25% by 2025:

The Impact on Utility Rates of the Michigan Clean Renewable Electric Energy Standard

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MICHIGAN Environmental Council

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About the Michigan Environmental Council

The Michigan Environmental Council (MEC) has intervened in utility rate cases and power supply cost recovery cases for more than ten years on behalf of residential ratepayers. Over that time, their efforts have saved ratepayers over $100 million. Since 2008, MEC has intervened in cases regarding PA 295 of 2008 and the requirements for renewable energy, energy optimization and integrated resource planning, to ensure they were implemented in compliance with the act and in a cost-effective manner.

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EXECUTIVE SUMMARY

America's fossil fuel–dominated energy infrastructure is moving toward a more balanced system incorporating renewable resources that are clean, inexhaustible, and declining in costs. Michigan is part of this transition, one of 30 states with a requirement that electricity suppliers provide customers with a growing proportion of renewable energy. But at 10 percent by 2015, Michigan's Renewable Electricity Standard (RES) is among the nation's lowest.[1] When that limit is reached, no further development is required under current law.

An initiative on the November 2012 general election ballot, Proposal 3, is a Clean Renewable Electric Energy Standard that would build on Michigan's current RES. It would require electricity providers to use renewable resources for 25% of their generation by 2025. To protect consumers, the RES includes a cost cap ensuring that compliance with Proposal 3 cannot cause electric rates to increase by more than 1% in any year.

Using data from the companies' federal and state regulatory filings, forecasts by the Energy Information Administration (EIA) and other available information, this analysis examines the likely effect of Proposal 3 on ratepayer electricity costs.[2]

The report makes the following findings:

The impact of Proposal 3 on electric rates would be minimal

Over the decade of 2016 to 2025, electric rates in Michigan would average 0.5% (one-half of one percent) higher under the proposed 25% renewable energy standard than under the current 10% standard. Between 2016 and 2025, monthly electric bills of a typical residential utility customer would be higher by an average of about 50 cents per month.

Rate cap is good insurance, but will not be needed

During all years of the forecast period, rate impacts remain well under the proposal's 1% cost cap.

Proposal 3 would put long-term downward pressure on rates

After the initial investments over the first ten years, renewable assets with zero fuel costs would put downward pressure on rates starting around 2027. By 2030, the higher renewable standard would be saving customers more than 80 cents per month and would continue to do so over the life of the facilities.

Cost trends favor renewable energy

Renewable energy prices continue to decline, and some technologies are already cost-competitive with fossil-fueled energy. In contrast, the cost of coal-fired power (Michigan's predominant source of electricity) is rapidly increasing.

Proposal 3 would result in greater rate stability

Contracts for wind energy and some other renewable resources can guarantee costs at least twenty years into the future. These long-term guarantees provide greater stability and predictability to electricity rates, making the 25% RES a buffer against volatile fuel markets.

This report provides an overview of Proposal 3 and an analysis of its effects on ratepayers. It is organized as follows:

- Part One describes the state's electricity system, market trends and future projections.
- Part Two examines the relative cost of energy from different generation sources.
- Part Three compares the future costs on ratepayers with and without Proposal 3.
- Part Four discusses how greater use of renewable energy can be reliably integrated into Michigan's electric power system.

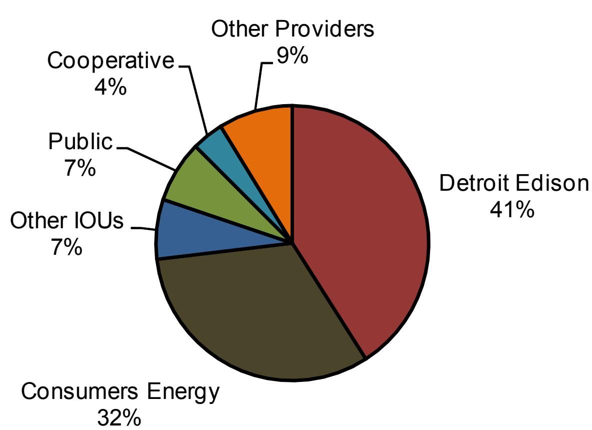
PART ONE: MICHIGAN'S ELECTRICITY PROFILE

Marketplace Summary

The U.S. Energy Information Administration (U.S. EIA) reports Michigan as the 12th largest electricity market in the United States.[3] Figure 1 shows the breakdown of total sales by provider. Michigan residents and businesses spend over $7.5 billion a year on electricity purchases. Two regulated investor-owned utilities—Detroit Edison and Consumers Energy—are the dominant providers with 73% combined market share. The other smaller investor-owned utilities, publicly owned municipal utilities, and electricity cooperatives account for 18% of the market. The remaining 9% are customers (mainly large industrial customers) who have taken advantage of customer choice programs that allow direct market purchases of power from independent suppliers.

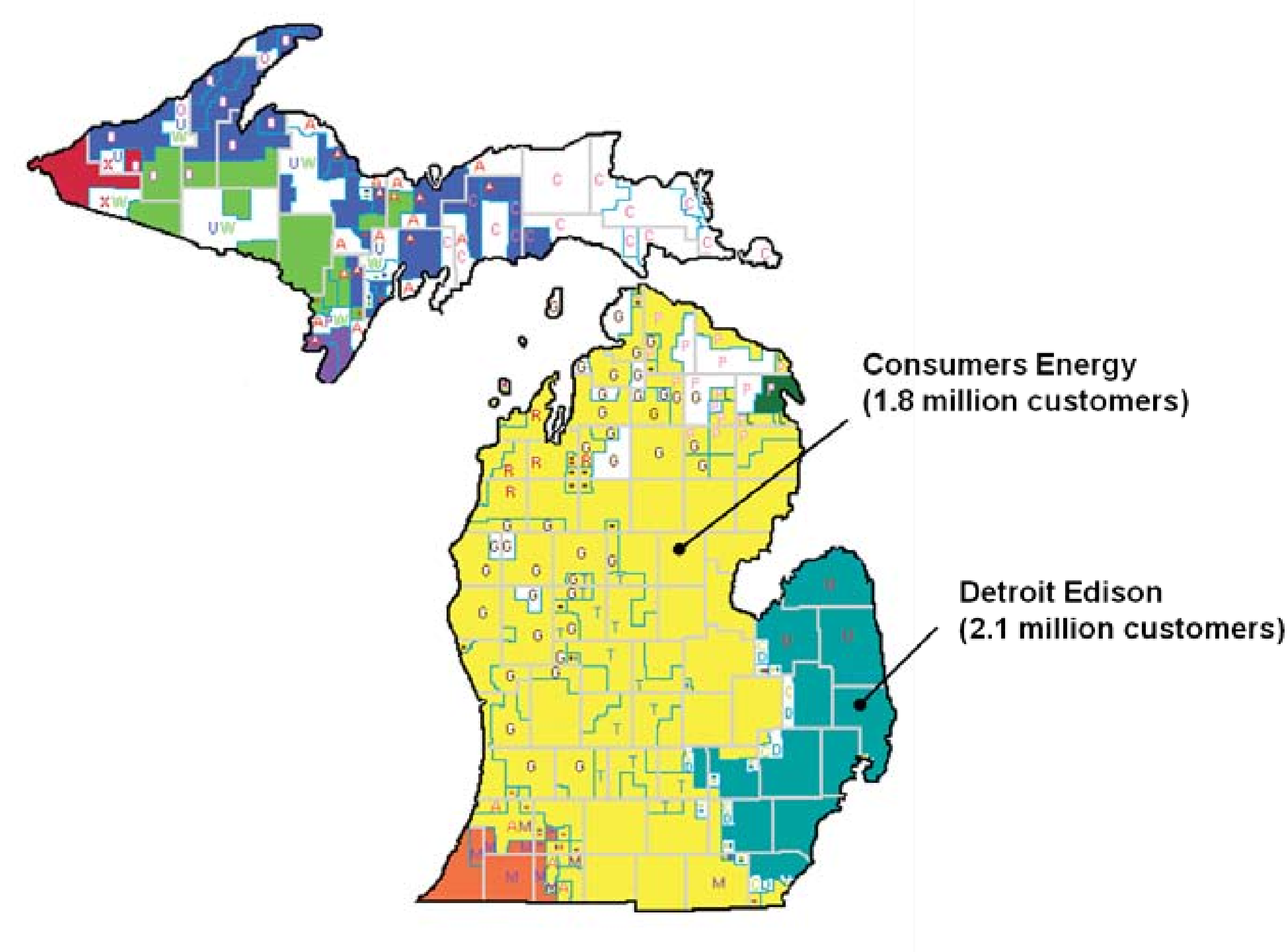
Detroit Edison and Consumers Energy hold a similarly dominant position in total number of customers. Together the two companies serve almost three-quarters of Michigan's 5.4 million electricity customers, with 2.1 million and 1.8 million customers respectively. Many of Michigan's remaining

Figure 1. 2010 Michigan Electricity Sales by Provider



Source: U.S. EIA, Michigan Electricity Profile, Table 9. Retail Electricity Sales Statistics, 2010

Figure 2. Michigan Electric Utility Service Areas



Source: www.michigan.gov/mpsc

customers are served by smaller utilities that buy a substantial portion of their electricity from Detroit Edison and Consumers Energy and to that extent mirror their generation mix.

Figure 2 illustrates that the service territories of Detroit Edison (shown in aqua blue) and Consumers Energy (shown in yellow) cover most of the Lower Peninsula.

Michigan's Current Electric Capacity Portfolio

Electricity production is described in terms of power capacity and energy generation. The capacity of a generator is the maximum power it can produce. Generation refers to the amount of energy that an electricity source produces over a given period of time. This energy, measured in units of megawatt-hours (MWh) or kilowatt-hours (kWh), is what travels through the wires and is used by customers to run equipment, appliances, and lighting. The relationship between capacity and energy can be illustrated by the fact that a 100 kW generator running at full capacity for 10 hours generates 1,000 kWh of electricity.

Because of their different operating characteristics, generators are also described in terms of "capacity factor," the ratio of their average annual energy production to maximum rated output. Generators that run only occasionally, such as gas-fired "peaker" plants, have relatively low capacity factors, while those that are designed to run almost all of the time, such as "baseload" nuclear plants, have relatively high capacity factors.

Renewable energy standards (RES) are requirements that apply to electricity generation. Under Public Act 295 of 2008 (PA 295), electricity providers must generate 10% of their electricity from renewable sources by 2015. The proposed ballot measure (Proposal 3) would increase this requirement to 25% by 2025, with incremental steps each year being established by the legislature or regulators.

