American Tradition Institute

The Cost and Economic Impact of Ohio's Alternative Energy Portfolio Standard

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Executive Summary

Ohio enacted its Alternative Energy Portfolio Standard (AEPS) legislation in May 2008. The law requires one-quarter of all electricity sales by Ohio utilities to come from "alternative energy" sources by the year 2025, with 12.5 percent required to come from sources identified as "renewable." While the law includes a provision cap electricity costs due to the mandate, it is unlikely that the cap would be breached due to its structure.

The American Tradition Institute commissioned the Beacon Hill Institute to apply its STAMP® (State Tax Analysis Modeling Program) to estimate the economic effects of the AEPS mandate. To account for excessively optimistic Energy Information Administration (EIA) measures of renewable electricity costs and capacity factors, we reviewed academic literature to provide three estimates of the cost of Ohio's AEPS mandates — low, average and high — using different cost and capacity factor estimates for electricity-generating technologies. Major cost findings include:

- The state's electricity consumers will pay $1.427 billion more for power in 2025, within a range of $262 million and $2.373 billion, because of the AEPS.
- Over the period of 2016 to 2025, Ohioans will pay an additional $8.629 billion over a baseline of no AEPS, within a range of $5.22 billion and $10.929 billion.
- Ohio's electricity prices in 2025 will increase by an average of 9.3 percent, within a range of 1.7 percent and 15.4 percent.

These increased energy prices will hurt Ohio's households and businesses and thus impair the state economy. According to the study, by 2025:

- Ohio will lose an average of 9,753 jobs, within a low-end estimate of 2,480 jobs and a high-end estimate of 15,523 jobs.
- The AEPS will reduce annual wages by an average of $334 per worker, within a range of $61 per worker and $556 per worker.
- Real disposable income will fall by $1.097 billion, within a range of $201 million and $1.824 billion.
- Net investment will fall by $79 million, within a range of $15 million and $132 million.
- The policy will cost families on average $123 per year, commercial businesses on average $867 per year, and industrial businesses on average $31,024 per year.
- From 2016 to 2025 the average household ratepayer will pay $756 in higher electricity costs; the average commercial ratepayer will pay an extra $5,350; and the average industrial ratepayer an extra $191,490.

Introduction

Beginning in May 2008, with the passage of Senate Bill 221, Ohio lawmakers began to dictate the generation technologies that utilities must use to produce the electricity sold in the state. The state passed an Alternative Energy Portfolio Standard (AEPS) that included a Renewable Portfolio Standard (RPS) and an Advanced Energy Sources (AES) requirement.

The RPS requires an increasing share of all retail electricity sold in Ohio to come from renewable sources, including solar, wind, biomass, geothermal, solid waste and hydroelectric facilities. Specifically, the law requires that beginning in 2009 at least 0.25 percent of all retail electricity sales derive from a renewable source. The share increases each year until it reaches 12.5 percent in 2025.[1] The RPS includes a provision requiring 0.5 percent of Ohio's total electricity supply derive from solar energy.[2] Moreover, half of all renewable energy production under the mandate, including solar, must be located in the state of Ohio.

The AES calls for an equal share of energy to be produced by 'Advanced Energy Sources', as has to be produced by the RPS, or 12.5 percent by 2025. AES are defined as nuclear, clean coal, fuel cells, any modification to current electric generating facilities that increases output but not emissions and demand side management practices. The AES does not contain any intermediate benchmarks prior to 2025.

The law includes cost containment provisions. Should a utility determine that their cost to comply with the AEPS would raise the price of electricity to all consumers by more than 3 percent, the utility can petition the Ohio Public Utility Commission (PUC) for a waiver. The AEPS also contains a force majeure provision that allows for non-compliance if circumstances are beyond the control of the utility. The law specifically places the burden of proof on the utility, to prove that after subtracting "unavoidable surcharge for construction or environmental expenditures of generation," the cost of generating electricity under the AEPS will be 3 percent more than without complying with the mandate.[3] However, since the law contains annual increases in the mandate, it allows the electricity costs due to the mandate to rise by 3 percent per year. Thus, the provision effectively allows electricity prices to rise by 60.5 percent between 2008 and 2025 due to the AEPS compliance costs. Furthermore the cost cap excludes the "unavoidable surcharge" in the calculation of AEPS costs, but includes them in the calculation of the non-compliance cost scenario, in effect pushing down the cost of compliance. These two factors render the cost control components of the AEPS ineffective and meaningless.

Most renewable electricity sources are more costly and unreliable than conventional energy sources such as coal and natural gas, and stand little chance of commercial success in a

[1] Ibid.
[2] Ibid. Also U.S. Energy Information Administration. Ohio Renewable Energy Profile. http://www.eia.gov/cneaf/solar.renewables/page/state_profiles/ohio.html.
[3] Ibid.

competitive market. In response, producers of renewable energy seek to guarantee a market through legislation similar to the AEPS. But whatever the market offers in terms of renewable energy, it will always be limited. In order to keep the electricity grid in equilibrium, intermittent resources such as wind and solar power need reliable back-up sources. If the wind dies down, or blows too hard (which trips a shutdown mechanism in commercial windmills), another power source must be ramped up instantly.

