“oversized” system that they were required to maintain.
- A change in electric choice policy may or may not result in stranded costs. Stranded cost considerations become greater as Michigan moves towards full deregulation and lessen as Michigan maintains current policy or moves toward full regulation.
- All states that transitioned from a regulated to a deregulated structure have varying methods used to estimate and recover stranded costs. The issues have proven to be highly contentious and have been aggressively litigated.
- In Michigan, stranded cost and securitization surcharges are assessed to full service and choice customers. Some commenters report that these costs have been substantial for choice customers representing up to 10% of a large choice customer’s total electric bill.
- These same commenters report that utility recovery of stranded costs has allowed utilities to compete in the electric market and therefore there is no need for a cap on choice participation, and also state that shifting ratepayer risk related to new generation to competitive suppliers would support the financial stability of utilities. The utilities report that the remaining customers are facing a much higher cost due to the 10% choice option (\$300M).

Separation of Transmission, Generation and Distribution

- For the most part, the electric industry remains fully integrated and regulated. Even deregulated states only required or encouraged the utility to divest or separate their

generation assets (leaving the regulated transmission and distribution assets with the utility).

- Michigan’s structure is unique in that distribution assets are owned by utilities and fully regulated by the MPSC. Transmission assets are owned by stand-alone companies (for example, ITC, METC and ATC). Generation assets are a mix of utility and independently owned facilities, with the latter being less common.
- The utilities report that once generation is divested it is extremely difficult to re-create a fully regulated, integrated model.
- An MPSC report found that “the implementation of structural separation of generation and distribution would lead to higher customer costs.” The MPSC further stated that it “did not receive any evidence that further separation of generation and distribution is necessary or desirable.”
- Some commenters report that separation of transmission and distribution in Michigan has had little impact and that the greatest impact would be to separate generation assets from the distribution business. Additionally, they report that through a properly administered transition, the regulated function of Michigan’s utilities can remain financially stable while the generation function transitions to market with a fair opportunity to compete with other providers of generation services.
- ITC Holdings reports that structural separation has improved overall transmission reliability, transmission efficiency, service restoration and regulatory compliance. The separation has made transmission planning independent from both local and regional perspectives and not influenced by market participants.
- COMPETE Coalition states that while complete divestiture of assets provides the preferred and cleanest separation of wires and supply, it is not required for a successful retail choice program.

Environmental Considerations

- Some commenters report that while there are a vast number of future events that could affect affordability, reliability, and environmental protection, a fully competitive market is the best system to effectively and efficiently handle the myriad of potential catalysts.
- The utilities report that the 10% cap reduced the uncertainty of unlimited switching and supports Michigan utility investment in reliable, clean energy for the future that includes the benefit of environmental protection.

Section I – Objective and Background

Objective

The Governor delivered an Energy and Environment address in November 2012. As a result of this address, the Michigan Public Service Commission (MPSC or Commission) and the Michigan Energy Office gathered public input on Michigan’s energy future. To help guide the participation process, a series of questions were created that ask for specific information related to Electric Choice.¹

This report provides a summary of the public comments submitted in response to the Electric Choice questions. This report provides reference to a particular position or response in a paragraph by paragraph format. Sections 1-8 of this report are summary based and, to the extent possible, reflect the verbiage as submitted by the commenter. Section 9 of this report is not summary based and uses verbiage designed in a manner that is best suited for policy making discussion. The definitions throughout this report are intended to promote universal understanding and does not supersede or modify definitions used in statute, administrative rules, Commission orders, tariff provisions or contracts. This report is based on the public input and does not attempt to recommend or advocate for any particular energy policy.

Background

A typical electric system consists of three main components that include generation, transmission and distribution. Electric Customer Choice (Customer Choice or Choice) in Michigan applies only to the generation component of the electric system. The regulation of transmission and distribution of electricity is not impacted by a customer’s choice of electric supplier.

From 1992 to 1999, there were a number of MPSC orders on electric restructuring. In 1995, Governor John Engler sent to the Commission a whitepaper outlining the broad parameters of a customer choice program. Thereafter, the Commission conducted public hearings and directed the state’s utilities to implement such a program. The Michigan Supreme Court later ruled that the Commission lacked jurisdiction to mandate a program. The focus then shifted to the Legislature.

On June 5, 2000 Governor Engler signed bills related to Michigan’s electric restructuring legislation which consisted of two laws, 2000 Public Act 141 (PA 141) and Public Act 142 (PA 142).² PA 142 allowed utilities to securitize or refinance high cost utility plants. PA 141, MCL 460.10 et seq. known as the Customer Choice and Electric Reliability Act, ensured that all retail

¹ <http://www.michigan.gov/energy>

² The legislation also mandated a five percent rate reduction and a temporary rate cap (freeze) that expired in 2005.

customers had a choice of electric suppliers and required an alternative electric supplier (AES)³ to obtain a license from the MPSC.⁴ Customer Choice allows a customer to choose between a regulated utility rate or an unregulated rate offered by an AES also known as retail open access (ROA). As a result, Michigan exhibits characteristics of both a regulated market⁵ and a deregulated market⁶ and is commonly referred to as a hybrid structure. In addition, PA 141 addressed stranded costs by directing the MPSC to consider the reasonableness and appropriateness of various methods to determine net stranded costs. Stranded costs are presented in greater detail in a different section within this report.

On October 6, 2008, Public Act 286 (PA 286) was enacted and amended PA 141. Section 10a(1)(a) of PA 286 provides that “no more than 10% of an electric utility's average weather-adjusted retail sales for the preceding calendar year may take service from an alternative electric supplier at any time.”⁷ This provision of the law is commonly referred to as “the cap,” or “the 10 percent cap” or “the choice cap.”

Michigan is one of the few states that have two different Independent System Operators. An Independent System Operator (ISO) or Regional Transmission Organization (RTO) coordinates regional transmission in a non-discriminatory manner and ensure the safety and reliability of the electric system while maintaining independence from all generation and power marketing interests. The Michigan jurisdiction is primarily situated within the Midcontinent ISO (MISO) with a small portion of southwest Michigan situated within PJM. **Figure 1** is a map of the MISO and PJM service areas.

³ An Alternative Electric Supplier or AES is a person selling electric generation service to retail customers in this state. Also known as a supplier, or a competitive supplier.

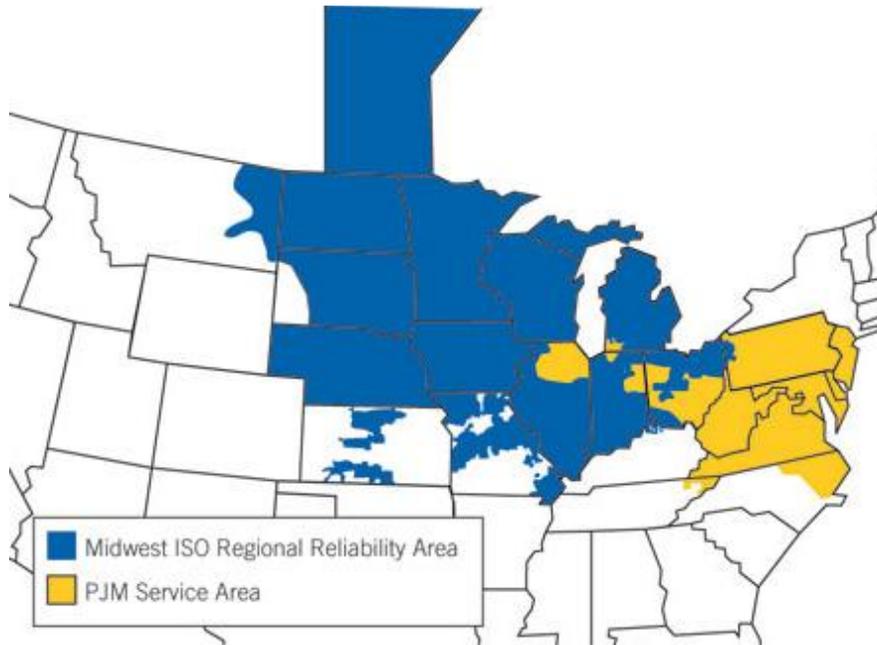
⁴ MCL 460.10x and MCL 460.10y outline different requirements for implementation of customer choice for cooperatively owned and municipal electric utilities. MCL 460.10x allows any retail customer of a rural electric cooperative with a peak of one megawatt or above to select an alternative electric supplier. MCL 460.10y provides that the governing body of a municipally owned utility determines whether it will permit choice programs in its service territory.

⁵ Regulated market is a market where generation, transmission and distribution services and pricing are fully governed by a regulatory body.

⁶ Deregulated market is a market where generation, transmission and/or distribution services and pricing are not fully governed by a regulatory body.

⁷ Any customer operating an iron ore mining facility, iron ore processing facility, or both, located in the Upper Peninsula of this state, is permitted to purchase all or any portion of its electricity from an AES, regardless of whether the sales exceed 10% of the serving electric utility's average weather-adjusted retail sales.

Figure 1: MISO and PJM Service Areas



Section II – Choice Participation

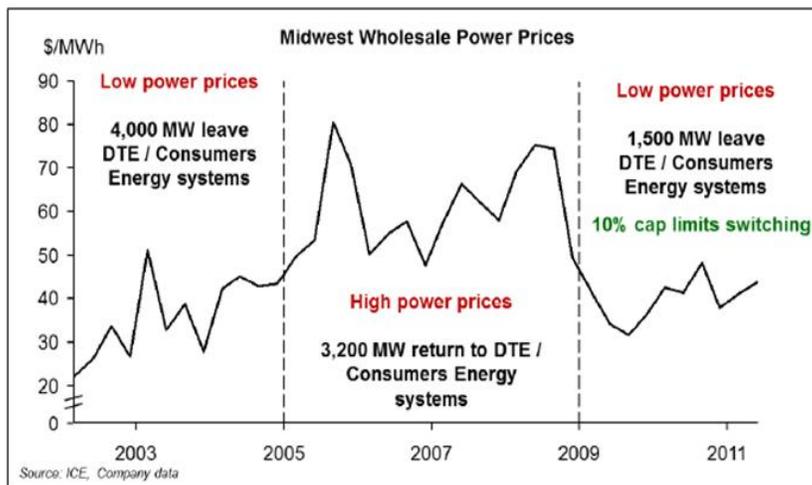
(Questions 1, 2, 3, 4, 6, 16 & 25)

This section presents information related to customer participation and the experience with customer choice, including customer savings, in Michigan and other states. This section will also present the impact of a change in the choice cap on the financial stability of utilities and investors' ability to make investment in new generation.

Choice Participation in Michigan

From 2001 to 2008 (PA 141 through PA 286), the level of choice participation ranged from 3 percent to 20 percent of utility load. This period of time did not have a limit, or cap, on the amount of choice participation. Choice participation typically moves in inverse proportion to wholesale energy prices and did so during this period. When wholesale energy prices were decreasing, choice participation was increasing. When wholesale prices were increasing, choice participation was decreasing. The Joint Utility Response table below, **Figure 2**, illustrates this relationship.

Figure 2: Midwest Wholesale Power Prices



In October 2008, PA 286 was enacted and amended PA 141. Section 10a(1)(a) of Act 286 provides that “no more than 10% of an electric utility's average weather-adjusted retail sales for the preceding calendar year may take service from an alternative electric supplier at any time.”⁸ As a result of Act 286, the Commission initiated [Case No. U-15801](#) to establish the provisions for allocating load as specified in PA 286.

⁸ Any customer operating an iron ore mining facility, iron ore processing facility, or both, located in the Upper Peninsula of this state, is permitted to purchase all or any portion of its electricity from an AES, regardless of whether the sales exceed 10% of the serving electric utility's average weather-adjusted retail sales.

Michigan is one of 16 states (including Washington D.C.) that currently have full or limited active restructuring.⁹ At present, five utilities experience active choice participation.¹⁰ As seen in **Figure 3** below, Consumers Energy (Consumers), DTE Electric (DTE), UPPCo and WEPCo are fully subscribed at the cap while WPSC is just below the cap. I&M was also fully subscribed at the 10 percent cap during 2012 but is no longer serving any choice load. Hypothetically, if the cap did not exist, choice participation would be approximately 25 percent for Consumers and 22 percent for DTE.

Figure 3: Michigan Electric Choice Participation Percentages by Utility¹¹

	Consumers	DTE Electric	I&M	UPPCO	WEPCo	WPSC
2012 Sales	37,298,206 MWh	46,830,494 MWh	2,835,839 MWh	847,567 MWh	2,549,536 MWh	286,303 MWh
Participation Level (Active & Awarded)	4,014,792 MWh	5,163,637 MWh	0	84,686 MWh	2,173,619 MWh	21,537 MWh
Participation % (Active & Awarded)	10.76%	11.03%	0%	9.99%	85.26%	7.52%
Current In-Service Customers*	1,069	5,521	0	38	51	13
Customers in Queue	6,082	5,261	0	13	2	0
Load in Queue	5,346,015 MWh	5,180,213 MWh	0	3,734 MWh	1,350 MWh	0
Participation % w/o Cap	25.10%	22.09%	N/A	10.43%	85.31%	N/A

*Current In-Service Customer numbers are as of October 31, 2013

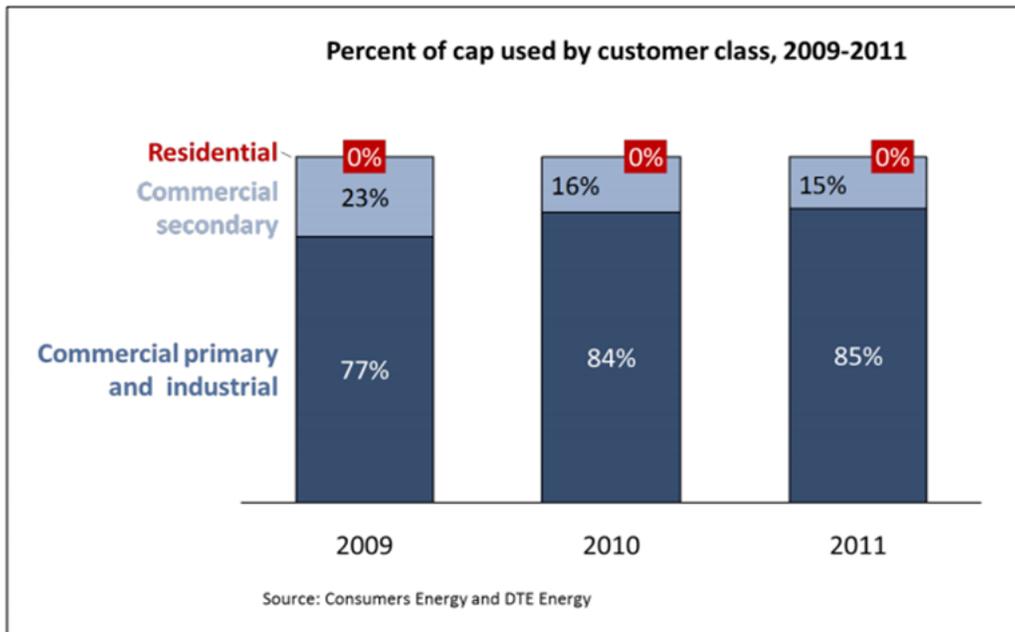
As shown in **Figure 4** below, choice participation consists primarily of commercial and industrial customers. Typical choice participants are large industrial manufacturers and mid-size commercial customers including retailers, restaurants, healthcare facilities, school systems and other service providers. The number of residential customers participating in choice is negligible, though residential customers are in queue for both Consumers and DTE.