Table 1 summarizes Michigan's existing electricity generators and maximum capacities. These facilities are located throughout the state and provide a total capacity of nearly 31,000 megawatts (MW)[4]. This number is significantly higher than Michigan's average demand for power, so many of the units listed in Table 1 are usually shut down or kept in standby mode. During times of peak demand, such as hot summer days when Michiganders use power to cool homes and businesses, more units are brought online to meet the higher load.

The facilities listed in Table 1 are augmented by the Ludington pumped storage facility. This unique and valuable asset, located on the shore of Lake Michigan, uses relatively inexpensive off-peak electricity to pump water uphill to a large reservoir. At times of greater demand, when electricity is most costly, water is released downhill through hydroelectric turbines to produce electricity. When operating in this mode, the Ludington facility adds another 1,872 MW of capacity to Michigan's system. Ludington is currently being upgraded to add an additional 300 MW of capacity.[6] Michigan also buys a relatively small amount of energy from neighboring states during periods of high demand.

Most of the 88 coal-fired power generating units listed in Table 1 are smaller in size. The majority of power produced by burning coal comes from about two dozen large facilities owned and operated by utility companies. In addition, three nuclear plants and two natural gas plants round out the group of relatively large plants that operate on a regular basis. Most of the remaining natural gas plants and all of the oil-fired units run less often because they are less efficient and more costly to run, so their use is limited to periods of peak demand.

Renewable electricity sources also come in various sizes. In Michigan, the typical biomass or hydroelectric facility is on the order of 1 – 10 MW in size. The six wind power facilities listed in Table 1 refer only to large "utility-scale" projects on the order of ten to several hundred MW. Not reflected in this table are small-scale renewable systems being installed around the state by a growing number of individuals, companies, and institutions.

Table 1. Summary of Michigan's Installed Capacity

Generator Type	Installed Capacity (MW)	Number of Units
Coal[5]	12,715	88
Natural Gas	12,237	59
Nuclear	3,947	3
Oil	760	55
Biomass	440	30
Wind Farms	420	6
Hydro	383	57
Total Capacity	**30,902**	

Source: US EIA; http://205.254.135.7/electricity/data/state/

Finally, generating units also vary by when they were built. Most coal plants in Michigan were designed to last 30 to 40 years, but the average age of the state's 49 coal generators with at least 50 MW generating capacity is more than 48 years, and several plants are more than 60 years old.[7]

Michigan's Current Generation Resource Mix

Figure 3 shows the amounts of electricity generated in Michigan in 2010 from the four main resource categories.

In 2010, about 59% of Michigan's electricity came from coal, 26% from nuclear power, 11% from natural gas and 3.6% from renewable energy.

Public Act 295 of 2008

The modest amount of renewable energy shown in Figure 3 will expand steadily to at least 10% by 2015 in accordance with the renewable electricity standard (RES) included in Public Act 295 of 2008. Michigan's current RES applies to all electricity providers and includes interim compliance targets beginning in 2012. Between 2010 and 2015 the amount of renewable energy will increase approximately 7%, or at a rate of about 1.3% a year. Once the 10% standard is met, no further development of renewable energy sources is required under current law.

These conclusions are confirmed by the Michigan Public Service Commission in its latest compliance report on PA 295 of 2008.[8]

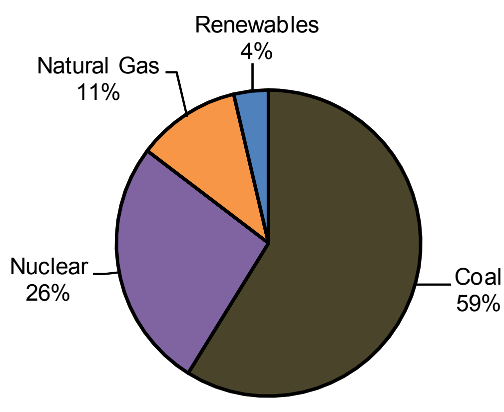
The report finds that 1,041 MW of new renewable energy will become commercially operational by the end of 2012, and that little further renewable resource development beyond 2013 will be needed to meet the current 10% standard.

The report breaks down the new renewable capacity that has been built as shown in Figure 4.

Proposal 3: Clean Renewable Electric Energy Standard

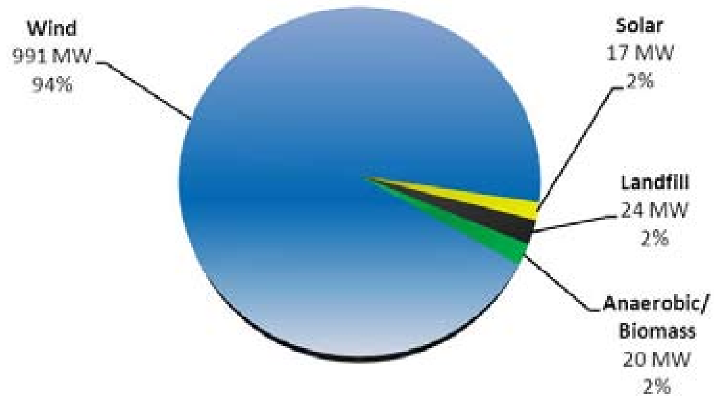
Under Proposal 3, utilities would be required to increase use of renewable energy to supply 25% of their total electricity sales by 2025, or an additional 15% over 10 years. This rate of growth (an average 1.5% annually) of renewable resources is approximately the same as required by PA 295 of 2008. In 2025, the remaining three-quarters of the generation mix could still be met using conventional

Figure 3. Michigan 2010 Annual Electricity Generation by Energy Source



Source: U.S. EIA State Electricity Report, Table 5, Electric Power Industry Generation by Primary Energy: & MPSC 2012 Rport on the Implementation of PA 295

Figure 4: New Renewable Capacity by Technology Type



Source: Electric provider contract approval filings. Note: Includes all renewable energy contracts approved by the MPSC from 2009 - 2011. Includes 12 MW of solar that will come online through 2015.

sources such as coal, nuclear and natural gas. Because of projected increases in electricity consumption, the actual amount of fossil-fueled generation would decline by about 8% under the 25% renewable standard.

This report assumes that electricity providers will slowly scale back the use of current generating sources, starting with the least efficient, and use renewable energy systems to replace them. Figure 5 shows one possible future resource mix.

Electricity Usage

Total electricity consumption is a product of the number of customers and their individual usage. Utility customers are typically segmented into three sectors: residential, commercial and industrial. There is significant variability in usage patterns both across and within these segments.

Figure 5. 2025 Projected Annual Electricity Output (Assuming 25% Renewable Energy by 2025)

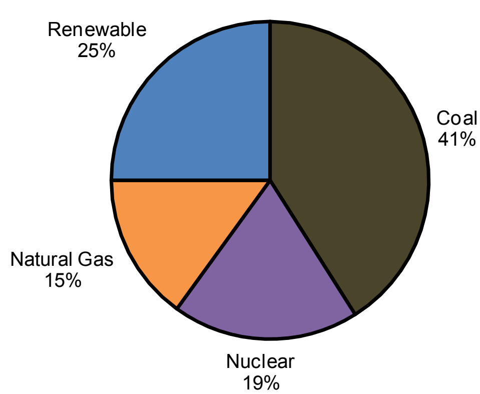
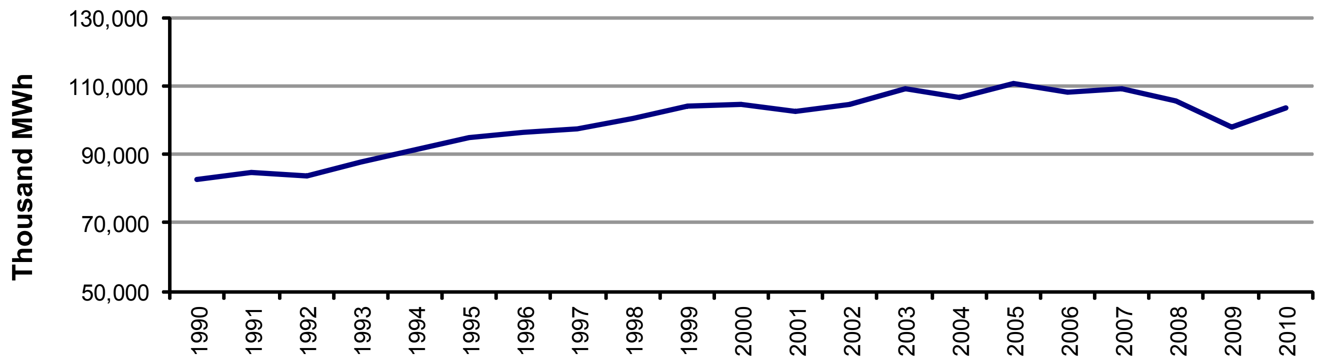


Figure 6. Michigan Electricity Consumption



Source: U.S. EIA, Michigan Electricity Profile

Figure 6 illustrates the recent trend in total electricity consumption among all customers. Because Michigan was among the states hardest hit by the economic downturn that began in 2008, overall electricity demand declined significantly in recent years. After rising 15% in the 10 years prior to 2005, Michigan electricity consumption tumbled with the economy, but has begun to rebound.

Looking ahead, the U.S. Energy Information Administration (EIA) forecasts annual national electricity consumption growth to average from 0.9% in its reference case to 1.2% in a stronger regional economic growth scenario for the decade of 2016 through 2025.[9] This report assumes Michigan will follow this pattern in outstate regions, but will recover more slowly in the Southeast Michigan area.

Electricity consumption in Michigan will also be influenced by changes in consumption driven by energy efficiency provisions in PA 295 of 2008. By 2012, utility companies are required to design and implement efficiency programs that reduce customer demand for electricity 1% annually compared to what consumption would have been projected to be otherwise.[10]

Because of different economic and demographic trends, electricity consumption is likely to grow at a higher rate for Consumers Energy than for Detroit Edison. Consumers Energy forecasts an average annual increase of 1.5% through 2016, with much of it coming from higher industrial demand. Given the ongoing energy efficiency efforts and rising energy prices, for the decade of 2016 through 2025, projections in this report are based on an average annual increase in sales of 1.2% for Consumers Energy.

In the Southeast Michigan area served primarily by Detroit Edison, a slow rate of economic growth through 2040 is forecast in a report prepared by the University of Michigan for Southeast Michigan Council of Governments (SEMCOG).[11] That report predicts a continued decline in population for the region through 2022. Employment in the region, which dipped sharply in 2009, is expected to grow slowly and return to 2000 levels by the year 2040. In state regulatory filings, Detroit Edison itself forecasts a slight decline in electricity usage through 2016. This report uses Detroit Edison's sales projections through 2016, and then employs a reasonable long-term growth rate of 0.25% per year, consistent with the SEMCOG analysis.

