Synapse
Energy Economics, Inc.

Potential Impacts of a Renewable and Energy Efficiency Portfolio Standard in Kentucky

Prepared for the Mountain Association for Community Economic Development & the Kentucky Sustainable Energy Alliance

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1. Executive Summary

Legislation being introduced in the Kentucky General Assembly proposes to establish a Renewable and Energy Efficiency Portfolio Standard (REPS) for utilities in the state. The Mountain Association for Community Economic Development (MACED) and the Kentucky Sustainable Energy Alliance (KySEA) retained Synapse Energy Economics, Inc. (Synapse) to estimate the potential impacts of establishing such a standard. The study estimates the impacts of a REPS on Kentucky's portfolio of electricity resources, on average electric bills, and on the state's economy.

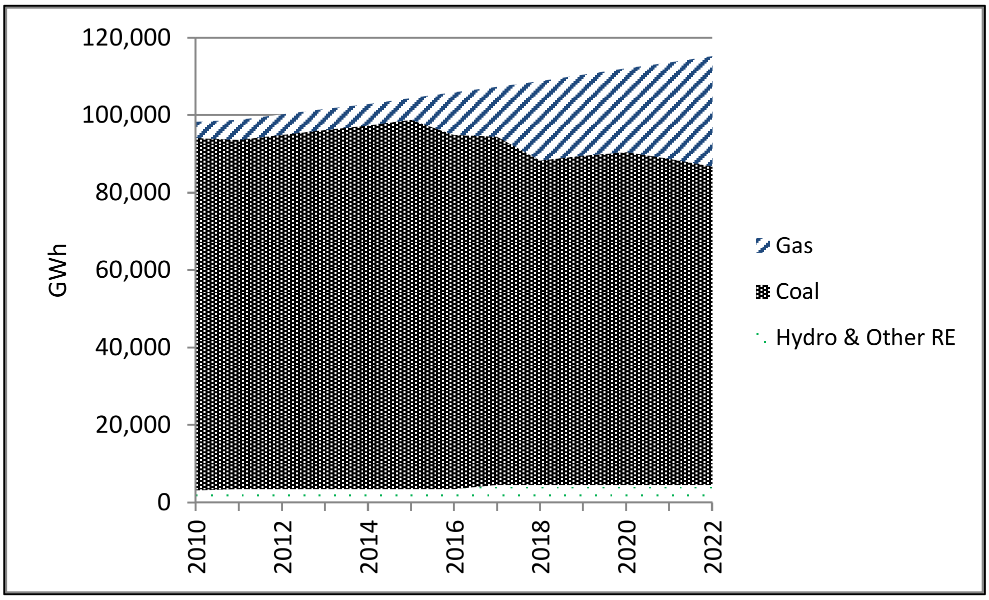
Proposed REPS. The study assumes the goals of the REPS would be to promote energy independence and security by diversifying the state's generating mix, stabilizing long-term energy prices, and creating high-quality jobs and business opportunities. It assumes the REPS would require all utilities in the state to meet specific portions of their retail load through energy efficiency (EE) and from renewable energy (RE) respectively. The assumed required cumulative reductions from EE begin at 0.25 percent in 2014 and increase to 10.25 percent of aggregate retail load by 2022. The assumed required cumulative portions of retail load to be met from RE begin at 2.25 percent in 2014 and increase to 12.5 percent by 2022.

Study Methodology. The study estimates various impacts of the proposed REPS over the ten year period 2013 – 2022 using a scenario approach. It then projects supply mix and average electric bills under a Business-as-Usual (BAU) scenario, i.e., a future without a REPS, and under a REPS scenario. The study develops the REPS scenario by estimating the cost of achieving the EE reductions and of acquiring the RE resources required under the REPS legislation. Finally, the study calculates the incremental impacts of the REPS scenario relative to the BAU scenario in terms of the state's electricity supply portfolio, average electric bills, and economic activity. All values are expressed in constant 2010$ unless noted otherwise.

The BAU scenario and the REPS scenario are based on a number of common assumptions. Both scenarios are based on the same projection of retail electric requirements excluding the effects of EE, which is an average annual rate of growth of 1.5% over the study period. Second, both are based on the same projections of electricity resource capital and operating costs, including projected long-term prices for coal and natural gas. Third, both scenarios assume Kentucky utilities will comply with new, more stringent regulations of various air emissions that are currently scheduled to take effect in 2016. Finally, both scenarios assume that carbon emissions from all generating units, both existing and new, will be subject to regulation beginning in 2018 at a cost per ton of $15 (2010$). Given the uncertainty regarding the timing and magnitude of future regulation of carbon, Appendix C of the study presents an estimate of the summary impacts of a REPS assuming no regulation of carbon in Kentucky until after 2022.

BAU scenario. Historically almost all of Kentucky's annual supply of electric energy has been coal-fired generation. For example, in 2010 Kentucky met over 92% of its annual retail electric requirements from coal-fired generation. The BAU scenario projects that coal-fired generation would decline but would continue to supply the majority of the state's annual electric energy requirements, as indicated in Figure 1-1. For example, the study projects that generation from coal would account for approximately 71% of the state's supply in 2022. The decline in coal-fired generation is due to generation from new gas-fired units projected to replace older coal units scheduled to retire starting 2016 and to meet load growth. Under the BAU scenario Kentucky utilities are projected to meet less than 5% of annual retail electric requirements from resources other than coal and natural gas.

Figure 1-1. BAU scenario annual electricity requirements and sources

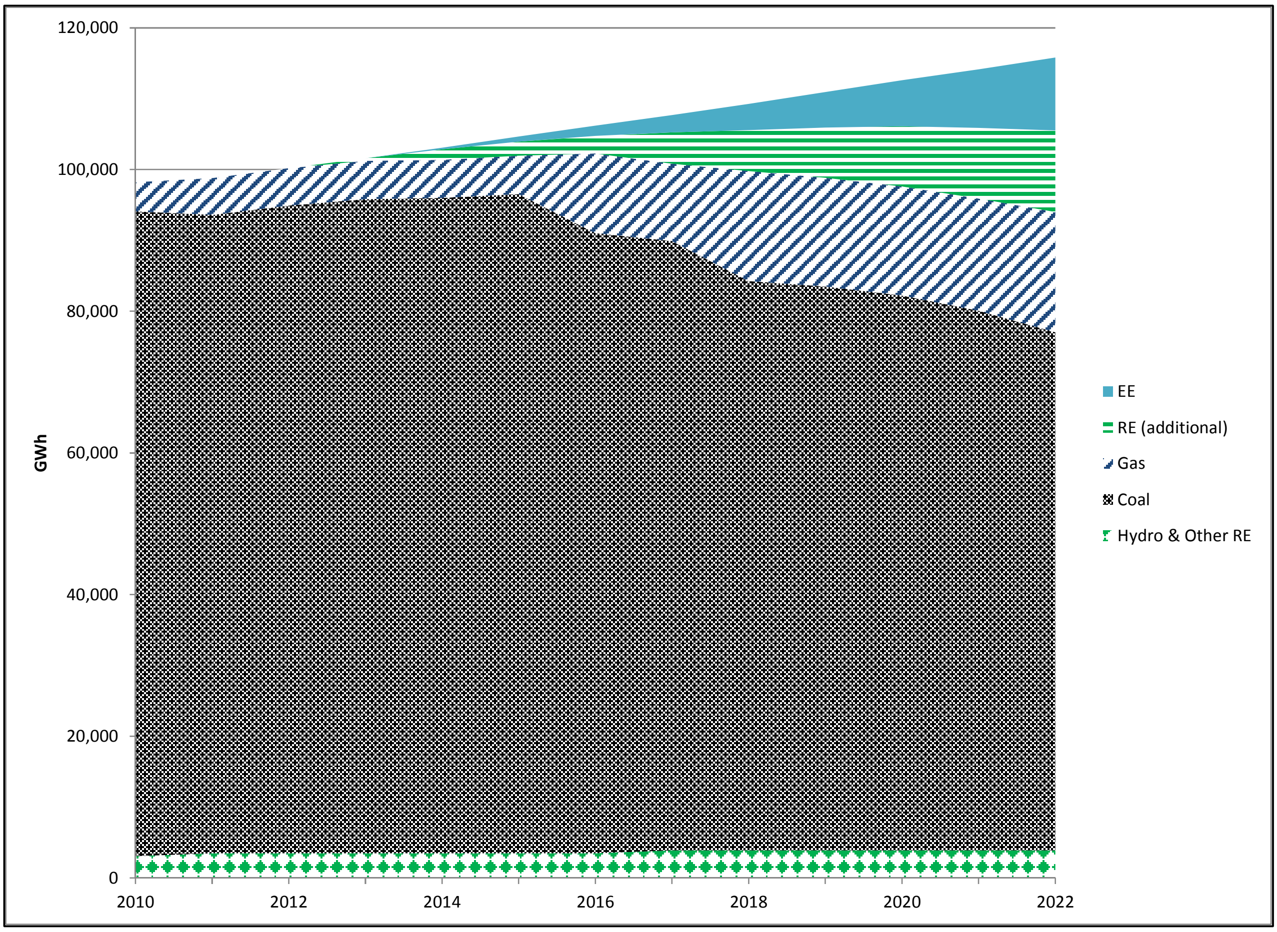


Average electricity prices and average electric bills are projected to increase substantially under the BAU, primarily due to the capacity costs of new gas-fired units and the higher costs of generation from those units (i.e., production costs). For example, the BAU scenario projects state-wide average residential bills would increase approximately 47 percent, in constant dollars, between 2010 and 2022.

The marginal, or avoided, cost of electricity under the BAU scenario is projected to double over the study period, from less than 4 cents/kWh in 2012 to approximately 9 cents/kWh by 2022. This increase is again attributable to the projected costs of adding and dispatching new gas-fired capacity as well as to the projected cost of complying with carbon regulation from 2018 onward.

REPS Scenario. The REPS scenario estimates the impacts of meeting total annual retail electricity requirements using greater levels of EE and RE than under the BAU scenario. The additional quantities of EE and RE would displace some of the generation from natural gas and coal projected under the BAU scenario. Under the REPS scenario, Kentucky would have a more diverse electricity resource portfolio, as illustrated in Figure 1-2. For example, the state's dependence on coal would decrease to approximately 63% of total annual requirements by 2022. This diversification of the state's generating mix has the potential to produce a number of benefits beyond those examined in this report, including mitigation of operational and financial risks.

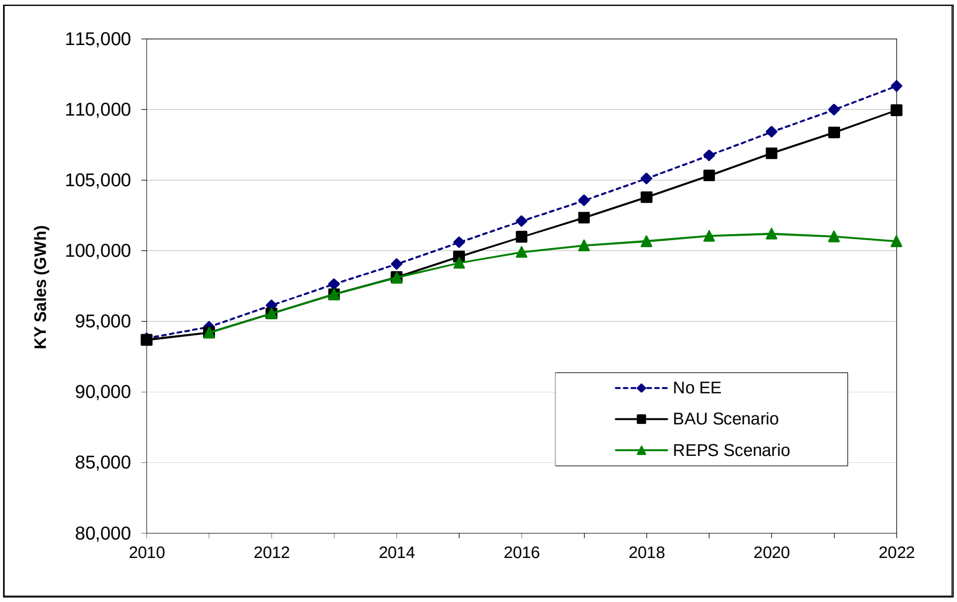
Figure 1-2. REPS scenario annual electricity requirements and sources



Additional EE reductions under REPS scenario. Our analyses project that, by 2015, cumulative reductions from EE required under a REPS would be large enough to offset incremental growth in annual electric sales. The potential for EE to flatten annual sales after 2015 is illustrated in Figure 1-3 (below).

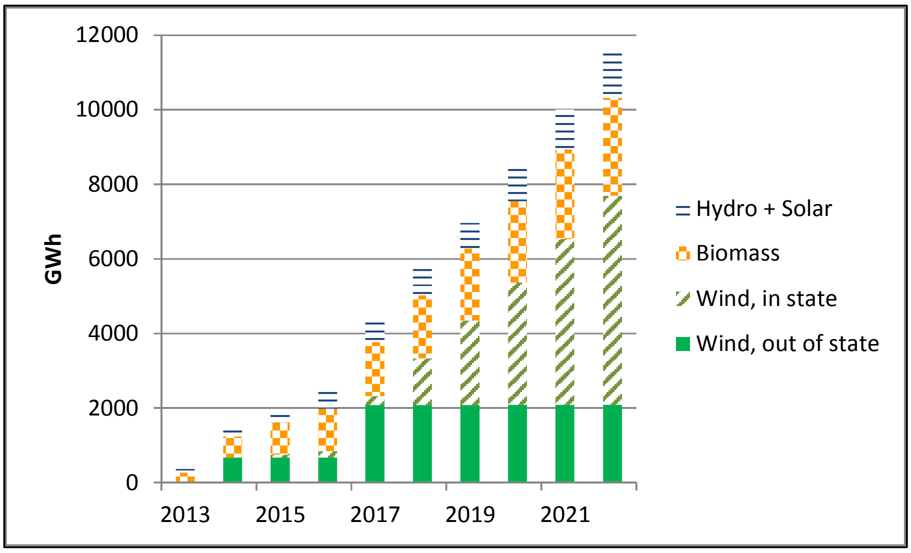
By capping annual retail sales, those EE reductions would reduce the quantity of new peaking capacity needed over the study period as well as reduce the quantity of annual generation required from new gas-fired plants. The study estimates these EE reductions could be achieved at levelized costs ranging between 3 cents/kWh and 4 cents/kWh, considerably less than the avoided costs projected under the BAU scenario.

Figure 1-3. Total annual sales without EE, BAU scenario, and REPS scenario



Additional RE generation under REPS scenario. The study projects that Kentucky could eventually acquire the majority of the additional RE generation required under the REPS scenario from in-state resources, primarily biomass and wind. The study projects that Kentucky utilities would acquire a portion of their required RE as wind energy imported from out-of-state, particularly during the initial years when in-state resources are being developed. The study assumes utilities would satisfy the solar RE requirement through a combination of solar water heating installations at customer sites and large-scale photovoltaic (PV) projects. Figure 1-4 illustrates the mix of projected additional RE sources.

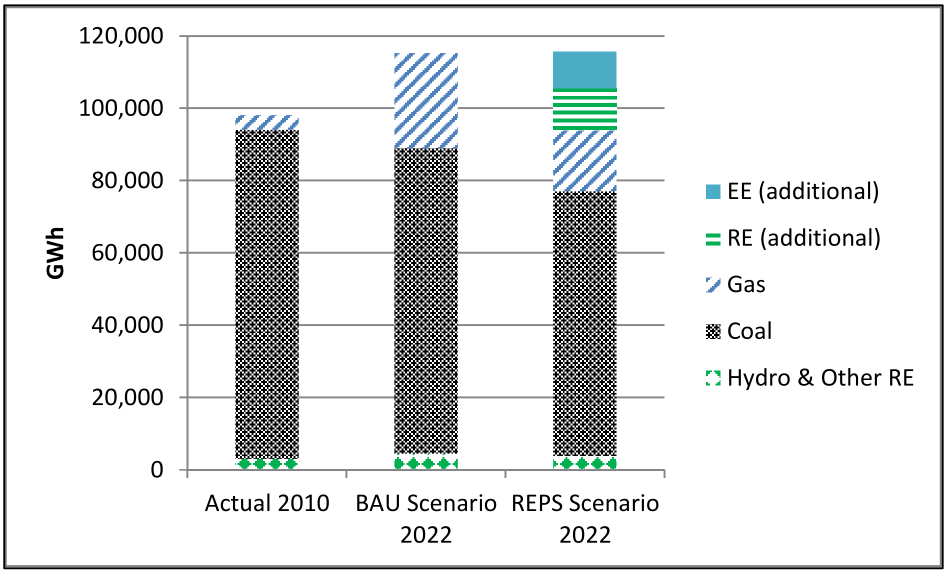
Figure 1-4. Mix of additional RE under REPS scenario



The cost of electricity from RE varies by RE resource and project scale. The study projects that the total cost of generation from new RE projects, i.e. capital plus variable production, will become increasingly competitive with generation from new natural gas units and existing coal units over time due to increases in the costs of carbon emissions and decreases in the costs of RE technologies.

