Appendix F
Energy Supply Policy Recommendations

Summary List of Policy Recommendations

No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)			Net Present Value 2009–2025 (Million $)	Cost-Effective-ness ($/$tCO_2e$)	Level of Support
		2015	2025	Total 2009–2025			
RECENT ACTION	PA 295, Clean, Renewable, and Efficient Energy Act	2.7	2.0	30.8	$1,024	$33	N/A
ES-1	Renewable Portfolio Standard and Distributed Generation "Carve-Out"	5.0	14.6	137.5	$6,600	$48.00	Unanimous
	RPS	4.6	13.7	129.5	$5,546	$42.83	
	Wind	3.7	10.3	100.4	$4,748	$47.31	
	Biomass	0.9	2.7	25.2	$376	$15	
	Solar PV	0.0	0.4	2.6	$392	$152	
	Plasma Gasification	0.0	0.3	1.3	$29	$22	
	Distributed Generation "Carve-Out"	0.4	0.9	8.0	$1,054	$131.51	
	Solar Hot Water	0.0	0.2	1.2	$26	$22.27	
	Geothermal	0.1	0.2	1.5	$82	$55	
	Wind (distributed)	0.1	0.3	2.7	$503	$186	
	Solar PV (distributed)	0.1	0.2	1.84	$508	$276	
	Biogas	0.1	0.2	2.3	$17	$7	
ES-3	Energy Optimization Standard	0.0	13.6	86.3	–$1,632	–$19	Unanimous
ES-5	Advanced Fossil Fuel Technology (e.g., IGCC, CCSR) Incentives, Support, or Requirements	*Not Quantifiable*					Unanimous
ES-6	New Nuclear Power	0.0	6.3	38.5	$1,001	$25.98	Majority
ES-7	Integrated Resource Planning (IRP), Including CHP	*Not Quantifiable*					Unanimous
ES-8	Smart Grid, Including Advanced Metering	*Not Quantifiable*					Unanimous
ES-9	CCSR Incentives, Requirements, R&D, and/or Enabling Policies	*Not Quantifiable*					Unanimous
ES-10	Technology-Focused Initiatives (Biomass Co-firing, Energy Storage, Fuel Cells, Etc.), Including Research, Development, & Demonstration						Super Majority
	Co-firing at 5%	0.2	0.2	3.3	$34.48	$10.6	
	Co-firing at 10%	0.5	0.5	6.5	$69.43	$10.7	
	Co-firing at 20%	0.9	0.9	13.0	$134.09	$10.3	
ES-11	Power Plant Replacement, EE, and Repowering	2.5	2.0	33.2	$313	$9.4	Unanimous

No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)			Net Present Value 2009–2025 (Million $)	Cost-Effective-ness ($/t$CO_2e$)	Level of Support
		2015	2025	Total 2009–2025			
ES-12	Distributed Renewable Energy Incentives, Barrier Removal, and Development Issues, Including Grid Access - TOTAL	*ES-12 Fully incorporated in distributed generation "carve-out" under ES-1.*					Unanimous
	Solar Hot Water						
	Geothermal						
	Distributed Wind						
	Solar PV						
	Biogas						
ES-13	Combined Heat and Power (CHP) Standards, Incentives and/or Barrier Removal	0.4	0.5	7.8	$31.91	$4.09	Unanimous
ES-15	Transmission Access and Upgrades	*Not Quantifiable*					Unanimous
	Sector Totals	**8.1**	**37.2**	**306.6**	**$6,348**	**$22**	
	Sector Total after Adjusting for Overlaps	**8.1**	**23.6**	**220.3**	**$7,980**	**$36**	
	Reductions From Recent Actions	**2.7**	**1.9**	**30.1**	**$1,025**	**$34**	
	Sector Total Plus Recent Actions	**10.8**	**25.5**	**250.4**	**$9,005**	**$36**	

$/t$CO_2e$ = dollars per metric tons of carbon dioxide equivalent; CCI = Cross-Cutting Issues; CCSR = carbon capture, and storage or reuse; CHP = combined heat and power; EE = energy efficiency; ES = Energy Supply; GHG = greenhouse gas; IGCC = integrated gasification combined cycle; IRP = integrated resource planning; MCAC = Michigan Climate Action Council; $MMtCO_2e$ = millions of metric tons of carbon dioxide equivalent; N/A = not applicable; PA = Public Act; PV = photovoltaic; R&D = research and development; TWG = Technical Work Group.

Note: The numbering used to denote each policy recommendation is for reference purposes only; it does not reflect prioritization among these important recommendations.

Overlap Discussion

Several of the energy supply recommendations overlap with each other insofar as they reduce the carbon dioxide (CO_2) intensity of Michigan's electricity supply. Energy Supply (ES) recommendations ES-1, ES-6, ES-10, ES-11, ES-12, and ES-13 all reduce the amount of CO_2 generated by each unit of electricity. The results presented in the table above account for this overlap.

Specifically, when estimating the amount of emissions avoided, the CO_2 intensity of a unit of electricity was reduced to account for multiple recommendations being implemented concurrently. For example, ES-3 avoids less CO_2 when ES-1 is implemented (i.e., when renewables displace primarily coal-fired generation). Therefore, a particular recommendation becomes less cost-effective when other recommendations are implemented concurrently, because while the cost of implementing the particular recommendation remains constant, the amount of CO_2 that the recommendation avoids will have decreased.

The reductions estimated to occur under ES-1, ES-6, ES-10, ES-11, ES-12, and ES-13 all assume successful implementation of each other. In the row labeled "Sector Total after Adjusting for

Overlaps," each of these recommendations accounts for the decreased CO_2 intensity resulting from all the other recommendations. Therefore, a scenario wherein some recommendations are implemented and others are not implemented would generate results that differ from those presented above.

Because ES-12 contributes to the targets established in ES-1, ES-12 has been designed as a "carve-out" of ES-1 to avoid overlap. ES-12, therefore, represents specific percentages of the goals outlined in ES-1. The emission reductions that would result from ES-12 have been accounted for in ES-1.

ES-3 is a direct overlap of Residential, Commercial, and Industrial (RCI) recommendation RCI-1. Therefore, the reductions under ES-3 are omitted from the sector totals table.

ES-1. Renewable Portfolio Standard

Policy Description

A renewable portfolio standard (RPS) is a requirement that utilities supply a certain amount of annual retail sales from eligible renewable energy sources by a certain date and each year thereafter. Beyond reducing utility-sector emissions of CO_2, benefits to Michigan would include lower emissions of smog and soot precursors, improved energy balance of trade, diversified fuel supply risk, and economic development potential. Michigan currently meets over 4% of its electricity needs from renewable sources.

Twenty-four states plus the District of Columbia have adopted some form of an RPS. In the Midwest, these include Illinois (25% by 2025), Minnesota (27.4% by 2025), Ohio (12.5% by 2025), and Wisconsin (10% by 2015).

Policy Design

Goals and Timing:

Goals are stated as a percentage of annual sales and represent total renewable contribution and not "new" or "incremental."

Short-term target (consistent with recently passed Michigan energy legislation [Public Act (PA) 295 of 2008])

- 10% by 2015.[1]
- Of this, at least 0.4% (468 gigawatt-hours [GWh] from 240 megawatts [MW]) will be supplied from small-scale distributed generation (DG) sources.

Long-term goals (consistent with the Midwestern Governors Association [MGA] platform)

- 20% by 2020.
- 25% by 2025, at least 1.1%, of which (1,396 GWh from 715 MW) will be supplied from small-scale DG.
- 30% by 2030.

Parties Involved: An RPS provision within state law will affect all aspects of Michigan's energy sector and the state's population. Therefore, all aspects of Michigan society will need to

[1] Public Act (PA) 295 specifies with up to 10% of the RPS able to be met with energy optimization (10% of the 10% RPS) or advanced cleaner energy credits (7% of the 10% RPS). Eligible renewable resources include; solar water heat, solar thermal process heat, photovoltaics, landfill gas produced from MSW, wind, biomass, certain hydroelectric, tidal, geothermal electric, municipal solid waste, gasification, industrial waste heat, and clean coal. Michigan RPS is subject to "cost caps" and extensions to meet RPS are permitted Consumer Energy must meet 200 MW of renewable energy capacity by 2013 and 500 MW of renewable capacity by 2015, and: Detroit Edison must meet 300 MW of renewable energy capacity by 2013 and 600 MW of renewable capacity by 2015. Credit Trading is available; Alternative Compliance Payments are not available.

participate in the formation of policy, in the generation and delivery of energy, or pay for renewable energy resources either (1) voluntarily through signing up for existing renewable energy programs offered by utilities and others, or (2) through costs embedded in general rates, through power supply cost recovery mechanisms, or through other social funding mechanisms. Renewable energy will need to be evaluated within statewide long-term energy planning and also within company-specific integrated resource planning (IRP), as detailed in another ES policy recommendation. Participation is required for all electricity distribution providers in Michigan.

Other:

- Given the economic benefits to Michigan of locating renewable energy projects and related manufacturing operations in the state, provisions that encourage these activities should be carefully considered.
- As defined within the Michigan Clean, Renewable, and Efficient Energy Act, 2008 PA 295, Part 1, Section 9, (I) "Renewable energy resource" means a resource that "naturally replenishes over a human, not a geological, time frame and that is ultimately derived from solar power, water power, or wind power. Renewable energy resource does not include petroleum, nuclear, natural gas, or coal. A renewable energy resource comes from the sun or from thermal inertia of the Earth and minimizes the output of toxic material in the conversion of the energy and includes, but is not limited to, all of the following:
    - (i) Biomass.
    - (ii) Solar and solar thermal energy.
    - (iii) Wind energy.
    - (iv) Kinetic energy of moving water, including all of the following:
        - (A) Waves, tides, or currents.
        - (B) Water released through a dam.
    - (v) Geothermal energy.
    - (vi) Municipal solid waste.
    - (vii) Landfill gas produced by municipal solid waste."
- Mechanisms that expose renewable energy projects to competitive bidding should be explored.
- This policy recommendation assumes that the provisions of ES-12, Distributed Renewable Energy, are included here. The DG policy design in ES-12 represents the DG "carve-out," or guarantee, within ES-1 within both the 2015 and the 2025 goals.
- Legislative support for the streamlining of siting, zoning, and permitting for renewable energy projects will be of significant importance to achieve the long-term RPS goals of greater than 10%.
- Long-term RPS goals beyond 10% will need to allow sufficient flexibility for delays in development and construction timing due to the need for development of the electric transmission system and the risks and challenges of developing offshore renewable energy systems.

Implementation Mechanisms

Available policy mechanisms to implement an RPS requirement include a legislative act or regulatory action by the Michigan Public Service Commission (MPSC), within its jurisdiction. In any case, program development and administration would be directed by the MPSC. Enforcement of the RPS requirement needs to balance the application of some form of a noncompliance penalty with allowance for a cost cap to control overall program costs. Typically, a renewable energy credit-trading program will also be instituted to facilitate the development of a viable intrastate renewable energy market. Renewable energy payments (REPs, also known as feed-in tariffs) as described in ES-12 are intended to be available under this policy to small- and large-scale generators at appropriate rates and terms.

There are a number of options for setting the REP price. For commercial-level distributed renewable energy projects, the REP price would most likely need to be set high enough to cover costs and ensure a reasonable return on investment. For household-level distributed renewable energy projects, the REP price needs to be set high enough to provide an adequate incentive for the homeowner to invest in the project. Homeowners would consider the financial incentive, the avoided costs of purchasing electricity over the life of the project, and such intangibles as the benefit of energy independence and the knowledge of knowing that they are powering their homes with little or no carbon footprint.

Related Policies/Programs in Place

In September 2008, the Michigan legislature enacted S.213, and Governor Granholm signed this bill into law (PA 295 of 2008), creating the "Clean, Renewable, and Efficient Energy Act." The act calls for the MPSC to order electric utilities to submit an energy optimization plan to the MPSC, demonstrating how they will comply with the new RPS. The RPS mandates that 10% of the state's electricity be derived from renewable sources by 2015, with some exceptions.

Section 51 of the act describes the electric providers' annual RPS reporting requirements, as well as the February 15, 2011, report the MPSC must submit to the legislature, which summarizes the data collected by the electric providers and describes whether the RPS and energy optimization programs have been cost-effective, etc.

According to the U.S. Department of Energy (DOE), 24 states plus the District of Columbia have RPS requirements in place. Together, these jurisdictions account for more than half of the electricity sales in the United States. Four other states—Illinois, Missouri, Virginia, and Vermont—have nonbinding goals for adoption of renewable energy instead of an RPS.[2]

Utilities and some municipal suppliers in Michigan currently offer renewable energy options to customers through voluntary programs. These programs allow customers to opt to supply a portion of their load from renewable energy sources for a pricing premium.

Type(s) of GHG Reductions

CO_2.

[2] Source: http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm

Estimated GHG Reductions and Costs or Cost Savings

F-1-1. Estimated GHG reductions and costs of or cost savings from ES-1.

ES-1. Renewable Portfolio Standard	2015	2025	Units
GHG emission reductions	5.0	14.6	Million metric tons of CO_2
Cumulative net costs (present value) (2009–2025)		$6,600	Million $
Cumulative emissions reductions (2009–2025)		137.5	Million metric tons of CO_2
Cost-effectiveness		$48.00	$/metric ton of CO_2

CO_2 = carbon dioxide; GHG = greenhouse gas.

Data Sources:

- U.S. DOE Energy Information Administration (EIA) 2007 Annual Energy Outlook (AEO).
- U.S. DOE, Office of Energy Efficiency and Renewable Energy, "Economic Benefits, Carbon Dioxide (CO_2) Emissions Reductions, and Water Conservation Benefits from 1,000 Megawatts (MW) of New Wind Power in Michigan" (http://www.windpoweringamerica.gov/pdfs/economic_development/2008/mi_wind_benefits_factsheet.pdf).
- Conversation with Recovered Energy, Inc. (for plasma gasification).

Quantification Methods: New renewables were assumed to displace primarily coal-fired power, as reflected in the Michigan inventory and forecast (I&F). The values presented above reflect the minimum amounts specified in the recent RPS legislation.

In order to quantify this recommendation, the first step was to identify the phase-in dates and percentages for the RPS. The second step identified the allocation among specific technologies that would fulfill the RPS obligation. This allocation is presented in Table F-1-2 under the Key Assumptions section of this recommendation. The next step identified capacity factors and total energy generation from each of these renewable generation sources in order to meet the RPS goals. Transmission and distribution losses were taken into account at this stage for central station generation. In order to estimate costs, capital, operation and maintenance, as well as fuel costs where relevant were incorporated into the model. These elements combined to produce the estimate of costs for meeting the RPS.

For the "carve-out" portion of this recommendation, the ES Technical Work Group (TWG) first determined the magnitude of the carve-out, as a percentage of total electrical energy consumption in the state, set at 1.1% (715 MW) in 2025, phased in from a level of 0.4% (240 MW) in 2015. This quantity of energy generated by distributed sources was spread across wind, solar photovoltaic (PV), and biogas based on the DG carve-out percentages shown above. Based on the capacity factors determined by the TWG, the total required capacity was calculated. Costs are based on the levelized cost of electricity from the various sources. The avoided cost of electricity is consistent with all other recommendations.

It is important to note that the costs presented here represent the total direct cost to society (public and private), as defined by the borders of the state of Michigan. Capital and operating costs are included in the total, regardless of who within Michigan actually pays these costs.

Therefore, DG costs reflect the total cost to ratepayers, taxpayers, and homeowners for recommended subsidies, incentives, and private expenditures. This policy recommends methods for creating the incentives necessary to achieve the goals, but does not prescribe specific rates, which would be set through the existing legislative and regulatory processes. It is believed that the goals can be achieved through the availability of public-sector incentives representing a fraction of the total costs presented here.

Key Assumptions:

The following portfolio of new renewables was used, based on input from the TWG.

Table F-1-2. Assumed portfolio of renewables

Type of Electricity Generation	2015	2025	Units
Wind	80%	75%	of RPS
Biomass	19%	20%	of RPS
Solar PV	1%	3%	of RPS
Plasma gasification	0%	2%	of RPS

PV = photovoltaic

The following assumptions were used for each type of generation:

Table F-1-3. Assumptions used for types of electricity generation

Types of Generation and Assumptions	2015	2025
Wind		
Capital cost ($/kW)	$1,650	$2,000
Transmission cost ($/kW)	$120	$120
Capacity factor	25%	25%
Solar Thermal		
Capital cost ($/kW)	$3,004	$2,524
Transmission cost ($/kW)	$80	$80
Capacity factor	25%	25%
Biomass		
Capital cost ($/kW)	$2,800	$2,500
Transmission cost ($/kW)	$80	$80
Capacity factor	90%	90%
Solar PV		
Capital cost ($/kW)	$4,915	$4,331
Transmission cost ($/kW)	$80	$80
Capacity factor	15%	15%
Geothermal		
Capital cost ($/kW)	$1,126	$3,231

Types of Generation and Assumptions	2015	2025
Transmission cost ($/kW)	$80	$80
Capacity factor	85%	85%
Plasma Gasification		
Capital cost ($/kW)	$9,601	$9,000
Transmission cost ($/kW)	$80	$80
Capacity factor	85%	85%

$/kW = dollars per kilowatt; PV = photovoltaic.

A second set of assumptions applies to the DG "carve-out." This analysis assumes that 1.1% of the total consumption (715 MW) is supplied by small-scale DG by 2025. This goal is phased in beginning at 0.4% of total consumption (240 MW) beginning in 2015. The analysis assumes that three technologies will fill these goals as follows:

Table F-1-4. Distributed generation "carve-out"

Type of Electricity Generation	2015	2025	Units
Wind	40%	40%	of carve-out
Solar PV	25%	25%	of carve-out
Biogas	35%	35%	of carve-out

PV = photovoltaic.

