Interindustry Forecasting at the University of Maryland

Economic Impact of Energy and Environmental Policy in Appalachia

Final Report
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prepared for
Appalachian Regional Commission

prepared by
Inforum and
Keybridge Research

Final Report

Economic Impact of Energy and Environmental Policy in Appalachia

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The Appalachian Regional Commission's mission is to be an advocate for and partner with the people of Appalachia to create opportunities for self-sustaining economic development and improved quality of life.

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Executive Summary

The Appalachian Regional Commission (ARC) has requested that this study be performed to analyze the potential economic impact for Appalachia of federal, state and local energy and environmental policies. To this end, a modeling system has been constructed that can evaluate the impacts of policies at the national, state and county level, particularly for the set of counties in the Appalachian region.

Although the ultimate policies that may be enacted are uncertain, an understanding of the likely impacts of such policies can be gained through the use of scenario analysis, using the modeling system mentioned above. Quantitative assessment of economic policies plays a useful role in informing dialogue among key stakeholders and policy decisions. One important type of such assessment is scenario based economic modeling, where scenarios of the future are compared to assess the economic benefits and costs of alternative policy choices.

Inforum brings experience to bear in detailed interindustry, regional and energy modeling, as well as experience in the analysis of alternative government and corporate policy. Inforum's special expertise is building models that provide a consistent and detailed representation of national and regional economic outcomes. For this study, Inforum has collaborated with energy policy experts from Keybridge Research. Keybridge Research has extensive experience with economic modeling and expertise in providing strategic guidance on the economics of federal climate change policy.

The study focuses particularly on issues germane to the electric power industry, and the interrelationships between the electric power industry and the local economies. However, the modeling system is comprehensive, in that all industry sectors of the economy are included, and energy demand is modeled for the residential, commercial and industrial sectors.

The policy scenarios have been developed partly with the objective of understanding what are the least cost and highest impact strategies and policies for the states to pursue. Since a framework for this understanding has already been developed in the ARC *Regional Blueprint*[1], we relate the current set of scenarios to the Strategic Objectives for economic and energy development are outlined in that blueprint:

1. Promote energy efficiency in Appalachia to enhance the Region's economic competitiveness.
2. Increase the use of renewable energy resources, especially biomass, in Appalachia to produce alternative transportation fuels, electricity, and heat.
3. Support the development of conventional energy resources, especially advanced clean coal, in Appalachia to produce alternative transportation fuels, electricity, and heat.

This report briefly describes the content and structure of the Energy Policy Impact Model (EPIM) developed by Inforum for the ARC. A more detailed description of the model is in Appendix B. The Energy Policy Impact Model constructed for this project is a dual-level

[1] Energizing Appalachia: A Regional Blueprint for Economic and Energy Development, October 2006, at http://www.arc.gov/images/newsroom/publications/energyblueprint/energyblueprint.pdf.

system, comprised of the Inforum LIFT (Long-term Interindustry Forecasting Tool) model of the U.S. national economy, combined with the CUEPS (County-Utility Energy Policy Simulator) model of counties and electric utilities.

The LIFT model works at a detailed sectoral level (about 90 private industries plus government sectors) and shows the interactions between industries, and the impacts on industry output of changes in exports and imports, personal consumption, investment, and government spending. The LIFT model integrates the National Income and Product Accounts (NIPA) with the detailed input-output accounts produced by the U.S. Bureau of Economic Analysis (BEA). LIFT forecasts at an annual frequency, and the standard version has a forecast interval to 2035.

The CUEPS model includes a detailed database of 3140 counties and 3356 electric utility establishments. A county-utility bridge is used to relate economic activity by county to service demands by electric utility, and to relate cost changes by utility to the effects on the local economies served by that utility. County level economic data is obtained from Woods & Poole, and aggregated to a level of 11 private sector industries and 3 government sectors. These 14 sectors are linked to the LIFT 90 sector forecasts to determine county level output, employment, prices and incomes.

In this study, we examine several policy scenarios that explore implications of pursuing the Strategic Objectives. These scenarios are compared to a reference case that was developed specifically for this study, but is consistent with the reference case of the Department of Energy (DOE) *2011 Annual Energy Outlook*. For each scenario, consistent simulations are developed of the LIFT national model and the CUEPS model of counties and utilities.

The following scenarios are analyzed in this study:

1. *Reference Case* – The reference case for LIFT and CUEPS was developed to be consistent with the Annual Energy Outlook (AEO) 2011 Reference Case.
2. *Electricity Efficiency* – ARC sponsored an earlier study *Energy Efficiency in Appalachia*[2] that summarizes various energy efficiency improvements in the residential, commercial, transportation, and industrial sectors in Appalachia, and quantifies the energy savings. A scenario has been implemented incorporating these savings in *LIFT* and CUEPS to obtain national and county wide results. This scenario relates to the Blueprint Strategic Objective #1.
3. *Carbon Mitigation* – This scenario assumes the adoption of a carbon price in the near future, and is designed to be consistent with the greenhouse gas (GHG) price case in the AEO 2011 side cases. This scenario ties to all three Strategic Objectives, as the presence of a carbon pricing scheme will spur increased energy efficiency, increased use of renewables such as wind and biomass, and stimulate the development of novel uses of conventional fossil fuel resources.
4. *Clean Energy Standard* – This scenario assumes the adoption of a clean energy standard for electric power generation, and assumes aggressive development of wind and biomass resources for electric power generation in the region. We have estimated the development of biomass potential by county and the calculation of local output and employment impacts of wind and biomass development. This scenario relates to Blueprint Strategic Objective #2.

[2] *Energy Efficiency in Appalachia: How Much More is Available at What Cost, and by When?*, May 2009, prepared by the Southeast Energy Efficiency Alliance, for ARC, available at http://www.arc.gov/assets/research_reports/EnergyEfficiencyinAppalachia.pdf.

5. *Expanded Natural Gas Development* – This scenario explores the intensive development of natural gas resources in the Appalachian region. We use the AEO 2011 side case high shale gas scenario to provide the national context, and have developed shale gas potential by county and state. This scenario relates to Blueprint Strategic Objective #3.

In the Reference case, the Inforum LIFT model was calibrated to the Annual Energy Outlook (AEO) 2011 macroeconomic and energy consumption variables. The CUEPS model was run in conjunction with LIFT, using national forecasts as determinants of the growth of basic industries, changes in prices and earnings rates, and the national changes in the interindustry relationships. The other scenarios were developed by changing selected assumptions in the Reference case to determine the national and county level impacts of policy changes or technology assumptions.

ES.1 Key Study Findings

This study has developed alternative scenarios to aid in the analysis of likely policy outcomes. The scenario choice, as stated above, was informed by decisions of likely outcomes, but also guided by the strategic objectives as outlined in the ARC regional energy blueprint. Our goal has been to contribute to the dialogue surrounding these objectives by providing quantitative, scenario-based analysis. The modeling system used provides comprehensive national level summaries of policy impacts, as well as economic and electric power sector impacts at the county level.

Some main policy conclusions which we can draw from this quantitative analysis are:

1. Energy Efficiency stands out as an extremely effective policy to pursue and may in fact pay for itself in terms of higher GDP, employment, and government revenue. It benefits the economy in terms of increasing aggregate multifactor productivity, reducing prices, and increasing employment and real incomes. However, certain localities that are dependent on coal are likely to have lower employment and income.
2. Natural gas from shale is a very promising avenue for stimulating employment and income growth in the northern Appalachian region, as well as contributing to a smaller carbon footprint.
3. Wind resources in Appalachia, though important, are not huge. Wind should be relied upon as one component of strategy for economic development of the region. According to our estimates, total potential wind capacity in the entire Appalachian region is about 16.6 GW, implying a total investment of about $34 billion (2009$), spread over a period of years.
4. Biomass resources are also important. We expect a total contribution of $10 billion to the Agriculture and forestry sector, as well as a contribution of about $5 billion to the Transportation sector through 2020, if biomass resources are aggressively developed.
5. Carbon mitigation strategies would accomplish important objectives through the reduction of a large share of U.S. carbon emissions which are generated from coal burned by electric utilities. However, unless accompanied by other strategies that stimulate development in the Appalachian region, several Appalachian counties would be hurt disproportionately.

ES.2 Scenario Comparisons

Results for selected key macroeconomic variables are summarized in table ES.1. For each variable, the first line shows the value of that variable in the Reference case in 2015 and 2020, and the other lines show the differences from the Reference for each of the policy cases.

Several main conclusions stand out at the macroeconomic level:

1. The High Efficiency case shows by far the largest positive impact. Gains from increases in electricity efficiency are significant, whether we use GDP, real income, or employment for our criteria. Policy actions that can be taken to accelerate increases in the development of efficient technologies or to provide incentives for the adoption of existing technologies have a high payoff, and may justify public expenditures either from direct subsidies, public assistance, or tax credits. By 2020, the High Efficiency case shows real GDP higher by 75 billion (2005$), with real Disposable income up by $61 billion. Total employment is higher by 526 thousand jobs. Note that the High Efficiency case also shows the largest reduction in aggregate energy intensity of all the scenarios examined, and also manages to reduce total CO2 emissions by 580 MMT by 2020.
2. The Carbon Mitigation case shows the largest negative impact. Although it is the most effective scenario at reducing carbon emissions (742 MMT reduction by 2020), it does so at the cost of lower GDP, employment and real income. Aggregate energy intensity is reduced, but not by as much as the High Efficiency scenario.
3. The Clean Energy Standard is a highly effective way of reducing carbon emissions, without a large cost to GDP, real income or employment. Although the changes in these three variables are all slightly negative with respect to the Reference case, the differences are not large in percentage terms.
4. Expanded Natural Gas Development is somewhat positive for aggregate GDP and real income, significantly positive for employment, and with measurable reductions in carbon emissions (285 MMT reduction by 2020).

Table ES.1 Macroeconomic Summary of Key Variables Across Scenarios

		2015	2020
Real Gross Domestic Product (bil 2005$)	Reference	15,474	17,723
	High Efficiency	34	75
	Carbon Mitigation	-60	-154
	Clean Energy Standard	-2	-26
	Expanded Natural Gas	14	21
Real Disposable Income (bil 2005$)	Reference	11,711	13,309
	High Efficiency	31	61
	Carbon Mitigation	-21	-45
	Clean Energy Standard	0	-20
	Expanded Natural Gas	10	15
Employment (thousands)	Reference	154,733	161,550
	High Efficiency	320	526
	Carbon Mitigation	-401	-999
	Clean Energy Standard	49	-39
	Expanded Natural Gas	147	284
GDP Deflator (2005 = 1.0)	Reference	1.19	1.31
	High Efficiency	0.00	-0.01
	Carbon Mitigation	0.02	0.04
	Clean Energy Standard	0.00	0.00
	Expanded Natural Gas	0.00	-0.01
Energy Intensity (btus/GDP)	Reference	6.66	5.93
	High Efficiency	-0.20	-0.45
	Carbon Mitigation	-0.23	-0.24
	Clean Energy Standard	-0.18	-0.28
	Expanded Natural Gas	-0.08	-0.10
Total CO2 Emissions (million metric tons)	Reference	5,762	5,791
	High Efficiency	-225	-580
	Carbon Mitigation	-555	-742
	Clean Energy Standard	-408	-718
	Expanded Natural Gas	-197	-285

Line 1 is reference case value

Other lines are differences from reference

These national level results are fully consistent with our findings at the Appalachia state and county levels. However, we find greater differences in impact at this level due to different distributions of production and employment by industry, as well as differences in the distribution of coal and natural gas resources, and in the availability of biomass and wind development in the Clean Energy Standard scenario.

As we will see in section 6.4, several West Virginia counties suffer from declines in employment and output in the High Efficiency case, even though this scenario shows strong positive effects at the national level. This is due to the fact that more than half the electric power generation in the West Virginia territory is from coal, and this coal consumption supports the local mining industry. As electricity efficiency increases, coal consumption decreases, with resulting decreases in coal industry employment.

In section 6.2.6 we show some comparisons at the aggregate state level across scenarios. Some of the main conclusions from these are:

1. Consistent with the U.S. national results, the High Efficiency case shows the most positive impacts on employment and real income. The Carbon Mitigation case shows the largest negative impacts. Results for the CES are mixed, but small, and the Expanded Natural Gas case has slightly positive impacts.

2. However, there is a significant degree of variation within the states, which is reflective of an even greater variation at the county level. For example, although all states benefit in the High Efficiency scenario, the benefit to Kentucky and West Virginia is not nearly as large, since these are states more heavily dependent on coal mining. The state and county impacts in the CES case are a mix of positive impacts from Wind and Biomass, countered by negative impacts from reductions in coal. Kentucky and Ohio stand out with negative employment changes relative to the Reference case. The Expanded Natural Gas case shows states like Ohio, New York and Pennsylvania benefitting more than the average, as these states contain some of the richer shale resources.

Introduction

This report describes a set of tools and analysis used to approach energy and environmental problems relevant to Appalachia. The goal of the project is not only to develop these tools, but to apply them to help inform policymakers about the costs and benefits of different energy strategies, from alternative and renewable energy policies to carbon mitigation schemes and energy efficiency regulation.

Inforum has a long and successful history in the development of detailed industry and regional models, as well as the development of models focusing on a particular industry or region. Working with government and private sector research sponsors, Inforum constructs and applies these economic models to investigate a variety of issues, including energy and environmental public policies. Inforum is widely recognized as a pioneer in the construction and application of dynamic, interindustry macroeconomic models which portray the economy in a unique "bottom-up" fashion.

