Abstract

In the US, fourteen states have introduced competition in their electricity markets. In competitive markets, any company can generate electricity and customers can choose from what supplier they receive electricity.

Michigan introduced competition in its electricity market in 2000. But in 2008, the state restricted the competitive market to only 10% of its customers. Today, some people want to introduce complete competition again.

This paper studies what is the best option for Michigan. First, it analyzes the different existing electricity market structures, and compares their prices to figure out which is the best structure. Then, it studies Michigan prices evolution (and other elements) and compares it to other states, to finally arrive to the conclusion that Michigan should introduce complete competition again. But to succeed in doing so, the state has the big challenge of divesting power plants from utilities.

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1. Introduction

Electricity is very present in our life. This is why it is so important to find the best way to manage its production and the delivery to customers. Until the 1990s, all electricity markets were vertical structured: utilities produced electricity and transmitted and distributed it to customers. This monopoly had sense, because the investment to build power plants was very high.

In the 1990s some started saying that there is a better way to manage electricity: competitive markets, in which consumers can choose from what supplier they receive their electricity looking at the price they offer. This is a big change. Warren Buffet said that this change "will create the largest transfer of wealth in US history". It can be compared to what happened with the phone and aviation markets several decades ago.

This research paper aims to study how both market structures work and what are their pros and cons. It will also take a close look to Michigan, a state that faces an important decision: move towards complete competition, stay with the current 10% cap (that only allows to 10% of its customers to access the competitive market) or go back to a vertical structured market.

To figure out what is the best option, there are going to be made several comparisons of electricity prices in Michigan and the other US states. The study is focused on residential prices, more than on commercial and industrial prices.

2. Understanding the electricity markets

2.1. US Electricity Market History

In 1882, Thomas Edison's company commenced operation of the first electricity generation plant and distribution system in the United States. The famous Pearl Street Station in lower Manhattan (New York City) provided lighting service to 59 customers within a few blocks of the plant. Soon, by the end of the 1880s, many cities had similar central stations. The rapid growth of the industry and the demand for electricity service led to regulation of these utilities[1] by local municipal governments.

One feature of the fast-paced technological development of the electric industry was the appearance of the transformer, enabling larger plants to produce at higher voltages that could be transmitted longer distances with the voltage stepped down for purposes of end-use customer needs. Things changed radically. Utilities began to produce electricity outside cities and deliver it to customers in different communities. The result was greater efficiency and a declining cost industry that could lower prices while significantly expanding.

Industry growth beyond the boundaries of cities and towns prompted a movement to state level regulation, often at the urging of the industry itself, in the interest greater certainty and uniformity. States could rely on the railroad regulation model inaugurated in 1869 with the creation of the Massachusetts Board of Railroad Commissioners. Three states led the way in creating utility regulatory commissions in 1907, Wisconsin, Georgia and New York. In 1914, 27 more states would establish utility regulatory commissions.

The Federal Government entered the field after the First World War[2] with the Federal Water Power Act of 1920 that created the Federal Power Commission (FPC), now called the Federal Energy Regulatory Commission.

As a general matter, the electric utility industry was organized as local vertical monopolies in which they generated, transported and distributed electricity. The massive capital needs of the industry fostered the growth of large utility holding companies with large numbers of local utilities that had been gradually acquired and built up[3]. In the 1930s, generation and distribution capacity grew very quickly, at an average of 12% every year. This led to a huge decrease in residential prices, going from $4.30/kWh in 1900 to $0.88/kWh in 1932 (see Figure 2.1).

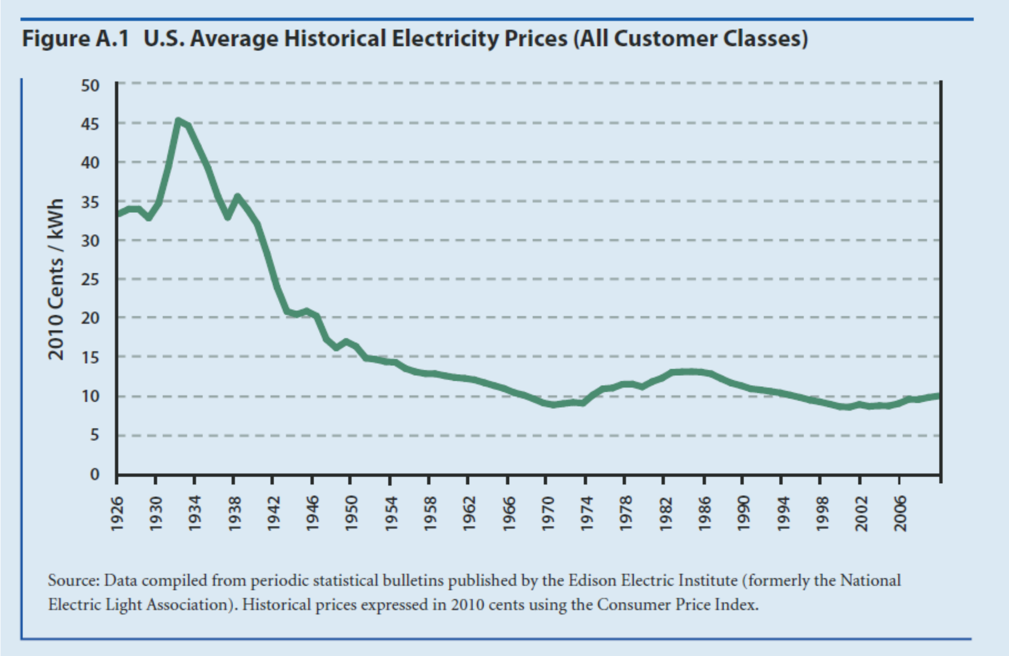

Figure 2.1

With the 1929 collapse of financial markets and the Great Depression that followed, confidence in unregulated markets collapsed as well. The New Deal era brought a more forceful assertion of authority by the Federal Government. In 1935, Congress delegated to the Securities and Exchange Commission authority over utility holding companies to dismantle those considered too large or presenting too much potential for market abuse and to regulate financial dealings within holding companies on an ongoing basis.

The FPC was tasked to regulate the wholesale market, including transmission rates. And, with considerable controversy, the Federal Government began to enter the market as a producer of power with the creation of such state-owned corporations as the Tennessee Valley Authority and the Bonneville Power Administration to produce low-cost power, usually from hydroelectric power plants[4]. By 1950, 12% of the total generation was federal government-owned.

Even as the industry grew and demand soared, utilities customarily served electricity in single state. Even when a utility might serve in adjacent states, regulation would be applied by each state to solely the service within its boundaries. The interconnection of power networks across state lines was not actively encouraged until the necessities of World War I made it an item of interest at the Federal level. Many utilities were not keen on interconnection out of concern over a loss of control. The 1927 PNJ Interconnection between Pennsylvania and New Jersey was the first significant interstate transmission facility. Maryland was soon added to the interconnection and the name was changed in 1956 to PJM.

Interconnections remained largely mattes of convenience and were not a result of any overall policy direction in the industry or by regulators. However, the Great Northeast Blackout of 1965 brought doubts about interconnected networks reliability. In response, the North American Electric Reliability Council (NERC) was created and charged with responsibility for establishing standards and procedures aimed at enhancing network reliability. The 1965 blackout was followed in the 1970s by the OPEC oil embargo which, because a large portion of generation on the east and west coasts was oil-fired, drove prices up significantly and the exposed the vulnerability of the electric system to unreliable fuel supplies. The Federal Government responded by reorganizing FPC as the FERC, and giving to it more power and responsibilities.

During the late 1970s and through the 1980s, Congress and FERC took steps to gradually introduce competitive market forces into the interstate natural gas industry by moving away from wellhead price controls and by opening up interstate pipelines for the transport of customer-owned or marketer-owned gas. This was followed by the Energy Policy Act of 1992, which gave FERC the authority to order transmission owners to "wheel" non-utility generation. This was a major step in the liberalization of the wholesale electricity market along the lines of the natural gas business.

In 1996, FERC issued Order No. 888 that broadly opened up transmission grids for non-discriminatory access for any energy generation company, both utility and non-utility, thus providing a substantial push for competition in the wholesale market. FERC undertook to provide for the creation of Independent System Operators (ISO) to as independent and federally regulated entities that would operate wholesale markets for generation. ISOs would determine which generators met standards for participating in the wholesale market and would be responsible for assuring that enough electricity was generated to match load, planning the transmission system and providing fair access to the grid. To guarantee true independence, ISOs do not own either generation or distribution assets.

Image 2.2 shows the currently operating ISOs and the areas where they operate.

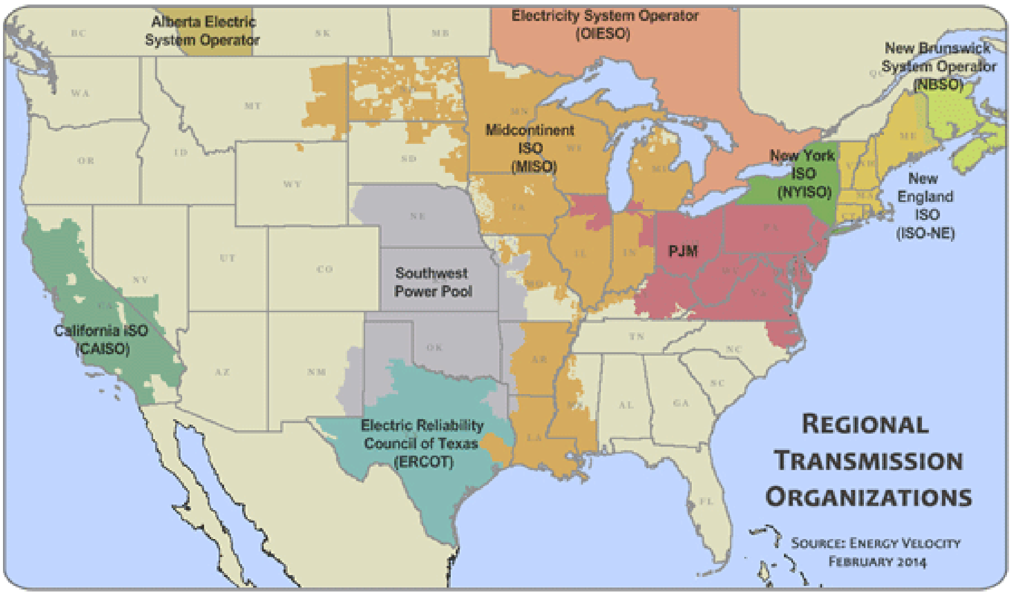

Image 2.2- Source: Energy Velocity

FERC's promotion of competition and open access in the wholesale sector left each state still as the regulator of the retail sector and free to choose whether to introduce retail competition or not. Since 1996 FERC and Congress have continued to provide increasingly favorable conditions for the implementation of retail competition in the United States.

The Energy Policy Act of 2005:

-Reaffirmed competition in wholesale power markets as national policy;

-Gave more regulatory tools to FERC in order to protect final electricity consumers; and

-Guaranteed development of a stronger energy infrastructure, including electric transmission.

In 2008, FERC issued Order No. 719 to improve competition in wholesale markets by encouraging long-term power contracts and giving more responsibility to ISOs and also now called Regional Transmission Organizations (RTO)[5].

In keeping with the American federalist system, the regulation of the electricity industry is a shared responsibility between the federal government and the states. As things stand in 2014, while the boundary lines are not always entirely clear and can be altered by regulatory decisions, legislation or court decisions, some issues are controlled by the federal government and some others by each state.

FERC	State
-Wholesale transactions and oversight of ISOs/RTOs	-Retail tariffs: bundled service or delivery service only
-Transmission rates and limited siting approval	-Transmission authorization and siting
-Hydroelectric licenses	-Certification and approval of new utility non-hydro generation facilities
	-Certification and approval for new transmission facilities
	-Delineate retail franchise areas

2.2. Regulation and Deregulation.

The terms *regulated* and *deregulated* with respect to the electricity industry can convey the wrong idea about actual conditions. In a deregulated market there are many laws and rules. It would be more accurate to talk about *competitive* market or a *restructure* in the market. Typically, people opposed to restructuring and media use the term *deregulation* and people supporting restructuring talk about *competitive* markets. In this paper all these terms are used.

2.2.1. The Traditional Regulated Market

Prior to 1996 utilities in every US state were organized as vertically integrated firms that included both production and delivery of electricity. In such a market there are three players: utilities, customers and regulators. The utility is solely responsible for generation, transmission and distribution of electricity to the exclusion of any other company. Regulators permit the utility to have a monopoly in a specified territory based on the rationale that the required capital investment is so large that the utility needs considerable certainty that it will recover the investment. The condition is that the state controls the prices and limits profits in the effort to balance the interests of utility investors and customers.

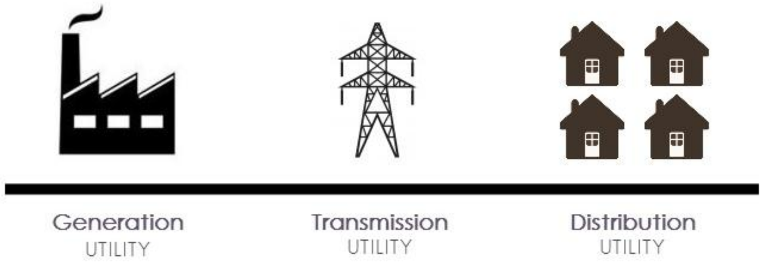

Figure 2.3 - Structure of a Vertical Market

2.2.2. Restructured Market

Deregulation in the electricity market basically means that the market is open to entry in various ways by players other than the local utility. Deregulation can take place in the wholesale market, in the retail market or in both.

Figure 2.4 - Structure of a Deregulated Market

Deregulated Wholesale Market

In this market structure, electricity generation is open to any company. They sell their electricity in the wholesale market by: selling it through the electricity pool[6] or through a bilateral agreement directly with a buyer. The wholesale market is overseen by FERC with delegation of substantial functions through an ISO (Independent System Operator). To make this structure possible there has to be a non-discriminatory access to transmission. ISOs are responsible for this.