Impact of REPS on Kentucky electricity resource portfolio. The study projects that the REPS would lead to a more diverse electricity resource portfolio. For example, by 2022 the state's utilities would be achieving reductions from EE equivalent to 10.2 percent of annual retail sales and acquiring generation from RE equivalent to 12.5 percent of annual sales. Those quantities of EE and RE would enable the state to reduce its dependence on generation from coal and natural gas for its total annual energy requirements in 2022 from 71 percent and 25 percent under the BAU scenario to 63 percent and 15 percent under the REPS scenario, as indicated in Figure 1-5. Kentucky would have 15% less emissions of carbon dioxide under the REPS scenario than under the BAU scenario as a result of these increased quantities of EE and RE.

Figure 1-5. Annual electricity requirements and sources in 2022 - REPS versus BAU



Impact of REPS on electric bills. The study indicates that the REPS would lead to lower electric bills over time. If one assumes no regulation of carbon in Kentucky until after 2022, our analyses indicate that a REPS would still lead to lower electric bills, although the savings would be less.

The study projects electric bills will increase under the REPS scenario, but by lesser amounts than under the BAU scenario. For example, the study projects annual bills will be approximately 8 to 10 percent lower under the REPS scenario in 2022 than under the BAU scenario, as indicated in Table 1-1. The lower average bills in that year are primarily due to the fact that, under the REPS scenario, retail customers are projected to use approximately 8 percent less electricity on average than under the BAU scenario due to reductions from EE. After 2022 the study projects that average bills would continue to be less under the REPS scenario, as the cost of electricity from

RE is projected to continue declining relative to the cost of electricity from coal-fired and natural gas generation.

Table 1-1. Annual electricity bills in 2022 - REPS versus BAU

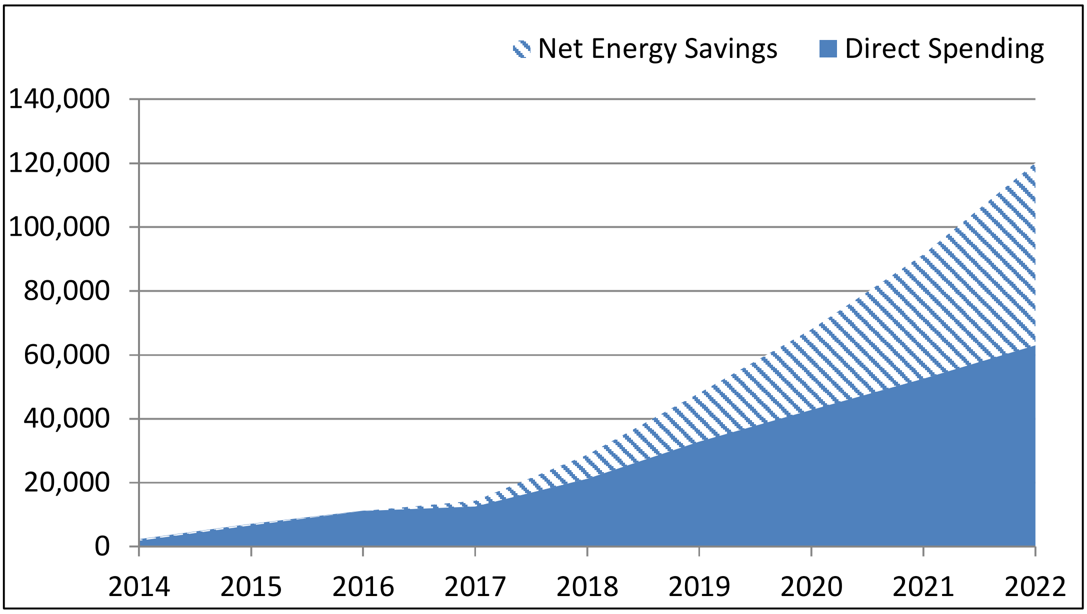
Average Electric Rates ($/kWh) (2010$)	2010	BAU Scenario 2022	REPS Scenario 2022	REPS Scenario vs BAU Scenario
Total (All Sectors)	$0.067	$0.101	$0.102	1%
Residential	$0.086	$0.120	$0.121	1%
Commercial	$0.079	$0.113	$0.114	1%
Industrial	$0.051	$0.085	$0.085	0%
Average Electric Bills ($) (2010$)	**2010**	**BAU Scenario 2022**	**REPS Scenario 2022**	**REPS Scenario vs BAU Scenario**
Residential	$1,249	$1,834	$1,657	-10%
Commercial	$5,198	$7,658	$7,067	-8%
Industrial	$325,409	$557,989	$513,178	-8%

Impact of REPS on Kentucky economy. The study estimates that a REPS would lead to a net increase in employment and business opportunities in Kentucky. In other words the expenditures on additional reductions from EE and additional RE generation required under a REPS would create more economic activity and employment in Kentucky than the electric generation from coal and natural gas that the additional EE and RE would displace. If one assumes no regulation of carbon in Kentucky until after 2022, our analyses indicate that a REPS would still lead to a net increase in employment and business opportunities in Kentucky, although those net increases would be somewhat smaller.

Complying with the EE targets will require expenditures on materials and equipment to improve the efficiency of residences, businesses, and factories, while complying with the RE targets will require expenditures on construction and operation of RE projects. The net positive impact of these expenditures is attributable to three major factors. First, the portion of total expenditures that would remain in Kentucky is projected to be higher for EE and RE than for generation from coal and natural gas. Second, the EE and RE projects are expected to be more labor-intensive than generation from coal and natural gas, and thus are projected to create more jobs per dollar spent. Finally, the additional quantities of EE and RE are projected to result in lower electric bills over time, leaving Kentuckians with more discretionary income available to spend on other goods and services, which in turn would produce additional economic impacts.

The study projects a REPS would create over 28,000 net additional job-years in Kentucky by 2022. (Employment impacts are in job-years since the duration of some jobs is limited, e.g. a RE construction project, while the duration of other jobs is longer-term, e.g. programs to install EE measures). The major sources of these incremental job-years are capital and operating expenditures on EE measures and RE facilities ($159 million in 2022) as well as electric customer spending of the amounts they saved on their electric bills, i.e., spending of their net energy savings from energy efficiency ($970 million in 2022). Figure 1-6 presents the projected cumulative net job-year impacts in Kentucky.

Figure 1-6. Cumulative net job-year impacts in Kentucky from a REPS



The study projects the net incremental impacts of a REPS on Kentucky by 2022 would include an increase in personal income of nearly $1 billion and an increase in Gross State Product of $1.5 billion. Those projections are reported in Table 1-2.

Table 1-2. Annual net economic impacts in Kentucky from a REPS

Economic Impacts	2017	2020	2022	Cumulative Total
Job-years	3,190	19,958	28,539	***120,140***
Personal Income (2010$ millions)	$119	$765	$1,088	***$4,634***
Gross State Product (2010$ millions)	$118	$1,004	$1,474	***$6,038***

2. Introduction

Kentucky has historically relied upon coal from mines in the state for the majority of its electricity generation. For example, in 2010 over 92% of the state's electricity production was from coal-fired generation, with approximately 67% of the coal used to generate that electricity produced in Kentucky.[1,2] Over the past several years various reports have identified energy efficiency and renewable energy as resources that could help Kentucky diversify its electricity supply portfolio, control its future electricity costs, and create jobs for Kentuckians.

Legislation being introduced in the Kentucky General Assembly proposes to establish a Renewable and Energy Efficiency Portfolio Standard (REPS). The expected goals of the legislation would be to:

1) Promote energy independence and security by diversifying the portfolio of energy sources used for generating electricity for Kentucky electric customers;
2) Stabilize long-term energy prices and encourage economic growth; and
3) Create high-quality jobs, training, business, and investment opportunities in the Kentucky energy sector.

This study assumes that the legislation would be designed to achieve those three goals by requiring all utilities in the state to meet specific portions of their retail load through reductions from EE and generation from RE, respectively. The study assumes required cumulative reductions from EE would begin at 0.25 percent in 2014 and increase to 10.25 percent of aggregate retail load by 2022. It assumes the required cumulative portions of retail load to be met from RE would begin at 2.25 percent in 2014 and increase to 12.5 percent by 2022.

Diversifying the state's generating mix through development of additional EE and RE has the potential to produce a number of benefits beyond those examined in this report, including mitigation of operational and financial risks. The benefits of meeting future electricity requirements through a diverse mix of cost-effective resources, including EE and new RE, in addition to traditional supply side resources have been recognized for several years at both the federal and state level, for example the Energy Policy Act of 2005 (EPAct) and *Intelligent Energy Choices for Kentucky's Future*.[3] [4]

MACED and KySEA retained Synapse to estimate the potential impacts of establishing a REPS. Synapse provides research, testimony, reports, and regulatory support on electric industry regulatory and environmental issues to consumer advocates, environmental organizations, regulatory agencies and energy offices at the state and federal level throughout the United States. For example, the American Council for an Energy Efficient Economy (ACEEE) has relied upon

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1 EIA state energy profile for Kentucky and EIA *Electric Power Monthly*
2 Synapse analysis of EIA coal statistics, report DOE/EIA-0584(2009) updated February 3, 2011
3 EPAct 2005 Title XII Electricity, Subtitle E, Amendments to PURPA §1251(a)

4 Beshear, Steven L. and Peters, Leonard, Intelligent Energy Choices for Kentucky's Future, Kentucky Energy and Environment Cabinet, November 2008

Synapse estimates of avoided electricity costs for its clean energy studies of Ohio, North Carolina, South Carolina, Arkansas, Virginia, and Pennsylvania.

The study provides an initial quantitative estimate of the approximate magnitude and direction, i.e., positive or negative, of several key impacts of the proposed REPS. The study estimates these in terms of state-wide impacts measured relative to a future without a REPS. Thus, the study is providing high level projections recognizing that the specific impacts of a REPS will vary by utility. Analyzing the impact of a REPS on individual or specific Kentucky utilities was beyond the scope of work of this study. The study estimates the impact of a REPS on Kentucky using state-wide data augmented by utility-specific data and projections where relevant and public. It estimates these impacts using a methodology that other parties could use to estimate the impacts of a REPS on individual Kentucky utilities.

A. Kentucky Electricity Market

Kentucky is served by more than 50 retail electricity service providers and has a complex wholesale electricity market. According to statistics from the United States Energy Information Administration (EIA), in 2009 Kentucky was served by 58 retail providers consisting of four investor-owned utilities (IOUs) and 54 cooperatives and public entities. The four IOUs, i.e., Louisville Gas and Electric (LG&E), Kentucky Utilities (KU), Duke Energy Kentucky, and Kentucky Power, accounted for about half of the state's electricity sales in that year, and about half of the in-state generation. The cooperatives and public entities accounted for the remaining sales and in-state generation.

Historically the annual quantity of electricity generated in Kentucky has closely matched the state's annual retail sales. According to EIA statistics the state has been a small net exporter of power.

Almost all of the in-state generation has been from coal units and approximately 67% of the coal those units consumed to generate that electricity was produced in Kentucky. In contrast, Kentucky's electric sector is not the dominant market for coal produced in Kentucky, accounting for only approximately 26% of the state's annual coal production. The majority of coal mined in Kentucky, approximately 74%, is sold to out-of-state markets and to Kentucky's industrial sector.[5]

The state's utilities appear to have limited potential to sell, or buy, power in the inter-state market. Most retail electric service providers in Kentucky are not currently members of the major wholesale electricity markets operated by the Mid-West Independent System Operator (MISO) or PJM. The potential to export or import power is subject to the availability of adequate transmission, with the existing major inter-state transmission lines in Kentucky running primarily north and south.

B. Study approach

The purpose of the study is to estimate the impacts of a REPS for a given set of explicit assumptions about the future. The study estimates the state-wide average impacts of a REPS on Kentucky's portfolio of electricity resources, on average electric bills, and on the state's economy over a ten year period, 2013 to 2022. It uses a scenario approach to estimate these impacts. As

[5] ibid.

such the study provides a “what if” analysis rather than a detailed forecast of Kentucky’s electricity supply.

The study developed its estimates of these impacts in the following major steps:

- Develop common assumptions applicable to both the BAU scenario and the REPS scenario, including assumptions regarding electricity resource costs and environmental regulations based upon national trends;
- Develop projections for the BAU scenario including future retail electric requirements, electric supply, average rates, and average bills. These projections are based upon Kentucky electric sector statistics and public planning documents of Kentucky utilities;
- Develop projections for the REPS scenario including future retail electric requirements, electric supply, average rates, and average bills. To develop the REPS scenario the study estimates the cost of achieving the EE reductions and RE generation required under the REPS legislation. These estimates draw upon prior reports that have addressed the potential impact of increasing reliance on EE and RE in Kentucky as well as the most recent estimates of EE and RE potential and costs relevant to Kentucky; and
- Calculate the incremental impacts of the REPS scenario relative to the BAU scenario on Kentucky’s portfolio of electricity resources, on state-wide average electric bills, and on the state’s economy.

As with every forecast, the projections for the BAU and REPS scenarios are subject to uncertainty because the key assumptions underlying those projections are subject to uncertainty. Those key assumptions include projections of future electricity sales, natural gas prices, and regulation of carbon dioxide emissions. Each of the study’s key assumptions is specified explicitly in order to enable parties to test the sensitivity of the BAU and REPS scenario projections to different values for key input assumptions.

The balance of the report is organized as follows:

- Chapter 3 describes the key common assumptions applicable to both scenarios and then describes the projections of electricity supply, average rates, and average bills for the BAU scenario;
- Chapter 4 describes the EE and RE assumptions specific to the REPS scenario and then provides the projections of electricity supply, average rates, and average bills for that scenario;
- Chapter 5 describes the analysis of net economic impacts of a REPS;
- Chapter 6 summarizes the incremental impacts of a REPS;
- Appendix A provides the references used to prepare the report;
- Appendix B provides key results for the BAU and REPS scenarios; and
- Appendix C provides summary impacts of a REPS assuming no regulation of carbon in Kentucky until after 2022.

3. Business as Usual Scenario

The BAU scenario assumes a future without a REPS. The projections for the BAU scenario provide the quantitative reference points against which the study will measure the incremental impacts of the REPS scenario. Those projections include electric resource costs, electric supply mix, average rates, average bills, and avoided costs for each year of the study period.

This chapter begins by describing the modeling framework and key common assumptions applicable to both the BAU scenario and the REPS scenario. It then describes the projections of electricity supply, average rates, and average bills for the BAU scenario.

A. Modeling Framework and Common Assumptions

The study develops projections of the capacity mix, energy mix, production costs, average rates, and average bills on a state-wide basis under the BAU scenario and the REPS scenario using an Electricity Costing Model (ECM) developed by Synapse.[6] The ECM is an annual production costing model implemented in Excel. It calculates the total revenue requirements for electricity service that utilities and/or resource owners would seek to recover from ratepayers for a given set of input assumptions. Revenue requirements consist of the annual amount required to recover the variable cost of producing electricity each year plus the cost of recovering capital investments including a return on those investments. Key input assumptions include projected retail energy requirements, both annual energy and peak demand, reserve margin, mix and characteristics of existing capacity, projected capacity retirements and additions, projected fuel prices, and projected environmental compliance costs.

The study developed a BAU scenario independently of the two scenarios presented in the Kentucky Department for Energy Development and Independence (DEDI) projections for several reasons.[7] First, the ECM requires numerous input assumptions and Synapse did not have access to all of the input assumptions that the DEDI used to develop its two scenarios. Second, Scenario A of the DEDI projection assumes construction of an Advanced Super Critical Pulverized coal plant while Scenario B implicitly assumes that Henry Hub gas prices will double in real terms between 2010 and 2020.[8] Synapse did not consider either of those two assumptions to be reasonable for a BAU scenario during the study period.

The base year of our analysis is 2010; this is the most recent year for which a complete set of statistics for Kentucky's electric sector were available from the EIA. All monetary values are reported in constant 2010 year dollars unless noted otherwise. The analysis begins in 2011 and ends in 2025, a study period of 15 years. The study focuses in particular on the ten-year period from 2013 through 2022, during which the REPS bill would be implemented.

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[6] Synapse developed the initial version of the ECM in order to provide the ACEEE with these projections for its clean energy studies of Ohio, North Carolina, South Carolina, Arkansas, Virginia and Pennsylvania.