For this project, Inforum has teamed with policy experts from Keybridge Research, an international economics and public policy consulting firm. Keybridge serves as energy policy advisors to a leading association of Fortune 500 CEOs and has previously teamed with Inforum to perform numerous energy-focused economic modeling studies for private and non-profit clients. The project team's experience with economic modeling and expertise in providing strategic guidance on the economics of federal climate change policy make it uniquely suited to estimate and evaluate the economic impacts of new energy policies in Appalachia.

1.1 Context and Objectives

Legislative and regulatory actions at the state, regional, and federal levels have already resulted in significant changes to energy markets. In 2005, Congress passed the Energy Policy Act (EPAct) with the goals of increasing energy efficiency and stimulating renewable power. In 2007, the Energy Independence and Security Act was passed, which contained additional incentives for energy efficiency as well as the stimulation of biofuels production. Sweeping regulatory and legislative actions related to reducing greenhouse gas emissions are yet to come and will have great impacts on the patterns of U.S. energy demand, supply, and prices. In turn, such changes will have important impacts on the growth and composition of local economies, especially those of Appalachia.

At the state and local level, several governments have initiated strategies to help promote energy efficiency investments and renewable energy technologies. ARC has developed a regional blueprint that established three goals for energy and economic development:

1. Promote energy efficiency in Appalachia to enhance the region's economic competitiveness.
2. Increase the use of renewable energy resources to produce alternative transportation fuels, electricity, and heat.
3. Support the development of conventional energy resources to produce alternative transportation fuels, electricity, and heat.

At the federal level, Congress has been considering various pieces of legislation ranging from renewable energy standards for the electric power sector to an economy-wide cap on carbon emissions. For a variety of reasons, including economic weakness, the progression of proposals through Congress has been temporarily suspended. Once economic growth is sustained, however, energy and climate legislation will likely reemerge as a priority for federal policymakers. In addition, the U.S. EPA is in the process of developing its regulations of greenhouse gases emissions that will probably take effect in 2012.

Within this context, the ARC has sought to identify and articulate a comprehensive regional response to such legislation and regulation, one that would enhance the benefits and mitigate the costs of such policies to the region's economy. As part of this task, ARC has expressed an interest in developing modeling infrastructure designed to assess the economic opportunities and challenges for the Appalachian region of energy policies and regulations of greenhouse gas emissions. Among several capabilities, this infrastructure should enable the evaluation of the employment and economic impacts of energy and environmental policies and investments. In this project we:

1. Develop modeling infrastructure that quantifies and models the Appalachian regional economy with particular regard to county-by-county makeup of industrial output and employment, energy use and production, and household income. Quantification has been realized via the compilation and validation of available data from U.S. government and other sources for the 13 states and 420 counties that make up Appalachia. The modeling of these regions has been accomplished by tying county-level economic models to Inforum's *LIFT* (Long-term Interindustry Forecasting Tool) model.
2. Use the modeling infrastructure to develop a baseline projection for the regional economy through 2020. Given this baseline, alternative scenarios have been developed to estimate the employment and economic impacts of plausible alternative energy and environmental policies. Once again, particular emphasis is on defining those impacts at the county level, as well as at a regional macro-level. These scenarios provide tangible examples of how the modeling system can be used for further research.
3. Consider the modeled impacts of various policies, and develop a strategy to enhance the benefits and mitigate the costs of policies on the region's industry and households. Such strategies could include how state and local governments can leverage federal initiatives for regional economic development, energy conservation, or alternative technologies. Modeling results could facilitate the development of such initiatives.

For example, the advent of carbon pricing under a cap and trade or direct taxation scheme might have a large negative impact on Appalachia's coal industry. However, policies to facilitate carbon sequestration or other emission-reducing technologies may mitigate these impacts. Moreover, there are many opportunities to leverage the region's other energy resources such as biomass, natural gas, and wind.

A modeling infrastructure, informed with insights on local economic composition, resource endowments, and technological possibilities can be used to illustrate the tradeoffs among various policy options and regional development strategies. Given the uncertainty with regard to the nature of future climate policies, as well as the market and technological responses to those policies, the timing and magnitude of economic impacts will also be uncertain. However, while the model proposed cannot provide certainty, it will provide an accounting framework that will identify areas of both vulnerability and opportunity and will greatly illuminate the issues which determine the timing and magnitude of climate policy impacts. In turn, this analysis can help policymakers craft strategies to better mitigate economic hardships and maximize economic opportunities associated with structural and technological change.

1.2 Overview of This Study

This study provides a context to the climate and energy issues facing Appalachia and uses scenario based analysis to understand aspects of likely policies' impacts on the Appalachian region. Chapter 2 begins with a review of the taxonomies of policies that have been proposed in the last ten years or so, including (1) national climate and energy legislation; (2) national environmental legislation; (3) state and regional climate and energy policies; and (4) energy supply policy. Chapter 3 reviews some of the wealth of literature and models that have been used to analyze policies and predict their impacts. This helps to put the present study in context, and to compare our approach with other modelers. Chapter 4 summarizes the EPIM modeling system, which consists of the Inforum LIFT model of the U.S. and the CUEPS model of counties and utilities. Chapter 5 summarizes the set of scenarios we have chosen to examine in this study, and provides rationale for those choices. It also describes how the scenarios were devised, including information about assumptions used or calibration to other modeling systems such as the National Energy Modeling System (NEMS). Chapter 6 presents selected model results for the scenarios, at the macro, state and county level. Chapter 7 presents conclusions and suggestions as to the usefulness of this study, and suggests directions for further research.

Several appendices are included that include detailed information not appropriate for the main text. Appendix A documents the derivation of county economic data, electric utility data, and the county-utility bridge used to link counties and utilities. Appendix B describes the operation of the LIFT and CUEPS models in more detail than chapter 4. Appendix C describes the development of wind and biomass assumptions that are used in the Clean Energy Standard scenario. Finally, Appendix D describes how the estimates of coal production by county were developed.

1.3 Scenario Based Analysis

This study is based on the method of scenario based analysis. First, a Reference case is developed which embodies assumptions as to likely trajectories of macroeconomic and energy variables. In this study, the Reference case is calibrated to the Annual Energy Outlook 2011, which is run using the NEMS model. The policy scenarios can be seen as alternative states of the world to the Reference case, and they embody specific changes in certain assumptions. By comparing results from the policy cases with the Reference case, one can determine the "delta" or change of selected variables in response to the changed assumptions in the policy scenarios. Section 4.4 describes this process in more detail, and concrete examples are discussed in Chapter 5.

2. Policy Review

2.1 National Climate & Energy Legislation

2.1.1 Policy Summary

Although several significant energy bills have been passed by Congress during the last six years, it is widely anticipated that more legislation that directly addresses climate change may be passed in the future. Thus far, the most widely discussed approach to climate policy has been a cap and trade system. Such a system would require GHG emitters to obtain permits for every ton of GHGs emitted, with the economy-wide number of permits available capped at a level that would be ratcheted down over time.

The 111th Congress came the closest to successfully passing a cap and trade bill, with the American Clean Energy and Security Act of 2009 ("Waxman Markey") passing the House. However, a similar bill, the American Power Act ("Kerry Lieberman") stalled in the Senate, prompting many legislators to pronounce the cap and trade approach to climate policy dead. Had they succeeded, these legislative efforts would have had a major impact on the nation's energy industry, increasing the costs associated with using traditional, more GHG-intensive energy sources and making less GHG-intensive sources of energy more competitive.

More recently, policymakers have discussed legislation that focuses on the electric power sector. Several legislators and the President have proposed the adoption of a national renewable energy standard (RES) or a clean energy standard (CES). Such legislation would require that an increasing proportion of electric power be produced from renewable energy, in the case of an RES, or with renewable, nuclear, and other low- or no-carbon energy sources, in the case of a CES. In his 2011 State of the Union address, President Obama suggested that 80% of the nation's electricity should come from "clean" sources by 2040. Similar policies have been proposed by Senator Bingaman, Senators Tom Udall and Mark Udall, Senator Lugar, and others. To date, no bills that include a national renewable energy standard have been passed.

2.1.2 Policy Impacts on Appalachia

Any of the policies discussed above would likely have a significant impact on Appalachia, although the net effects on different sectors within the regional economy are likely to vary significantly. For instance, one of the region's major industries, the coal industry, will almost certainly be negatively impacted by an RES or CES. Any climate policy coming out of Congress is likely to give electric utilities and/or industrial users of electricity an incentive or a mandate to switch from conventional coal-burning technologies to less GHG-intensive fuels or technologies. Some experts, including several leading utilities, claim that the still largely untested carbon capture and sequestration (CCS) technologies can lower the GHG footprint of coal combustion, making the fuel's use more compatible with the achievement of climate goals. Furthermore, because capturing, transporting, and pumping GHGs into underground storage require significant energy inputs, the adoption of CCS technologies also lowers the efficiency of power plants – often referred to as a parasitic loss – increasing the amount of coal required to produce a given amount of electricity. Nevertheless, many experts believe that this technology will be too costly to be widely adopted and that as a result, climate policies will further reduce already declining domestic coal demand.

The same incentives that are expected to hurt conventional coal technologies, however, would also increase investment in and demand for renewable fuels. Given that Appalachia holds the richest biomass and onshore wind resources in the eastern U.S., there is the potential for significant positive economic impacts from national climate or energy legislation.

The impact of climate policy on other key Appalachian industries, however, is far less certain. Natural gas production, an industry that is growing rapidly in Appalachia, could benefit from a shift away from coal toward less carbon-intensive fuels. However, many climate proposals include long-term emissions reduction goals so stringent that even electricity produced by natural gas would be considered too carbon-intensive, if not accompanied by CCS technology. Additionally, current proposals to establish a CES or RES differ significantly in whether they consider natural gas to be a "clean" generation fuel, adding more uncertainty to how legislation might affect the industry.

Finally, the impact of RES and CES policies on manufacturing is also uncertain. Manufacturing in Appalachia could be negatively impacted as a legislated shift away from cheap fossil fuels drive up electricity prices, although some proposals include provisions to protect manufacturing industries from rising costs. Some policy proposals even provide incentives for investments in energy efficiency that could enhance the competitiveness of domestic manufacturers.

2.2 National Environmental Regulation

2.2.1 Policy Summary

While climate change and energy legislation have stalled in Congress, the EPA is moving closer to regulating GHG emissions under its existing regulatory authority. The 2007 Supreme Court case Massachusetts v. EPA, mandated both that the EPA assess whether or not GHG emissions constitute a danger to society and that the EPA regulate those emissions under its Clean Air Act authority if they are found to be a danger. In December 2009, the EPA announced that "the current and projected concentrations of [greenhouse gases] threaten the public health and welfare of current and future generations." This "endangerment" finding is the basis for national EPA regulation of GHG emissions.

EPA has already used its authority under the Clean Air Act to raise CAFE standards for light duty cars and trucks, and is currently working to design GHG emissions regulations for stationary emitters, including power plants and other industrial facilities. Regulations under consideration are likely to require any newly constructed or significantly modified emissions source to apply best available control technology (BACT), as determined on a case by case basis, and to comply with minimum emissions performance standards. As currently envisioned, such regulation would only apply to large stationary emitters, responsible for 70% of national stationary emissions, until 2016. Nevertheless, it is currently unclear what the final regulation regarding stationary source emissions will look like.

The EPA is also in the process of revising and updating its regulations regarding criteria pollutants – sulfur dioxide ("SO2"), nitrogen oxides ("NOX"), mercury, particulate matter

("PM"), carbon monoxide (CO), dioxins, and volatile organic compounds ("VOCs") – under the Clean Air Act. Regulations subject to revision include:

1. **The Clean Air Transport Rule (Transport Rule)**: Sets power plant SO2 and NOX emissions limits for 31 states (including the 13 Appalachian states) and the District of Columbia.

2. **The National Ambient Air Quality Standard (NAAQS)**: Regulates the emissions of ozone forming compounds, including NOX, CO, methane (CH4), and VOCs.

3. **National Emissions Standards for Hazardous Air Pollutants (NESHAPs) for Utility Boilers**: Also known as the Utility Boiler MACT (Maximum Achievable Control Technology) Rule, it regulates emissions of hazardous air pollutants ("HAPs") including mercury, hydrochloric acid ("HCl"), VOCs, and others from utility boilers.

4. **NESHAPs for Industrial, Commercial, and Institutional Boilers**: Also known as the Industrial Boiler MACT Rule, it regulates emissions of HAPs from industrial boilers.

EPA is scheduled to issue final rules for each of these regulations in early 2012. Assuming that the revision process proceeds in a timely manner, utilities and industrial facilities will have until 2014 or 2015 to make the required modifications or be forced to shut down.

In addition to implementing new or revised regulations under the Clean Air Act, the EPA is also seeking to regulate power plant and industrial facility energy use under the Clean Water Act. One recently proposed regulation is meant to reduce the negative impacts that power plants' and industrial facilities' water usage has on aquatic life. The new rule will require many facilities to make significant investment to their cooling water intake structures ("CWIS") which may be relatively minor investments for some but would represent a major expense for facilities that may be force to replace open-loop or once-through CWIS with closed-loop CWIS. Although the specific timeline remains uncertain, implementation will take place in three phases: (1) new facilities, (2) existing power plants that use over 50 million gallons of cooling water per day, and (3) remaining power plants and manufacturing facilities. The EPA's final rule is expected by July 27, 2012.