⁹ Conflicting comments were submitted in regards to the number of states that are considered to be restructured or deregulated, ranging from 14 to 20 based on certain interpretive factors such as market structures (hybrid vs. fully restructured). The reference to 16 states is based on EIA reported data (Michigan is considered one of 16 because it allows each utility to have 10% load participation with an AES).

¹⁰ At present, there are 26 licensed AESs with 12 of those actively serving choice customers. The number of licensed AESs peaked at 28 in 2004 and the number of active AESs peaked at 19 in 2003.

¹¹ Data in Figure 3 is as of November 15, 2013.

Figure 4: Percent of Cap Used by Customer Class



Comments submitted by ABATE assert that the 5% rate reduction and five year rate freeze for residential customers that was part of the legislative package enacting customer choice in Michigan distorted the market, making utility generation service artificially attractive and driving low residential participation in choice. ABATE also asserts that the choice program in Michigan failed to encourage residential aggregation, which has contributed to substantial residential choice participation in other states.

Michigan has treated the various customer classes¹² essentially the same in terms of choice participation. The key differences in terms of participation in customer choice between residential and business class customers include the minimum participation term, the return to full service notification requirements and the applicability of market priced power charges. These differences were established to help ensure that the various program participants are protected in consideration of the expected difference in knowledge level between the customer classes.

Comments from COMPETE Coalition note all customer groups, including residential customers, have seen value from competitive markets.

For additional information regarding choice participation, see [The Status of Electric Competition in Michigan](#) report which is prepared by the MPSC and submitted to the Governor annually.

¹² Customer Class is a common customer characterization that generally includes residential, commercial and industrial groupings.

Upper Peninsula Developments

Choice participation has been virtually nonexistent in Michigan's Upper Peninsula until 2012. A total of four customers were taking choice service within Upper Peninsula Power Company at the close of 2012. Customers of Wisconsin Public Service Corporation and Wisconsin Electric Power Company (WEPCo) began taking choice service during June 2013. As of November 2013, there were approximately 100 customers taking choice service in the Upper Peninsula.

Two mining facilities recently migrated to choice within WEPCo's service territory. The result of this is that approximately 85% of WEPCo's load is now taking choice service. Current choice law, MCL 460.10a(1)(d), provides that any customer operating an iron ore mining facility, iron ore processing facility, or both, located in the Upper Peninsula of this state, is permitted to purchase all or any portion of its electricity from an AES, regardless of whether the sales exceed 10% of the serving electric utility's average weather-adjusted retail sales. For reliability reasons, MISO has denied a request made by WEPCo to suspend operations at the Presque Isle Power Plant in Marquette in 2014. If the MPSC were to spread the costs of the loss in load in the WEPCo territory (85% load loss) to remaining full service customers in a manner consistent with prior Commission action, the result would be a rate increase of approximately 2% to those remaining customers.¹³ However, if the costs were spread only to Michigan full-service customers, the increase in rates could be greater than 70%.

Comments submitted by Michigan Municipal Electric Association (MMEA) state that MISO has indicated that the plant is needed for reliability reasons. However, the costs to keep the plant in operation will likely be spread across a larger customer base in the MISO footprint. Many of these customers had not left for an alternative electric supplier, but will pay the costs for those that have. In a "true market" this plant would likely close, as the competition seems to have a lower price and the plant is no longer competitive. However, the value of the plant from a geographic perspective is immeasurable when it comes to reliability. This plant will still provide a large amount of the electric output to the retail customers that, "on paper," have left WEPCo.

Customer Savings

The savings experienced by choice customers is difficult to quantify without full knowledge of executed contracts between the AES and its customers. According to Continental Economics, Inc.'s paper "[Retail Competition in Michigan; Growing Michigan's Economic Garden.](#)" it is estimated that customers that were able to switch within the 10 percent cap have saved approximately \$350 million in the three years from July 2009 through June 2012 while those customers in the queue are missing out on over \$170 million annually in savings.

¹³ In the past, the allocation factors for WEPCo's Michigan and Wisconsin load have been reset in rate cases and if the impact of the 85% load loss was spread to WEPCo's Wisconsin customers as well as Michigan customers, the resulting rate increase to Michigan customers would be in the 2% range.

ABATE comments that market prices are now \$25/MWh lower than utility supply, and that this translates into \$235 million in potential savings for the 9.4 million MWh in the queue.

The Joint Utility Response reports that AESs have "cherry picked" the markets and served only the large commercial and industrial customers with favorable load factors and more attractive credit profiles. Conversely, commenters assert that the large more sophisticated commercial and industrial customers with multiple meters and properties were quick to respond to the opening of Choice and filled the limited 10% cap.

Comments submitted by Energy Choice Now, prepared by Continental Economics, (ECN/CE) state that it's not that the utilities oppose free markets and customer choice generally; after all affiliates of DTE and Consumers haven taken advantage of competitive retail and wholesale markets in the Midwest (Illinois, Ohio) as well as other markets such as Pennsylvania and New Jersey in order to derive revenues. It should be noted that some of the Michigan licensed AESs are affiliated with regulated utilities.

The nearly 11% load participation in the choice market today translates into 0.3% of total customers for DTE and 0.06% for Consumers Energy. The current rate structure essentially transfers fixed costs no longer recoverable from customers participating in choice to all remaining customers, creating a subsidy from more than 99% of customers to less than 1% of customers.

ABATE asserts that the benefits received by customers not participating in choice, such as reduced variable expenses and increased revenue from sales of the capacity formerly used by choice customers, more than offset the fixed costs.

The Joint Utility Response also reports that the cost recovery methodologies for choice implementation costs, generation fixed costs and residential rate subsidies have been inconsistent over the history of choice, leading to winners and losers. Some costs were borne by all customers (choice implementation, securitization) while other costs were borne by full-service customers only (rate deskewing, fixed asset costs).

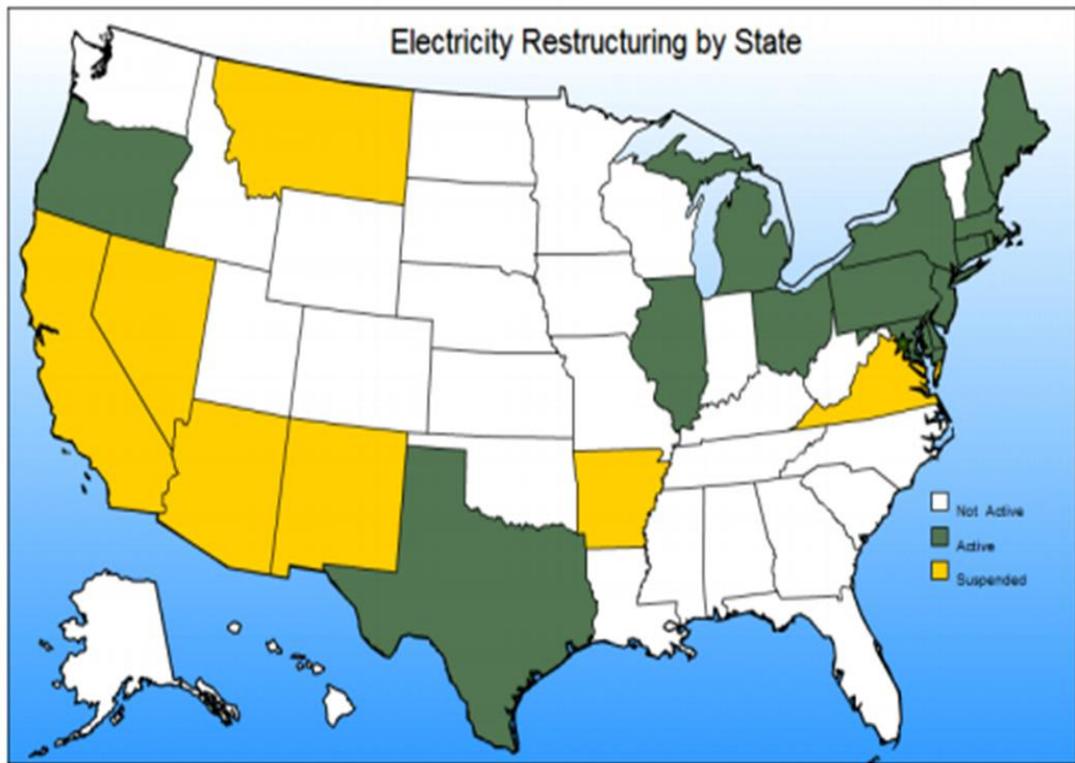
The responses related to customer savings and other responses throughout the electric choice area tend to focus on two distinct sets of customers, those being choice customers and non-choice customers. The responses did not offer a total impact analysis. While it may be true that under the current construct that some customers pay less under choice while others pay more, the customer choice program could be measured in terms of net benefits to all customers as a whole. In addition, the responses did not offer a discussion related to AES headroom (a/k/a the profit portion of its price). While the full savings opportunity of customer choice might appear to be the difference between the utility regulated rate offering and the market price of power, it is actually the difference between the utility regulated rate offering and the AES rate offering. An AES does not have an incentive to pass along to customers the lowest price of power available in the market. That would leave little to no room for profit. Its incentive is to enroll a customer at

a price that is sufficiently below the utility offering as to be attractive to the customer, while at the same time sufficiently above the market price of power or the cost of their own generation to ensure as much headroom/profit as possible.

Choice Participation and Structures in Other States

Most states throughout the country operate under full regulation. Many of the states in MISO are regulated states while many of the states in PJM are deregulated. The states which operate under some form of deregulation are heavily concentrated in the northeast. The regulatory structures of the states surrounding Michigan vary. Indiana, Wisconsin and Minnesota are all fully regulated and do not provide for electric choice. Illinois is fully restructured, allowing electric choice without any limit. Ontario has restructured, and Ohio has recently changed its regulatory structure to allow for more electric choice. Below, **Figure 5** illustrates active deregulated states and also identifies a few states that have suspended deregulation.

Figure 5: Electricity Restructuring by State (EIA)



Source: Energy Information Administration

The states along the East and West coasts of the country as shown in Figure 5 that have attempted restructuring have typically been among the states with the highest electric rates in the country. Section VI of this report (Rates) discusses the impact that deregulation has had on electric rates.

FirstEnergy Solutions reports that the key to the success seen in other states is state-wide policies in support of electric choice that provide nearly all customers the opportunity to access the market, without any restrictions such as a choice cap. By removing barriers that restrict customer access to the competitive market place, the transition to full restructuring allows customer access which benefits competition and the statewide economy.

Energy Choice Now reports that there are four primary categories that summarize the market structures adopted by other states. In many of the states, the utilities divested and/or spun-off generation assets to a competitive affiliate making it possible for all generation in the state to compete on a level playing field. The categories include:

- 1) *No Utility-Provided Default Service (Texas):* Utilities unbundled activities into three groups: power generation companies, retail electric providers and transmission and distribution companies. All customers are eligible to select an electric provider except for those in service territories and cooperatives that have opted out of competition. The Public Utility Commission of Texas has full jurisdiction over both the wholesale and retail electricity markets.
- 2) *Market Pass-Through (New York):* Retail choice was established through individually negotiated utility settlement agreements, resulting in a phased in approach to retail competition. Retail rate structures are generally complex and vary significantly from utility to utility, although the New York PSC has begun increasing uniformity of rules and rate structures. Utilities rely on a supply pricing mechanism based on the NYISO market clearing price from energy, capacity¹⁴ and ancillary services, called the Market Supply Charge.
- 3) *Auction or Request for Proposal (RFP) Common throughout PJM & New England:* Generation, transmission and distribution activities are unbundled, with default service provided by the host utility. Default service is procured through competitive wholesale auctions or RFPs held by the utility, which then sets the Price To Compare. Within this type of default service model there are many variations such as rate setting frequency, length of default service contracts, laddered or multi-year procurements and customer segmentation.
- 4) *Other (Ohio, California):*

Ohio utilities are required to choose between an Electric Security Plan (ESP) or a Market Rate Offer (MRO). In ESP, rates are set in a contested proceeding at the Public Utility Commission of Ohio and must usually be more favorable than market pricing but can also rely upon a competitive bidding plan. In MRO, utilities use a competitive bidding

¹⁴ Capacity refers to the amount of power generated by a system, usually measured in megawatts (MW).

plan to acquire market supplies. A portfolio approach is allowed in addition to RFPs and auctions.

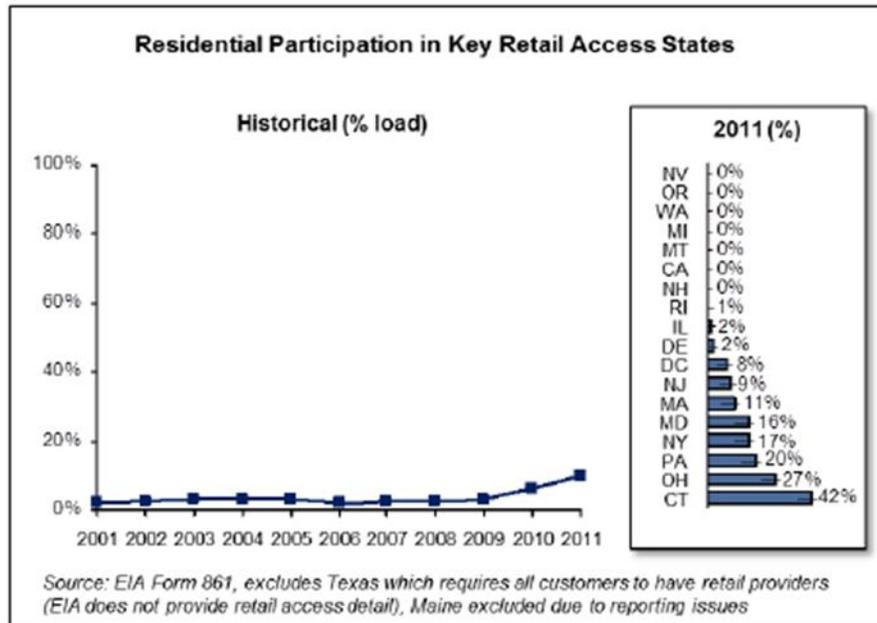
California allows for limited access to retail choice for non-residential customers and is capped at the highest amount of historic competitive load in each service area during the previous 12 month period.

The Joint Utility Response reports that customer participation in retail access today is at its historically highest level due to low deregulated (wholesale) market power prices and notes that this participation is only 12% of U.S. customers (22% of electric load). **Figures 6 and 7** below illustrate choice participation throughout the country.

Figure 6: U.S. Retail Access Participation



Figure 7: Residential Participation in Key Retail Access States



In addition, approximately 60% of residential customers in Texas are being served by a competitive Retail Electric Provider (REP).¹⁵ Although, it could be argued that 100% of customers are required to take service from an REP, as utility affiliated companies who serve customers could be characterized as an REP.