Not unlike taxes, higher electricity prices produce negative effects on economic activity, since one is paying a higher price for electricity without an increase in the value of that electricity. Prosperity and economic growth depend upon access to reliable and competitively priced energy. Consumers will have limited opportunity to avoid these costs. For low-income consumers, these higher electricity prices will force difficult choices between energy and other necessities such as such as clothing and shelter.

In this report, the American Tradition Institute commissioned the Beacon Hill Institute (BHI) to estimate the costs of the AEPS mandate and the economic impact of the legislation on the state economy. To that end, BHI applied its STAMP® models (State Tax Analysis Modeling Program) to estimate the economic effects of the state AEPS mandate.

Results

A wide variety of cost estimates exist for renewable electricity sources. The U.S. Energy Information Administration (EIA), a division of the Department of Energy, provides estimates for the cost of conventional and renewable electricity generating technologies. A literature review shows that in most cases the EIA's projected costs are at the low end of the range of estimates while the EIA's capacity factor for wind to be at the high end of the range.[4] The EIA appears to overlook the actual experience of existing renewable electricity power plants.

In measuring the effects of the AEPS on the Ohio economy, we account for the effects of the RPS and AES. The RPS mandate increases by 0.25 percent per year until it reaches 12.5 percent in 2025, which we calculate the cost for each year from 2016 to 2025. The AES does not ramp up similarly; it simply requires 12.5 percent of all electricity be produced from advanced energy sources by 2025. Due to the costs and lead times associated with implementation of AES, such as clean coal and nuclear, we follow the letter of the law and assume that the generation units are completed in 2025, when the full 12.5 percent is implemented.[5] We also assume the AES mandate is satisfied through clean coal and nuclear power generation, since these are the only sources that can produce electricity in industrial quantities.

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[4] The capacity factor measures the ratio of electrical energy produced by a generating unit over a period of time to the electrical energy that could have been produced at 100 percent operation during the same period.

[5] Details on the methodology used can be found in the Appendix.

In light of the wide divergence in the costs and capacity factor estimates available for the different electricity generation technologies, we provide three estimates of the effects of Ohio AEPS mandate using low, average and high cost projections of both renewable and conventional generation technologies. Each estimate represents the change that will take place in the indicated variable against the assumption that the AEPS mandate would not be implemented. The Appendix details our methodology. Table 1 displays our estimates.

Table 1: The Cost of the AEPS Mandate on Ohio (2010 $)

Costs Estimates	**Low**	**Medium**	**High**
Total Net Cost in 2025 ($ m)	262	1,427	2,373
Total Net Cost 2016-2025 ($ m)	5,220	8,629	10,929
Electricity Price Increase in 2025 (cents per kWh)	0.18	0.97	1.61
Percentage Increase	1.7%	9.3%	15.4%
Economic Indicators			
Total Employment (jobs)	(2,480)	(9,753)	(15,523)
Gross Wage Rates ($ per Worker)	(61)	(334)	(556)
Investment ($ m)	(15)	(79)	(132)
Real Disposable Income ($ m)	(201)	(1,097)	(1,824)

The results for the low cost scenario are substantially lower than the other two. This divergence is primarily due to the EIA's projections that costs of nuclear and clean coal will fall dramatically over the next 15 years. See Table 5 in the Appendix. The AEPS will impose costs of $1.427 billion in 2025, within a range of $262 million and $2.373 billion. For the period of 2016 – 2025 the AEPS mandate will cost $8.629 billion, with a low estimate of $5.22 billion and a high estimate of $10.929 billion. As a result, the AEPS mandate will increase electricity prices by 0.97 cents per kilowatt-hour (kWh), or by 9.3 percent, within a range of 0.18 cents per kWh, or by 1.7 percent, and 1.61 cents per kWh, or by 15.4 percent.[6]

Upon full implementation, the AEPS law will reduce economic output in Ohio. Ratepayers will face higher electricity prices, which will increase the cost of living and the cost of doing business in the state. By 2025 Ohio will employ 9,753 fewer workers than without the AEPS policy, within an estimated range of 2,480 and 15,523 workers.

The decrease in labor demand — as seen in the job losses — will cause gross wages to fall. In 2025 the Ohio AEPS will reduce annual wages by $334 per worker, within a range of $61 and $556 per worker.

[6] We converted the aggregate cost of the RPS into a cost per-kWh by dividing the cost by the estimated total number of kWh sold for that year. For example, for 2025 under the average cost scenario above, we divided $1,427 million into 147,058 million kWhs for a cost of 0.97 cents per kWh.

The job losses and price increases will reduce real incomes as firms, households and governments are forced to allocate more resources to purchase electricity and less to purchase other items. In 2025 annual real disposable income will fall by $1.097 billion, within a range of $201 million and $1.824 billion under our low and high cost scenarios respectively.

Net investment will fall by $79 million in 2025, within a range of $15 million and $132 million. The relatively moderate investment losses will be offset by the investments required to build renewable power plants, transmission lines and reconfigurations to the electricity grid. However, these investments are not as productive as the ones based on conventional energy because the renewable mandate works its way through the production methods less efficiently. A good analogy would be applying a mandate to telecommunications. An AEPS is akin to requiring that 25 percent of all Internet access to comprise of dial-up service over telephone service lines. Business would indeed be good for dial-up modem manufacturers, and Internet Service Providers would need to retrofit their networks, but this investment would not increase productivity in the economy.