Deregulated Retail Market

In states that have deregulated their retail markets, customers can choose to purchase their electricity supply from competing alternative electricity providers (AEP) offering differing prices as well as differing terms and conditions. The power supply is delivered over the wires network of the local utility at rates approved by state utility regulators. In most deregulated states, local utilities can also sell electricity to customers, often doing so as a provider of last resort (POLR) for customers who have not decided to choose an AEP.

At the retail level –both in regulated and deregulated structures-, end-use customers are customarily categorized into the industrial, commercial and residential sectors. Prices for the sectors differ due to quantities purchased and in some cases different delivery voltage levels. Figure 2.5 shows the national average price levels for the three customer categories since 2001. The waviness in the trend lines reflects seasonal price difference with prices tending to be higher in the summer peak cooling periods.

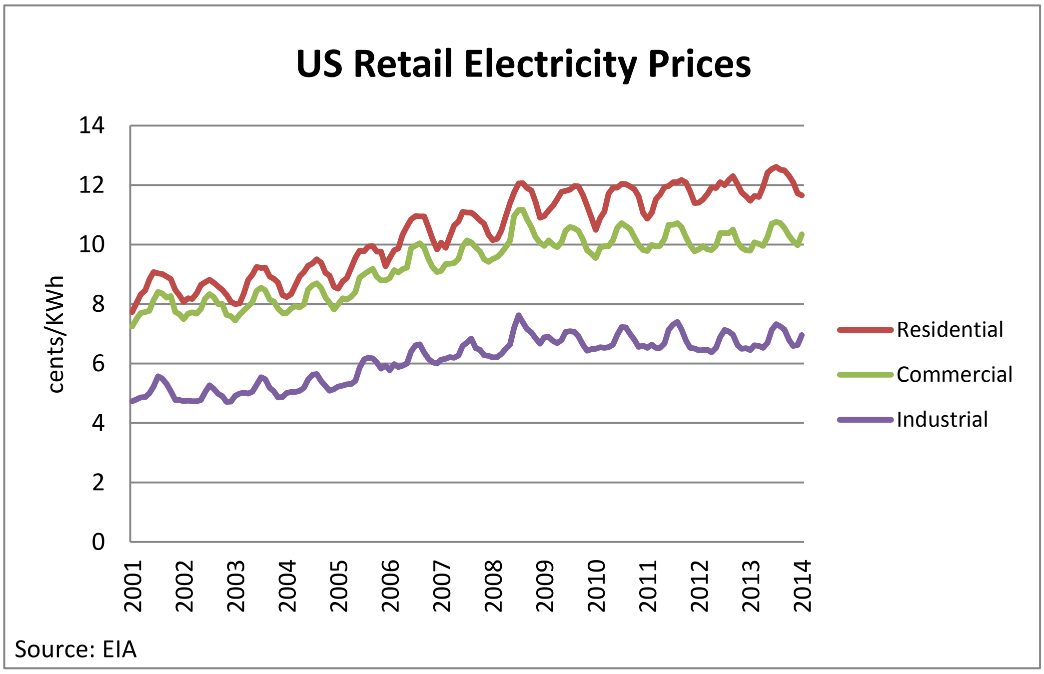

Figure 2.5

2.3. Comparison of Regulated - Deregulated Markets

There are varying opinions of how to classify states with respect to the extent that they have moved toward deregulation. For example, the classification scheme used by the U.S. Energy Information Administration is more of a legalistic one, based on the status of state laws and regulations. Figure 2.6 shows that 22 states and the District of Columbia, took at least initial steps toward electricity supply deregulation. As Figure 2.6 shows, seven states (yellow) suspended their processes and went back to a mainly regulated market and 16 states (green) with active customer choice, though in some cases restricted.

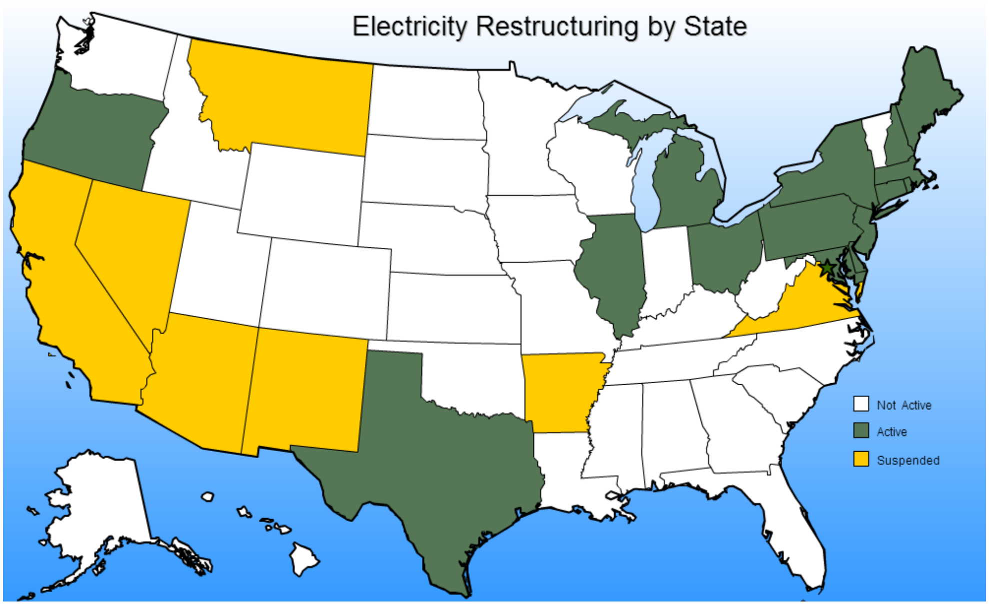

Image 2.6 - Source: EIA

However, for purposes of this paper, which is focused on actual market performance, 14 jurisdictions (13 states and the District of Columbia) have been identified as having extensive retail electricity choice. These are Connecticut, Washington DC, Delaware, Illinois, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island and Texas.

Three other states, California, Michigan and Montana, started moving towards competition but for different reasons they could not achieve it completely. They have now a hybrid structure in which only a small percentage of their customers can access the competitive market.

Thirty-two states are treated as regulated while Alaska and Hawaii are excluded from the study due to their remoteness from the continental electricity markets. [7]

Before examining the evolution of prices in some individual states, a review of overall price development in the regulated and deregulated groups of states is in order. Figure 2.7 shows the yearly average percentage price evolution of all deregulated states compared to the group of regulated states. Figure 2.8 shows evolution of average nominal prices.

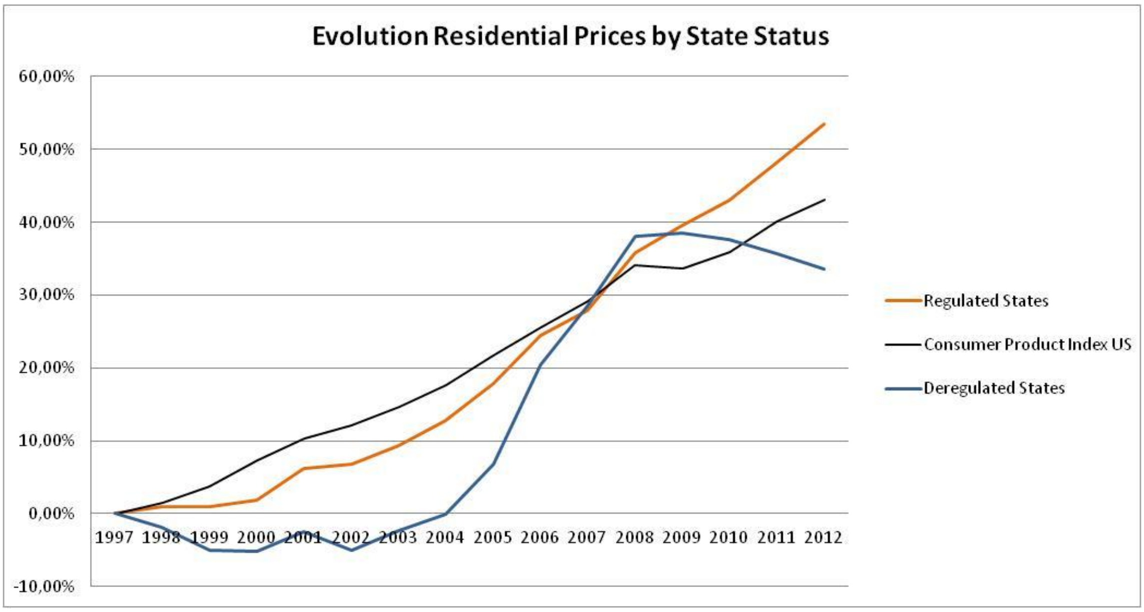

Figure 2.7

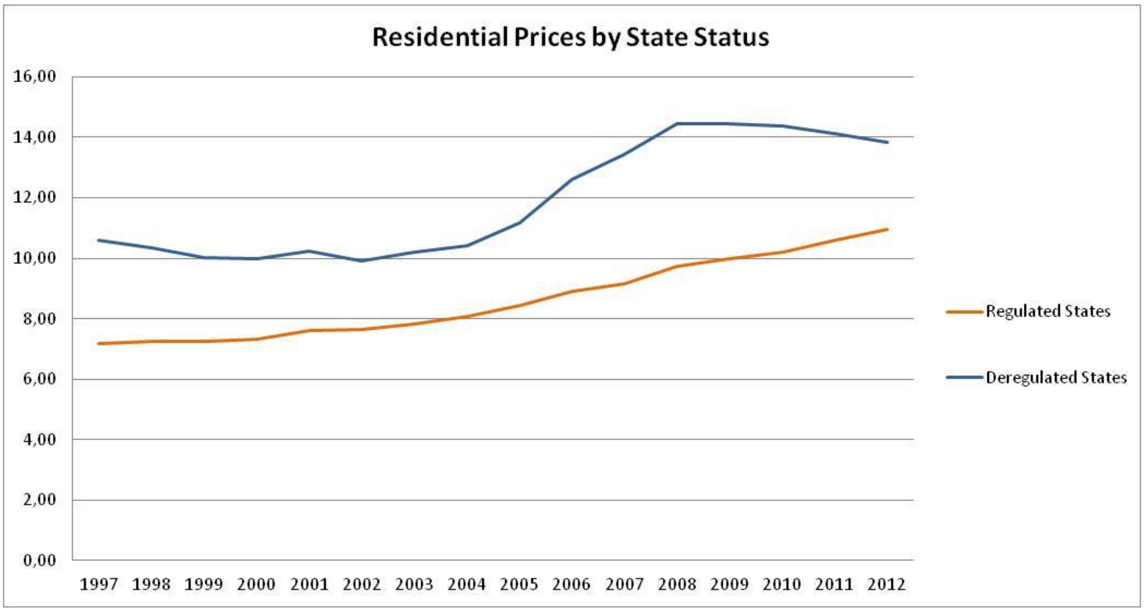

Figure 2.8

Prices in the group of deregulated states are higher than regulated states. They were higher at the outset of deregulation due to pre-existing conditions under traditional regulation. However, Figures 2.7 and 2.8 also show that increases in the competitive states have been less since 1997 than in the regulated states. It can be reasonably concluded that deregulation has not caused prices to increase relative to regulation.

Analysts of electricity markets have addressed the question of why the nominal prices in the deregulated are higher on average. The main factors are that the general cost of living, including such things as labor rates, taxes and land prices, is higher in deregulated states (most of them located on the east coast) and that the cost of transporting fuels by pipeline and rail is higher than to areas closer to fuel sources. Further, there are other regional factors such as the availability in the Pacific Northwest of substantial supplies of low-priced, federally subsidized hydroelectric power generated from federally owned facilities.[8]

The following tables help to illustrate how the level of nominal residential electricity prices (Table 2.1) and the general cost of living[9] (Table 2.2) tend to correlate. States in grey are deregulated and in green, regulated.

State	Electricity Prices
Alaska	16,52
Connecticut	15,68
New York	15,62
Massachusetts	14,51
Vermont	14,46
New Hampshire	14,31
Rhode Island	13,91
New Jersey	13,7
Maine	11,87
Maryland	11,65
Delaware	10,98
Wisconsin	10,64
Florida	10,3
Pennsylvania	9,83
Colorado	9,8
Kansas	9,57
Georgia	9,53
Minnesota	9,52
Tennessee	9,22
North Carolina	9,18
Ohio	9,16
Mississippi	9,15
South Carolina	9,14
Nevada	9,04
Alabama	9,02
South Dakota	8,83
Texas	8,77
Indiana	8,63
Montana	8,58
Oregon	8,39
North Dakota	8,19
Utah	8,18
Iowa	8,12
Louisiana	8
Illinois	7,99
West Virginia	7,91
Oklahoma	7,81
Idaho	7,61
Wyoming	7,55
Kentucky	7,54
Washington	7,06

Table 2.1

State	Cost of Living
New York	136,4
Connecticut	132,6
Alaska	131,4
New Jersey	130
Rhode Island	125,7
Massachusetts	122,1
New Hampshire	120,7
Vermont	120,5
Maryland	119,9
Maine	110,6
Delaware	107,2
Oregon	106,8
Washington	102,6
Minnesota	101,9
Pennsylvania	100,7
North Dakota	99,9
South Dakota	99,6
Colorado	99,5
Montana	98,4
Florida	98,2
West Virginia	97,2
Wyoming	96,7
Wisconsin	96,5
North Carolina	95,9
South Carolina	95,6
Illinois	95,6
Nevada	95,5
Louisiana	95
Georgia	92,9
Ohio	92,5
Alabama	92,4
Iowa	92,1
Kansas	92
Texas	91,8
Utah	91,1
Indiana	90,6
Oklahoma	90,4
Tennessee	90,2
Kentucky	90,1
Idaho	89,8
Mississippi	89,1

Table 2.2

While those who favor regulation are correct that average prices are higher in the deregulated group of states as a group, they do not appear to be correct in attributing those higher average prices to regulation. Rather, the gap between the prices in the group of states that have deregulated and the average prices of the regulated states appears to have narrowed since the late 1990s when deregulation began.