These results rely on additional assumptions for capacity factors as follows:

Table F-1-5. Assumed capacity factors

Type of Electricity Generation	Capacity Factor
Wind (distributed)	18%
Solar PV (distributed)	15%
Biogas	65%
Geothermal	85%

PV = photovoltaic.

Finally, capital costs are based on the following assumptions:

Table F-1-6. Assumed capital costs

Type of Electricity Generation	Capital Cost ($/kWh)	
	2015	2025
Wind (distributed)	$6,000	$5,000
Solar PV (distributed)	$8,131	$6,756
Biogas	$3,250	$3,250

$/kWh = dollars per kilowatt-hour; PV = photovoltaic.

Key Uncertainties

- Feasibility of plasma gasification.
- Future capital costs for all types of renewable generation.

Additional Benefits and Costs

The use of renewable sources in lieu of fossil fuels often reduces emissions of criteria pollutants and air toxics in addition to greenhouse gases (GHGs). These reductions offer indirect public health and related economic benefits, none of which is quantified or included here.

Feasibility Issues

The RPS enacted in 2008 and effective in 2015 is equivalent to the policy recommended here for 2015. The policy recommended here calls for progressively more stringent renewable contributions in 2020, 2025, and 2030. The likelihood that future legislatures will extend and expand the RPS will depend in part on the experience with the 2015 requirement.

Meeting the target for the DG "carve-out" will be extremely challenging, given the high costs and low capacity factors for distributed wind.

Status of Group Approval

Approved.

Level of Group Support

Unanimous

Barriers to Consensus

None.

ES-3. Energy Optimization Standard

Policy Description

Energy optimization means energy efficiency, load management that reduces overall energy use, and related energy conservation. An energy optimization standard (EOS) requires energy savings as a percentage of total annual retail electricity sales in megawatt-hours (MWh) and total annual retail natural gas sales in decatherms or equivalent thousand cubic feet (MCF) in a specified year. To accomplish this, electric and natural gas providers are to develop energy optimization plans sufficient to ensure the achievement of applicable energy optimization standards. Ratepayers benefit from avoided construction costs of new power plants, and lower utility bills for those who directly participate in available energy efficiency programs.

In the Midwest, states that have adopted this policy mechanism include Minnesota (1.5% annual energy savings), Illinois (1% annual energy savings by 2011, 2% annual energy savings by 2015), and Ohio (1% annual energy savings by 2014, 2% annual energy savings by 2019).

Policy Design

Goals and Timing: The 2008–2012 energy optimization program savings goals included below are established by PA 295 of 2008. Goals for years 2013–2015 are given under Tier 2 below. For years beyond 2015, Section 97 of the act requires the MPSC, by September 30, 2015, to review opportunities for additional cost-effective energy optimization programs, and to make any recommendations for legislation providing for the continuation, expansion, or reduction of EOSs. For the purposes of modeling a long-term energy optimization goal under this policy recommendation (Tier 3), the 2015 goals for incremental energy savings were extended through 2025 to mirror how the long-term goal was established under the MGA energy efficiency policy option EE-1: Establish Quantifiable Goals for Energy Efficiency.

Tier 1: 2008–2012 Electricity Energy Optimization Program Savings

- Biennial incremental electricity savings in 2008–2009 equivalent to 0.3% of total annual retail electricity sales in MWh in 2007.
- Annual incremental electricity savings in 2010 equivalent to 0.5% of total annual retail electricity sales in MWh in 2009.
- Annual incremental electricity savings in 2011 equivalent to 0.75% of annual retail electricity sales in MWh in 2010.
- Annual incremental electricity savings in 2012 of 1.0% of annual retail electricity sales in MWh in 2011.

Tier 1: 2008–2012 Natural Gas Energy Optimization Program Savings

- Biennial natural gas savings in 2008–2009 equivalent to 0.1% of total annual retail natural gas sales in decatherms or equivalent MCF in 2007.
- Annual incremental natural gas savings in 2010 equivalent to 0.25% of total annual retail natural gas sales in decatherms or equivalent MCF in 2009.

- Annual incremental natural gas savings in 2011 equivalent to 0.5% of total annual retail natural gas sales in decatherms or equivalent MCF in 2010.
- Annual incremental natural gas savings in 2012 of 0.75% of total annual retail natural gas sales in 2011.

Tier 2: 2013–2015

- Annual gross savings for electricity equal to 1.33% in 2013, 1.66% in 2014, and 2.0% in 2015. For natural gas, 0.75% annual gross savings by 2015 and each year thereafter, based upon prior year sales.

Tier 3 (Long Term)

- Annual incremental electricity savings in 2016 and each year thereafter through 2025 equivalent to 2.0% of total annual retail electricity sales in MWh in the preceding year. Annual incremental natural gas savings in 2016 and each year thereafter through 2025, equivalent to 0.75% of total annual retail natural gas sales in decatherms or equivalent MCF in the preceding year.

Parties Involved: Participation is required for all electricity and natural gas distribution providers in Michigan. Consistent with PA 295, if a given utility does not wish to run its own energy efficiency programs, it may collect funding through surcharges on customer bills to fund a third-party administrator to design and implement such programs in that utility's service territory.

Other: Complementary policies that better align utility decision making with energy efficiency are essential. Utilities should be allowed to capitalize and recover their investments in energy efficiency programs (analogous to what they do with the power plants the Michigan Climate Action Council [MCAC] is trying to avoid having them build), and they should be made whole for the revenue erosion through decoupling. Refer to the residential, commercial, and industrial (RCI) sectors policy recommendation RCI-1 (Utility Demand-Side Management), RCI-3 (Regulatory Changes To Encourage Energy Efficiency), and RCI-7 (Public Benefits Funding). In addition, ES-7 (Integrated Resource Planning [IRP], Including CHP) is an important mechanism to fully tap cost-effective energy savings beyond the initial EOS requirement.

Implementation Mechanisms

Tier 1 goals have already been enacted through PA 295. Available policy mechanisms to implement additional EOS requirements could include a legislative act or regulatory action by the MPSC, within its jurisdiction. Funding for the required programs could be included in utility bills, either assessed as a public benefits charge or incorporated as part of the normal rate case proceedings, for all customer classes. Alternatively, funding could come from a general appropriation from the legislature to customers as a subsidy through tax abatement or incentives for implementing energy efficiency measures.

Because Michigan has electric choice, the program must be competitively neutral—thus funded equally by all customers and available to all customers. Stated differently, the programs, funding, and savings must not create structural advantages or disadvantages for utilities or alternative electric suppliers.

Related Policies/Programs in Place

PA 295 of 2008 establishes Michigan's EOS and related requirements through 2012. Section 97 of the act describes the electric providers' annual energy optimization plan reporting requirements as well as various reports the MPSC must provide the legislature, which summarize the data collected by the electric providers and describe such things as the rate impacts, recommendations for legislative action, and cost-effectiveness of the energy optimization program. The quantitative goals and results of this act are shown below:

Electric providers must achieve the following collective minimum energy savings:

- Biennial incremental energy savings in 2008–2009 equivalent to 0.3% of total annual retail electricity sales in MWh in 2007.
- Annual incremental energy savings in 2010 equivalent to 0.5% of total annual retail electricity sales in MWh in 2009.
- Annual incremental energy savings in 2011 equivalent to 0.75% of total annual retail electricity sales in MWh in 2010.
- Annual incremental energy savings in 2012, 2013, 2014, and 2015 and each year thereafter equivalent to 1.0% of total annual retail sales in MWh in the preceding year.

A natural gas provider must meet the following minimum energy savings:

- Biennial incremental energy savings in 2008–2009 equivalent to 0.1% of total annual retail natural gas sales in decatherms (Dth)[*] or equivalent MCF in 2007.
- Annual incremental energy savings in 2010 equivalent to 0.25% of total annual retail natural gas sales in Dth or equivalent MCF in 2007.
- Annual incremental energy savings in 2011 equivalent to 0.5% of total annual retail natural gas sales in Dth or equivalent MCF in 2007.
- Annual incremental energy savings in 2012, 2013, 2014, and 2015 equivalent to 0.75% of total annual retail natural gas sales in Dth or equivalent MCF in the preceding year.

These legislated actions will result in the effects on energy consumption and GHG emissions shown in Table F-3-1.

Table F-3-1. Estimated GHG reductions and costs of or cost savings from recent[3] legislated actions

Recent Legislated Actions: Utility Demand-Side Management for Electricity and Natural Gas	2015	2025	Units
GHG emission savings	3.3	24.6	Million metric tons of CO_2
Cumulative net costs (present value) (2009–2025)		–$4,415	Million $
Cumulative emissions reductions (2009–2025)		193.9	Million metric tons of CO_2

[*] Decatherm (Dth): A measurement of the heat equivalent to one million British thermal units (Btus).

[3] Recent actions are those that have been approved but not yet implemented.

Cost-effectiveness		–$23	$/metric ton of CO_2

CO_2 = carbon dioxide; GHG = greenhouse gas.

Also, the Customer Choice and Electricity Reliability Act of 2000 authorized the creation of a Low-Income and Energy Efficiency Fund, administered by the MPSC via grants to qualifying organizations. The purpose of the fund is to provide utility service shutoff and other protection for low-income customers and to promote energy efficiency by all customer classes. Since 2002, approximately $89 million (24% of available funds) has been used for efficiency-related grants.

According to the Alliance to Save Energy, several states have set performance standards for their energy efficiency programs. However, the regulatory environment in some of these states is quite different from that in Michigan or the Midwest in general. Programs that work in one state may not be fully or partly applicable in another jurisdiction, such as Michigan. The following programs are for illustrative purposes and do not purport to be goals for Michigan per se.[4]

- *Texas* requires utilities to avoid a percentage of the forecast increase in electric demand through efficiency programs, rising to 20% starting in 2009. *Illinois* requires electricity savings rising to 2% of sales in 2015, and *Minnesota* requires 1.5% annual savings starting in 2010.
- *Pennsylvania, Nevada, Hawaii, and North Carolina* include energy efficiency and renewable energy as options in a broader RPS.
- *Connecticut* revised its RPS to require utilities to save 4% of electricity use by 2010 through residential and commercial programs and combined heat and power.
- The *California* Public Utilities Commission sets multi-year targets for electric and natural gas utilities based on a study of how much cost-effective savings the programs can achieve.
- *Colorado*'s largest utility, Xcel, has agreed to achieve a set level of savings, and *Vermont* has performance requirements in its contract with an independent efficiency provider.

Type(s) of GHG Reductions

Primarily CO_2 reductions resulting from avoided electricity generation, but could reduce to some degree all six statutory GHGs (CO_2, methane [CH_4], nitrous oxide [N_2O], hydrofluorocarbons [HFCs], perfluorocarbons [PFCs], and sulfur hexafluoride [SF_6]).

Estimated GHG Reductions and Costs or Cost Savings

The estimated GHG reductions and cost savings from this policy recommendation that are additional to the results of the legislation presented in Table F-3-1 above are as follows;

Table F-3-2. Estimated GHG reductions and costs of or cost savings from ES-3

ES-3. Energy Optimization Standard	2015	2025	Units
GHG emission savings	0.0	13.6	Million metric tons of CO_2

[4] Source: http://www.ase.org/content/article/detail/4070.

Cumulative net costs (present value) (2009–2025)		–$1,632	Million $
Cumulative emissions reductions (2009–2025)		86.3	Million metric tons of CO_2
Cost-effectiveness		–$19	$/metric ton of CO_2

This analysis assumes that the costs of and benefits from PA 295 of 2008 are treated as "recent actions," as shown in table F-3-1. The benefits and costs shown in table F-3-2 result from the recommended policy above and beyond PA 295. PA 295 states that energy optimization targets will only continue beyond 2015 if the utilities have been achieving their targets and the MPSC issues a report to the legislature saying it is reasonable to expect utilities to keep meeting them. The analysis in Tables F-3-1 and F-3-2 assumes that this condition is met and these reductions continue at the same pace between 2015 and 2025.

Data Sources: Projections for energy sales are based on AEO 2008 projections for energy sales in Michigan. The cost of energy is based on the most recent EIA data. The levelized costs of natural gas savings and electricity savings are based on data provided (September 2008) by the American Council for an Energy Efficient Economy (ACEEE), with the electricity cost based on ACEEE's survey of numerous electricity efficiency programs across the country. The primary data source is ACEEE's *Five Years In: An Examination of the First Half-Decade of Public Benefits Energy Efficiency Policies*.

Quantification Methods: Energy savings for both electricity and natural gas are calculated by multiplying the percentage of energy to be saved by the amount of energy projected to be sold in the baseline year. Those electricity or natural gas savings are then multiplied by the cost of electricity and natural gas savings and by the avoided electricity and gas costs to produce a net total cost of this policy recommendation. In the case of these energy efficiency measures, the total cost is negative—meaning the energy efficiency measures produce net savings.

Key Assumptions: All emission reductions shown are incremental to any energy savings required by existing Michigan legislation. The goal of this policy recommendation is 2% electricity savings and 0.75% natural gas savings, phased in between 2009 and 2015. The savings targets continue through the year 2025. The analysis also assumes that the residential, commercial, and industrial sectors meet the same energy savings goals, and that all energy sales in all three sectors must meet the same energy savings targets. The other key cost assumptions, based on the data sources described above, are presented in Table F-3-3.

Table F-3-3. Some key cost assumptions

Types of Costs	Assumptions
Levelized Cost of Electricity Savings	$30/MWh
Avoided Electricity Delivery Cost	$60/MWh
Levelized Cost of Natural Gas Savings	$2.5/MMBtu
Avoided Delivered Natural Gas Cost	$7.7/MMBtu

MMBtu = million British thermal units; MWh = megwatt-hour.

Key Uncertainties

Key uncertainties are related to the assumed avoided cost of energy. If the assumed avoided cost (the energy that consumers do *not* need to purchase, as a result of energy efficiency measures) rises, then the policy recommendation's cost per metric ton ($/t) of CO_2 reduced decreases. If the avoided cost of energy falls, then the $/t$CO_2$ reduced increases.

Additional Benefits and Costs

Energy efficiency measures that reduce the use of fossil fuels often reduce emissions of criteria pollutants and air toxics in addition to GHGs. These reductions offer indirect public health and related economic benefits, none of which is quantified or included here.

Emission reduction benefits beyond those recommended here may also be achieved through ES-7 (Integrated Resource Planning, [IRP], Including CHP). The IRP policy is not quantified due to the multiple uncertainties associated with the results of future planning efforts. Nonetheless, real and measurable reductions should be produced through IRP. IRP-related emission reductions may provide mitigation beyond the requirements of the EOSs.

Feasibility Issues

The EOSs for electricity and natural gas recommended here are equivalent to the one recently enacted by Michigan through 2012. EOSs beyond 2012 would require legislative action.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

None.

ES-5. Advanced Fossil Fuel Technology

Policy Description

Advanced fossil fuel-based electric generation technologies include those that can be more efficient and thus lower-emitting generation technologies than current or older technologies. Alternative, advanced fossil generation may include technologies different from conventional ones that could have higher or lower efficiencies but pose other advantages. Advanced fossil generation technologies combined with carbon capture and storage or reuse (CCSR) may have the potential to materially lower CO_2 emissions associated with fossil fuel-based electricity generation. Such technologies include (but are not limited to) circulating fluidized-bed combustors, integrated gasification combined-cycle (IGCC) units, and pulverized coal (advanced supercritical and ultra-supercritical units). The classes of supercritical technologies (advanced and ultra) serve to increase electric output (efficiency) through increases in pressure and temperature in the combustion and heat transfer cycles. IGCC technologies may offer low-emission capability for certain measured or regulated parameters.

Policies to encourage the development of these technologies may include performance requirements, mandates, or incentives to use advanced coal technologies for new coal plants, such as a performance requirement for new fossil fuel-fired power plants to achieve a specific CO_2 emission rate. Alternatively, a mandate might require that all or a portion of new coal plants be of a certain technology or include certain control technologies. Incentives could take the form of direct financial subsidies or assistance in securing low-interest financing. A combination of mandates and incentives may be desirable to balance incentives for replacing older existing power plants.

As with certain advanced electric generation technologies, CCSR technology will most likely increase the cost of generating electricity. Policies to encourage development of CCSR technology should include a state agency tasked with promoting CCSR and with the ability to mandate changes and/or offer financial incentives to capture, store, and/or reuse CO_2.

Policy Design

The proposed policy has three elements:

1. *A post-combustion technology pilot and demonstration project applied to a single coal unit.* Given Michigan's promising opportunities for carbon geostorage, a pilot or demonstration project is proposed to fund and manage the application of a promising technology to capture, transport, and store carbon. The state should act in partnership with industry, the federal government, and others to develop a project plan, budget, and funding proposal.
2. *Michigan-specific comparison of the costs and benefits of advanced methods.* Analyze and report a Michigan-specific comparison of the costs and benefits of advanced methods, such as IGCC and supercritical technologies, against existing coal technologies from a GHG reduction and cost perspective. The policy will not propose to set goals to achieve broad GHG reductions, but rather will perform a general analysis within the MCAC process of the current state of the costs and benefits of these emerging technologies.

3. *State actions to promote CCSR.* Use financial incentives, performance requirements, mandates, or other measures to encourage or require the early adoption of these technologies. Since these technologies are not yet mature, consideration will be given to specific incentives, etc., but this policy will not be quantified as predictably contributing to GHG reductions at this time.

Goals: This policy is not quantified, as stated above.

Timing: The post-combustion CCSR technology pilot project will be in operation in the 2012–2013 time frame. A preliminary analysis of all of the various advanced technologies will be undertaken through this process. If indicated, a more detailed analysis may be recommended. State actions to promote CCSR should be implemented as soon as the analysis indicates that technology maturity as well as costs and benefits are supported.