PART TWO: COSTS AND RISKS OF PROVIDING ELECTRICITY

This report projects the effect on average utility rates of a 25% by 2025 renewable electricity standard compared to a business-as-usual approach under current law. Central to this analysis is an examination of the relative costs of different resource options. Given that utility electricity generation assets are designed to operate for many decades, assessments of uncertainty and risk are inherent to these investment decisions. A recent independent report addressed to state regulators summarized this concept: "Effectively managing risk is not simply achieving the least cost today, but rather is part of a strategy to minimize overall costs over the long term." [12]

This section begins with a brief discussion of managing utility-related risks, and continues with a review of historical cost data and likely trends for both non-renewable and renewable resources.

Managing Utility-Related Risks

Evaluation of risk-related variables is at the core of utility planning and decision-making. Salient issues include projected capital costs of installing different technologies, fuel price forecasting, and compliance with potential regulatory actions to protect public health and the environment.

To effectively address these and other risk factors, decision-makers can employ strategies that reduce uncertainty and minimize the potential cost impact of any single factor. **A basic tenet of financial management is that a diverse portfolio is less risky than any single investment.** The same is true for commitments to commodity supply, such as electricity. Overdependence on any one source, such as coal, exposes Michigan utility customers to the risk of fuel price volatility and rate shock if fuel costs rise quickly. Overall, diversification gives the portfolio manager more flexibility and protection from uncontrollable and extreme outcomes.

Another basic risk management strategy is to extend the length of supply contracts. **Renewable electricity resources such as wind and solar offer a utility the opportunity to purchase energy through 20-year (or longer) contracts at set prices. Fossil fuel providers are unable to guarantee long-term prices.** The price of coal for electricity generation in Michigan is in large part driven by delivery costs, which can account for up to 75% of its price. For this reason, it is impossible to secure fixed-price long-term contracts.

Regulated public utilities are largely immune to financial harm from the risks of price volatility.[13] Instead, under current regulatory policy these risks are borne by ratepayers, and utilities are not required to make investment decisions that reduce exposure to them.

Regulatory risk must also be considered in long-term utility system planning. National policies to address global climate change by reducing emissions of carbon dioxide and other greenhouse gases may be implemented during the period covered by this analysis. These policies could be in the form of "carbon taxes," "cap and trade" programs, or mandated emissions reductions, all of which would have the effect of increasing costs of fossil-fueled power and making renewable energy even more cost effective. However, because of uncertainty about the timing and costs of a national carbon reduction strategy, no specific carbon cost is included in this analysis.

Non-Renewable Resource Options

Costs Related to Coal

The cost of fossil-fueled electricity is likely to continue rising in coming decades. A primary driver is the cost of coal, which jumped 71% for fuel delivered to Michigan power plants between 2006 and 2011. This upward movement, measured in dollars per million BTU as shown in Figure 7, was due primarily to escalating transportation costs and increased global demand.[14] Detroit Edison's projected overall coal cost increase of $80 million for 2012 is based solely on this effect.

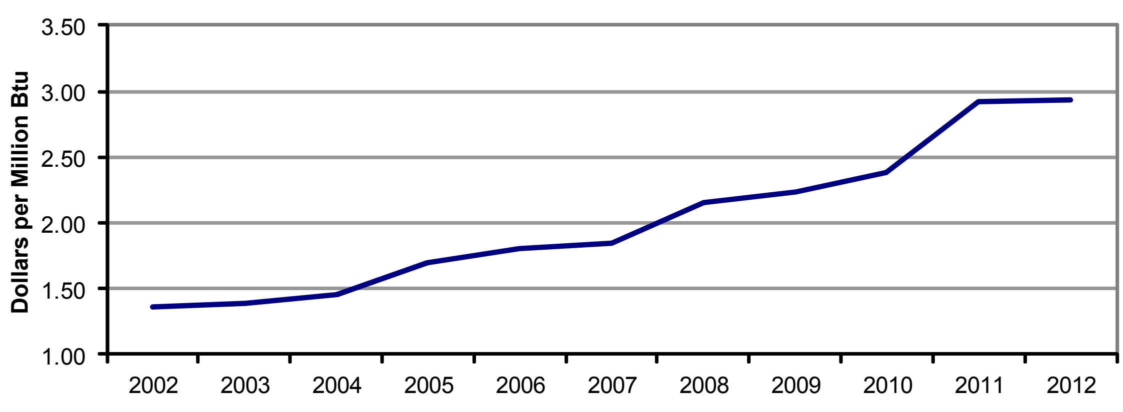
Michigan's reliance on coal imported from distant mines in western states explains the State's sensitivity to variable shipping costs. With 60% of Michigan's coal transported by rail from Wyoming and Montana, it is particularly exposed to the price of diesel fuel, which rises and falls with the volatile global oil market. Fuel is not the only factor driving higher prices for western coal shipments. Freight system challenges and bottlenecks can also play a negative role. For example, in 2005, heavy rain and snow, two train derailments, and resulting track damage reduced deliveries of coal to Michigan power plants for months and caused western coal spot prices to more than double.[16]

Another risk factor for Michigan ratepayers is increasing exposure to global coal markets. Rising demand, particularly in Asia, translates into long-term price increases for U.S. coal, even with flat or declining domestic demand.[17]

Lastly, the aging of Michigan's coal fleet (an average age of 48 years) has contributed to rising costs and other problems, such as requiring additional investments just to keep these plants running:

"After 30 years of operation, the availability of a coal-fired boiler declines sharply and the plant faces higher rates of forced outages; large capital-improvements projects, which overhaul or replace key plant components, are typically needed to extend the plant's operating life. Such projects are not only costly but can also require extended plant shutdowns."[18]

Figure 7. Recent Cost of Coal in Michigan



Source: U.S. Energy Information Administration[15]

In considering what actions to take to address an aging coal fleet, utilities are faced with the fact that coal plants are not only very costly to build or upgrade, they also are not very flexible in the way they can be used to serve loads. They cannot ramp up or down quickly or easily, and coal capacity cannot be quickly added in small increments—only in large and expensive blocks that require many years of lead time and decades of operation in order to recover the initial investment.[19]

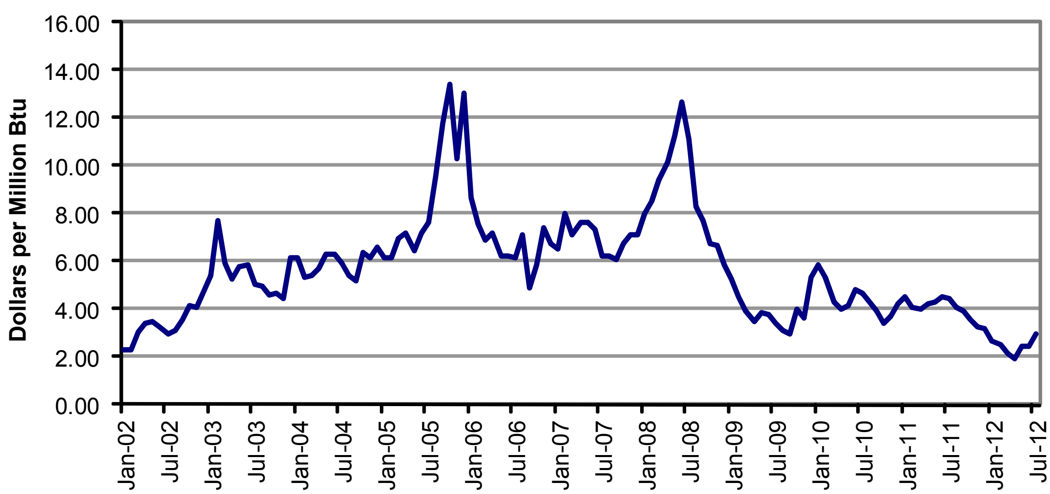
Utilities must soon make decisions on whether to retire or continue to operate older coal units. Their decision-making will examine the significant costs associated with upgrading and running very old coal plants, particularly in an emerging era of greater competition from cleaner alternatives, such as natural gas, renewable energy, and energy efficiency, and stronger federal air quality standards to protect public health and the environment. By providing long-term targets for renewable generation, Proposal 3 facilitates efficient utility system planning to meet future supply requirements.

Costs Related to Natural Gas

Natural gas prices have been unstable during the last decade as shown in Figure 8. Gas market prices nearly tripled from 2002 to 2008, peaking at $8.61/MMBtu.[20] Prices then fell by almost half within a year and are even lower today, following another brief increase during 2010. Many variables affect the price of this critical commodity.

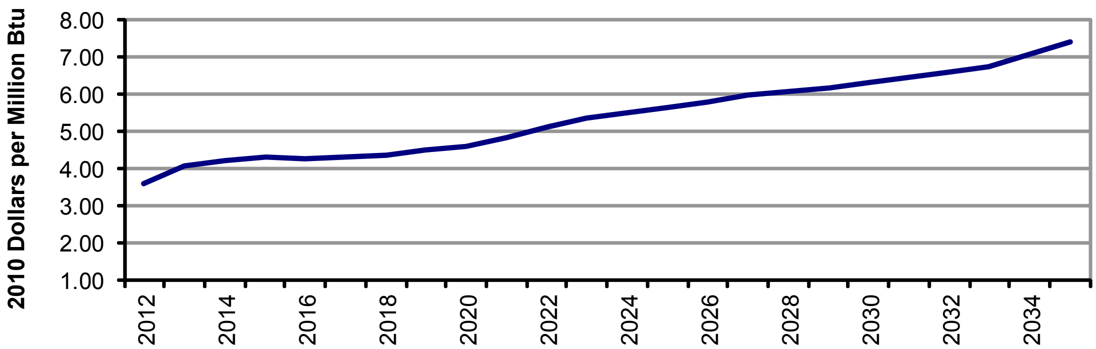
Upward pressure on market prices is growing, due in part to the higher cost of extracting shale gas, which has become more important in the U.S. supply mix. Growing evidence suggests that today's low prices do not cover these higher production costs, which therefore must increase over time. Indeed the U.S. Energy Information Administration predicts natural gas prices to increase steadily as shown in Figure 9.[21] They forecast natural gas spot prices to rise from an average $2.67 per MMBtu in 2012 to $3.34 per MMBtu in 2013, a 25% jump in one year.[22] This coincides with natural gas futures market data and similar forecasts by utility companies of prices reaching $5 or $6 within several years.[23]

Figure 8. Recent Cost of Natural Gas



Source: U.S. Energy Information Administration (monthly data)

Figure 9. Natural Gas Price Forecast to 2025



Source: U.S. EIA, 2012 Annual Energy Outlook

As with other fuels, the risks of higher natural gas costs and price volatility are entirely borne by ratepayers, not utility companies.