The Joint Utility Response reports that retail electric choice in the U.S. has resulted in inconsistent customer participation, few clear drivers of savings for customers, financially struggling deregulated power providers, and concerns about electric reliability.

Arkansas, Virginia, New Mexico, Nevada, and Arizona re-regulated prior to separating generation from the utilities and these states now operate in practice as regulated models. California and Montana fully transitioned to deregulation before re-regulating. California re-regulated by entering above-market power contracts through the state, suspending future retail access, and allowing utilities to re-contract for and in some cases own generation. Montana re-regulated by eliminating future retail access and allowed the utilities to have regulated generation. New Jersey and Maryland intervened with guaranteed state-sponsored contracts that reflect skepticism that their deregulated markets would adequately provide power in the time needed without intervention.

Virginia suspended retail choice in 2007 but allows large customers (>5MW) to purchase power from an alternative supplier. In addition, under certain conditions, smaller nonresidential

¹⁵ Public Utilities Commission of Texas, March 2013 Market Share Data <http://www.puc.texas.gov/industry/electric/reports/RptCard/Default.aspx>

customers can aggregate load and residential customers can seek 100% renewable power from alternative suppliers. At present, alternative suppliers are not serving customers in Virginia.¹⁶

In May 2013 the Arizona Corporation Commission (ACC) filed an application to open a docket “In the Matter of the Commission’s Inquiry into Retail Electric Competition” inviting concerned parties to provide detailed comments regarding retail electric competition in Arizona. Initial comments were filed by July 15 and responsive comments were filed by August 16. In September 2013, the ACC decided in a 4 to 1 vote to close the docket concerning deregulation of the retail electric market in Arizona and to maintain the current system.

Similarly, Indiana is reviewing the topic of electric customer choice. Specifically, Senate Bill 0560 (Section 7) states that “the legislative council is urged to assign to the regulatory flexibility committee the topic of electric customer choice programs.” The regulatory flexibility committee issued a final report to the legislative council on November 1, 2013 which provided a brief overview or position of each party’s testimony on the subject of customer choice, deregulation and competitive procurement. The report did not make any formal recommendations.¹⁷

Mackinac Center comments that in some situations, states have tried something that has been called “competitive” or “deregulated” but actually have imposed new and often worse regulatory requirements that have undermined the introduction of competition.

In contrast to the Joint Utility Response, comments submitted by IGS Energy provide examples of states where electric competition has been extremely successful and brought great benefits to customers. IGS states that Texas is probably the most mature competitive electric generation market in the country and it is an example of how to restructure electric markets correctly. Despite electricity demand in Texas growing significantly, the most recent statistics published by the EIA identifies Texas as having electric rates 15% below the national average. Beyond just efficient pricing, the Texas market offers the most diverse range of retail electric products to customers than anywhere else in the country. IGS claims that competition is also working in states close to and with many similarities to Michigan, such as Ohio, Illinois and Pennsylvania.

However, data was also submitted outlining problems occurring in deregulated states. The following summarize three deregulation reports for New Jersey, Illinois and Texas that were prepared by Public Sector Consultants.

- 1) New Jersey: In the beginning of deregulation for New Jersey, participation among residential and commercial customers was low. The price cap imposed did not provide opportunity for new suppliers to make a profit. New Jersey then passed the Long-Term Capacity Agreement Pilot Program designed to ensure adequate capacity generated by in-state facilities at acceptable prices. The legislation created a battle between the State of

¹⁶ Source: http://www.scc.virginia.gov/comm/reports/2012_veur.pdf

¹⁷ Source: <http://www.in.gov/legislative/interim/committee/reports/RFSCGB1.pdf> (p. 2)

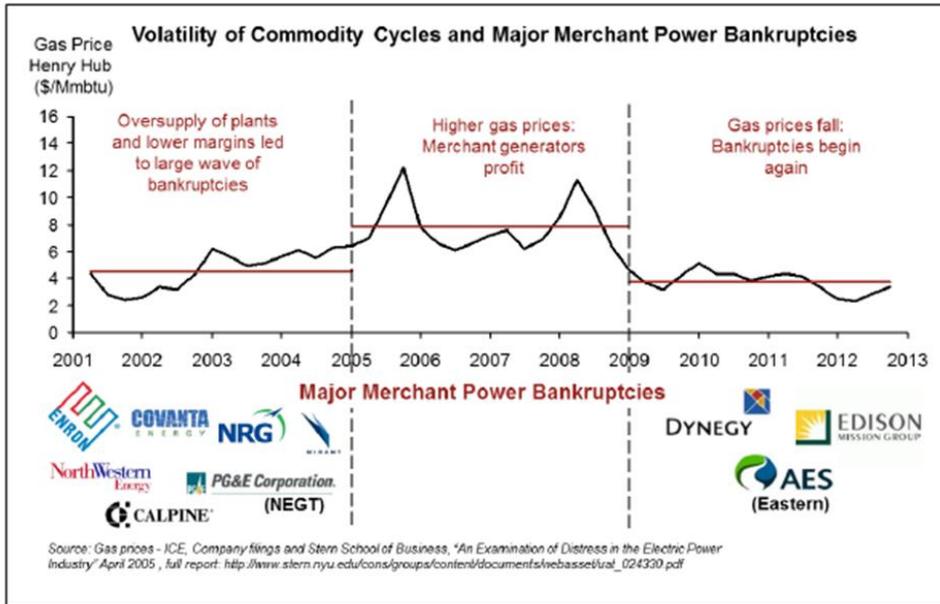
New Jersey and PJM, FERC and various out-of-state electricity providers and was ruled unconstitutional by a US District Court, see Section IV Reliability and Capacity (page 31) for details. Despite 14 years of deregulation, rates continue to be high compared to other states.

- 2) Illinois: Illinois deregulated in 1999, but due to political, legislative, rate volatility issues, the state's policy makers created a state agency to oversee the purchase and sale of electricity for residential and commercial customers. The government is essentially serving in critical roles traditionally provided by a regulated utility. State and local government roles in power procurement and pricing bring into question whether this is a truly deregulated industry.
- 3) Texas: Texas began full deregulation in 2002 and has experienced high levels of Choice participation, but has challenges with reliability and affordability of electric service. Rates have been higher and more volatile in the deregulated areas of Texas.

Impact of Choice Cap Change on the Financial Stability of Utilities

The Joint Utility Response reports that an increase in the choice cap would reduce the financial stability of utilities and therefore investors' willingness to make long-term investments in new generation. An increase in the cap would allow more customers to move freely between regulated rates and retail access, creating demand uncertainty equivalent to a few power plants of capacity which inhibits long-term planning and investment for reliability. Under deregulation, the volatility of commodity cycles and lack of cost recovery assurance could lead to financial distress and limit the willingness of deregulated generators to invest in existing and new generation assets. Deregulation in Michigan was originally seen as negative by credit rating agencies and the establishment of the 10 percent cap was seen as positive for stability and therefore credit profile. Deregulated (or "merchant") power producers have experienced significant financial distress since deregulation began around 2000. The Joint Utility chart below, **Figure 8**, illustrates this concept.

Figure 8: Volatility of Commodity Cycles and Major Merchant Power Bankruptcies



The Joint Utility Response reports that prior to the full implementation of deregulation, there was a capacity over-build in the early 2000s. This period of over-investment, coupled with lower than expected demand, resulted in an oversupply of capacity. This oversupply of capacity and the volatility of commodity cycles have led to numerous bankruptcies of deregulated generators. Those bankruptcies are a good indicator that the merchant industry, and those who finance it are unlikely to repeat the same mistake and that it would very risky to rely on deregulated generators to once again overbuild to guarantee reliability.¹⁸ Comments from ABATE note that these bankruptcies cost ratepayers nothing and point out the financial bailouts that Michigan’s utilities have received over numerous decades for financially disastrous energy facilities that have cost ratepayers three times what a cogeneration facility should have cost.

FirstEnergy and Energy Choice Now report that shifting ratepayer risk related to new generation to competitive suppliers would support the financial stability of utilities. Of transmission, distribution, and generation investments made by utilities, generation represents the largest cost and highest risk investment. The value of generation investments is affected by future market prices, technological change and, especially, environmental regulation. Collectively, these market and non-market risks make investments in generating assets, as well as operational decisions of existing generating assets, more difficult. By transferring these risks away from utilities to competitive generators, regulated electric utilities' financial stability increases. Comments from the Joint Utilities add that owners of generation, whether regulated or deregulated, need financial stability to support investment in long-lived generating assets that

¹⁸ No information was submitted as to patterns of bankruptcy among merchant providers

ensure reliability of electric supply. This debate should not be about who faces financial instability, but rather about ensuring that those parties responsible for electric reliability have sufficient stability to invest in providing it.

FirstEnergy and Energy Choice Now also report that empirical research has shown that competitively owned/operated generating units are operated more efficiently and produce more power. The market and regulatory risks surrounding generation-related investments and operations would then be shifted from ratepayers to the competitive generators' shareholders.

Additionally, FirstEnergy and Energy Choice Now report that competitive generators will be in the best position to assess future consumer demand to determine the best strategy for economically investing in future generation expansion projects - either through building new generation or upgrading existing facilities. Therefore, through a properly administered transition, the regulated function of Michigan's utilities can remain financially stable while the generation function transitions to market with a fair opportunity to compete with other providers of generation services.

ECN/CE asserts that the claims regarding utilities' loss of financial integrity because of customer choice are not supported by empirical evidence. Utilities in states providing customer choice have an average credit rating that is indistinguishable from the average of utilities in traditionally regulated states. Regulated utilities in competitive jurisdictions have full access to capital markets. Additionally, ECN/CE comments that the actual record of utility financial solidity in restructured, competitive states stands in stark contrast to the Joint Utility Response of allegations of financial devastation. The key factor to examine is utility bond ratings, and specifically whether bond ratings of utilities in restructured competitive states have fallen relative to those in states that did not restructure their electric markets. They suggest that an examination of utility bond ratings by S&P and Moody's show that the rankings of utilities in restructured competitive states cluster in the middle range of credit quality just as do utilities in monopoly regulated states.

Section III – Market Structure

(Questions 8, 15, 21, 22 & 24)

This section presents information related to AES licensing, provider of last resort, factors that could change the choice market dynamic, uncollectibles and low-income customers. This section also presents the expected impact on jobs, infrastructure, supplier base and tax base in an open market system.

AES Licensing

License and license renewal processes vary by state. Most states have a requirement that suppliers notify the respective Commissions of any material changes to the information provided on the original applications for certification and maintain sufficient financial, technical and managerial requirements.

In Michigan, PA 141 requires all AESs to be licensed by the MPSC. The Michigan licensing requirements are listed on the [AES Application](#) approved by the MPSC. The applicant must sign a legal affidavit that the company can safely and competently provide power and the following:

- Certificate for Authority to Transact Business in Michigan (if Foreign Corp, LLC, LPC);
- Financial Statements;
- \$100,000 bond or letter of credit;
- Company history with biographies of key personnel;
- Safety record including any citations resulting from violations of any governmental or electric industry rule or regulation covering the sale of electric generation;
- Outline of staffing and procedures for service quality;
- Overview of risk management strategy, including any violations or failures to perform;
- Legal affidavit attesting to the technical ability, knowledge, skill, and competency of company and employees to safely and reliably deliver electricity;
- Michigan office plans and company contacts.

Commission staff performs a review of, and meets with, each applicant. Staff provides a recommendation to the Commission and the Commission issues an order on the request for license. Once licensed, an AES must also adhere to ongoing regulations such as reporting of aggregate statistics, filing a renewable energy plan, and compliance with Commission orders, utility tariffs and state and federal laws.

Energy Choice Now and FirstEnergy report that current licensing and reporting requirements in Michigan are sufficient to keep the Commission informed of critical updates to the status of licensed suppliers and that the process has been successful with no record of customer abuses in

the competitive electric retail markets. While it is unclear if this is viewed as a licensing matter, the Joint Utility Response reports that AESs do not have any requirements related to low-income or energy efficiency programs and have greater flexibility in meeting renewable energy requirements since AESs do not have a renewable energy capacity requirement.

Provider of Last Resort (a/k/a Supplier of Last Resort or Obligation to Serve)

The Joint Utility Response reports that all states that fully deregulated generation have a provider of last resort (POLR), or default supplier, or both. POLR and default supplier are technically not the same, although some states and data sources use the terms interchangeably. The POLR has a legal obligation (traditionally assigned to utilities) to provide service to any customer at any time. In the context of customer choice, a utility assigned to this obligation must serve customers who receive service from an AES but for any reason seek to return to utility service. Default or standard offer service is for customers who have not selected a competitive supplier.

The Joint Utility Response also reports that there is variation among states in terms of the role and details of POLR and default service. POLR service is difficult to structure and price, and is often priced through a bidding or auction process that is overseen by state regulators. Pricing of POLR is important in terms of the overall impact of the development of the market and potential competitors. In some cases, states have stepped in as the ultimate provider of last resort. When caps on default retail prices, combined with high wholesale prices, caused providers to go into bankruptcy in California and there was an “imminent threat of widespread and prolonged disruption of electrical power,” the state stepped in to procure power on behalf of end users.

The following data sources or reports summarize POLR service in various states.

- [*Annual Baseline Assessment of Choice in Canada and United States \(2012 ABACCUS\): An Assessment of Restructured Electricity Markets*](#) (December 2012)
- United States of America Electric Energy Market Competition Task Force and the Federal Energy Regulatory Commission (June 5, 2006), Docket No. AD05-17-000, [*Report to Congress on Competition in the Wholesale and Retail Markets for Electric Energy*](#) (see pp. 6-8 and Chapter 4 for discussion on POLR and default service)
- Joseph Cavicchi and Andrew Lemon, [*Power Procurement: What's In Your Mix?*](#), Public Utilities Fortnightly (November 2006)
- Kenneth Rose, *State Retail Electricity Markets: How Are They Performing So Far?* Electricity Policy, (2012)
- John Kwoka, [*Restructuring the U.S. Electric Power Structure: A Review of Recent Studies*](#), Report for American Public Power Association (November 2006)
- Public Sector Consultants, [*Electricity Restructuring in Michigan: The Effects to Date of PA 141 and Potential Future Challenges*](#), 2006 pp. 14-15

Factors That Could Change the Market Dynamic for Choice

It is impossible to accurately predict long-term changes to the energy market. Factors that could change the choice market include removing/adjusting the choice cap, municipal aggregation, structural corporate separation, changes to environmental regulations, price of coal and natural gas, and renewable energy requirements. In addition, regulatory uncertainty serves as an impediment to competition, innovation and investment in infrastructure.

FirstEnergy reports that removing the choice cap would substantially increase the success of Michigan's choice program by allowing the tens of thousands of customers in the queue to participate in choice. In addition, increased opportunities for municipal aggregation programs within Michigan's restructuring model will encourage and allow more residential choice participation. Under municipal aggregation, local municipalities or townships aggregate the demand of residents and seek to secure a power supply for the aggregated demand. In addition, requiring structural corporate separation will allow the utilities to act as facilitators of choice rather than as direct competitors for load.

Consumers Energy reports that environmental regulations may force retirement of older coal fueled generating units. EPA regulations leading to coal plant retirements and federal carbon legislation would drive market prices much higher. The price of coal and coal transportation, as well as the price of natural gas, could also impact the utility's competitive position versus the MISO market. In addition, renewable energy requirements that differ between utilities and AESs create a variance in cost structures.