Parties Involved: Michigan Departments of Environmental Quality (MDEQ) and Natural Resources (MDNR), MPSC, DOE, owners of coal-fired generating units. Michigan's universities have detailed knowledge of the state's unique geology and will be a valued partner in CCSR evaluations and analyses.

Other: None.

Implementation Mechanisms

As adopted from the MGA Advanced Coal and Carbon Capture and Storage (AC/CCS) Renewable Energy Policy Options 1 & 2:

- *Provide state support for front-end engineering and design (FEED).* FEED studies provide the cost estimates needed to secure private investment in power plant projects. State tax credits or grants can help offset FEED study costs and allow utilities and developers to recoup those initial engineering costs that are most difficult to finance. This approach has been effective in Illinois, North Dakota, and Wyoming in spurring project development, and is under consideration in other parts of the Midwest.
- *Provide direct state financial incentives (grants, tax credits, loan guarantees, and performance wrap engineering/procurement/construction coverage).* States should establish the same incentives as or incentives complementary to those in the federal Energy Policy Act of 2005 to help reduce the financial cost of the overall project once engineering and cost studies are completed.
- *Allow regulated utilities cost recovery for appropriate commercial projects.* Utilities committed to developing advanced technology coal plants with CCSR should be ensured cost recovery, as long as they meet a state commission's standards for proper spending decisions. States should also consider a comparable process for merchant and independent power producers involved in request for proposal (RFP) bidding processes.
- *Enhance IRP policies, where applicable, by using them to encourage low-CO_2 coal technologies.* Regional leaders should adopt well-designed IRP rules to weigh the full costs, benefits, and risk characteristics of various resource options. Doing so would improve the accuracy of "least-cost" planning for generation options, which currently penalizes advanced coal and CCSR proposals because it does not fully address future regulatory and

environmental costs. Future risks to be factored in should include fuel price fluctuation, carbon constraints, emission limits of criteria pollutants and mercury, and technology uncertainty.

- *Modify state policies and regulatory programs to favor advanced CO_2-limiting generation technologies with CCSR over conventional pulverized coal units.* These policies could include:
  1. A low-carbon electricity portfolio standard or objective that combines fossil electricity generation resources (such as IGCC with CCSR) with traditional renewable resources;
  2. A CCSR portfolio standard for electricity providers;
  3. A CO_2 performance standard for all new electric power plants;
  4. Innovative, long-term power purchase agreements to provide developers with higher rates of return and reduced risk in exchange for price stability that benefits ratepayers (allowing regulators to qualify more stable prices as a benefit);
  5. Specific incentives and financing assistance to replace or repower existing coal plants in favor of advanced generation technologies with CCSR;
  6. Market-based environmental regulatory programs to provide incentives to invest in low-CO_2 emission technologies with flexibility and certainty for achieving reductions; and
  7. Three-party covenants in which the federal government provides credit, the state regulatory commission provides an assured revenue stream from the syngas to protect the federal credit, and a project developer provides equity and initiative to build the project.
- *Increase federal funding of incentives to accelerate deployment of advanced coal technologies with CCSR at commercial scale.* Current federal funding is completely inadequate, given the scale of the task and urgency of commercializing advanced coal technologies with CCSR. Midwestern governors call on the region's congressional delegation to expand significantly the federal commitment of resources in this area.
- *Provide incentives for deployment of innovative coal gasification technologies, including co-gasification of biomass and underground coal gasification, and the utilization of captured CO_2.* Co-gasification of biomass feedstocks with coal has been commercially demonstrated in Europe and, when combined with CCSR, could provide CO_2-neutral or even CO_2-negative energy production. Underground coal gasification has entered commercial operation overseas and has the potential to bring the capital costs of CCSR with coal to at or below that of conventional pulverized coal generation. Finally, research is underway to convert captured CO_2 into useful and advanced materials and other products.

The following regards the CCSR aspect of this policy (repeated in ES-9).

- Consider an infrastructure build-out that extends beyond Michigan. In this context, the term "infrastructure" should be understood to include regional power markets. Developers will not build advanced coal generators with CCSR, or retrofit existing generators with CCSR, unless these units will be competitive in regional power markets (e.g., PJM and Midwest Independent Transmission System Operator [MISO]), taking into account their anticipated construction costs.

- Develop a report that quantifies the costs and benefits and potential capacity of enhanced oil recovery (EOR). This report will identify CO_2-EOR resource potentials in Michigan, and will quantify the potential GHG reduction benefits of CO_2-EOR projects.
- Review regulations of other states governing or potentially relating to CO_2 capture and underground injection. This review will provide guidance by laying out existing statutes and regulations and identifying gaps in regulation for policymakers.
- Develop a legal and regulatory framework for geologic storage of CO_2. To set the stage for geologic storage projects to move forward in a 5–10-year time frame, Michigan must establish the necessary legal and regulatory framework in partnership with the federal government. Michigan must ensure that the necessary statutes and regulations for geologic storage are in place, including guidance on pipelines, injection, monitoring, mitigation, verification, and long-term liability.
- Evaluate and comment on the underground injection control (UIC) regulations proposed by the U.S. Environmental Protection Agency (EPA) on geologic sequestration of CO_2. EPA's UIC regulations related to geologic sequestration will have broad impacts on CCSR project development and technology deployment.
- Provide state-based incentives for CCSR, encompassing projects that use captured CO_2 for EOR as well as deep-saline formation storage. Stability in the CO_2 credit market is also important for CCSR.
- Provide EOR project development assistance. Michigan has a mature oil and gas industry, with many small oil and gas producers that have not traditionally used CO_2-EOR, in part because they are not large enough to develop projects. The public sector, companies, and trade associations can play a useful role in helping to identify the specific mechanisms by which producers can band together to leverage cost-effective projects.
- Support comprehensive assessments of geologic reservoirs at the state and federal levels to determine CO_2 storage potential. Governments should build on the work of the DOE-funded regional sequestration partnerships to complete comprehensive, basin-level geologic assessments of storage potential. Regions with a history of oil and gas exploration tend to have better data available on geologic formations, making such assessments easier and less expensive, although these regions suffer the deficiency of having much previous drilling that can diminish reservoir integrity. Detailed, accurate mapping of lesser-known potential reservoirs for CCSR will require continued federal and state investment.
- Participate in and/or fund sufficient underground injection tests to prepare for future storage on a widespread commercial basis. Congress and the president should support sufficient federal funding for DOE to ensure a robust program of tests to demonstrate to the private sector, policymakers, and the public the viability, efficacy, and safety of widespread commercial geologic storage of CO_2. These tests should focus on a variety of geologic settings, including reservoirs other than oil-and-gas-bearing formations, and should produce guidelines for appropriate monitoring, mitigation, and verification.
- Evaluate the feasibility of alternate sequestration options for jurisdictions without as-yet adequately documented underground injection potential, such as the western Upper Peninsula. This includes evaluating the cost and feasibility of CO_2 pipelines from other areas

of the state and other CO_2 sequestration options, such as mineralization, carbon nano-fibers, or biological means.

- Consider the use of transported synthetic natural gas to areas where near-term carbon storage options are as yet unknown. This could also allow better use of peaking/intermediate generating capacity and complement the expanded development of wind power.

Related Policies/Programs in Place

See Table F-9-1. MDEQ, MDNR, the Michigan Attorney General, and others are currently mapping out the various regulatory matters pertaining to CCSR to identify appropriate actions to address such issues as landowner rights, liability (both short and long term), revenue streams, environmental impacts, and other issues as identified.

Type(s) of GHG Reductions

Principally CO_2.

Estimated GHG Reductions and Costs or Cost Savings

Not applicable. This policy is not quantified.

Data Sources: Not applicable.

Quantification Methods: Not applicable.

Key Assumptions: Not applicable.

Key Uncertainties

The key uncertainties fall into three categories: technological and cost uncertainties for some capture, transport, and storage technologies; legal uncertainties, such as permitting, liability, and property rights; and sequestration uncertainties, such as the long-term suitability for certain geologic formations.

Additional Benefits and Costs

It is expected that real and measurable emission reduction benefits will result from the implementation of CCSR and other advanced technologies. However, it is not possible to reliably predict the magnitude of these savings or their costs or cost savings at this time. A proposed pilot project would be designed to answer some of these questions.

Feasibility Issues

The feasibility of advanced technologies depends upon resolving the legal issues and successfully demonstrating that the technologies and storage methods are reliable and cost-effective. The feasibility of the pilot project depends upon the availability of sufficient funding.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

None.

ES-6. New Nuclear Power

Policy Description

Nuclear power is a large-scale low-GHG, baseload source of electricity that could complement renewable energy resources in a mix of low-GHG-emitting electric generating options. According to the Nuclear Energy Institute, nuclear energy generates over 70% of the carbon-free electricity in the United States and avoids almost 700 million metric tons of CO_2 emissions that otherwise would be emitted by fossil fueled generation. Evaluation of CO_2 emissions on a total life-cycle basis (i.e., mining, to fuel shipping, to fuel disposal) indicates that CO_2 emissions from nuclear energy are comparable to most other non-emitting energy sources, such as solar, wind, and hydropower. The United Nations' Intergovernmental Panel on Climate Change and other international and U.S. policy groups recognize that nuclear energy should play a significant role in global GHG emission-reduction policies. EIA, EPA, and the Clean Air Task Force all depended heavily in their modeling on new nuclear power to meet the proposed required GHG emission reductions of the Lieberman-Warner Climate Security Act of 2008.

Nuclear energy accounts for approximately 25% of electricity generation in Michigan from four nuclear power plants:

- Donald C. Cook 1 (AEP), Bridgman, MI—1016 MW (license expiration in 2034);
- Donald C. Cook 2 (AEP), Bridgman, MI—1077 MW (license expiration in 2037);
- Fermi 2 (Detroit Edison), Newport, MI—1,111 MW (licence expiration in 2025); and
- Palisades (Entergy), Covert, MI—775 MW (license expiration in 2031).

Michigan's 21st Century Electric Energy Plan (21st Century Plan) recognizes the need for new baseload plants to be built in Michigan to meet forecasted electric growth in Michigan. The 21st Century Plan also notes that nuclear power cannot meet the need for new generation for at least 12 years due to the extremely long lead time required to bring a new nuclear plant on line. Nuclear power can, however, play a significant role in reducing GHG emissions in conjunction with other low-GHG-emitting generating technologies in the time period beyond 2020. The 21st Century Plan contains legislative and regulatory recommendations for providing financing for construction of new power plants in Michigan.

Barriers to the implementation of new nuclear plants may include the following:

- Public concerns regarding the safety and reliability of nuclear power plants, especially following high-profile incidents, such as Three Mile Island and Chernobyl.
- Continued uncertainty regarding federally mandated long-term used fuel storage.
  - DOE filed a license application after much delay for the Yucca Mountain geologic repository on June 3, 2008. The licensing process begins the first step in creating a permanent disposal facility in the United States for used nuclear and radioactive waste.

  - Used fuel recycling or reprocessing is not performed in the United States for economic reasons. The federal government and the nuclear industry are supporting research and development on advanced recycling technologies.
- High capital costs that continue to rise for all baseload generating options.
- State regulatory structures that may prevent cash return on new plant investments until after commercial operation, and that may in turn increase the overall customer cost of the plant.
- A long federal licensing process for new nuclear plants that effectively makes deployment of a new nuclear plant more than an 11-year project.

Nuclear power can continue to provide baseload power to a growing Michigan economy, while also reducing or avoiding overall GHG emissions. Policies that address the barriers to implementation and encourage the licensing of new nuclear plants in Michigan, as well as relicensing of existing plants, should be considered. These policies could also address opportunities for reducing the long time frame required to license and construct a new nuclear power plant.

Policy Design

Goals:

- Develop policy recommendations to encourage the licensing and construction of baseload nuclear power plants in Michigan. Recommendations should consider:
  - State-level legislative and regulatory approaches to overcome barriers and facilitate construction of new nuclear plants;
  - Increased utilization of federal initiatives (e.g., DOE incentives, such as loan guarantees) to encourage development of nuclear energy;
  - Public outreach efforts to demonstrate the improved safety of nuclear power and to highlight the GHG reduction potential of nuclear power; and
  - Assurances that spent fuel will be stored safely and, if at all possible, safely away from the Great Lakes.
- Identify GHG emission reduction or avoidance potential as a result of new nuclear plant construction or relicensing of existing plants in Michigan through 2030.

Timing: Beginning in 2009.

Parties Involved: MPSC, regulated utilities, the U.S. Nuclear Regulatory Commission (NRC), MDEQ, Michigan legislature.

Other: On September 18, 2008, Detroit Edison submitted to the NRC a combined construction and operating license application for a new nuclear plant to be located at the site of Detroit Edison's existing Fermi 2 power plant near Monroe. The filing of the application will preserve the option for Detroit Edison to build a nuclear power plant in the future after the extensive (3–4-year) federal licensing review process, as well as maintain eligibility for Federal Production Tax Credits. The submittal of the license application does not guarantee that Detroit Edison will build a plant.

Implementation Mechanisms

Many implementation mechanisms for increased use of nuclear power to mitigate GHG emissions will be managed at the federal level, including incentives for new commercial reactors, radioactive waste management policy, research and development priorities, power plant safety and regulation, and security against terrorist attacks. Michigan should implement policies that support federal incentives and that will encourage development of additional nuclear power in the state.

Similar to financing construction of other fossil fuel baseload assets, the Michigan regulatory process is not conducive to major investments by the utilities without structural changes to the cost recovery and cost allocation processes. At the state level, the following mechanisms may help facilitate construction of new nuclear power plants:

- MPSC should allow electric utilities to recover financing interest costs in base rates for certified capital improvement construction work (as opposed to waiting until the plant is operational to collect a cash return on the interest) through the ratemaking process. This would be consistent with language in HB 5524, enacted on October 6, 2008.
- The Michigan legislature should provide tax and other incentives to investors and equity partners that can help to fund nuclear plants.
- The existing IRP process in Michigan (see ES-7) should include nuclear generation in the plan to meet the needs of future generations in Michigan.

New nuclear plants within Michigan will require highly skilled and highly paid workers during the plant's construction and operation. Michigan universities and colleges should consider enhancing programs that will attract engineering, science, and related disciplines that can support a growing nuclear energy industry.

In addition, state and local governments, the educational community, and the environmental community should partner in conducting educational and community outreach on the GHG benefits, safety, and risks of nuclear power.

Related Policies/Programs in Place

- Federal incentives for nuclear energy in the recent Energy Policy Act of 2005 included (among others) the following:
  - Extending the Price Anderson Act, which limits liability for nuclear power plant accidents to 2025;
  - Increased safety, security, and radioactive waste disposal measures; and
  - Tax credits for new nuclear plants in service prior to January 2021.
- The NRC is currently the regulatory agency for nuclear facilities.
- The Michigan comprehensive energy legislation that was signed into law on October 6, 2008 (HB 5524, SB 213, and HB 1048), should be expected to facilitate the construction of new baseload generation in Michigan by providing rate recovery for financing the costs of new capital expenditures, as well as limiting the number of customers who can pick their energy providers (i.e., leave the regulated utilities). Limiting the number of customers who choose

alternative suppliers provides more certainty to lenders that an electric utility will have the customers to help pay for the cost of building a nuclear power plant.

Type(s) of GHG Reductions

CO_2.

Estimated GHG Reductions and Costs or Cost Savings

The costs and GHG emission reduction benefits of nuclear power are analyzed to illustrate the current DTE Energy (Fermi 3) nuclear unit being proposed on the existing site of Fermi 2, near Monroe, Michigan. This nuclear unit, sized at 1,550 MW, has had the combined operating and licensing application (COLA) filed by DTE with the NRC. The illustration in Table F-6-1 assumes a single 1,550-MW unit is permitted and constructed and comes on line in 2020. Costs are annualized over the expected life of the unit. Cumulative GHG reduction benefits accrue for the years 2020–2025.

Table F-6-1. Estimated GHG reductions and costs of or cost savings from a 1,550-MW nuclear unit

ES-6. New Nuclear Power	2015	2025	Units
GHG emission savings	0.0	6.3	Million metric tons of CO_2
Cumulative net costs (present value) (2009–2025)		$1,001	Million $
Cumulative emissions reductions (2009–2025)		38.5	Million metric tons of CO_2
Cost-effectiveness		$25.98	$/metric ton of CO_2

Data Source: AEO 2008.

Quantification Methods: New nuclear power is assumed to displace primarily coal-fired power, as reflected in the Michigan I&F. The values presented above *do not* reflect the recent RPS legislation, but do account for reductions associated with other options.

- Assume a given capacity of a nuclear facility (1,550 MW).
- Assume the commissioning date (2020).
- Assume a capacity factor (93%).
- Calculate the electricity generation (capacity x time x capacity factor).
- Determine the annualized cost of the program, based on EIA AEO 2008 data.
- Determine the avoided cost, based on the amount of electricity generation.
- Determine the net costs and the net present value.
- Determine the emissions avoided, based on electricity generation.

Key Assumptions:

- A new nuclear facility would come on line in 2020, operating for only 5 years before the end of the modeled period of 2009–2025.