Finally, the EPA is in the process of adopting a new regulation to govern the disposal of coal ash under the Resource Conservation and Recovery Act ("RCRA"). This rule would mandate certain safety controls at coal ash impoundments and landfills, and regulate the recycling of coal ash. The EPA is still in the process of weighing two alternative regulatory paths: one in which it would directly regulate coal ash management and disposal, the second in which it would set performance standards and rely on citizen lawsuits to enforce them. However, even as the rulemaking process is still underway, Republican legislators have introduced legislation that would prevent the EPA from enforcing coal ash regulations.

2.2.2 Policy Impacts on Appalachia

These newly proposed and revised regulations are likely to significantly impact the Appalachian regional economy. As with proposed GHG legislation, the industry most likely to sustain net negative effects is the coal industry. Emissions regulation would make coal less attractive relative to other fuels, as coal-burning facilities usually emit more greenhouse gases and criteria pollutants than gas-burning facilities in particular. Additionally, the CWIS rule is likely to require the most costly changes to water cooling systems at older power production and manufacturing plants, which primarily burn coal.

Finally, coal ash regulations will raise utilities' cost of coal ash removal and storage. The resulting retrofit costs and additional operating costs are likely to be substantial, and may force a number of coal-fired facilities to close sooner than they otherwise would.

The impacts of these regulations on other energy sources in Appalachia are more ambiguous, and could be positive in the case of several fuels. Natural gas combustion is a source of far fewer criteria pollutant emissions than coal, does not produce waste byproducts that require special disposal, and is about half as GHG intensive as coal combustion. Nuclear power has no direct emissions associated with its use and its waste management processes will remain unaffected by the EPA's regulatory changes. Some older facilities may, however, face additional costs as a result of the CWIS regulation requirements. Renewable power generation facilities will for the most part not be directly affected by proposed EPA regulations, with the exception of rules that may regulate criteria pollutant emissions from biomass facilities. Hence, to the extent that coal is harmed by regulations, these competing energy sources will likely benefit.

Another major beneficiary of regulatory policies will be the manufacturers of pollution control equipment, but other manufacturers could be hurt by these regulations, especially the most energy-intensive manufacturers. Many of these manufactures, especially those in Appalachia, use coal in their boilers and kilns and will have to invest in expensive equipment upgrades, or switch to more expensive, lower emitting fuels. Additionally, manufacturers that use a lot of electricity could be hurt by higher electricity rates if utilities pass the costs of pollution control equipment through to them. These added costs could reduce manufacturers' competitiveness and, in some cases, prompt the closure of Appalachian manufacturing facilities. Meanwhile, if the regulations lead to an economy-wide flight from coal to gas or biomass, facilities that are already using those fuels may face higher fuel prices as a result of that increased demand.

Nevertheless, these regulations have significant benefits too. While some pollution control equipment require additional energy inputs, some investments, particularly those aimed at complying with GHG regulations, may increase plant efficiency and improve the long-term competitiveness of those plants. An earlier ARC study, *Energizing Appalachia*[3], identified manufacturing in the region that would benefit from additional demand for solar, wind and biomass related equipment. In addition, the region has rich resources of biomass and wind that could be developed. Other benefits, however, like reductions in pollution, are difficult to put dollar values on. For example, reducing air pollution and controlling waste are expected to result in significant health benefits for communities near to and downwind from the regulated facilities. These benefits include the reduction of pollution related illnesses and mortalities, which would improve productivity through reductions in work and school absences and reductions in premature deaths of people who contribute to the economy, benefits which are difficult to quantify. Another example is the impact of the CWIS regulation on aquatic life and the benefits that the rule could have to commercial and recreational fishermen.

[3] Energizing Appalachia: Global Challenges and the Prospect of a Renewable Future, Pennsylvania State University Department of Geography, September, 2007, at http://www.arc.gov/assets/research_reports/EnergizingAppalachiaGlobalChallenges.pdf.

2.3 State & Regional Climate & Energy Policies

2.3.1 Policy Summary

In addition to various proposed and already approved federal policies, utilities and industrial facilities face a patchwork of state-specific energy and climate laws. West Virginia, Pennsylvania, New York, Ohio, Maryland, and North Carolina all have mandatory renewable or clean energy standards (“RES” and “CES”). The stringency of these standards and how they define “renewable” and “clean” vary by state, in addition to a range of other policy specifications that aim to create more flexibility.

Table 2.3.1 Sample of CES and RES Policies

State	Target	Includes:				
		Renew.	Hydro*	Nuclear	CCS	New Coal
Maryland	20% by 2022	X	X			
New York	29% by 2015	X	X			
North Carolina	12.5% by 2021 (investor-owned) 10% by 2018 (cooperative/municipal)	X	X (up to 10 MW)			
Ohio	25% by 2025	X	X	X	X	
Pennsylvania	18% by 2020	X	X		X	
West Virginia	25% by 2025	X	X		X	X

*Most of these RES exclude existing hydro and some large scale or non-run-of-river hydro.

Other states use incentives and mandates outside of RES systems to promote the use of renewable fuels or energy efficiency. Pennsylvania, for example, requires electric utilities to develop and implement plans to reduce consumer demand. A number of states, including West Virginia and Kentucky, offer tax incentives and adjustments to encourage renewable energy investment.

Enactment of energy and climate policy varies widely between Appalachian states. While Alabama and Tennessee have yet to enact any significant climate or energy-related legislation, New York and Maryland participate in the Regional Greenhouse Gas Initiative (RGGI), which imposes a cap and trade system on power producers in ten Northeast and Mid-Atlantic states. Meanwhile, Ohio is participating as an observer to the Midwest Greenhouse Gas Reduction Accord (MGGRA), which has proposed implementing a similar multi-state cap and trade system.

2.3.2 Policy Impacts on Appalachia

As with the national policies discussed in the previous sections, state and regional climate and energy policies are likely to negatively impact the coal industry. States with RESs or participating in RGGI will direct power producers away from coal-fired generation, reducing the demand for Appalachian coal. Nevertheless, some coal-fired power utilities in Appalachia could benefit from regional and state policies through leakage. For example, a poorly designed RPS or cap and trade system may result in opportunities to sell coal-fired electricity produced in Appalachia to states and regions with more stringent regulations.

Appalachia’s fast-growing natural gas industry is likely to feel more ambiguous impacts from regional climate and energy policies. Cap and trade systems, including RGGI, are likely to favor natural gas in the short and medium terms as a relatively affordable and clean alternative to coal. However, while some state regulations explicitly favor natural gas, others, particularly those with established RES, treat gas no differently than coal.

The Appalachian renewable energy industry will unambiguously benefit from all of these policies, as they incentivize or mandate the increased use of renewable power. Additionally, because Appalachia is home to the most abundant renewable resources in the eastern half of the country, Appalachian counties stand to disproportionately benefit from investments in renewable energy. Meanwhile, the costs of most regional and state policies will be more evenly distributed among ratepayers throughout those jurisdictions.

Finally, the majority of regional and state regulations focus relatively narrowly on the power sector and include no provisions that would directly affect manufacturing. However, many heavy manufacturers (e.g., aluminum producers) are highly sensitive to changes in electricity prices. These manufacturers could face a significant cost increase as a result of policies that make electricity in Appalachia more expensive. Such an outcome would negatively affect the competiveness of those heavy manufacturers.

2.4 Energy Supply Policy

2.4.1 Policy Summary

The policies discussed in the previous sections focus on the use of energy. As a major energy producer, however, Appalachia could be significantly impacted by new and revised regulations concerning natural gas and coal production, particularly those that restrict mountaintop removal mining and hydraulic fracturing. Mountaintop removal ("MTR") mining has been widely criticized as environmentally harmful, but continues to be utilized by several Appalachian coal mines. One specific criticism is that the debris removed from mountaintops has been moved to valley fills that pollute local streams and rivers, violating the Clean Water Act.

The Bush Administration eased regulations on MTR mining by removing a specific restriction on depositing mining waste in U.S. waterways in 2002 and relaxing restrictions governing when a mining company could alter the flow of a stream in 2008. The Obama Administration has been less permissive of the practice, promising to revise the rule change made by the Bush Administration in 2008, refusing to grant new permits for new MTR mines, and even revoking some permits that had already been granted. Additionally, in April 2010, the EPA issued new guidelines aimed at protecting rivers and streams from pollution resulting from MTR mines. These guidelines, various legal rulings, and prospective new legislation, including the Clean Water Protection Act of 2009 which was proposed but not passed, could result in the tighter restrictions on MTR mining.

The rapidly growing Appalachian natural gas industry could also be significantly impacted by the forthcoming regulations and legislation. Most natural gas resources in the region are unconventional and can only be accessed through hydraulic fracturing – a process in which drillers use high pressure mixtures of water, sand, and chemicals to release pockets of natural gas from shale rock. Many opponents of hydraulic fracturing worry that the process contaminates groundwater and creates health hazards, while studies of the method lack consensus on whether the process is truly hazardous and requiring of regulation.

Past legislation is also undecided on supposed health risks related to hydraulic fracturing. In the Energy Policy Act of 2005, it was deemed a non-hazardous practice and exempted from federal regulation under the Safe Drinking Water Act. In 2009, however, the Fracturing Responsibility and Awareness of Chemicals Act was introduced in Congress. Although it was never passed, it would have removed the prior exemption on regulating hydraulic fracturing and both allowed the EPA to regulate the process and required companies to disclose the chemical makeup of fracturing fluid. Even if the method remains exempt from federal regulation, it could still be subject to state regulations, given the increased public scrutiny surrounding the practice.

2.4.2 Policy Impacts on Appalachia

Tighter regulation of both MTR mining and hydraulic fracturing would significantly raise the costs of mining Appalachia's fossil fuel resources and could force energy companies to shut down portions of their Appalachian operations if less environmentally damaging methods prove to be uneconomical. These shutdowns would, in turn, negatively affect communities that are dependent on the mining industry for employment and revenue, in the form of royalties and taxes. Although the net effect on the mining industry is likely to be negative, opportunities may also exist to offset those effects by ramping up production at Appalachian mines that already use or are able to adopt less controversial methods. Furthermore, such policies could also help to strengthen competing industries including renewable energy. Additional avenues for positive impact include positive impacts on the tourism industry in the absence of such highly visible mining operations as MTR, and positive health benefits to the general population.

3. Literature Review

Over the past several years, a host of governmental, academic, private, and non-profit institutions have produced scores of analyses that have estimated the impacts of state, regional, and national climate and energy policies. The most prominent and cited studies have used modeling tools to project the impacts of these policies on national or state accounts, incomes, employment, utilities, or industries in affected jurisdictions. However, these studies vary greatly with regard to model inputs, outputs, and assumptions, as well as the type of modeling tools employed.

More than 40 studies were reviewed for this analysis. The following section reviews and summarizes some of their key insights and methods. Specifically, this section reviews:

- The methodology for translating specific policy features into model inputs and economic and energy sector outcomes;
- The models used for different impact analyses, the strengths and weaknesses of those models, and their impact on a study's methodology, results, and conclusions; and
- Key assumptions and their relationship to model outputs and policy conclusions.

3.1 Policy Choices and Their Impacts on Economic Outcomes

3.1.1 Cap & Trade Impacts

As discussed in the previous section, the U.S. Congress and many state and local governments have considered several major climate and energy bills over the past several years, including cap and trade systems, renewable fuels standards, renewable portfolio standards, energy subsidies, and other regulatory mechanisms. Of these various proposals, cap and trade schemes have received the most sustained attention and debate. As a result, many of the energy and climate policy analyses that have been performed in recent years have focused on cap and trade GHG mitigation systems.

At the federal level, McCain-Lieberman, then Bingaman-Specter, Lieberman-Warner, Waxman-Markey, and finally Kerry-Graham-Lieberman have been analyzed by a host of government agencies, think tanks and public policy groups, including EPA, EIA, MIT, the Nicholas Institute, the Heritage Foundation, etc.[i] Meanwhile, other groups have evaluated the regional cap and trade policies associated with New England's Regional Greenhouse Gas Initiative (RGGI), California's AB 32 Implementation Plan, and a Proposed Western Climate Initiative (WCI), as well as some cap & trade schemes that are not associated with a specific law or policy proposal.[ii]

The majority of these studies conclude that implementing a cap and trade system will have negative impacts on the growth of GDP, employment, income, and other economic indicators. Nevertheless, a handful of studies estimate positive impacts, highlighting how differences in the geographical scope, model, underlying assumptions, and the policy design features can lead to a broad range of impact estimates.[iii] Importantly, none of these analyses estimate the noneconomic costs and benefits associated with climate change mitigation and other changes to environmental and health outcomes.

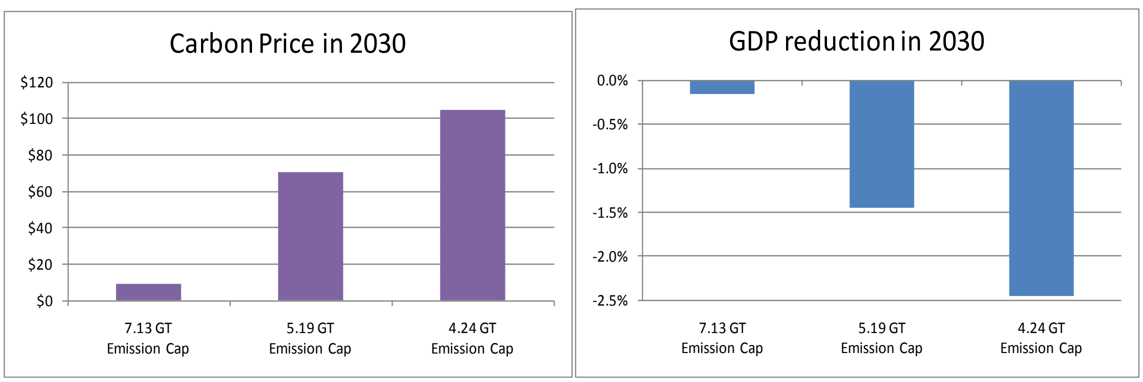
3.1.2 Cap & Trade Policy Features

Cap Stringency

One of the key policy choices driving model results is the stringency of the cap. MIT's Joint Program on the Science and Technology of Climate Change released a series of studies that look specifically at this link between policy design features and economic impact. Using their Emissions Prediction and Policy Analysis (EPPA) model, the MIT team simulates the impacts of scores of different cap and trade policies, with the defining difference between many of the policies being the stringency of the cap. As would be expected, simulations show that, as the stringency of the cap increases, making emissions permits scarcer, the price of emissions permits also increases. Higher permit prices, in turn, worsen the policy's impact on broader economic indicators.[iv]

Nevertheless, while policymakers and the public often consider the emissions cap stringency to be the most important design feature of any cap and trade policy, modeling results from a number of studies show that other features can be just as important, potentially even more so, in determining a policy's economic impact.