Costs Related to Nuclear Power

This report does not analyze the future cost of nuclear power, but construction of a new nuclear plant appears to be unlikely in Michigan during the period of our analysis. Capital costs to build a nuclear plant are projected by the EIA to be more than twice the cost of an equivalent amount of wind capacity, and lifetime nuclear costs include not only billions of dollars for fuel, but billions more for permanent storage of nuclear waste and eventual "decommissioning" of the plant.[24] Typical nuclear units have the further disadvantages of their sheer size—10 times larger than a large wind facility—and their decade-long lead time for planning and construction. Therefore, our analysis assumes continued operation of Michigan's current fleet of nuclear power plants, but includes no new construction.

Renewable Resource Options and Costs

While cost projections have been rising for coal-fired power plants, they are steady or declining for renewable energy, such as solar and wind. For a coal or gas plant, fuel is the primary cost driver over time. Generating power from the wind and sun has no fuel costs and can provide electricity at an incremental cost of zero. Even if the initial cost to build a fuel-burning generator is less than a renewable facility, any cost advantage can quickly disappear as annual fuel and operating costs mount up.

A comparison of generation costs takes into account all projected costs over the anticipated life of the generator, including capital, operation and maintenance, and fuel, and divides this total by the expected life-cycle energy output. The result is known as the "levelized" cost of energy (LCOE). The levelized cost of renewable energy is declining as technology improves and greater economies of scale are achieved, and it is already competitive with many traditional generation technologies. The Michigan Public Service Commission (MPSC) has estimated the levelized cost of energy from new wind power facilities to be 30% less than the levelized cost of energy from a new coal-fired power plant.[25]

A report issued by the MPSC in February of 2012, "Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards," found that the costs of renewable energy had declined since passage of Public Act 295 of 2008: from initial contract prices of $115/MWh to $61 – 64/MWh—

a 40% decline in 3 years.[26] Falling costs have allowed the MPSC to reduce the monthly renewable surcharge for residential customers of Consumers Energy from an initial $2.50 down to $0.65, and then to $0.52, which is significantly under the cost cap set by the legislature in 2008.

Wind

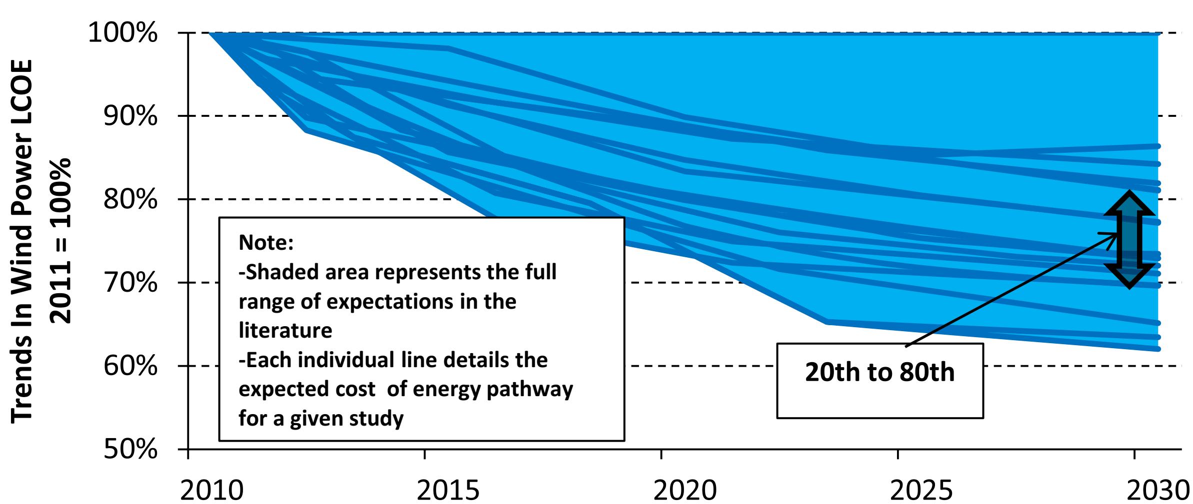
A recent report by the National Renewable Energy Laboratory (NREL), "The Past and Future Cost of Wind Energy," finds a long-term downward trend in the cost of wind energy.[27] The report examines 18 scenarios from 13 different analyses that looked at the future cost of wind power. Figure 10 combines the normalized forecasts of these scenarios. Using various methods and assumptions, these studies generally show steady or declining real cost estimates over several decades. By focusing on the results falling between the 20th and 80th percentiles of scenarios, projected future cost reduction narrows to a range of about 20 – 30% lower LCOE compared with a baseline year of 2011.

Developers of large wind projects have financial incentive to site facilities where strong and steady winds raise the capacity factor and lower the average cost of generation. Michigan has many areas with excellent wind resources and as wind development proceeds, more locations that support higher capacity factors will be identified.

Higher capacity factors are the result not only of selecting project locations with optimal wind profiles, but of developers' ability to improve turbine performance over time. New technologies are enabling more efficient conversion of wind currents to energy. Assuming continued advancements, Detroit Edison forecasts a future average capacity factor of 35% for Michigan wind facilities, a significant increase over the 31% capacity factor forecast for a 120MW project under development in Tuscola County. This project, at a capacity factor of 31%, shows a LCOE of $73/MWh. The same project with output adjusted to reflect Detroit Edison's forecast capacity factor of 35% would produce LCOE of about $60/MWh.[28] The most recent Detroit Edison application for approval of a wind power contract is based on a forecast capacity factor of 47%, which would result in even lower costs per unit of energy.[29] Although Detroit Edison has not published LCOE for this project, it should average less than $50/MWh.

The federal production tax credit (PTC) for renewable energy is scheduled to expire on December 31, 2012. Discussions regarding extension of the tax credit are ongoing but no extension has re-

Figure 10. Estimated range of wind LCOE projections across 18 scenarios



Source: NREL

ceived Congressional approval. Because fossil fuel sources receive far higher federal government subsidies than renewable resources, the PTC has acted as a mechanism to maintain competitive parity.[30] However, the calculations in this report do not assume extension of PTC for projects that are built after 2015 to comply with Proposal 3.

Using the cost of wind power as a proxy for renewable energy costs, this analysis begins with 2012 renewable energy costs of $73/MWh, based on the Tuscola project described above. These projected unit costs are adjusted to anticipate system efficiency improvements of 1.9% annually during the period of 2016 – 2025, consistent with the mid-range of the 18 NREL cost scenarios. After adjusting for anticipated inflation averaging 2.13%, the net result is a projected levelized cost for new wind facilities beginning at $75.47/MWh in 2016 and reaching $81.41/MWh in 2025.

There has been no shortage of developers willing to invest in Michigan renewable energy projects. In response to Detroit Edison's request for bids to provide renewable generation, the company received 146 proposals from 46 suppliers.[31] Michigan has been ranked 14th among states with wind potential, and to meet the 25% RES, it needs to harness only 8% of the on-shore high-quality wind generation sites identified by the U.S. Department of Energy.[32]

Solar

Rapid expansion of America's solar industry continued in 2011, which saw the number of photovoltaic (PV) installations in the U.S. grow to 109% of the 2010 total.[33] The full cost of an installed system fell by 17% in 2010, the largest cost decline on record.[34] Factors driving this downward trend include less expensive solar panels, improved manufacturing, and lower installation costs.

Ongoing research, development and commercialization are making a range of solar technologies more efficient. The result is more power per amount of solar materials, leading to fewer solar panels needed on a given project. Competition among manufacturers and technologies is also producing lower costs. In tracking solar PV price trends over several decades, the National Renewable Energy Laboratory has seen the price of solar modules drop from $22/Watt in 1980 to under $3/Watt in 2009.[35] Solar module prices have further declined to about $1/Watt in 2012.

As installed worldwide solar power capacity expands, production economies of scale continue to be realized. PV component manufacturers are improving processes, reducing waste, and accelerating production. At the same time, these lower prices are also driving demand for more solar systems, and costs related to PV system installation are also declining.

After decades of impressive declines in solar costs, PV has just reached "grid parity"—i.e., its levelized cost is lower than the average price of power on the grid in prime solar locations. PV with storage is now cheaper than diesel generators in applications calling for off-grid electricity.[36] PV is forecast to reach grid parity in Michigan late this decade.[37] The report does not predict the level of market penetration to be achieved by solar energy in Michigan, but assumes renewable portfolios will be diversified once prices match those of other renewable energy resources.

Some of the inherent benefits of solar energy are expected to contribute to ongoing expansion of PV. As an energy resource, solar electricity is particularly valuable because its peak output corresponds with peak demand on hot summer days when electricity is most needed and most expensive. And because it is often a distributed rooftop resource, solar power can help relieve congestion in the transmission and distribution network.

Biomass

"Biomass energy" refers to a wide range of fuels derived from crops, wood, and waste. Almost any organic material can be used to produce energy, either by burning it as a solid, fermenting it into a liquid, or decomposing it into gases. In solid dry form, energy crops and crop residues can be grown or collected and used to replace coal and natural gas as fuel for electricity. In 2009, almost 800,000 MWh of electricity were generated in Michigan from landfill gas at 29 sites, plus more than 1,500,000 MWh from wood waste at seven biomass power plants—enough power to supply the electricity needs of more than 250,000 households.[38]

Biogas, produced from animal waste and other organic waste materials, can also be used to generate electricity. Methane from decomposing manure is a powerful greenhouse gas with 21 times the global warming effect of carbon dioxide, but burning methane curbs its harmful environmental effect and creates both energy and ancillary benefits. In addition to providing a potential source of revenue and energy and for livestock and food processing operations, "anaerobic digestion" systems create high-quality fertilizer and other byproducts while reducing odors, water pollution, and emissions.