Table 2 shows how the AEPS will affect the annual electricity bills of households and businesses in Ohio. In 2025 the AEPS will cost families on average $123 per year; commercial businesses on average of $867 per year; and industrial businesses on average $31,024 per year. Between 2016 and 2025 the average household ratepayer will pay $756 in higher electricity costs; the average commercial ratepayer will spend an extra $5,350; and the average industrial ratepayer an extra $191,490.

Table 2: Effects of the AEPS on Electricity Ratepayers (2010 $)

Cost in 2025	**Low**	**Medium**	**High**
Residential Ratepayer ($)	22	123	204
Commercial Ratepayer ($)	159	867	1,441
Industrial Ratepayer ($)	5,695	31,024	51,596
Total over period (2016-2025)			
Residential Ratepayer ($)	402	756	1,013
Commercial Ratepayer ($)	2,841	5,350	7,166
Industrial Ratepayer ($)	101,685	191,490	256,507

One could justify the higher electricity costs if the environmental benefits, in terms of reduced GHG emissions, outweighed the costs. But it is unclear that the use of renewable energy resources, especially wind and solar, significantly reduces GHG emissions. Due to their intermittency, wind and solar require significant backup power sources that are cycled up and down to accommodate the variability in their production. As a result, wind power could actually increase pollution and greenhouse gas emissions, according to a recent study.[7] Thus the case for the heavy use of wind to generate "cleaner" electricity is undermined.

[7] See "How Less Became More: Wind, Power and Unintended Consequences in the Colorado Energy Market," BENTEK Energy, LLC. (Evergreen Colorado: May, 2010).

Conclusion

The rush to renewable energy found in AEPS mandates in states across the nation is flawed. The policy promotes certain forms of renewable energy — expensive ones — at the cost of other, more affordable and dependable sources. The Ohio law is no different. On the surface, the cost caps included in the Ohio law appear reasonable. However, a detailed examination reveals that the cost cap provision will allow Ohio's electricity prices to rise by 65.5 percent due to the AEPS. The cost caps will not protect electricity ratepayers from higher utility prices or the state economy from employment losses, diminished investment, and lower incomes. Moreover, the environmental benefits of wind and solar power are illusionary since both forms of energy require readily available backup power generation sources.

The Ohio AEPS law requires the state's Public Utilities Commission to file an annual compliance report that includes a section pertaining to "any strategy for utility and company compliance or for encouraging the use of alternative energy resources in supplying this state's electricity needs in a manner that considers available technology, costs, job creation, and economic impacts."[8] The evidence presented in this report shows that the impacts are decidedly negative.

The Ohio AEPS puts the state's competitiveness at risk. These costs will result in slower economic growth for Ohio in the future, and it will fall behind competitor states. Policymakers should pay careful attention to the real dangers posed by higher electricity prices and repeal the mandate at the first opportunity. At the very least, lawmakers should amend the law to require the PUC annual compliance report to include a cost/benefit analysis section.

[8] Ohio Revised Code, Title [49] XLIX PUBLIC UTILITIES, » Chapter 4928: COMPETITIVE RETAIL ELECTRIC SERVICE, paragraph D1, http://codes.ohio.gov/orc/4928.64 (accessed February 15, 2011).

Appendix

Electricity Generation Costs

As noted above, governments enact Renewable Portfolio Standard policies because most sources of renewable electricity generation are less efficient and thus more costly than conventional sources of generation. The RPS policy forces utilities to buy electricity from renewable sources and thus guarantees a market for the renewable source. These higher costs get passed on to all electricity consumers: residential, commercial and industrial.

The U.S. Department of Energy's Energy Information Administration (EIA) estimates the Levelized Energy Cost (LEC), or financial breakeven cost per MWh, to produce new electricity in its *Annual Energy Outlook*.[9] The EIA provides LEC estimates for conventional and renewable electricity technologies (coal, nuclear geothermal, landfill gas, solar photovoltaic, wind and biomass) assuming the new sources enter service in 2016. The EIA also provides LEC estimates for conventional coal, combined cycle gas, advanced nuclear and onshore wind only, assuming the sources enter service in 2020 and 2035.

While the EIA does not provide LEC for hydroelectric, solar photovoltaic and biomass for 2020 and 2035, it does project overnight capital costs for 2015, 2025 and 2035. We can estimate the LEC for these technologies and years using the percent change in capital costs to inflate the 2016 LECs. In its *Annual Energy Outlook*, the EIA incorporates many assumptions about the future price of capital, materials, fossil fuels, maintenance and capacity factor into their forecast. Table 3 on the following page shows over time the EIA projects that the LEC for all four electricity sources (coal, gas, nuclear and wind) fall significantly from 2016 to 2035. The fall in capital costs drives the drop in total system LEC over the period.

The EIA estimates that wind generation will benefit from lower transmission and maintenance costs. EIA forecasts that transmission costs for wind will drop from $8.4 per MWh in 2016 to $5.6 per MWh, or by 33 percent, between 2020 and 2035. Fixed operations and maintenance costs will drop from $11.4 per MWh to $8.9 per MWh, or by 22 percent, over the same period. The drop in capital, maintenance and transmission costs combine to reduce wind power cost from $149.3 per MWh to $78.9 per MWh, or by an astounding 47.2 percent over the period. By 2035, wind would become the third least expensive behind biomass and natural gas.

[9] U.S. Department of Energy, Energy Information Administration, *2016 Levelized Cost of New Generation Resources from the Annual Energy Outlook 2010* (2008/$MWh), http://www.eia.doe.gov/oiaf/aeo/electricity_generation.html (accessed September 20, 2010).