The other discussion point is the sudden price increases in deregulated markets (see Figure 2.7). In the first years, deregulated states had very steady rates, but after those years rates rose fast. The initial steady rates were because of capped and frozen rates. During this period (1997-2004), electricity prices increased in all other states. Therefore, when caps expired, prices went up to meet the real electricity prices, producing a sudden hike (see Figure 2.7) and exposing end-use customers to all its consequences.

So far, all deregulated states have experienced this increase during the transition to a competitive market. But it cannot be said that applying caps and frozen rates always imply price increases. If this measures had been set after 2008 (when the markets started going down due to the financial crisis) rates would presumably have decreased.

The other question is if this transition is possible without setting a price cap and freezing rates. There is no reason to think that this is not possible. But it has been a common policy among competitive markets because it is a way to protect customers –especially residential customers- from unexpected increases during the transition (which would be very unpopular and could produce the suspension of deregulation), and because it is a way to adapt little by little to the new structure.

After the hike in prices during the transition, prices in deregulated states stabilized (see Figure 2.7). Now, after fourteen states have finished their restructuring processes, it can be said with quite confidence that in these days these states have better prices than the ones they would have if they continued with regulated markets (they have had lower increases, as it has been pointed out before).

Taking a look at regulated states, it can be seen that until 2008 their prices were not bad, as they increased at a slower pace than inflation[10]. But from 2008, prices have been increasing at a faster pace than inflation. The reason is that regulated markets are not flexible[11]. Then, when there is a bad economic environment, utilities have less demand but the same fixed costs and their only solution is to raise rates.

The conclusion from all this is that deregulation has been positive for those states that have applied it and seems better than regulation so far.

2.4. Deregulation: Three States That Took Different Paths

The experiences of three states with deregulation help to illustrate the variety of approaches that have been taken under the system of state retail market regulation and allow for some comparisons in outcomes to be made.

2.4.1. California

California was the first state to deregulate. In 1998 the state allowed non-utility generating companies to sell electricity in the wholesale market and also opened the market to a new class of retail suppliers (AEPs) who could buy in the wholesale market and sell to retail end-use customers.

California utilities sold their fossil generation assets while retaining their nuclear and hydro assets. This was encouraged by policy makers and regulators to assure real competition. Utilities were still allowed to supply electricity to the end-use customers who chose to remain with them and not to switch to an AEP.

In 2000 and 2001 California experienced serious blackouts and price increases, known as the California Electricity Crisis. The reasons for this crisis were complex and even today there is divided opinion on the underlying factors. What is known for sure is that the problem was not a lack of generation capacity.

The wholesale market was deregulated and competitive, but retail rates were frozen. This is what other states used successfully during the transition to competitive markets, but in California three other factors were added to these frozen rates producing wholesale prices to be higher than retail prices, and thus producing economic losses to AEPs and utilities.

First, generators could only sell their electricity through the California Power Exchange. This means that AEPs and utilities were not able to escape from the wholesale market prices. If bilateral transactions (electricity transacted out of the CPE) had been allowed, suppliers could have avoided the high prices at CPE.

Second, utilities were required to buy in a day-ahead market and not permitted to hedge against price fluctuations. In contrast, large end-use retail customers could contract with AEPs for price protection, leaving utilities with few customers.

Third, partly due to lax oversight and poorly developed market rules, some generators and traders, especially Enron, manipulated the markets. For example, some power plants were shutdown at short notice to reduce supply, thus unexpectedly increasing wholesale prices (800% from April 2000 to December 2000). All of this had limited impact on most retail end-use customers because their rates were either frozen under the deregulation design or were fixed by individual contracts with AEPs, but had a big impact on AEPs and specially utilities.

Utilities were in an impossible position. They had to buy electricity at a higher price than the price at which they were allowed to resell it, losing money and causing bankruptcy of one utility and near-bankruptcy of another. In January 17 of 2001, Governor Gray Davis declared a state of emergency.

Among the consequences were a loss between $40 and $45 billion, the imposition of a cap that limited the number of customers that could access the competitive electricity market and the entry of state government into the wholesale market as a buyer of long-term supply at elevated prices out of fear that the temporary high prices, due to manipulation, would persist. Further, a number of states that were in the process of implementing deregulation pulled back in the belief that California's problems were inherent in deregulation rather than in the specific rules in California.

One statement of the lessons to be taken from the California experience is that of Professor James L. Sweeney: "The issue is not that deregulation does not work but that it should not be done the California way"[12]. He also points out that "retail prices should reflect wholesale prices, either on average or through real-time pricing"[13].

In the past five years ago California has lifted the cap somewhat, letting more customers access the competitive market. California will likely continue to have a mixed (or hybrid) system of partial deregulation and traditional regulation.

2.4.2. Texas

Deregulation in Texas started on January 1, 2002 under the terms of Senate Bill 7 providing for a phase-in over several years.

Texas is in the unique position of having jurisdiction over not only retail, as do other states, but also over a large portion of its wholesale market. The Texas Electricity Reliability Council is an ISO that covers most of Texas but is not interconnected with any other state and thus outside the interstate jurisdiction of FERC. About 85% of the Texas electrical load has been deregulated, with the remaining 15% accounted for by utility load outside ERCOT and by such exempt utilities as rural cooperatives and the cities of San Antonio and Austin city-owned utilities.

About 80% of industrial and commercial final customers have switched to another electricity supplier since 2002, and among residential customers 58,9% have switched with the other 41,1% served by default supply companies formerly affiliated with utilities[14]. A comparison between utility and non-utility prices can be seen in Figure 2.9.

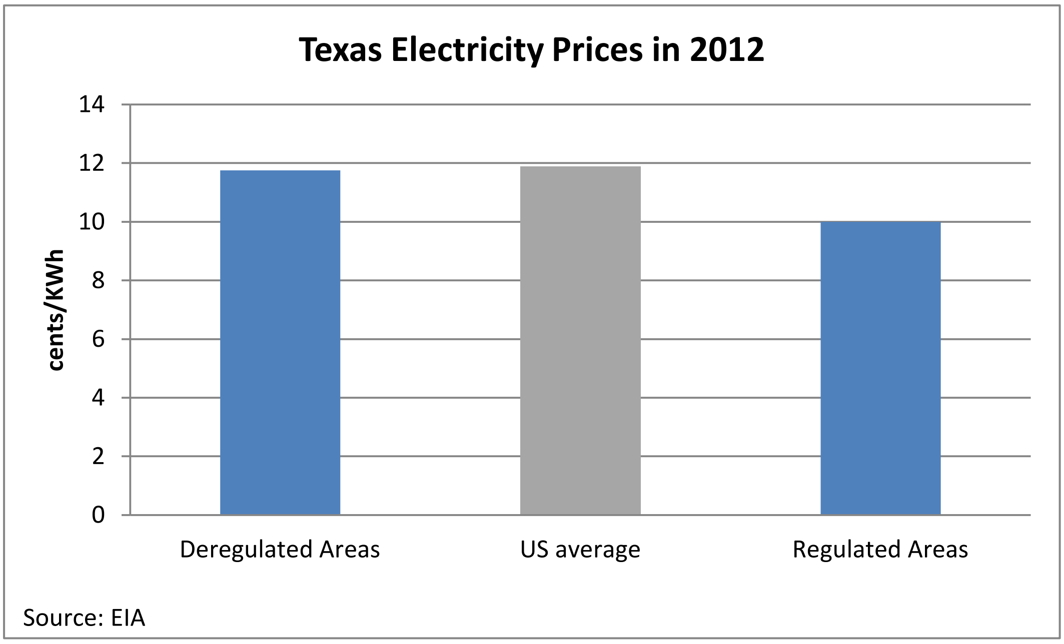

Figure 2.9

To attract new Retail Electricity Suppliers, Texas opted to establish a floor in utilities electricity prices. Otherwise, utilities would benefit from their economies of scale and would be able to sell at much lower prices than new retail suppliers.

The evolution of Texas residential electricity prices is shown in Figure 2.10.

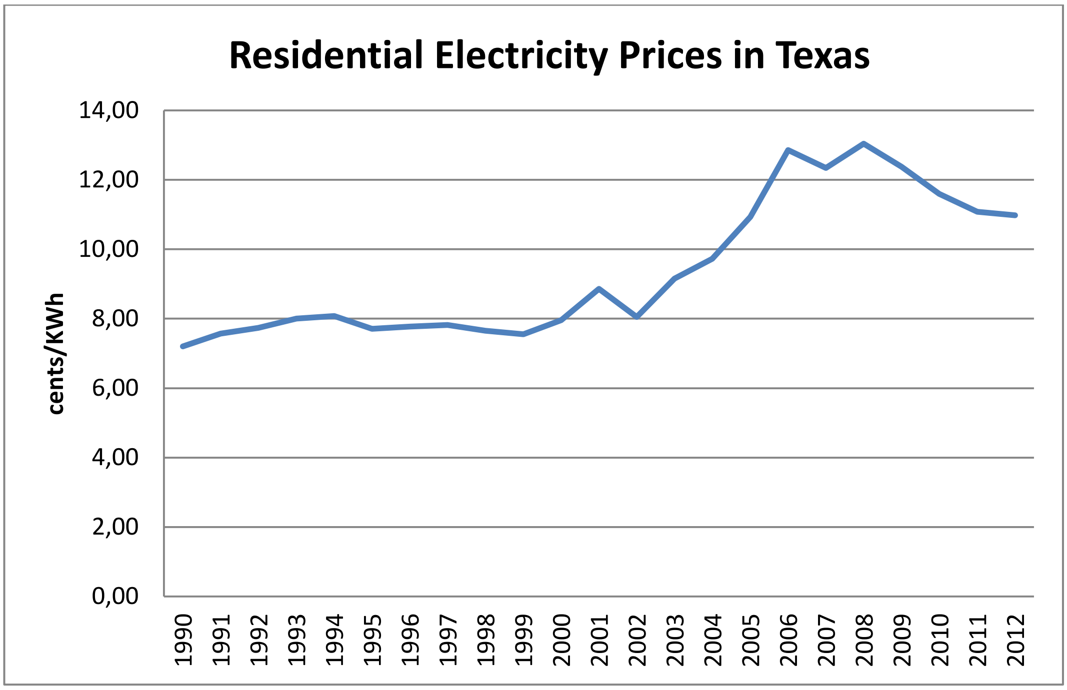

Figure 2.10

When deregulation was applied electricity experienced an increase in prices, but five years later prices stabilized and now seem quite reasonable. Texas will have to wait some more years to be able to take conclusions.

2.4.3. Illinois

The Illinois Electric Service Customer Choice and the Rate Relief Law of 1997 commenced a Mandatory Transition Period during which the state would fully implement a competitive retail electricity market.

The transition included a freeze on utility tariffs through 2006[15], a reduction of up to 20% for residential customers, cost-based delivery rates for customer choosing an alternative supplier and stranded cost charges to compensate utilities for over-market power plant investments. Further, with only minimal regulatory conditions utilities sold or spun-off to affiliates virtually all generation assets including nuclear plants and, as required, selected an ISO to join. There were also a series of mergers that required only minimal regulatory involvement.

At the beginning, in late 1999, only larger commercial and industrial customers were allowed to choose a non-utility electricity supply provider. The following year more non-residential customers were allowed to switch to a non-utility provider. Residential customers were eligible to choose a supplier in May 2002.

In 2006, in reaction to expected price increases following the end of the price freeze, the Retail Electric Competition Act created the Illinois Power Agency to conduct supply procurement auctions on behalf of residential customers who did not choose alternative suppliers. Municipalities were allowed, subject to local voter approval, to enter into electricity aggregation contract for power supplies to serve those community residents not choosing an alternative provider. The law also accelerated the deregulation process with respect to non-residential customers with a more rapid termination of requirements on utilities to provide supply for non-residential customers.

As shown in Figure 2.11, average residential prices in 2007 following the end of the rate freeze were still below those in 1997 when the deregulation law was enacted. After some additional price increases post-2007, prices stabilized and they are now the 8th state with cheapest prices in the country. It is estimated that restructuring the electricity market has supposed \$37 billion in consumer savings, of which \$18 are residential customer savings[16].

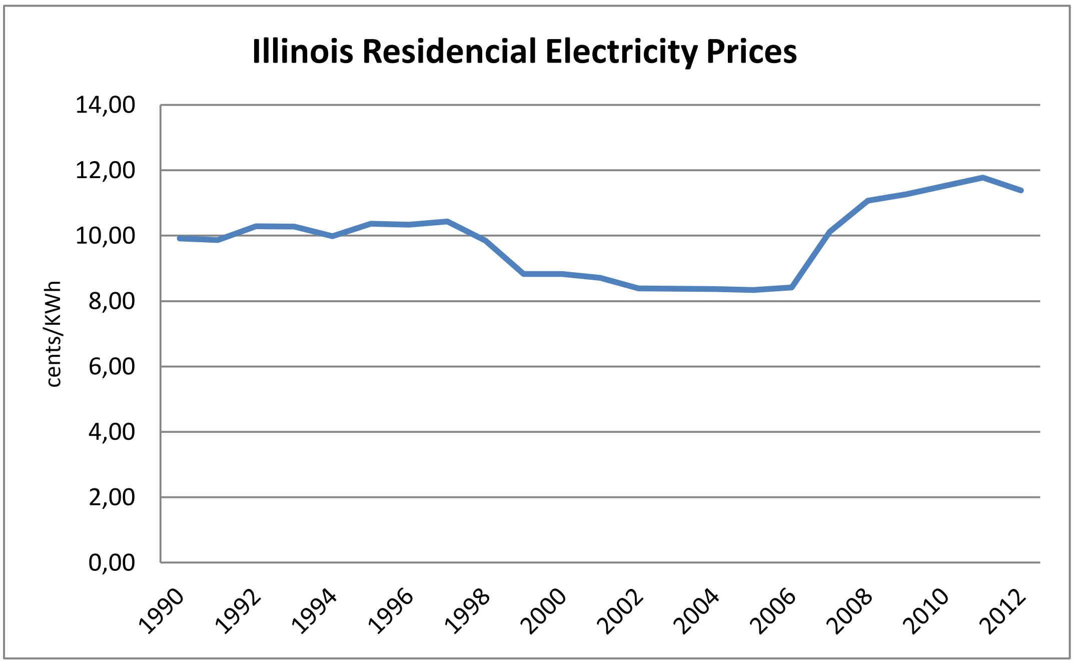

Figure 2.11

At the end of 2013, almost all non-residential customers were served by alternative providers and more than 3 million residential customers had an electricity provider different from a utility. It seems that deregulation in Illinois is widely accepted in the state and is working well enough to be a model of how to design and implement deregulation.