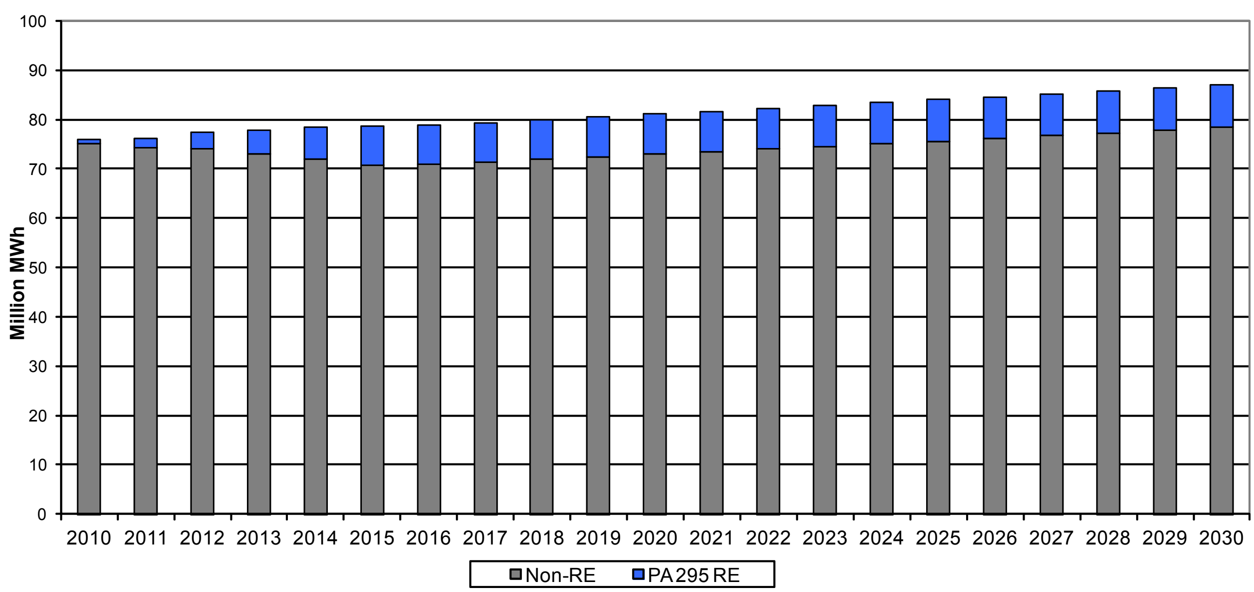
Hydroelectricity

Hydroelectric dams in Michigan produce about 1% of Michigan's electricity output. Out of more than 3,000 dams, only about 100 currently produce electricity. Significant environmental issues are associated with these dams making them expensive and problematic to relicense. No new dams have been built in Michigan for decades due to the environmental challenges, so potential growth in this area is limited.

PART THREE: COMPARISON OF DIFFERENT ENERGY STRATEGIES

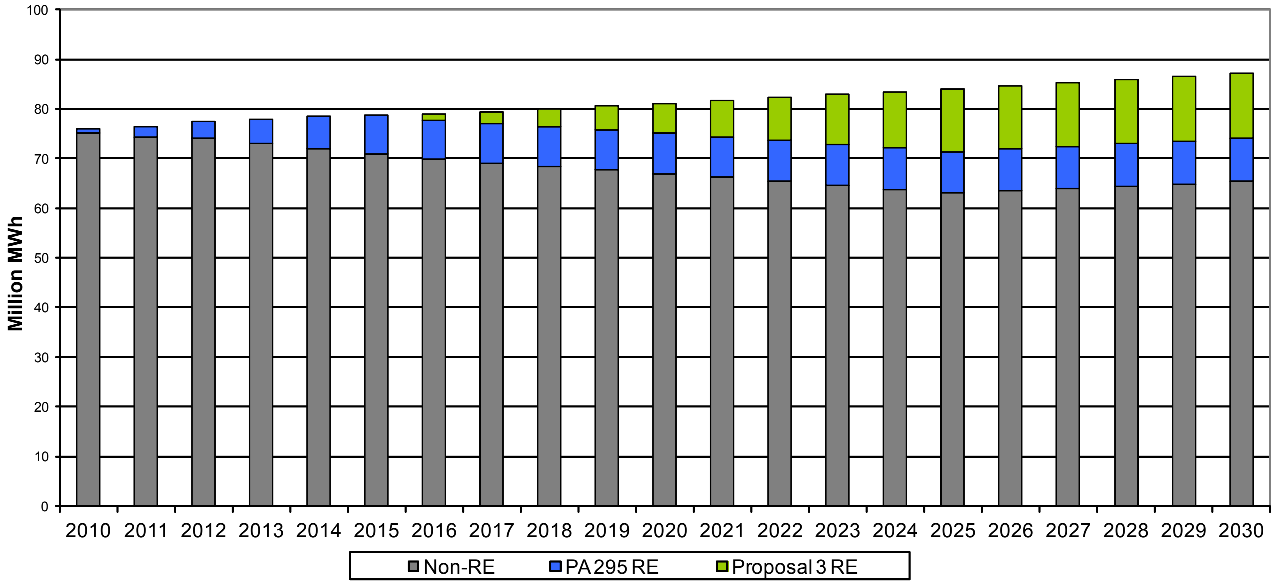
This section of the report compares projected costs of a 'business-as-usual' case—in which non-renewable generating sources are supplemented by the current 10% RES required under Public Act 295 of 2008—with Proposal 3, in which renewable energy generation continues to increase incrementally by 1.5% each year in order to reach 25% by 2025. The figures below depict the combined generation forecast for Detroit Edison and Consumers Energy under each scenario. The bars represent the total annual generation needs through 2025. The bottom portion of each bar shows the non-renewable resources, and the blue portion shows the renewable energy required under PA 295 of 2008. Figure 11 shows the business-as-usual case. In Figure 12, the green portion represents the continued growth of renewable resources under Proposal 3.

Figure 11. Electricity Generation: Detroit Edison and Consumers Energy (business-as-usual case)



Source: MPSC Statistical Data of Total Electric Sales

Figure 12. Electricity Generation for Detroit Edison and Consumers Energy (25X25)



Source: MPSC Statistical Data of Total Electric Sales

Overall Electricity Rates

Rates paid by utility customers are a function of the total revenues approved by state regulators divided by the amount of electricity anticipated to be consumed (calculated separately for each customer class and including fixed amounts for monthly service and volumetric charges for usage). The average retail cost of a kilowatt-hour (kWh) in Michigan increased from 6.97 cents in 2000 to 10.37 cents in 2011, a growth rate averaging 4% a year over the period.[39] From 2005 to 2010, the growth rate averaged 7% per year.

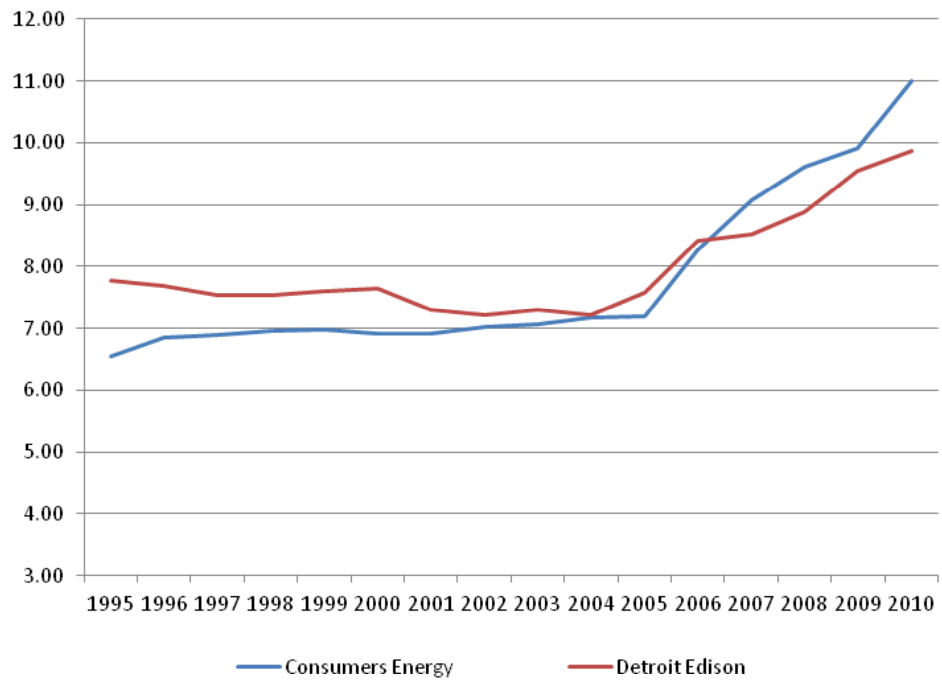
While fluctuations occur due to economic trends, weather, and statutory changes, the key drivers of electricity costs are the growing costs of providing reliable generation, transmission, and distribution services. These cost increases are expected to accelerate due to needed upgrades to old coal-fired power plants, growing electricity demand, and normal inflation of other costs over time.

Developing the Business-As-Usual Case

Using historical and forecast data provided by Consumers Energy and Detroit Edison in state and federal regulatory filings and other public documents, we estimate total costs for these utilities to provide electricity through 2030, including the requirements of Public Act 295 of 2008 (see Appendix I).

Detroit Edison and Consumers Energy are analyzed in depth due to their combined 73% share of the Michigan electricity market. Rate impacts may

Figure 13. Average Electricity Rates, Consumers Energy and Detroit Edison



Source: MPSC Statistical Data of Total Electricity Sales
http://www.dleg.state.mi.us/mpsc/electric/download/electricdata.pdf

ever, the MPSC noted in its report on PA 295 of 2008 that, "Based on the number of renewable energy projects shown in the Midwest Independent System Operator (MISO) queue and reported in press releases as being under development without purchase agreements, competition for utility power purchase agreements will be steep." These market forces should allow smaller electricity providers, individually or in combination with others, to obtain renewable energy credits at competitive prices, resulting in rate impacts similar to larger utilities.

Consumers Energy

For the 14-year period of 1998 through 2011, total costs paid by Consumers Energy customers rose at an average annual rate of 3.6%.[40] These costs were almost exclusively for the generation, transmission, and distribution of energy from traditional sources, as the renewable energy requirements of Public Act 295 were still in their infancy at the end of this period. Consumers Energy has estimated it will spend a total of $1.5 billion on pollution control equipment from 2012 to 2016. The company has also projected its total costs to customers through 2016 will continue to grow at an average rate of 3.4%. Based on the historical average increase in costs paid by its customers for the past decade, this analysis employs an estimate of 3.4% for average annual increases in overall costs for Consumers Energy through 2025. On September 19, 2012, Consumers Energy filed a rate hike request to increase rates by 6% over all and over 11% for residential ratepayers. This rate increase request comes just three months after receiving a rate increase of 3.5%[41]

Consumers' federal regulatory filings show that 73% of its total costs have been associated with conventional power generation, including fuel, purchased power, depreciation, and power plant operating and administrative costs.[42] Applying the historical cost growth rate to this proportion of overall costs, we project costs for required volumes of non-renewable electricity each year. By adding estimated costs to meet the 10% renewable energy standard to this amount, we derive a total energy cost to customers for each year of the business-as-usual case. Dividing this number by projected usage produces a projected business-as-usual unit cost of electricity, which rises from 11.17 cents/kWh in 2012 to 14.52 cents/kWh in 2025.