Figure 3.1: Carbon Prices and GDP Impacts in Scenarios with Alternative Cap Stringencies



Scope of the Cap

Cap and trade policies vary significantly in the scope of industries that they include under the cap. New England's RGGI, for example, only covers electric utilities, whereas AB 32, WCI, and most national climate proposals also include other sectors (i.e., industrial, residential, commercial, and transportation). The Beacon Hill Institute's cost-benefit analysis of WCI simulated both a "narrow" scope case, in which the cap and trade system covers only large stationary emitters, and a "broad" scope case, which caps emissions from smaller transportation, residential, and commercial sources in addition to large stationary sources. The Institute's report shows that the economic costs experienced in the narrow case were amplified in the broad case as more sectors were forced to reduce emissions in order to achieve a greater amount of economy-wide emissions reductions.[v] However, had the overall level of emissions reductions required under both the broad and narrow scope scenarios been the same, then the broader scope scenario would have likely lead to the adoption of more cost-effective emissions reductions activities than those in the narrow scope scenario as broadening the cap would have expanded the pool of emissions reductions sources.

Compliance Flexibility

The EPA's analyses of various cap and trade proposals have shown that assumptions about the availability of international and domestic offsets can have a very significant impact on the estimated effects of a given policy.[4] In fact, the EPA estimated that some of the costs associated with implementing the Lieberman-Warner Bill would be five times higher if no offsets were allowed, compared to allowing the unlimited use of offsets.[vi] The Pew Center's meta-analysis, which compares analyses conducted by seven different groups, also found that the greater availability of offsets is associated with reduced economic costs effects on the economy. Across studies, greater use of offsets also led to lower allowance prices and overall economic costs.

Additionally, Terry Barker and the Tyndall Center for Climate Change Research's meta-analysis of studies estimating the economic impacts of cap and trade systems concluded that international carbon permit trading (including offsets) increased projected 2030 GDP estimates by 0.7 percentage points relative to cap and trade scenarios that did not include international carbon permit trading.[vii] This conclusion stems from the fact that the offsets increase the pool of emissions reduction options available to regulated entities, and the assumption that many of those options are more cost-effective than the options that would be employed if offsets were not available. This assumption is based on the experience of existing cap and trade schemes that have benefited from the availability of low-cost emissions reduction options through the use of offsets. Nevertheless, estimates of the cost and availability of offsets vary significantly and can be a major determinant of conclusions regarding the economic cost of cap and trade policies.

In addition to offsets, other mechanisms exist that would increase the flexibility of compliance obligations under a cap and trade policy. For example, the EIA's analyses of multiple federal cap and trade bills demonstrate that provisions allowing for intertemporal flexibility in complying with the emissions cap (i.e., the ability to borrow and bank emissions permits) can shift costs of the policy from earlier years to later years, but that they don't necessarily lower the cumulative costs of the cap and trade policy.[viii] However, a Stanford University study of federal cap and trade policies similar to those in the Waxman-Markey Bill arrives at a different conclusion. According to this study, allowing for the banking of emissions permits would reduce industry losses and improve national economic indicators such as GDP and employment in all years as firms would be able to take advantage of less expensive mitigation options in the earlier years of the policy, and avoid making more costly emissions reductions in the latter periods of the policy.[ix]

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[4] Offsets are emissions reductions that are made by unregulated entities in order to generate emissions allowances that can be sold to entities that are regulated under a cap and trade system. Permitting their use, therefore, increases the total number of emissions allowances available to regulated entities but offsets that increase with an emission reduction by an unregulated entity or in an unregulated jurisdiction that would not have otherwise occurred.

Permit Allocation

Perhaps more than any other policy feature, the allocation of permits has been the primary focus of many cap and trade policy analyses, and has been shown to be a major driver of economic impact estimates. Resources for the Future (RFF) measured how five different methods of allocating permits to the electric power sector – 100% auction, grandfathering, or load-based allocation based on population, emissions, or consumption – would have significantly different impacts on electricity consumers, and how those impacts also vary depending on whether consumers live in regulated or competitive markets.[x] The authors show that auctioning of emissions permits would result in higher electricity price impacts and lower electricity consumption than under other allowance distribution methods. The study also finds that, while alternative allocation methods diminish a cap and trade policy's average price impact on electricity, they also distort prices in favor of consumers in regulated markets and against those in competitive markets. The reason for this distortion is because customers in regulated markets would benefit from the full pass through of the benefits of free allocation while customers in competitive markets would not, as those prices would still equal the marginal cost of power production, including carbon costs. Finally, RFF's report also demonstrates that free allocation would lower electricity sector emissions reductions, forcing other sectors of the economy to increase their own emissions reductions in order to comply with the cap, likely resulting in higher overall compliance costs.

The decision of whether or not to freely allocate permits is most critical to energy-intensive industries that are exposed to trade with unregulated jurisdictions. When considering subnational policies, this group is more inclusive and includes the electric power industry, but for national policies, this group is more limited to industries that compete internationally, such as steel, cement, and paper. Most of the federal cap and trade bills have included a special mechanism for freely allocating permits in order to prevent these industries from being disadvantaged relative to foreign competitors. The Stanford study discussed above assesses the impacts of different allocation methods on eight emissions-intensive sectors (most of which are also highly exposed to international competition). The study finds that the full auction of emissions permits would reduce profits and that free allocation would increase profits in those emissions-intensive industries relative to what profits would be if no climate policy were adopted.[xi] The study finds that only 14% of all emissions permits would have to be freely allocated to these eight industries in order to return them to the same level of profitability that they would have achieved had no climate policies been adopted. The remaining 86% could then be auctioned without harming those eight vulnerable industries.

Use of Auction Revenues

The auctioning of emissions permits can generate substantial government revenues and it should be noted that the simulation of any revenue generating policy needs to be complemented by revenue use policies. Revenue use assumptions can be categorized as falling into one of four revenue use categories:

1. **Government spending** – Some studies add the revenues collected from a permit auction or carbon tax to a government's general fund and assume that it is spent on government programs in the same proportions as other government funds. In general, such an assumption would mean that the policy would have a negative

economic impact as most models estimate that governments would not spend money as efficiently as the private sector would had they not been subject to the tax. Other studies assume that all or some of the funds are earmarked for energy projects, particularly those that invest in efficiency and renewables. Like regular government spending, earmarking funds for a particular purpose is usually modeled as being less efficient than leaving revenues in the hands of the private sector. However, the case is often made that directing money to certain investments can be more efficient than leaving the money in the private sector if the investments help to correct existing inefficiencies of private spending caused by market externalities. None of the studies reviewed, however, attempt to gauge the accuracy of this claim.

2. **Debt reduction** – Simulations that assume revenues would be used for debt reduction tend to show major negative impacts on measures of economic wellbeing such as GDP or income. In contrast, the effect on other economic indicators such as the savings and government debt levels are generally ignored.

3. **Rebating** – The rebating of carbon revenue to people and businesses that face higher costs as a result of the carbon price has essentially the same impact as freely allocating emissions permits to GHG emitters. Both strategies offset some or all of the carbon costs paid, reducing the negative impacts on targeted industries or populations, but in some cases also reducing the effectiveness of the policy by reducing the incentive to change behavior or invest in new technologies.

4. **Reduction of other taxes** – Several studies show that an efficient use of revenues would be to reduce other taxes. If the taxes being reduced are estimated to be less efficient (or more distortionary) than collecting carbon revenues, then the net economy-wide impact is likely to be positive. Like the other choices of how to use carbon revenues however, the economy-wide impact estimates could mask negative impacts on certain industries and population groups.

In the Stanford study discussed above, the question of which allocation method was best for the national economy depended largely on how auction revenues were distributed. The study found that if all auction revenues were used to reduce income taxes, the full auctioning of allowances would not only be better than the other permit allocation methods, but it would lead to better national economic outcomes than those that would be achieved if no climate policy were adopted. Similarly, several other analyses, including EPI's[xii], the University of New Hampshire's, and EPA's analysis of the American Power Act, have also shown the efficient use of auction revenues, particularly the reduction of other distortionary taxes, can significantly improve projected economy-wide outcomes. In addition, Terry Barker's meta-analysis of climate studies showed that cap and trade policy simulations that assume the efficient use of auction revenues improved 2030 GDP estimates by 1.9 percentage points over what they would be with less efficient revenue usage assumptions.[xiii]

3.1.3 Important Features of Other Climate Policies

Fewer sophisticated analyses have been done of carbon taxes, renewable portfolio standards, and other non-cap and trade climate policies. Fortunately, however, many of the simulations of cap and trade policies either include features that are similar to these other policies or simulated those policies in conjunction with cap and trade.

Carbon Taxes

Carbon taxes are modeled in essentially the same manner as cap and trade policies. Both policies put a price on carbon, encouraging all sectors covered by the cap or tax to change behavior or make investments that can reduce emissions for a cost that is less than the carbon price. The only difference between modeling carbon taxes and modeling cap and trade is the variable that is held constant. Carbon tax simulations fix the carbon price and allow the emissions level to vary, whereas cap and trade simulations fix the emissions level and vary the carbon price. The latter are generally achieved by running iterative simulations of carbon tax scenarios until the tax is sufficiently high to induce enough GHG emissions reductions to achieve the cap. The Business Roundtable's modeling analysis of its own policy recommendations acknowledges the practical equivalence of simulating either carbon taxes or cap and trade, acknowledging that "the study remained agnostic as to the type of instrument that is used to establish the carbon price." That study simulated two carbon price trajectories that were based on the carbon prices estimated in various analyses of the Lieberman-Warner cap and trade bill. Unlike those studies, however, the Roundtable's simulations fixed the carbon price and allowed the GHG emissions levels to vary.[xiv]

Renewable Energy Standards (RES) or Clean Energy Standards (CES)

In general, economists consider technology mandates such as these to be less efficient mechanisms for reducing GHGs than market mechanisms such as cap and trade and carbon taxes. The reason is that market mechanisms provide incentives to make the least expensive emissions reductions first and they allow they allow the market to find the most cost-effective reductions. In contrast, RES and CES mandate the adoption of certain emissions reducing technologies in the electric power sector, which may not be the most cost-effective emissions reduction strategies.

This does not necessarily mean that these standards are more costly policy options than carbon taxes or cap and trade. The reason is that RES and CES do not generally require the collection of revenues, which as discussed above, can create other economic inefficiencies. Because most RES and CES do not generate government revenues, they lack this form of inefficiency. An RFF study demonstrates how regulatory approaches that do not collect carbon revenues could result in better economic outcomes even if they result in less cost-effective emissions reductions than a market based revenue collecting scheme.[xv]

Nevertheless, none of the studies reviewed compare market mechanisms to RES or CES. Three government studies, however, do show that RES and CES would have relatively low costs. A 2005 EPA study reviewed 22 state level analyses and found that renewable energy standards in those states would increase electricity rates by less than 5%.[xvi] In 2009, the EIA performed a modeling analysis of the 25% RES that was a component of the American Clean Energy and Security (ACES) Act and found that the standard would increase average national electricity rates by less than 3%.[xvii] Furthermore, a 2007 EIA analysis showed that a national CES requiring 20% clean electricity production (renewable, CCS, plus new nuclear and hydro) by 2025 would cause electricity rates to increase by just 1%[xviii]. None of these studies takes the extra step to show how the standards would affect broader economic indicators, but considering the small changes in the electricity rates – the prices that would be most directly impacted – it is likely that the macroeconomic impacts, if estimated, would have been minimal.

An MIT study, in contrast, does estimate the full economic impact of a RES, but it does this in the context the adoption of an economy-wide cap and trade system, as was proposed in the ACES Act. The study concluded that inclusion of a RES requirement in a cap and trade bill drove up the overall costs of the policy without reducing GHG emissions any further. For example, it found that implementing a 20% RES in conjunction with a cap and trade system similar in stringency to that in the ACES ACT would increase policy costs from less than 1% to almost 1.7% of the nation's overall level of economic welfare – a composite measure used in the EPPA model to represent economy-wide utility.[xix] This reduction in welfare was caused by forcing the model to adopt emissions reduction strategies (i.e., displacing fossil fuel electricity with renewable electricity production) that were not most cost-effective strategies available while imposing equivalent revenue collection schemes.