- The levelized costs of nuclear power are $90.00/MWh in 2015 and $85.51/MWh in 2025.The following line items are included in the levelized costs:

  Construction Costs

  - Combined Operating License Application [COLA] Preparation Costs
  - COLA Review Support Costs
  - NRC Costs & Fees
  - Program Office Costs
  - University of Michigan Office of Engineering Outreach and Engagement [OE^2] Engineering Staff for COLA Review Support
  - Other Project Management Costs
  - General Program Management Costs
  - Certificate of Need Development/Support
  - Owner's Engineer Costs
  - NRC Costs & Fees (During Construction)
  - Site Preparation & Development Costs
  - Site Prep & Development Engineering Costs
  - Wetlands Replacement
  - Reactor Technology Costs
  - Owner's Balance of Plant Costs
  - Owner's Plant Staffing Costs (Pre-Commercial Operation Date [COD])
  - Spare Parts
  - Direct Construction Cost
  - Project Indirects
  - Insurance
  - Property Tax
  - Sales Tax
  - Performance Bond Costs
  - Construction Indirects
  - Other Indirect Costs (Administrative and General)
  - Contingency
  - First Fuel Load (Included in Fuel Costs)
  - Allowance for Funds Used During Construction

  Costs Included in Busbar

  - Average Rate Base
  - Pre-Tax Return on Rate Base
  - Operations & Maintenance
  - Administrative and General

- Fuel Amortization
- Fuel Decommissioning
- Decommissioning Fund
- Depreciation
- Property Taxes
- Insurance
- NRC Fees
- Production Tax Credit (None Currently Assumed)
- Power Ascension to COD Sales

Key Uncertainties

- Actual date of commissioning a new nuclear facility.
- Future capital costs.
- The ultimate disposition of spent fuel. Concern over the hazardous nature and persistence of spent fuel remains an uncertainty despite recent federal efforts to license the Yucca Mountain Repository. Opposition from Nevada and others has raised the expectation that multiple legal challenges are all but certain. Additional concerns have been raised regarding the capacity of Yucca Mountain to meet the needs of both current and planned reactors due to major delays in repository licensing and renewed interest in new nuclear power plants prompted by concerns for GHG emissions from fossil fuel-fired generation.

Additional Benefits and Costs

As discussed under the Policy Description and Policy Design sections.

Feasibility Issues

Some of the recommended policy changes require legislative approval. Ultimate disposition of spent fuel is also a feasibility issue, as noted under Key Uncertainties above.

Status of Group Approval

Approved.

Level of Group Support

Majority—16 in favor, 6 opposed, and 2 abstentions.

Barriers to Consensus

MCAC members who voted against this policy recommendation expressed a range of concerns about the fate of existing and new high-level waste, or spent fuel. Members who were both in favor of and opposed to the policy expressed frustration over the failure of the federal government to fulfill its promise to site and license a permanent high level waste repository. As a result, spent fuel is being stored on site at both active and decommissioned plants awaiting federal action. Because these sites are adjacent to the Great Lakes, members believe they represent an unacceptable risk to the lakes and surrounding environment. Members voting against the policy expressed the concern that until a solution to this problem is found, no new plants should be constructed. Some in opposition believe that conditioning the approval of new nuclear plants on the resolution of the spent fuel storage problem would also place pressure on the federal government to accelerate efforts to resolve this issue. Two members abstained.

ES-7. Integrated Resource Planning (IRP), Including CHP

Policy Description

IRP is a process that develops plans to meet needs for electricity services in a manner that meets multiple objectives, such as least-cost generation, emission standards, fuel diversity, and RPS requirements. An IRP process includes the evaluation of all feasible options, from both the supply and the demand sides, in a fair and consistent manner. The IRP process can also build in flexibility (in manner of either probability analysis or scenario analysis) to account for future uncertainties in the technologies, costs, capacities, and markets. While originally targeted primarily toward cost minimization, IRP processes have increasingly considered the environmental risks and the potential costs associated with future regulation of GHGs.

IRP is a process that is analogous in many ways to utility least-cost planning. In the IRP process, companies or the state can highlight supply-side (generation capacity) options to meet a forecasted growth in electricity demand, and can also evaluate equally technology and policy options on the demand side to satisfy the anticipated demand. Demand-side measures include energy efficiency, distributed generation, and peak-shaving measures. In this fashion, supply and demand analyses are paired and evaluated jointly in a least-cost planning environment.

Policy Design

Goals: To refine the existing comprehensive state resource adequacy plan (the IRP) for Michigan that meets the reliability, environmental, public health, and economic policies of the state. The plan should support and attempt to balance all four policies. Any IRP process should be focused on the various stakeholders, with emphases on the load-serving utilities.

Timing: The IRP process could be implemented by the end of 2009. The MPSC could refine and update the state's Comprehensive Resource Plan, developed as a part of the Capacity Needs Forum and the 21st Century Plan planning process, or it could direct *de novo* analysis to meet load-serving entity demand in 2009, with the first IRP and RFP issued by early 2009.

Parties Involved: MPSC, MDEQ, regulated electric utilities, alternative energy suppliers [AESs], independent power providers (IPPs), generators, environmental and consumer advocates, renewable energy industry, energy efficiency industry, financial community, and public health representatives. It should be noted that an effective IRP process is transparent and open to full public intervention with discovery.

Implementation Mechanisms

Michigan has adopted IRP requirements for electric utilities under H.5524, Sec. 6s (11) (a)–(g) (see Related Policies/Programs in Place). The MPSC must establish the necessary standards to make this provision effective.

Related Policies/Programs in Place

Under Michigan's current IRP requirements for electric utilities (H.5524, Sec. 6s (11) (a)–(g)), the MPSC must establish standards to be met by electric utilities seeking a certificate of necessity for construction of an electric generation facility, a significant investment in an existing electric generation facility, or a purchase of an existing electric generation facility, to enter into a power purchase agreement for the purchase of electric capacity for a period of 6 years or longer for that construction, investment, or purchase if that construction, investment, or purchase costs $500 million or more and a portion of the costs would be allocable to retail customers in Michigan. The specific requirements are as follows:

> "(11) The commission shall establish standards for an integrated resource plan that shall be filed by an electric utility requesting a certificate of necessity under this section. An integrated resource plan shall include all of the following:
>
> (a) A long-term forecast of the electric utility's load growth under various reasonable scenarios.
>
> (b) The type of generation technology proposed for the generation facility and the proposed capacity of the generation facility, including projected fuel and regulatory costs under various reasonable scenarios.
>
> (c) Projected energy and capacity purchased or produced by the electric utility pursuant to any renewable portfolio standard.
>
> (d) Projected energy efficiency program savings under any energy efficiency program requirements and the projected costs for that program.
>
> (e) Projected load management and demand response savings for the electric utility and the projected costs for those programs.
>
> (f) An analysis of the availability and costs of other electric resources that could defer, displace, or partially displace the proposed generation facility or purchased power agreement, including additional renewable energy, energy efficiency programs, load management, and demand response, beyond those amounts contained in subdivisions (c) to (e).
>
> (g) Electric transmission options for the electric utility."

Michigan also adopted an energy optimization (EO) requirement under PA 295 of 2008 (S.213), the Clean, Renewable, and Efficient Energy Act (Subpart B, sec. 71–97). The EO plan must be designed to delay the need for constructing new electric generating facilities and thereby protect consumers from incurring the costs of such construction. The EO plan is essentially a demand-side energy efficiency requirement, with limits and exceptions. The statute requires:

> "an electric provider's energy optimization programs . . . shall collectively achieve the following minimum energy savings:
>
> (a) Biennial incremental energy savings in 2008-2009 equivalent to 0.3% of total annual retail electricity sales in megawatt hours in 2007.
>
> (b) Annual incremental energy savings in 2010 equivalent to 0.5% of total annual retail electricity sales in megawatt hours in 2009.
>
> (c) Annual incremental energy savings in 2011 equivalent to 0.75% of total annual retail electricity sales in megawatt hours in 2010.
>
> (d) Annual incremental energy savings in 2012, 2013, 2014, and 2015 and, subject to section 97, each year thereafter equivalent to 1.0% of total annual retail electricity sales in megawatt hours in the preceding year."

Natural gas providers are required to:

> "Meet the following minimum energy optimization standards using energy efficiency programs under this subpart:
>
> (a) Biennial incremental energy savings in 2008-2009 equivalent to 0.1% of total annual retail natural gas sales in decatherms or equivalent MCFs in 2007.
>
> (b) Annual incremental energy savings in 2010 equivalent to 0.25% of total annual retail natural gas sales in decatherms or equivalent MCFs in 2009.
>
> (c) Annual incremental energy savings in 2011 equivalent to 0.5% of total annual retail natural gas sales in decatherms or equivalent MCFs in 2010.
>
> (d) Annual incremental energy savings in 2012, 2013, 2014, and 2015 and, subject to section 97, each year thereafter equivalent to 0.75% of total annual retail natural gas sales in decatherms or equivalent MCFs in the preceding year."

The provisions in PA 295 are not an IRP process, but they require utilities to plan and implement programs to achieve specified energy savings for similar purposes.

Type(s) of GHG Reductions

All six statutory GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6).

Estimated GHG Reductions and Costs or Cost Savings

Not applicable. This policy is not quantified.

Data Sources: Not applicable.

Quantification Methods: Not applicable.

Key Assumptions: Not applicable.

Key Uncertainties

None.

Additional Benefits and Costs

It is expected that real and measureable emission reductions will result from the implementation of this policy. However, it is not possible to reliably predict the magnitude of these savings or their costs or cost savings.

Feasibility Issues

With the passage of H.5524, most feasibility issues have been resolved. The MPSC must set standards for projecting energy and capacity purchased or produced pursuant to any renewable portfolio standard, energy efficiency program, or load management and demand response savings.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

None.

ES-8. Smart Grid, Including Advanced Metering

Policy Description

Smart Grid systems promote efficiency through improvements in system monitoring, control technology, and systems integration. Combining advanced metering and two-way communication to end users with the Smart Grid technology provides a system where both the utility and the customer can engage in integrated decisions, thus enabling and improving energy efficiency. In addition, a Smart Grid system allows enhanced opportunities for demand response and optimizes the deployment of distributed resources and renewable energy. The policy to develop Smart Grid systems supports the overall goal of reducing GHG emissions by improving energy efficiency in all areas of the electric grid operations, including generation dispatch, transmission, and distribution systems.

Title XIII of the 2007 Energy Independence and Security Act describes the characteristics of the Smart Grid beyond advanced metering infrastructure (AMI). Although the industry has not settled on a clear definition, Title XIII provides a sense of what is meant by the Smart Grid, including such features as increased use of digital information and controls to improve reliability, security, and efficiency of the electric grid; optimization of grid operations and resources; deployment of distributed resources, including renewables; incorporation of demand response resources and energy efficiency resources; deployment of smart technologies for metering, communications concerning grid operations and status, and distribution automation; integration of smart appliances; integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles; provision to consumers of timely information and control options; development of interoperability standards for grid-connected appliances and infrastructure; and identification of barriers to adoption of Smart Grid technologies and practices. It is a common belief that moving to the Smart Grid will be a phased evolution, and that policy guidelines for the Smart Grid should be established with the long-term view in mind.

The Federal Energy Regulatory Commission (FERC) has defined advanced metering as a system that records customer consumption and possibly other data hourly or more frequently, and that provides daily or more frequent transmittal of the measurements over a communication network to a central collection point. AMI includes advanced meters, communications networks, and data management systems. This technology ultimately allows consumers much greater opportunity to manage their electricity consumption. Further information about AMI technologies is available at http://www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf.

Policy Design

This policy will provide guidelines to utilities for evaluating AMI and Smart Grid technology projects, including cost-benefit analysis methodologies for determining GHG emission benefits. Energy efficiency in this context is defined as improvements in energy utilization (kWh) and demand (kW) as realized at the end user or on the utility delivery system.

Goal: The potential benefits of Smart Grid and AMI are such that all regulated electric utilities and other load-serving entities should develop a plan to deploy AMI, including an appropriately configured two-way communication network with capability to interact with customer home and business devices by 2015. Such AMI deployment should enable interoperability with future implementation of Smart Grid technologies.

Timing: As described above.

Parties Involved: Michigan regulated utilities, other load-serving entities, and the MPSC.

Other: None.

Implementation Mechanisms

- Establish a select work group of utility representatives from the Smart Grid Collaborative to participate in the AMI minimum functionality criteria investigation work group and in a Smart Grid work group. These work groups will develop and recommend policy guidelines and cost-benefit methodologies to the MPSC.
- Conduct AMI, demand response, and Smart Grid pilots to determine and validate the policy guidelines and potential of energy efficiency and GHG savings.
- Apply the policy in the development of utility general rate case filings that include AMI and Smart Grid investments.

Related Policies/Programs in Place

The MPSC commenced the Smart Grid collaborative in an order issued in Case No. U-15278 on April 24, 2007, related to Smart Grid technologies:

> [T]he Commission Staff (Staff) shall convene a collaborative process to monitor national smart power grid infrastructure developments. When options appear cost effective and practical to implement, the Staff should establish evaluation criteria and standards, triggering pilot programs or broader deployment in Michigan. The collaborative should emphasize reviewing and adopting technologies that make the grid flexible and efficient, enable distributed technologies, and preserve reliability.
>
> *April 24, 2007, order, p. 1.*

In April 2008, an MPSC staff report was filed in the Smart Grid collaborative docket, which recommended that the MPSC undertake a public input process to develop minimum AMI functionality guidelines. Subsequently, on July 1, 2008, the MPSC issued an order in Case No. U-15620, which directed MPSC staff to begin an investigation of minimum functionality criteria necessary for rate recovery of infrastructure investments by regulated utilities. In its order, the MPSC recognized that the investigation must consider that AMI infrastructure developed today will be a foundation for a continually evolving technology, and so guidelines and policies need to be flexible. A staff report on preliminary findings of this investigation was filed on October 1, 2008. Among staff comments was the recommendation that development of minimum AMI functionality standards should be the subject of a rulemaking procedure, as opposed to a less formal approach of developing guidelines.[5]

[5] Link to the full staff report: http://efile.mpsc.cis.state.mi.us/efile/docs/15620/0025.pdf.

This policy is in keeping with the Smart Grid collaborative directive and the subsequent investigation into minimum functionality standards for AMI rate recovery of infrastructure investments.

There are no other known policies or programs of this nature in Michigan that combine AMI and Smart Grid technologies.

Type(s) of GHG Reductions

All six statutory GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6).

Dynamic pricing and demand response.

Operational efficiencies: system losses and reduction in field workforce vehicle emissions.

Estimated GHG Reductions and Costs or Cost Savings

Not applicable. This policy is not quantified.

Data Sources: Not applicable.

Quantification Methods: Not applicable.

Key Assumptions: Not applicable.

Key Uncertainties

Two areas of uncertainty are the potential of demand/price response programs and the potential for grid efficiency improvements by deploying new technology. The first is a customer demographic, acceptance, program design, and pricing issue and how that impacts energy savings. The second is an issue of system design and operating practices. The uncertainties can be minimized through the implementation of well-designed pilots.

Additional Benefits and Costs

Other benefits for AMI and Smart Grid technologies include operational efficiencies, avoided costs, credit and collections, remote disconnects/reconnects, outage management, meter accuracy, and theft reduction. Each utility’s business case would be unique based on the relation of these and other benefits to the utility’s current operating and business practices.

Feasibility Issues

It would require approximately 2 years to deploy technologies, gather baseline data, and pilot demand/price response programs and Smart Grid treatments to validate energy efficiency saving. This would provide a more credible basis for evaluating wide-scale implementation.

Technologies that have not reached maturity would not be able to be evaluated.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

None.

ES-9. Carbon Capture, Storage, and Reuse Incentives, Requirements, R&D, and/or Enabling Policies

Policy Description

Carbon capture and storage or reuse (CCSR) is a process that includes separation of CO_2 from industrial and energy-related sources, transport to a storage location, and permanent or long-term storage in isolation from the atmosphere. Ideally, the CO_2 from large point sources, such as power plants, can be compressed and transported for storage in geological formations for use in industrial processes or for enhanced recovery of oil and gas. The net reduction of emissions to the atmosphere through CCSR depends on the volume of CO_2 captured, the volume of CO_2 storage available, and the amount of CO_2 retained in geostorage or used for other purposes.

CCSR technology will most likely increase the cost of generating electricity. Policies to encourage development of CCSR technology should include a state agency tasked with evaluating CCSR and with the ability to recommend changes and/or financial incentives to capture, store, and/or reuse CO_2.

Technology to capture and store or reuse CO_2 from power plants continues to evolve. Some of these technologies are in fact in industrial-scale use in a limited number of cases or applications, principally to support enhanced oil recovery (EOR), while others are in the early developmental stages. Specifically, CO_2 injection for EOR is currently being used in Michigan. Further potential use of CO_2 injection for EOR is also very probable. Industrial-scale, long-term geostorage in deep saline formations is not as well developed or proven, though there is strong potential in Michigan based on the state's geology.

In addition, a host of non-technological challenges must be addressed before CCSR can be realized at a large scale. These include permitting, liability, property rights, monitoring, and other public policy questions.

Further research and development (R&D) to improve all phases of CCSR, including transport, is needed. Further localized studies to identify geologically sound geological strata are needed before this can play a significant role in reducing GHG emissions. The process of evaluating the potential of Michigan's brine formations for carbon sequestration has commenced. In early 2008, as part of a sequestration test, 10,000 metric tons of CO_2 were injected into a suitable geological formation. The test was successful and is now in the post-injection monitoring mode. If the Michigan investigation yields promising results, the state should move in a deliberate fashion to evaluate the potential of other areas and geological formations. Shared information from similar projects throughout the United States will assist in proving the use of brine aquifer storage potential.

Policy Design

Goals: Promote the safe and effective use of EOR and deep carbon geostorage using Michigan's promising geological assets.

Timing: Michigan should initially encourage EOR and the accompanying modest carbon storage from this activity, and sequestration in depleted oil and gas fields within the 2–5-year time frame. By 2015, Michigan should encourage and support additional pilot/demonstration activity for deep carbon geostorage in several locations in the state. By 2020, Michigan should have a robust legal and policy framework consistent with national intent that enables full-scale industrial carbon geostorage capabilities.