Table 3: Levelized Cost of Electricity from Conventional and Renewable Sources (2008 $)

Plant Type	Capacity Factor	Levelized Capital Costs	Fixed O&M	Variable O&M (with fuel)	Transmission Investment	Total Levelized Cost
Advanced Coal - 2016	0.850	81.2	5.3	20.4	3.6	110.5
2020		77.1	5.3	19.6	3.6	105.6
2035		55.9	5.3	20.2	3.5	84.9
Gas - 2016	0.870	22.9	1.7	54.9	3.6	83.1
2020		21.4	1.6	53.7	3.6	80.3
2035		15.6	1.6	54	3.7	74.9
Nuclear -2016	0.900	94.9	11.7	9.4	3.0	119.0
2020		86.9	11.7	9.9	3.0	111.5
2035		60.9	11.7	11.6	3.0	87.2
Wind - 2016	0.344	130.5	10.4	0.0	8.4	149.3
2020		81.6	8.9	0.0	5.6	96.1
2035		64.4	8.9	0.0	5.6	78.9
Solar PV - 2016	0.217	376.8	6.4	0.0	13.0	396.1
2025						297.7
2035						208.6
Biomass -2016	0.830	73.3	9.1	24.9	3.8	111.1
2025						62.8
2035						47.5
Hydro -2016	0.514	103.7	3.5	7.1	5.7	119.9
2025						101.3
2035						83.4

Using the EIA change in overnight capital costs for solar and biomass produces reductions in LECs similar to wind from 2016 to 2035. The biomass LEC drops by 57.3 percent and solar by 47.3 percent over the period. These compare to much more modest cost reductions of 23.1 percent for coal, 9.9 percent for gas, and 26.7 percent for nuclear over the same period. EIA does provide overnight capital costs for renewable technologies under a "high cost" scenario. However, for each renewable technology the EIA "high cost" scenario projects capital costs to drop between 2015 and 2035.

Moreover the building of vast wind power plants will require large quantities of raw materials, particularly aluminum and other commodities. The rising demand for these commodities – from the construction of renewable energy plants and from fast growing emerging market economies – will certainly increase their prices and therefore costs for wind power plants. Aluminum prices have doubled over the past two years as the world economy struggles to emerge from the recession.[10] As a result capital and other costs are more likely to rise than fall over the next two decades.

Table 3 also displays capacity factors for each technology. The capacity factor measures the ratio of electrical energy produced by a generating unit over a period of time to the electrical energy that could have been produced at 100 percent operation during the same period. In this case, the capacity factor measures the potential productivity of the generating technology. Solar, wind and hydroelectricity have the lowest capacity factors due to the intermittent nature of their power sources. EIA projects a 34.4 percent capacity factor for wind power, which, as we will see below, appears to be at the high end of any range of estimates.

Estimating a capacity factor for wind power is particularly challenging. Wind is not only intermittent but its variation is unpredictable, making it impossible to dispatch to the grid with any certainty. This unique feature of wind power argues for a capacity factor rating of close to zero. Nevertheless, wind capacity factors have been estimated to be between 20 percent and 40 percent.[11] The other variables that affect the capacity factor of wind are the quality and consistency of the wind and the size and technology of the wind turbines deployed. As the U.S. and other countries add more wind power over time, presumably the wind turbine technology will improve, but the new locations for wind power plants will likely have diminishing or less productive wind resources.

The EIA estimates of LEC and capacity factors paint a particularly rosy view of the future cost of renewable electricity generation, particularly wind. Other forecasters and the experience of current renewable energy projects portray a less sanguine outlook.

Today wind and biomass are the largest renewable power sources and are the most likely to satisfy future RPS mandates. The most prominent issues that will affect the future availability and cost of renewable electricity resources are diminishing marginal returns and competition for scarce resources. These issues will affect wind and biomass in different ways as state RPS mandates ratchet up over the next decade.

Both wind and biomass resources face land use issues. Conventional energy plants can be built within a space of several acres and can be located close to large population centers with high electricity demand. However, a wind power plant with the same nameplate capacity (not actual capacity) would require many square miles of land. According to one study, wind power would require 7,579 miles of mountain ridgeline to satisfy current state RPS mandates

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[10] MetalPrices.com, "LME Aluminum Price Charts," http://www.metalprices.com/FreeSite/metals/al/al.asp#MoreCharts (accessed January 2011).

[11] Renewable Energy Research Laboratory, University of Massachusetts at Amherst, "Wind Power, Capacity Factor and Intermittency: What Happens When the Wind Doesn't Blow?" Community Wind Power Fact Sheet #2a, http://www.ceere.org/rerl/about_wind/RERL_Fact_Sheet_2a_Capacity_Factor.pdf (accessed December, 2010).

and a 20 percent federal mandate by 2025.[12] Mountain ridgelines produce the most promising locations for electric wind production in the eastern and far western United States.

After taking into account capacity factors, a wind power plant would need a land mass of 20 by 25 kilometers to produce the same energy as a nuclear power plant that can be situated on 500 square meters.[13]

The need for large areas of land for situating wind power plants will require the purchase of vast areas of land by private wind developers and/or allowing wind production on public lands. In either case land acquisition/rent or public permitting processes will likely increase costs as wind power plants are built. Offshore wind is vastly more expensive than onshore wind power and suffers from the same type of permitting process faced by onshore wind power plants, as seen in the 10-year permitting process for the planned Cape Wind project off the coast of Massachusetts.