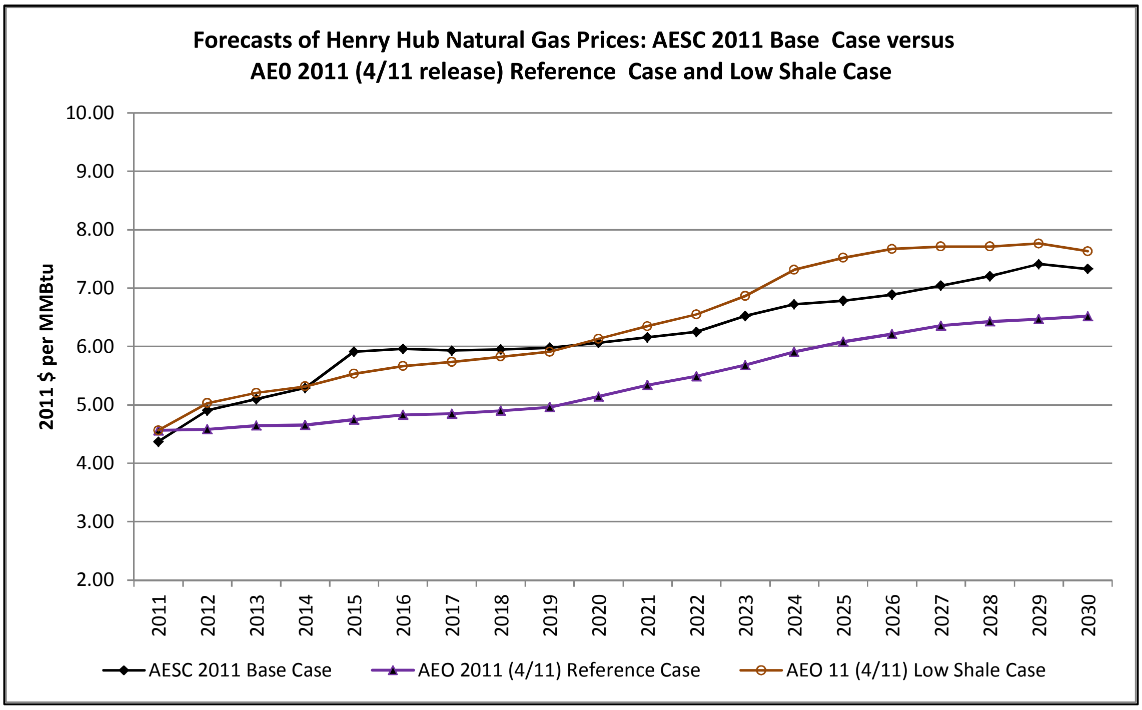
[7] Patrick, Aron et al. *Kentucky Electricity and Natural Gas Price and Consumption Forecasts to 2035*. DEDI. August 9, 2011.

[8] Ibid. Table 5. Implied by increase in industrial customer retail prices from $5.30 in 2010 to $10.03 in 2020 (2010$/MMBtu)

The analysis assumes inflation at 2.00% per year, discount rates of 8.0% nominal and 5.88% real, income tax rates of 35% federal and 6.0% Kentucky, and a property tax rate at 0.5% per annum of initial plant cost.

Fuel Prices. The study assumes coal prices will remain close to current levels over the study period based upon EIA reference case projections in Annual Energy Outlook 2011 (AEO2011).[9] The study assumes that the price of natural gas delivered to gas-fired units in Kentucky, the burner-tip price, will increase from $5.29/MMBtu in 2010 to approximately $6.50/MMBtu (in 2010$) by 2022. The largest component of that price is the projected Henry Hub price, with the other component being an estimate of the basis differential between the Henry Hub price and Kentucky.[10] The projection of Henry Hub prices underlying the study's burner-tip prices is drawn from *Avoided Energy Supply Costs in New England: 2011 Report* (AESC 2011), a report Synapse prepared for a group of efficiency program administrators in New England. That projection received considerable scrutiny during the development of AESC 2011. The study's projected Henry Hub prices are lower than those implied in the DEDI projection but within the range of Henry Hub prices that LG&E/KU considered in their April 2011 CPCN filing and also within the range of Henry Hub price projections the EIA analyzed in AEO 2011, as indicated in Figure 3-1.

Figure 3-1. Projections of Henry Hub prices



9 ____. *Annual Energy Outlook 2011.* U.S. Energy Information Agency. April 2011. http://www.eia.gov/forecasts/aeo/
10 Hornby, Rick et al. *Avoided Energy Supply Costs in New England: 2011 Report.* Synapse Energy Economics. July 2011.

Particulate, Sulfur Dioxide and Nitrogen Oxide Emission Compliance Costs. The United States Environmental Protection Agency (EPA) is in the process of implementing tighter regulations of emissions of various air pollutants including particulate matter, ozone, sulfur dioxide, and nitrogen oxides. The changes include revisions to several National Ambient Air Quality Standards (NAAQS), a Cross-State Air Pollution Rule (CSAPR), and proposed standards for hazardous air pollutants (HAPS). These new tighter regulations are currently scheduled to take effect in 2016. Our study assumes that Kentucky utilities will comply with these new, more stringent regulations by December 2015. The study assumes that some existing coal units have the necessary control technology required to comply, some units will require major capital investments in new control technology in order to comply, and some units will be retired.

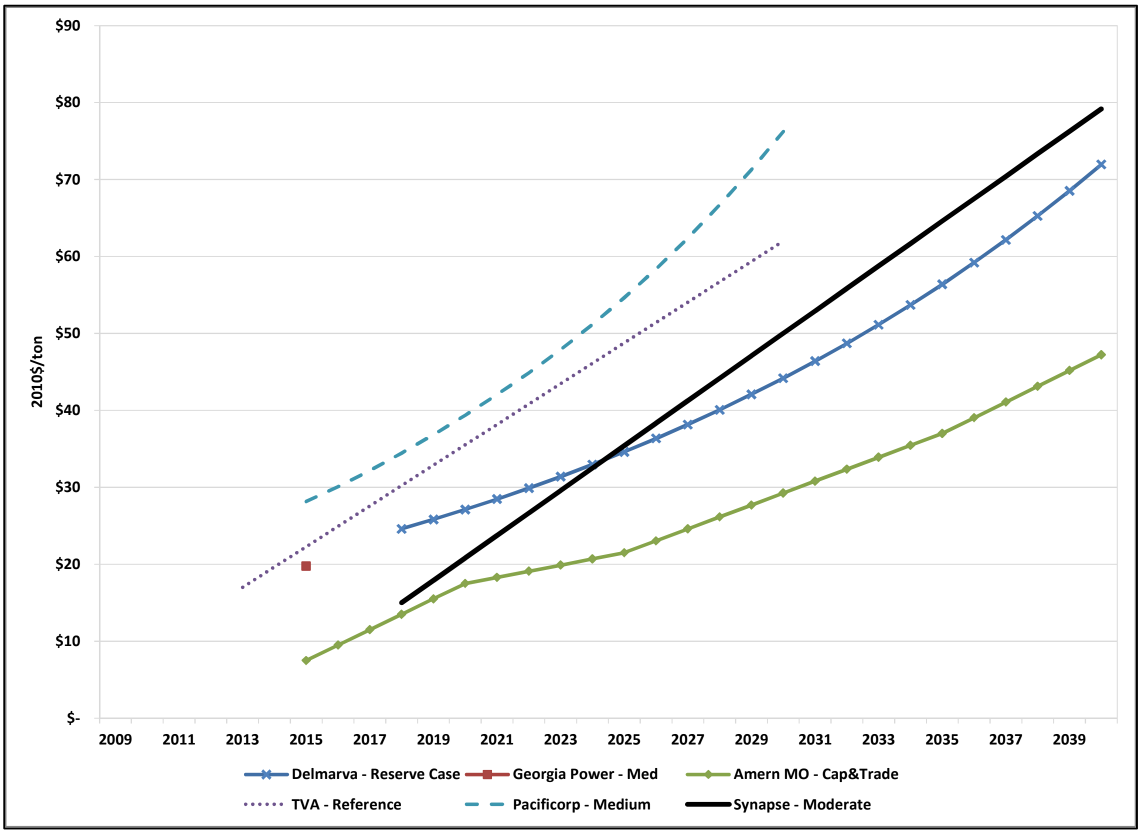
The study's projections of capacity costs under the BAU and REPS scenarios do not include capital costs that Kentucky utilities might incur in order to enable their existing coal units to comply with the tighter environmental regulations scheduled to take effect in 2016. In addition to the difficulty of obtaining estimates of those capital costs for each coal unit in Kentucky, the study assumed those costs would be relatively unavoidable under both scenarios because the utilities would make those capital investments between 2012 and 2015 and would be able to recover them in full through a special environmental surcharge.

Carbon Dioxide Emission Compliance Costs. There is considerable uncertainty regarding the timing and design of future federal regulation of carbon emissions. However, Synapse considers it reasonable to assume that some form of carbon regulation will occur during the planning horizon covered by this study. A number of electric utilities apparently share that expectation, as they have assumed a cost for complying with carbon emission regulation in long-term plans filed in the last year. Those utilities include Delmarva Delaware, Ameren Missouri, PacifiCorp, TVA, Duke Energy Ohio, Georgia Power, and Duke Energy Carolinas.[11] This study assumes that emissions of carbon dioxide from all generating units in Kentucky, both existing and new, will be subject to federal regulation beginning in 2018 at a cost of compliance of $15 per ton of carbon.[12] Figure 3-2 plots that carbon dioxide assumption relative to the assumptions used by most of those electric utilities for their reference or medium cases.

[11] COMMENTS OF INTERVENORS NATURAL RESOURCES DEFENSE COUNCIL AND SIERRA CLUB ON THE 2011 JOINT INTEGRATED RESOURCE PLAN OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC . CASE NO. 2011-00140. November 23, 2011. Page 10.

[12] Johnston, Lucy et al. Synapse 2011 CO2 Price Forecasts, February 2011, mid-case

Figure 3-2 Projections of Carbon Dioxide Prices (2010$)



Given the uncertainty regarding the timing and magnitude of future regulation of carbon, the study also includes an estimate of the impacts of a REPS assuming no regulation of carbon in Kentucky until after 2022. The summary impacts from that analysis are presented in Appendix C.

B. Projection of Retail Electricity Requirements

The study projects retail electricity requirements in terms of annual sales and aggregate peak demand. The study develops a projection of state-wide annual electricity sales for each of the three major sectors, i.e., residential, commercial, and industrial. It also develops a projection of the aggregate peak demand from all three sectors. It begins by developing a projection of requirements assuming no reductions from EE. From that projection it develops projections of retail sales for the BAU scenario and the REPS scenario by deducting the reductions from EE assumed in each of those scenarios.

The projection of state-wide sales with no reductions from EE assumes that all utilities in the state will have approximately the same rate of growth as LG&E/KU have projected for their service territory, prior to the impact of their proposed EE.[13] LG&E/KU assume their annual retail sales will

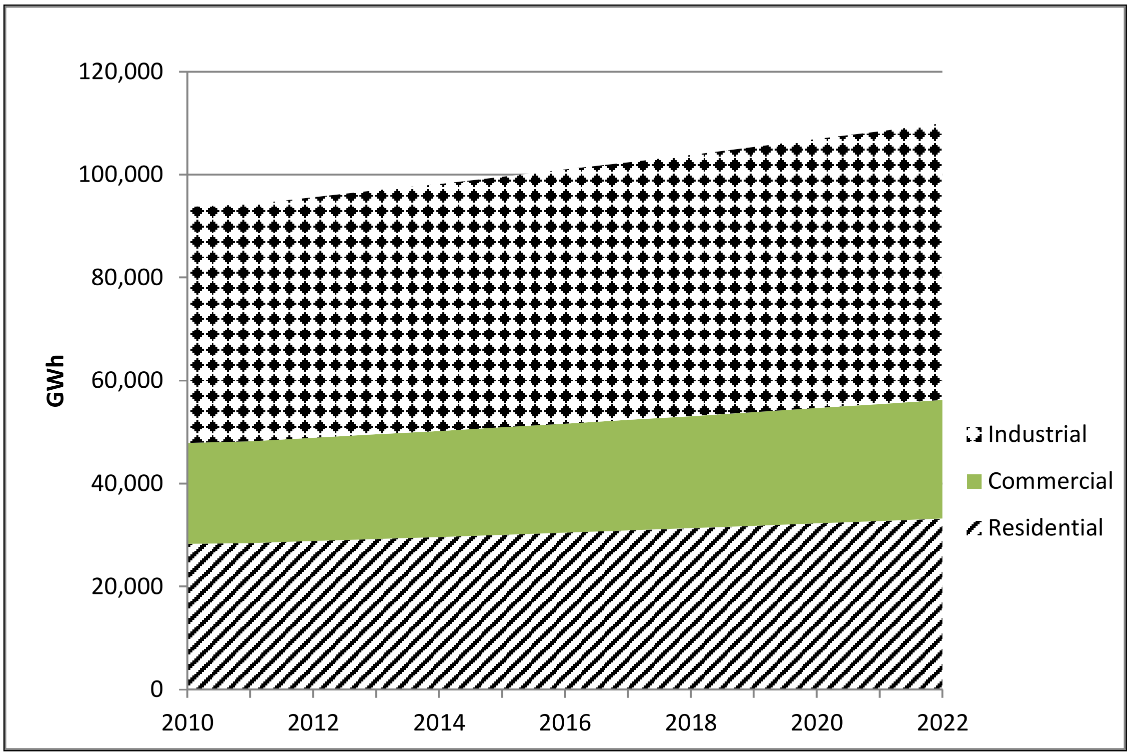
[13] LG&E/KU Integrated Resource Plan (IRP), April 2011, Table 6.(1)-1, page 6-4

rebound in 2011 and 2012 from their 2009 and 2010 recession levels and will increase steadily thereafter.

The study projects that annual sales and aggregate peak demand under the BAU scenario will each increase at an annual average rate of approximately 1.5% per year over the study period. This projection reflects our estimates of reductions from EE for those Kentucky utilities who offer EE programs. For example, the BAU forecast projects a total state-wide cumulative annual reduction from EE under the BAU scenario of approximately 2,000 GW in 2025, or 1.7% of annual sales forecast for that year. This projection is based on our review of public data on EE programs of Kentucky utilities. LG&E/KU have projected reductions from their EE programs equal to 4.8% of 2025 sales. The state's other utilities do not appear to be projecting any material reductions from EE.

The BAU scenario projection of electricity sales by sector is presented in Figure 3-3. This projection assumes that each major customer sector, i.e., residential, commercial, and industrial, would account for the same proportion of total sales in the future as it did on average between 2008 and 2010. During that period the residential, commercial, and industrial sectors respectively accounted for 30%, 21% and 49% of total annual retail sales in the state.[14] The BAU scenario projection assumes that the number of customers in each sector will grow at 1.1% per year, the average annual rate of total customer growth between 1990 and 2009.

Figure 3-3. BAU scenario - Forecast of annual electricity sales by sector



[14] Industrial sales as a percentage of total sales in all sectors are about twice the national average.

The average annual rate of growth projected under the BAU scenario, at 1.5%, is less than the actual average rate of state-wide load growth from 2000 to 2010 (1.8%). However, that projection is higher than the state-wide average rate of load growth the DEDI has projected for the period 2010 through 2035 (0.7%).[15] The fact that the study projects a higher average annual rate of growth for the BAU scenario than the DEDI report may be attributable to several factors, including a shorter forecast period than the DEDI report, i.e. through 2022 rather than through 2035, and no reflection of the impact of price elasticity on retail load.

C. Projection of Electricity Resources and Costs

The study developed the BAU scenario projection of electricity resource mix and costs in two steps. In step one the study determined the quantity of total capacity required each year to meet peak demand plus losses and a reserve margin. In years in which the total of existing capacity plus planned additions were less than the total quantity of capacity required to ensure reliable service, Synapse added generic capacity to the ECM. In step two the study estimated the quantity of total annual generation required each year to meet annual sales plus losses, i.e. total annual retail electric requirements. Synapse used the ECM to calculate the quantity of generation from each category of capacity each year and the annual costs of producing that generation. The study also developed a projection of avoided electricity costs.

Step One - Ensure Adequate Capacity

In order to ensure reliable service, Kentucky utilities must have sufficient capacity to meet each year's forecast of peak demand plus a reserve margin. Our analysis of capacity requirements for the BAU scenario revealed the following key points:

- LG&E/KU assume a 55% load factor in their April 2011 IRP. Our study assumes a 60% load factor because industrial load, the customer class with the highest load factor, accounts for 50% of total sales in the state but only 28% of LG&E/KU total sales. With a 60% load factor, and a 15% reserve margin as LG&E/KU assume in their April 2010 IRP,, our analysis of EIA statistics for Kentucky in 2010 indicates that Kentucky met 94% of its reserve margin requirement in 2010 with capacity located in-state and 6% with capacity located out-of-state;[16]
- Approximately 824 MW of hydro capacity is currently available and an additional 130 MW is scheduled to be in-service by 2017. Under the REPS, generation from hydro built after 1992 would quality as RE. Therefore the study assumes that 57.8 MW of existing hydro and all of the proposed hydro would qualify as RE;[17]
- LG&E/KU plan to retire at least 800 MW of older coal units by 2016. They have concluded that it is not economic to install new emission controls on those units in order to comply

[15] Patrick, Aron et al. *Kentucky Electricity and Natural Gas Price and Consumption Forecasts to 2035*. DEDI. August 9, 2011.