Parties Involved: Federal, state, and regional bodies, along with all applicable stakeholders.

Other: None.

Implementation Mechanisms

As adopted from the MGA AC/CCS-1.

Some of the key implementation issues that will need to be explored regarding the establishment of a CCSR infrastructure are as follows:

- Consider an infrastructure build-out that extends beyond Michigan. In this context, the term "infrastructure" should be understood to include regional power markets. Developers will not build advanced coal generators or retrofit existing generators with CCSR, unless these units will be competitive in regional power markets (e.g., PJM and MISO), taking into account their anticipated construction costs.
- Develop a report that quantifies the costs and benefits and potential capacity of EOR. This report will identify CO_2-EOR resource potentials in Michigan and quantify the potential GHG reduction benefits of CO_2-EOR projects.
- Review regulations of other states governing or potentially relating to CO_2 capture and underground injection. This review will provide guidance by laying out existing statutes and regulations and identifying gaps in regulation for policymakers.
- Develop a legal and regulatory framework for geologic storage of CO_2. To set the stage for geologic storage projects to move forward in a 5–10-year time frame, Michigan must establish the necessary legal and regulatory framework in partnership with the federal government, and must ensure that the necessary statutes and regulations for geologic storage are in place, including guidance on pipelines, injection, monitoring, mitigation, verification, and long-term liability.
- Evaluate and comment on the UIC regulations proposed by EPA on geologic sequestration of CO_2. EPA's UIC regulations related to geologic sequestration will have broad impacts on CCSR project development and technology deployment.
- Provide state-based incentives for CCSR, encompassing projects that use captured CO_2 for EOR as well as for storage in deep saline formations. Stability in the CO_2 credit market is also important for CCSR.
- Provide EOR project development assistance. Michigan has a mature oil and gas industry, with many small oil and gas producers that have not traditionally used CO_2 EOR, in part because they are not large enough to develop projects. The public sector, companies, and trade associations can play a useful role in helping to identify the specific mechanisms by which producers can band together to leverage cost-effective projects.

- Support comprehensive assessments of geologic reservoirs at the state and federal levels to determine CO_2 storage potential. Governments should build on the work of DOE-funded regional sequestration partnerships to complete comprehensive, basin-level geologic assessments of storage potential. Regions with a history of oil and gas exploration tend to have better data available on geologic formations, making such assessments easier and less expensive, although these regions suffer the deficiency of having much previous drilling that can diminish reservoir integrity. Detailed, accurate mapping of lesser-known potential reservoirs for CCSR will require continued federal and state investment.
- Participate in and/or fund sufficient underground injection tests to prepare for future storage on a widespread commercial basis. Congress and the president should support sufficient federal funding for DOE to ensure a robust program of tests to demonstrate to the private sector, policymakers, and the public the viability, efficacy, and safety of widespread commercial geologic storage of CO_2. These tests should focus on a variety of geologic settings, including reservoirs other than oil-and-gas-bearing formations, and should produce guidelines for appropriate monitoring, mitigation, and verification.
- Evaluate the feasibility of alternate sequestration options for jurisdictions without adequately documented underground injection potential, such as the western Upper Peninsula. This includes evaluating the cost and feasibility of CO_2 pipelines from other areas of the state and other CO_2 sequestration options, such as mineralization, carbon nano-fibers, or biological means.
- Consider the use of transported synthetic natural gas to areas where near-term carbon storage options are unknown. This could also allow better use of peaking/intermediate generating capacity and complement the expanded development of wind power.

Related Policies/Programs in Place

MDEQ, MDNR, and the Attorney General are currently mapping out the various regulatory matters pertaining to CCSR to identify appropriate actions to address such issues as landowner rights, short- and long-term liability, revenue streams, environmental impacts, and other issues as identified. Legislation will be required to ensure that CO_2 can be effectively sequestered and that the costs of this effort are adequately addressed. The state will need to participate in efforts to define and manage long-term liability and to address the issue of property rights and pore space rights[6] for injection and sequestration into deep geologic formations.

Table F-9-1 provides the legislative status of CCSR in states and provinces. It is reprinted from the Interstate Oil and Gas Compact Commission Web site @ www.iogcc.state.ok.us.

[6] These are the legal rights to inject a gas or liquid into the rock formation to fill or occupy the voids (pores) within the formation.

Table F-9-1. Status by state and province of CO_2 storage legal and regulatory development 5/8/2008

State/ Province	Active Effort Begun	Legislation Draft/ Enacted	Regulations Draft/ Enacted	Summary of Status	Date Info Updated	Link to Additional Information
Alabama	No			Something could emerge in 2008 legislative session.	2/7/2008	
Alaska	No				2/7/2008	
Arizona	No				4/24/2008	
Arkansas	No				4/24/2008	
California	Yes			Report already released (see link), being further developed.	4/29/2008	http://www.energy.ca.gov/2007publications/CEC-500-2007-100/CEC-500-2007 100-SF.PDF
Colorado	No				4/28/2008	
Florida	No				2/19/2008	
Georgia	No				2/7/2008	
Idaho						
Illinois	Yes	Enacted: Senate Bill 1704		SB 1704: Clean Coal–FutureGen. Creates the Clean Coal FutureGen for Illinois Act for the purpose of providing the FutureGen alliance with adequate liability protection, land-use rights, and permitting certainty to facilitate the siting of the FutureGen Project in Illinois.	4/28/2008	
Indiana	Yes				2/19/2008	
Kansas	Yes	Enacted: House Bill 2419 (2007)		HB 2419 mandated development of regulations no later than July 1, 2008. Preliminary draft has been developed and will go through public notice and hearing process this spring.	2/7/2008	
Kentucky	No				2/19/2008	
Louisiana	No				2/14/2008	
Maryland	No				2/22/2008	
Michigan	Yes	Part 615 Oil and Gas Regulations Part 625, Mineral Well Regulations (NREPA)		Part 615 regulates CO_2 injection utilized for EOR. Part 625 may regulate permitting and well construction for CO_2 storage.	4/28/2008	http://www.legislature.mi.gov

State/ Province	Active Effort Begun	Legislation Draft/ Enacted	Regulations Draft/ Enacted	Summary of Status	Date Info Updated	Link to Additional Information
		Draft SB 707, 708, 801, 1166, 1184 and HB 5604		Bills are introduced; require development of regulations prior to July 1, 2008, provide for tax credits and exemptions to electric generating facilities capturing and sequestering carbon dioxide, tax credits for emission reductions and sequestration, tax credits for purchasing and constructing capture machinery or equipment, and authorization for storage of GHG on state-owned lands.		
Mississippi	No				2/19/2008	
Missouri	No				2/14/2008	
Montana	Yes				2/14/2008	
Nebraska	No				2/14/2008	
Nevada	No				2/26/2008	
New Mexico	Yes			Report issued on December 1, 2007, to (see link) Governor's Climate Change Action Implementation Team. No legislative action in 2008.	4/28/2008	*A Blueprint for the Regulation of Geologic Sequestration of Carbon Dioxide In New Mexico*: http://www.emnrd.state.nm.us/ocd/documents/CarbonSequestrationFINALREPORT1212007.pdf
New York	Yes				2/14/2008	
North Carolina	No				2/14/2008	
North Dakota	Yes			Rules were promulgated in 2007 but based on comments submitted and analysis by the North Dakota Attorney General's office, it was concluded that statutory jurisdiction was lacking in a few critical areas. A work group composed of representatives from the lignite and oil & gas industries, PCORP, the North Dakota Industrial Commission and the Attorney General's Office has been formed to develop a bill based on the IOGCC	5/8/2008	

State/ Province	Active Effort Begun	Legislation Draft/ Enacted	Regulations Draft/ Enacted	Summary of Status	Date Info Updated	Link to Additional Information
				model statute for introduction during the 2009 North Dakota legislative session. Once legislation is passed and signed into law, rules will be re-promulgated.		
Ohio	Yes	Enacted: Ohio SB 221	No; Using EPA Class V temporarily.	Pending legislation includes some requirements to limit carbon emissions and charges state agencies to develop rules.	5/7/2008	http://www.legislature.state.oh.us/bills.cfm?ID=127_SB_221
Oklahoma	Yes			SB 1765 pending. This bill will determine which agency will take the lead.	3/27/2008	http://webserver1.lsb.state.ok.us/WebBillStatus/main.html
Oregon	No				4/24/2008	
Pennsylvania	No				2/14/2008	
South Carolina	No				2/26/2008	
South Dakota	No				2/14/2008	
Texas	Yes				2/7/2008	
Tennessee	No				4/29/2008	
Utah	Yes			SB 202 passed by legislature and signed by Governor requiring, among other things, development of rules and recommended legislative changes by January 1, 2011.	4/2/2008	http://le.utah.gov/~2008/htmdoc/sbillhtm/sb0202s01.htm
Virginia	No				2/21/2008	
Washington	Yes	Enacted: http://www.leg.wa.gov/pub/billinfo/2007 08/Pdf/Bills/Session%20Law%202007/6001S.SL.pdf	DRAFT: http://www.ecy.wa.gov/lawsrules/wac173407_218/Draft_Rule/OTS1277.2final.pdf	Process begun. Public hearings held in April 2008. Final rule adoption expected in June 2008.	4/24/2008	
West Virginia	Yes			Preparing draft legislation. Possible introduction in 2008 legislative session.	2/7/2008	

State/ Province	Active Effort Begun	Legislation Draft/ Enacted	Regulations Draft/ Enacted	Summary of Status	Date Info Updated	Link to Additional Information
Wyoming	Yes	Enacted: http://legisweb.state.wy.us/2008/Enroll/HB0089.pdf AND http://legisweb.state.wy.us/2008/Enroll/HB0090.pdf		Two bills were introduced and passed by the legislature and signed by the Governor in March 2008. One addresses ownership and the other regulatory issues. Both bills required and passed by a 2/3 majority in both houses. Legislation on eminent domain aspect of CO_2 storage will likely be addressed in 2009.	4/15/2008	
Alberta	Yes			The province of Alberta is in the process of conducting a review of its current regulatory framework for large-scale implementation of geological storage. The province has also recently established a Carbon Capture and Storage Development Council (a partnership between governments, industry, and scientific researchers) to conduct an assessment of CCSR and to recommend steps for implementation in Alberta, including a legal and regulatory framework. The Council will be reporting back to the Alberta government in the fall of 2008.	5/8/2008	
British Columbia	Yes				2/21/2008	
Newfound-land & Labrador	No				2/19/2008	
Nova Scotia	Yes			The lead in Nova Scotia on climate change issues is now with the Department of Environment. An initiative is under way to examine the potential for the sequestration of CO_2 into both offshore and onshore geologic formations.	4/26/2008	
Saskatche-wan	Yes				2/14/2008	

CO_2 = carbon dioxide; EPA = U.S. Environmental Protection Agency; GHG = greenhouse gas; HB = House Bill; IOGCC = Interstate Oil and Gas Compact Commission; NREPA = Natural Resources and Environmental Protection Act; PCORP = Plains CO_2 Reduction Partnership; SB = Senate Bill.

Type(s) of GHG Reductions

Principally CO_2.

Estimated GHG Reductions and Costs or Cost Savings

Not applicable. This policy is not quantified.

Data Sources: Not applicable.

Quantification Methods: Not applicable.

Key Assumptions: Not applicable.

Key Uncertainties

As noted under the Policy Description section, the key uncertainties fall into three categories: technological and cost uncertainties for some capture, transport, and storage technologies; legal uncertainties, such as permitting, liability, and property rights; and sequestration uncertainties, such as the long-term suitability for certain geologic formations. Technological uncertainties apply at all phases of the project, from carbon capture to compression and transportation to injection to long-term injection field integrity.

Additional Benefits and Costs

It is expected that real, measurable, and potentially substantial emission reduction benefits will result from the implementation of this policy. However it is not possible to reliably predict the magnitude of these savings or their costs or cost savings at this time.

Feasibility Issues

As noted in the Policy Description and Key Uncertainties sections, feasibility depends upon resolving the legal issues and successfully demonstrating that the technologies and storage methods are reliable and cost-effective.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

None.

ES-10. Technology-Focused Initiatives

Policy Description

States can undertake initiatives focused on developing, promoting, and/or implementing one or more specific technologies that have the potential to reduce GHG emissions. Technologies could include (among others) hydrogen production and fuel cells for electricity storage, compressed air energy storage systems (to enable greater penetration of intermittent renewable technologies, such as wind), or biomass co-firing. Biomass co-firing can be a low-cost, near-term means of converting biomass to electricity and displacing a fraction of coal use by adding up to 20% biomass in high-efficiency coal boilers.

Policy Design

Goals: This set of policies would provide state government and other private and public parties with resources and incentives for analysis, targeted R&D, market development, and adoption of GHG-reducing technologies that are not covered by other policies. The overall goals would be:

- To position Michigan as a world leader in climate-related technology development and deployment,
- To achieve actual emission reductions from technology investments, and
- To develop state industries with high in-state and export capability.

The specific goal would be to maximize effective use of biomass for co-firing at appropriate coal plants as soon as practicable. Co-firing needs to be based on a comprehensive fuel supply study ensuring that the expected supply is supported by the use of sustainable forestry practices. The proximity and availability of individual baseload generation assets to suitable supplies of biomass (forest feedstock) need to be determined on a case-by-case basis. Based upon a review of the Wolverine Power Cooperative/Michigan Technological University biomass study and report, this policy assumes three rates of co-firing: 5%, 10%, and 20%. All three assume that the plant is new and designed and constructed specifically to be operated in this fashion.

The Michigan Department of Labor and Energy Growth (MDLEG) Energy Office is preparing to issue an RFP to determine the available amount of biomass in Michigan. The Agriculture. Forestry, and Waste Management TWG has calculated the availability of biomass for all uses in Michigan and included the demand from this plant in the budget, assuming a co-fire rate of 10%. If a higher co-fire rate is used, there is sufficient excess biomass to meet the demand.

Timing: This policy is intended to come into effect in 2009, and would continue indefinitely as an enabling mechanism for other climate-related policies aimed to reduce GHG emissions from the electric utility sector.

Parties Involved: Michigan government, private and public partners on a voluntary basis, owners and operators of coal-fired generators, providers and growers of biomass fuel.

Implementation Mechanisms

Enact legislation to include electricity generated by the biomass fraction at a co-fired facility as eligible for a renewable energy credit (REC) allowance if the owner can demonstrate that the biomass was harvested using sustainable forestry practices.

Related Policies/Programs in Place

Biomass (i.e., co-firing) is currently an eligible renewable energy technology under the Michigan energy legislation for RPS. However, the incentive as drafted provides no REC allowance for those IPPs using biomass as a feedstock. Other than this, no federal or state programs currently exist to promote biomass-to-energy production.

Type(s) of GHG Reductions

CO_2.

Estimated GHG Reductions and Costs or Cost Savings

The MCAC is aware of three active proposals to construct new baseload coal/biomass co-fired facilities: the cities of Lansing and Holland, and Wolverine Power Rogers City. Wolverine Power provided the MCAC analyses and studies undertaken in support of its proposed Rogers City plant. This analysis of this policy recommendation examined a specific scenario for that particular co-fired power plant. This analysis and recommendation are informational only, and are not intended to be an endorsement of the Rogers City proposal or any other specific proposed facility.

The Wolverine Power Rogers City facility is a fluidized bed facility. Note that the results reported below may be specific to this power plant. Other coal technologies would yield different results. In addition, it is important to note that this analysis is based on a single power plant. Biomass fuel costs, in particular, are assumed not to change as a result of an increase in usage from this single power plant. If many co-firing facilities were built in Michigan, the demand on biomass fuel would grow, and it is likely that biomass fuel costs would increase as a result.

This analysis examines three potential co-firing rates for the proposed Wolverine Power Rogers City facility. A biomass availability study has been conducted for this proposed facility. Any such proposal must be analyzed on a case-by-case basis; therefore, it should not be assumed that these results are typical or directly scalable to other proposals. All assumptions that are common to this as well as other options are described in the description of common assumptions above.

ES-10-specific assumptions are as follows: GHG reductions provided here are based on three different scenarios: a 5%, a 10%, and a 20% co-fired coal plant with the CO_2 emissions from the existing Michigan fuel mix. (See Tables F-10-1, F-10-2, and F-10-3, below.) The assumption is that the coal plant is a new facility.

Table F-10-1. Estimated GHG reductions and costs of or cost savings from ES-10 with 5% co-firing

ES-10. Technology Based Initiatives: *5% Co-Firing Option*	2015	2025	Units
GHG emission savings	0.2	0.2	Million metric tons of CO_2
Cumulative net costs (present value) (2009–2025)		$34.48	Million $
Cumulative emissions reductions (2009–2025)		3.3	Million metric tons of CO_2
Cost-effectiveness		$10.59	$/metric ton of CO_2

CO_2 = carbon dioxide; GHG = greenhouse gas

Table F-10-2. Estimated GHG reductions and costs of or cost savings from ES-10 with 10% co-firing

ES-10. Technology Based Initiatives: *10% Co-Firing Option*	2015	2025	Units
GHG emission savings	0.5	0.5	Million metric tons of CO_2
Cumulative net costs (present value) (2009–2025)		$69.43	Million $
Cumulative emissions reductions (2009–2025)		6.5	Million metric tons of CO_2
Cost-effectiveness		$10.67	$/metric ton of CO_2

CO_2 = carbon dioxide; GHG = greenhouse gas

Table F-10-3. Estimated GHG reductions and costs of or cost savings from ES-10 with 20% co-firing

ES-10. Technology Based Initiatives: *20% Co-Firing Option*	2015	2025	Units
GHG emission savings	0.9	0.9	Million metric tons of CO_2
Cumulative net costs (present value) (2009–2025)		$134.09	Million $
Cumulative emissions reductions (2009–2025)		13	Million metric tons of CO_2
Cost-effectiveness		$10.30	$/metric ton of CO_2

CO_2 = carbon dioxide; GHG = greenhouse gas

Data Sources: This analysis is designed to show the costs of and GHG emission reductions from co-firing at the Wolverine Power Rogers facility. Therefore, figures are based on data provided by Brian Warner of Wolverine Power, and on that company's estimates and research as to costs, operating characteristics, and other factors for constructing and operating this co-fired facility.