Detroit Edison

Detroit Edison's rate increase history, as well as its forecasts to state and federal regulators of costs, revenues and anticipated loads, form the basis of the business-as-usual projections. The company's rates have been rising and can be expected to continue to rise over the period examined in this report.[43]

According to the MSPC 2012 Michigan Energy Appraisal, residential customers of Detroit Edison can expect to pay 13.5% more for electricity this year than last year, without accounting for higher usage due to the hot summer. Detroit Edison has estimated it will spend between $1.3 and $1.8 billion on pollution control equipment from 2012 to 2016. The company also has projected fossil fuel cost increases of $530 million over the next four years, which alone would raise rates by 3.1% annually.[44]

Based on the historical average increase in costs paid by its customers for the past decade, we employ a conservative estimate of 3.4% for average annual increases in overall costs for Detroit Edison through 2025. The portion of these costs related to generation comes to 62% for Detroit Edison, which spends a lower proportion of its revenues on generation costs than does Consumers Energy.

Using the same method as described above for Consumers Energy, we project the unit costs of energy to Detroit Energy's customers for each year. However, economic and demographic trends in Detroit Edison's service territory indicate slower sales growth than forecast for Consumers Energy. Detroit Edison has forecast a decline in its electricity sales through 2016, as discussed above in Part Two of this report.[45] Shrinking sales as predicted by the company would mean recovery of increased costs of conventional generation over fewer kilowatt-hours, resulting in even larger rate hikes under the business-as-usual case. In developing the business-as-usual case we assume modest annual sales growth of 0.25% after 2016. Dividing this number by projected usage gives a projected unit cost of electricity, which rises from 10.66 cents/kWh in 2012 to 17.75 cents/kWh in 2025.

Additional Pollution Control Costs

The above estimates of capital investment by Consumers Energy and Detroit Edison do not include the substantial costs associated with reducing mercury pollution at existing coal plants. For example, Consumers Energy budgeted $159 million for capital expenditures on mercury control in the first nine months of 2012. The eventual total would be much higher after implementation of pending federal standards.[46] We estimate the statewide total cost for mercury control could be as high as $2.5 billion over a ten-year period, adding more than 50% to the cost of upgrading coal power plants.[47]

Electricity Costs under Proposal 3

Because wind would likely be the dominant renewable resource in the near term under any scenario, the cost of wind power generation is used in this analysis as a proxy for the cost of renewable energy. As other forms of renewable energy become more cost-effective, they would be included in the mix by utilities.

To project the costs of compliance with Proposal 3, we examine the changes in renewable energy development that would occur after 2015 (when the current RES policy reaches the current 10% level). Proposal 3 allows the state (either the legislature or the Michigan Public Service Commission) to set interim standards to ramp up to 25% by 2025. For purposes of this report, renewable energy production is assumed to grow by 1.5% each year from 2016 through 2025. Using unit cost projections quantified above, the combined costs in each year of requisite amounts of traditional and renewable energy are projected for Consumers Energy and Detroit Edison.

Assuming load growth as detailed above, combined annual procurement of renewable energy would increase from approximately 8 million MWh in 2015 to 22 million MWh in 2025, while fossil-fueled generation would decline by 6 million MWh, or about 8% from today's amount.

Michigan's renewable electricity generating capacity would grow to more than 6,000 MW in 2025 from 2,500 MW in 2015. Achieving the 25% standard would require the annual addition of about 375 MW a year of capacity in the decade after 2015, about the same amount of renewable energy expansion that is occurring under PA 295.

It is anticipated that the utilities would be able to close a portion of their most inefficient fossil fuel capacity. Due to their advanced age and relatively low current utilization rates, this should have no impact on utilities' ability to meet future demand. Fossil-fueled capacity needs would be reduced by about 825 MW under Proposal 3.

Implementation of Proposal 3 over 13 years would allow utilities sufficient time to optimize the resource mix and plan for new facilities as necessary. This longer planning period than allowed under PA 295 (just seven years) should improve integration of new renewable resources with existing capacity.

Renewable Energy Cost Recovery

Like other utility costs, investment in utility-owned renewable energy facilities is recovered through the regulatory process over the projected life of the asset. Detroit Edison has proposed that its investment in wind facilities be recovered over 22.4 years, and Consumers Energy has agreed to an estimated service life of 29.5 years for its wind projects. This means that costs to build utility-owned facilities would be spread over a period extending to 2054.

For independent renewable energy facilities, utility customers would pay for the actual Megawatt-hour electricity output each year. The risk of non-performance would be borne by the plant owners, not utility customers.

The net costs to consumers would be the cost per unit of output minus the avoided costs associated with building, maintaining, operating, and fueling necessary facilities under the business-as-usual case. These offsets include capital upgrades that otherwise would have been required at older, inefficient units, some of which have already exceeded their expected useful lives by twenty years. In addition, fossil plants that are now underutilized would improve their efficiency if they were run on a more optimal basis.

For this analysis, we employ an avoided cost methodology projecting that 50% of the non-fuel costs associated with generation of non-renewable electricity would be avoided for those volumes of energy that are displaced by renewables.

Table 2. Projected Net Cost to Customers of Achieving 25% Renewable Energy by 2025

Year	Impact on rates
2016	0.21%
2017	0.40%
2018	0.54%
2019	0.64%
2020	0.68%
2021	0.69%
2022	0.64%
2023	0.55%
2024	0.42%
2025	0.24%
2026	0.02%
2027	-0.20%
2028	-0.42%
2029	-0.63%
2030	-0.84%

Summary Cost Results

The trajectory of increasing revenue requirements for Detroit Edison and Consumers Energy is marginally affected by adding 1.5% more renewable energy each year from 2016 to 2025. Electric rates will rise in either the business-as-usual or 25% by 2025 case as new plants are built, additional pollution controls are added to coal plants, and other costs rise.

The projected net cost to customers of achieving 25% renewable energy by 2025, as shown in Table 2, equals the incremental impact of adding the renewable energy each year minus the costs avoided by reducing fossil-fueled energy generation (see Appendix II).

The 25% renewable energy case, as summarized in Figure 14, shows a cost impact over the 10 year period averaging 0.5% (one-half of one percent) compared to the business-as-usual case.

Over the decade of 2016 to 2025, electric rates in Michigan would average 0.5% (one-half of one percent) higher under the proposed 25% renewable energy standard than under the current 10% standard. During all years of the forecast period, rate impacts remain well under the proposal's 1% cost cap. **Between 2016 and 2025, monthly electric bills of a typical residential utility customer would be higher by an average of about 50 cents per month.**

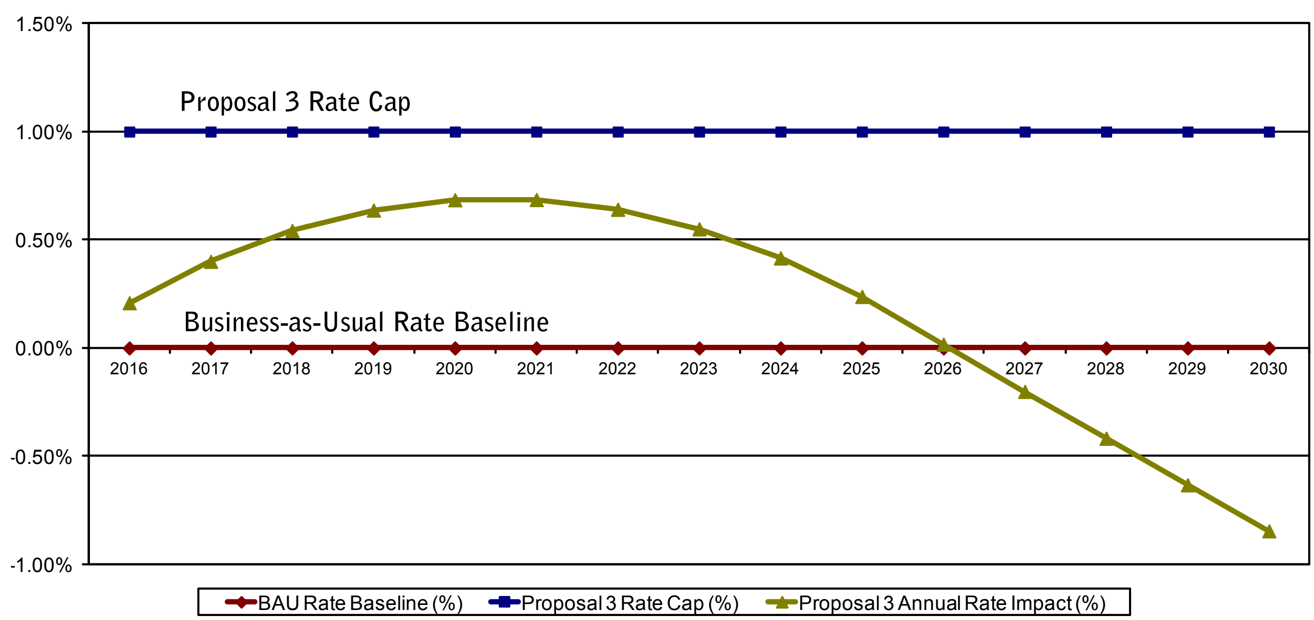
Once the initial investments are made, renewable assets would put downward pressure on rates starting in 2027, and by 2030 would be saving customers more than 80 cents per month and would continue to do so over the useful life of the assets.

Operation of the Rate Cap

The expanded renewable commitment of the Michigan Clean Energy amendment is subject to a consumer safeguard:

> *"To protect consumers, compliance with the clean renewable electric energy standard shall not cause rates charged by electricity providers to increase by more than 1% in any year. Annual extensions for meeting the standard may be granted, but only to the extent demonstrated to be necessary for an electricity provider to comply with the foregoing rate limitation."* [48]

Figure 14. Projected Rate Impact of 25% by 2025



This provision means that if, for any reason, net costs for renewable energy would result in a rate increase of more than 1% in any year, utilities are eligible for an extension of time to comply with an interim or final standard. Under the projected rate impact, in no year are costs expected to exceed the 1% cap. If market conditions did change and renewable energy costs rose or the increase in the cost of conventional sources slowed, the rate cap would limit rate increases to no more than roughly $1 a month for the average residential customer.

The inclusion of the rate cap in the constitutional amendment ensures that it cannot be bypassed by the utility, the legislature or the Michigan Public Service Commission.