[16] Reliance on out-of-state capacity would be lower with a higher average load factor &/or lower reserve margin

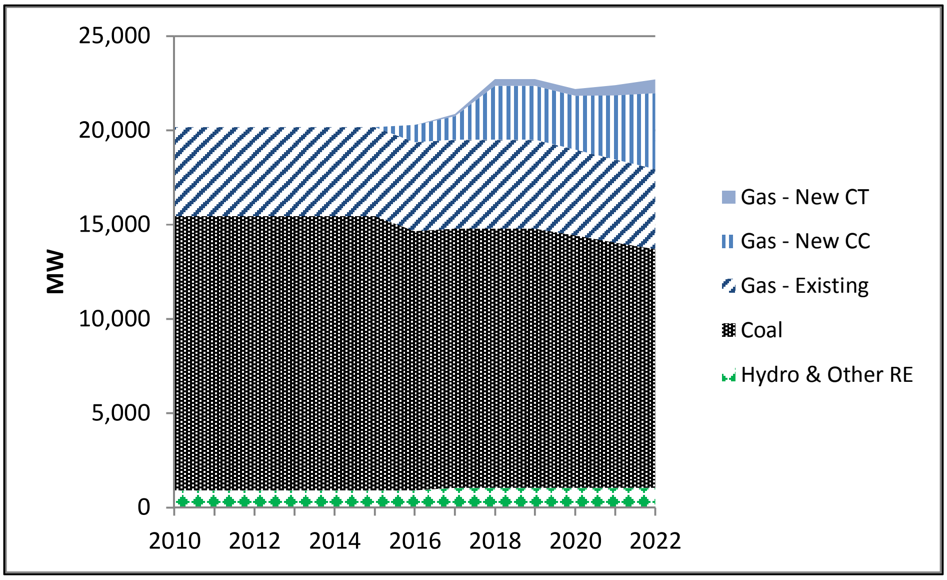
[17] The 57.8 MW equals hydro capacity reported in Form EIA 860 Annual Electric Generator Report for 2009 minus capacity reported for 1990, since report for 1992 was not available.

with the more stringent limits on emissions scheduled to take effect in 2016 under NAAQS, CSAPR, and HAPs;

- LG&E/KU plan to add 907 MW of gas-fired combined cycle units in 2016 and another 907 MW in 2018 to replace the units retiring in 2016 and to meet growth in peak demand; and
- Further capacity additions will be needed from 2017 onward to maintain the reserve margin in response to projected growth in peak demand and annual energy.

Synapse added capacity to the Electricity Costing Model (ECM) by specifying the timing, quantity, type, capital cost, and operating characteristics of each capacity addition. Under the BAU scenario we assume these generic capacity additions will be a mix of new natural gas combined-cycle (NGCC) capacity and new natural gas combustion turbine (NGCT) capacity. Figure 3-4 presents the projection of capacity in Kentucky for the BAU scenario resulting from these analyses.

Figure 3-4. BAU scenario - Forecast of capacity in Kentucky



Synapse developed assumptions regarding capital cost and operating characteristic of each category of new capacity based upon its review of various cost projections and on the assumptions for new capacity the EIA used to prepare AEO 2011.

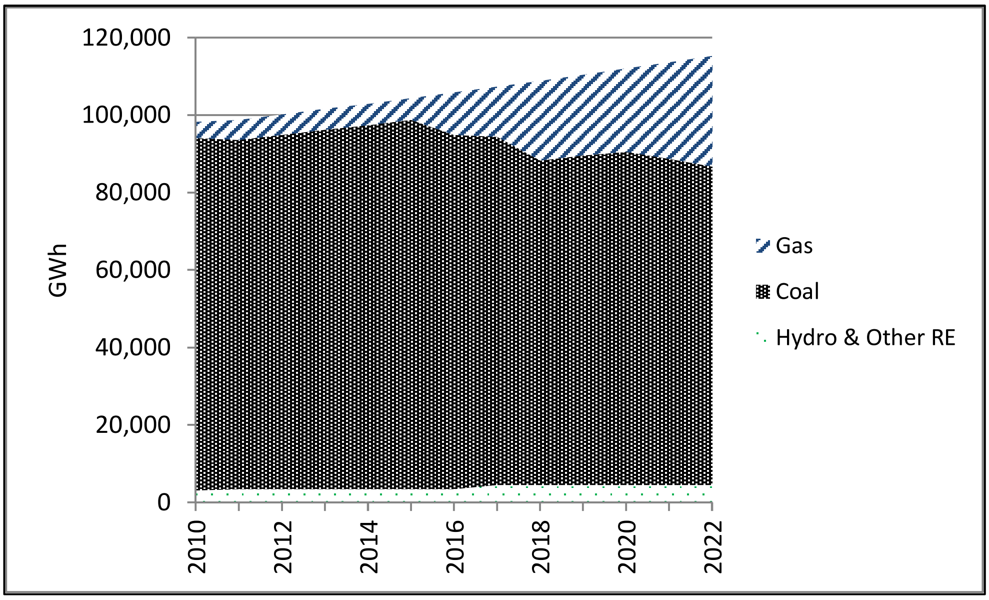
Step Two - Calculate Annual Generation from Each Category of Capacity

The ECM estimates the annual quantity of generation required from each category of capacity to meet the projected annual retail requirements for the year and calculates the annual cost of producing that generation. The ECM estimates the quantity of generation from each category of capacity, existing and new, based upon an analysis of historic load and operating patterns, including capacity factors. For example, if load increases by 1% in a year with no increase in capacity, the model increases the annual generation from each category of capacity by 1% to meet the increase. In a year in which some quantity of existing capacity is retired and new units are added, the remaining reduced quantity of existing capacity is dispatched at its historic capacity factor and the new capacity is dispatched at a capacity factor based on general industry experience.

The ECM calculates the unit cost of generating electricity from each category of capacity, referred to as the production cost, in $ per MWh, based upon numerous input assumptions. These assumptions include the quantity, efficiency, and non-fuel variable production cost of each category of existing capacity available each year.[18] The study derived those assumptions from an analysis of base year and historical data for existing generating units in Kentucky. Two other key assumptions are fuel prices and carbon emission costs.

Figure 3-5 presents the generation mix for the BAU scenario based upon those assumptions. Kentucky's reliance on coal generation is projected to decline under the BAU scenario, from over 92% in 2010 to 71% in 2022. This decline is due to the retirement of several older coal units starting in 2016 and their replacement by gas-fired NGCC units.

Figure 3-5. BAU scenario - annual electricity requirements and sources



Annual Avoided Cost of Electricity Supply

The annual avoided cost of electricity supply associated with this scenario is an estimate of the costs that all retail customers could avoid paying if less electricity was required from the resources projected under this scenario. The ECM calculates the avoided cost of electricity supply based upon the costs of the marginal, or avoidable, sources of capacity and generation.

- Prior to 2015 the avoidable capacity resource is new NGCT, and the avoidable generation is primarily production from existing coal units. Thus, the avoided cost during this period

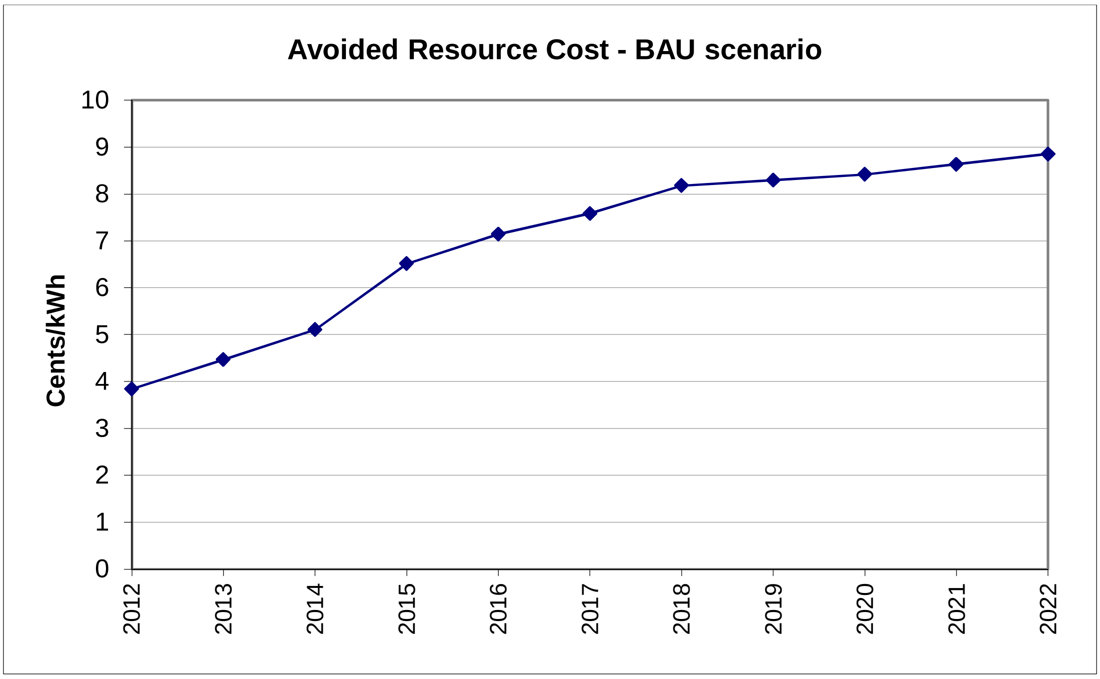
[18] The efficiency with which a generating unit converts fuel into electricity is referred to as its heat rate.

reflects the average operating costs of coal-fired generation and the levelized capital cost of a new NGCT.

- From 2016 onward the avoidable capacity resources are a mix of new NGCC and new NGCT, while the avoidable generation is production from those new gas units. Thus, from 2016 onward the avoided cost reflects the levelized capital cost of the mix of projected new NGCC and NGCT units and the average operating costs of new gas-fired generation.

As indicated in Figure 3-6, under the BAU scenario the total annual avoided cost of electricity supply, capacity plus generation, is projected to increase from approximately 4 cents/kWh in 2012 to approximately 9 cents/kWh in 2022.

Figure 3-6. BAU scenario – avoided electricity resource cost



D. Projection of Average Retail Rates and Average Retail Bills

The study projects state-wide average rates, and state-wide average bills, by sector for each year. These projections are indicative approximations, not forecasts of precise rates or bills. First, as noted earlier, the projections are state-wide averages; actual rates and bills will vary by utility. Second, the projections of system average rates are essentially the total projected revenue requirements in a year divided by total projected retail sales in that year. The projected average rates by sector are derived from the system average rate by applying the historical ratio of each sector's rate to the system average rate. In contrast, development of precise estimates of specific rates by utility requires a detailed allocation of utility revenue requirements among rate classes and the calculation of various type of charges, e.g., customer charges ($/month), demand charges ($/kW), energy charges ($/kWh), and surcharges or riders. Finally, the projected state-wide average bills by sector in a year equal the projected average rates by sector in that year multiplied by the projected annual electricity sales per customer by sector each year.

State-Wide Average Retail rates

The state-wide average rate in each year equals the total projected costs utilities would seek to recover from retail customers in that year divided by projected annual electricity sales in that year. Our analyses assume utilities would seek to recover four major types of costs each year:

- Transmission and distribution (T&D) costs,
- Annual fixed costs of existing generating capacity,
- Annual fixed costs of new generating capacity, and
- Annual production costs.

The study projects the first two types of costs, i.e., T&D and existing generating capacity, based upon an analysis of historical costs and historical rates. The study assumes that Kentucky utilities will need to recover the same amount of those projected costs in the BAU scenario and the REPS scenario.

The study projects the last two types of costs, i.e., fixed costs of new generating capacity and production costs, based upon the ECM outputs for each scenario. The projection of fixed costs of new generating capacity and of production cost for the BAU scenario is different from the projections for the REPS scenario.

Table 3-1 presents the BAU scenario projections of average rates by sector and electric bills by sector. These projections are in 2010 constant dollars.

Table 3-1. BAU scenario - Forecast average rates and bills by sector

Average Electric Rates ($/kWh) (2010$)	2010	2015	2020	2022	Increase from 2010
Total (All Sectors)	$0.067	$0.070	$0.095	$0.101	50%
Residential	$0.086	$0.088	$0.114	$0.120	40%
Commercial	$0.079	$0.081	$0.106	$0.113	43%
Industrial	$0.051	$0.053	$0.078	$0.085	67%
Average Electric Bills ($) (2010$)	**2010**	**2015**	**2020**	**2022**	**Increase from 2010**
Residential	$1,249	$1,319	$1,727	$1,834	47%
Commercial	$5,198	$5,384	$7,185	$7,658	47%
Industrial	$325,409	$342,448	$513,290	$557,989	71%

The study projects that average retail rates will increase substantially by 2022 under the BAU scenario. For example, the study projects that system-wide average rates would be 50% higher in 2022 than in 2010 under the BAU scenario, while residential rates would increase by 40%. These projected increases are somewhat higher than, but consistent with, the magnitude of increases in state-wide average electricity prices that the Kentucky DEDI has projected for the period 2010 through 2020 under Scenario B.[19]

The study projects average residential bills to increase by 47% between 2010 and 2022. This projected increase reflects the combined effect of a projected 40% increase in rates and a projected 5% increase in annual use per residential customer over that period.

The increases in rates and bills projected under the BAU scenario are conservative because, as noted earlier, they do not reflect the capital costs that some Kentucky utilities, such as LG&E/KU, will incur by 2015 in order to retrofit certain of their existing coal units to comply with tighter emission regulations.

[19] Patrick, Aron et al. *Kentucky Electricity and Natural Gas Price and Consumption Forecasts to 2035*. DEDI. August 9, 2011. Table 3.b.

4. REPS Scenario

The REPS scenario assumes a future in which Kentucky utilities achieve reductions from EE and acquire generation from RE according to the annual targets specified in the REPS. As a result, the REPS scenario meets the projection of total annual retail electricity requirements using a different mix of electricity resources than the BAU scenario, which leads to a different projection of average rates and average bills.

This chapter provides a general description of the key assumptions and methodology the study used to develop the REPS scenario projections, and reports those projections. The study develops the REPS scenario in four steps:

1. Calculate the additional reductions from EE and generation from RE required under the REPS scenario,
2. Estimate the cost of acquiring the additional reductions from EE,
3. Estimate the cost of acquiring the additional generation from RE, and
4. Develop projections of electric resource costs, electric supply mix, average rates, and average bills.

A. Additional EE and RE required under the REPS scenario

The REPS bill specifies the total reductions from EE and generation from RE required each year as percentages of average retail sales in the previous two years. The bill refers to that average as a “rolling baseline.”

The study estimated the additional reductions from EE and generation from RE required under the REPS scenario by calculating the aggregate quantities of EE and RE required to comply with the REPS bill, and then subtracting the quantities of qualifying EE and RE projected under the BAU scenario. These estimates represent the additional quantities of EE and RE that Kentucky utilities would have to achieve, over and above the quantities projected in the BAU scenario, in order to comply with the REPS.

Table 4-1 provides the development of these estimates of additional reductions from EE and generation from RE. Note that:

- The rolling baseline, reported in column d, is developed from the projections of annual retail requirements presented in columns a through c;
- The additional reductions from EE required under the REPS scenario, reported in column h, is developed from the rolling baseline, the REPS aggregate requirements presented in column e, and the qualifying EE projected under the BAU scenario in column g; and
- The additional generation from RE required under the REPS scenario, reported in column m, is developed from the rolling baseline, the REPS aggregate requirements presented in column j, and the qualifying RE projected under the BAU scenario in column l.