Industry-Specific Climate Policies

While economic modeling and theory suggest that some technology-specific mandates like RES and CES result in the adoption of less cost-effective emissions reduction strategies than those that would be adopted if market mechanisms were used alone, many believe that some technology mandates and standards can result in the adoption of more cost-effective strategies than those that would result from market mechanisms alone. Fuel economy standards are considered by many to be such a strategy. As part of its analysis of the ACES Act, the EIA simulated scenarios that included the adoption of the ACES Act, both with and without strengthened fuel economy standards.[xx] The study found that the inclusion of stronger fuel economy standards resulted in slightly more positive economic impacts. The implication of this finding is that market mechanisms can fail to stimulate some cost-effective emissions reduction strategies because those strategies suffer from market failures that are not resolved by the imposition of carbon pricing. Many economists would argue that more stringent appliance and building efficiency mandates would resolve similar market failures.

Policymakers have a wide variety of other industry-specific policy tools that don't involve mandates that could help advance investments in new technologies and overcome market failures. The Business Roundtable's climate policy analysis, for example, focuses on quantifying the benefits of removing barriers to investment in six technology categories including energy efficiency, renewable power, nuclear power, CCS, renewable fuels, and vehicle efficiency. The study estimates targeted policies and investments in these six technology areas can cut the costs that carbon fees would impose on the nation's GDP in half while achieving twice the GHG emissions reductions.[xxi]

Similarly, a study released by Industrial Energy Consumers of America that measures the economic impacts of its own policy proposals indicates that policies aimed at improving manufacturing efficiency can have significant positive impacts on the nation's wellbeing. It highlights combined heat and power (CHP) and recycled energy as two technologies that currently face non-economic barriers that prevent these efficiency improving and money saving investments from taking place. The study estimates that implementation of six of the organization's policy proposals would improve GDP by 0.4% by 2020.[xxii]

3.1.4 Environmental Regulations

Policies Affecting Fuel Users

With national climate change policy discussions at an impasse, federal lawmakers, industry, think tanks, and academic intuitions have turned their attention to the potential impacts of environmental regulations that have been and are being developed by the EPA in particular. More than a dozen studies estimating the impact of air, water, and waste regulations on power plants and industrial facilities were reviewed. Most of these studies only measured the impacts on the electric power sector, but some estimated the total impact of regulations on the economy.

The EPA, for example, accompanies each proposed rule with a Regulatory Impact Analysis that includes economic impact estimates of the rule. EPA has used economic modeling analyses to show that each of several clean air, water, and waste regulations would result in slightly higher electricity prices, and for some regulations, small negative impacts on industrial profits and output. Nevertheless, for all but one of the regulations, EPA estimates the negative impacts of the regulation on the overall economy to be negligible. The exception is the revision of ozone standards, which EPA estimates to cost the economy $19-90 billion annually by 2020, depending largely on the level at which the standard is set.[xxiii]

In addition to the costs, the EPA's analyses of these regulations also include estimates of benefits. These estimates are done by quantifying the economic benefits of better health outcomes resulting from lower pollution levels. The estimates, however, are done independently of the cost estimates and do not utilize economic modeling, although EPA is currently working to integrate its health benefit estimates with its economic modeling tools for future analyses.

Studies by other organizations of EPA regulations other than those discussed above estimate the impacts that those regulations would have on the electric power sector but do not take the extra step of measuring the broader impact on the economy. For example, the Edison Energy Institute's (EEI) and several other industry and non-profit groups estimate that multiple air, water, and waste regulations will increase electricity prices and force many plants to retire or retrofit with pollution control equipment. The range of compliance costs to meet those regulations range from a few billion to more than $250 billion over a decade.[xxiv]

Only one study (other than those done by EPA) attempts to quantify how such costs to the electric power sector filter through to the rest of the economy. A study released by the University of Massachusetts-Amherst's Political Economy Research Institute (PERI) of air regulations that are targeted at electric utilities estimates that even without accounting for the health benefits of the regulations, they would have positive and significant impacts on jobs and investment in the 2010-2015 period. It does not, however, discuss the longer term impacts when one might expect electricity prices to be higher as utilities pay for their investments. [xxv]

Policies Affecting Fuel Suppliers

None of the studies reviewed estimated the economic impacts of environmental policies that restrict domestic energy production. Among the most actively debated energy supply restrictions that are especially relevant to the Appalachian region are restrictions on shale gas drilling and fracking and on mountaintop removal (MTR) coal mining. While no studies have been done that directly estimate the impacts of restrictions on shale gas drilling and fracking, the EIA's 2011 Annual Energy Outlook estimates the impact that increasing the number of shale gas wells and shale gas production by 50% may have on the U.S. economy.[xxvi] Without factoring in potential environmental costs, the EIA estimates that increased shale gas drilling would have a slightly positive impact on national GDP, increasing it by an average of 0.07% over the 2011-2035 period, although those economic impacts would tend to be more positive in Appalachia because of the larger concentration of shale gas resources there.

No analysis of the impacts of restrictions on MTR were found or reviewed, although considering that the tactic is used at just a handful of mines, the economic impact of its restriction on the national and even the Appalachian regional economy is likely to be negligible.

3.1.5 Regional Policies

While many national regulations are pending and several national climate policy bills have been dismissed, scores of state and regional policies have been proposed and enacted. Many of these were the foci of studies reviewed for this analysis, in particular California's AB 32 climate law, the Western Climate Initiative (WCI), and the Regional Greenhouse Gas Initiative (RGGI). These studies yielded additional findings that highlight how differences in policies between neighboring jurisdictions can affect the costs of policies.

For example, a report by University of New Hampshire shows that RGGI will have a significant impact on the New Hampshire economy, whether or not the state participates in RGGI's electricity sector cap and trade program. In its baseline scenario, the analysis assumed that the other nine RGGI member states, including all three states with which New Hampshire shares a border, would participate. The study found that, regardless of whether New Hampshire participates in RGGI, the customers of three of New Hampshire's four utilities would face higher electricity rates because those utilities purchase electricity from generation facilities in other RGGI states. The study concludes that not participating in RGGI would not only disadvantage those utilities versus the one that produces all of its electricity in-state, but also deprive the state of sharing the benefits of auction revenue collections, despite the fact that many of its residents would be paying higher electricity rates.[xxvii]

A report by the University of California Energy Institute looks at how differences in participation in a WCI cap and trade program would affect the policy's impact. It simulates three policy scenarios in addition to a business-as-usual baseline: one in which only California participates, one in which all WCI states participate, and one in which all western states participate. The authors find that in the lower participation scenarios, the problem of emissions leakage would undermine the effectiveness of the policy in lowering GHG emissions because participating states would start importing more electricity from GHG emitting sources in neighboring states, offsetting the emissions reductions achieved in the participating states. However, the study estimated that once all of the western states were participating, the opportunities to import more emissions intensive electricity disappeared, incentivizing more energy efficiency and local production of cleaner electricity.[xxviii] This finding highlights the importance of adopting emissions leakage protection measures to prevent the outsourcing of economic activities that generate GHG emissions.

One such measure for reducing emissions leakage in the electric power sector is to treat imported electricity the same as domestically produced electricity. Several analyses, however, show that utilities can get around such a restriction by using "contract shuffling." This occurs when utilities trade contracts in such a way that the utilities in jurisdictions with carbon restrictions buy electricity from low carbon sources while the contracts for more carbon intensive electricity are traded to utilities in jurisdictions with lower or no carbon restrictions. Navigant Consulting's analysis of emissions leakage in the Eastern Canadian WCI provinces of Quebec, Ontario, and Manitoba demonstrated the impact of contract shuffling, concluding that allowing for contract shuffling would increase electricity imports and reduce the impact of the GHG policy on emissions.[xxix]

Together, these analyses demonstrate the problem of emissions leakage and the importance of having well designed policies to prevent it. They also show that emissions leakage becomes less of a problem when neighboring jurisdictions adopt similarly stringent climate policies. Nevertheless, studies at the national level show that even climate policies that cover the entire U.S. can leave the economy vulnerable to regulation-related outsourcing and emissions leakage if thoughtful policies to prevent leakage are not included.

3.1.6 Policy Scenarios in this Analysis

This study focuses on four policy simulations that estimate how different national climate and energy policies may impact Appalachia. While most sectors of the economy are likely to be at least mildly effected by major climate or energy policies, the discussion above highlights the fact that the most significant impacts are likely to occur in the electric power sector. This sector is the largest contributor to greenhouse gas emissions, emitting more than a third of all the nation's GHG emissions, and the industry most capable of significantly reducing the nation's GHG emissions profile.[xxx]

The scenarios analyzed in this study simulate the adoption of three different electric power sector policies or strategies that could profoundly impact the sector, including:

1. End-Use Energy Efficiency
2. Clean Energy Standard
3. Carbon Mitigation

These three scenarios were chosen because they represent three of the most often discussed federal policy proposals and because they are likely to significantly affect demand for Appalachia's coal, natural gas, and renewable energy resources. These scenarios also relate directly to the three Strategic Objectives in ARC's Regional Blueprint. They analyze the implications of extending existing legislation, including Epact 2005, EISA 2007, and the new EPA ruling on GHG emissions. More detailed descriptions of the policy scenarios and results are discussed in sections 5 and 6.

3.2 Model Type and Use in Policy Analysis

3.2.1 Economic Models

All of the studies reviewed for this project that included economic impact estimates made use of economic models. These macroeconomic models ranged from very simple spreadsheet models that included few variables to very sophisticated models with thousands of variables.

Simple Static Input-Output Models

Simple static input-output models were used in a few of the studies reviewed. These models, which include the IMPLAN and RIMS 2 models, use economic multipliers to estimate the first order impacts of how a change in costs or prices in one or more sectors would filter through the economy to affect other sectors in the economy. For example, T^2 and Associates performed an analysis of California's AB 32 cap and trade policy assuming a full auction of allowances would result in carbon fees equal to $20, $60, and $200 per ton of CO2 by 2020. The authors estimated that, in the scenario where the fee was assumed to be $60 per ton, California's employment would be reduced by nearly 500,000 jobs in 2020.[xxxi]

This loss of jobs would be considered very significant even at a national level, but such a loss would be considered catastrophic for just one state. This result, however, is an outlier and is a product of using this type of model to simulate a long term, multifaceted policy. The T^2 simulation shows how the energy sector may react to a tax on fossil fuels, but because it does not calculate any secondary effects it assumes that:

1. All people who lose their jobs are unable to find new ones;
2. Industries affected by the tax shrink and no other industries are able to benefit from the resulting glut of labor and capital or to fill the energy supply void that those industries left; and
3. The revenue collected from the permit auctions is not used for a productive purpose.

Such assumptions do not reflect the tendencies of the real economy where second and third order effects tend to mitigate costs.

In summary, simple static input output models do not do a good job of simulating any long term policy effect or even short-term secondary effects. They generally do not accommodate structural or industrial change in the economy, efficiency and productivity gains, or benefits from a shift in resources toward more competitive or high-tech industries. The lack of a macroeconomic component in such models results in a calculation of multipliers that are generally too large, as the models ignore the constraints of overall GDP potential in the economy.

Computable General Equilibrium Models

In healthy market economies, surpluses of capital and labor resulting from production losses in one industry tend to get employed in other industries. The theory is that prices for factors of production, goods, and services adjust in such a way that their supply and demand equalize. When that happens for a particular good or service, that particular market is said to be in equilibrium. General equilibrium is said to occur when the prices for all goods and services equal values such that the supply and demand for all goods and services equalize. Computable general equilibrium (CGE) models assume that economies will tend back toward a general equilibrium state. They are run iteratively with prices throughout the economy, and therefore supply and demand adjusting until the model reaches general equilibrium. Through this process, the model captures the second, third, and *n*th order effects of policy changes that are often ignored by simple static input-output models.

Basic CGE models only simulate the economy for a single time period assuming that the process of adjustment to a new equilibrium state is instantaneous. The vast majority of the studies reviewed, however, used dynamic CGE models to estimate the economic effects of climate and energy policies over time. These models do simulate a time path for adjustment to a new equilibrium state, but most require that the modelers project values for all exogenous variables for all years. CGE models also must assume that households, firms, and governments (the main agents in the model) act with perfect knowledge of future prices and that they maximize utility and profitability over time given that knowledge. Critics say that this characteristic causes CGE models to overestimate the ability of model agents to react intelligently to policy changes. Terry Barker's meta-analysis of studies estimating the economic impacts of cap and trade systems concluded that simulations performed using CGE models tended to improve projected 2030 GDP estimates by 1.5 percentage points as compared to those that used other models.[xxxii]

Econometric Models

Econometric models are another major model type used for economic analyses of climate and energy policies. The major differences between econometric and CGE models are:

1. The parameters that define the interrelationships between variables of econometric models are determined by econometric analysis of historical data, whereas CGE models use input-output matrices.
2. Unlike CGE models, econometric models do not generally assume that the agents of the model have perfect foresight, which allows them to optimize their behavior over time.

The IHS Global Insight U.S. Macroeconomic Model is an econometric model that has been used to simulate the macroeconomic impacts in all of the energy policy modeling analyses performed by the Energy Information Administration (EIA). This model represents the macroeconomic module of a larger system of interlinked models that form EIA's National Energy Modeling System (NEMS). The movement of variables in this model is driven largely by econometric equations based on historical relationships, but, like other econometric models, they are also constrained by an underlying economic theory, such as the general equilibrium theory that underlies CGE models. Nevertheless econometric models tend to be more loosely constrained by those theories than CGE models are by general equilibrium theory.

Hybrid Models

Two of the models used in the studies reviewed – the University of Maryland, Inforum's LIFT (Long-term Interindustry Forecasting Tool) and Regional Economic Models, Inc.'s (REMI's) Policy Insight Plus (PI+) – would more accurately be described as hybrid models that include characteristics of both CGE and Econometric models. Like CGE models, they both have input-output matrices at their core which guide many of the interrelationships among industries, and both include CGE tendencies to return to a general equilibrium state. However, like econometric models, much of the movement of model variables are driven by econometric equations and activities in those models are not based on the assumption of perfect foresight.