3. Michigan Electricity Market

3.1. Background

Until 2000, Michigan electricity market had a traditional regulated structure. The state's two major utilities (DTE Energy and Consumers Energy) as well as other smaller ones, generated, transmitted and distributed electricity. End-use retail customers could only receive electricity from regulated utilities.

As it is typical in non-competitive markets, Michigan had "skewed" rates. Skewing happens when prices for the various rate classes (residential, commercial, and industrial) are not set according to the real cost of service to each class. Some classes are intentionally set above cost to allow rates for others classes to be set below cost. In Michigan, residential rates were set at 10-20% below the real cost while commercial and industrial were set at 10-20% above, thus providing a subsidy to one class from others. This is being turning around now, producing an increase in residential prices.

Michigan restructuring towards competition began in 2000 with Public Act 141 and Public Act 142, known together as the *Customer Choice and Electric Reliability Act*. The Michigan Public Service Commission (MPSC) was authorized to deregulate the electricity market and encouraged "to foster competition in this state in the provision of electric supply..."[17].

Key features of PA-141 included the following:

- Customers would be allowed to choose to purchase electricity from an AEP or to remain with the utility.

- Utilities were directed to separate their generation and transmission functions. In other states, such as Illinois, utilities sold or spun-off their generation assets, but in Michigan utilities chose to sell transmission assets.

- Lowered residential rates of all utilities customers by 5%.

- Froze residential rates at the reduced levels from 2000 through 2005 and froze utility commercial rates through 2004 and industrial rates through 2003.

From 2001 to 2008, the level of choice participation (customers that received electricity from an AEP) ranged from 3 to 20 percent of utility load. Choice participation moved in inverse proportion to wholesale energy prices and did so during this period, as it can be seen in Figure 3.1.

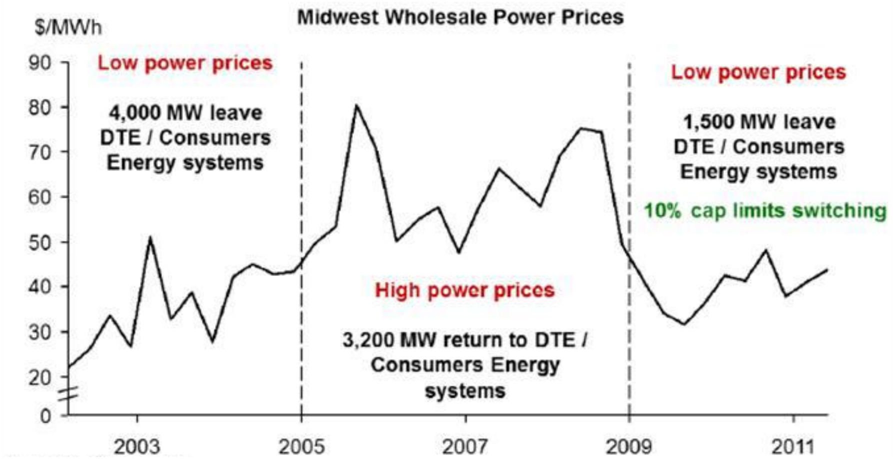

Figure 3.1 - Source: Joint Utility Response

Apart from opening the retail market on the customer side, PA 141 also intended to assure on the supply side that non-utility generating companies would be attracted by a competitive market in which to sell their electricity. There was a belief that Michigan needed additional generating power plants.

PA 142 applied to Consumers Energy and Detroit Edison, who had invested in expensive nuclear power plants that had made their rates uncompetitive. The utilities argued that an essential element of a transition to competition was that they needed to be protected from during the transition to give them time to adjust to the new competitive market. PA 142's securitization provisions allowed DTE and Consumers to refinance their high cost nuclear power plant debt at lower customer-backed interest rates.

In 2005 the rate cap set by PA 141 expired. Electricity prices increased considerably in the following years (see Figure 3.2) as wholesale prices had been increasing during the rate freeze years. Customer choice declined and many customers returned to utility supply under the rules in Michigan.

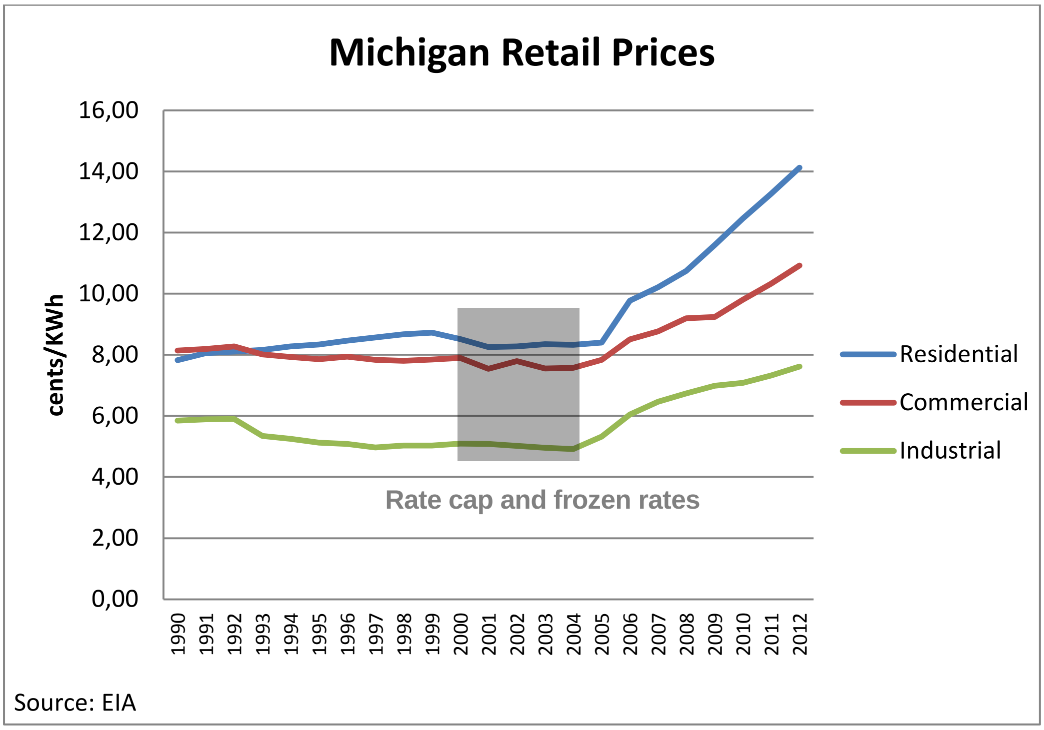

Figure 3.2

In 2008, as part of a larger energy legislative package that included setting goals for renewable energy share of the electricity market, Public Act 286 provided 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." This meant that only 10% of customer electricity load in each utility could switch to an AEP. The reasons for this controversial cap are going to be analyzed later.

3.2. Current situation

Since deregulation, and thanks to PA 141, Michigan has been able to attract new investments in generation power plants (see Figure 3.3). Figure 3.3 shows that this new generation came mainly from non-utility investors. In the 18 months after the passage of PA 141, construction started on almost 6000 MW of new generating plants by companies that were not affiliated with any Michigan utility. Construction started by affiliates of Michigan utilities during this period was less than 1000 MW (see Figure 3.4).

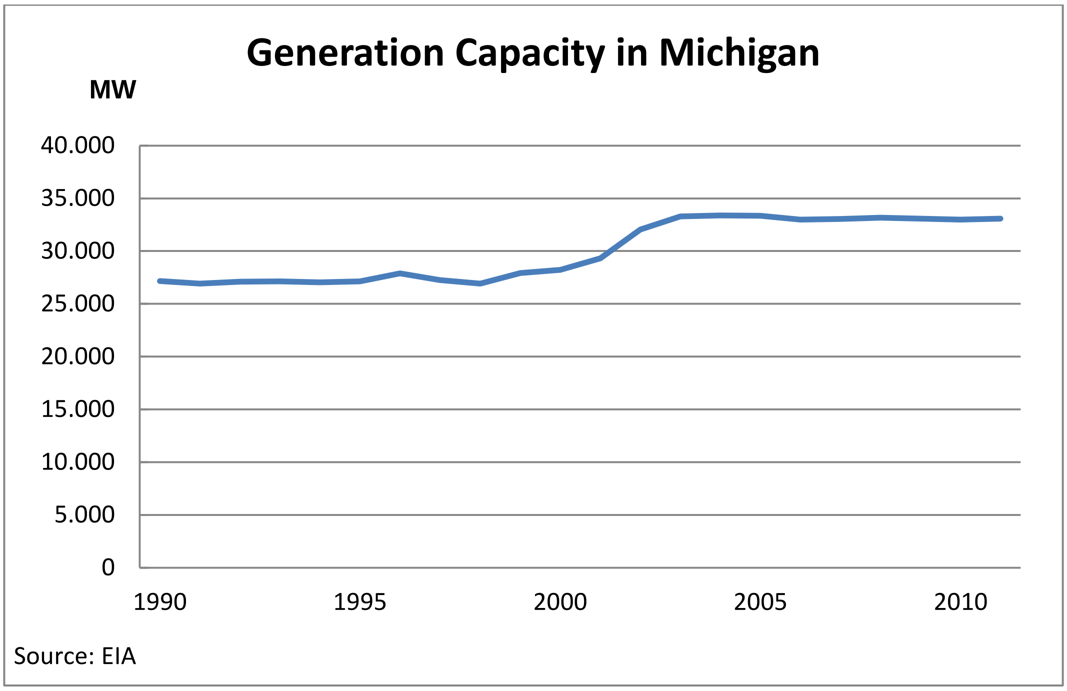

Figure 3.3

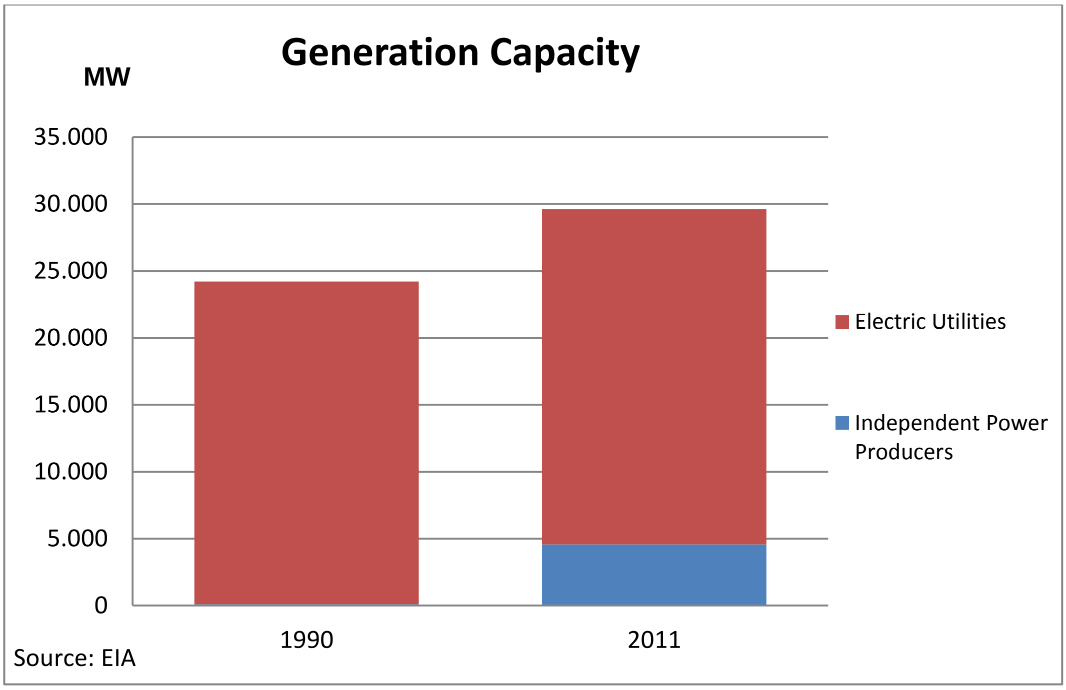

Figure 3.4

The new non-utility investment was mainly in gas-fired generation. This has contributed to a more diversified Michigan generation portfolio, shown in Figure 3.5.

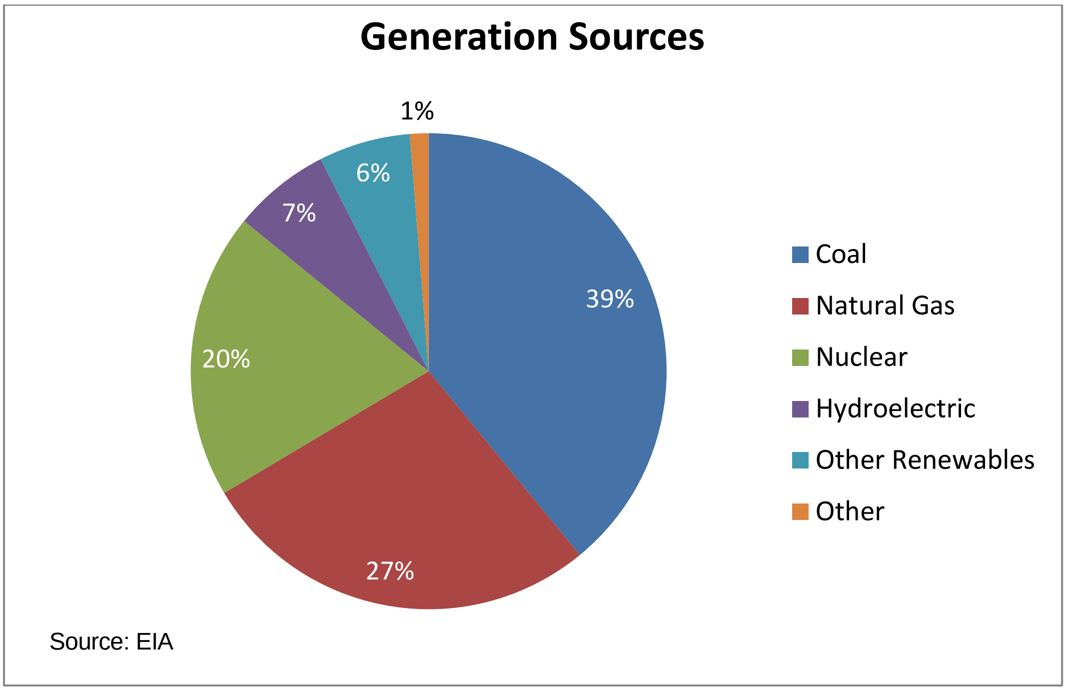

Figure 3.5

As said before, nowadays Michigan has a hybrid structure, with 10% of load served competitively and the remaining 90% served under traditional utility tariffs. However, residential load is not being served under the 10% competitive supply. This 10% is being accessed mainly by industrial customers, accounting for 85% of the competitive load, and commercial customers, accounting for 15% (see Figure 3.6). Residential customers are not there because there was a reluctance to switch to AEPs because they did not know how the market worked and because residential market tends to develop only after the industrial and commercial markets have gained substantial traction.