Low-Income Customers and Uncollectibles

The Joint Utility Response reports that electricity is viewed as an essential service in modern society. During extreme weather events, the lack of electricity can lead to injury or even death. State and federal governments, as well as utility companies, have instituted safety nets to assist low-income customers through a variety of programs and policies such as bill payment assistance, disconnection moratoriums, weatherization, discounted rates and payment plans. These programs generally strive to make electricity more affordable in the short-term (payment plans, discounted rates, and emergency bill assistance relief) and the long-term (reduced consumption). These programs are often intended to reduce bad debt expense from unpaid electric bills (uncollectibles).

The Joint Utility Response also reports that issues related to uncollectibles and low-income customers are present under both regulated and deregulated industry structures and raise many public policy questions, such as who pays and how, and what is the scale, efficacy, and impact of various programs. There are additional challenges to serving low-income customers in a deregulated market because of the number of providers (some without an obligation to serve),

profit motivation, limited regulatory oversight, and other factors. Recognizing these challenges, many states adapted the funding and delivery mechanisms for low-income programs as part of the transition to deregulation.

The Joint Utility Response also reports that the major low-income policies and programs in deregulated states are highlighted below in **Figure 9**. Even though the specific approaches and funding mechanisms often change through the deregulation process, all states have continued programs to assist low-income customers in some fashion.¹⁹ The funding amounts, mechanisms, and the scale of these programs vary between states. In addition to the traditional low-income programs, some states (Connecticut) have explored the concept of purchasing pools for low-income customers.

Figure 9: Low-Income Policies and Programs in Deregulated States

State	Rate discount (recurring)	Emergency payment and/or credits on arrearages	Low-income weatherization/energy efficiency	Deferred payment plans
California	Yes	Yes	Yes	Yes
Connecticut	No	Yes	Yes	Yes
Delaware	No	Limited	Limited	Not required
D.C.	Yes	Yes	Yes	Yes
Illinois	Yes	Yes	Yes	Yes
Maine	Yes	Yes	Yes	Yes
Maryland	Yes	Yes	Yes	Yes
Massachusetts	Yes	Yes	Yes	Yes
New Hampshire	Yes	Yes	Yes	Yes
New Jersey	Yes	Yes	Yes	Yes
New York	Yes	Yes (some)	Yes	Yes
Ohio	Yes	Yes	Yes	Yes
Texas	Yes	No	Yes	Yes
Pennsylvania	Yes	Yes (some)	Yes	Yes
Rhode Island	Yes	Yes	Yes	Yes

FirstEnergy Solutions reports that the treatment of uncollectibles varies by state and that the most conducive policy to sustainable retail competition is a purchase of receivables program allowing the billing party to refund uncollectible accounts at a discounted rate which is then socialized across the entire rate base. And whether it is via direct access to the market through shopping or through a wholesale bid auction for suppliers, low-income customers should have equal opportunity to experience savings through a restructured electricity market.

¹⁹ See LIHEAP Clearinghouse for state-by-state summaries of such programs.

Expected Impact on Jobs, Infrastructure, Supplier Base and Tax Base in an Open Market System

FirstEnergy reports that fully competitive retail markets foster efficiencies and economies that result in affordable electric prices across all customer classes. In general, lower electric bills decrease the cost of doing business and cost of living in the area, which will attract new business and help retain existing businesses. When residential customers are spending less on their electric bills, they are able to spend more on consumer goods, which translates to increased revenues for local businesses. These increased revenues, coupled with an additional layer of savings on electric bills for commercial and industrial customers, translates into additional monies available for business expansion and investment, which results in stimulating businesses to increase payrolls, through pay increases and headcounts, to meet the additional consumer demand. These increased payrolls then provide additional spending power for consumers to use at local business, perpetuating a virtuous circle resulting in a vibrant, prosperous economy.

Energy Choice Now and FirstEnergy submit the following publication which discusses competitive electric market, job creation and economic growth. Specifically, this report touches on the importance of electricity to the U.S. economy and the long term focus which will provide the greatest economic benefits, leading to higher economic growth and more jobs. Additionally, this report provides an overview of the competitive success story of the natural gas industry and general policy considerations.

- [*Electricity Competition at Work: The Link Between Competitive Electricity Markets, Job Creation, and Economic Growth*](#)

The Joint Utility Response reports that utilities are planning new investments to ensure long-term supply of electric generation, which will bring new jobs and expand the tax base. Historical facts and figures are presented, but the impact or change to these historical facts and figures resulting from a move to an open market system, if any, is not presented. The electric utility facts and figures include:

- Serve five million customers thus impacting the economy
- Electric industry had \$10.2 billion direct economic impact in Michigan in 2010
- Support nearly 100,000 jobs (full time equivalent) annually
- Provide \$3 billion in tax revenues to federal, state and local governments annually
- Use many Michigan suppliers for construction, IT, and maintenance services

General comments regarding competitive innovation suggest taking a broader view of competition policies by looking into other markets where we can see the results from introducing competition to formerly regulated markets such as cable, television, telephone service, airline travel, natural gas production and freight shipment over railroads. It is important to understand the very unique characteristics of the physical market of electricity. Section IV: Reliability and Capacity touches on these characteristics.

Section IV – Reliability and Capacity

(Questions 7, 9, 10 & 11)

This section presents a summary of the commenter responses related to reliability and capacity. The responses in this section focus on the concept of reliability and do not attempt to recommend a definition or redefine the term reliability. The Readyng Michigan – Additional Areas report provides a discussion of possible definitions that have been used or proposed for use by policy makers. Additional commenter responses addressing reliability, capacity, and rate considerations are also found throughout others areas of this report.

The primer [*New Electric Resources: How New Power Plants Can Be Built*](#) submitted by Alex Zakem, Energy Consultant, provides a plain English presentation of the capacity and reliability framework in MISO and does not advocate for any particular policy outcome. In addition, it explains the main factors that suppliers, developers, and regulators face in assessing the need for, and merits of, building new electric resources.

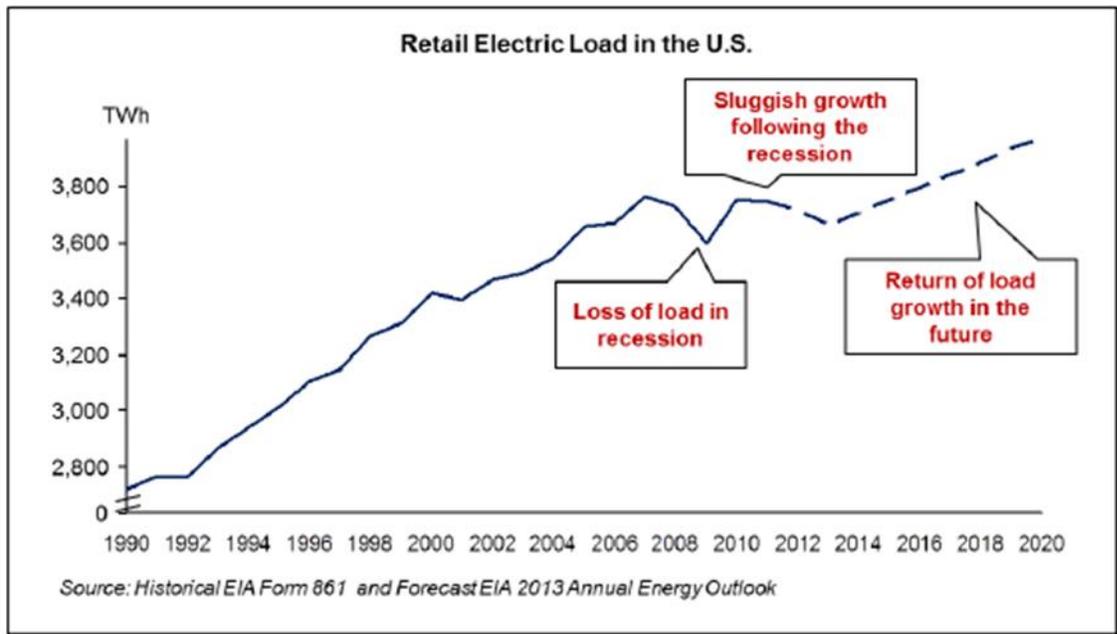
A key area of discussion regarding customer choice or deregulation is how such a policy may affect reliability of the system and the price paid by customers. Reliability is critical to a strong economy and is vital for homes, hospitals, businesses and schools. The reliability of a system is determined by the amount of electricity it can generate at any given instant. This highlights a very unique characteristic of the physical market of electricity. Due to the unavoidable physics involved, the market for electricity is completely different from a typical retail product market. Unlike typical goods where prices simply increase when supply decreases, an electric market in shortage results in the potential for rolling outages which could be an inconvenience for some and cause economic harm, bodily harm or even death for others.

Reliability typically becomes an issue when demand is at “peak load,” a period when the most electricity is being demanded (also known as “peak demand”). If a system cannot generate enough electricity to meet peak load then brownouts and blackouts may occur. Even though power plants in the blackout area are generating power, the particle physics of electrons may prevent the delivery of that power. Certain types of generation assets are slower to respond to the need for electricity than others. An idle coal plant may take hours or even days to fire up in the event of an unexpected shortage, perhaps weeks for a nuclear power plant. This may be acceptable if the need is the result of a predicable event such as a planned shutdown or extended heat wave. But if the shortage is due to an unexpected event, such as a plant malfunction, then taking several hours/days to power up a coal plant may not be sufficient to prevent a blackout. Natural gas, wind and solar generation assets have different response characteristics as well.

Sufficient reliability is the result of an appropriate level of current and future generation capacity. Advocates for deregulation argue that reliability is not negatively impacted and may be

better suited to respond to ever changing market conditions. Advocates for full regulation argue that regulated systems are more reliable because regulation is more conducive to new generation investment. The Joint Utility chart below, **Figure 10**, shows historical and projected load in the U.S.

Figure 10: Retail Electric Load in the U.S.



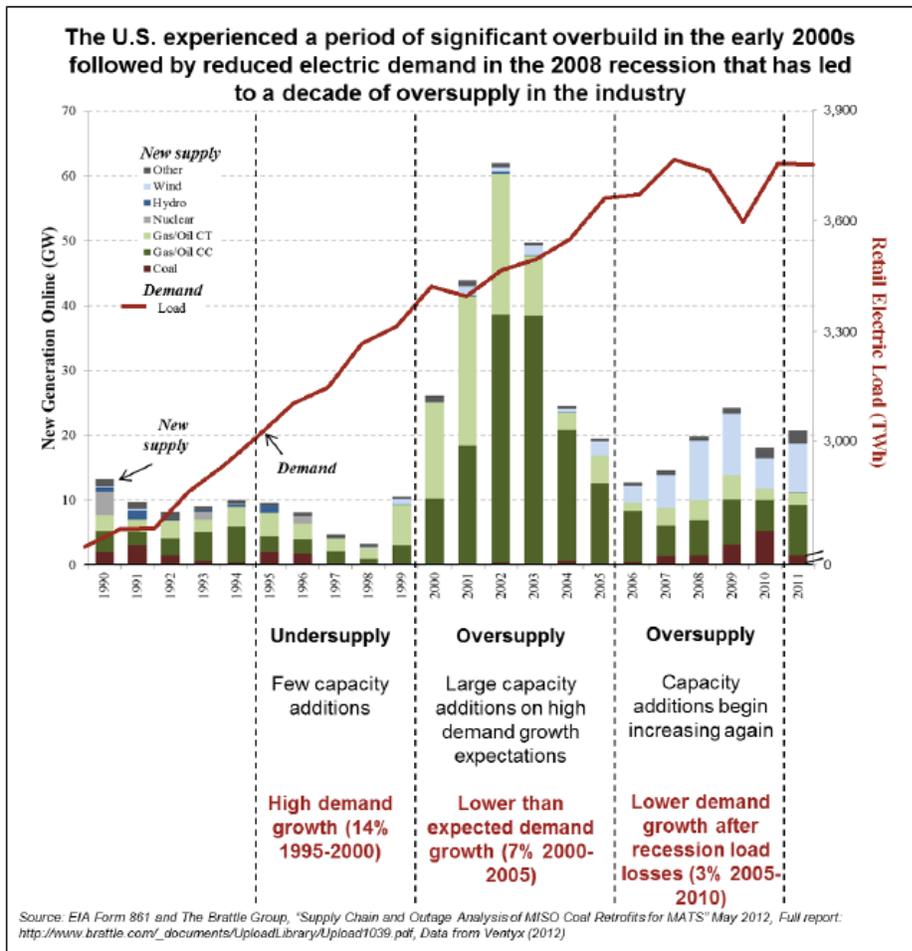
FirstEnergy Solutions, Energy Choice Now and ABATE report that since Michigan is a member of MISO that reliability issues (such as ensuring adequate capacity is available to serve all customers) are handled through MISO. Related, the Joint Utilities assert that MISO does not have the authority to require that new generation be built in the event of a capacity shortfall.

ABATE also reports that there have been no shortages of capacity and energy under any of the regulatory regimes in Michigan.

Energy Choice Now reports that load-serving entities within MISO can procure generation directly from the market, enter into bilaterally negotiated market based contracts and/or conduct competitive procurements to obtain necessary resources. In organized wholesale competitive markets, price signals determine when and where generation is needed and gets built and there have been no reliability problems for any of the states that have restructured their electric markets. For example, over half of PJM's 13 states and DC have fully restructured to competitive retail electricity markets. In the last five years alone, PJM has added over 26,000 MW of supply resources, net of retirements, and has a 20.3% Reserve Margin.

The Joint Utility Response reports that there is currently a surplus of capacity in the MISO market and that the full extent of the challenges of meeting capacity needs under deregulation has not yet been experienced due to these over-supply conditions. COMPETE Coalition attempts to refute these comments by stating that they are intended to cast doubts on the ability of competitive generators to provide reliable service and that they ignore the success of the PJM capacity market when faced with the retirement of nearly 14,000 MW of coal-fired generation over a period of three years. The Joint Utility chart below, **Figure 11**, illustrates the over-supply condition.

Figure 11: Over-Supply Condition



Because the United States has had an oversupply of capacity in the last decade, there has not been a need for significant investment in new generation

This lack of need for new generation has masked the difficulties of investing for reliability in a deregulated market

The Joint Utility Response reports that restructured markets are not well-suited to sufficiently provide for generation capacity needs and that regulated models support a long-term investment planning process. Regulated models ensure that capacity is available for future reliability at reasonable cost of service and that the overall generation portfolio provides for fuel diversity and other needs. In recent years, both New Jersey and Maryland (both deregulated) became concerned that the PJM energy and forward capacity market had not incited a sufficient amount

of generation investment for future reliability. After performing their own studies, both states implemented regulated mechanisms to guarantee a return on investment for new generation needed to meet reliability standards. Joint Utility table below, **Figure 12**, summarizes this information.