Table 4-1. Additional EE and RE required under REPS

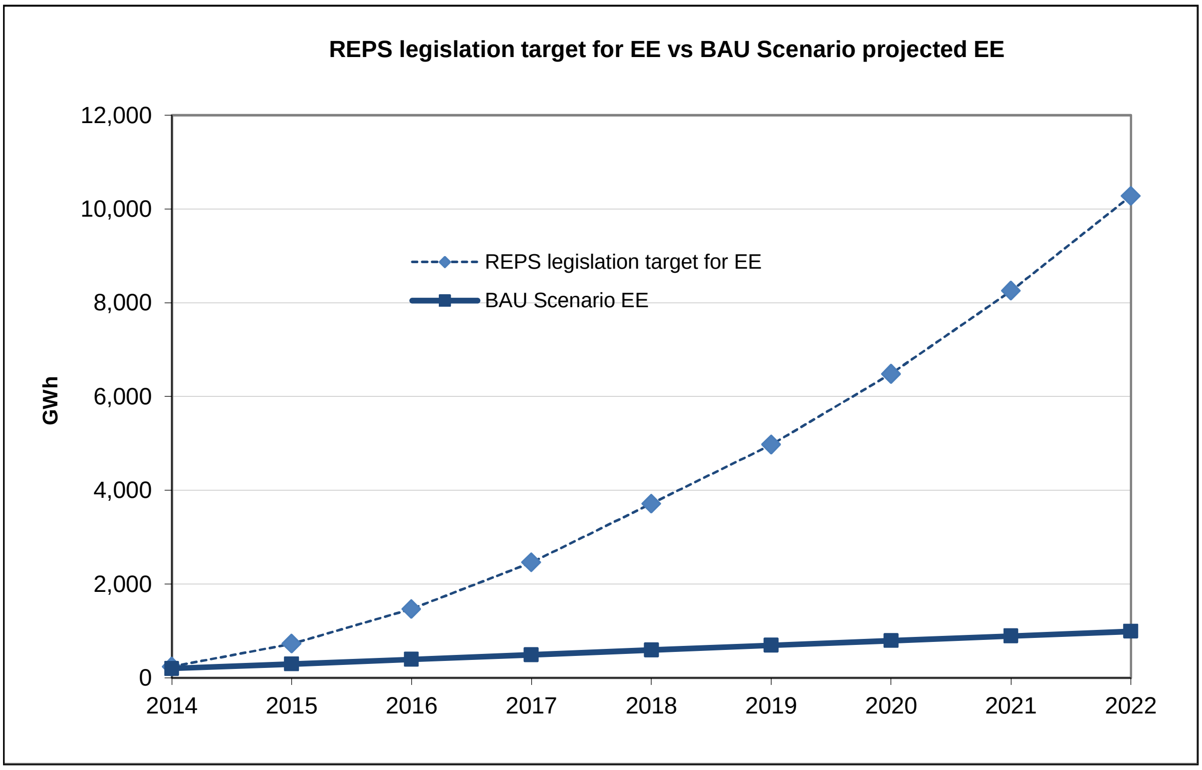
Year	Sales Forecast (GWh)				Additional EE Required under REPS Scenario (GWh)					Additional RE Required under REPS Scenario (GWh)			
	BAU Scenario	BAU Scenario without incremental EE after 2013	REPS scenario	Rolling Baseline (Average of sales in prior 2 years)	REPS Legislation Requirement for EE		Incremental EE in BAU Scenario	Additional EE under REPS Scenario	Cumulative EE	REPS Legislation Requirement for RE		Eligible RE in BAU scenario	Additional RE under REPS Scenario
Column	a	b	c	d	e	f	g	h	i	j	k	l	m
2010	93,686	93,794	93,686										
2011	94,203	94,605	94,203										
2012	95,558	96,132	95,558										
2013	96,916	97,642	96,916										
2014	98,130	98,330	98,089	96,237	0.25%	241	200	41	241	2.25%	2,165	685	1,480
2015	99,571	99,868	99,140	97,502	0.50%	488	97	390	728	2.25%	2,194	685	1,509
2016	100,976	101,370	99,903	98,615	0.75%	740	97	642	1,468	2.25%	2,219	685	1,534
2017	102,341	102,833	100,370	99,521	1.00%	995	97	898	2,463	5.50%	5,474	1104	4,370
2018	103,793	104,387	100,672	100,136	1.25%	1252	102	1,150	3,715	5.50%	5,508	1104	4,404
2019	105,333	106,027	101,056	100,521	1.25%	1257	100	1,156	4,971	5.50%	5,529	1104	4,425
2020	106,897	107,691	101,207	100,864	1.50%	1513	100	1,413	6,484	9.25%	9,330	1104	8,226
2021	108,369	109,263	101,010	101,132	1.75%	1770	100	1,670	8,254	9.25%	9,355	1104	8,251
2022	109,948	110,942	100,666	101,108	2.00%	2022	100	1,922	10,276	12.50%	12,639	1104	11,535

a, b	BAU scenario sales forecast
c	2010 to 2013 equals column a, *BAU Scenario*.
	2014 onward equals column b, *BAU Scenario without BAU incremental EE after 2013, minus column i, cumulative EE*
d	average of prior two years from column c, *REPS Scenario*
f	column d * column e
g	BAU scenario sales forecast
h	column f minus column g
k	column d * column j
l	BAU scenario projected generation mix
m	column k minus column l

B. Cost of Additional EE Reductions

Under the REPS scenario Kentucky utilities would have to achieve much greater reductions from EE than under the BAU scenario. The projected additional reductions are reported in Table 4-1 (above) and plotted in Figure 4-1.

Figure 4-1. Additional EE required under REPS



Fortunately, Kentucky has a tremendous potential for cost-effective EE, despite the Commonwealth's relatively low electricity prices. To date Kentucky utilities have not pursued EE as actively and aggressively as those in other states. For example, Kentucky ranked 37th in the nation for efficiency policies and programs according to the *ACEEE 2011 State Energy Efficiency Scorecard*. According to the ACEEE Scorecard Kentucky utilities, on average, achieved annual savings relative to sales of 0.07% in 2009. In contrast, the top fifteen states achieved annual savings ranging from 0.68% to 1.64%, i.e., the annual reductions from EE achieved by utilities in those states were ten to twenty times greater than the annual reductions achieved by Kentucky utilities.[20]

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[20] Sciortino, Michael et al. *The 2011 State Energy Efficiency Scorecard*. American Council for An Energy Efficient Economy. October 2011. Table 8.

Table 4-2 presents our assumptions for the unit cost of acquiring EE in Kentucky in the residential and C&I sectors, respectively.

Table 4-2. Estimated unit cost of energy efficiency in Kentucky (levelized ¢/kWh)

	RESIDENTIAL	C&I
Participant	1.8	1.4
Incentive	1.7	1.3
Program Administration	0.5	0.4
Total	4.0	3.0

Since the unit cost of acquiring EE varies by sector, we began the development of those unit costs by estimating the portions of additional EE that would be achieved from each sector each year. Based upon our review of the LG&E/KU April 2011 IRP and our experience in other states, we assume that through 2018 additional EE would be achieved primarily in the residential and commercial sectors, with a gradual ramp up in the quantity achieved in the industrial sector. From 2019 onward we assume each sector achieves the same percentage reduction in annual electricity use, i.e. the percentage specified in the draft bill.

Synapse developed estimates of the levelized unit cost of acquiring EE reductions in the residential sector and in the combined commercial and industrial sector (C&I) based primarily upon a review of prior reports prepared for Kentucky and states comparable to Kentucky. We checked those estimates against reports on the experience with efficiency throughout the United States over the past 20 years.

Our review covered two studies prepared for Kentucky, one study for Eastern Kentucky Power Cooperative, which covers a portion of Kentucky, and a 2009 report for Ohio. Table 4-3 provides estimates of the unit costs of acquiring EE based upon the costs in those reports. The total cost of acquiring EE consists of three major categories of costs – participant, incentives, and program administration. For those reports that provided only certain of those costs, we estimated the total cost based upon ACEEE statistics, which indicate an average composition of 45% participant costs, 42% incentives, and 13% administration costs.[21]

Table 4-3. Estimates of total unit cost of energy efficiency (levelized cents/kWh, 2010$)

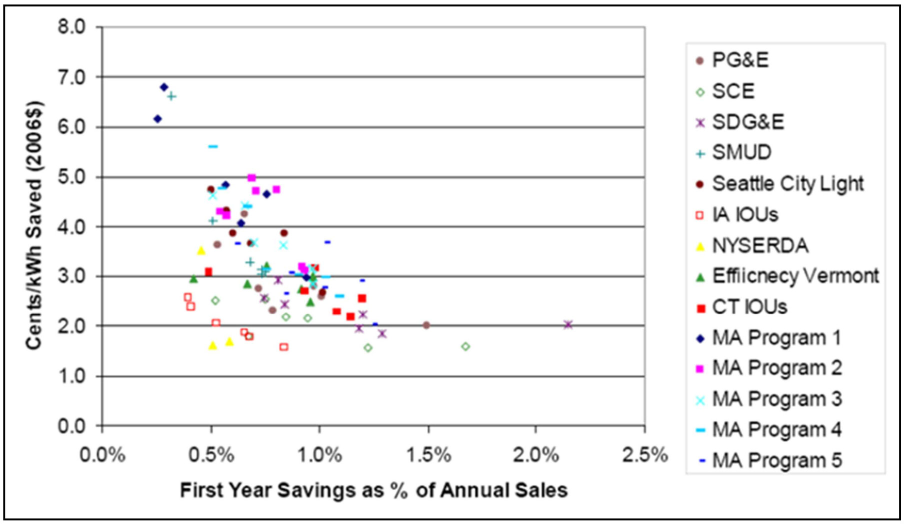
Study	Brown, et al. 2010	KPPC and ACEEE 2007	Zinga and McDonald 2008	ACEEE 2009
Region	KY	KY	EKPC	OH
Customer Sector				
Residential	4	n/a	4.1	3.4
Commercial	3.2	n/a	5.9	1.9
Industrial	1.5	3.7	4.4	2.7

The estimates of total unit costs for Kentucky presented in Table 4-3 are consistent with experience throughout the United States over the past 20 years. A 2009 ACEEE review of cost of saved energy from programs in 14 leading states found average program costs ranged from 1.5 cents/kWh to 3.4 cents/kWh,

[21] Friedrich, Katherine et al., *Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved through Utility-Sector Energy Efficiency Programs.* ACEEE 2009.

with an average of 2.5 cents/kWh.[22] That average equates to a total cost of approximately 4.5 cents/kWh when participant costs are included. The results of a Synapse study, summarized in Figure 4-2, indicate an average program cost of 2.6 cents/kWh (2010$), which indicates average total costs in the range of 4.7 cents/kWh (2010$).[23] That study indicates that the cost of saved energy declines at higher levels of annual savings, likely due to economies of scale and experience.

Figure 4-2. Variation in cost of energy efficiency with quantity of annual savings

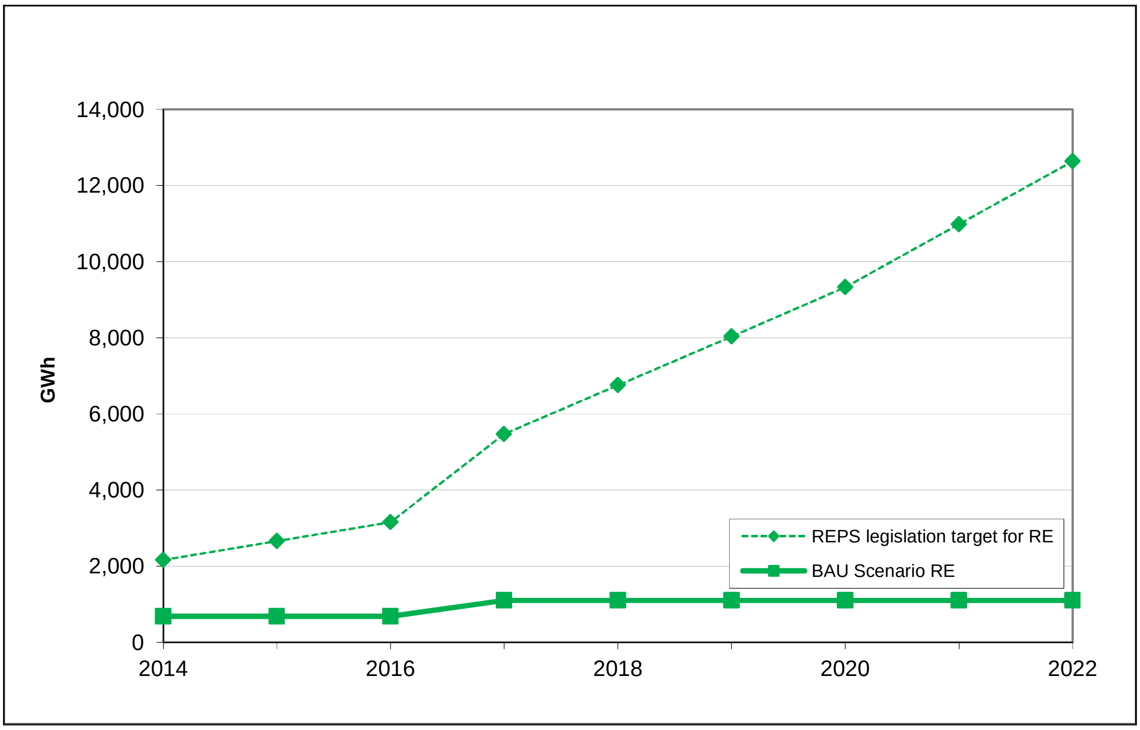


C. Cost of Additional RE Generation

Under the REPS scenario, Kentucky utilities would have to acquire much greater quantities of generation from RE than under the BAU scenario. The projected additional quantities are reported in Table 4-1 and plotted in Figure 4-3. The REPS legislation requires that a specific portion of that RE generation be met from solar resources. Our study refers to that portion as the “solar carve out.”

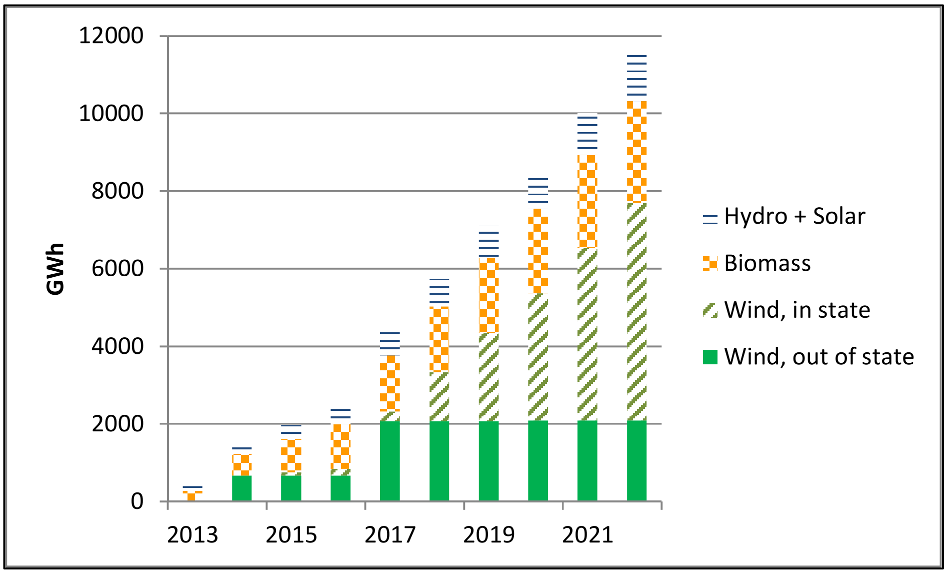
[22] Ibid.
[23] Hurley, Doug et al. *Costs and Benefits of Electric Utility Energy Efficiency in Massachusetts*. Synapse Energy Economics. August 2008.

Figure 4-3. Additional RE required under REPS



Our analyses indicate that Kentucky could eventually acquire the majority of these additional quantities from in-state resources. As indicated in Figure 4-4, the largest in-state RE resources are projected to be biomass and wind. The study estimates the remaining additional RE resources will be wind energy imported from out-of-state as well as hydro and solar RE developed in state.

Figure 4-4. Mix of additional RE in REPS Scenario



The study developed estimates of the quantity and cost of generation from each RE resource each year based upon a review of prior assessments of renewable energy resources in Kentucky and of renewable resources available to Kentucky from other states.

Biomass

Use of biomass for electric generation would require capital investments to install co-firing capability at various existing coal-fired plants, transportation infrastructure to deliver biomass to plants which add that co-firing capability, and projects to harvest various sources of biomass. Our analysis indicates that the costs of adding co-firing capability may be relatively modest and that the existing transportation infrastructure for delivery of coal may accommodate the delivery of biomass. However, adding co-firing capability and developing biomass transportation infrastructure will take time.

The major sources of biomass that could be harvested in sustainable quantities in Kentucky include logging residue, urban wood, trees that are not merchantable, underbrush, and short rotation woody crops such as hybrid poplar and willow.[24] The least expensive of those sources are logging residue and urban wood, which could be harvested to provide fuel at a price of approximately $2.50/MMBtu, while the cost of biomass from other sources is more expensive, in the order of $4.00/MMBtu. Those projected prices do not reflect the cost of transporting biomass to the coal plants with co-firing capability. Studies indicate that approximately 2600 GWh per year could be generated from biomass obtained at a fuel cost of $2.50/MMBtu, and an additional 3900 GWh could be generated each year at a biomass price of $4.00/MMBtu.[25,26]

Based on the relatively low capital costs required to add co-firing capability to existing coal fired units, we estimate the total levelized cost of generation from biomass at $2.50/MMBtu to be $0.028/kWh. Our study assumes that 100% of the less expensive biomass, i.e. logging residue and urban wood, would be used to generate electricity by 2022. That biomass represents approximately one-quarter of the total biomass that studies indicate could be harvested sustainably each year.[27]

Wind (in state)

The levelized cost of generation from wind turbines in Kentucky will vary based on several factors including turbine costs, meter hub height, capacity factor, and siting. Our study analyzed the potential for wind generation in Kentucky from wind turbines at two heights: units with an 80 meter hub height, and units with a 100 meter hub height. We estimate the total levelized cost of wind generation from 80 meter height units at $0.11/kWh and from 100 meter height units at $0.10/kWh based upon our review of the literature on the factors affecting the cost of wind generation in Kentucky. [28,29]

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[24] Anderson, Kristina et al. *Final Report from the Executive Task Force on Biomass and Biofuels Development in Kentucky.* Commonwealth of Kentucky. December 10, 2009. page 12.

[25] AEO 2011. Kentucky data. page 101

[26] Brown, Marilyn et al. *Renewable Energy in the South*. Southeast Energy Efficiency Alliance. December 2010.

[27] Logging residue plus urban wood represents 2.3 million dry tons per year out of a total biomass resource of 9.2 million dry tons per year.

[28] Zinga, Susan and McDonald, Andy. *A Portfolio of Energy Efficiency and Renewable Energy Options for East Kentucky Power Cooperative.* February 2008.

[29] Wiser, Ryan and Bolinger, Mark. *2010 Wind Technologies Market Report*. U.S. Department of Energy, June 2011.

Most assessments of wind potential to date have been limited to wind turbines with an 80 meter hub height. Our study assumes that 110 MW of wind turbines of that height will be installed by 2017. The annual generation from those units, at a 26% capacity factor, is projected to be 250 GWh/yr.