PA 295 also includes a cap on the amounts paid by customers for any incremental costs of renewable energy above the cost of an equivalent amount of traditional generation. All major providers of electricity have reported that they will be able to meet the current standard while remaining under the cost cap. According to the MPSC, actual renewable energy costs have been falling, allowing Consumers Energy to adjust its renewable energy monthly surcharge from $2.50 down to $0.65, and recently down to $0.52 per month for residential customers.

PART FOUR: INTEGRATION OF RENEWABLE GENERATION

Power generators are divided into three general types: baseload, intermediate, and peaking. Baseload power plants are designed to run at constant production levels for long periods of time and are rarely ramped up and down. Intermediate plants, also known as load-following or load-matching units, are cycled to meet anticipated surges in demand as the load shape changes predictably during the day and season. "Peakers" are smaller units used to meet quick increases in demand that occur on hot days when air conditioners get turned on, or to make up for a large plant that shuts down for repairs or refueling. A small amount of capacity is often kept running by system operators as "spinning reserves" to meet momentary fluctuations in power demand.

Renewable resources come in a variety of forms. Some act as baseload power, such as hydro and landfill gas facilities. Some renewable generators are dispatchable when needed, such as biomass facilities. Solar power is not dispatchable but has added value because it reaches maximum production during daylight hours when electricity demand peaks. Wind power output varies with wind speed. At 100 meters, the wind blows steadily enough to produce estimated capacity factors of more than 45% for future wind facilities in many of Michigan's windy areas. Compared to capacity factors of 28 – 30% for early stage projects, this means greater output and lower costs per unit of production.

The proposed 25% renewable standard is averaged over 365 days a year, 24 hours a day. Under many conditions and for many hours in the year, renewable resources produce the lowest cost power available, with costs well below the variable costs of operating fossil-fueled generators.

The variable output of wind and solar resources is accommodated through optimization of complementary dispatchable resources. Michigan is home to many facilities which can provide grid operators significant flexibility to meet fluctuating electricity supply and demand. These facilities include the Ludington Pumped Storage plant, one of the world's largest electricity storage facilities, and flexible natural gas generators in Midland and Zeeland.

The Midland Cogeneration Venture, with 12 turbines totaling 1630 Megawatts of capacity, has a purchase power agreement with Consumers Energy. The units can be dispatched to simultaneously serve peak and baseload needs as well as load following to accommodate fluctuating supply and demand. Midland has announced plans to add an additional 640 megawatts of capacity by 2015, making it the second largest power plant in Michigan.[49] This new capacity, available through longer-term purchase power agreements or market energy procurement, will complement renewable development.

Consumers' Zeeland Generating Station has five natural gas–fired turbines totaling 930 Megawatts capacity and is also capable of both cycling and peak operation.

The Ludington Pumped Storage Plant is jointly owned by Consumers Energy and Detroit Edison. With six turbines totaling 1872 Megawatts capacity, it has the flexibility to quickly ramp up and down to meet changing system loads. An upgrade to expand Ludington's capacity by 300 Megawatts and extend its life by 40 years is scheduled to begin in 2013 and be completed by 2019.[50]

In addition, substantial new peaking capacity is being planned by other companies in the regional market operated by MISO. For example, FirstEnergy recently announced plans to convert an existing coal plant in Eastlake, Ohio to an 800 Megawatt peaking plant to serve MISO market demand. Michigan utilities can take advantage of the growing competitive electricity market to supplement their own generating capacity as needed.

Both Consumers Energy and Detroit Edison are modifying some of their coal plants to give them load following capacity to address the changing dynamics of the energy market. The expansion of Ludington and the overhaul of natural gas plants to allow faster ramping up and down will also facilitate the integration of higher percentages of renewable energy resources and address customers' evolving power needs.

At the same time, continuing technology improvements are making renewable energy generators more efficient. Wind turbine advances are continually increasing the amount of electricity produced relative to rated capacity. Sophisticated new wind forecasts are vastly improving prediction of wind speeds and patterns, allowing easier integration of wind output by system operators.

These many system adaptations and technology improvements lead to the conclusion that our current fossil-fueled power capacity with the announced expansion of natural gas facilities would be sufficient to meet system needs under the 25% by 2025 expansion of renewable energy.

CONCLUSION

Public policies to provide reliable electricity at rates that are as low as possible and stable over the long term are critically important to Michigan consumers and businesses. This analysis demonstrates that a continuing commitment to renewable energy development can help achieve these goals.

Michigan's heavy dependence on old coal-fired generating capacity has resulted in rate increases that significantly exceed the national average. This trend is anticipated to continue, due to increasing costs to maintain aging power plants and rising prices for delivered coal. Coal costs alone currently result in approximately $1.5 billion leaving Michigan each year. Over $500 million of that is spent on diesel fuel needed to transport the coal to Michigan from distant states.

In contrast, the cost of renewable energy continues to decline as technologies improve and systems are designed for maximum efficiency in Michigan. Long-term commitment to renewable development facilitates effective planning to meet tomorrow's electricity needs and locks in a significant portion of electricity supply at known prices for decades.

Projections based on reasonable assumptions for future costs show that meeting the 25% renewable standard would not trigger the cost cap contained in the ballot measure, and instead would result in eventual savings for electricity customers. Compared to the business-as-usual case, adoption of the 25% renewable energy standard is projected to have only a marginal effect on electric rates paid by Consumers Energy and Detroit Edison customers, averaging less than 0.5% (one half of 1 percent) higher from 2016 to 2025, and eventually leading to lower costs for electricity.

Proposal 3's 25% RES would help diversify the state's energy portfolio, stabilize electricity rates and reduce the risk of price spikes for electricity customers, while providing significant economic development and a measure of energy independence for Michigan.

ENDNOTES

1 See DSIRE state summary tables, http://www.dsireusa.org/summarytables/rrpre.cfm

2 All data used in this report are publicly available and primarily derived from regulatory filings of Michigan public utilities, including testimony, exhibits and reports to state and federal regulatory authorities. Michigan Public Service Commission cases relied on by this report include:

Detroit Edison Cases U-15806, U-16472, U-16582, U-16047, U-16892

Consumers Energy Cases U-16045, U-16045, U-16890

3 U.S. EIA; Michigan Electricity Profile, Table 1. 2010 Summary Statistics (Michigan).

4 1000 kilowatts = 1 megawatt

5 For listing of all Michigan coal plants, see: http://www.sourcewatch.org/index.php?title=Michigan_and_coal#Proposed_coal_plants

6 Ludington pumped storage facility is co-owned by Consumers Energy and Detroit Edison.

7 For a listing of all Michigan coal plants, see: http://www.sourcewatch.org/index.php?title=Michigan_and_coal#Proposed_coal_plants

8 Report on the Implementation of the P.A.295 Renewable Energy Standard and the cost-effectiveness of the energy standards, Michigan Public Service Commission (February 2012)

9 http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2012&subject=0-AEO2012&table=2-AEO2012&region=1-0&cases=hm2012-d022412a,ref2012-d020112c

10 MPSC report finds energy efficiency to be the most cost-effective resource option. Nevertheless, PA 295 includes a spending cap on these programs of 2% total revenues.

11 See Retrenchment and Renewal: The Economic and Demographic Outlook for Southeast Michigan Through 2040, http://library.semcog.org/InmagicGenie/DocumentFolder/RetrenchmentandRenewal.3-12.pdf SEMCOG (2012)

12 Ceres, Practicing Risk-Aware Electricity Regulation, p.10, April 2012

13 Ceres, p. 45

14 BTU stands for British Thermal Units, a measure of the heat content of fuel.

15 http://205.254.135.7/coal/annual/, http://www.eia.gov/state/seds/sep_fuel/html/pdf/fuel_pr_cl.pdf; http://205.254.135.7/electricity/monthly/index.cfm, http://205.254.135.7/electricity/monthly/current_year/september2012.pdf

16 National Research Council (NRC). 2007. Coal: Research and development to support national energy policy. Washington DC: National Academies Press. Online at http://www.nap.edu/catalog.php?record_id=11977.

17 A Risky Proposition: The Financial Hazards of New Investments in Coal Plants, Union of Concerned Scientists, (2011), http://www.ucsusa.org/assets/documents/clean_energy/a-risky-proposition_report.pdf , p. 13

18 UCS, Risky Proposition, p. 4

19 UCS, Risky Proposition, p. 39

20 MMBtu refers to Million British Thermal Units, a measure of heat content of a fuel. All data derived from EIA, see: http://205.254.135.7/coal/annual/, http://www.eia.gov/dnav/ng/hist/n3045mi3a.htm

21 Source: EIA: Michigan Electric Power Delivered Fuel Prices and Quality for Coal, Petroleum, Natural Gas

http://www.eia.gov/electricity/state/michigan/ and Energy Prices by Sector and Source, East North Central: http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2012&subject=0-AEO2012&table=3-AEO2012&region=1-3&cases=ref2012-d020112c (nominal dollars)

22 U.S. Energy Information Administration, http://www.eia.gov/forecasts/steo/pdf/steo_full.pdf, 2012

23 See Henry Hub natural gas futures prices at http://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_globex.html

24 See http://www.eia.gov/oiaf/beck_plantcosts/

25 See http://www.michigan.gov/documents/mpsc/implementation_PA295_renewable_energy2-15-2012_376924_7.pdf.
MPSC projection assumes that carbon constraints will add to coal power incremental costs; however, new conventional coal power remains more costly than new wind power even after eliminating carbon emission costs.

26 http://www.michigan.gov/documents/mpsc/contract_summary_392291_7.pdf

27 http://www.nrel.gov/docs/fy12osti/53510.pdf

28 See MSPC Order in Case No. U-15806

29 http://www.dleg.state.mi.us/mpsc/orders/electric/2012/u-16582_9-11-12.pdf re: Echo Wind Farm

30 Estimating U.S. Government Subsidies to energy Sources: 2002-2008, Environmental Law Institute (2009), http://www.elistore.org/Data/products/d19_07.pdf

31 See MSPC Order in Case No. U-15806

32 http://www.windpoweringamerica.gov/wind_resource_maps.asp?stateab=mi

33 See: http://www.renewableenergyworld.com/rea/news/article/2012/03/solar-industrys-exponential-growth-in-2011-indicates-healthy-u-s-pv-market

34 See Lawrence Berkeley National Lab report, "An Historical Summary of the Installed Cost of Photovoltaics in the United States from 1998 to 2010" http://eetd.lbl.gov/ea/emp/reports/lbnl-5047e.pdf

35 Ramez Naam, Smaller, cheaper, faster: Does Moore's law apply to solar cells?, Scientific American, March 16, 2011

36 See International Renewable Energy Agency, Renewable Energy Technologies: Cost Analysis Series, Volume 1: Power Sector, Issue 4/5, June 2012.