Figure 12: State Reliability Concerns

	State Reliability Concerns	Intervention
New Jersey	<p><i>"New Jersey is experiencing an electric power capacity deficit and high power prices that may result in the loss of jobs and investment... Construction of new, efficient generation must be fostered by State policy" - 2011</i></p>	<p>NJ legislature required regulated T&D utilities to enter long-term contracts for 1,950 MW of new gas generation that guarantee a capacity price even if above PJM capacity auction clearing price</p>
Maryland	<p><i>"We cannot rely on PJM's Reliability Pricing Model to deliver new generation to Maryland... Maryland has not seen any significant new generation constructed here since 2003" - 2012</i></p>	<p>MD regulators required regulated T&D utilities to enter a contract for 650 MW of new gas generation that guarantees a capacity price even if above PJM capacity auction clearing price</p>

Source: State filings, State Commissions, Press Releases

In April 2012, the Maryland Public Service Commission ordered a select number of Electric Distribution Companies to enter into a Contract for Differences with CPV Maryland, LLC to enable the construction of a 661 MW natural gas-fired combined cycle facility in Charles County, MD with an in-service date of June 1, 2015.²⁰ In late September, a United States District Court for the District Court of Maryland judge deemed Maryland’s efforts to contract for new generation as violating the Supremacy Clause of the United States Constitution, effectively rejecting its pending contracts to construct the facility.²¹

In October 2013, a US District Court for New Jersey decided in favor of PJM and declared that the Long Term Capacity Agreement Pilot Program Act (LCAPP) is “preempted by the Federal Power Act and in violation of the Supremacy Clause of the United States Constitution; and is therefore null and void.”

ECN/CE comments that the assertion that restructured markets will not incent sufficient new generation supplies is not only false, it can be refuted physically. Substantial new capacity increments have come into the market since 1997 in the five states of the East North Central region (IL, OH, IN, MI, WI), in both competitive and monopoly states. Additionally, ECN/CE states that over the fourteen year period, 1997-2011, beginning with Illinois’ adoption of the region’s most competitive structure, Illinois added twice as much additional generating capacity

²⁰ Maryland Public Service Commission Order No. 84815, Case No. 9214

²¹ United States District Court for the District Court of Maryland Recent Opinion dated September 30, 2013 in Civil Action No. MJG-12-1286 <http://www.mdd.uscourts.gov/Opinions/Opinions/12-1286.pdf>

as has Michigan: over 11,000 MW compared with less than 6,000MW in Michigan. More significantly, Illinois' new generation has proven sufficiently efficient and competitive such that Illinois has become a major power exporter. Of the five East North-Central states, Michigan has added the least amount of generation. It should be noted that Illinois produced just over 2 trillion British thermal units (Btu) of energy, making it a net importer.²²

²² [State of Illinois Energy Assurance Plan, February 28, 2013 \(p 9\)](#)

Section V – Stranded Costs

(Question 13 & 20)

This section presents information related to stranded costs in Michigan and other states, as well as policy considerations related to stranded costs.

In general, “stranded cost” refers to the decline in the value of an asset which may not be recoverable by the utility as a result of a change, such as a regulatory change or a market change. In the context of regulatory models, stranded costs refer to the decline in value of regulated assets as a result of transitioning from a regulated utility model to a deregulated model. These assets may include generating plants, power purchase agreements, regulatory assets and capitalized investments in social programs mandated by regulators.

The treatment of stranded costs is an important consideration when transitioning from a regulated to a deregulated market structure. Stranded costs serve to recognize that investments made or costs incurred and authorized for recovery under one set of rules (regulation/policy at the time of the investment) could prove to be unrecoverable under a different set of rules (changes to regulation/policy). Stranded costs typically increase as market prices for power decrease.

Stranded Costs in Michigan

Michigan addressed stranded costs when it implemented uncapped customer choice from 2001–2008 as required by PA 141. The MPSC was directed to consider the reasonableness and appropriateness of various methods to determine net stranded costs, including evaluating the relationship of market value to the net book value of generation assets and purchased power contracts of utilities, evaluating net stranded costs based on the market price of power in relation to prices assumed by the MPSC in its orders, and any other method considered appropriate. From 2001 through 2004, the MPSC opened several cases to determine the net amount of stranded costs associated with that period of deregulation. Stranded costs could be securitized (discussed later) under PA 141, which lowered the financing expenses associated with them.

Customer Impact in Michigan

Utility customers pay surcharges designed to provide the utility with recovery of stranded costs. In addition, customers are required to pay securitization charges which are largely attributable to the Fermi 2 (DTE) and Palisades (Entergy) nuclear plants. These securitization charges are designed to recover the difference between the embedded costs of utility nuclear facilities and the market value as compensation for stranded costs (~\$2.2 billion). Securitization charges are assessed to all full service and choice customers and, at present, are approximately \$340 million

(DTE) and \$70 million (Consumers) annually. These securitization charges are scheduled to expire during 2015.

Energy Choice Now reports that stranded costs, securitization costs and nuclear decommissioning costs has been very substantial for choice customers, representing 10 percent and 6 percent of a large business customer's total electric bill for DTE and Consumers, respectively. The Joint Utilities comment that the recovery for stranded costs, securitization costs, and nuclear decommissioning costs are very similar for both full-service and retail access customers.

Stranded Costs in Other States

The Joint Utility Response reports that all states that transitioned from a regulated to a deregulated environment, including Michigan, have gone through the process of determining both the amount of stranded costs and the mechanism appropriate for the recovery of those costs. The methods used to estimate stranded costs vary, as do the estimates themselves and the mechanisms used to recover them. Consequently, the issue has proven to be highly contentious and has been aggressively litigated. For example, despite comprehensive statutory language governing stranded costs, litigation in Texas continued for a decade after the state deregulated its electric industry. The Texas deregulation law was designed to require utilities to mitigate stranded costs before full deregulation went into place, provide for early collection based on estimated stranded costs when deregulation began, and true-up stranded costs based on a final market valuation several years after deregulation began. Market conditions and regulatory decisions complicated the matter, with estimates of stranded costs ranging from \$4.4 billion in 1998 to negative \$2 billion in 2000/2001 (due primarily to high natural gas prices making higher-cost plants more economic), and back up to over \$6 billion several years later as part of the final valuation of stranded costs.

Energy Choice Now reports that unlike Michigan, some states (Connecticut, Massachusetts, Rhode Island) required utilities to fully divest their generating assets and established regulatory proceedings in which stranded costs were estimated. These estimates were typically based on an "income approach," which establishes the market value of an asset based on the present value of the expected future stream of revenues and costs. The stranded cost of each generating asset was then set to the difference between the market value of the asset and its undepreciated book value. The other method that has been used to estimate stranded costs is based on "comparable sales." For example, a nuclear plant's market value might be based on estimates of the previous (\$/ per-MW) sale value of nuclear plants that had been sold in the market. States that did not require divestiture such as Ohio, allowed utilities to recover both generation-related stranded costs and regulatory costs, such as regulatory assets related to generating resources. At the end of the recovery periods, utilities were deemed to have recovered all transition-related costs.

Policy Considerations for Stranded Costs

A change in electric choice policy may or may not result in stranded costs. Stranded cost considerations become greater as Michigan moves toward full deregulation and lessen as Michigan maintains current policy or moves toward full regulation. Major policy issues regarding stranded costs include identifying what costs should be included, defining how to calculate them, developing ways to mitigate them, and establishing a process to recover them. Another element that complicates the calculation of stranded costs is that the market value of these assets continually changes. The fluctuation in asset value driven by volatile market conditions (in particular, energy commodity and fuel prices) underscores the difficulty of this issue. Consequently, an amount of recoverable costs that was developed at one point in time may not turn out to be accurate or final.

The Joint Utility Response reports that any method of stranded cost calculation and recovery will be highly controversial due to the complexity of the issue and the magnitude of the dollars involved, and invite debate about fundamental fairness.

FirstEnergy Solutions reports that the continued ability of the utilities to recover stranded costs even though the market is substantially re-regulated (due to the 10 percent cap) leads to utilities being able to unfairly recover these costs because there is no real competition. FirstEnergy provides a study titled *Retail Electric Competition in Michigan: Growing Michigan's Economic Garden* that discusses this issue at length.

Energy Choice Now reports that utility recovery of stranded costs allowed each utility to be able to compete in the electric markets and therefore there is no need to cap choice participation. PA 286 basically ended new stranded cost recovery but required that existing authorized but uncollected stranded costs amounts be fully paid off. Power plant investments incurred by utilities after 2000 were incurred with the full knowledge that those investments might be subject to market risk. With the 10 percent cap on choice, the utilities have effectively been paid well over \$2 billion to participate in a competitive market but the customers of those utilities have been deprived of all but 10 percent of that competitive market.

Mackinac Center offers that a good test regulators can employ to determine if any compensation should be considered is if a utility can show that it has made an investment at the insistence of regulators, and resisted the action but was forced to move forward anyway. Any utility which can show that it was ordered to make expenditures that it would not have undertaken on its own, and which other utilities were not ordered to make, should be given some opportunity to recover those outlays.

Section VI – Rates

(Questions 5, 11, 12, 14 & 26)

This section presents information related to rate levels in regulated and deregulated states, pricing volatility, stability and visibility, and the residential rate impact of the choice program.

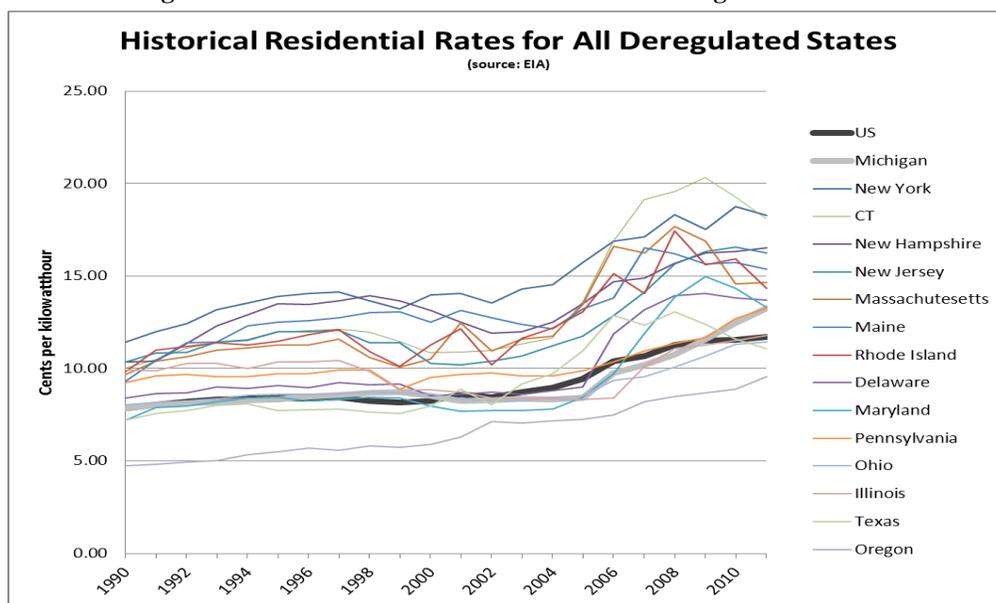
A presentation by Marathon Oil compares Michigan’s electricity rates to surrounding states asserting that competitive electricity rates create an attractive business climate and investment for Michigan. Similarly, a presentation by Ford Motor Company states they are DTE Electric Company’s largest customer spending over \$100 million per year on energy costs. The presentation states that any percentage cost increase is substantial and higher costs are responsible for driving business’ away from Michigan.

Rate Levels in Regulated and Deregulated States

The Joint Utility Response reports a national perspective in that electric rates have historically been higher in choice (deregulated) states than in fully regulated states. Rates in deregulated states have grown at the same pace as rates in regulated states since deregulation began to take effect around 2000. Rate freezes and price caps were often employed in states that deregulated to allow the deregulated market to develop over a transition period prior to full implementation of deregulated rates. Many deregulated states experienced significant price increases (50%+) after the expiration of rate freezes.

The Joint Utility Response also reports that even in today’s low natural gas price environment, electric rates are 30% higher on average in deregulated states than in regulated states. This may be accurate, but deregulated states generally had higher rates prior to deregulating. In theory, states with low rates would see no reason to deregulate. **Figure 13** shows historical rates for all deregulated states. All but three states that deregulated had rates higher than the national average before deregulation (which began in 1996).

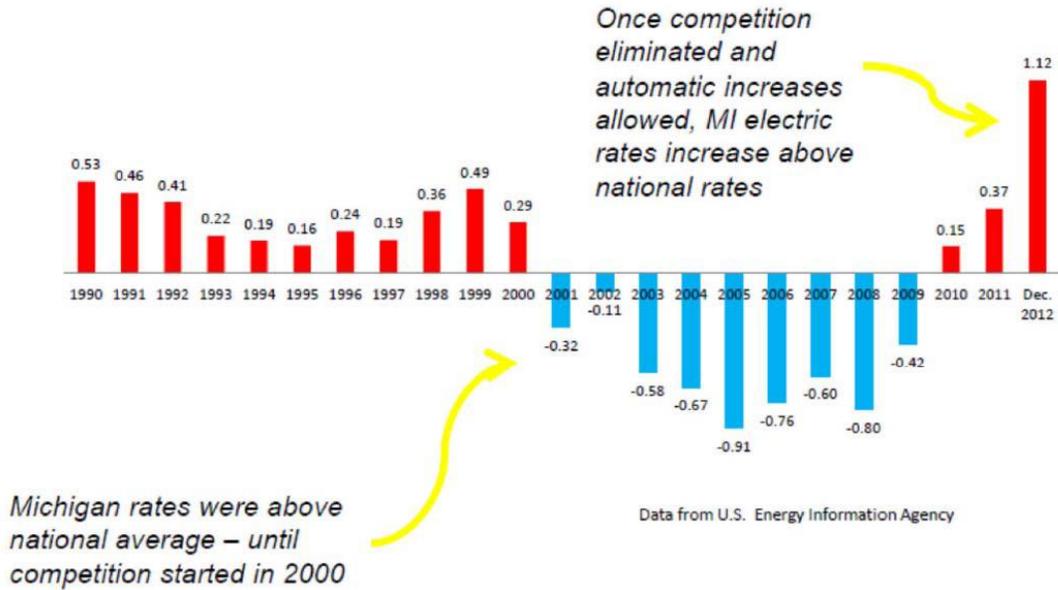
Figure 13: Historical Residential Rates for all Deregulated States.



COMPETE Coalition asserts that, from 1997-2012, inflation-adjusted rates in competitive states have decreased by 4% and rates in monopoly states have increased 7%.