The swift expansion of wind power will also suffer from diminishing marginal returns as new wind capacity will be located in areas with lower and less consistent wind speeds. As a result, fewer megawatt hours of power will be produced from newly-built windmills. Moreover the new wind capacity will be developed in increasing remote areas that will require larger investments in transmission and distribution, which will drive costs even higher.

The EIA estimates of the average capacity factor used for onshore wind power plants, at 34.4 percent, appears to be at the higher end of the estimates for current wind projects. This figure is inconsistent with estimates from other studies.[14] According to the EIA's own reporting from 137 current wind power plants in 2003, the average capacity factor was 26.9 percent.[15] In addition, a recent analysis of wind capacity factors around the world finds an actual average capacity factor of 21 percent.[16] Moreover, other estimates find capacity factors in the mid teens and as low as 13 percent.[17]

Biomass is a more promising renewable power source. Biomass combines low incremental costs relative to other renewable technologies and reliability. Biomass is not intermittent and therefore it is distributable with a capacity factor that is competitive with conventional energy

[12] Tom Hewson and Dave Pressman, "Renewable Overload: Waxman-Markey RES Creates Land-use Dilemmas," *Public Utilities Fortnightly* 61 (August 1, 2009).
[13] "Evidence to the House of Lords Economic Affairs Committee Inquiry into 'The Economics of Renewable Energy'," Memorandum by Dr. Phillip Bratby, May 15, 2008.
[14] Nicolas Boccard, "Capacity Factors for Wind Power: Realized Values vs. Estimates," *Energy Policy* 37, no. 7 (July 2009): 2680.
[15] Cited by Tom Hewson, Energy Venture Analysis, "Testimony for East Haven Windfarm," January 1, 2005, http://www.windaction.org/documents/720 (accessed December 2010).
[16] Boccard.
[17] See "The Capacity Factor of Wind, Lightbucket," http://lightbucket.wordpress.com/2008/03/13/the-capacity-factor-of-wind-power/, (accessed December 22, 2010) and National Wind Watch, FAQ, http://www.wind-watch.org/faq-output.php (accessed December 2010).

sources. Moreover biomass plants can be located close to urban areas with high electricity demand. But biomass electricity suffers from land use issues even more so than wind.

The expansion of biomass power plants will require huge additional sources of fuel. Wood and wood waste comprise the largest source of biomass energy today. Other sources of biomass include food crops, grassy and woody plants, residues from agriculture or forestry, oil-rich algae, and the organic component of municipal and industrial wastes.[18] Biomass power plants will compete directly with other sectors (construction, paper, furniture) of the economy for wood and food products and arable land.

One study estimates that 66 million acres of land would be required to provide enough fuel to satisfy the current state RPS mandates and a 20 percent federal RPS in 2025.[19] When the clearing of new farm and forestlands are figured into the GHG production of biomass, it is likely that biomass increases GHG emissions.

The competition for farm and forestry resources would not only cause biomass fuel prices to skyrocket, but also cause the prices of domestically-produced food, lumber, furniture and other products to rise. The recent experience of ethanol and its role in surging corn prices can be casually linked to the recent food riots in Mexico and the surge in hunger in the Darfur region of Sudan. These two examples serve as reminders of the unintended consequences of government mandates for biofuels. The lesson is clear: biofuels compete with food production and distort the market.

Calculation of the Net Cost of New Renewable Electricity

To calculate the cost of renewable energy under the AEPS, BHI used data from the Energy Information Administration (EIA), a division of the U.S. Department of Energy, to determine the percent increase in utility costs that Ohio residents and businesses would experience. This calculated percent change was then applied to calculated elasticities, as described in the STAMP modeling section.

We collected historical data on the retail electricity sales by sector from 1990 to 2008 and projected its growth through 2025 using its historical compound annual growth rate (3.6 percent).[20] To these totals, we applied the percentage of renewable sales prescribed by the Ohio AEPS. By 2025, renewable energy sources must account for 25 percent of total electricity sales in Ohio.

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[18] Biomass Energy Basics, National Renewable Energy Laboratory, Biomass Basics, http://www.nrel.gov/learning/re_biomass.html (accessed December, 2010).
[19] Hewson, 61.
[20] U.S. Department of Energy, Energy Information Administration, Ohio Electricity Profile 2010, "Table 5: Electric Power Industry Generation by Primary Energy Source, 1990 through 2008," http://www.eia.doe.gov/cneaf/electricity/st_profiles/Ohio.html. (accessed January 2011).

Next we projected the growth in renewable sources that would have taken place absent the AEPS. We used the EIA's projection of renewable energy sources by fuel for the East Central Area Reliability Coordination Agreement Power Area through 2025 as a proxy to grow renewable sources for Ohio. We used the growth rate of these projections to estimate Ohio's renewable generation through 2025 absent the AEPS.[21]

We subtracted our baseline projection of renewable sales from the AEPS-mandated quantity of sales for each year from 2016 to 2025 to obtain our estimate of the annual increase in renewable sales induced by the AEPS in megawatt hours (MWhs). The AEPS mandate exceeds our projected renewable in all projected years (2016 to 2025). This figure also represents the maximum number of MWhs of electricity from conventional sources that are avoided, or not generated, through the AEPS mandate. We will revisit this shortly. Table 4 contains the results.