Assessments of wind potential from wind turbines with a 100 meter hub height are a relatively recent phenomenon nationally and completely new to Kentucky. However, the combination of falling prices for wind turbines and the development of 100 meter hub height wind turbines present a tremendous opportunity for Kentucky. At less than a 30% capacity factor, wind turbines of this size have the technical potential to generate more electricity than the state's annual retail electricity requirements.[30] While the economics of wind projects are certainly better the higher the capacity factor, more than a dozen wind projects out of 87 installed in 2009 had capacity factors below 30%.[31] Our study assumes that wind generation from 100 meter hub height units would begin to come online in 2020 in quantities sufficient to provide all of the incremental RE generation required to comply with the REPS in that year and thereafter.

This assumed pace of wind generation development is consistent with the recent experience in other states. For example, the pace of wind generation development in 12 states has averaged more than 250 MW/year over the past three years.[32]

Wind imports

The study assumes that Kentucky utilities could comply with the REPS by purchasing renewable electricity generated outside the state as long as that electricity is delivered to their customers. It is possible that utilities in Kentucky could enter into a power purchase agreement (PPA) for generation from RE with generators in the wholesale markets operated by MISO and PJM. The total delivered cost of that RE generation would be the price for generation under the PPA plus the transmission costs incurred to have that electricity delivered to its local distribution system.

Although the terms of PPAs are rarely disclosed, the study did gain some insight from the 2009 proceedings in case 2009-00545, in which the Kentucky PSC considered an application by Kentucky Power for authority to enter into a Renewable Energy Purchase Agreement with FPL Illinois Wind LLC. The PPA would have been for a 100 MW share of the Illinois based Lee-DeKalb Wind Energy Center for a 20-year term at the price of $43/MWh.[33] Furthermore, research by the US Department of Energy suggests that the cost to build wind projects in the Heartland (largely MISO) range from $30/MWh to $70/MWh, with a capacity weighted average of $48/MWh. These data points, when combined with the tremendous growth of wind generation and total wind resources in MISO, suggest that utilities in Kentucky could tap as much MISO wind as necessary for compliance without substantially impacting the price of supply. While limits on transmission could conceivably become a constraint, projects like the Grain Belt Express transmission project suggest that market forces will ensure sufficient transmission. Our study estimates the cost of imported wind generation at $72/MWh based on a conservative estimate

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[30] ___. *Kentucky – Wind Resource Potential, 80m and 100m.*" National Renewable Energy Lab and AWS Truepower, February 2010.

[31] Wiser, Ryan and Bolinger, Mark. *2010 Wind Technologies Market Report*. U.S. Department of Energy, June 2011. Figure 34 page 55.

[32] Ibid.

[33] ____. Order in Case No. 2009-00545. *APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF RENEWABLE ENERGY RESOURCES BETWEEN KENTUCKY POWER COMPANY AND FPL ILLINOIS WIND LLC. ENERGY PURCHASE AGREEMENT FOR WIND.* Commonwealth of Kentucky Public Service Commission. June 28, 2010

of wind costs in the Heartland of $60/MWh plus twenty percent for transmission to specific utilities in Kentucky.

Our study assumes that Kentucky utilities import sufficient quantities of wind generation from MISO to comply with their REPS requirements from 2014 through 2019. From 2020 onward we assume imports of wind generation remain at the 2019 level. Because wind developers typically seek a long term PPA, the study assumes any wind PPAs signed with MISO generation would be constant throughout the length of the study.

Solar

The REPS legislation defines solar resources that qualify as RE resources to include solar water heating and photovoltaics (PV).

Our analysis indicates significant potential in Kentucky for solar water heating as well as for large scale PV. (An example of large scale PV, also referred to as utility scale PV, would be a 10 MW or larger ground mounted installation.) Our study estimates the average cost of electricity from large scale PV units at $0.20/kWh based upon assumptions drawn from a recent Synapse projection of the cost of various sources of generation.[34] The study estimates the cost of solar water heating, expressed in terms of avoided electricity use, to range between $0.20/kWh and $0.22/kWh.

The 61 percent of Kentucky households who use electric hot water heaters represent 1,000,000 potential residential installations. They have a technical potential of 2700 GWh of avoided electricity use per year at a price of approximately $0.22/kWh. Commercial solar water heating offers fewer GWh of avoided electricity, but economies of scale offer a lower price; the technical potential is 1900 GWh at a price of approximately $0.20/kWh. Although solar water heating is less expensive than PV and there is sufficient solar water heating opportunity, the number of installations per year is limited by the ability to enroll customers and ramp up the number of installations per year. Our study assumes that one percent of the technical potential is installed each year, for both residential and commercial solar water heating. The potential achieved at that installation rate is not sufficient to fully comply with the solar carve out. Therefore the study assumes PV satisfies the remaining portion of the solar carve out. Some may consider the assumption of a one percent installation rate for solar water heating overly optimistic. However, if that level is not achieved, the shortfall could be achieved from PV without a significant material difference in total cost because the solar carve out is small relative to the total generation required from RE.

Like other states, the achievable potential for PV in Kentucky is limited primarily by cost. With an ever changing set of state and federal subsidies available for PV and a rapidly decreasing price per watt, estimating the “sticker price” of a solar project is difficult. What remains clear is that the price of electricity from PV is higher than other forms of renewable electricity available to Kentucky.

D. REPS Scenario Projections

The study develops the REPS scenario projection of electricity resource mix and costs using a process similar to that used for the BAU scenario.

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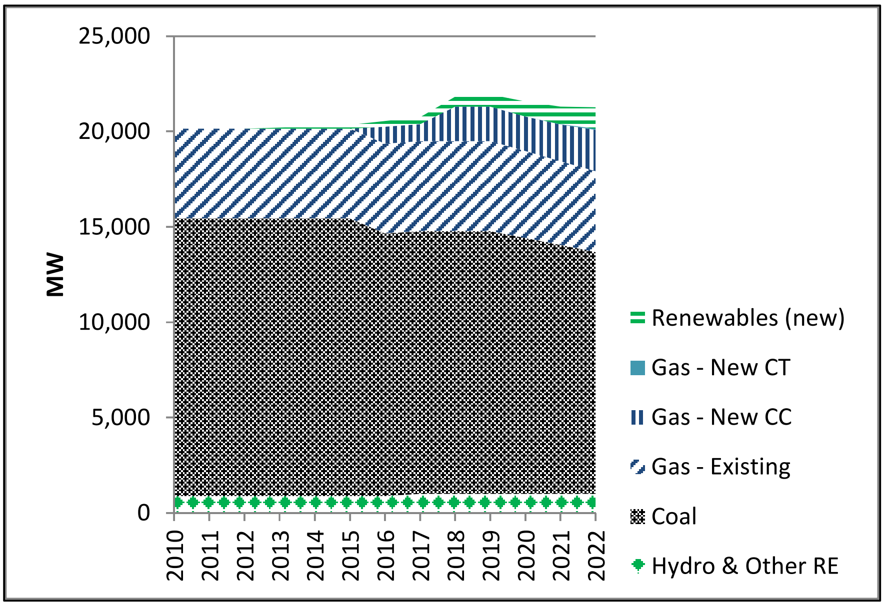
[34] Keith, Geoffrey et al. *Toward a Sustainable Future for the US Power Sector: Beyond Business as Usual 2011. Synapse Energy Economics*. November 2011. www.synapse-energy.com.

Since the RE targets are expressed as a percent of annual sales, Synapse derived the quantity of each category of new RE capacity that would have to be added to the ECM in each year from the quantity of annual generation projected from that RE resource. Because wind and solar capacity cannot be dispatched in the same manner as traditional fossil fuel capacity, Synapse assumed load carrying capacities of 20% for in-state wind and solar and zero for wind imports when calculating the effective capacity available from each resource for reliability purposes. Figure 4-5 presents the capacity mix for the REPS scenario resulting from these analyses.

Figure 4-5. REPS scenario - Forecast capacity in Kentucky



In the REPS scenario, the ECM begins by using the reductions from EE and the generation from RE and then dispatches each remaining category of capacity available in each year in the same manner as in the BAU scenario. Figure 4-6 plots the additional EE and generation mix for the REPS scenario resulting from those assumptions. Note that the state's reliance on coal generation under the REPS scenario declines to 63% of its total annual energy requirements in 2022 due to displacement of generation from existing coal units by additional EE and RE resources.

Figure 4-6. REPS scenario – annual electricity requirements and sources

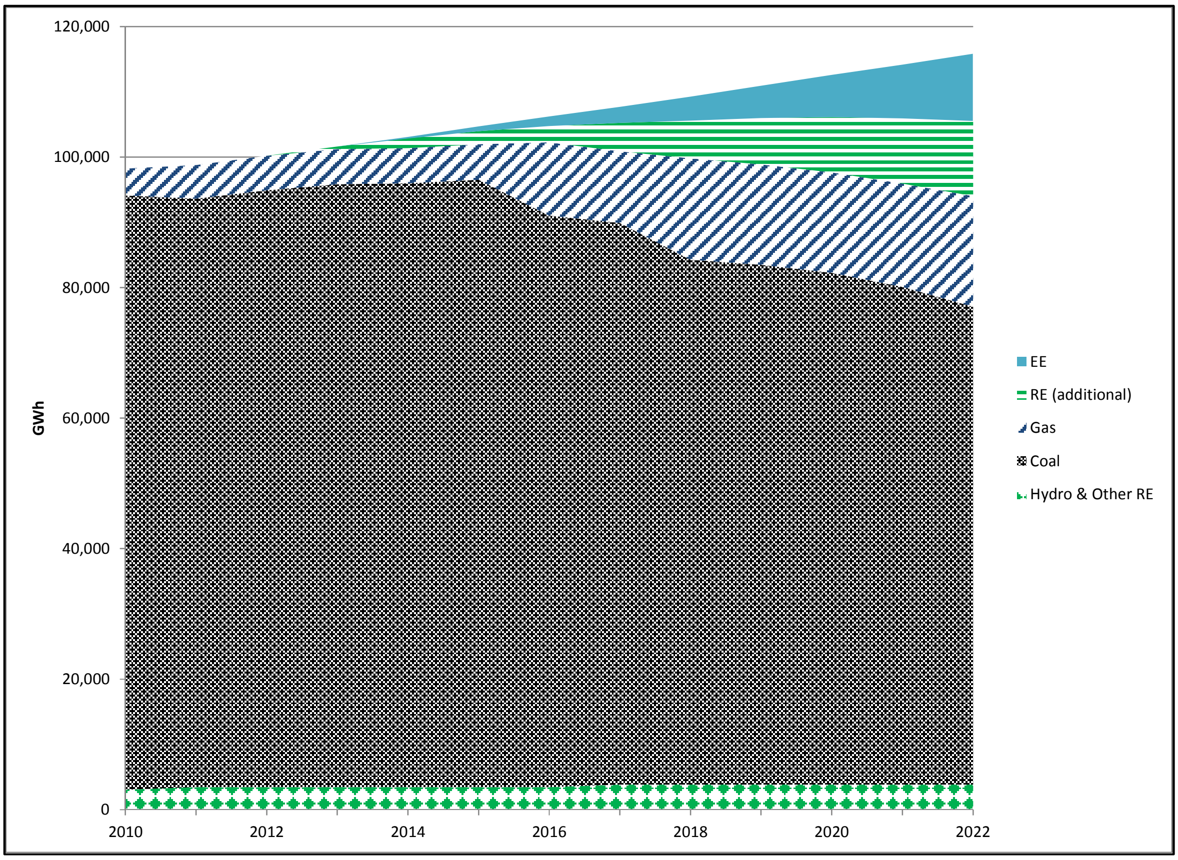


Table 4-4 presents the projections of average rates and average bills by sector for the REPS scenario.

Table 4-4. REPS scenario – Projected average rates and average bills by sector

Average Electric Rates ($/kWh) (2010$)	2010	2015	2020	2022	2022 versus 2010
Total (All Sectors)	$0.067	$0.070	$0.096	$0.102	51%
Residential	$0.086	$0.089	$0.114	$0.121	41%
Commercial	$0.079	$0.081	$0.107	$0.114	44%
Industrial	$0.051	$0.054	$0.079	$0.085	68%
Average Electric Bills ($) (2010$)	**2010**	**2015**	**2020**	**2022**	**2022 versus 2010**
Residential	$1,249	$1,292	$1,611	$1,657	33%
Commercial	$5,198	$5,392	$6,850	$7,067	36%
Industrial	$325,409	$344,740	$489,393	$513,178	58%

The study projects that average rates (in constant 2010 dollars) will increase slightly more under the REPS scenario over the period 2010 to 2022 than under the BAU scenario. The increase is driven by the fixed costs of T&D and existing generating capacity, common to both scenarios, Kentucky utilities would recover from a smaller quantity of annual sales under the REPS scenario. The magnitude of the increase is offset by savings in the absolute amount of incremental capacity costs and production costs that Kentucky utilities would have to recover as a result of the incremental EE and RE.

For example, the study projects that average residential rates (in constant dollars) would increase by 41% under the REPS scenario over the period 2012 to 2022 as compared to 40% under the BAU scenario. However, the study projects that average bills will increase by lesser amounts under the REPS scenario than under the BAU scenario over this period, primarily because customers will be using less electricity on average. For example, average residential bills are projected to increase by 33% over that period as compared to 47% under the BAU scenario.

If one assumes no regulation of carbon in Kentucky until after 2022 our analyses indicate that a REPS would still lead to lower electric bills. The reductions in electric bills would be less since customers would not be avoiding payment of carbon costs. The summary results from that analysis are presented in Table C-1 of Appendix C.

5. Impacts of a REPS on Kentucky's Economy

One of the key goals of the proposed REPS legislation is to "... create high-quality jobs, training, business, and investment opportunities in the Kentucky energy sector." Increased expenditures on EE and RE would generate increased economic activity in Kentucky directly as well as through various multiplier effects. The direct impacts would be additional jobs and increased business earnings resulting from increased expenditures on the production, sale, installation, and maintenance of materials and equipment required to achieve reductions from EE and to generate electricity from RE. In addition, there would be increased jobs and business earnings resulting from the multiplier effect of the direct expenditures as well as from the spending of any savings on electricity bills on other Kentucky goods and services.

Increased expenditures on EE and RE are not only expected to increase economic activity, they are generally expected to create more economic activity than expenditures on the electricity generation they would displace (e.g., generation for coal and natural gas). In other words increased expenditures on EE and RE are expected to have net positive economic impacts. The expectation of a net positive impact is based on several factors. First, EE and some forms of RE are projected to be less expensive in the long-term than electric generation from coal and natural gas. Second, typically a higher percentage of the total dollars spent on energy efficiency and renewable energy remain in the local economy than dollars spent on those traditional sources of electric generation. Finally, energy efficiency and renewable energy projects tend to be more labor-intensive than traditional generation, and thus typically create more jobs per dollar spent.

This chapter describes our estimate of the net incremental economic impact of the proposed REPS on Kentucky over the study period. The net incremental economic impact measures the difference between economic activity under the REPS scenario and under the BAU scenario. It is an estimate of "net" incremental impact because it reports the increase in economic activity from investments in additional quantities of EE and RE under the REPS scenario minus the decrease in economic activity due to the displacement of some electricity generation from coal and natural gas that would have otherwise occurred under the BAU scenario.

A. Expenditures on Electricity Resources and Change in Electricity Bills

Our study estimated the net incremental economic impact of the REPS on Kentucky based upon two major outputs of the ECM analyses of the BAU scenario and the REPS scenario. The first major output was net incremental expenditures on electric capacity, generation and efficiency resources in Kentucky. The second major output was the net change in electricity bills. The study uses those two outputs from the ECM as inputs to its economic models, IMPLAN and JEDI.

The ECM provides the expenditures to generate electricity from Kentucky resources and to reduce electricity use in Kentucky as capital costs plus operation and maintenance (O&M) costs in each year. The study calculates the net expenditure each year as expenditures under the REPS scenario minus expenditures under the BAU scenario. Thus, that net amount consists of two major components, an increase in capital and O&M expenditures associated with the acquisition of additional quantities of EE and RE under the REPS scenario and decrease in expenditures on generation from new natural gas units and existing coal units. The largest components of the increase are capital and O&M expenditures of $3.0 billion on EE, $5.4 billion on in-state wind, and $1.8 billion on solar while the decreases in capital plus O&M expenditures on new natural gas units and existing coal units are $5.7 billion and $ 2.1 billion respectively. Those projected changes in expenditures are reported in Table 5-1. The cumulative total net incremental capital and O&M expenditure in Kentucky through 2022 is $3.0 billion.