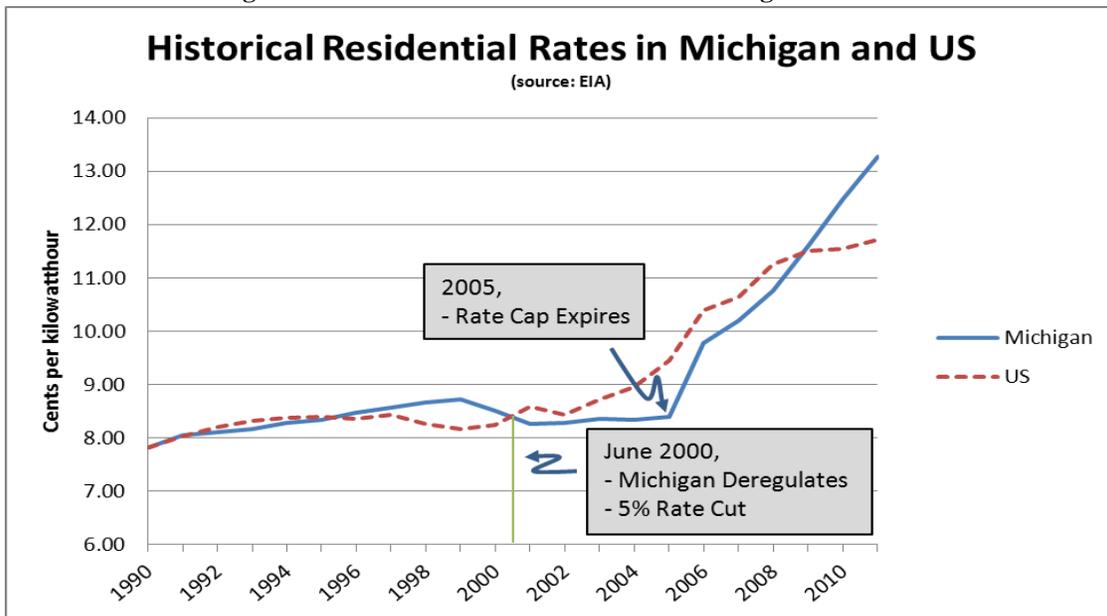
FirstEnergy Solutions reports a Michigan perspective in that prior to PA 141 electric rates in Michigan were above the national average. Once PA 141 was enacted electric rates in Michigan then fell below the national average. Subsequent to PA 286 (10% cap), electric rates in Michigan increased above national rates. The FirstEnergy chart below, **Figure 14**, illustrates this perspective.

Figure 14: Michigan Rates Compared to National Rates, 1990 to Present
Michigan rates compared to national rates, 1990 to present



This perspective may not tell the entire story. PA 141 included a five percent rate cut and a rate cap until late 2005. The rate cut may have put Michigan below the national average and the rate cap may have kept Michigan below the national average. After the rate cap expired, Michigan’s rates rose extremely fast and four years later would exceed the national average. **Figure 15** below shows this trend.

Figure 15: Historical Residential Rates in Michigan and U.S.



The Joint Utilities comment that the comparison of Michigan's rates to the national average is highly dependent on natural gas prices, as discussed in the Additional Areas report and shown in Figure 21 later in the report.

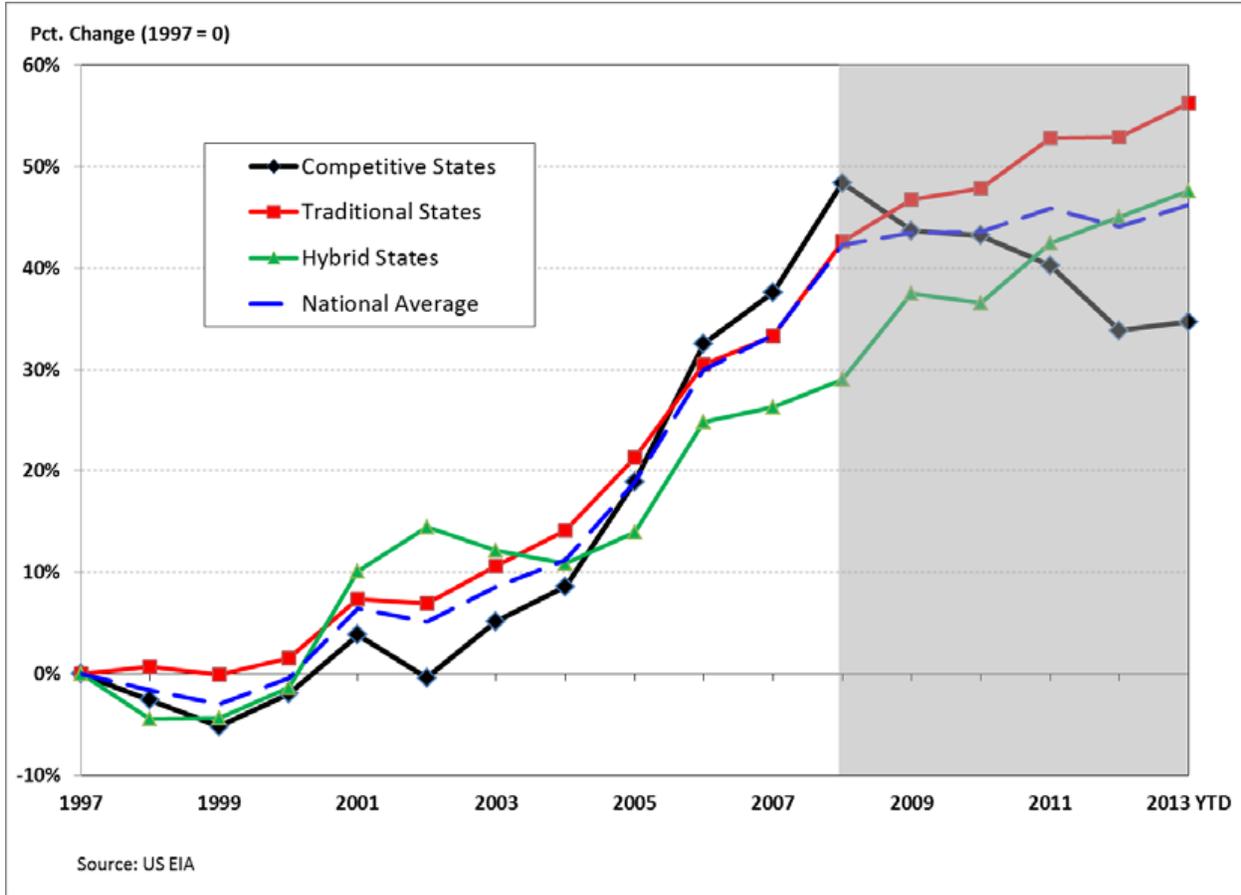
The Mackinac Center comments that the influence of the rate cut and cap are overstated. The Mackinac Center asserts that, because the rate cut only applied to residential customers, it does not explain why commercial and industrial rates also rose after the expiration of the cut and cap. The Mackinac Center also asserts that this explanation fails to take into account the fact that average electricity prices in the surrounding states and nation as a whole were similarly rising at this time, as well as other factors that were influencing the price of electricity, such as the price of fuels used for electricity generation. The Mackinac Center comments that various actions taken by the MPSC between 2004 and 2007 hindered the development of competition and discouraged entry to the market.

Many broader market factors make it very difficult to separate the signal from the noise when it comes to measuring the impact of deregulation. Such factors include national events (such as terrorist attacks or hurricanes), policy changes in other state jurisdictions and ISOs and regional similarities or differences (climate, culture). Numerous studies and articles have attempted to discern what effect deregulation has on rates, and come to very different conclusions.²³ To be sure, the rates in Michigan have risen faster than other states regardless of whether those states were regulated or deregulated.

ECN/CE comments that utilizing prices to make the comparison between regulated and restructured states is inappropriate, as many price differences between states existed before choice and restructuring began, and are due to unrelated factors (e.g. cost of living, subsidized hydro). ECN/CE asserts that data shows efficiency gains in power plants participating in restructured markets. ECN/CE present **Figure 16** below of cumulative percentage price changes from 1997-2013 YTD in competitive, traditional, and hybrid states which show decreases in competitive states from 2008 to the present, largely due to natural gas and wholesale power price decreases.

²³ See, for example, Kenneth Rose, *State Retail Electricity Markets: How Are They Performing So Far?* *Electricity Policy.com*, <http://www.electricitypolicy.com/articles/4455-stateretailelectricitymarkets> and John L. Domagalski and Philip R. O'Connor, *Regulation & Relevancy: Assessing the Impact of Electricity Customer Choice*. *Electricity Policy.com*, <http://www.electricitypolicy.com/articles/5122-regulation-relevancy-assessing-the-impact-of-electricity-customer-choice>

Figure 16: Cumulative Prices Changes, Average of All Rate Classes, 1997-2013 YTD

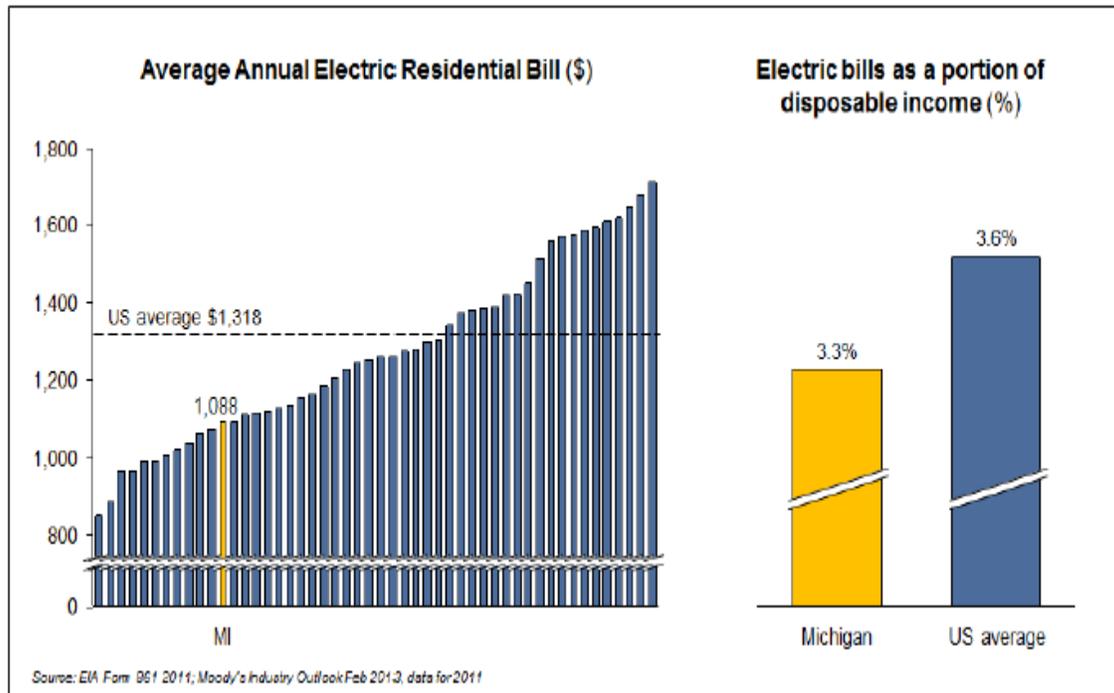


Rate Levels and Total Electric Bills

Rates are just one measure of the cost of electricity to customers. Rates are affected by the cost of the system and the way it is used. The facilities of a utility must be sized to meet peak load, which tends to occur in the summer due to air conditioning load. For example, if a utility has very few customers using electric heat in the winter, the load factor (average load divided by peak load) is very low. This means the cost of the facilities required to serve peak load must be spread over lower overall usage, which increases the rate. A double-peaking utility, one with significant cooling and electric heating load, does not have to build larger or additional facilities to serve the smaller peak, as the facilities are already sized to meet the higher peak. The cost of those facilities can then be spread over higher overall usage due to the increased usage associated with the second peak, leading to lower rates. Another way of looking at the cost of electricity to consumers is the average annual bill.

The Joint Utility Response provides the following graph, **Figure 17**, which shows the average annual electric bills for residential customers.

Figure 17: Average Annual Electric Residential Bill



States measure up very differently when considering customer impact/cost in this fashion. This illustrates that rates and costs are different, and it is very difficult to distinguish the reasons for differences between states.

IGS Energy (IGS) comments that average residential bills are not an appropriate basis for comparison. IGS claims that, because Michigan's average temperature is below the national average, Michigan customers have lower air-conditioning needs. IGS also claims that the vintage of the data is an issue. At the time of preparation, 2011 was the most recent annual data available. As many states have differing rate structures between summer and winter, using one summer month as IGS does may not be an appropriate basis for comparison.

Rate Levels and Other Measures

Another way to examine the effects of regulation on rates in different states is to examine the cost of generation, or power supply costs, for utilities in deregulated and regulated states, as well as between competitive suppliers and incumbents in deregulated states. There are several sources of data to make these comparisons, though they all have flaws.

The FERC Form 1 can be used to compare power supply costs between utilities. The financial data in the Form 1 is functionalized, meaning it is split between production, transmission, distribution, and other functions of the utility. Summing the production expenses, including an estimate of the actual return on production plant, and dividing by the amount of generated and

purchased power in MWh, gives a reasonable (if incomplete) power supply cost per MWh. In Michigan, and likely other states, certain administrative and general expenses/plant, common expenses/plant, and intangible expenses/plant are functionalized in the cost of service process based on some factor to approximate the amount of each that should be assigned to each function, including production. These expenses and plant, as they support all functions of the utility, cannot be directly assigned. Therefore, looking purely at production costs does not capture some costs that would be considered power supply related. In addition, relying on an estimate of actual return to compute the cost of capital to customers may not match the return the companies are allowed to earn. **Figure 18** below is a chart showing the production costs of certain large utilities in the East North Central region. Illinois is not included due to its completely divested generation.

Figure 18: FERC Form 1 Power Supply Costs \$/MWh Comparison

FERC Form 1 Power Supply Costs \$/MWh Comparison							
Northern Indiana Public Service (IN)	Duke Energy Indiana (IN)	Consumers (MI)	DTE Electric (MI)	Ohio Power Company (OH)	Dayton Power & Light (OH)	Wisconsin Electric Power Company (WI)	Wisconsin Power & Light (WI)
48.13	48.36	57.72	49.49	47.14	59.31	61.31	47.43

The data from EIA-861 can be used to compare the power supply revenue between competitive suppliers and regulated utilities, though there are limitations. Distribution utilities that also supply customers report data as “bundled” and “delivery” service. The bundled data combines all aspects of serving bundled customers, while the delivery data is only for the utilities’ delivery service supplied to customers purchasing generation from a competitive supplier. In order to compare power supply revenue, it is necessary to assume that delivery service is charged the same between bundled customers and delivery only customers, and remove this assumed delivery service from the bundled to give imputed power supply revenue. It is unclear where revenue due to transmission is included. This methodology can only be used in states with competitive suppliers serving customers. **Figure 19** below is a table showing the results of the calculation for states in the East North Central region.