3.2.2 Modeling the Energy Sector

While many of the analyses reviewed use modeling tools to simulate the impact of energy and environmental policies on the macroeconomy, the studies also employ a wide variety of strategies for modeling the energy sector. They include both:

1. Exogenous strategies – estimating energy sector policy responses outside of the main economic model used and then inputting those results into the model; and
2. Endogenous strategies – estimating energy sector policy responses within the same modeling system used to estimate economic impacts.

Exogenous Modeling of the Energy Sector

Many of the economic models used for these policy analyses do not contain sufficient energy sector detail to suitably simulate the adoption of carbon prices or other policies within the model. In lieu of this ability, modelers use the output of other models, side calculations, or other tools to approximate policy impacts on the sector. Those estimates are then used as inputs for economic model in order to simulate those policies. The University of New Hampshire's analysis of that state's participation in RGGI does this. The authors use a simple "spreadsheet model" that they developed to estimate delivered electricity prices in different scenarios by adding carbon costs – the product of carbon price data from other climate policy studies and emissions data from EPA's Clean Air Markets database – to business-as-usual electricity rates. These price data were then input into a REMI model of the New Hampshire economy. In this model, the utilities were not capable of adopting new technologies or switching fuels, limiting its usefulness to short run analyses in a region where the existing ability to switch to natural gas is limited.[xxxiii]

Other studies, including most of the analyses of EPA environmental regulations, use more sophisticated electricity market models, often called dispatch models. The models include fuel switching as an abatement option in areas where excess gas, nuclear, or renewable capacity already exists. Analyses of longer term energy and environmental policies, however, require that longer term policy-adaptation strategies, including the development of new infrastructure and technologies, be considered. Because many of the models used are incapable of automatically estimating levels of new plant construction and technological changes, many modelers have to find other ways to estimate longer term impacts.

One strategy is to base technological development and deployment assumptions on expert opinions. The Electrification Coalition's analysis of its own policies to promote the electrification of the light-duty vehicle fleet used this strategy. The coalition asked subject matter experts from PRTM Consulting to develop a deployment schedule and technological cost and efficiency assumptions that corresponded to the policies that the coalition was advocating. Those assumptions were then input into Inforum's LIFT model in order to estimate the macroeconomic effects of the policies.[xxxiv]

Similarly, the Business Roundtable's Balancing Act study of its own energy policy recommendations relied on expert opinions. For that analysis, the Roundtable formed six technology working groups – building efficiency, biofuels, transportation, and renewable, nuclear, and CCS electricity – to provide inputs for the model. The groups included technology, policy, and economic experts from the Roundtable companies as well as the economic modeling team. Each group was tasked with estimating trajectories for the cost, deployment, and technical specs for the most important technologies within its scope and for four policy scenarios. Industry modules for each of the technologies were then constructed within the LIFT model in order to integrate the inputs from the groups and to project the economic impacts of the technologies' collective deployment.[xxxv]

Finally, one other way that modelers estimate energy sector policy impacts without the use of a model that has sufficient energy sector detail is to use information from a related study that did use such a model. For example, a study done by University of Massachusetts-Amherst Political Economy Research Institute (PERI) estimates the economic impacts of criteria pollutant regulations using an IMPLAN model that is not capable of estimating the direct cost of the regulations to the electric power sector. Nevertheless, they were able to borrow results from a Charles River Associates (CRA) analysis that used CRA's National Energy and Environment Model (NEEM) to measure the impacts of the same regulations on the electric power sector. PERI then adapted those sector level results and pushed them through the IMPLAN model in order to estimate total economic effects.[xxxvi]

Similarly, the Inforum and Keybridge modeling team have used a similar approach for various analyses. In a report for the Clean Air Task Force on the economic effects of provisions in the Waxman-Markey Bill that support carbon capture and sequestration, the team draws on EIA's electric power sector results from various scenarios that it does in its analysis of the same bill. The team uses electric power sector outputs from two of EIA's Waxman-Markey policy scenarios in order to estimate changes in deployment levels for different types of power production including CCS and competing technologies. Those deployment levels were then input into the LIFT model in order to capture economic effects.[xxxvii]

These techniques for exogenously estimating energy sector responses to policies are widely-used and well-accepted techniques in energy and environmental policy analysis. They save the need to operate a model with greater energy sector detail, which can add significantly to the cost and complexity of an analysis without necessarily improving the estimates. Nevertheless, one drawback of estimating energy sector impacts exogenously is that those estimates – including deployment levels, prices, and technological changes – are then set and unlike other model variables, they will not change as the model iterates. Some of the modeling analyses, however, include endogenous modeling of the energy sector, which allows the modelers to vary more of the key energy sector variables and can also allow for a more objective estimation of those impacts.

Endogenous Modeling of the Energy Sector

Endogenously modeling energy sector policy impacts with a macroeconomic model was generally employed in one of two ways in the analyses reviewed:

1. Linking an energy sector model(s) to an economic model so that the two would feed results to one another with each iteration; and
2. Using an economic model that includes sufficient energy sector detail to do the analysis within that model.

Two studies that linked energy and economic models together are CRA's analyses of the Lieberman-Warner national cap and trade bill and the California Air Resources Board's analysis of it's the AB 32 scoping plan for regulating GHG emissions. CRA combined its partial equilibrium model of the electricity sector (NEEM) with its computable general equilibrium model of the US economy (MRN). NEEM, which is a model of the U.S. electric power system and coal industry, was used to forecast electricity price effects, emission allowance prices, and EGU retirements and additions among other key energy sector variables. Those outputs are then incorporated into the MRN model, which estimated impacts on the overall economy. The MRN-NEEM combined model then works iteratively with key outputs from each model being sequentially input into one another.[xxxviii]

The California Air Resources Board (CARB) used a similar strategy linking the E2020 energy sector model with the E-DRAM model of the California economy. CARB faced the additional challenge getting two models that were not developed and are not usually operated by the same organization to communicate with one another.[xxxix]

Other studies have made use of models that include both sufficient energy detail and the capability of estimating macroeconomic effects. MIT's Emissions Prediction and Policy Analysis (EPPA), which was used for several of the MIT analyses reviewed for this project, is a macroeconomic model that aggregates non-energy activities into just seven sectors but includes significant detail in the energy sector, which is divided into 15 different sectors. In this model, the deployment of various technologies endogenously responds to macroeconomic conditions, and technical specifications for those technologies – such as their costs and efficiencies – endogenously respond to the deployment levels. As the model iterates, both the energy sector and the macroeconomic variables adjust until they are in equilibrium with one another.[xl]

EIA's National Energy Modeling System (NEMS) is a modular model that combines energy demand, conversion, and supply modules with a macroeconomic module to determine the effect that policy changes will have on energy markets and the economy. By far the most sophisticated of the models used in the studies reviewed, each of NEMS's energy modules (e.g., electricity, coal, oil & gas, petroleum refining) include a great amount of regional and product-specific detail. Additionally, unlike the EPPA model, which includes only seven non-energy sectors, NEMS's macroeconomic module includes a significant amount of non-energy sector detail, with 56 non-energy sectors being modeled. However, like the EPPA model, most of the energy sector and macroeconomic variables adjust as the model iterates until an overall equilibrium is reached.[xli]

3.2.3 Simulating Regional Variation

Another major difference between modeling studies is the degree of regional variation that the studies include. Most of the analyses reviewed simulate the effects of energy policies on a single jurisdiction, estimating only the cumulative national effects on industries and households and providing no regional differentiation. The studies that do provide regional detail, however, do so for different purposes and often only provide regional details for certain variables.

Regional Variation Due to Policy Differences

One of the key factors that drive economic impact estimates is the degree to which climate policies are symmetric across regions. Some of the studies reviewed simplify their analyses by ignoring the impacts on trade with nations, states, and regions that are not subject to the policies being considered. The more sophisticated studies, however, consider these trade relationships between the region of interest and the rest of the world as key determinants of how certain policies may impact economic outcomes. The key parameters determining how these relationships are modeled are the assumed trade elasticities and changes in relative production costs.

Several of the studies that consider these relationships are one region studies in which a general assumption is made about how economies in the rest of the world may respond to the adoption of policies in the region of interest. The Business Roundtable's Balancing Act study, for example, assumes that reciprocal action on climate change by the U.S.'s trading partners would result in policy induced price changes that would be 80% the magnitude of the equivalent price changes in the U.S. In contrast, many other studies assume no price increase for foreign goods, an assumption that would likely increase the estimated cost of new regulations or carbon prices to the U.S. economy.

In several other studies, multiregional models are used to simulate the full economies or energy sectors of multiple regions, not just the primary region of interest. The University of California Energy Institute's study of the Western Climate Initiative cap and trade program uses such a model. This model splits the Western Electricity Coordinating Council into state electricity markets, allowing the modelers to capture the changes in the relative costs of power production between states that do and do not participate in a cap and trade program.

Similarly, Navigant consulting uses a regional power production model to analyze the Western Climate Initiative's impacts on the three participating Eastern Canadian provinces. The PROMOD model of the power sector includes electricity generating unit (EGU)-specific data. The EGUs are then grouped geographically in order to differentiate the carbon costs that corresponded with each group's adopted regulatory scheme – WCI, RGGI, or MGGRA. Each EGU's carbon costs are then added to its production costs, which are used in the electricity dispatch model. This regional breakdown also allows the modelers to simulate the imposition of import tariffs on electricity transmitted from unregulated to regulated regions. As discussed above, both of these studies, like several of the single region analyses, demonstrate that asymmetric climate policies can render a policy largely ineffective in lowering total GHG emissions while also reducing local production of tradable goods like electricity. The unique contribution of these regional models, however, is that they allow the modelers to show which regions would be the likely winners and which would be the losers under a host of scenarios.

Regional Variation Due to Differences in Existing Energy Markets

Other studies used models with regional details to show how a uniform policy across multiple regions would have differential impacts due to differences in existing energy market policies, energy infrastructure, or resource endowments. A Resources for the Future study, for example, uses an electricity market model with regional specifications to estimate how different emissions allowance allocation methods would affect consumers in different electricity markets. While a uniform national climate policy is applied across the continental U.S., 21 regional electricity markets are distinguished not only by their mixes of electricity generation sources (e.g., nuclear, coal, wind), but also by whether or not they use regulated or market-based pricing. The model then estimates interregional electricity trade in the context of these different mixes of energy generation infrastructure and regulatory systems, determining price and sales impacts at the regional level.[xlii]

Many other analyses also focus on how differences in regional electricity markets will lead to differential regional impacts of uniform policies. Most of these, however, focus solely on the different power generation infrastructure that exists in those regions. Several such studies focus on how criteria pollutant regulations will impact electricity prices and reliability at the regional level. The analyses estimate that regions that rely more heavily on coal-fired power generation, the source of most of the regulated pollutants in the electric power sector, will experience more plant closures and require more investment in new plants and pollution control retrofits. Meanwhile, regions that are more reliant on nuclear, renewable, and gas-fired power are estimated to require fewer investments as a result of the policies.[xliii]

The EIA's National Energy Modeling System further distinguishes regions from one another based on their production of primary energy sources, showing, for example, how policies may affect coal production in one region more than another. For example, in its analysis of the American Power Act (APA) as well as other climate policy analyses, the EIA concludes that putting a price on carbon would have a much larger impact on Western coal production than it would on Appalachian production, in large part because global metallurgical coal demand, a key export market for Appalachian coal, would be largely unaffected by the policy. NEMS includes similar regional detail for petroleum and gas markets. [xliv]

Regional Variation Due to Firm-level Differences

Some of the models used in the studies reviewed include regional variations with firm and geographic specific data in the electric utility sector. One example is the University of New Hampshire's analysis of that state's participation in RGGI. This study used a simple model that simulated the behavior of the four utilities that provide power to New Hampshire. The main distinguishing factors between those utilities are their electricity generation mix and the fact that only one of them produces in-state power while the others import electricity from neighboring states. The study's simulations show the differential effects on consumers living in the areas covered by the different utilities and estimates that customers living in areas that are served by the one utility that produces power in state would be better off if New Hampshire did not participate in RGGI while those living in other areas would be worse off.

3.2.4 The Inforum LIFT-CUEPS Model

The modeling system used for this analysis is a linkage of Inforum's National LIFT model with its County-Utility Energy Policy Simulator (CUEPS). The combined models constitute a tool that can measure policy impacts at the national level with significant industry detail while also facilitating the measurement of local impacts at the regional, state, and county levels.

As described earlier, the LIFT model is a hybrid, including characteristics of both CGE and econometric models. The model contains full demand and supply accounting for 97 productive sectors, including variables for investment, prices, imports and exports, employment, wages, and other key variables. The LIFT modeling framework is ideal for addressing questions where the interactions between industries is crucial. Several modules incorporating many of the variables in the Department of Energy National Energy Modeling System (NEMS) have been added to LIFT, which makes it possible to calibrate the LIFT model to the Annual Energy Outlook (AEO) and to derive alternative scenarios. Eight detailed electric power subsectors for different energy generation technologies (e.g., wind, nuclear, etc.) allow for the simulation of dynamic changes to plant efficiency and fuel use and for greenhouse gas emissions accounting.