Quantification Methods: The quantification relied on three scenarios for co-firing, as described above, although based on information provided by Wolverine Power, capacity factors for each co-firing scenario were assumed to be equal, at 92.5%.

Key Assumptions: Key assumptions for this analysis are the facility begins operation in 2012, and the plant has an assumed life of 30 years. According to Wolverine Power, the heat plant heat rate should be identical, at 10,000 British thermal units per kilowatt-hour (Btu/kWh) for each of the three scenarios. The primary difference among the three scenarios is capital cost for additional biomass storage and handling. That incremental capital cost is assumed to be as shown in Table F-10-4.

Table F-10.4. Assumed incremental capital costs for the three co-firing scenarios

Scenario	Additional Cost
5% Co-firing	$12/kW
10% Co-firing	$25/kW
20% Co-firing	$40/kW

kW = kilowatt.

The base capital cost for the co-fired power plant is assumed to be $2,140, although because this analysis focuses only on the *incremental* cost of the co-firing option, the base capital cost of the power plant does not affect the final outcome reported above. The costs of biomass fuel and coal, based on estimates provided by Wolverine Power (for biomass) and by DTE and Consumers Energy (for coal), are expected to be $4.75 for biomass and $3.50 for coal in 2015. These costs are assumed to escalate annually at a constant 2.5% rate for each.

Key Uncertainties

The key uncertainties that may influence this analysis are related to possible changes in capital costs for biomass co-firing and future biomass fuel costs. For example, if more than one plant were to compete for the same biomass resource, at a minimum, the cost of that resource would increase for all competing facilities. Furthermore, even if multiple plants were constructed in a manner to avoid local competition, the statewide increase in demand could also increase the fuel cost, given the limited supply and competing demands from other sectors.

There is some question about whether certain biomass co-firing technologies could result in higher GHG emissions than other coal-based technologies. Policymakers are encouraged to clarify this issue prior to making decisions about specific projects.

Additional Benefits and Costs

An additional concern may be the effect of co-firing coal and biomass on the emissions of non-GHG regulated pollutants. The existing regulatory process will address these issues.

Feasibility Issues

The main concerns for feasibility are regulatory. For example, using biomass in a manner that qualifies for REC allowance credits will require certification that the feedstock was grown and harvested in a renewable, or sustainable, fashion.

Status of Group Approval

Approved.

Level of Group Support

Super majority—18 in favor, 3 opposed.

Barriers to Consensus

MCAC members voting against this policy recommendation expressed the concern that new co-firing generating facilities would still be burning coal as the primary fuel and, therefore, represent the continuation of reliance on coal for generation of electricity, which they oppose.

ES-11. Power Plant Replacement, EE, and Repowering

Policy Description

Michigan has the second-oldest fleet of power plants in the nation. The state will most likely be facing the retirement or repowering of a number of old, less efficient units within the time frame of this planning process. In addition, both the Upper and Lower Peninsulas are net importers of electrical power. The opportunity to replace aging units and reduce GHG-intensive imports with more efficient in-state generation could offer a reduction in GHG emissions from this sector. Furthermore, existing coal-based generation technologies may benefit from additional technologies and upgrades to make their fuel burning more efficient, resulting in more electric output for the amount of fuel burned. However, certain existing policies, such as New Source Review (NSR), deter some efficiency improvements. NSR is the general term applied to the permitting requirements of new stationary sources or modifications of existing stationary sources under the Clean Air Act. NSR encompasses the Prevention of Significant Deterioration (PSD)[7] permitting requirements for attainment areas[8] and the NSR permitting requirements for nonattainment areas.

Generation efficiency improvements refer to increasing generation efficiency at power stations through incremental improvements at existing plants (e.g., more efficient boilers and turbines, improved air and feedwater heaters, condensers, or improved power plant control systems). An efficiency upgrade results in lower GHG emissions at the same or a higher level of electrical output.

Repowering existing power plants refers to the engineering and installation of technologies that enable switching to lower- or zero-emitting fuels for these plants, including the use of biomass or natural gas in place of coal or oil.

Power replacement refers the wholesale removal and replacement of an existing plant with another plant of similar or different technologies. Replacement plants of new, modern design are inherently more efficient than the older generation technologies in terms of GHG emissions per unit of fuel consumed.

Policies to encourage generation efficiency improvements, repowering of existing plants, or power plant replacement(s) could include incentives or regulations as described in other recommendations, with adjustments for financing opportunities and emission rates of existing plants. The cost basis of these activities could be evaluated for cost and performance within the context of an IRP model described in ES-7. This evaluation would be part of an overall plan identifying cost-effective options for reducing system CO_2 and other emissions to applicable regulatory levels or limits on a short-term and long-term basis, requiring generation owners to pursue

[7] Federal PSD/NSR requirements are in 40 CFR 52.21. Michigan requirements are in R 336.2801–2830 and R 336.2901–2908.

[8] An attainment area is a geographic zone within which the concentration of a pollutant is considered to meet U.S. National Ambient Air Quality Standards. These standards are set per pollutant, so it is possible for a zone to meet these standards for a certain pollutant and not for another.

cost-effective options for reducing their emissions profile through measures identified above, and creating financial incentives that reward such emission reductions.

Policy Design

Estimates of efficiency improvements at existing power plants could range up to 5% of heat rate.

Repowering coal-fired generation with natural gas for instance could result in efficiency improvements of up to 30% of heat rate, assuming the availability of natural gas. Full or partial repowering of coal-fired generation with biomass-based fuels may also be feasible in some limited circumstances predicated on plant configuration and fuel availability.

New generation assets could realize efficiency improvements over existing older generation technologies of up to 10% of heat rate for coal-fired generation.

Goals:

- Electric generators should evaluate the efficacy of efficiency upgrades, repowering, and/or plant replacements against other generation options, including GHG compliance cost options, such as a market-based procurement of allocations that the company would need to meet its generation output.[9]
- Convene a stakeholder group comprised of staff from electric generators, MDEQ, MPSC, and others to study and potentially propose a publicly funded pilot project on the repowering of an existing baseload coal-fired power plant. The stakeholder group would solicit and evaluate proposals for repowering from generator owners, and select the most viable project, with a preference for the project that had the potential for the greatest GHG reductions per unit cost. The process would involve, among other activities, securing public funding, site and/or facility selection, permit coordination, contract scope and effectuation, pilot project authorization by the owner, and cost recovery authorization as appropriate for the type of ownership of the plant.
- Evaluate and determine appropriate funding sources for partial reimbursement of the successful respondent to the RFP on the pilot project. It is recommended that $50 million in funding be secured for this pilot project.
- Evaluate potential policy deterrents, such as NSR, to determine if modifications should be advocated to help achieve desired climate benefits.

Timing: Efficiency could be improved over short periods of time, while repowering and replacements could take up to 10 years to implement.

Parties Involved: This recommendation applies to all Michigan generation owners. For regulated utilities, efficiency upgrades, repowering, and power plant replacement would ultimately be evaluated through one of the MPSC review processes. For unregulated generators,

[9] A reliable estimate of benefits and costs from efficiency, repowering, and replacement will not be known until the utility studies are completed. Not as a goal, but for the purpose of estimating GHG reduction potential and cost-effectiveness at this time, it is assumed that 75% of the coal-fired fleet are candidates for efficiency improvements, 5% are candidates for repowering with natural gas, and 5% are candidates for replacement with advanced-technology coal.

these projects would be economically driven based on market forces. For municipals, their local boards or commissions would evaluate these projects.

Other: None.

Implementation Mechanisms

The planning and emission reduction requirements for regulated utilities could be implemented through planning processes already implemented by the MPSC. For IPPs, the costs and benefits of such efficiency increases or upgrades would be evaluated against the locational marginal pricing or other financial recovery mechanism.

Related Policies/Programs in Place

For regulated utilities owning generation assets, the IRP process is strongly related to the selection of cost-effective generation technologies. Michigan has adopted IRP requirements for electric utilities under H.5524, Sec. 6s (11) (a)–(g) (see ES-7).

On August 6, 2008, in Case No. U-15631, the MPSC directed utilities with fossil fuel generation to file 10-year fossil fuel generation efficiency plans with the MPSC by December 31, 2008. The MPSC directed that these plans should include a comprehensive technical and economic analysis of the consequences resulting from the potential retirement of existing fossil fuel generation facilities, and plans for repair or replacement of units. In addition to cost and service issues, the analysis should address environmental concerns, including potential GHG abatement measures.

Type(s) of GHG Reductions

All six statutory GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6).

Estimated GHG Reductions and Costs or Cost Savings

The estimation of the potential GHG reductions and costs in Table F-11-1 employs the assumptions listed in Table F-11-2. The repowering pilot project goal above is assumed to be a 25-MW coal-fired facility for which a $50 million demonstration grant would be targeted.

Table F-11-1. Estimated GHG reductions and costs of or cost savings from ES-11

ES-11. Power Plant Replacement, Energy Efficiency, and Repowering	2015	2025	Units
GHG emission savings	2.5	2.0	Million metric tons of CO_2
Cumulative net costs (present value) (2009–2025)		$313	Million $
Cumulative emissions reductions (2009–2025)		33.2	Million metric tons of CO_2
Cost-effectiveness		$9.4	$/metric ton of CO_2

Data Sources: Mostly placeholders to be confirmed by the ES TWG.

Quantification Methods: Improvements at facilities are modeled as new generation, displacing primarily coal generation. Reductions account for the impacts of other energy supply recommendations.

Key Assumptions:

Table F-11-2. Key assumptions used to estimate the GHG reductions and costs of or cost savings from ES-11

Types of Improvements	Assumptions
Applicability	
Improvements at existing plants	75% of all plants
Refiring coal plants with natural gas	5% of all plants
Replacing old technology with new	5% of all plants
Cost of Efficiency Improvements	
Improvements at existing plants	$500/kW
Refiring coal plants with natural gas	$1,000/kW
Replacing old technology with new	$2,000/kW

kW = kilowatt.

Key Uncertainties

- Applicability (see assumptions above).
- Cost of improvements (see assumptions above).
- Repowering a coal-fired plant with natural gas will reduce GHG emissions, but will also increase the cost factor for the plant. Increasing the cost factor will affect when and how often the plant is dispatched, effectively reducing the capacity factor, and thereby affecting the GHG savings. For those periods when the repowered plant is not dispatched, lower-cost generation will be used, which in most cases will be coal-fired. This is why there is not a 1:1 relationship for GHG reductions per MW in this analysis. Given the complexity of generation costs and availability, it is not possible to project the exact net GHG reductions from repowering.
- The actual results of the generator-specific evaluation of efficiency, repowering, and technology improvements will not be known until the evaluation is completed.
- Power plant efficiency projects (e.g., turbine blade replacements) may trigger the NSR permitting process that can require the installation of best available control technologies (BACTs) for conventional pollutants, such as sulfur dioxide (SO_2), oxides of nitrogen (NO_X), and particulate matter (PM). The business case for making the efficiency improvement may be negated by the cost of installing BACTs on an existing unit. The ongoing EPA NSR utility enforcement initiative has created an era of uncertainty for power plant owners in making any kind of modifications to their plants that could trigger NSR. Unfortunately, this uncertainty results in postponements or delays in efficiency projects and perpetuates emissions from older and less efficient power plants. The actual cost associated with installing BACT will be facility-specific and could vary widely. BACT reviews are performed by permitting agencies on a case-by-case basis and take into account such factors as energy consumption, environmental impacts, and economic costs. Recent BACT reviews conducted by the MDEQ have identified the following estimated costs for BACTs:
    - $4,000/ton of SO_2 removed,

- $8,000/ton of NO_X removed,
- $2,000/ton of PM removed, and
- $3,000/ton of carbon monoxide removed.

These are very approximate estimates, and will vary considerably depending on boiler types, fuels burned, design and configuration of the plant, and interactions among different control technologies. The multitude of variables makes it difficult to assess the need for and cost of BACT for modifications to existing plants; therefore, these costs are not included in the model.

Additional Benefits and Costs

None.

Feasibility Issues

The pilot project is dependent on the availability of funding. Repowering, efficiency, and technology improvements will require capital funding and possibly cost recovery.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

None.

ES-12. Distributed Renewable Energy

Policy Description

This policy recommendation focuses on removing barriers to and providing incentives to encourage the development of distributed renewable energy throughout the state. Distributed renewable energy is generally defined as small scale (generally less than 10 MW), located at or near the point of end use, interconnected to the distribution (as opposed to transmission) system, and more likely to have homeowner or community ownership.[10] Increasing the use of distributed renewable energy provides electricity reliability, security, and environmental benefits. Policies that have been developed and implemented successfully elsewhere to promote distributed renewable energy can be adapted for Michigan.

Policy Design

The main focus of this policy is developing and leading the market to produce distributed renewable energy by assuring investors of the opportunity to earn a reasonable return. Michigan must seek an appropriate combination of policies fitting the state's unique circumstances, which together will provide sufficient leverage/incentives to establish and grow a vibrant market. This could include any combination of utility rate treatment, financial incentives, tax policy, and consumer education.

The preferred policy design would include a well-designed and fully implemented renewable energy payment (REP) program. While this policy recommendation and associated goals specifically refer to distributed renewable energy, there is interest in making REPs available to large-scale projects also. A REP program may be designed to promote and encourage development of renewable energy projects of all sizes, ranging from small residential up to the largest utility-scale projects.

Goals: With an objective to completely open the distributed renewable energy market, set a goal for new distributed renewable energy to reach 0.4% of Michigan's electricity consumption by 2015, and increase the goal to 1.1% of consumption by 2025. These goals represent 468 GWh of distributed generation in 2015 and 1,396 GWh in 2025, which will be generated from 240 MW of new capacity in 2015 and 715 MW of new capacity in 2025.

Small-scale renewable energy not connected to the grid and non-electric generating renewable resources, such as geothermal heating and cooling and solar thermal domestic water heating systems, should be encouraged. Incentive programs should be developed according to the schedule in Table F-12-1, such that by 2025, an additional 1% of Michigan households are making use of these systems.

[10] "Self-Service Power" defined in MCL 460.10a(6a). See http://www.legislature.mi.gov/(S(dm4pmzapcyxj0fi2oor0t5fa))/mileg.aspx?page=getobject&objectname=2000-PA-0141&query=on.

Table F-12-1. Proposed schedule for developing incentive programs

Year	Cumulative Percentage of Michigan Housing Units With Each Type of System at End of Year Range	Solar Thermal Domestic Water Heating		Geothermal Heating and Cooling	
		Annual Installations	Cumulative Installations at End of Year Range	Annual Installations	Cumulative Installations at End of Year Range
2010–2014	0.125%	1,125	5,625	1,125	5,625
2015–2019	0.375%	2,250	16,875	2,250	16,875
2020–2024	0.875%	4,500	39,375	4,500	39,375
2025	1%	5,625	45,000	5,625	45,000

There are 4.5 million housing units in Michigan. See http://quickfacts.census.gov/qfd/states/26000.html.

A public education program would determine and widely disclose to the public the full cost accounting for renewable energy and fossil fuel production, including costs to public health and the environment. The public education program should be adequately funded.

Timing: As soon as possible.

Parties Involved: Legislation must be passed to provide for property tax exemptions. After passage of legislation, utilities would administer the REPs and net metering programs under the supervision of a state agency. The local distribution utility interconnection process is currently under review, and an improved process is under development at the direction of the MPSC. Efforts to quantify the benefits of distributed renewable resources would be undertaken by a state agency. State agencies have already provided funding on a county-by-county basis to work with local governments to develop model distributed wind energy facility siting and zoning ordinances. This work could be continued and expanded to other counties and to other types of renewable energy resources.

Other: The net metering policy helps remove barriers by requiring utility companies to provide access to the power grid, including streamlining and simplifying their interconnection procedures. Supplemental policies could (1) provide assistance and incentives to local units of government to streamline and modernize zoning and siting rules and processes, and (2) determine and widely disclose to the public full cost accounting for renewable energy and fossil fuel production, including costs to public health and the environment.

Implementation Mechanisms

Legislation is most likely needed to establish the REP program.

REPs would provide for producers of renewable electrical energy to be paid an established rate for each kilowatt-hour of energy they "feed into" the grid. The key principles of REPs include:

- The REP price should be set just high enough to cover costs and ensure a reasonable return on investment for commercial installations. Prices vary according to the source of the energy (sun, wind, water, biomass, etc.) and the size of the energy-producing installation.[11] For

[11] See for example: Gipe, Paul (2007). *Advanced Renewable Tariff Pricing Worksheets*. Web site: http://www.wind-works.org/PricingWorksheets/ARTsTariffsPricingWorksheets.html. Mendonça, Miguel (2007). *Feed-In Tariffs,*

household-level distributed renewable energy projects, the REP price needs to be set high enough to provide an adequate incentive for the homeowner to invest in the project. Homeowners would consider the financial incentive, the avoided costs of purchasing electricity over the life of the project, and such intangibles as the benefit of energy independence and the knowledge of knowing that they are powering their homes with little or no carbon footprint.