There are currently 27 AEPs that have received authorization from MPSC; the most important are AEP Energy, Constellation, Direct Energy and Duke Energy.

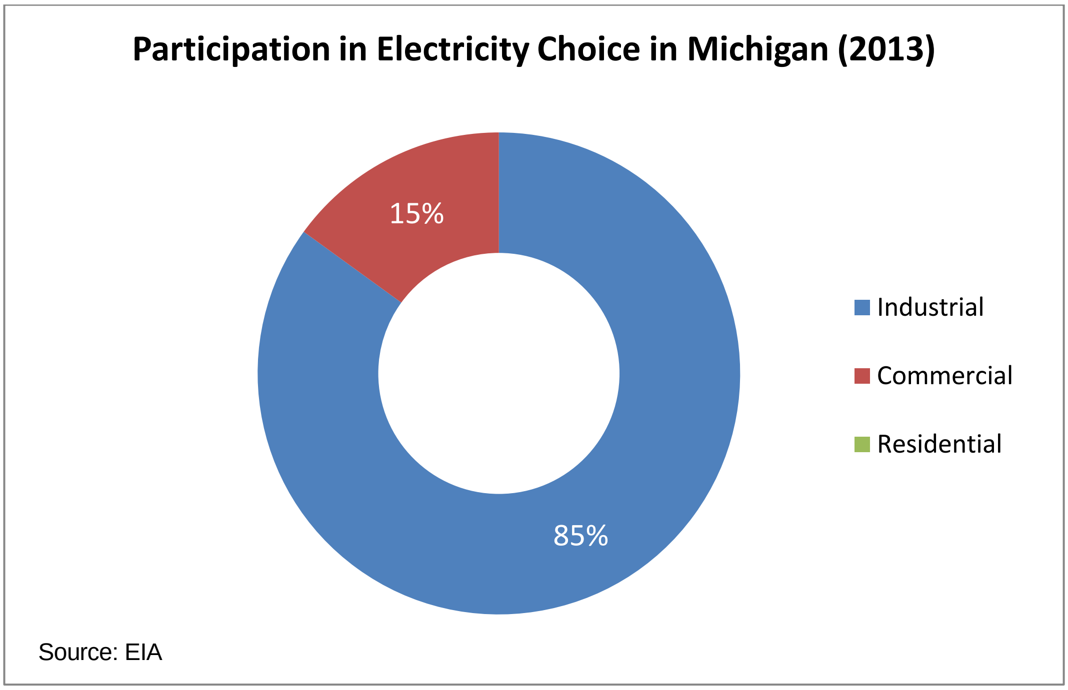

Figure 3.6

PA 286 provided for customers seeking access to the market to go on a waiting list, generally called "the queue," if the 10% cap has been reached. At the end of 2013 there were 11,000 customers in the queue that represented about 11% of load (more than the entire load served under the cap). If these customers were allowed to access the market, competitively served load would likely more than double.

The debate over deregulation customer choice has started again in Michigan due the escalation of regulated rates since 2008 as compared to price in the competitive segment of the market. Michigan electricity rates average used to be lower than the US average, but this changed with the 2008 cap and now Michigan has the 15th more expensive prices in the US (see Figures 3.7 and 3.8). The reasons for that are going to be analyzed later.

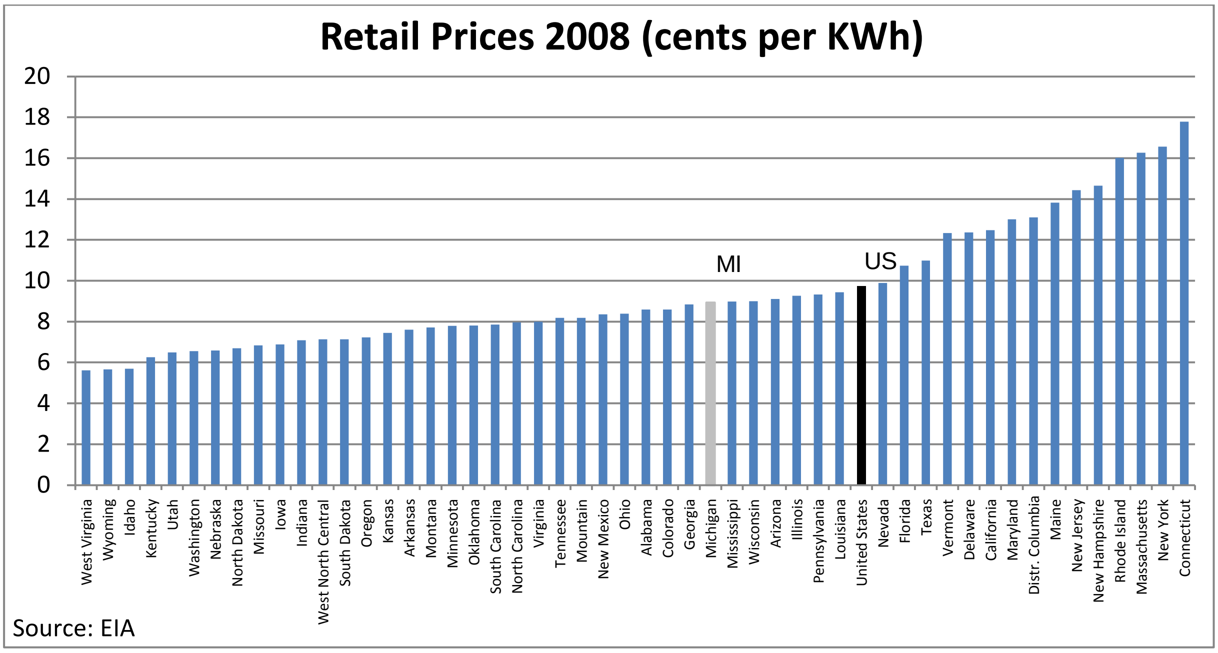

Figure 3.7

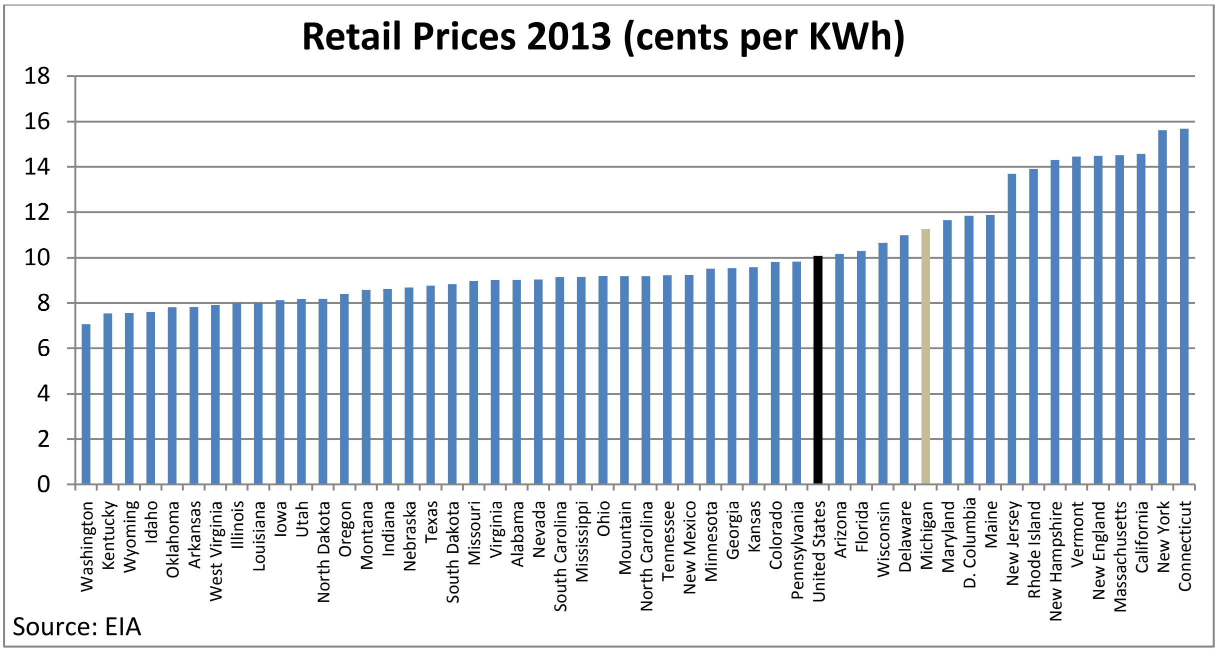

Figure 3.8

Not fully reflected in these illustrations is that in addition to the average price of electricity rising in Michigan relative to national and regional averages, a wide disparity has developed within Michigan between utility prices and lower competitive market prices paid by customers accounting for the 10% cap quota. Competitive prices would be closer to average prices in Illinois, where virtually all prices making up the average are set at the competitive market.

The debate prompted by the price problem led to the 2013 introduction in the Michigan Legislature of House Bill 5184 sponsored by Rep. Mike Shirkey. The bill would repeal the 10% cap and require the separation of utility generation from the delivery business.

3.3. How MISO works

Before proceedings with an analysis of the situation in Michigan it is useful to review the Midcontinent Independent System Operator (MISO), the RTO to which Michigan's utilities belong.

MISO's footprint extends from the Gulf Coast into Canada, and represents a large portion of the U.S. electricity market and transmission grid. MISO's mission is to coordinate, control and monitor the electricity transmission grid not only in Michigan but in all the colored area in Figure 3.9.

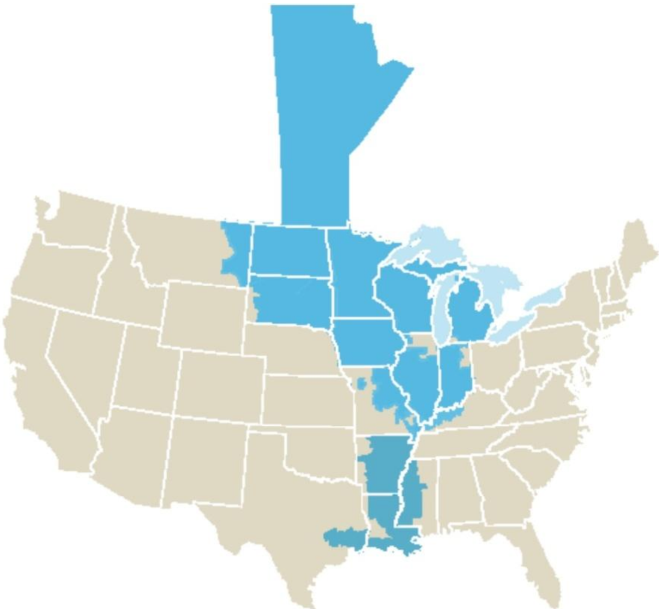

Figure 3.9

MISO's main tasks are assuring grid reliability, administering transmission tariffs, managing grid congestion, monitoring the wholesale market, operating the day ahead and real-time wholesale markets and planning grid expansion.

MISO has two markets: the energy and capacity markets. In the energy market, electricity is bought and sold as any other commodity. The capacity market "directs investment a few years ahead of when electricity needs to be delivered"[18]. The objective of the capacity market is to incentive the building of new power plants by assuring to power plants several years ahead that they will sell their electricity.

As a general matter, as shown in Figure 3.10, there are several main components of electricity cost: supply or production costs, capacity charges, line losses, transmission and ancillary services fees and local distribution company rates. The price paid by end-use customers includes the electricity cost plus the profit margin of market participants (power generation companies, brokers, AEPs…).

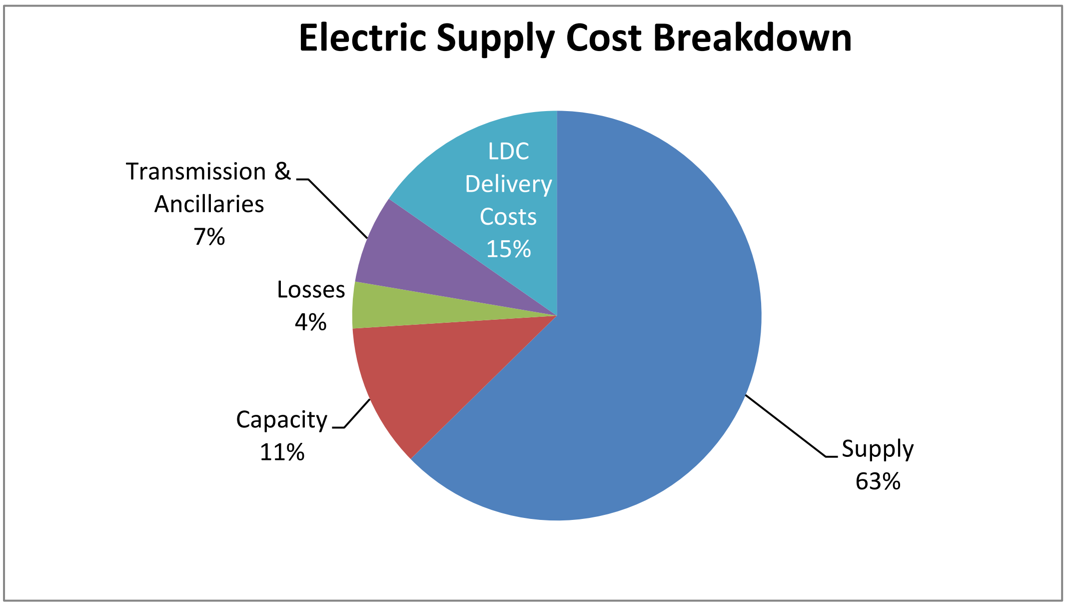

Figure 3.10

Supply: it is the cost of production. It varies between power plants based on factors such as fuel and heat rate.