Table 4: Projected Electricity Sales, Eligible Renewables and Required under RPS

Year	Projected Electricity Sales MWhs (000s)	Eligible Renewable MWhs (000s)	RPS Requirement MWhs (000s)	Difference MWhs (000s)
2016	140,878	756	6,340	5,584
2017	142,792	756	7,854	7,098
2018	144,691	756	9,405	8,649
2019	143,779	756	10,783	10,028
2020	142,862	756	12,143	11,388
2021	141,942	756	13,484	12,729
2022	143,232	756	15,039	14,284
2023	144,515	756	16,619	15,863
2024	145,790	756	18,224	17,468
2025	147,058	756	18,382	17,626
Total	1,437,539	7,558	128,274	120,716

To estimate the cost of producing the additional extra renewable energy under an AEPS against the baseline, we used estimates of the LEC, or financial breakeven cost per MWh to produce the electricity.[22] However, as outlined in the "electricity generation cost" section above, the EIA numbers provide a rather optimistic picture of the cost and generating capacity

[21] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2010,* "Table 92: Renewable Electricity Generation by Fuel," http://www.eia.doe.gov/oiaf/archive/aeo10/aeoref_tab.html (accessed January 2010).

[22] U.S. Department of Energy, Energy Information Administration**,** *2016 Levelized Cost of New Generation Resources from the Annual Energy Outlook 2010* (2008/$MWh), http://www.eia.doe.gov/oiaf/aeo/electricity_generation.html (accessed September 2010).

of renewable electricity, particularly for wind power. A literature review provided alternative LEC estimates that were generally higher and capacity factors that were lower for renewable generation technologies than the EIA estimates.[23] We used these alternative figures to calculate our "high" LEC estimates and the EIA figures to calculate our "low" cost estimates and the average of the two to calculate our "average" cost estimates. Table 5 displays the LEC and capacity factors for each generation technology.

Table 5: LEC and Capacity Factors for Electricity Generation Technologies

	Capacity Factor (percent)	Total Production Cost (cents/MWh) 2010	2020	2025
Coal				
Low	74.0	67.41	64.82	63.53
Average	79.5	83.96	85.21	79.39
High	85.0	100.50	105.60	95.25
Gas				
Low	85.0	75.86	73.25	73.25
Average	86.0	79.48	76.77	75.42
High	87.0	83.10	80.30	77.60
Nuclear				
Low	90.0	76.94	59.20	49.33
Average	90.0	97.97	85.35	74.34
High	90.0	119.00	111.50	99.35
Biomass				
Low	83.0	113.90	103.54	98.36
Average	75.5	112.50	95.27	80.62
High	68.0	111.10	86.99	62.88
Wind				
Low	34.4	287.67	269.54	251.40
Average	26.9	201.22	188.54	175.85
High	15.5	148.78	96.10	87.50

[23] For coal, gas and nuclear generation we used the production cost estimates from the International Energy Agencies, Energy Technology Analysis Programs, "Technology Brief E01: Cola Fired Power, E02: Gas Fired Power, E03: Nuclear Power and E05: Biomass for Heat and Power," (April 2010), http://www.etsap.org/E-techDS/ (accessed December 2010). To the production costs we added transmission costs from the EIA using the ratio of transmissions costs to total LEC costs. For wind power we used the IEA estimate for levelized capital costs and variable and fixed O & M costs. For transmission cost we used the estimated costs from several research studies that ranged from a low of $7.88 per kWh to a high of $146.77 per kWh, with an average of $60.32 per MWh. The sources are as follows:
Andrew Mills, Ryan Wiser, and Kevin Porter, "The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies," Ernest Orlando Lawrence Berkeley National Laboratory, http://eetd.lbl.gov/EA/EMP (accessed December 2010); Competitive Renewable Energy Zones (CREZ) Transmission Optimization Study, The Electric Reliability Council of Texas, April 2, 2008 http://www.ercot.com/news/presentations/2006/ATTCH_A_CREZ_Analysis_Report.pdf (accessed December 2010); Sally Maki and Ryan Pletka, Black & Veatch, California's Transmission Future, August 25, 2010, http://www.renewableenergyworld.com/rea/news/article/2010/08/californias-transmission-future (accessed December 22, 2010).

We used the 2016 LEC for the years 2010 through 2018 to calculate the cost of the new renewable electricity and avoided conventional electricity, assuming that before 2016 LEC underestimates the actual costs for those years and for 2017 and 2018, the 2016 LEC slightly overestimates the actual costs. We assumed that the differences would, on balance, offset each other. For 2019 and 2020 we used the 2020 LEC. The assumption is that LEC will decline over time due to technological improvements over time.

We use the EIA's reference case scenario for all technologies. Since capital costs represent the large component of the cost structure for most technologies, we used the percentage change in the capital costs from 2016 to 2025 to adjust the 2016 LECs to 2025. For the technologies that the EIA does not forecast LECs in 2020, we used the average of the 2016 and 2025 LEC calculations, assuming a linear change over the period.

Once we computed new LECs for the years 2020 and 2025 we applied these figures to the renewable energy estimates for the remainder of the period.