- Barriers to interconnection must be removed. Implementation of ES-15a (Transmission Access and Upgrades) and ES-15b (Distribution System Access and Upgrades) are key elements to successful implementation of REPs. A fully implemented REP program would have no limit on the amount of renewable energy that can be sold to utility companies.
- Distributed renewable energy producers must be able to obtain 15–20-year tariffs. All tariffs are transparent and open for inspection.
- The utility companies can recoup their increased costs of paying higher prices for renewable energy by spreading these costs among all their customers.
- An independent government review board periodically sets the prices and terms for new tariffs. It is expected that the REP price will decrease for new installations as technology advances decrease the costs of distributed renewable generation.

The financial subsidy need not come from utility ratepayers. Any source of public funding could be used to augment utility rates.

Based on the design of the REP program, net metering may be an additional incentive and a complement to the REP program for certain types of distributed renewable energy. The net metering program may be established either through legislation or through state agency actions. The simplest form of net metering allows owners of grid-connected distributed energy (generating units on the customer side of the meter, often limited to some maximum kW level) to be billed based on net usage and receive a credit for excess electricity from their electricity supplier. This type of net metering provides several incentives for distributed renewable energy by reducing transaction costs (e.g., no need to negotiate contracts for the sale of electricity back to the utility or purchase expensive upgraded meters), and reducing customer utility bills by providing for monthly netting of customer electricity usage.

For grid-connected and non-grid-connected distributed renewable energy, consideration should be given to how other incentives, such as tax credits, property tax exemptions, installation cost rebates, and low-interest loans, would best complement the REP program. These additional incentives may have a high impact on the development of renewable energy that is not grid-connected and non-electricity-generating renewable resources, such as solar thermal domestic water heating and geothermal heating and cooling systems. Such non-electricity generating systems reduce the use of electricity needed for household heating and cooling, which would benefit from these economic incentives. Such incentives may be established through a combination of legislation or state agency actions.

Utilities, state agencies, environmental groups, and other interested parties should develop and implement the renewable energy public education program.

Accelerating the Deployment of Renewable Energy, World Future Council, Earthscan. Web site: http://www.earthscan.co.uk/default.aspx?tabid=298.

Related Policies/Programs in Place

On October 6, 2008, PA 295 was enacted. Part 5 of the act requires the MPSC to establish a statewide net metering program applicable to electric utilities and alternative electric suppliers. The program provides “true net metering” for eligible generators with a capacity of 20 kW and under, and “modified net metering” for eligible generators with a capacity of up to 150 kW, and methane digesters with a capacity of up to 550 kW. Electric utilities and alternative electric suppliers are required to offer net metering until the size of their program reaches 1% of their in-state peak load for the preceding year.

Since 1991, Germany, Spain, Denmark, and over 40 other nations, states, and provinces, have successfully implemented REPs as incentives for homeowners, farmers, businesses, etc., to become producers or increase their production of renewable energy. In many of these countries, these policies are called “feed-in tariffs." Eighteen out of 25 European Union countries have established a variety of different feed-in tariff designs.[12]

With REPs, producers of distributed renewable energy are offered long-term, standard tariffs with prices intended to provide developers with ample revenues to assure them a reasonable return on their investment. As such, REPs have the potential to increase overall production and use of renewable energy, and decrease consumption and burning of fossil fuels. At least some researchers believe REPs represent the fastest, least expensive means for supporting wide growth of distributed renewable energy.

A bill titled Michigan Renewable Energy Sources Act was introduced in the Michigan House during 2008.[13]

New Jersey, Colorado, Pennsylvania, Maryland, and California are states with net metering programs that received an “A” grade in *Freeing the Grid*.[14]

Michigan currently has a limited net metering program available to customers of regulated utilities. The program is not standardized and varies widely by utility. As of the most recent reporting period, 23 customers were participating in the program.

The MPSC issued an order on August 6, 2008, in Case No. U-15316, adopting the Energy Policy Act of 2005 net metering standard.[15] Utilities are ordered to file an application for approval of a new net metering tariff by December 31, 2009. Utilities that file a rate case before that date or that have a rate case pending on the date of issuance of this order do not need to file a separate application for the new tariff.

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[12] Klein, Arne; Held, Ann; Ragwitz, Mario; Resch, Gustav; Faber, Thomas. (2007). Evaluation for different feed-in tariff design options: Best practice paper for the International Feed-in Cooperation. German Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU). Web site: http://www.feed-in-cooperation.org/images/files/best_practice_paper_final.pdf.

[13] See HB 5218, http://www.legislature.mi.gov/(S(fg1phg45vqwgaqijnikisaao))/mileg.aspx?page=getObject&objectName=2007-HB-5218.

[14] See *Freeing the Grid*, 2007 Edition, Network for New Energy Choices, available at: www.newenergychoices.org.

[15] See the order at: http://efile.mpsc.cis.state.mi.us/efile/docs/15316/0022.pdf.

Other forms of financial incentives for renewable energy include special utility rates, tax credits (for example, the Federal Production Tax Credit[16]), installation cost rebates, and low-interest loans. Both New Jersey and California have had very successful rebate programs.[17]

As of January 2008, six utilities in Michigan are member utilities of Wisconsin Public Power, Inc. These utilities offer rebates or low-interest loans for qualifying solar thermal domestic water heating, solar photovoltaic, and small-scale wind installations.[18]

The MDLEG Energy Office implemented a $3/watt incentive program for small solar and wind systems in 2001. The program budget was $300,000 from the State Energy Program grant from DOE. It was anticipated that the program would start slowly after January 1 and end late in calendar year 2001. By the end of March, 18 incentives had been approved. By the end of April, 86 incentives and the entire budget of $300,000 had been approved. The 86 incentives represented 47 kW of solar energy and 62 kW of wind energy. The Energy Office learned that there was a significant amount of interest on the part of consumers, and the budget was not large enough to have a program in place for a reasonable amount of time. A 4-month program generated significant interest, but also a lot of disappointment.

In 2005, a, MDLEG Energy Office solar thermal domestic water-heating program offered incentives totaling $415,000. Of the 117 systems receiving incentives, 20 rebates were provided for repair of existing systems. Rebates varied within a range of $2,000–$4000, based on the type of system selected. At the time the program ended, approximately $290,000 had been spent.

Type(s) of GHG Reductions

CO_2.

16 See http://www.dsireusa.org/library/includes/incentivesearch.cfm?Incentive_Code=US13F&state=US&currentpageid=7&search=TableState&EE=1&RE=1 for more information on the production tax credit.

17 See http://www.njcleanenergy.com/renewable-energy/programs/core-rebate-program/incentives/core-rebate-program for information on New Jersey's rebate program. See http://www.gosolarcalifornia.ca.gov/csi/index.html for information on California's solar rebate program.

18 See http://www.wppisys.org/programs_services/default.asp?CategoryID=38&SubcategoryID=82.

Estimated GHG Reductions and Costs or Cost Savings

Table F-12-2. Estimated GHG reductions and costs of or cost savings from ES-12

ES-12. Distributed Renewable Energy	2015	2025	Units
GHG emission savings	0.40	0.92	Million metric tons of CO_2
Cumulative net costs (present value) (2009–2025)		$1,054	Million $
Cumulative emissions reductions (2009–2025)		8.0	Million metric tons of CO_2
Cost-effectiveness		$131	$/metric ton of CO_2

Note: these results are included as the 'carve-out' in ES-1

Data Sources:

- AEO 2008.
- Data provided by MPSC.
- U.S. DOE, Office of Energy Efficiency and Renewable Energy (EERE). *A Plan for the Integrated Research, Development, and Market Transformation of Solar Energy Technology.* Available at: www1.eere.energy.gov/solar/solar_america/pdfs/sai_draft_plan_Feb5_07.pdf.

Quantification Methods: Distributed generation would displace primarily coal-fired electricity. Solar hot water and geothermal energy would displace 50% natural gas heating and 50% electricity heating.

Key Assumptions:

- Table F-12-3 presents the portfolio of new distributed generation that was used, based on input from the TWG:

Table F-12-3. Portfolio of new distributed generation used to quantify ES-12

Type of Electricity Generation	2015	2025	Units
Wind	40%	40%	of new distributed generation
Solar photovoltaic	25%	25%	of new distributed generation
Biogas	35%	35%	of new distributed generation

- Solar hot water installations: 7,875 homes by 2015; 45,000 by 2025.
- Geothermal installations: 7,875 homes by 2015; 45,000 by 2025.
- Table F-12-4 presents the assumptions used for the capital costs for each type of generation.

Table F-12-4. Assumptions for estimating the capital costs of new distributed generation

Capital Costs	2015	2025	Units
Solar hot water	$4,459	$5,203	$/installation
Geothermal	$16,000	$16,000	$/installation
Wind (distributed)	$6,000	$5,000	$/kW
Solar photovoltaic (distributed)	$8,131	$6,756	$/kW
Biogas	$2,500	$2,500	$/kW

- Avoided emissions rate: 0.73 metric tons of carbon dioxide per megawatt-hour (tCO_2/MWh) (2015); 0.56 tCO_2/MWh (2025). This accounts for the effect of other recommendations (ES-1, ES-3, ES-6, ES-10, ES-11, ES-12, and ES-13).
- Biogas heat rate: 10,000 Btu/kWh.
- It is important to note that the costs presented here represent the total direct cost to society (public and private), as defined by the borders of the state of Michigan. Capital and operating costs are included in the total, regardless of who within Michigan actually pays these costs. Therefore, DG costs reflect the total cost to ratepayers, taxpayers, and homeowners for recommended subsidies, incentives, and private expenditures. This policy recommends methods for creating the incentives necessary to achieve the goals, but does not prescribe specific rates, which would be set through the existing legislative and regulatory processes. It is believed that the goals can be achieved through the availability of public-sector incentives representing a fraction of the total costs presented here.

Key Uncertainties

Future capital costs.

Additional Benefits and Costs

Distributed renewable energy anticipates a relatively large number of small-scale installations. The successful implementation of the policy will require the establishment of a large number of enterprises to meet the new demand. This will create many new jobs requiring new skills. In addition, the demand will most likely spur R&D of new technologies, which will further promote investment and job creation.

Feasibility Issues

None.

Status of Group Approval

Approved

Level of Group Support

Unanimous.

Barriers to Consensus

None.

ES-13. Combined Heat and Power (CHP)

Policy Description

The state of Michigan and the various stakeholders involved all recognize that the state needs to increase its electric generation resources, while at the same time reduce associated GHG emissions to address the impact of global warming and improve its business climate so that the job pool for its citizens can grow.

Literally, every business in Michigan that uses energy to heat and/or cool its buildings or as part of a production process is technically a candidate to simultaneously also generate electricity at its site, using one of several commercially proven and widely used combined heat and power (CHP) technologies. CHP technologies, also referred to as "co-generation," include steam turbines with steam extraction or back pressure, gas turbines with waste heat recovery boilers, combined-cycle units, reciprocating engines with manifold exhaust and cooling heat recovery, as well as less proven technologies, such as fuel cells and Stirling engines. Every currently used fuel source (including natural gas, coal, biomass, landfill gas, and municipal solid waste) can be and has been used for such purposes. If, and only if, there is a match between the real-time requirements for thermal energy and the electrical load that is generated, then the energy/fuel requirements to produce a given amount of electricity can be less than half of what is possible with even the largest and most efficient power generation technologies in existence today.

As a "co-benefit" of this inherent efficiency, CHP installations significantly reduce GHG emissions by increasing the overall efficiency of fuel use relative to making the same energy products (i.e., power and heat) separately in stand-alone installations.

Policy Design

A new approach to planning, constructing, and utilizing generation resources is envisioned by this policy. This new approach would favor on-site distributed generation opportunities (along with energy efficiency, demand-side management, and renewable resources), and then central station units as needed to meet supplemental demand.

To achieve this goal, it will be necessary to revise regulatory policies and remove institutional barriers to allow distributed renewable energy and CHP systems to compete on a level playing field with other sources of electric and thermal energy.

Goal: Set a goal for CHP facilities of up to 10% (180–2,000 MW) by 2020. This target does not include the current target of 10% for the RPS as proposed in ES-1 or established as a goal under PA 295. This would be accomplished with a phase-in beginning in 2010. It should achieve a goal for CHP equal to 15% of in-state CHP technical potential at commercial and industrial facilities by 2020, with a phase-in beginning in 2010.

Timing: As noted above.

Parties Involved: Financial incentives would be administered by a state agency, such as the Michigan Economic Development Corporation or Department of Treasury, possibly managed through the MPSC, with regulatory assistance through the MDEQ and provided to IPPs and commercial and industrial entities.

Other: A source of funds to cover these financial incentives would need to be determined. It may be possible to link incentives to (or condition them upon) the manufacture and installation of associated CHP equipment within the state of Michigan. Possible "seed money" funding sources could include bond funds, securitization monies, etc., with long-term financing mechanisms (revolving loan funds) to sustain the effort.

Implementation Mechanisms

A variety of implementation mechanisms can be utilized to address the various barriers and issues related to greater market penetration of CHP. The ES TWG recommends the use of the following mechanisms as necessary to achieve the goals stated under the Policy Design section:

- *Information and education*—If Michigan industries are going to seriously consider incorporating CHP into their business plans on a widespread basis, then a significant level of marketing of the incentives available must be provided. Michigan's utilities, MDEQ, and MDLEG are the likely candidates for such marketing efforts. This assumes that incentives recognizing the value of the potential capacity to reduce GHG emissions through the application of CHP technology to existing steam production facilities will, in fact, be made available, and the impact of such incentives on the CHP economics can be demonstrated.
- *Technical assistance*—The one area where technical assistance may prove to be invaluable is with regard to interconnection requirements, particularly for sell-back installations. Long lead times and expensive analysis to review such issues as system stability will have a very negative impact on the feasibility of wide-scale application of CHP, unless some entity, such as the electric utility, can shoulder this responsibility. Costs incurred for such activities should be recouped from all ratepayers as a legitimate capacity planning and procurement expense.
- *Financial incentives*—A state entity, such as the Michigan Strategic Fund, should be empowered to provide long-term loans to facilities employing CHP technology. Such loans should be designed to generate internal rates of return adequate to meet the risk/reward requirements of Michigan businesses, as well as take into account job development and emissions criteria. Projects meeting such criteria might be candidates for some sort of guaranteed loan recovery similar to a utility plant after the facility is operational and is found to be useful by the MPSC. Similarly, utility ownership of such facilities as dedicated on-site producers should be facilitated.
- *Regulatory policies*—Utility standby rates need to be redesigned to reflect an aggregate diversity to be found in many smaller facilities, rather than treating each facility on a stand-alone basis. The odds of numerous smaller units being out of service at any one given time and the ability to schedule maintenance in smaller increments suggest that a large number of units could be backed up with a relatively small reserve, and thus reduce such costs significantly. High standby costs have been attributed to being a major barrier to the implementation of CHP on a larger scale.
- *Codes and standards*—CHP facilities will produce more emissions—not less—at a given location than just the production of steam or power alone. Some means to address this issue

needs to be incorporated into the permitting process, so that the two-for-one emission benefits of CHP can be taken into account.

Generating electricity and heat is a cost-intensive undertaking that carries considerable risk to any Michigan business or institution that might consider implementing such projects. There are numerous barriers to CHP, including:

- Inadequate or incomplete information.
- Institutional barriers, such as high transaction costs and long return on investments due to such factors as small project size; high financing costs because of lender unfamiliarity and perceived risk; "split incentives" between building owners and tenants; and utility-related policies, such as interconnection requirements, high standby rates, exit fees, etc.
- Lack of standard offer or long-term contracts.
- Payment at avoided cost levels and lack of recognition for emission reduction value provided.

Policies to remove these barriers can include:

- Making interconnection rules and procedures less onerous and more conducive to encouraging CHP applications.
- Improving rates and fees policies.
- Streamlining or simplifying permitting processes.
- Recognizing the emission reduction value provided by CHP.
- Offering financing packages and bonding programs that would in turn make it easier for struggling manufacturers to make the capital investment required.
- Providing power procurement policies, such as "feed-in tariffs," that make it easier for facilities with excess generation to sell their product (electricity).
- Improving education and outreach on the potential of CHP.

Related Policies/Programs in Place

Federal and state tax policy could be adjusted to make CHP more attractive. Where such changes cannot be made directly, steps should be taken to improve the viability of facilities within the existing regulations. For example, biomass-fueled CHP does not qualify for a federal production tax credit if the power is consumed internally. If the utility buys the power under a simultaneous buy/sell structure, then the project would qualify and would receive a credit worth 1–2 cents per kWh for up to 10 years, depending on the fuel type.

Similarly, RECs may not be made available for many such facilities, regardless of fuel source, if the power is used internally. Some means needs to be established to monetize the REC value of such generation within an RPS. Even fossil-fueled CHP should receive credit somewhere—under either an RPS or an efficiency standard of some sort—because of its ability to reduce overall emissions.

See Annex F-1 to this appendix for background information on CHP potential and associated narrative, excerpted from the 2007 MPSC *Michigan's 21st Century Electric Energy Plan*.

Type(s) of GHG Reductions

Reductions in CO_2 emissions from fossil fuel-based combustion sources (coal, oil, etc.) as CHP electric production would reduce demand and output from such facilities. Many Michigan facilities with large steam loads have been backed off or even shut down due to economic considerations in the marketplace. Overall, GHG emission reductions from retrofitting CHP systems on older boilers on existing sites are more beneficial than constructing new state-of-the-art facilities.

Estimated GHG Reductions and Costs or Cost Savings

Table F-13-1. Estimated GHG reductions and costs of or cost savings from ES-13

ES-13. Combined Heat and Power (CHP)	2015	2025	Units
GHG emission savings	0.4	0.5	Million metric tons of CO_2
Cumulative net costs (present value) (2009–2025)		$32	Million $
Cumulative emissions reductions (2009–2025)		7.8	Million metric tons of CO_2
Cost-effectiveness		$4.09	$/metric ton of CO_2

Data Sources:

- *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector*. Available at: http://www.eere.energy.gov/de/pdfs/chp_comm_market_potential.pdf.