For this project, LIFT is linked to the detailed County-Utility Energy Policy Simulator (CUEPS), which is a detailed model that contains economic data at the county level and electric power data by utility. CUEPS includes a county-utility bridge that facilitates the estimation of power sector efficiency and the generation mix at the county level. This allows the modeling team to estimate electricity price impacts and income effects of national policies that are specific to each county. Additional assumptions, such as the deployment of wind power infrastructure at the county or utility level, can also be adopted within CUEPS.

3.3 Other Key Assumptions

In addition to the policy design and the selection of models and modeling strategies, estimated impacts of energy and environmental climate policy are largely dependent on several key assumptions, including:

- The degree to which the economy operates at full employment,
- The cost and efficiency of different technologies,
- Energy price assumptions, and
- Whether alternative energy resources and technologies are domestic or imported

3.3.1 Full Employment of Resources

A key assumption in any economic modeling analysis is the degree to which resources are employed. This is important because, in an economy where resources are being employed (as would be expected in normal economic times), the devotion of more resources to one purpose will often require reducing the amount of resources dedicated to other purposes, often reducing the impact of policies that encourage particular investments. However, the assumption that resources are being underemployed (as is usually the case during a recession) means that a policy encouraging the employment of resources toward a given purpose would not necessarily require that fewer resources be available to other industries. Both of these assumptions – the economy is at full employment and the economy is not at full employment – are used in different analyses with significant consequences.

The University of Massachusetts Political Economy Research Institute (PERI) study of the criteria pollutant regulations that was discussed above implicitly makes the assumption that the economy is not at full employment through its use of the static input-output model from IMPLAN. This study assumes that the investments that the electric power sector would need to make in order to comply with the regulations would utilize capital and labor that would otherwise not have been employed. As a result, there is no offsetting reduction in the amount of capital and labor devoted to other purposes as a result of the new investments that would be required to reduce criteria pollutant emissions. Given this assumption, the study simply applies economic multipliers to the cost of the required pollution abatement investments in order to estimate economy-wide impacts. As a result, PERI estimates that the regulations would significantly increase employment levels in the economy in the 2013-2015 period, as otherwise unemployed resources are put to work.[xlv]

Terry Barker's analysis of global climate policy studies, however, points out that while the assumption that an economy has excess capital and labor in particular may be appropriate for simulations of many developing economies, most analyses of developed economies assume that the economy is in full employment in the base year (first year) of the simulation.[xlvi] Nevertheless, given the current post-recession U.S. economy, the assumption that there will be an excess of labor and capital in the U.S. over next few years is more defensible than it would be in better economic times.

In longer run analyses, most of the studies reviewed implicitly assume – through their use of CGE models – that the U.S. economy tends to operate at full employment and that capital and labor are scarce. This means that, while the economy is unlikely to benefit from an excess of labor or capital that can be employed without some offsetting reductions in their use in other sectors, it is also unlikely to undergo persistent bouts in which resources are unemployed. CGE models assume that, after the economy is shocked by a policy or price change, it will undergo adjustment after adjustment in order to get back towards its equilibrium where resources are employed at their long-run equilibrium level. As a result, the job losses and gains attributed to energy policies in the studies using such models are mostly short-run job losses due to the shock of the policy change. Job losses that are estimated to be persistent and/or increasing over time are usually attributable to the continual shock of an increasing carbon price or ever more stringent regulation. Meanwhile, the changes in long run equilibrium employment levels attributed to energy or environmental policies are often much smaller than the temporary initial changes.

Dynamic non-CGE (or econometric) models were also used in several of the reviewed analyses. These models are often not bound by the assumption that an economy will eventually return to an equilibrium state, and in some of the analyses the models estimate persistent bouts of underemployment of productive resources as a result of energy policy. For example, the National Association of Manufacturers (NAM) concluded that the Lieberman-Warner Bill would have caused the loss of 1-2 million U.S. jobs in 2020 and 3-4 million U.S. jobs in 2030, multiple times larger than the job loss estimates in any of the other studies of that particular bill.[xlvii]

In contrast, the EIA's analysis of the same bill uses the same model and estimates that economy-wide job losses would be 200,000 in 2020 and 62,000 in 2030.[xlviii] The NAM analysis includes a number of assumptions that are much more conservative than those used by the EIA, such as limited technological progress and limited availability of offsets. The EIA presents a number of scenarios with similarly conservative assumptions, but their GDP and employment impact estimates in those alternative scenarios still do not approach the large impacts projected by NAM. Instead, the difference between the studies' results is likely due to differences in their assumptions governing whether or not and with what speed the economy will tend towards full employment of productive resources, with the EIA assuming that the economy will tend to return to full employment while NAM assumes that the economy will be much less capable of adjusting.

3.3.2 Technology Assumptions

Another key reason why the NAM simulations showed such negative economic consequences of climate policy was that they concluded that carbon prices would have to be very high in order to meet the emissions reduction targets being proposed, making adjustments to those price changes more difficult. Conclusions such as this are driven by pessimistic assumptions about the cost, efficiency, and availability of the technologies needed to achieve given environmental goals.

The EIA, in several of its analyses, tests the sensitivity of its technology assumptions by simulating alternative scenarios that included higher technology cost assumptions or limited technology availability assumptions. Those simulations show higher unemployment and reductions in GDP as compared to scenarios with more optimistic technological assumptions. The changes in employment and production between scenarios, however, never reach the same scale as those estimated in the NAM study.

Studies of EPA regulation by different organizations show how a major difference in technology assumptions can lead to vastly different economic impact estimates. In its analysis of potential new ozone standards, the EPA estimates that the new standards will require some regions of the country to use technologies that do not yet exist. They estimate that the costs of those technologies will be higher but not dramatically higher than technologies that are currently available and in use. In contrast, studies by NERA Economic Consulting (NERA) and the Manufacturers Alliance (MAPI) estimate technology costs that are about ten times higher. While the EPA estimates a significant annual compliance cost of $19-90 billion, the MAPI study, which is based on state by state cost estimates from NERA, estimates the catastrophic (and largely unheard-of in any other policy analysis) annual compliance cost of about $1 trillion.[xlix] While this incredible finding raises a lot of questions about the methodology used, it serves as an extreme example of how different technological assumptions can impact the policy cost estimates.

3.3.3 Energy Price Assumptions

Another key set of assumptions that could have a major impact on economic outcome are the energy price assumptions. Assumptions for baseline scenarios are usually just borrowed from existing business-as-usual forecasts, and in most of the analyses reviewed, energy price forecasts from the EIA's Annual Energy Outlook series are used. This is not to say that most of these modeling teams believe that the EIA's forecasts are the most accurate, but rather it is simply because this is conventional practice and helps make independent studies somewhat more comparable then they would be if they were starting with entirely different baseline assumptions. Nevertheless, some studies have veered from this convention, which in some instances has significantly influenced results.

The Business Roundtable's Balancing Act study was conducted at a time when the AEO's energy price forecasts for crude oil and natural gas differed substantially with existing spot and future prices. As a result, the Roundtable chose to assume a flat real crude oil price forecast of $100 per barrel. The analysis also assumed that natural gas prices would gradually rise to reach parity on a $/Btu basis with oil. The oil price assumptions, which now appear to have been more in line with the reality to date than the AEO forecasts available in 2008, would have influenced the results by making alternative technologies that reduce the use of petroleum seem more economical than they would have been had lower oil price forecasts been used. The natural gas price assumptions, however, were much higher than both current natural gas price forecasts and the AEO forecasted prices that were available in 2008. This higher price forecast would have influenced the overall economic cost estimates in two offsetting ways:

1. Making gas, as a lower emissions alternative to coal and petroleum, more expensive than it would have otherwise been, increasing the estimated cost of the climate policy; and
2. Making substitution of other technologies for gas seem less costly than they would have been had lower gas prices been assumed.

Either way the study's use of this higher price forecast would have diminished natural gas's role in the simulated transition to a lower carbon economy.[l]

The studies reviewed also differed in how they estimated changes in energy prices from the baseline scenarios to their policy scenarios. Several studies assume that prices would not differ between scenarios; some allow the model to determine the change in prices; but most keep the prices of some energy sources the same while changing the prices of other energy sources. For example, most of the studies reviewed include electricity prices that change as a result of policy changes. This is because electricity markets are more local than primary energy source markets and because electricity markets are expected to be significantly affected by both local and national policies.

The prices of primary energy sources, however, either changed or did not change depending on the scope of the analysis and the type of fuel. For example, some of the state and provincial analyses assume that local policy changes would not be enough to influence the price of fossil fuels, which are typically determined by national (e.g., natural gas) and global (e.g., crude oil) markets. In contrast, many national policies were assumed to be significant enough to influence fossil fuel prices, especially prices for natural gas, and to a lesser degree, coal. Some studies, such as the Business Roundtable's, estimated these changes in price effect exogenously, although many simply allowed the models to determine the changes in prices endogenously.

3.3.4 Sources of Fuels and Energy Technologies

One of the model variables that drives energy prices is energy supply and a key characteristic of supply is whether or not it is domestic or international. More sophisticated models include industry-specific parameters which estimate the proportions of that industry's output that are domestically produced versus imported, assumptions that can largely influence the estimated economic impact of a policy. For example, in 2010 the net imports of natural gas represented about 10% of the domestic supply and are forecast in the 2011 AEO to represent an even smaller percentage by

2030. However, many of the policy scenarios that have been modeled in the different studies are estimated to result in significant increases in the natural gas consumption over baseline scenarios that do not include these policies. In order to meet this increased demand for natural gas, the models used and/or the modelers must estimate whether that incremental demand will be met with an increase in domestic supply, an increase in imports, or an increase in both.

The EIA, for example, simulates a scenario in its Kerry-Lieberman study in which clean coal and nuclear technologies will be more costly than expected and that gas will be used as a substitute for them in the production of electricity. In this scenario they forecast that natural gas demand would be 2.8 trillion cubic feet (or 12%) higher in 2030 than it would be in the baseline scenario. They meanwhile estimated that although barely 8% of demand would be met by imports in the baseline scenario, over 53% of the incremental demand would be. Had the EIA assumed that the incremental demand would be met primarily with increased domestic supply, it is likely that estimates of several key economic measures, such as GDP, would have been more positive.

In contrast, the Electrification Coalition study simulates a policy that would encourage electric vehicle deployment and use, reducing domestic oil demand. The authors estimate that this reduction in demand, although significant, would be unlikely to dramatically lower the globally set oil price and would therefore be unlikely to affect the profitability of domestic oil production. Given this conclusion, the modeling team assumes that any reduction in oil demand would result in an equal reduction of oil imports, an assumption that would tend to have a positive impact on estimated economic outcomes. Results, however, would likely be less positive if it were assumed that domestic oil production would fall as a result of falling domestic demand.

In many models, similar assumptions about the proportion of a good or service that are domestically supplied can be made for other key industries, just as is often done for the oil and natural gas industries. For the most part, however, the parameters controlling the proportions of an individual industry's output that are domestic versus imported are left unchanged between baseline and policy scenarios, only to be changed when there is a compelling reason to believe that the policy may induce such a change. [li]

Endnotes for Section 3

[i] Beach, 2007; EIA, 2008a, 2008b, 2010; EPA, 2008; Paltsev, 2008; Murray, 2007; NAM, 2008.
[ii] CARB, 2010; Gittell, 2008; Navigant 2010;Bushnell, 2009; Tanton 2010.
[iii] CARB, 2010; Houser, 2010; Peterson, 2010.
[iv] Paltsev, 2008.
[v] Tuerck, 2009.
[vi] EPA, 2008.
[vii] Barker, 2006.
[viii] EIA, 2008a, 2008b, 2010.
[ix] Goulder, 2009.
[x] Paul, 2008.
[xi] Goulder, 2009.

[xii] Barrett, 2002.
[xiii] Barker, 2006.
[xiv] Business Roundtable, 2009.
[xv] Parry, 2011.
[xvi] Wiser, 2005.
[xvii] EIA 2009b.
[xviii] EIA, 2007.
[xix] Morris, *2010.*
[xx] EIA, 2009a.
[xxi] Business Roundtable, 2009.
[xxii] Keybridge Research, 2010a.
[xxiii] EPA, 2010.
[xxiv] ICF 2010; ICF, 2011; .EPRI, 2011; Bernstein, 2010; Brattle, 2010; EPA, 2010b; EPA, 2011.
[xxv] Heintz, 2011.
xxvi EIA, 2011
[xxvii] Gittell, 2007.
[xxviii] Bushnell, 2009.
[xxix] Navigant, 2010.
[xxx] EPA, 2011.
[xxxi] Tanton, 2010.
[xxxii] Barker, 2006.
[xxxiii] Ross, 2007.
[xxxiv] Electrification Coalition, 2009.
[xxxv] Business Roundtable, 2009.
[xxxvi] Heintz, 2011.
[xxxvii] Keybridge Research, 2010b.
[xxxviii] Smith, 2010.
[xxxix] CARB, 2010
[xl] Morris, 2010; Paltsev, 2008.
[xli] EIA 2009c.
[xlii] Paul, 2009.
[xliii] North American Electric Reliability Corporation, 2011; ICF, 2011.
[xliv] EIA, 2009c.
[xlv] Heintz, 2011.
[xlvi] Barker, 2006.
[xlvii] NAM, 2008.
[xlviii] EIA, 2008.
[xlix] MAPI, 2010.
[l] Business Roundtable, 2009.

4. Methodology: Models and Data

4.1 Model Capabilities and Objectives

The Energy Policy Impact Model constructed for this project is a dual-level system, comprised of the *LIFT* (Long-term Interindustry Forecasting Tool) model of the U.S. national economy, combined with the *CUEPS* (County-Utility Policy Simulator) model of counties and electric utilities.