For conventional electricity we assumed that the technologies are avoided based on their costs, with the highest cost combustion turbine avoided first. For coal and gas, we assumed they are avoided based on their estimated proportion of total electric sales for each year. Although hydroelectric and nuclear are not the cheapest technology, we assume no hydroelectric or nuclear sources are displaced since most were built decades ago and offer relatively cheap and clean electricity today.

We also adjusted the avoided cost of conventional energy to account for the lower capacity factor of wind relative to conventional energy sources. We multiplied the cost of each conventional energy source by the difference between its capacity factor and the capacity factor for the renewable source, and then by the ratio of the new generation of the renewable source to the total new generation of renewable under the AEPS. For example, for coal, we multiplied the avoided amount generation of electricity from coal (15.102 million MWhs in 2025) by the LEC of coal ($79.39 per MWh) and then by one minus the difference between the capacity factor of coal and the weighted average (using MWs as weights) capacity factor of wind (27 percent). This process is repeated for each conventional electricity resource.

These LECs are applied to the amount of electricity supplied from renewable sources under the AEPS, because this figure represents the amount of conventional electricity generation capacity that presumably will not be needed under the AEPS. The difference between the cost of the new renewable sources and the costs of the conventional electricity generation Ohio represents the net cost of the AEPS. Tables 6, 7 and 8 on the following pages display the results of our Average, Low and High Cost calculations respectively.

We converted the aggregate cost of the AEPS into a cost per-kWh by dividing the cost by the estimated total number of kWh sold for that year. For example, in 2025 under the average cost scenario in Table 6, we divided $1.427 million into 147.058 million kWhs for a cost of 0.97 cents per kWh.

Table 6: Average Cost Case of RPS Mandate from 2016 to 2025

Year	Gross Cost (2010 $000s)	Less Conventional (2010 $000s)	Total (2010 $000s)
2016	640,053	159,736	480,317
2017	813,605	203,052	610,553
2018	991,433	247,433	744,001
2019	1,149,449	286,869	862,580
2020	1,036,689	321,571	715,118
2021	1,158,790	359,446	799,345
2022	1,300,342	403,353	896,988
2023	1,444,168	447,967	996,201
2024	1,590,240	493,277	1,096,963
2025	1,604,669	497,753	1,106,916
Total	**11,729,439**	**3,420,456**	**8,308,983**

Table 7: Low Cost Case of RPS Mandate from 2016 to 2025

Year	Gross Cost (2010 $000s)	Less Conventional (2010 $000s)	Total (2010 $000s)
2016	628,556	256,756	371,800
2017	798,991	326,379	472,612
2018	973,625	397,715	575,910
2019	1,128,802	461,104	667,699

2020	994,660	538,994	455,666
2021	1,111,811	602,476	509,335
2022	1,247,624	676,072	571,552
2023	1,385,620	750,850	634,770
2024	1,525,769	826,795	698,974
2025	1,539,614	834,297	705,316
Total	**11,335,073**	**5,671,438**	**5,663,634**

Table 8: High Cost Case of RPS Mandate from 2016 to 2025

Year	Gross Cost (2010 $000s)	Less Conventional (2010 $000s)	Total (2010 $000s)
2016	658,952	101,244	557,708
2017	837,629	128,698	708,931
2018	1,020,708	156,828	863,881
2019	1,183,390	181,823	1,001,567
2020	1,073,642	212,553	861,089
2021	1,200,096	237,588	962,508
2022	1,346,693	266,610	1,080,082
2023	1,495,646	296,099	1,199,547
2024	1,646,925	326,048	1,320,876
2025	1,661,869	329,007	1,332,862
Total	**12,125,550**	**2,236,499**	**9,889,051**

The Advanced Energy Source (AES) section of the law was calculated using a slightly different methodology. The law does not include a step-up requirement, unlike the RPS section, but does include a language requiring 12.5 percent of energy be produced by advanced energy sources by 2025. For this reason, we only considered costs that would be incurred in 2025, leading to our results being a minimum should AES be required prior to 2025.

Using Ohio Public Utility Commission estimates, energy sales in 2025 would be 145,790,000 MWh, meaning that 18,223,750 MWh of energy would need to come from advanced energy sources, as defined by the AEPS laws.[24] Due to the raw size of this requirement, we believe that the source will likely come from two types of power plants that the law specifically mentions: new nuclear power and clean coal.

Our assumption is that each advanced power source would account for 50 percent of the mandate, or 9,111,875 MWH. Applying the same cost per MWh methodology as used for the RPS, we determined the cost, in 2025 of the AES section of the AEPS law. This cost was combined with the calculated cost of the RPS, to determine the percentage increase in the cost of electricity, which was then used to determine the ratepayer and economic effects.

Ratepayer Effects

To calculate the effect of the AEPS on electricity ratepayers, we used EIA data on the average monthly electricity consumption by type of customer: residential, commercial and industrial.[25] The monthly figures were multiplied by 12 to compute an annual figure. We inflated the 2008 figures for each year using the average annual increase in electricity sales over the entire period.[26]

We calculated an annual per-kWh increase in electricity cost by dividing the total cost increase – calculated in the section above — by the total electricity sales for each year. We multiplied the per-kWh increase in electricity costs by the annual kWh consumption for each type of ratepayer for each year. For example, we expect the average residential ratepayer to consume 12,629 kWhs of electricity in 2025 and we expect the average cost scenario to raise electricity costs by 0.97 cents per kWh in the same year in our average cost case. Therefore, we expect residential ratepayers to pay an additional $123 in 2025.