Transmission and Ancillary Services: These include both the movement of the power over high voltage wires and six functions that support operation of the grid: scheduling and dispatch, reactive power and voltage control, loss compensation, load following, system protection and energy imbalance.

Capacity: A fee with the objective of promoting the building of additional generating capacity;

<u>Losses</u>: Loss of electricity from thermal conversion and loss in transmission lines.

<u>Local Distribution Charges</u>: The charge because of the delivering from the Grid to the meter.

The energy market in MISO operates at three levels. First, MISO oversees bilateral transactions. Utilities and AEPs are allowed to serve retail customers through contracts for wholesale supply (the price is not set by the market). Second, MISO administers a Day Ahead Market. Generators and buyers post offers and bids in the Day-Ahead Market (DAM) and MISO uses that information to schedule the next day's dispatch of generation based on plant production costs and to anticipate congestion potential in the grid.

Third is the Real-Time Market (RTM), known as the Day-2 Market, by which MISO adjusts supply for differences between what was scheduled in the DAM and what is really happening in the network in short intervals. Differences can be the result of generation problems, increase/decrease in demand, congestion of the grid and so forth.

Prices in DAM and RTM are usually similar but almost never the same. The amount of energy scheduled in the DAM is paid at the price set in the DAM. If adjustments are necessary (for example, a company needs to buy more energy than he had estimated in the DAM) these adjustments are made at the RTM price. An example helps to clarify:

The Company A buys 40 MWh in the Day-Ahead Market at $25. The next day- the Operational Day- the company sees that needs 5 MWh more and buys this extra electricity in the Real-Time Market at the price of $27/MWh. The Company A is going to pay 40 MW at $25/MWh and 5 MWh at $27/MWh.

3.3.1. Locational Marginal Prices in MISO's DAM and RTM

MISO's grid has hundreds of local input and output nodes where generators deliver power into the grid and customers buy it. In each of these nodes, MISO calculates the Location Marginal Price (every five minutes in the RTM and every hour in the DAM). The LMP, which is intended to send price signals indicating if lower cost generation is not flowing to a node due to transmission constraints, has several key elements as discussed further below.

LMP can be different in different nodes because of congestion and losses. A buyer can choose at which node buys electricity. The price paid is the LMP in that node at the time the transaction is scheduled. LMP in the DAM and RTM differ somewhat.

LMPs in the Day Ahead Market are set with the following inputs: Resource Offers, Resource Parameters, Physical Schedules, Demand Bids, the Network Model, and Transmission Outages.

-Resource Offer: is made by a generator. An offer contains how much energy the generator would supply, the price at which it is willing to sell the energy and how much more energy it could produce in case of a demand increase. The offer is provided in an increasing curve, indicating that if the sell price is high the generator is willing to supply more energy and the contrary if the sell price is low. As MISO schedules the energy produced by the cheapest power plants, generators will set their offer price as close as they can to generation costs.

-Resource Parameters represent the speed at which the generator can increase/decrease production.

-Physical Schedules (or Interchange Schedules) reflect the bilateral transactions that have already taken place directly between any generator and buyer. It identifies the amount, price and place of the electricity transaction.

-Demand Bids are requests to purchase energy that identify the MWh quantity, location and time of purchase. There are two types of demand bids: fixed bids, which offer to request purchase energy at whatever price indicated by the market; and price-sensitive bids, which present the possibility of buying more energy if the price in the market decreases.

-Transmission Outages are those planned for some parts of the grid, usually for maintenance purposes.

All inputs must be submitted by 11:00 EST on OD-119. Then, from 11:00-15:00 EST MISO clears the Energy and Operating Market for each hour of the next day using two algorithms. At 15:00 EST the cleared supply and demand and the LMP for the next day are made public. From 16:00-20:00 EST, MISO selects which generators will run during each time period of the next day, trying to configure energy flow in the most cost effective manner. Finally, at

20:00 EST, notifications are sent out to generators so that they know when they have to produce electricity the next day. Buyers are notified at 15:00 EST of how much energy are they getting the next day.

In RTM, LMPs have the same inputs as in the DAM. The only difference is that in RTM the inputs have to be submitted 30 minutes before the Operating Hour (this is, the hour in which that energy is going to be sold/bought).

If the demand and supply were in perfect balance, the RTM would not be necessary. But there are usually variations between the energy scheduled the day before in the DAM and the energy required at any given time. These variations are:

-A generator may wish to produce less energy for economic reasons. In this case, MISO will approve the change only if reliability is not affected.

-Another generator may wish to produce more energy. MISO will determine if there is *space* for the offered amount of electricity.

-An increase in electricity demand. In this case, MISO has two options: accepting the offer of a generator to produce more electricity or, in case there are no offers, requiring a generator to produce more electricity, even though it is not economically profitable for the generator.

Figure 3.11 shows a typical merit order of dispatch of energy to meet demand. The curve will be based on the lowest fuel cost at any given time, with nuclear and coal customarily meeting the bulk of the base load. Electricity prices in the DAM and RTM are always set at the highest price offer of the scheduled power plant offers. Figure 3.12 shows the relative prices by fuel source. Traditionally, natural gas has been more expensive than coal. While there are almost always power plants that use natural gas sending electricity to the grid they have generally be used maximally only during period of higher demand. Therefore, electricity price will be sensitive to natural gas price variations rather than to coal.

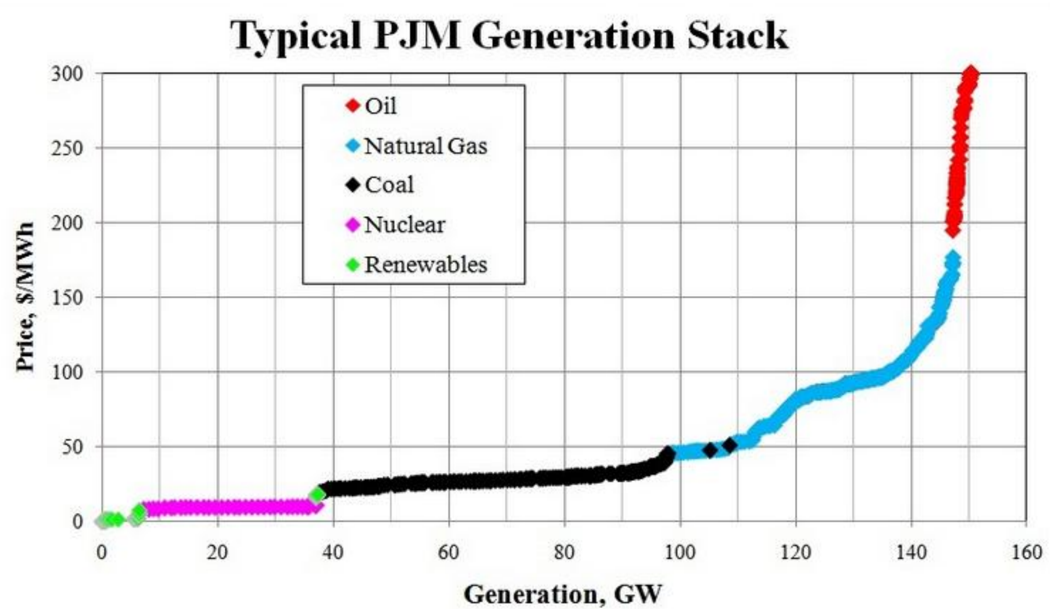

Figure 3.11[20]

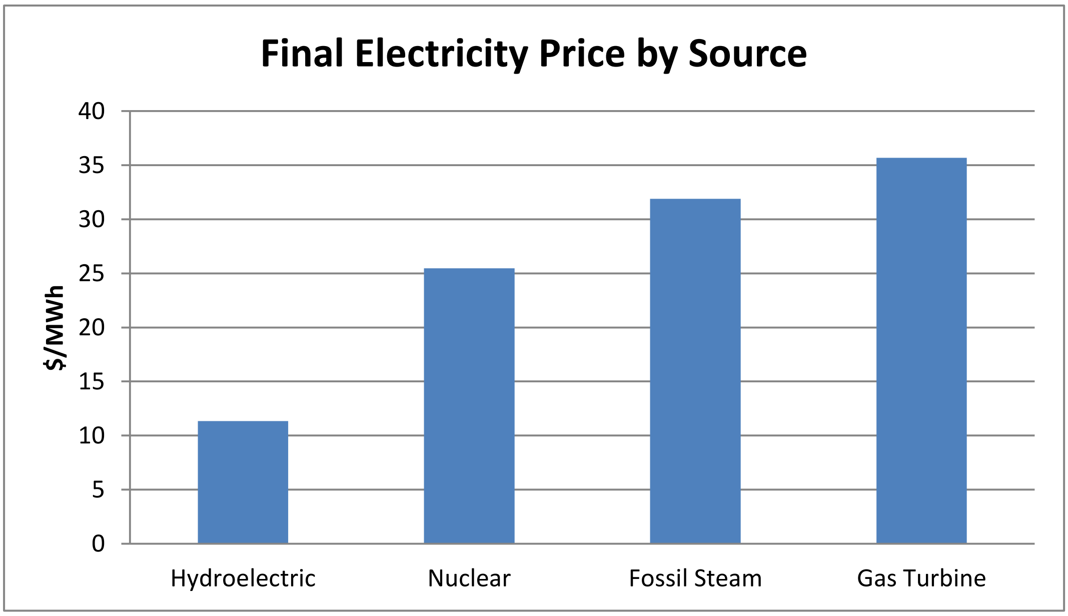

Figure 3.12

While location and line losses are important in electricity prices, the primary factor is fuel prices. Figure 3.13 shows how gas prices in recent years have fallen producing a fall in electricity prices. Gas prices are going down because of the *fracking* phenomenon which is producing that natural gas is getting into greater competition with coal.

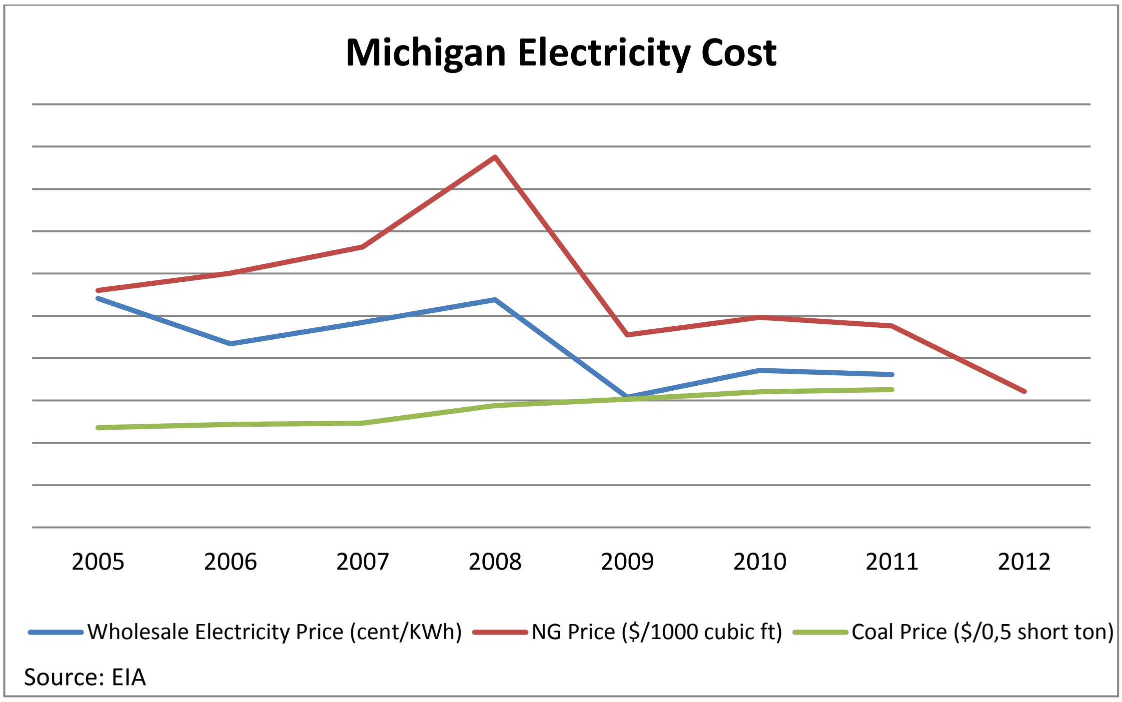

Figure 3.13

Finally, in any competitive electricity market, Risk management is essential. MISO offers four tools to manage it: forward contracts, options, swaps and the futures contracts. MISO has to be notified of the use of any of these tools before 11:00 EST on the DAM.

3.4. Arguments in the Michigan Regulation v Deregulation Debate

The bill has been subject to vigorous debate. Both sides have created organizations to support or oppose the measure and have been intensely lobbying legislators. The main organizations are listed below.

PRO Deregulation	CON Deregulation
Energy Choice Now	DTE and Consumers Energy (utilities)
COMPETE	MEGA – Michigan Electric & Gas Association
ABATE	Michigan Jobs & Energy Coalition

The debate centers on three key issues: prices evolution, reliability of the grid and prices volatility. In the following chapter these issues will be addressed and conclusions reached as to what seems the better path for Michigan.