Table 5-1. Incremental capital and O&M expenditures (REPS scenario minus BAU)

Annual Expenditures (2010$ million)	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*TOTAL*
Energy Efficiency	$12	$130	$210	$292	$371	$367	$448	$530	$610	*$2,970*
Hydro	$0	$50	$50	$51	$28	$28	$29	$24	$24	*$285*
Wind (in-state)	$0	$86	$87	$88	$935	$949	$962	$1,120	$1,135	*$5,363*
Biomass	$25	$32	$39	$46	$52	$58	$62	$65	$69	*$449*
Solar	$234	$158	$159	$161	$178	$180	$182	$264	$266	*$1,782*
Natural Gas	-$14	-$24	-$228	-$799	-$796	-$405	-$765	-$1,223	-$1,418	*-$5,672*
Coal	-$40	-$65	-$111	-$116	-$155	-$266	-$395	-$443	-$528	*-$2,119*
Total	***$218***	***$367***	***$207***	***($277)***	***$614***	***$911***	***$523***	***$337***	***$159***	***$3,058***

The net expenditures include the costs of EE programs, costs of construction and operation of new RE facilities, and the reduction in expenditures on coal and natural gas generation due to the additional EE and RE. There is a reduction in expenditures on natural gas because less new gas capacity is built under the REPS scenario and there is less generation from natural gas. The reduction in expenditures on coal is attributable to the reduction in generation from existing coal units as compared to the BAU scenario, and a corresponding reduction in production and use of Kentucky coal associated with that reduction in generation. (Note that this estimate may over-state the reduction in coal-related expenditures, since Kentucky mines may sell the coal not used for electric generation in other markets.)

The second key input to the economic modeling was net incremental changes in electricity bills. Those net changes are reported in Table 5-2. The changes in bills are reported for the residential sector and the commercial/industrial sector since those sectors treat those changes differently. Residents re-spend savings elsewhere in the local economy, while business re-invest savings to increase their competitive position and increase their bottom line.

Table 5-2. Net incremental change in annual electricity bills (REPS scenario minus BAU)

Aggregate Change in Electricity Bills (2010$ million)	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*TOTAL*
Residential	-$7	$6	$24	$55	$123	$152	$198	$263	$341	*$1,154*
Commercial & Industrial	-$15	-$7	$12	$55	$197	$261	$349	$477	$630	*$1,959*
Total	***-$21***	***-$1***	***$36***	***$109***	***$320***	***$413***	***$547***	***$741***	***$970***	***$3,113***

If one assumes no regulation of carbon in Kentucky until after 2022 our analyses indicate that that the cumulative total net incremental capital and O&M expenditure in Kentucky through 2022 would be higher and the reduction in bills would be lower. Net direct expenditures are higher because the additional expenditures on EE and RE would be much the same but the decrease in expenditures on gas- and coal-fired generation would be less since those two amounts would not include carbon costs. The reduction in bills would be lower since customers would not be avoiding payment of carbon costs, as noted earlier. Those summary results are presented in Tables C-2 and C-3 of Appendix C.

B. Net Economic Impacts on Kentucky

This study estimates the net incremental impact of the proposed REPS on Kentucky's economy in terms of dollars (i.e., personal income, gross state product) and employment. Employment impacts are expressed in job-years since the duration of some jobs is limited (e.g. a RE construction project), while the duration of other jobs is longer-term (e.g. programs to install EE measures).

Each of those metrics is a function of three categories of economic activity, i.e., direct impacts, indirect impacts, and induced impacts. For example, total personal income from expenditures on EE is equal to personal income from direct impacts plus from indirect impacts plus from induced impacts. Direct economic impacts typically measure direct spending on goods and services (e.g., direct spending on construction or on purchases of equipment). The other two categories of impacts, indirect and induced, reflect the "multiplier" or ripple effect of direct economic impacts throughout the economy. Indirect impacts measure spending on local supplies and services by the firms that are providing the direct activity, while induced impacts measure the spending of wages earned by the workers involved in the direct activity as well as the workers providing the supporting supplies and services.

The net incremental dollar impact of the proposed REPS on Kentucky is equal to the net direct impacts from the EMS analyses plus indirect and induced impacts, i.e., the multiplier effects. The net incremental employment impact of the proposed REPS on Kentucky is equal to the job-years from the direct expenditures plus job-years from the indirect and induced impacts.

The study projected these dollar and employment impacts using IMPLAN, an input-output model, with augmentation for RE resources from the National Renewable Energy Laboratory JEDI model. The IMPLAN model uses industry and region-specific data sets describing the purchases of consumers and industries, as well as flows of goods and services between regions, to estimate indirect and induced impacts for a given set of direct expenditures. IMPLAN has built-in assumptions regarding the portion of each industry's supplies that are provided in-state and the portion of household spending that remains in-state. Synapse augmented the standard IMPLAN assumptions for the electricity industry by using JEDI to develop distinct coefficients for each renewable technology. Those coefficients are a more detailed and accurate estimate of the components of expenditures for each category of RE, such as manufacturing, installation, O&M and the composition of those components such as labor, raw materials, manufactured equipment, and services. By using these RE specific coefficients, and by calibrating the IMPLAN coefficients for Kentucky, the study was able to use IMPLAN to estimate the spin-off effects in Kentucky of new industry-specific activity by estimating the activity of suppliers required for that activity (indirect impacts) and the re-spending of workers' wages in the state's economy (induced impacts). The study also used IMPLAN to estimate the induced impacts from changes in annual electricity bills.

Dollar Impacts

The REPS is projected to have a positive net incremental impact on personal income and Gross State Product (GSP) in Kentucky as shown in Table 5-3. The incremental economic activity associated with the

REPS is projected to generate accumulative $4.6 billion in personal income and $6.0 billion in GSP for Kentucky over the study period.

Table 5-3. Net impacts on Kentucky economy (2010$ millions)

Economic Impacts	2017	2020	2022	Cumulative Total
Personal Income	$119	$765	$1,088	***$4,634***
Gross State Product	$118	$1,004	$1,474	***$6,038***

Employment Impacts

The REPS is also projected to have a positive net incremental impact on employment in Kentucky, as shown in Table 5-4. By 2022 the study projects a net increase of over 28,000 job-years, i.e., net of a reduction in job-years associated with electricity generation from new natural gas units and existing coal units. This projection consists of approximately 9,700 net direct job-years and approximately 18,800 net job-years from indirect and induced activity in Kentucky. The major sources of these incremental job-years are capital and operating expenditures on EE measures and RE facilities ($159 million in 2022) as well as electric customer spending of the amounts they saved on their electric bills, i.e., spending of their net energy savings from energy efficiency ($970 million in 2022).

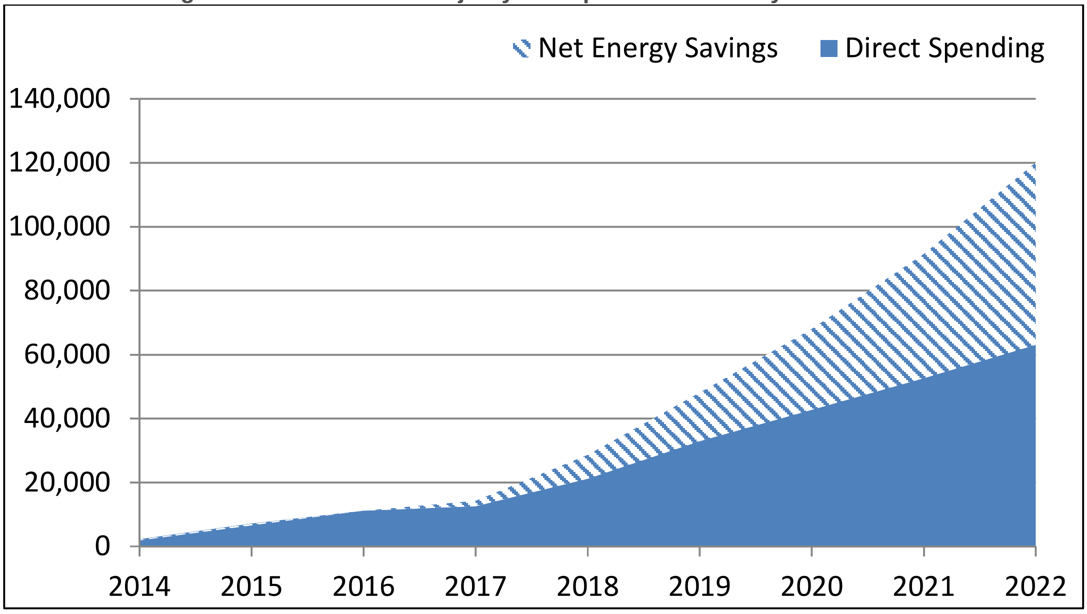
The net additional 9,700 direct job-years consists of over 12,500 job-years associated with acquiring additional EE and RE offset by a reduction of 2,500 job-years associated with less construction and operation of new natural gas units and a reduction of nearly 300 job-years associated with less generation from existing coal units.

Table 5-4. Net job-years in Kentucky by major electricity resource by year

Direct	***2014***	***2015***	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***
RE & EE	1,661	3,532	4,423	5,326	9,028	9,018	9,935	11,568	12,478
Natural Gas	-2	-3	-1,009	-3,103	-2,123	-53	-1,383	-2,533	-2,482
Coal	-24	-38	-65	-68	-90	-154	-230	-258	-307
Sub-Total	**1,636**	**3,491**	**3,348**	**2,156**	**6,815**	**8,811**	**8,322**	**8,777**	**9,688**
Indirect and Induced									
RE & EE	504	1,592	2,658	4,404	10,621	12,487	15,475	20,084	24,874
Natural Gas	-20	-35	-857	-2,770	-2,243	-593	-1,805	-3,058	-3,302
Coal	-208	-333	-572	-599	-800	-1,368	-2,034	-2,284	-2,720
Sub-Total	**276**	**1,225**	**1,229**	**1,035**	**7,578**	**10,525**	**11,636**	**14,742**	**18,851**
Direct, Indirect, and Induced									
RE & EE	2,166	5,124	7,081	9,730	19,649	21,505	25,410	31,651	37,351
Natural Gas	-22	-38	-1,867	-5,873	-4,366	-647	-3,188	-5,591	-5,785
Coal	-232	-370	-637	-666	-890	-1,522	-2,264	-2,542	-3,027
Total	**1,912**	**4,716**	**4,578**	**3,190**	**14,393**	**19,336**	**19,958**	**23,518**	**28,539**

The cumulative job-years from Table 5-4 amount to 120,000 over the study period. The cumulative job-years by year are shown in Figure 5-1, which illustrates the timing of impacts from new spending and net energy savings. As indicated in the figure, the impact of net energy savings increases in later years as the savings accumulates from increasing efficiency measures.

Figure 5-1. Cumulative net job-year impacts in Kentucky from a REPS



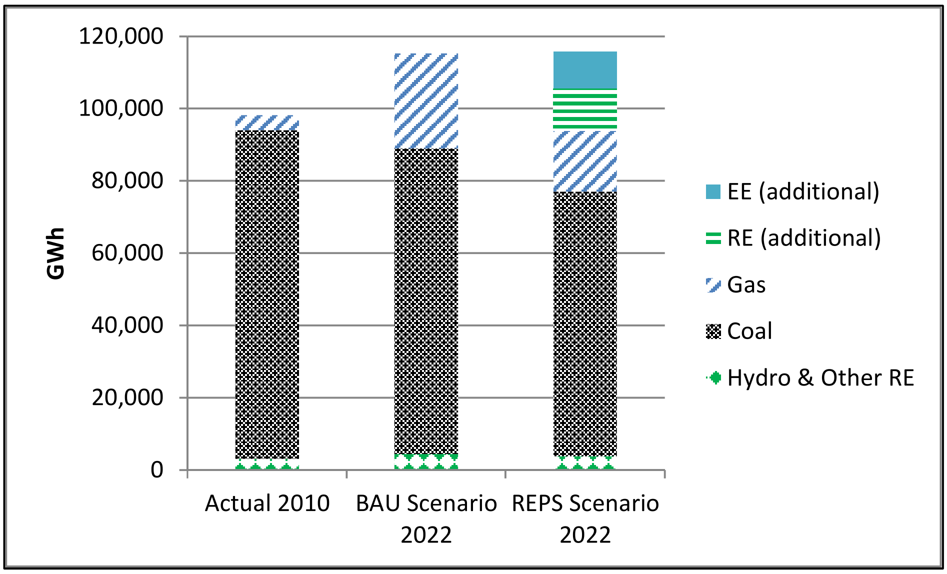
6. Conclusion

Our analysis indicates that establishment of a REPS has the potential to promote energy independence, control electricity costs, create jobs, and encourage economic growth in the Kentucky energy sector with, or without, carbon regulation during the study period. Key results of our analysis are summarized below. Appendix C provides the corresponding summary estimates of the impacts of a REPS assuming no carbon regulation during the study period.

A. Electricity Resource Portfolio

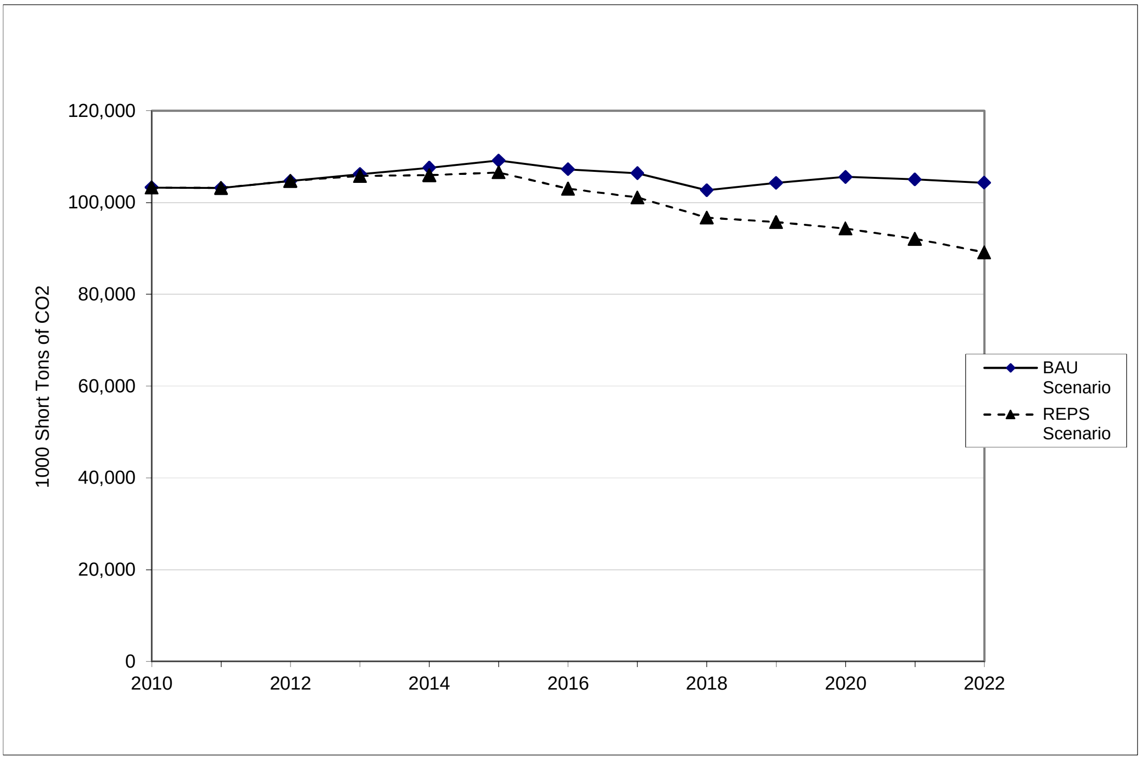
The REPS would increase the diversity of Kentucky's electricity resource portfolio. The increase in diversity is illustrated by the three bars in Figure 6-1. The first bar is Kentucky's actual generation mix in 2010, the second bar is the projected generation mix in 2022 under the BAU scenario, and the third bar is the projected generation mix in 2022 under the REPS scenario. The REPS scenario bar is clearly more diverse because the state's utilities would be achieving additional reductions from EE equivalent to 10.2 percent of annual retail sales and acquiring generation from RE equivalent to 12.5 percent of annual sales. Those additional quantities of EE and RE would enable the state to reduce its dependence on generation from coal and natural gas for its total annual energy requirements in 2022 from 71 percent and 25 percent under the BAU scenario to 63 percent and 15 percent under the REPS scenario.

Figure 6-1. Annual electricity requirements and sources in 2022 - REPS versus BAU



This increased diversity would result in lower annual emissions of carbon dioxide from Kentucky's electricity sector, as indicated in Figure 6-2. By 2022 the Kentucky electric sector would emit approximately 15% less carbon emissions under the REPS scenario than under the BAU scenario.

Figure 6-2. Annual carbon dioxide emissions in 2022 - REPS versus BAU



B. Electricity Bills

The REPS would lead to lower increases in electric bills over time. Table 6-1 provides comparison of the changes in average rates and average electric bills through 2022 under the BAU scenario and the REPS scenario, respectively.

Table 6-1. Annual electricity bills in 2022 - REPS versus BAU

Average Electric Rates ($/kWh) (2010$)	2010	BAU Scenario 2022	REPS Scenario 2022	REPS Scenario vs BAU Scenario
Total (All Sectors)	$0.067	$0.101	$0.102	1%
Residential	$0.086	$0.120	$0.121	1%
Commercial	$0.079	$0.113	$0.114	1%
Industrial	$0.051	$0.085	$0.085	0%
Average Electric Bills ($) (2010$)	**2010**	**BAU Scenario 2022**	**REPS Scenario 2022**	**REPS Scenario vs BAU Scenario**
Residential	$1,249	$1,834	$1,657	-10%
Commercial	$5,198	$7,658	$7,067	-8%
Industrial	$325,409	$557,989	$513,178	-8%

Under the REPS scenario, average rates are projected to be 1% higher than under the BAU scenario by 2022. However, average annual bills under the REPS scenario are projected to be 8% to 10% lower. The lower average bills in that year are primarily due to the fact that retail customers will be using approximately 8 percent less electricity on average than under the BAU scenario due to load reductions from EE. After 2022, the study indicates that average bills will be even less under the REPS scenario than under the BAU scenario as carbon regulation continues to drive the cost of electricity from natural gas and coal up and improvements in technology continues to drive the cost of electricity from RE down.