Quantification Methods: Modeled as heat-driven CHP, where heat displaces 50% natural gas heat and 50% electricity heat. Electricity derived from waste heat displaces primarily coal power.

Key Assumptions:

- Capital costs: $4,000/kW for coal and $1,200/kW for natural gas.
- Non-fuel operation and maintenance (O&M) costs: $12/MWh for coal and $5/MWh for natural gas (to be revised).
- New CHP to be powered as follows: 90% by coal, 10% by natural gas.

Key Uncertainties

- Future capital costs.
- O&M costs.
- Ratio of new coal CHP to new natural gas CHP.

Additional Benefits and Costs

Secondary economic benefits can be expected as a result of lowered energy costs for industries, businesses, and institutions utilizing CHP. Such benefits result from a more competitive cost structure, which can lead to increased employment, profitability, and investment. For public- and nonprofit-sector institutions, benefits may include greater productivity and lower costs.

Feasibility Issues

As stated in the Policy Design and Implementation Mechanisms sections of this policy recommendation, CHP fails to be fully utilized due to regulatory and other constraints. Many of these barriers can be removed without harmful consequences, but this is most likely not true of all. For example, depending on the size and location of the facility, emissions of regulated air pollutants might be elevated on a localized basis due to less stringent thresholds for smaller boilers or pre-existing ambient air quality concerns.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

None.

ES-15a. Transmission Access and Upgrades

Policy Description

Issue 1—Various efficiency measures can be implemented to reduce transmission line losses of electricity. Utilities and transmission system operators use a variety of components throughout the transmission system to manage losses. A portion of each kWh generated is lost in the transmission activity. Improving the efficiency of the system lowers the amount of energy consumed in the transmission function and directly reduces generator fuel consumption. By reducing constraints in the transmission system, improved transmission facilities reduce congestion, hence reducing energy costs and improving the efficiency of the transmission and generation system. Increasing the efficiency of these components can further reduce losses and associated GHG emissions. Regulations, incentives, and/or support programs can be applied to achieve greater efficiency of transmission and distribution system components.

Opportunities exist to increase or improve transmission line carrying capacity through the implementation of new construction and retrofit activities on the transmission grid, including incorporating advanced composite conductor technologies and other advanced technologies (static VAR compensators, phase shifters, etc.), as well as grid management software. In addition, increasing the voltage of high-voltage lines will increase the efficiency of the transmission system and will facilitate access to all sources of generation. As transmission voltage increases, the capacity of the line is greatly increased (a 765-kilovolt [kV] line can have 5–6 times the load ability of a 345-kV line). This higher capacity and reduced resistance results in increased efficiency and lower losses, which means generation is reduced. The economics of such transmission improvements needs to be justified, with the participation of the Midwest Independent [Transmission] Service Operator, Inc. (MISO), to the extent the improvements provide benefits to Michigan customers using the cost recovery in transmission rates.

Issue 2—To facilitate widespread adoption of renewable energy technologies, the current transmission system requires upgrades and additions. These transmission improvements will enable renewable energy systems and CHP projects to interconnect to the grid. Improvements in the bulk power system will also provide the operational flexibility required by the addition of renewable resources.

Issue 3—Renewable energy facilities may require the addition of new or improved transmission lines that must be seamlessly integrated into the transmission grid. Measures facilitating development of these projects can be a critical part of Michigan's renewable energy future—for example, renewable energy projects "queue issues," relative to MISO's coordination efforts with FERC. FERC has approved MISO's proposals to streamline the queue process.

Policy Design

Goals:

- Implement a transmission system efficiency study for Michigan to determine the most cost-effective measures to reduce line losses and improve overall system reliability and management, including improving access for new generation assets, such as renewable energy, CHP, and distributed generation projects.

- Assess the effectiveness of the existing transmission system to accommodate new generation assets, including renewable energy projects and CHP projects, and implement infrastructure improvements and development to meet the future demand of existing and new power generation.
- Reassess the effectiveness of siting and routing of transmission lines to accommodate new generation assets, including commercial-scale renewable energy projects (wind).

Timing: These studies should be conducted and completed in 2009.

Parties Involved: The MPSC, investor-owned utilities, municipal utilities, and cooperatives.

Other: None.

Implementation Mechanisms

The MPSC and other stakeholders would work with MISO to implement the transmission system efficiency study, which would address each of the above goals.

Related Policies/Programs in Place

In July 2008, the MPSC established the Michigan Planning Consortium to improve the planning process for electricity infrastructure projects and identify possible ways to reduce costs to ratepayers.

MISO's transmission expansion planning process involves assessing existing transmission adequacy and reliability and sets forth measures to remediate and address these deficiencies. This planning process is overseen by FERC, as the MISO tariff is administered by FERC and subsequently authorized accordingly. MISO is the North American Electric Reliability Corporation Planning Authority for its member footprint and performs regional planning in accordance with the FERC Planning Principles delineated in Order 890. These planning principles provide mechanisms to ensure that the regional planning process is open, transparent, and coordinated and includes reliability and economic planning considerations and mechanisms for equitable sharing of expansion costs. The MISO planning process integrates the local planning processes of MISO member companies into a coordinated regional transmission plan and identifies additional expansion requirements.

The MISO planning process objectives include:

- Planning to:
  - Provide an efficient and reliable transmission system,
  - Provide access to diverse energy resources,
  - Expand trading opportunities, and
  - Enable state and federal energy policy objectives to be met.
- Interconnecting new generation and transmission.
- Providing transmission service.

The planning activities are performed collaboratively between the MISO planning staff and the planning staffs of the transmission owners, with regular input from stakeholder groups. MISO recently augmented its transmission planning process to include a Michigan Sub-Regional Technical Study Task Force to address Michigan-specific transmission planning issues.

The purpose of Act 30 of 1995, titled the Electric Line Certification Act, is to regulate the location and construction of certain electric transmission lines.

Type(s) of GHG Reductions

All six statutory GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6).

Estimated GHG Reductions and Costs or Cost Savings

Not applicable. This policy is not quantified.

Data Sources: Not applicable.

Quantification Methods: Not applicable.

Key Assumptions: Not applicable.

Key Uncertainties

As noted under the Policy Description section, uncertainties mainly result from a lack of Michigan-specific information and planning. In addition, cost and permitting uncertainties are associated with the desire to have the transmission grid support new generation assets, such as renewables and CHP.

Additional Benefits and Costs

It is expected that measurable emission reduction benefits will result from the implementation of this policy. However, it is not possible to reliably predict the magnitude of these savings or their costs or cost savings at this time.

Feasibility Issues

As noted under the Policy Description and Key Uncertainties sections.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

None.

ES-15b. Distribution System Access and Upgrades

Policy Description

Issue 1—Various energy efficiency measures can be implemented to reduce distribution line losses of electricity. Utilities and transmission system operators use a variety of components throughout the distribution system to manage losses. Increasing the efficiency of these components can further reduce losses and associated GHG emissions. Regulations, incentives, and/or support programs can be applied to achieve greater efficiency of distribution system components. In general, higher capacity and reduced impedance result in increased efficiency and lower losses, which means generation is reduced.

Issue 2—Infrastructure improvements to the distribution system through various measures to reduce line losses and enhance throughput may be required to meet long-term electricity demands and improve the efficiency of operations system-wide in Michigan. Such distribution system improvements will help reduce line losses and improve and manage outages, as well as enable renewable energy systems, including distributed generation and CHP projects, to interconnect to the grid.

Issue 3—In addition to distribution system upgrading issues, various barriers regarding distribution system access need to be addressed to facilitate greater adoption of renewable energy technologies, CHP, and distributed generation.

Policy Design

Goals:

- Implement a distribution system efficiency study for Michigan to determine the most cost-effective measures to reduce line losses and improve overall distribution system reliability and management, including improving access for new generation assets, such as renewable energy, CHP, and distributed generation projects.
- Assess the effectiveness of existing distribution lines to accommodate new generation assets, including renewable energy projects, CHP projects, and other distributed energy projects, and implement infrastructure improvements and development in order to meet the future demand of existing and new power generation.

Timing: These studies should be conducted and completed in 2009.

Parties Involved: The MPSC, investor-owned utilities, municipal utilities, and cooperatives.

Other: None.

Implementation Mechanisms

The distribution system efficiency study can be implemented by order of the MPSC for investor-owned utilities and co-operatives. Municipal utilities would be handled by other such applicable authorizations, as granted and approved by their local governing bodies. The focus of the study will be based on the above goals.

Related Policies/Programs in Place

Michigan has Electric Interconnection Standards in place for all regulated electric utilities.[19]

In October 2006, the MPSC began an investigation into the **i**nterconnection of new generation to the distribution system. As part of the investigation, formal rulemaking to revise the Electric Interconnection Standards has commenced.[20]

Type(s) of GHG Reductions

All six statutory GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6).

Estimated GHG Reductions and Costs or Cost Savings

Not applicable. This policy is not quantified.

Data Sources: Not applicable.

Quantification Methods: Not applicable.

Key Assumptions: Not applicable.

Key Uncertainties

Cost and permitting uncertainties are associated with the desire to have the distribution system support new generation assets, such as renewables and CHP.

Additional Benefits and Costs

It is expected that measureable emission reduction benefits will result from the implementation of this policy. However, it is not possible to reliably predict the magnitude of these savings or their costs or cost savings at this time.

Feasibility Issues

As noted under the Policy Description and Key Uncertainties sections.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

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[19] See http://www.state.mi.us/orr/emi/admincode.asp?AdminCode=Single&Admin_Num=46000481&Dpt=LG&RngHigh=.

[20] See http://efile.mpsc.cis.state.mi.us/efile/viewcase.php?casenum=15239.

Barriers to Consensus

None.

Annex F-1

(Excerpts taken from *Michigan's 21st Century Electric Energy Plan*[21])

III. RENEWABLE RESOURCES AND ALTERNATIVE TECHNOLOGIES FOR MICHIGAN

A. RENEWABLE RESOURCE FORECASTING

Modeling indicates a potential for at least 1,100 MW, and up to 2,700 MW, of new electric power capacity development in Michigan from renewable resources with another **180 MW available from combined heat and power, or CHP**. Forecasting in this area is particularly problematic, in light of the rapid pace of technological advancements and policy changes that will affect renewables. It is thus important to revisit renewable resource modeling on a regular basis, and to expand the renewable portfolio when appropriate.

Renewable resource assessment modeling for the Plan shows that Michigan's electric supply portfolio can achieve 7–10 percent renewable energy by the end of 2015. Based on the energy forecast, this amounts to approximately 5,200 to 9,200 GWh of additional renewable energy by December 31, 2015. The resource assessment conducted for the Plan demonstrates that Michigan has ample resources available to meet this level of renewable energy for electricity production.

CHP is useful when there is need for both electricity and process steam at a location. CHP facilities use fuel to make steam to turn an electric generator, and then use the leftover steam in the factory's processes.

Estimate of CHP Potential – Alternative Technologies Workgroup

1. Introduction and Methodology

1.1 Introduction

The purpose of this supplemental document is to describe the methodology used to estimate the potential achievable new supply of electricity that could be reasonably developed over the next 10 years at Michigan's large industrial, institutional and commercial facilities.

1.2 Methodology

During the prior Capacity Needs Forum (CNF) process, the combined heat and power (CHP) Team was able to use boiler permit data from the Department of Labor and Economic Growth (DLEG) to identify the scope of Michigan's large and medium sized boilers. Unfortunately, the boiler permit database did not indicate the degrees to which boilers were actually in use, making it difficult to accurately calculate the capacity factors of the selected boilers. The CHP Team therefore had to rely on ad hoc information regarding which steam boilers were actually available to potentially add CHP systems.

Fortunately, during the 21st Century Energy Planning process, the CHP Team was able to obtain better data from the Michigan Department of Environmental Quality (MDEQ), Michigan Air

[21] The entire *Michigan's 21st Century Electric Energy Plan* is available at: http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/index.htm.

Emissions Reporting System (MAERS) Database. This database not only has a comprehensive universe of industrial, institutional, and commercial boilers in its system, but it also indicates the type and amount of fuel they consumed in 2005. Using this fuel data, the CHP Team could calculate capacity factors for all boilers in use in 2005—providing a major improvement in accuracy of the projected results. Using the boilers database supplied by MDEQ, the CHP Team went through the following steps:

Step 1: Calculate Capacity Factors—The CHP Team calculated capacity factors for each boiler where both capacity and fuel usage was available in the MAERS database. 159

Step 2: Categorize Boilers by Size (MMBTUHR Capacity)—All boilers were first classified into the following categories:

- Industrial boilers
- Large boilers (100+ MMBTUHR)
- Medium boilers (26–99 MMBTUHR)
- Small boilers (20–25 MMBTUHR)
- Very small boilers (<20 MMBTUHR)
- Commercial boilers (including institutional and municipal)
- Other boilers (all boilers for which capacity factors could not be calculated)
- A total of 884 boilers were considered as a result of Step 2.

Step 3: Sort Out Non-CHP Candidates Based on Location—The CHP Team reviewed each category and removed boilers located at:

- Existing utilities, merchant plants or independent power producer facilities;
- Known CHP sites; or
- Steel mills.

Those boilers that used wood as a fuel were also excluded in this step, since these biomass fueled boilers are included in the state's renewable standard. A total of 228 boilers were excluded as a result of Step 3.

Step 4: Sort Out Non-CHP Candidates Based on Usage—Next, the CHP Team excluded most boilers that had one or more of the following concerns:

- Questionable data
- Low pressures (<150 PSI)
- Capacity factors less than 25 percent
- Consumed less than 50 MCF of natural gas (if capacity factor was unknown); and
- Fueled with wood (this was transferred to the Renewable Energy Subgroup for inclusion in their analysis.

A total of 431 boilers were excluded as a result of Step 4.

Step 5: Sort for Economic Suitability—The CHP Team conducted a "positive sort" to select boilers that were located at businesses thought to be likely to adopt CHP due to business factors, or due to prior feasibility studies known to members of the Team. Rejected boilers were moved to the "Excluded" worksheet. A total of 225 industrial boilers were kept. 160

Step 6: Conducted CHP Supply Analysis—Once a dataset was established of potential boilers that were established in suitably located facilities and businesses considered more likely adopters of CHP, the Team summarized key information. The CHP Team began to evaluate CHP electrical production potential. In this effort, it was assumed that natural gas boilers would be equipped with higher efficiency gas turbines, while boilers fueled with coal, oil, or other fuels would be equipped with steam turbines. It was further assumed that design megawatt (MW) capacity would exceed calculated output by 35 percent.

The estimated kilowatt-hours (kWh) of each category of boilers was then calculated at CHP "penetration rates" of 100 percent, 50 percent, and 27 percent. Effective heat rates and average MW/boiler estimates were also calculated for each category of boilers.

Estimates of additional CHP potential from three additional specific sources: new ethanol plants, steel mills, and cement kilns, were then added.

The CHP Team realizes each of these three sectors represent significant CHP potential, but the team was able to make only preliminary estimates of this potential, based upon prior knowledge of group members.

Annex F-2
ES-15a and ES-15b

EXPLANATORY NOTES:

NOTE 1:

<100 kV is handled under MPSC regulations/procedures at distribution level (Interconnection & Net-metering for smaller generators). Generally speaking generation systems less than 1 MW in size are connected at the distribution level. MPSC has been actively working with stakeholders on revising interconnection procedures and net-metering policy.

>100 kava and up is handled by MISO/FERC for regulations/procedures at the transmission level. Generally speaking, large generation is considered 20 MW or higher in size.

NOTE 2:

Siting new lines is difficult due to "not in my back yard" issues and the time involved to review and rule on regulatory siting cases. The cost of line construction along with the availability of transmission components are issues when attempting to build and repair transmission facilities, but they are not specifically issues related to siting or location/routes. The costs of transmission construction, cost recovery, and cost allocation currently fall under the jurisdiction of FERC and are addressed in various MISO forums.

Siting new lines can reduce carbon emissions by reducing transmission losses, increasing the efficiency of the flow of energy, and enabling cleaner renewable energy resources to reach the market. Reducing the barriers to constructing transmission in new corridors should be encouraged in order to encourage new industrial and commercial developments and renewable generation additions and expansions. Transmission is also key in connecting renewable resources to the grid, which will further reduce dependency on traditional fossil fuel generation, resulting in lower carbon emissions.

NOTE 3:

All of the stated energy initiatives are facilitated by a robust transmission system. For instance, transmission is essential in the integration of renewable resources that have a naturally variable component to the output at any one point in time. A perfect example is wind, which is variable and needs transmission to balance the variability for reliability purposes. Transmission also provides essential support for other initiatives, like CHP and Smart Grid. While both are implemented at the distribution level, the transmission system provides backup and demand response when those sources are not available. Like renewable generation sources, these programs can introduce some variability in load and generation balance. A robust transmission system maintains reliability in the face of this variability. Transmission also facilitates traditional and renewable sources of generation and provides a safe and reliable delivery system. The problems associated with the generator interconnection “queue process” must be addressed to move viable renewable projects and new fossil-fuel baseload projects through the queue more quickly. MISO has proposed measures to streamline this process with FERC and FERC has approved the proposals.

NOTE 4:

Cost allocation issues between states (in MISO footprint) and their respective regulatory processes, unique project situation, and market condition are factors that affect transmission planning and are an integral component of sound transmission planning.

NOTE 5:

Cost recovery and cost allocation issues of utilities and regional transmission organizations and the respective regulatory process, unique project situation, and market condition are factors that affect distribution system planning and are an integral component of sound project planning.