The comparative analysis of traditional regulation and competitive restructuring is focused on retail prices and reliability. The chart below summarizes the main arguments being made for and against retail electricity competition[21].

	PRO-REGULATION	PRO-DEREGULATION
PRICES LEVELS	- Deregulated markets have prices 25% higher than regulated markets. - Deregulated markets have experienced extreme sudden price spikes.	- Comparing prices against inflation, in deregulated markets prices have declined 5%, while in regulated markets prices have increased 15%. - The problem in a few states has been how deregulation has been applied, not deregulation itself.
PRICES VOLATILITY	- Deregulated states have very high prices volatility because of competition. - In regulated markets, prices are more steady as are set by regulators	- There is no significant difference between volatility in competitive and in regulated markets.
RELIABILITY	- Reliability is fragile in deregulated states.	- RTOs and ISOs are responsible for reliability and there is no evidence of reliability problems in deregulated states.

4. Michigan Analysis

After the previous analysis of deregulation pros and cons and the overview of Michigan's current situation, it is time to analyze Michigan.

4.1. Prices Study

From 2001 to 2008, Michigan had an open competitive market where any customer could choose its electricity supplier. In 2008 Michigan reduced the competitive market and now only 10% of its people can participate on it. Were the complete deregulation years good for Michigan? And the present 10% cap? To start, let's take a look at Figure 4.1, which compares Michigan's electricity prices with electricity prices in deregulated and regulated states.

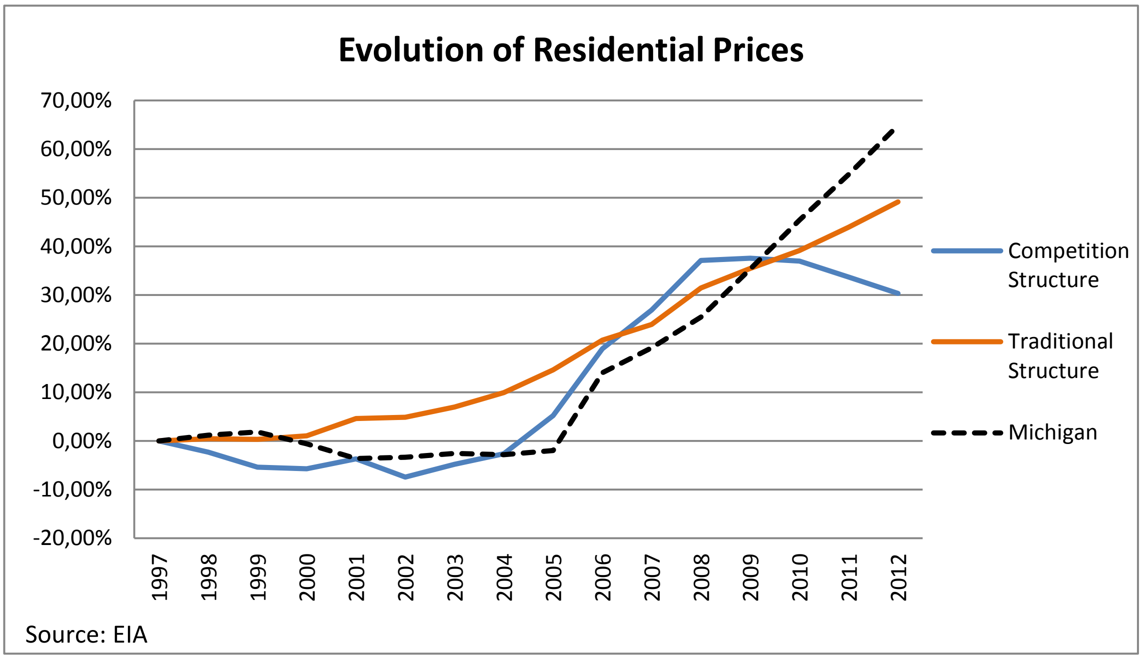

Figure 4.1

Michigan froze and lowered electricity rates for 4 years (until 2005). These measures ended in 2005 and prices rose abruptly. It happened the same in Illinois in 2006 (see Figure 2.10), where they experienced price hikes during two years. But in Michigan, prices have been rising since then (it has been 7 years so far). There are two main reasons for that. The most important one is the 10% cap. The cap puts Michigan in the same situation as regulated markets: lack of flexibility during the 2008 financial crisis. Competitive markets are flexible and able to adapt all the time to the economic environment. In the case of an economic crisis –and, as a consequence, a demand decrease- prices in such markets also decrease. But regulated markets do not have this flexibility. Neither do hybrid markets. This produces that during an economic turndown, prices go up instead of going down.

The other reason is skewed rates. In the past, when Michigan had a complete regulated market, the state chose to reduce residential customers' rates by increasing rates of commercial and industrial customers. This measure has to be reversed at some point (deskewing), and Michigan is doing it now, producing an increase in residential prices (and a decrease in industrial and commercial prices).

Figure 4.2 summarizes all this. For more than 10 years, Michigan had steady electricity prices, around 8.5 cents/KWh. But since the end of frozen rates and the start of the 10% cap, rates have been rising and there are now above 14 cents/KWh, more than 55% more than the price in 1990.

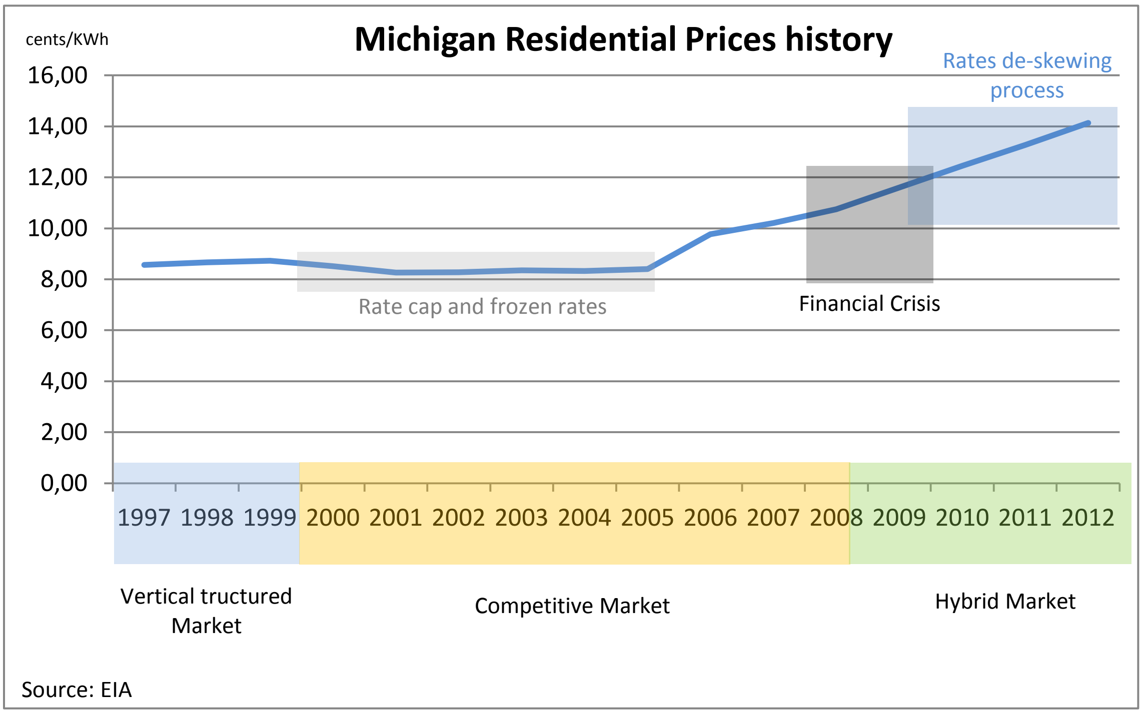

Figure 4.2

The next figure shows a comparison between Michigan and the other states in the Great Lakes area. These five industrial states share many characteristics (economic, geographic…), which makes this comparison useful as there are less distorting elements. Wisconsin and Indiana have traditional structured markets; Illinois and Ohio have competitive markets; and Michigan has a hybrid market.

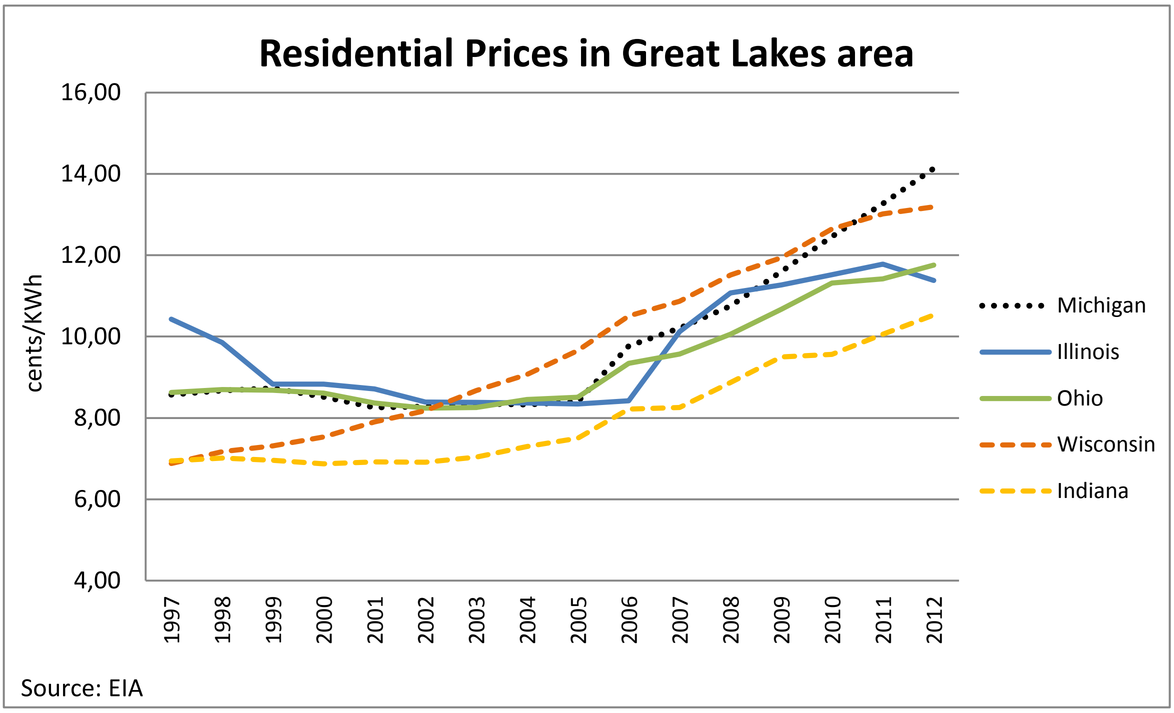

Figure 4.3

Wisconsin and Indiana follow the same trend. The same happens with the competitive states. Michigan follows competitive markets' evolution until 2008, when it behaves more like Wisconsin and Indiana (regulated states). Year 2008 coincides with the year in which Michigan ended its competitive market by putting the 10% cap. All seems to indicate that if Michigan had continued with a competitive structure it would also have experienced a much slower increase –and maybe a decrease- in its electricity prices.

From all the four Great Lake area states, Indiana (a deregulated state) has nowadays the lowest electricity prices. As it already had the lowest prices in 1997 (before any states had competition), it is needed Figure 4.4 to better tell the influence of regulation and deregulation in these five states.

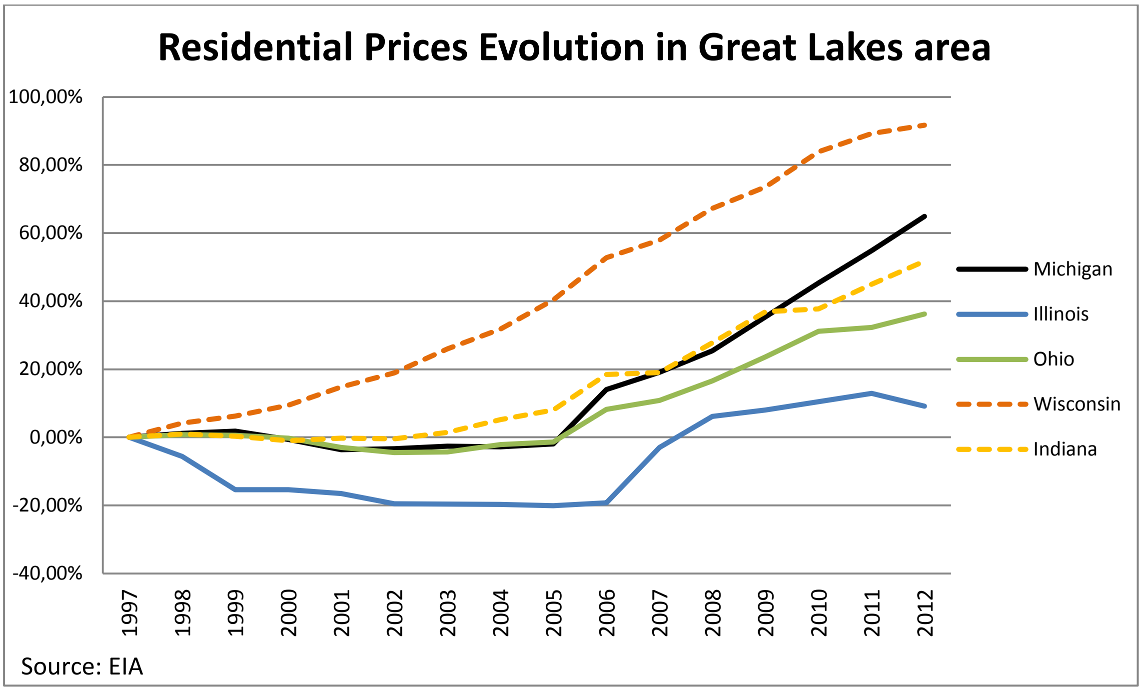

Figure 4.4

It seems that restructuring their markets has benefitted Illinois and Ohio, which have the two lowest increases. The two states that have stayed with a regulated market plus Michigan have experienced higher increases. Indiana has lower nominal prices, but it seems that it would have lower ones if it applied competition in its market.