Figure 19: Power Supply Revenue \$/MWh Comparison

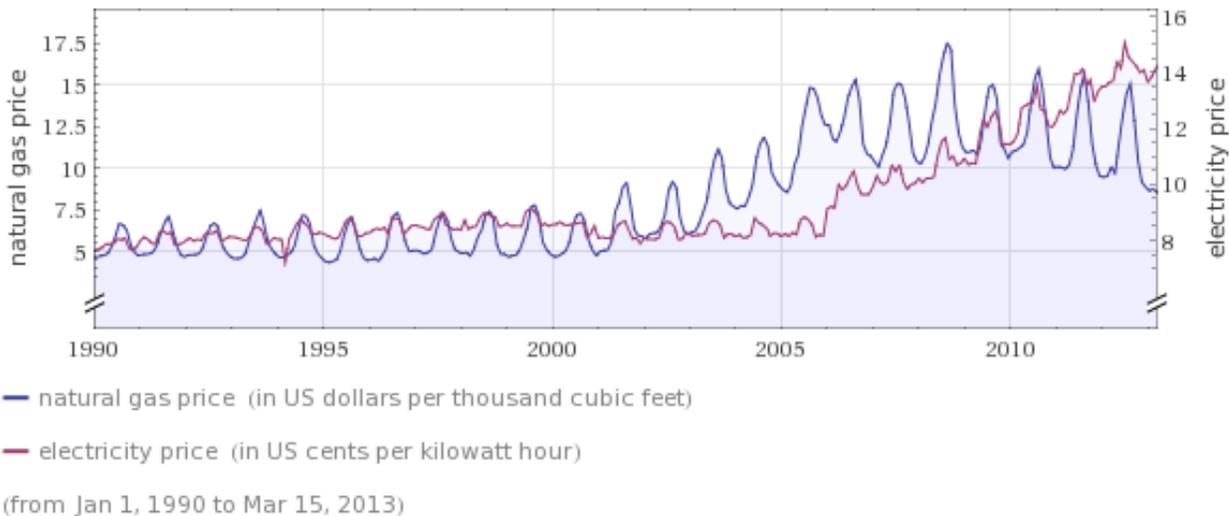
Power Supply Revenue \$/MWh Comparison				
		MI	OH	IL
Imputed Weighted Average Bundled Power Supply Revenue \$/MWh:		72.28	63.49	72.34
Weighted Average Retail Power Supply Revenue \$/MWh:		58.65	57.18	51.34
Source: 2011 EIA-861 data, http://www.eia.gov/electricity/data/eia861/zip/f86111.zip				

Rate Volatility and Pricing Stability

Predictable rates are of interest to policy makers because they allow for energy customers to budget their expenses with greater certainty. This is particularly important for businesses and low- and fixed-income residential customers. While there are predictable seasonal demand bumps, the long-term price of energy is driven mostly by the price of the materials used to produce it. **Figure 20** shows historical residential natural gas and electric prices in Michigan:

Figure 20: Historical Residential Natural Gas and Electric Prices in Michigan

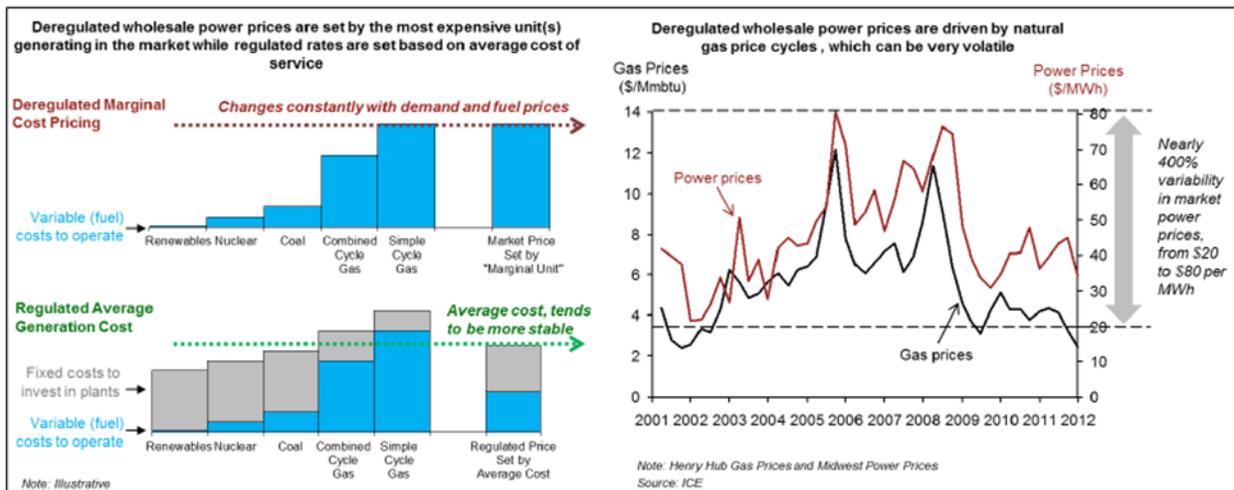
History:



Advocates of deregulation suggest that market mechanisms are the most efficient at addressing change in prices and that market systems, such as wholesale auctions, can help mitigate rate volatility. Advocates of a regulated market suggest that a deregulated market results in increased price volatility as firms quickly buy, sell, and adjust prices, not unlike the stock market, because the firms are more sensitive to the fluctuations of commodity prices. By comparison, regulated utilities apply for rate changes through a regulatory body and are subject to proceedings on the merits of a rate request.

The Joint Utility Response reports that regulated rates tend to be more stable than competitive rates. Wholesale power prices are affected by commodity cycles (the price fluctuations of fuel used to generate power), as these power prices are driven by the fuel cost of the highest-cost (“marginal”) unit providing power in the market. Historically, gas prices have been the driver of wholesale power prices, as natural gas plants have been the marginal unit in most markets, resulting in volatility. As a result of their exposure to market price volatility, deregulated states have experienced significant price spikes, with 50-100+% price increases. Markets with a heavy reliance on a single generating fuel source are more exposed to extreme commodity price swings. The Joint Utility chart below, **Figure 21**, illustrates this relationship.

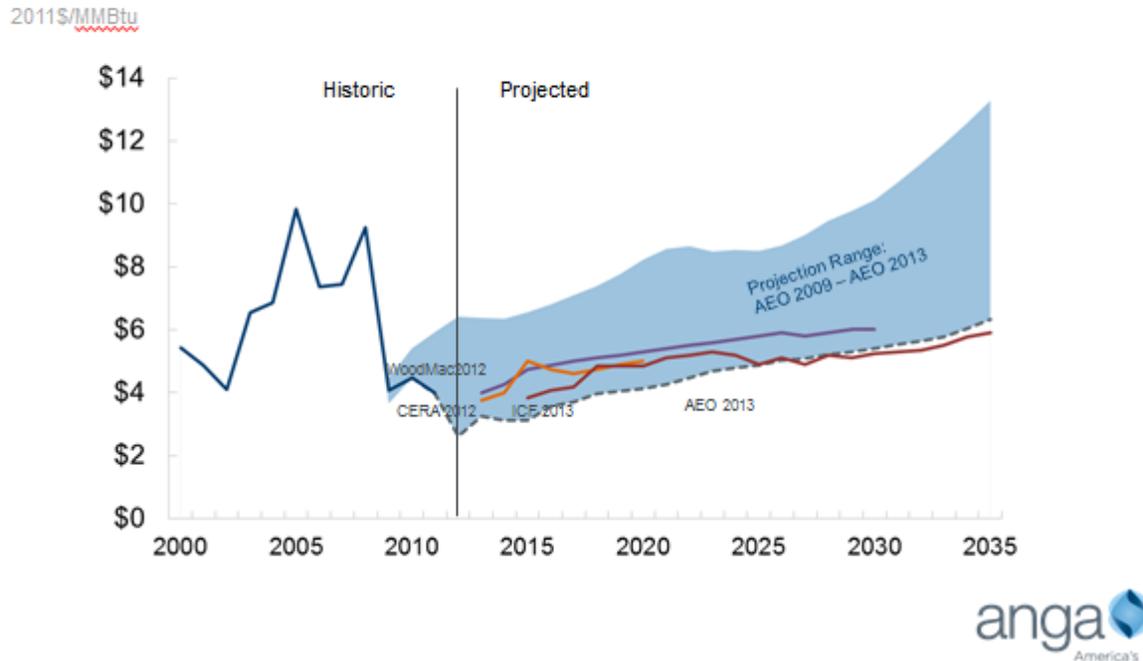
Figure 21: Regulated Rates vs. Competitive Rates



The American Natural Gas Association (ANGA) asserts that the emphasis on natural gas-fired generating units as marginal units setting wholesale prices is not entirely accurate. ANGA states that areas with transmission congestion have multiple marginal units setting prices, and that areas with high amounts of coal generation often have various coal units setting prices, and these various coal units have different cost structures based on heat rates, coal types, and cost of transportation. ANGA also identifies several factors in addition to fuel costs that affect wholesale power prices, such as the laws of supply and demand, customer load profiles, generator outages, and weather. ANGA also comments that natural gas prices are no longer, and are not projected to be, volatile. ANGA submits the **Figure 22** to illustrate:

Figure 22: Long-Term Price Stability

Long-Term Price Stability



ECN/CE empirically examined the notion that competitive rates are more volatile than regulated rates. The report states that the Joint Utility Response’s assertion amounts to the claim that retail prices mirror the volatility of wholesale prices. ECN/CE asserts that analyses of price data shows no statistically significant volatility difference between competitive and regulated states over the period 1999-2013, but that volatility was higher by a statistically significant amount in regulated states from 2009-2013.

The Joint Utility Response reports that surveys of residential and small-business customers in Michigan and other states indicate that these customers place the most value on price stability and predictability. Businesses with the option of switching between regulated rates and market-based rates show a clear pattern of selecting regulated rates when market prices are high and selecting market prices when they are low. When this switching is a “free option,” with the costs borne by other customers, businesses obviously like it.

Severstal comments that while it may be true that smaller customers value stability and predictability highly, large industrial customers place a higher value on lower power costs. Severstal also asserts these customers are used to volatile supply markets, and are willing and able to manage this volatility in power supply prices if the average cost is lower.

Energy Choice Now and FirstEnergy Solutions present several publications regarding the importance of pricing stability and market-based pricing, including:

- [*Annual Baseline Assessment of Choice in Canada and the United States \(2012 ABACCUS: An Assessment of Restructured Electricity Markets\)*](#)
- [*Retail Electric Competition in Michigan: GROWING MICHIGAN'S ECONOMIC GARDEN*](#)
- [*Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices*](#)
- [*State Competitive Procurement: Model Success Stories and Lessons Learned*](#)
- [*Retail Electric Choice: Proven, Growing, Sustainable*](#)
- [*Electricity Competition at Work: The Link Between Competitive Electricity Markets, Job Creation, and Economic Growth*](#)

Pricing Visibility

Energy Choice Now reports that there are very few policies to ensure pricing visibility in Michigan. PA 295 required that a portion of renewable energy costs and energy optimization costs be charged as line items on customer bills. Otherwise, the typical Michigan electric bill is a veritable maze of surcharges, adjustments, trackers and program specific charges. Consumers Energy uses eight separate surcharges currently, with DTE being comparable. As a result, Michigan electric bills are so complex that it is highly doubtful that any business customer would be able to determine the benefit of reducing electric consumption without consulting an expert management or engineering firm in the area of electric pricing. To the contrary, in restructured electricity markets where rates have been unbundled, energy, capacity and ancillary service costs are all transparent and known.

FirstEnergy Solutions reports that few policies exist in Michigan that require utilities to provide useful and transparent pricing, which has caused utility bills to become unduly complex. These complex billing practices do not provide the average customer with the necessary information it needs to make informed decisions regarding electric choice, which creates uncertainty and, in turn, only inhibits the success of competitive electric markets.

Other jurisdictions have several simple policies or forums to ensure pricing visibility, such as requiring incumbent utilities to include the default service price on the customer's bill, posting default service prices as well as current supplier's offers on a [*shopping website*](#) and using a competitive bidding process to procure electric generation for setting default service prices.

Energy Choice Now and FirstEnergy provided the only two responses related to pricing visibility.

Residential Rate Impact of the Customer Choice Program

There are differing views about the impact of Michigan's electric choice program on residential customer rates. There are, however, other policies to consider which have an impact on residential rates. For instance, Michigan will very soon complete the process of "deskewing," which eliminates the former subsidization of residential customers by commercial and industrial customers.

The Joint Utility Response reports that Michigan is the only state to offer a regulated rate option supported by utility-owned generation for the majority of customers and an essentially free option to switch to electric choice for a very small number of customers. This costs approximately \$300 million per year in Michigan and is borne by full-service utility customers, including all residential customers. Other jurisdictions have stricter rules which limit the customer ability to switch between regulated and deregulated generation rates.

FirstEnergy Solutions reports that it is impossible to comprehend the full extent to which residential customers in Michigan have been economically burdened by regionally high electric rates. Since the cap prevents 90% of Michigan utilities' load from shopping, incumbent utilities were not forced to efficiently operate or invest in making their generation facilities more productive as they would have under a market-based restructuring model. Therefore, captive non-shopping customers were required to pay rates that were significantly above-market. Since PA 286, electric rates in Michigan have increased substantially with the average rates for residential customers from 2008 through 2012 in the Consumers and DTE territories increasing 47% and 28%, respectively. Residential electric rates in Michigan rank highest in the Midwest.

Energy Choice Now reports that residential rates in Michigan have increased by 35% since the cap was imposed on customers. During the same period, wholesale prices within the local region fell by 45%. According to Continental Economics, Inc.'s paper [*Retail Competition in Michigan: Growing Michigan's Economic Garden*](#), it is estimated that customers that were able to switch within the 10 percent cap have saved approximately \$350 million in the three years from July 2009 through June 2012 while those customers in the queue are missing out on over \$170 million annually in savings. However, since the shopping queue mainly consists of commercial and industrial customers, the \$170 million in potential savings does not even include the potential savings that could be realized by Michigan's residential customers if they could select an AES. The Michigan Environmental Council presented a report that DTE provided to the Michigan Senate Energy and Technology Committee related to residential rate increases by DTE from 2008-2012. The residential rate increase categorization includes:

- 13% - Capital Investments - These include investments and operating expenses for environmental controls, renewable energy, energy efficiency and investment in base capital. There was no further breakdown between those categories.

- 11% - Load loss - The report did not distinguish between load loss due to customers leaving the system for other power providers or from the loss due to the economic downturn experienced by Michigan beginning in 2008.
- 6% - Increase in fuel costs.
- 9% - Cost or service changes that transferred costs from other rate classes to residential ratepayers.

ABATE reports that residential rates were actually reduced because of a drop in the power supply cost recovery factors attributable to large customers moving from bundled service to retail open access.

The Joint Utilities comment that, in total, residential customers' rates have increased as a result of retail open access.

Section VII – Separation of Generation, Transmission & Distribution

(Questions 17, 18 & 19)

This section presents information related to the impact of structurally separating transmission and distribution in Michigan, as well as data or studies regarding the effect of divesting or separating generation assets when moving to a restructured market. This section also provides data or studies regarding the costs or benefits of an integrated system versus a separated system.

Impact of Separating Transmission and Distribution in Michigan

The Joint Utility Response reports that the electric industry operated as a vertically integrated regulated system for over a century with electric utilities responsible for power generation, transmission, and distribution to end users. For the most part, the industry remains fully integrated and regulated. Many restructured states required or encouraged the incumbent utility to divest or separate their generation assets. The regulated transmission and distribution assets typically remained with the utility to deliver power to all customers.

Michigan utilities operate within a unique, hybrid structure. Generation and distribution assets are owned by utilities and are fully regulated by the MPSC. However, 10 percent of utility load is able to obtain choice service (generation) from an AES. Transmission assets are owned by stand-alone companies (ITC *Transmission* and METC in the Lower Peninsula, and ATC in the Upper Peninsula) and under the operational control of MISO. Wolverine, a generation and transmission cooperative, also operates in the Lower Peninsula. This structure applies to all Michigan investor owned utilities except Indiana Michigan Power which remains fully integrated with generation, transmission and distribution assets and operates under PJM territory.