If one assumes no regulation of carbon in Kentucky until after 2022, our analyses indicate that a REPS would still lead to lower electric bills. The reductions in electric bills would be less since customers would not be avoiding payment of carbon costs. Those summary results are presented in Table C-1 of Appendix C.

C. Economic Impacts

The study estimates that a REPS would lead to a net increase in employment and business opportunities in Kentucky. In other words, the expenditures on additional reductions from EE and additional RE generation required under a REPS would create more economic activity and employment in Kentucky than the electric generation from new natural gas units and from existing coal units displaced by the additional EE and RE.

EE will require expenditures on materials and equipment to improve the efficiency of residences, businesses, and factories, while RE will require expenditures on construction and operation of RE projects. The net positive impact of these expenditures is attributable to three major factors. First, the portion of total expenditures that would remain in Kentucky is projected to be higher for EE and RE than for generation from coal and natural gas. Second, the EE and RE projects are expected to be more labor-intensive than generation from coal and natural gas, and thus are projected to create more jobs per dollar spent. Finally, the additional quantities of EE and RE are projected to result in lower electric bills over time, leaving Kentuckians with more discretionary income available to spend on other goods and services, which in turn would produce additional economic impacts.

The REPS is projected to have a positive net incremental impact on personal income, GSP, and employment in Kentucky. The incremental economic activity associated with the REPS is projected to generate a cumulative $4.6 billion in personal income and $6.0 billion in GSP for Kentucky over the study period. The REPS is also projected to lead to a net increase of over 28,000 job-years, i.e., net of a reduction in job-years associated with electricity generation from new natural gas units and existing coal units. This projection consists of approximately 9,700 net direct job-years and approximately 18,800 net job-years from indirect and induced activity in Kentucky. The major sources of these incremental job-years are installation of EE measures, construction of RE facilities, and electric customer spending of the amounts they saved on their electric bills. These summary results are shown in Table 6 2.

Table 6-2. Net impacts on Kentucky economy

Economic Impacts	2017	2020	2022	Cumulative Total
Job-years	3,190	19,958	28,539	***120,140***
Personal Income (2010$ millions)	$119	$765	$1,088	***$4,634***
Gross State Product (2010$ millions)	$118	$1,004	$1,474	***$6,038***

If one assumes no regulation of carbon in Kentucky until after 2022, our analyses indicate that a REPS would still lead to a net increase in employment and business opportunities in Kentucky, although those net increases would be somewhat smaller. Those summary results are presented in Tables C-4 and C-5 of Appendix C.

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Appendix B. Tables of Key Results

TABLE B-1 BAU Scenario Requirements, Sources and Supply Price

All costs in constant 2010 dollars.

CASE:	**BAU Scenario**											
Category	Units	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Retail Sales Forecast												
Retail Energy	GWh	95,558	96,916	98,130	99,571	100,976	102,341	103,793	105,333	106,897	108,369	109,948
Retail Demand	MW	18,181	18,439	18,670	18,944	19,212	19,471	19,747	20,041	20,338	20,618	20,919
Supply Forecast												
Capacity Requirement	MW	21,923	22,235	22,513	22,844	23,166	23,479	23,812	24,166	24,525	24,862	25,225
Capacity Sources												
Hydro & Other RE	MW	893	893	893	893	893	1,023	1,023	1,023	1,023	1,023	1,023
Coal	MW	14,553	14,553	14,553	14,553	13,753	13,753	13,753	13,753	13,389	13,025	12,662
Gas - Existing	MW	4,715	4,715	4,715	4,715	4,715	4,715	4,715	4,715	4,558	4,401	4,244
Gas - New CC	MW	0	0	0	1	909	1,251	2,862	2,862	2,862	3,402	4,030
Gas - New CT	MW	1	1	1	2	3	117	352	352	352	532	741
Renewable (additional)	MW	0	0	0	0	0	0	0	0	0	0	0
Sub-total In-State Capacity	MW	20,162	20,162	20,162	20,164	20,273	20,859	22,705	22,705	22,184	22,383	22,699
Out-of-State Capacity	MW	1,761	2,073	2,351	2,680	2,893	2,620	1,107	1,461	2,341	2,479	2,526
Total Capacity Provided	MW	21,923	22,235	22,513	22,844	23,166	23,479	23,812	24,166	24,525	24,862	25,225
Energy Requirement	GWh	100,198	101,622	102,895	104,406	105,879	107,311	108,833	110,448	112,088	113,632	115,287
Energy Sources												
Hydro & Other RE	GWh	3,445	3,445	3,445	3,445	3,445	4,472	4,472	4,472	4,472	4,472	4,472
Coal	GWh	91,442	92,747	93,914	95,293	91,416	89,959	83,798	85,057	85,965	84,257	82,205
Gas	GWh	5,293	5,411	5,517	5,649	10,999	12,860	20,544	20,899	21,631	24,883	28,590
Renewable (additional)	GWh	0	0	0	0	0	0	0	0	0	0	0
Sub-total In-State Generation	GWh	100,180	101,604	102,876	104,387	105,860	107,291	108,813	110,428	112,068	113,611	115,266
Out-of-State Generation	GWh	18	19	19	19	19	20	20	20	21	21	21
Total Energy Provided	GWh	100,198	101,622	102,895	104,406	105,879	107,311	108,833	110,448	112,088	113,632	115,287
Supply Price Forecast												
Average Production Cost	¢/kWh	5.31	5.33	5.36	5.40	5.58	5.72	7.34	7.64	7.93	8.25	8.56
Retail Margin	¢/kWh	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58
Average Retail Rate	¢/kWh	6.89	6.91	6.94	6.98	7.16	7.31	8.92	9.22	9.52	9.83	10.15

TABLE B-2 BAU Scenario Avoided Cost, Average Retail Rates and Average Electric Bills

All costs in constant 2010 dollars.

CASE:	BAU Scenario											
Category	Units	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Avoided Costs by costing period												
Avoided Resource Cost	¢/kWh	5.10	6.51	7.14	7.58	8.18	8.29	8.42	8.63	8.85	9.22	9.52
Avoided Capacity Cost	$/kW-yr	64.00	64.00	64.00	64.00	64.00	64.00	64.00	64.00	64.00	64.00	64.00
	¢/kWh	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
Avoided Energy Only Cost	¢/kWh	3.88	5.29	5.92	6.36	6.96	7.07	7.20	7.41	7.63	8.00	8.30
Average Retail Rates												
System-Wide average	¢/kWh	6.89	6.91	6.94	6.98	7.16	7.31	8.92	9.22	9.52	9.83	10.15
Residential	¢/kWh	8.73	8.75	8.77	8.82	8.99	9.15	10.77	11.07	11.36	11.68	11.99
Commercial	¢/kWh	8.00	8.02	8.05	8.10	8.27	8.43	10.05	10.34	10.64	10.95	11.27
Industrial	¢/kWh	5.21	5.23	5.26	5.31	5.48	5.62	7.23	7.53	7.83	8.14	8.46
Average Customer Bills (2010$)												
Residential	$/yr	1,295	1,302	1,308	1,319	1,350	1,377	1,625	1,676	1,727	1,780	1,834
Commercial	$/yr	5,280	5,309	5,335	5,384	5,517	5,632	6,735	6,960	7,185	7,417	7,658
Industrial	$/yr	333,811	336,054	338,329	342,448	354,950	364,340	470,667	491,971	513,290	535,362	557,989

TABLE B-3 REPS Scenario Requirements, Sources and Supply Price

All costs in constant 2010 dollars.

CASE:	**REPS Scenario**										
Category	Units	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Load Forecast												
Retail Energy	GWh	95,558	96,916	98,089	99,140	99,903	100,370	100,672	101,056	101,207	101,010	100,666
Retail Demand	MW	18,181	18,439	18,662	18,862	19,007	19,096	19,154	19,227	19,256	19,218	19,153
Supply Forecast												
Capacity Requirement	MW	21,923	22,235	22,504	22,745	22,920	23,027	23,096	23,185	23,219	23,174	23,095
Capacity Sources												
Hydro & Other RE	MW	893	893	893	893	893	1,023	1,023	1,023	1,023	1,023	1,023
Coal	MW	14,553	14,553	14,553	14,553	13,753	13,753	13,753	13,753	13,389	13,025	12,662
Gas - Existing	MW	4,715	4,715	4,715	4,715	4,715	4,715	4,715	4,715	4,558	4,401	4,244
Gas - New CC	MW	0	0	0	1	909	909	1,816	1,816	1,816	1,909	2,156
Gas - New CT	MW	1	1	1	2	3	3	3	3	3	34	116
Renewables (new)	MW	0	62	124	202	280	358	496	634	773	922	1,071
Sub-Total In-State Capacity	MW	20,162	20,224	20,286	20,366	20,553	20,761	21,806	21,945	21,562	21,314	21,271
Out-of-State Capacity	MW	1,761	2,011	2,218	2,379	2,367	2,266	1,290	1,240	1,657	1,860	1,824
Total Capacity Provided	MW	21,923	22,235	22,504	22,745	22,920	23,027	23,096	23,185	23,219	23,174	23,095
Energy Requirement	GWh	100,198	101,622	102,852	103,954	104,754	105,244	105,561	105,963	106,122	105,915	105,554
Energy Sources												
Hydro & Other RE	GWh	3,445	3,445	3,445	3,445	3,445	3,864	3,864	3,864	3,864	3,864	3,864
Coal	GWh	91,442	92,380	92,518	93,057	87,582	85,988	80,390	79,597	78,355	76,206	73,153
Gas	GWh	5,293	5,378	5,390	5,447	11,216	10,975	15,531	15,368	15,393	15,813	16,983
RE (additional)	GWh	0	401	1,480	1,986	2,491	4,397	5,756	7,115	8,490	10,012	11,535
Sub-Total In-State Generation	GWh	100,180	101,604	102,834	103,935	104,735	105,225	105,541	105,944	106,102	105,895	105,535
Out-of-State Generation	GWh	18	19	19	19	19	19	19	19	19	19	19
Total Energy Provided	GWh	100,198	101,622	102,852	103,954	104,754	105,244	105,561	105,963	106,122	105,915	105,554
Supply Price Forecast												
Average Production Cost	¢/kWh	5.31	5.34	5.39	5.45	5.65	5.79	7.35	7.68	8.00	8.32	8.63
Retail Margin	¢/kWh	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58
Average Retail Rate	¢/kWh	6.89	6.92	6.98	7.04	7.23	7.37	8.93	9.27	9.58	9.90	10.22

TABLE B-4 REPS Scenario Avoided Cost, Average Retail Rates and Average Electric Bills

All costs in constant 2010 dollars.

CASE:	**REPS Scenario**											
Category	Units	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Avoided Costs by costing period												
Avoided Resource Cost	¢/kWh	5.11	6.09	7.28	7.70	8.12	8.36	8.56	8.80	9.01	9.17	9.36
Avoided Capacity Cost	$/kW-yr	64.00	64.00	64.00	64.00	64.00	64.00	64.00	64.00	64.00	64.00	64.00
	¢/kWh	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
Avoided Energy Only Cost	¢/kWh	3.89	4.87	6.06	6.48	6.91	7.14	7.34	7.58	7.79	7.95	8.14
Average Retail Rates												
System-Wide average	¢/kWh	6.89	6.92	6.98	7.04	7.23	7.37	8.93	9.27	9.58	9.90	10.22
Residential	¢/kWh	8.73	8.76	8.82	8.86	9.05	9.20	10.77	11.12	11.44	11.77	12.10
Commercial	¢/kWh	8.00	8.04	8.09	8.15	8.33	8.48	10.05	10.39	10.71	11.03	11.36
Industrial	¢/kWh	5.21	5.24	5.30	5.37	5.57	5.71	7.26	7.57	7.88	8.19	8.50
Average Customer Bills (2010$)												
Residential	$/yr	1,267	1,276	1,285	1,292	1,314	1,327	1,541	1,580	1,611	1,635	1,657
Commercial	$/yr	5,280	5,319	5,360	5,392	5,498	5,559	6,533	6,707	6,850	6,966	7,067
Industrial	$/yr	333,811	336,599	340,410	344,740	356,455	363,176	458,093	474,524	489,393	501,857	513,178

Appendix C. Summary impacts of a REPS assuming no regulation of carbon in Kentucky until after 2022

Given the uncertainty regarding the timing and magnitude of future regulation of carbon, this Appendix presents an estimate of the summary impacts of a REPS assuming no regulation of carbon in Kentucky until after 2022

Table C-1. Annual electricity bills in 2022, no carbon regulation - REPS versus BAU

Average Electric Rates ($/kWh) (2010$)	2010	BAU Scenario 2022	REPS Scenario 2022	REPS Scenario vs BAU Scenario
Total (All Sectors)	$0.067	$0.077	$0.080	3%
Residential	$0.086	$0.096	$0.099	3%
Commercial	$0.079	$0.089	$0.091	3%
Industrial	$0.051	$0.060	$0.062	3%
Average Electric Bills ($) (2010$)	**2010**	**BAU Scenario 2022**	**REPS Scenario 2022**	**REPS Scenario vs BAU Scenario**
Residential	$1,249	$1,466	$1,350	-8%
Commercial	$5,198	$6,020	$5,671	-6%
Industrial	$325,409	$398,623	$376,421	-6%

Table C-2. Incremental capital and O&M expenditures, no carbon regulation (REPS scenario minus BAU)

Annual Expenditures (2010$ million)	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*TOTAL*
Energy Efficiency	$12	$130	$210	$292	$371	$367	$448	$530	$610	*$2,970*
Hydro	$0	$50	$50	$51	$28	$28	$29	$24	$24	*$285*
Wind (in-state)	$0	$86	$87	$88	$935	$949	$962	$1,120	$1,135	*$5,363*
Biomass	$25	$32	$39	$46	$52	$58	$62	$65	$69	*$449*
Solar	$234	$158	$159	$161	$178	$180	$182	$264	$266	*$1,782*
Natural Gas	-$14	-$24	-$228	-$799	-$762	-$359	-$703	-$1,123	-$1,276	*-$5,288*
Coal	-$40	-$65	-$111	-$116	-$100	-$159	-$223	-$236	-$266	*-$1,315*
Total	***$218***	***$367***	***$207***	***($277)***	***$704***	***$1,064***	***$757***	***$644***	***$563***	***$4,246***

Table C-3. Net incremental change in annual electricity bills, no carbon regulation (REPS scenario minus BAU)

Aggregate Change in Electricity Bills (2010$ million)	***2014***	***2015***	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***TOTAL***
Residential	-$7	$6	$24	$55	$95	$104	$125	$167	$214	*$783*
Commercial & Industrial	-$15	-$7	$12	$55	$130	$151	$184	$261	$347	*$1,118*
Total	***-$21***	***-$1***	***$36***	***$109***	***$226***	***$256***	***$309***	***$428***	***$561***	***$1,901***

Table C-4. Net impacts on Kentucky economy, no carbon regulation (2010$ millions)

Economic Impacts	**2017**	**2020**	**2022**	**Cumulative Total**
Personal Income	$119	$646	$877	***$4,011***
Gross State Product	$118	$837	$1,174	***$5,157***

Table C-5. Net job-years in Kentucky by major electricity resource by year, no carbon regulation

Direct	***2014***	***2015***	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***
RE & EE	1,661	3,532	4,423	5,326	9,028	9,018	9,935	11,568	12,478
Natural Gas	-2	-3	-1,009	-3,103	-2,118	-47	-1,375	-2,520	-2,464
Coal	-24	-38	-65	-68	-58	-93	-130	-137	-155
Sub-Total	**1,636**	**3,491**	**3,348**	**2,156**	**6,851**	**8,878**	**8,430**	**8,910**	**9,859**
Indirect and Induced									
RE & EE	504	1,592	2,658	4,404	8,787	9,448	10,871	14,065	17,004
Natural Gas	-20	-35	-857	-2,770	-2,193	-526	-1,714	-2,912	-3,094
Coal	-208	-333	-572	-599	-514	-820	-1,147	-1,214	-1,369
Sub-Total	**276**	**1,225**	**1,229**	**1,035**	**6,081**	**8,102**	**8,009**	**9,939**	**12,541**
Direct, Indirect, and Induced									
RE & EE	2,166	5,124	7,081	9,730	17,815	18,466	20,805	25,633	29,482
Natural Gas	-22	-38	-1,867	-5,873	-4,311	-573	-3,090	-5,432	-5,558
Coal	-232	-370	-637	-666	-572	-913	-1,277	-1,351	-1,524
Total	**1,912**	**4,716**	**4,578**	**3,190**	**12,932**	**16,980**	**16,439**	**18,850**	**22,400**