The other very-discussed point is prices volatility. Advocates of regulation say that competitive markets are subject to more price variations and volatility. It is true that prices in competitive markets change much more frequently (remember that in RTM, prices are calculated every 5 minutes). But, although some customers choose to pay the real time price (which varies), most of them choose to pay fixed prices using one of the several tools that the market offers to do so. Therefore, the analysis of volatility does not have to be made in a daily period, but in a monthly period.

Table 4.1 shows the standard deviation and the coefficient of variation of the monthly prices from 1999 to 2013 and calculates the:

-Standard Deviation: indicates the rank in which prices can be found. Multiplying the standard deviation by three, gives the rank in which 99% of the prices are found.

-Coefficient of Variation: it is calculated by dividing standard deviation by the mean.

Groups	Standard Deviation (σ)	σ x 3	Coefficient of Variation (σ/mean)
Competitive (14)	0.0512	0.1536	0.1866
Traditional (32)	0.0415	0.1245	0.1693
Hybrid (3)	0.0588	0.1764	0.1651

Table 4.1-Volatility study of electricity prices from 1999-2013

In competitive markets, 99% of prices are in a rank of [mean+/- 0.1536 cents/KWh]. The rank for traditional markets is [mean+/- 0.1245 cents/KWh]. The difference is so little that there is no significance difference between competitive markets and traditional markets volatility. Coefficients of variation lead to the same conclusion.

4.2. Why Michigan imposed the 10% Cap

This is an unclear point. To understand it, the author of this paper talked with several people who shared their views on the issue. All of them said they did not know for sure what the reason was and that what they said was only their guess. The author tried to talk with people working in Michigan utilities but did not hear back from them.

The first important thing to understand is that, for some historical reasons, Michigan's two large utilities have an incredible grip on the Michigan legislature. The gist of the argument that the utilities successfully made to the legislature in order to put the 10% cap after some years of competition, can be summarized in these points:

- Michigan is going to need new base load power plants;

- Wall Street will not lend the money, or will lend only at too-high interest rates if Wall Street is not certain that the power plants will be able to sell their output;

- To be able to sell their output, there needs to be a cap on electric choice. Otherwise, customers would go to other electricity providers different from the utilities.

- Other aspects: nobody will serve residential customers if utilities do not do it.

Basically, the argument that utilities exposed is that they were the most suitable to invest in power plants. And if they were the ones investing they would have huge fixed costs from those investments, which would imply an increase in customer prices in order to cover those costs. To prevent that customers leave utilities and go to AEPs in search of cheaper prices, the solution they expose was to set the cap.

An alternative solution –that utilities did not bring up- would be to sell their power plants (as utilities in all the other deregulated states did). As said before, utilities in all deregulated markets are required by law to separate generation from transmission. Michigan, instead of selling generation, sold transmission. Why did Michigan do so? There are probably two main reasons.

First reason is that at that moment (2008) Michigan utilities had an urgent need of cash to pay their debt. Selling transmission was a rapid way to get that money. The second reason seems to be that utilities want to keep AEPs out of the electricity market or, put in another way, they are not interested in competition.

In short, Michigan utilities don't support further customer choice because they make money by building and owning infrastructure (power plants), and they are still in love with the idea that adding giant base load plants is a good way for them to grow rate base and insure ROI and profits. This is their business model and they do not want to change it.

Utilities know that to really implement competition the only way is to sell generation assets. By selling transmission the state moves in theory towards competition, but in practice this puts utilities in a situation where they can keep AEPs pretty out of the market.

4.3. Reliability

This point cannot be analyzed with the graphs in the previous pages. The sense of the author after reading and talking with people with experience in the field, is that reliability is not be a problem in restructured markets, because there grids are controlled by RTOs, which are organizations completely independent from any company. In fact, Order 888 from FERC (in 1998) ordered utilities to give control to their transmission facilities to the RTOs in order to make sure that reliability is fine.

4.4. Possibilities for the future.

There are three possible future scenarios to consider for the Michigan electricity market, each having their pros and cons.

-Increase the cap;

-Fully deregulate completely the retail supply market; or

-Regulate completely the market again.

4.4.1. Fully deregulated the market

To do so, Michigan should make two changes. First, remove the 10% cap; second, tell utilities to sell their generation assets (power plants). Doing so, any company would be able to generate electricity. Also, as the amount of customers in the competitive market would increase, more AEPs would appear to provide electricity to these customers. Customers would have more offers and thus, prices would go down.

Removing the cap and keep utilities being owners of generation assets is not a good combination if Michigan really wants to implement competition. The reason has been explained previously and has been seen in Michigan's past history: when deregulation started in 2000, Michigan utilities kept their power plants and after some years of deregulation, they were able to push the state to put the 10% cap, which benefitted them.

There are currently 11,000 customers waiting to enter the competitive market (they cannot enter because of the 10% cap). In theory, all these customers would switch to an AEP if the cap was lifted. This would mean that 20% of Michigan's customers would receive electricity from an AEP, most likely at lower rates than utilities rates. And more customers would follow them in this process, producing final prices to be more adjusted to wholesale prices.

During the transition time –typically the first 5 years of implementing full competition- states usually freeze electricity prices. After this period, prices would go to meet the competitive electricity prices. So far, all deregulated states have experienced increases at that point, as market prices had been increasing during the freeze period. But this measure is not strictly necessary. In fact, if Michigan evolved right now towards a competitive market without any price-freeze measure, prices would probably go down, as competitive prices in the past years have gone down (see Figure 4.5). Therefore, if deregulation happened today in Michigan, it would probably bring lower prices.

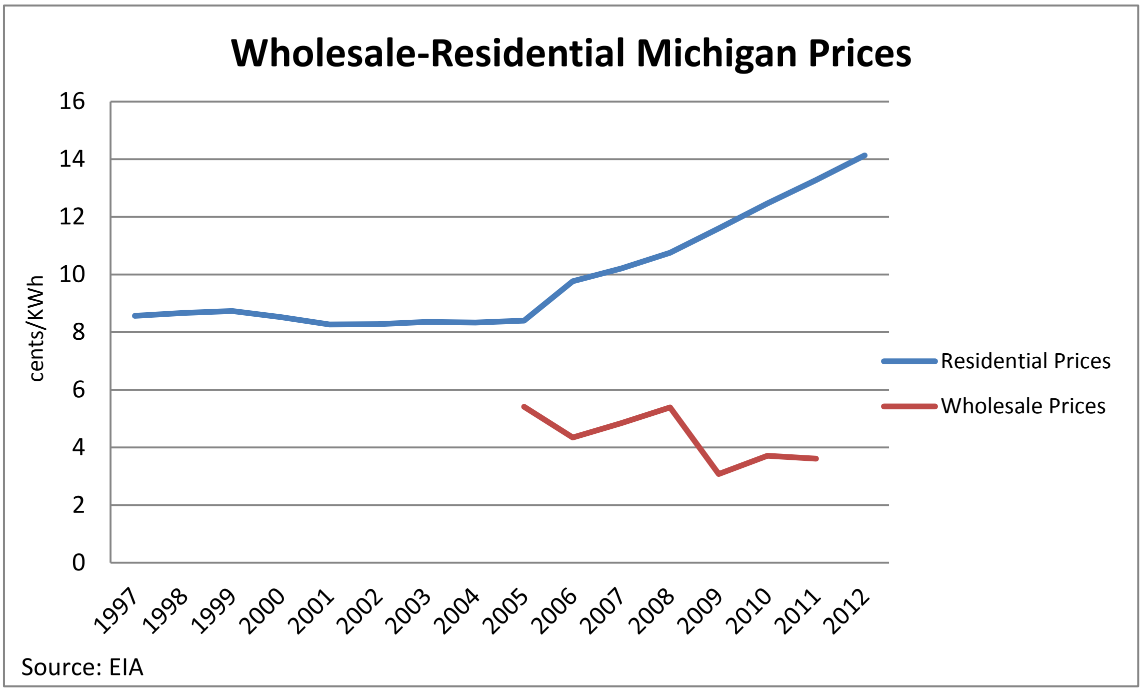

Figure 4.5

The hardest part of this restructure would be to convince utilities to accept this change. Utilities in this market structure would have much less influence than they have now. After selling their power plants they would only serve electricity to those customers who would not want to receive it from an AEP (utilities would be Providers of Last Resort).

Right now, there is a bill in the Michigan House introduced in 2013 by Rep. Mike Shirkey that wants to move Michigan towards a competitive market.

4.4.2. Increase the cap

Implementing this scenario is easier than the one before. It would only be necessary to arrive to an agreement of what the increasing would be. This was done a few years ago in California: after the California crisis the state put a very restrictive cap, which was increased some years later. The consequence: still having a hybrid market but with more AEPs and more customers being able to choose their electricity providers.

Utilities say that a cap increase would bring less financial stability to them, as they would have fewer supply customers. This is true in case utilities own generation assets, not true if utilities sell their power plants. This means that if utilities keep power plants, the cap cannot be very high.

This scenario can work with either one of the two options (utilities owning or not owning power plants). But if the purpose of increasing the cap is arriving to a competitive market eventually, utilities would have to sell their generation assets at some point.

4.4.3. Regulate completely the market again.

This would basically be a market in which utilities generate and serve electricity to customers, and with prices regulated by the state (more details in chapter 1.2.1).

90% of Michigan electricity market is regulated today, so there would not be a big change in how the market works. However, to implement regulation again would mean to get rid of all the competitive elements in today's Michigan market: AEPs, wholesale market… This would be quite chaotic and very economically harmful for many people (especially for people working in AEPs). For this reason this is a highly unlikely path. No state has stepped back to regulation after developing so much competitive market elements.

5. Conclusions

Competition in US electricity markets started in 1997. So far, fourteen states have applied competition, with the result of having today almost 20% of the US electricity load being served through competitive markets. In the last years these markets have experienced a significant lower increase in prices than regulated electricity markets. In other words, competition means lower prices for end-use customers.

Some say that one of the problems with competition is that it always brings a hike in prices during the transition from the traditional structure. This has happened in the fourteen competitive states. But, as seen in the paper, the increase was because during the transition (in which prices were frozen) the market was going up. If the transition had taken place during, for instance, the financial crisis, prices would probably have gone down as they would go to meet the low prices that the US had after the crisis. Therefore, competition does not necessarily mean a hike in prices during the transition from the traditional to the competitive structure.

Backers of traditional markets also say that competitive markets have great volatility in prices, but it has been proved in the paper that there is no significant difference between competitive and traditional markets volatility.

As for the grids reliability, neither traditional nor competitive markets have a problem with this. In traditional markets, utilities are responsible of it under the supervision of the state; and in competitive markets the company that owns the grids is overseen by an ISO which makes sure that all the necessary electricity is sent.

Taking all these into account and after talking with people in the field, the author of this paper concludes that the current hybrid structure in Michigan is not working and that competition is the best option for Michigan electricity market. This would lead to a more flexible market and to cost-based prices (and not prices established by regulators). Like the phone and aviation markets some decades ago, now it is time for competition in the electricity market. Michigan should not be afraid of this natural change.

Regarding Michigan's 10% cap, the author's conclusion is that Michigan utilities were the ones who pushed for it and that they did so because it meant to go back to an almost traditional structure, a structure in which they earn much more money. This step back was possible because when Michigan implemented competition in 2000, utilities kept their generation assets instead of selling them. The author's opinion is that a necessary condition for real competition in electricity markets is that utilities divest from their generation assets. Otherwise, utilities have too much influence in the market.

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- Shawn Schukar (Senior Vice President, Ameren Energy)

- Philip O'Connor (President, ProActive Strategies)

- Tom Stanton (National Regulatory Research Institute)

- Robert Marritz (Energy Policy)

- Mike Healy (CEO, Velocity Energy)

Endnotes

[1] Electric utility: company that generates, transports and/or distributes energy, and is regulated by the local or national authority.

[2] During the WWI, the Federal Government controlled wages and prices. Electricity prices were among the controlled prices.

[3] From McCRAW, Thomas K., *Prophets of Regulation*, 1986, Harvard University Press

[4] In this period, Hoover Dam (1936) and Grand Coulee Dam (1942) were constructed.

[5] An RTO (Regional Transmission Operator) is an ISO that operates in more than one state.

[6] It works quite similar to the stock exchange. Explained in detail on Chapter 2.2.

[7] Traditional Structure: AL, AR, CO, FL, GA, IA, ID, IN, KS, KY, LA, MN, MO, MS, NC, ND, NE, NM, NV, OK, OR, SC, SD, TN, UT, VA, VT, WA, WI, WV, AZ, WY.

Hybrid Structure: CA, MI and MT.

Competitive Structure: CT, DC, DE, IL, MA, MD, ME, NH, NJ, NY, OH, PA, RI, TX.

[8] LESSER, J. and O'CONNOR, P. R. *Ensuring Michigan's Future,* Continental Economics.

[9] Cost of Living Data 2013, from Missouri Economic Research and Information Center.

[10] To measure inflation, it has been used the Consumer Product Index, given by the US Department of Labor.

[11] They are not flexible because utilities have to cover huge fixed costs -which are the investments in power plants.

[12] James L. Sweeney, James L., *The California Electricity Crisis: Lessons for the Future*, Stanford University, 2002.

[13] Ídem

[14] It is 2012 data, taken from US Energy Information Administration.

[15] Originally the period was until 2004 but it was extended two years.

[16] ICC, IMA, IRMA and IBRT, *Electricity and Natural Gas Customer Choice In Illinois-A Model For Effective Public Policy Solutions*, February 2014.

[17] Public Act 141, Section 460.10 2b.

[18] James A., *How Capacity Markets Work*, Midwestern Energy News.

[19] OD stands for Operating Day and OD-1 refers to the day before the Operating Day. In Day Ahead Market buyers and sellers transact energy in OD-1 for the next day, the OD.

[20] MISO's data was not available, but its curve is qualitatively the same as PJM's.

[21] Arguments taken from Energy Choice Now and Compete Coalition (pro-deregulation); Michigan Energy Regulation, DTE Energy and Consumers Energy (pro-regulation).