The Joint Utility Response also reports that generation became unregulated in the states that had utilities divest generation or transfer generation to unregulated utility affiliates or holding companies. This makes it extremely difficult, if not impossible, to reverse course following divestiture of generation. Once the generation is divested, it is extremely difficult to re-create a fully regulated, integrated model. Unlike many deregulated states, Michigan implemented a measured approach with continued state oversight and regulation of generation.

The MPSC provided a report on this topic in 2010 pursuant to a requirement in PA 286. The MPSC's [*Report on the Advisability of Separating Generation and Distribution within Electric Utilities in Michigan*](#) found that “the implementation of structural separation of generation and

distribution would lead to higher customer costs.”²⁴ The MPSC further stated that it “did not receive any evidence that further separation of generation or distribution is necessary or desirable.”

FirstEnergy reports that separation of transmission and distribution in Michigan has had little impact and opines that the greatest impact would be to separate generation assets from the distribution business. Until generation separation occurs, the utilities continue to have a financial interest in retaining customers that could otherwise experience savings through access to a fully competitive retail market. Generation separation removes the utilities' financial stake in a deregulated market, and renders them indifferent to customers who choose to shop.

Energy Choice Now reports that it is very difficult to determine if any specific impact was created by the separation of transmission and distribution that might not have occurred if those two services were still offered on a combined basis by state regulated utilities. The more important issue is the impact of not structurally separating generation from the distribution system. Because Michigan utilities did not divest generation, a truly level competitive playing field has not been developed for non-incumbent utility generation assets. In addition, the available empirical data shows that the effects divestiture or structural separation are improved operating efficiency, reduced costs, and improved output at generating plants that are competitively owned and operated. This is because competitive generation owners reap the rewards of lower costs and greater production.

ITC Holdings reports that structural separation has improved overall transmission reliability, transmission efficiency, service restoration and regulatory compliance. ITC's only line of business is electric transmission, and the company is structured to be free from influence by entities that buy or sell energy as a commodity. ITC does not own generation or distribution assets, or fuel suppliers, and it makes no retail or wholesale electricity sales. In addition, ITC is not owned by utility companies, the holding companies of utilities, or entities that buy or sell energy as a commodity. The structural separation has made transmission planning independent from both local and regional perspectives and not influenced by market participants.

COMPETE Coalition notes that while complete divestiture of assets provides the preferred and cleanest separation of wires and supply, it is not required for a successful retail choice program. What is required is that incumbent utilities not be allowed to make investments going forward on behalf of retail suppliers and their customers and recover the associated costs through non-bypassable charges.

²⁴ See Michigan Public Service Commission, Letter to Governor Granholm and State Legislature with Report on the Advisability of Separating Generation and Distribution within Electric Utilities in Michigan, October 6, 2010.

Data or Studies Presented

- Robert J. Michaels, [*Vertical Integration and the Restructuring of the U.S. Electricity Industry*](#), CATO Policy Analysis, July 13, 2006. Cato Institute, Washington, D.C.
- United States of America Electric Energy Market Competition Task Force and the Federal Energy Regulatory Commission (June 5, 2006), Docket No. AD05-17-000, [*Report to Congress on Competition in the Wholesale and Retail Markets for Electric Energy*](#) (see Chapter 1, see also p. 93).
- Bushnell, J., and C. Wolfram, "[*Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generation Plants*](#)," California Energy Institute, Center for the Study of Energy Markets, CSEM-WP-140, March 2005.
- Global Energy Decisions, LLC, "[*Putting Competitive Power Markets to the Test*](#)," July 2005.

Section VIII – Environmental Considerations

(Questions 9 & 10)

This section presents information related to environmental protections under different regulatory structures. Other areas of this report discuss reliability and affordability at length (also a focus of questions 9 and 10) and those presentations will not be repeated in this section.

Environmental Considerations

Consumers Energy reports that environmental rules like the Mercury and Air Toxics Standard (MATS) will require coal fueled power plants to install expensive air quality control systems to meet more stringent emissions rules. The industry expects that many smaller, older coal fueled generating units will retire when the MATS rule takes effect in April 2015, or possibly April 2016 if a one year extension for meeting the rule as provided by the rule is obtained by some generators. The amount of coal fueled generation being retired is anticipated to bring the amount of generation within the MISO footprint back into balance with electric demand, or even possibly cause a shortage of electric capacity.

Consumers Energy reports that legislative requirements for renewable energy for utilities are different than those for an AES, creating a variance in costs incurred per customer to meet renewable standards. Both utilities and AESs have a requirement based on kWh, but only utilities have a capacity requirement for new renewable energy resources by 2015. The capacity requirement can only be met by building or causing to build new renewable generation facilities; the kWh requirement can be met through the purchase of RECs in addition to the energy generated by new facilities.

Consumers Energy also reports that because the actual energy output of some recent wind farms that have gone into service are higher than were expected, more energy has been generated than was needed to meet requirements (note that the capacity was necessary regardless of the output). The excess energy is therefore being sold through the Renewable Energy Credit (REC) market. In addition, under the law the large utilities only receive approximately 80% of the RECs generated by existing PURPA facilities. The result is excess RECs pushed to the market annually. As a result, the REC market has been flooded and their associated value is low. The difference in requirements means that AESs can meet their requirements for a lower price than utilities can.

FirstEnergy reports that while there are a vast number of future events that could affect affordability, reliability, and environmental protection, a fully competitive retail market is the best system to effectively and efficiently handle the myriad of potential catalysts. Competitive

retail marketers are uniquely situated to perform dynamically to adapt to changing market conditions. For example, when competitive barriers are removed, a competitive retail market will become more economically attractive and more marketers will enter the service territory, causing the supply of retail electric services to increase, which will cause electric prices to decrease, all while providing continuing affordability to consumers. Increased marketers in a region will enable more visibility into a region's future generation needs, which may cause certain marketers to consider generation expansion projects to provide reliability under market-based economies to preserve affordability. Fully competitive markets also provide the necessary environment for marketers to appropriately respond to demand for environmental protection efforts in the marketplace.

The Joint Utility Response reports that the 10 percent choice cap reduced the uncertainty of unlimited switching and supports Michigan utility investment in reliable, clean energy for the future that includes the benefit of environmental protection. Michigan utilities have invested billions since the 2008 energy legislation and plan to invest billions in the coming years in base infrastructure, environmental compliance, and renewable energy and energy efficiency.

Section IX – Possible Policy Outcomes

The public comments center around one of two primary outcomes, namely full regulation or full deregulation/choice. The public comments recognize and contemplate other potential outcomes, such as a change to the current choice cap or no change at all, but the majority of the information supplied is presented in an all or nothing construct. Below are a few considerations within each possible outcome that were not presented at length by the public commenters.

Adjust the 10% Cap

Policy Considerations: Should a modification to the cap be implemented, policy makers may consider the level of the adjustment to the cap as well as the possible implications of such an adjustment. In consideration of the adjusted cap, there could also be the potential of setting separate caps for different classes of customers. Policy makers could also consider granting the MPSC the authority to adjust the cap, which may provide for increased flexibility and responsiveness in the long run administration of the program. Although not required, policy makers could consider and address the additional loss of full-service load that a regulated utility may expect to experience and how the loss of such load should be handled for ratemaking purposes. Examples of these considerations may relate to the possible provision for immediate rate relief for large volume losses to customer choice or alternatively the requirement that a utility not be able to project customer choice load loss as part of a rate case before the loss has materialized. This option assumes that the generation assets of any affected utility operating under an adjusted cap would remain regulated by the MPSC, although that may be a policy consideration depending on the cap amount and other factors. Policy makers may also be confronted with issues related to allocation of certain types of costs to full-service customers versus all customers, including those on choice.

Regulatory Impact: An adjustment to the 10% cap would require the Commission to issue at least two orders, one to update Case No. U-15801 to reflect the new applicable cap number and a second to update the AES application materials. The current ratemaking process for setting both base rates and the power supply cost recovery (PSCR) would not be impacted by an adjustment to the 10% cap unless additional guidance was provided by policy makers.

Administrative Impact: Upward modification to the 10% cap would result in a larger volume of licensed suppliers in Michigan as well as a larger volume of choice customers. The amount of administrative work would be expected to increase as the cap number becomes higher. This would include additional supplier marketing material to be reviewed and an increased volume of inquiries from both suppliers and customers. In addition, an update to the MPSC website, including the MPSC's Consumer Tips, would be required to reflect these changes to the Choice Program. Additional staff may be required to address the increased volume in marketing

materials, customer questions and general program administration – especially if residential participation were to gain traction.

The Detroit Area Green Skills Alliance recommends continuing the “hybrid structure” as there are advantages and disadvantages to both regulated and deregulated markets and that limitations should be placed as to not overload the participation with one customer class, limiting access for others, which has happened in the recent past.

Move to Full Regulation

Policy Considerations: A decision to move to full regulation would require policy considerations regarding the implementation process. Specifically, it would be necessary to determine what would be done with customers currently taking service from an AES. There are many paths that could be taken during the transition to full regulation. Customers being served by an AES could be allowed to continue the service through the end of their contract or could be asked to go back to full service by a certain date. Policy makers could also consider allowing current choice customers to remain on choice until a time when they choose to take full service from the utility, simply closing the door to new entrants. This provision could also be extended to customers currently waiting to move to customer choice. Although not presented in the public comments, policy makers should be aware of and consider the potential impact and ramifications of interference with contracts within a move to full regulation (or decrease of the 10% cap). The provisions outlined above may or may not impact current choice contracts in such a transition. These are just a few of the many possible paths policy makers could take to transition to full regulation.

Regulatory Impact: The Commission would need to issue a modifying order in Case No. U-15801 to reflect the details of a move to full regulation and, depending how policy makers choose to implement full regulation, the Commission may issue one or more orders to rescind AES licenses. The current ratemaking process for setting both base rates and the PSCR would not be impacted by a move to full regulation unless additional guidance was provided by policy makers.

Administrative Impact: MPSC Staff would facilitate the relinquishing of all Bonds and Letters of Credit secured by the AESs once those suppliers were no longer serving customers. MPSC Staff would also be tasked with updating the electric choice tariff provisions of each electric utility. These tasks may also include assisting the Commission in issuing orders to remove or rescind the renewable energy plans required for each AES. These administrative tasks are manageable whether there is an immediate switch to full regulation or a gradual transition to full regulation. The amount of time and resources needed to carry out these tasks in a move to full regulation is largely dependent on the type and pace of the transition.

The Utility Workers Union of America believes that at a minimum the customer choice cap should remain at 10% but that a move back to a fully regulated electric utility system should be strongly considered.

Move to Full Customer Choice or Full Deregulation

The difference between full customer choice and full deregulation is the existence of a regulated utility rate for generation (a/k/a power supply). Full deregulation would not include a regulated rate option. The pre-PA 286 choice structure was considered full customer choice since there was no cap and it also provided customers with a regulated rate option. The policy considerations, regulatory impact, and administrative impact of moving to full customer choice are identical to those provided for with an adjustment to the 10% cap as full choice would simply mean “no cap” with a regulated rate option.

Policy Considerations: A move to full deregulation (no regulated rate offering) is an option that requires considerable policy consideration. The main points of consideration would be whether or not to require the divestiture of generation assets and the treatment of stranded costs, if applicable. Policy makers could consider requiring the divestiture of generation assets, whether such divestiture is to an unregulated affiliate of the utility, spun off to create a new public entity or a sale to an independent party. In lieu of this, divestiture may not be required but could be incentivized by other policy considerations. Should divestiture be required, policy makers may need to consider the treatment of stranded costs and whether these costs would be allowed to be collected from customers. In addressing stranded costs, policy makers may consider the option of allowing for securitization of the assets. Given the potential impact of the collection of the stranded costs, policy makers may also give consideration to temporary rate freezes or other rate structures for the default provider during this transition period.

In the event that policy makers did not require divestiture or allow for the divestiture of generation assets to an affiliate, the current Code of Conduct may need to be updated and/or enhanced to ensure equitable competition under full deregulation. The Code of Conduct is intended to promote fair competition by establishing measures to prevent cross subsidization, information sharing, and preferential treatment between the regulated and unregulated operations of electric utilities. Policy makers may also consider whether POLR services are appropriate and, if so, who performs such a service and how the POLR rate would be calculated and monitored. Full deregulation could take shape in many different forms.

If policy makers are intrigued by the concept of market-based pricing under the deregulated model but have reservations about non-pricing related aspects of deregulation, then policy makers may consider a fundamental shift in utility capacity planning. A utility could meet

anywhere from zero to 100 percent of its demand through owned generation. Policy makers could consider a requirement that each utility secure a certain portion of its demand through the open market. This approach would capture, to the extent desired by policy makers, the impact of market based rates while removing other characteristics of a deregulated structure. The [2012 ABACCUS](#) Report provides regulators and policy makers with a series of considerations to improve the likelihood of success of its retail electricity restructuring. This methodology points to public policies that promote market forces to the greatest degree possible, while maintaining essential consumer protections.²⁵

Regulatory Impact: The regulatory impact would be driven by the policy decisions as part of the move to deregulation. The rate setting process for the distribution of electricity by the regulated utility would go unchanged but the need for power supply cost recovery plan and reconciliation cases would presumably be eliminated.

Administrative Impact: The administrative impact of a move to full deregulation would be significant due to the increase in the volume of work related to customer choice. The transition process in other states has taken approximately 3-10 years with many proceedings and rulemakings to establish (and revise) the ground rules in a deregulated environment. The number of AES applications and licenses would increase, as would the number of contracts and marketing materials being used in the marketplace. In addition to processing more AES license applications and reviewing more marketing materials, a full-scale review and update to each of the utility tariffs would be required to properly reflect a fully deregulated structure. A tariff revision of this size and scope is a significant undertaking. MPSC Staff would also expect an increase in the number of customer inquiries in a deregulated structure. This could necessitate a customer outreach/education program, as well as possible Commission orders or rulemaking related to disconnection, deposits, and other provisions applicable to the incumbent utilities and AESs. MPSC Staff may also be tasked with adding new and existing suppliers to the Public Utilities Assessment process. Significant amounts of administrative work would be required if policy makers were to enhance the Code of Conduct or to require regulated entities to divest generation. Similar to a move to full regulation, the amount of time and resources needed to carry out the tasks in a move to full deregulation would be dependent on various aspects of the transition as desired by policy makers. It is likely that a move to deregulation would require additional staff, at least in the short-run, to address the additional administrative effort required to carry out the transition.

COMPETE Coalition urges Michigan decision makers to eliminate the current 10% limitation on electric choice and take the necessary steps needed to advance well-structured competitive retail electric markets.

²⁵ 2012 ABACCUS Report p. 32-34

Summary

This report outlines and describes electric choice in Michigan and offers alternative options to consider in response to Governor Snyder's 2012 address on Energy and Environment. Michigan currently operates under a unique hybrid structure that exhibits characteristics of both a regulated and unregulated market. The public comments center around two primary outcomes, namely full regulation or full deregulation. An overview of the comments summarizes the topics such as participation, market structure, reliability, capacity, stranded costs, rates, separation of generation/transmission/distribution, environmental considerations and the potential impact of each should the law be changed.

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