Modeling the AEPS using STAMP

We simulated these changes in the STAMP model as a percentage price increase on electricity to measure the dynamic effects on the state economy. The model provides estimates of the

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[24] Ohio Public Utility Commission. Estimated Quantification of Statewide Compliance Obligations Associated with Renewable Energy Component of the Alternative Energy Portfolio Standard. http://www.puco.ohio.gov/emplibrary/files/util/EnergyEnvironment/SB221/aeps%20estimate.pdf

[25] U.S. Department of Energy, Energy Information Administration, "Average electricity consumption per residence in MT in 2008," (January 2010) http://www.eia.doe.gov/cneaf/electricity/esr/table5.html, The 2008 consumption figures were inflated to 2010 using the increase in electricity demand from the EIA of 0.89 percent compound annual growth rate.

[26] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2010*, "Table 8: Electricity Supply, Disposition, Prices, and Emissions," http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html. (accessed December 22, 2010).

proposals' impact on employment, wages and income. Each estimate represents the change that would take place in the indicated variable against a "baseline" assumption of the value that variable for a specified year in the absence of the AEPS policy.

Because the AEPS requires Ohio households and firms to use more expensive "advance" power than they otherwise would have under a baseline scenario, the cost of goods and services will increase under the AEPS. These costs would typically manifest through higher utility bills for all sectors of the economy. For this reason we selected the sales tax as the most fitting way to assess the impact of the AEPS. Standard economic theory shows that a price increase of a good or service leads to a decrease in overall consumption, and consequently a decrease in the production of that good or service. As producer output falls, the decrease in production results in a lower demand for capital and labor.

BHI utilized its STAMP (State Tax Analysis Modeling Program) model to identify the economic effects and understand how they operate through a state's economy. STAMP is a five-year dynamic CGE (computable general equilibrium) model that has been programmed to simulate changes in taxes, costs (general and sector-specific) and other economic inputs. As such, it provides a mathematical description of the economic relationships among producers, households, governments and the rest of the world. It is general in the sense that it takes all the important markets, such as the capital and labor markets, and flows into account. It is an equilibrium model because it assumes that demand equals supply in every market (goods and services, labor and capital). This equilibrium is achieved by allowing prices to adjust within the model. It is computable because it can be used to generate numeric solutions to concrete policy and tax changes.[27]

In order to estimate the economic effects of the AEPS we used a compilation of six STAMP models to garner the average effects across various state economies: New York, North Carolina, Washington, Kansas, Indiana and Pennsylvania. These models represent a wide variety in terms of geographic dispersion (Northeast, Southeast, Midwest, The Plains and West) economic structure (industrial, high-tech, service and agricultural) and electricity sector makeup.

First, we computed the percentage change to electricity prices as a result of three different possible AEPS policies. We used data from the EIA from the state electricity profiles, which contains historical data from 1990-2008 for retail sales by sector (residential, commercial, industrial, and transportation) in dollars and MWhs and average prices paid by each sector.[28] We inflated the sales data (dollars and MWhs) though 2020 using the historical growth rates

[27] For a clear introduction to CGE tax models, see John B. Shoven and John Whalley, "Applied General-Equilibrium Models of Taxation and International Trade: An Introduction and Survey," *Journal of Economic Literature* 22 (September, 1984): 1008. Shoven and Whalley have also written a useful book on the practice of CGE modeling entitled Applying General Equilibrium (Cambridge: Cambridge University Press, 1992).

[28] U.S. Department of Energy, Energy Information Administration, Ohio Electricity Profile 2010, Table 8: Retail Sales, Revenue, and Average Retail Price by Sector, 1990 through 2008, http://www.eia.doe.gov/cneaf/electricity/st_profiles/Ohio.html (accessed January 2011).

for each sector for each year. We then calculated a price for each sector by dividing the dollar value of the retails sales by kWhs. Then we calculated a weighted average kWh price for all sectors using MWhs of electricity sales for each sector as weights. To calculate the percentage electricity price increase we divided our estimated price increase by the weighted average price for each year. For example, in 2025 for our average cost case we divided our average price of 10.47 cents per kWh by our estimated price increase of 0.97 cents per kWh for a price increase of 9.26 percent.

Using these three different utility price increases – 1 percent, 4.5 percent and 5.25 percent – we simulated each of the six STAMP models to determine what outcome these utility price increases would have on each of the six state's economy. We then averaged the percent changes together to determine what the average effect of the three utility increases. Table 9 displays these elasticities, which were then applied to the calculated percent change in electricity costs for the state of Ohio discussed above.

Table 9: Elasticities for the Economic Variables

Economic Variable	Elasticity
Employment	-0.022
Gross wage rates	-0.063
Investment	-0.018
Disposable Income	-0.022

We applied the elasticities to percentage increase in electricity price and then applied the result to Ohio economic variables to determine the effect of the AEPS. These variables were gathered from the Bureau of Economic Analysis Regional and National Economic Accounts as well as the Bureau of Labor Statistics Current Employment Statistics.[29]

[29] See the following: Bureau of Economic Analysis, "National Economic Accounts," http://www.bea.gov/national/; Regional Economic Accounts, http://www.bea.gov/regional/index.htm. See also Bureau of Labor Statistics, "Current Employment Statistics ," http://www.bls.gov/ces/.

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