37 See http://www.ilsr.org/mapping-solar-grid-parity/

38 See EIA state data tables: http://www.eia.gov/cneaf/electricity/epa/epa_sprdshts.html and http://www.eia.gov/cneaf/alternate/page/renew_energy_consump/table6.html

39 In nominal dollars; see EIA data: http://205.254.135.7/electricity/state/michigan/ and http://www.eia.gov/electricity/monthly/pdf/epm.pdf

40 Based on FERC Form 1 filings

41 U-17087, http://efile.mpsc.state.mi.us/efile/viewcase.php?casenum=17087, http://www.michigan.gov/lara/0,4601,7-154-10573_11472-280008--,00.html

42 See FERC Form 1 for 2010, prior to inclusion of significant renewable energy under PA295. The remaining 27% of costs were largely for the transmission, distribution and customer service systems

43 http://www.dleg.state.mi.us/mpsc/reports/energy/12summer/ea-summer12.pdf ;
The total cost of power supply is detailed in the company's most recent Power Supply Cost Recovery Docket U-16892, filed with the MSPC in late 2011. Detroit Edison plans capital investments totaling $4 billion from 2012 through 2014; see: Detroit Edison Investment Profile 2012-2016, http://www.sec.gov/Archives/edgar/data/28385/000119312512272587/d367716dex991.htm

44 See Exhibit A-2, Docket U-16047

45 See five-year forecast in MSPC Case U-16892

46 Exhibit A-29, MSPC Case U-16794

47 Estimated investment of $250 million per year for ten years, based on average estimated cost of $250/kW applied to 10,000 MW of coal power, the approximate anticipated combined operational coal capacity

48 For complete ballot initiative language, see: http://mienergymijobs.com/Proposal.aspx

49 See, e.g., http://generationhub.com/2012/07/12/mcv-looking-to-add-new-640-mw-combined-cycle-gas-u

50 See http://consumersenergyinyourcommunity.wordpress.com/2012/02/06/key-milestone-reached-in-ludington-pumped-storage-plant-upgrade/

APPENDIX I. Business as Usual

A	B	C	D	E	F	G	H
Year	DTE Electricity Delivery	Consumers Energy Electricity Delivery	Combined Electricity Delivery	DTE Business as Usual Total Cost to Customers	Consumers Energy Business as Usual Total Cost to Customers	Combined Business as Usual Total Cost to Customers	Average Rates under Business as Usual
	(billions of kwh)	(billions of kwh)	(billions of kwh)	(billions of $/Year)	(billions of $/Year)	(billions of $/Year)	($/kwh)
2010 (A)	42.831	33.290	76.121	$ 4.243	$ 3.741	$ 7.984	$ 0.105
2011 (A)	42.760	33.603	76.363	$ 4.509	$ 3.815	$ 8.324	$ 0.109
2012	42.615	34.991	77.606	$ 4.688	$ 3.907	$ 8.595	$ 0.111
2013	42.591	35.449	78.040	$ 4.882	$ 4.039	$ 8.921	$ 0.114
2014	42.346	36.188	78.534	$ 5.046	$ 4.175	$ 9.222	$ 0.117
2015	41.991	36.793	78.784	$ 5.225	$ 4.317	$ 9.542	$ 0.121
2016	41.714	37.235	78.949	$ 5.364	$ 4.463	$ 9.827	$ 0.124
2017	41.818	37.681	79.500	$ 5.557	$ 4.614	$ 10.171	$ 0.128
2018	41.923	38.134	80.056	$ 5.758	$ 4.770	$ 10.528	$ 0.132
2019	42.028	38.591	80.619	$ 5.967	$ 4.932	$ 10.898	$ 0.135
2020	42.133	39.054	81.187	$ 6.183	$ 5.099	$ 11.282	$ 0.139
2021	42.238	39.523	81.761	$ 6.408	$ 5.271	$ 11.680	$ 0.143
2022	42.344	39.997	82.341	$ 6.642	$ 5.450	$ 12.092	$ 0.147
2023	42.449	40.477	82.927	$ 6.885	$ 5.635	$ 12.520	$ 0.151
2024	42.556	40.963	83.518	$ 7.138	$ 5.825	$ 12.963	$ 0.155
2025	42.662	41.454	84.116	$ 7.400	$ 6.023	$ 13.423	$ 0.160
2026	42.769	41.952	84.720	$ 7.673	$ 6.227	$ 13.900	$ 0.164
2027	42.876	42.455	85.331	$ 7.956	$ 6.438	$ 14.394	$ 0.169
2028	42.983	42.965	85.947	$ 8.250	$ 6.656	$ 14.906	$ 0.173
2029	43.090	43.480	86.571	$ 8.555	$ 6.882	$ 15.437	$ 0.178
2030	43.198	44.002	87.200	$ 8.873	$ 7.115	$ 15.988	$ 0.183

Column	Explanation
A	Calendar Year: All data for years 2010 and 2011 are actual data, subsequent years are projected.
B	From FERC Form 1, page 304, escalated after 2016 at 0.25% per year
C	From FERC Form 1,page 304, and MPSC Case U-16890 Exhibit A-21, escalated after 2015 at 1.2% per year
D	Sum of Column B and Column C
E	Total cost to customers - see narrative
F	Total cost to customers - see narrative
G	Sum of Column E and Column F
H	Average Rate calculated as total cost to customers (Column G) divided by electricity delivered (Column D)

APPENDIX II. 25% by 2025

J	K	L	M	N	O	P	Q	R	S	T	U
Year	Average Rates under Business as Usual	Renewables Energy incremental increase	Renewables Contract Cost	Avoided Fossil-fuel Costs	Non-Fuel Avoided Generation Costs	Total Avoided Fossil-fuel Generation Costs	Allowance for Backup Capacity and Transmission	Net Avoided Costs	Net Renewables Cost	Incremental Impact of Renewables on Rates	Rate Impact
	($/kwh delivered)	(% of electricity delivered)	($/kwh renewables)	($/kwh renewables)	($/kwh renewables)	($/kwh renewables)	($/kwh renewables)	($/kwh renewables)	($/kwh renewables)	($/kwh delivered)	(%)
2016	$ 0.124	1.5%	$ 0.075	$ (0.036)	$ (0.040)	$ (0.076)	$ 0.018	$ (0.058)	$ 0.017	$ 0.0003	0.21%
2017	$ 0.128	3.0%	$ 0.076	$ (0.038)	$ (0.041)	$ (0.079)	$ 0.020	$ (0.059)	$ 0.017	$ 0.0005	0.40%
2018	$ 0.132	4.5%	$ 0.077	$ (0.040)	$ (0.042)	$ (0.082)	$ 0.021	$ (0.061)	$ 0.016	$ 0.0007	0.54%
2019	$ 0.135	6.0%	$ 0.077	$ (0.041)	$ (0.043)	$ (0.084)	$ 0.021	$ (0.063)	$ 0.014	$ 0.0009	0.64%
2020	$ 0.139	7.5%	$ 0.078	$ (0.043)	$ (0.044)	$ (0.087)	$ 0.022	$ (0.065)	$ 0.013	$ 0.0010	0.68%
2021	$ 0.143	9.0%	$ 0.079	$ (0.045)	$ (0.045)	$ (0.091)	$ 0.023	$ (0.068)	$ 0.011	$ 0.0010	0.69%
2022	$ 0.147	10.5%	$ 0.079	$ (0.047)	$ (0.046)	$ (0.094)	$ 0.023	$ (0.070)	$ 0.009	$ 0.0009	0.64%
2023	$ 0.151	12.0%	$ 0.080	$ (0.050)	$ (0.048)	$ (0.097)	$ 0.024	$ (0.073)	$ 0.007	$ 0.0008	0.55%
2024	$ 0.155	13.5%	$ 0.081	$ (0.052)	$ (0.049)	$ (0.101)	$ 0.025	$ (0.076)	$ 0.005	$ 0.0006	0.42%
2025	$ 0.160	15.0%	$ 0.081	$ (0.054)	$ (0.050)	$ (0.104)	$ 0.025	$ (0.079)	$ 0.003	$ 0.0004	0.24%
2026	$ 0.164	15.0%	$ 0.082	$ (0.057)	$ (0.052)	$ (0.108)	$ 0.026	$ (0.082)	$ 0.000	$ 0.0000	0.02%
2027	$ 0.169	15.0%	$ 0.083	$ (0.059)	$ (0.053)	$ (0.112)	$ 0.027	$ (0.085)	$ (0.002)	$ (0.0003)	-0.20%
2028	$ 0.173	15.0%	$ 0.084	$ (0.062)	$ (0.054)	$ (0.116)	$ 0.028	$ (0.088)	$ (0.005)	$ (0.0007)	-0.42%
2029	$ 0.178	15.0%	$ 0.084	$ (0.064)	$ (0.056)	$ (0.120)	$ 0.028	$ (0.092)	$ (0.008)	$ (0.0011)	-0.63%
2030	$ 0.183	15.0%	$ 0.085	$ (0.067)	$ (0.057)	$ (0.124)	$ 0.029	$ (0.095)	$ (0.010)	$ (0.0015)	-0.84%

Column	Explanation
J	Calendar Year: Analysis begins in 2016 because no change from Business as Usual as a result of Proposal 3 is expected until then
K	Projected Average Utility Rates under Business as Usual, from Column H on previous page
L	Additional renewable generation above Business as Usual to comply with Proposal 3, assumed to be implemented as 1.5% of load per year from 2016 through 2025
M	Contract price for utilities to buy electricity wholesale from renewable generators, based on actual contracts in 2011 and adjusted for inflation and technology change
N	Fuel cost savings from using renewables instead of fuel, per kwh generated from renewables
O	Non-fuel cost savings, such as power plant maintenance and replacement, from using renewables instead of fuel, per kwh generated from renewables
P	Total utility cost savings from using renewables instead of fuel, per kwh generated from renewables, as sum of Column N and Column O
Q	Allowance for additional transmission and back-up fossil-fuel generation to provide reliability with variable renewables, per kwh generated from renewables
R	Net savings from using renewables, per kwh generated from renewables, after allowing for transmission and back-up capacity, as sum of Column P and Column Q
S	Net cost of using renewables, per kwh generated from renewables, as sum of Column M and Column R
T	Change in average retail rates, per kwh delivered, due to increase in renewables required by Proposal 3, as product of Columns L and S
U	Difference between projected rates under Proposal 3 and under Business as Usual, as a percentage of rates under Business as Usual, as Column T divided by Column K