The *LIFT* model works at a detailed sectoral level (about 90 private industries plus government sectors) and shows the interactions between industries, and the impacts on industry output of changes in exports and imports, personal consumption, investment and government spending. The *LIFT* model integrates the national income accounts (NIPA) with the detailed input-output accounts produced by the U.S. Bureau of Economic Analysis (BEA). *LIFT* forecasts at an annual frequency, and the standard version has a forecast interval to 2035.

LIFT also incorporates additional modules that focus on variables of interest for energy and environmental modeling, including:

- a biofuels module
- electricity generation module, showing generation by type
- transportation module, with 5 vehicle types
- buildings module
- renewable energy (solar and wind) module
- nuclear module

Other modules can be added flexibly to *LIFT* to offer additional analytical capacity that works with the main *LIFT* model either in top-down fashion, or simultaneously.

LIFT is used to drive two other Inforum models in a top down manner. The Inforum *Iliad* model has a more detailed industry database, forecasting final demands, output, and employment for 360 industrial sectors. The Inforum *STEMS* model forecasts output, employment, earnings, personal consumption and other variables by 50 states and the District of Columbia, at the 65 industry level.

The *CUEPS* model includes a detailed database of 3140 counties and 3356 electric utility establishments. A county-utility bridge is used to relate economic activity by county to service demands by electric utility, and to relate cost changes by utility to the effects on the local economies served by that utility. Although not as detailed as the national model, the county level data does include data for 11 private sector industries and 3 government sectors.

4.2 Source Data for CUEPS

County level data are derived primarily from data published by the Bureau of Economic Analysis (BEA), and include data or estimates for employment, earnings, output, value added, costs and capital income by industry. In addition, aggregate data on personal income and its components, population, number of households are compiled from BEA sources. A small (14x14) IO table consistent with the national level detailed table is used to calculate electricity demands for the industrial and commercial sectors.

Utility data is obtained from the detailed Energy Information Administration (EIA) 860 and 861 datasets, and includes data on revenues, sales, costs, rates, fuel type, and number of customers by customer class. The *CUEPS* model traces the effect of changes in electrical generation costs on Kwh electricity rates for residential, commercial, industrial, and other customers.

The model has been tested in a 10 year forecast (to 2020) but should be able to forecast as far as 2035, if suitable assumptions can be specified for exogenous variables.

4.3 Outline of the Modeling System

The Energy Policy Impact Model (*EPIM*) developed for ARC is comprised of two main components:

- The Inforum *LIFT* model, forecasting macroeconomic and industry variables at the national level.
- The *CUEPS* model, forecasting economic activity by county, electric utility generation and revenues by utility, and a county-utility bridge linking counties and utilities.

The *LIFT* model determines the sources of demand and output growth for each of about 90 industries. These sources of demand growth may be combinations of the following:

- Personal consumption expenditures
- Equipment investment and software
- Residential and non-residential construction
- Inventory change
- Federal and state and local government spending
- Exports
- Intermediate demand, which consists of sales to other industries

The *LIFT* model projects each of these components by industry sector. In the case of intermediate demand, sales to each of the other industry sectors are identified. Total demand may be satisfied by domestic production, or by imports. The import equations in *LIFT* determine what share of demand will be satisfied by imports, based on relative foreign and domestic prices, and historical trends of import shares.

LIFT also forecasts labor productivity, hours worked, and employment by sector, to arrive at total economy wide employment. Incomes by industry are forecast for 13 subcomponents, which can be categorized as either labor compensation, profit-type income, or indirect tax. Prices by industry are also forecast, or may be specified exogenously.

The aggregate macroeconomic variables, such as total consumption, investment, exports, imports, government spending, employment, personal income, and disposable income, are calculated wherever possible as aggregates of detailed industry variables. The *LIFT* model is a fully bottom-up and internally consistent model of the national U.S. economy.

In developing a simulation with *LIFT*, there are thousands of variables that can be specified exogenously, or modified by the user. Indeed, it is a given set of assumptions that determine a particular outcome or scenario with the model. The descriptions of simulations below provide some examples of how scenarios are developed with *LIFT*.

The *CUEPS* database consists of national level data from the Inforum *LIFT* model, aggregated to the 14 sector level, county level data, based on the Regional Economic Information System (REIS) from the U.S. Bureau of Economic Analysis, and electric utility data from the Energy Information Administration (EIA).

The 14 industry sectors used in *CUEPS* are listed in Appendix B in table B-1. The data from *LIFT* include output in current and constant dollars, prices, employment, productivity, labor compensation, proprietors' income, other return to capital, indirect business taxes, total value added, personal consumption expenditures, federal defense expenditures, federal nondefense expenditures, state & local government expenditures, and total final demand.

Data for the 3140 counties comprising the U.S. include population, employment, total earnings, number of households, total wages and salaries, other labor income, proprietors' income, dividends, interest and rental income, transfer income, social insurance contributions, and a residence adjustment. Data for earnings and employment are available from each county for the 14 sectors listed in table B-1. In addition to these data, estimates were made for current and constant dollar output, return to capital, and indirect business taxes.

The electric utility data is available from EIA for a set of 3356 utilities. These data consist of sales in megawatt hours (Mwh), revenue, and number of customers, for five markets: Residential, Commercial, Industrial, Public, and Other.

Residential customers are defined as household establishments that consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking, and clothes drying. Commercial actually includes both commercial and industrial establishments which have demands generally less than 1000 kilowatt hours (kW). Industrial includes commercial and industrial establishments which have demands generally greater than 1000 kW per year. Public is energy supplied to ultimate consumers for public street and highway lighting. Other includes any customers not included in the other four categories, and is primarily for agricultural use. Average price data were also calculated by dividing revenue by megawatt hour sales in each market, by utility.

The solution process of *CUEPS* is described in more detail in Appendix B.

4.4 Scenario Analysis

The next chapter describes the development of the Reference case scenario and 4 policy scenarios that incorporate aspects of likely policies or technologies. The minimum requirement for the development of a scenario using the LIFT model is to make assumptions for the exogenous variables in the model. The word ‘exogenous’ derives from Greek, and means “born outside”. Endogenous variables (“born inside”) of the model are calculated within the model. Exogenous variables must have assumptions supplied for their projected values. Variables that are commonly considered to be exogenous include population, labor force, real government consumption and investment, tax rates, and social insurance contribution rates. The LIFT model forecasts final demand, value added, employment, and prices by industry endogenously. However, certain prices, such as energy and commodity prices are often treated as exogenous, since they are determined on the world market.

The process of *calibrating* the LIFT model to projections of another model involves making assumptions about exogenous variables that are consistent with the other model, and making modifications of the projections of endogenous variables to bring them into consistency with the projections of the other models. For example, the LIFT model forecasts personal income and its components based on income by industry. It derives disposable personal income based on personal income and exogenous assumptions about tax and contribution rates. The measure of real disposable personal income used in the model is nominal disposable income divided by the personal consumption deflator. In matching the LIFT real income growth to that of another model such as NEMS, many components of the model may need to be adjusted, such as wages, proprietors’ income and corporate profits, and taxes and contribution rates. Some of these adjustments are on endogenous variables, and some are on exogenous variables.

In the Annual Energy Outlook 2011, many side cases were developed, and some of these side cases were used to calibrate the LIFT model for policy scenarios considered in this study. For these side cases, energy prices, energy demands, electricity generation by type, energy import shares, and input-output coefficients are some of the variables that are adjusted to calibrate to the AEO side case.

The CUEPS model runs in conjunction with LIFT, and makes a county level projection that is consistent with the national model projection. However, additional assumptions can be layered on at the county level, that incorporate additional information. For example, this is done in the development of wind, biomass, and shale gas assumptions, which are further described in Appendices C and D.

5. Scenario Implementation and Assumptions

5.1 Summary of Policy Scenarios

The Appalachian region is rich in energy resources and will no doubt continue to play an important role in the national energy landscape. Which energy policies are chosen in the next decade and beyond will have significant implications on the region's contribution to national energy supply, and will have important impacts on economic growth and employment in the region.

In the ARC *Regional Blueprint*[5], several Strategic Objectives for economic and energy development are outlined:

1. Promote energy efficiency in Appalachia to enhance the Region's economic competitiveness.
2. Increase the use of renewable energy resources, especially biomass, in Appalachia to produce alternative transportation fuels, electricity, and heat.
3. Support the development of conventional energy resources, especially advanced clean coal, in Appalachia to produce alternative transportation fuels, electricity, and heat.

In this study, we examine several policy scenarios that explore implications of pursuing these objectives. These scenarios are compared to a Reference case that was developed specifically for this study, but is consistent with the reference case of the Department of Energy (DOE) *2011 Annual Energy Outlook*. For each scenario, consistent simulations are developed of the LIFT national model and the CUEPS model of counties and utilities.

In addition to the Reference case, the following scenarios are analyzed in this study:

1. **Energy Efficiency** – This scenario is related to Strategic Objective #1, and uses assumptions about changes in end use electricity efficiency derived from ARC's *Energy Efficiency in Appalachia.*[6] This study finds that if the set of policy recommendations in the energy-efficiency policy portfolio were followed, by 2020 there would be a 5.4 percent increase in electricity efficiency in the residential sector, a 22.3 percent increase in the commercial sector, and an 18.0 percent increase in efficiency in the industrial sector. These efficiency increases are assumed for both the LIFT and the CUEPS models, to determine the economic and energy consumption impacts at the regional level and across counties and states in the Appalachian region.
2. **Carbon Mitigation** – While carbon tax or cap and trade policies seem less likely now than they did 2 years ago, there is still interest in analyzing the economic impacts of mitigating carbon emissions in the U.S., especially from the electric power sector. There are major differences between outcomes of these policies,

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[5] *Energizing Appalachia: A Regional Blueprint for Economic and Energy Development*, October 2006, at http://www.arc.gov/images/newsroom/publications/energyblueprint/energyblueprint.pdf.

[6] *Energy Efficiency in Appalachia: How Much More is Available, At What Cost, and By When?*, May 2009, at http://www.arc.gov/assets/research_reports/EnergyEfficiencyinAppalachia.pdf.

resulting from the different assumptions about scope, stringency, offsets, allowance allocation, and revenue usage. We define the national level LIFT scenario to encompass many of the assumptions in the AEO 2011 greenhouse gas scenario. Our scenario does not include any offsets or international permit trading. We endeavor to estimate the increase in electricity prices in Appalachia resulting from the policy, and the resulting impacts on output and employment. This scenario ties to all three Strategic Objectives, as the presence of a carbon pricing scheme will spur increased energy efficiency, increased use of renewables such as wind and biomass, and stimulate the development of novel uses of conventional fossil fuel resources, such as advanced clean coal.

3. **Clean Energy Standard** – This scenario ties into Strategic Objective #2, and assumes aggressive development of wind and biomass resources for electric power generation in the region. The national scenario in the LIFT model draws on a study of the Clean Energy Standard recently published by the Energy Information Administration.[7] The CUEPS level scenario draws on findings of the ARC study *Energy Efficiency and Renewable Energy in Appalachia.*[8] For wind power, we make use of information and assumptions from the NREL Eastern Wind Integration and Transmission Study (EWITS)[9] and for biomass we use information from DOE's *2011 U.S. Billion Ton Update* and the EIA's 2011 Annual Energy Outlook. This policy scenario includes the modeling of a national-level context in LIFT and county specific investments for wind and biomass. We propose to use multipliers available from the NREL Jobs and Economic Development Impact (JEDI) tool[10] to ascertain the impacts on output and jobs by county in the CUEPS model.
4. **Expanded Natural Gas Development** – This scenario ties into Strategic Objective #3, exploring the intensive development of natural gas resources in the region. While natural gas is a conventional energy resource, the extraction of natural gas from the abundant Marcellus Shale deposits represents a very promising development for the Appalachian region. We use the *AEO 2011* high shale gas scenarios to provide the national context, and use GIS software to analyze a series of digital datasets published by the USGS to estimate the Appalachian specific impact of increased natural gas demand and development.

5.2 Reference Case

The Reference case for the Inforum LIFT model was calibrated to the Annual Energy Outlook (AEO) 2011 Reference Case, which was released in March 2011[11]. This calibration was done in two stages. In the first stage, industry variables, macroeconomic variables, and IO coefficients were modified to produce a macroeconomic forecast consistent with the AEO. In the second stage, imports, exports, personal consumption expenditures, and IO coefficients were modified to calibrate energy and carbon

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[7] *Analysis of Impacts of a Clean Energy Standard, as requested by Chairman Hall*, U.S. Department of Energy, Energy Information Administration, October 2011, at http://www.eia.gov/analysis/requests/ces_hall/.

[8] *Energy Efficiency and Renewable Energy in Appalachia: Policy and Potential*, July 2006, at http://www.arc.gov/assets/research_reports/arc_renewable_energy_full.pdf.

[9] See http://www.nrel.gov/wind/systemsintegration/ewits.html.

[10] See http://www.nrel.gov/analysis/jedi/about_jedi.html.

[11] The AEO 2011 is produced by the Department of Energy (DOE) Energy Information Administration (EIA) The AEO Reference Case and Side Cases are described and documented at http://www.eia.gov/forecasts/aeo/. For the reference case, and many of the side cases, detailed tables of results are available in Excel format, as well as in PDF.

projections from the AEO. The current forecasting horizon of both AEO 2011 and LIFT is 2035.

The AEO is produced using the National Energy Modeling System (NEMS)[12]. NEMS is an energy-economy modeling system of the U.S. through 2035. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. NEMS is comprised of several modules which can work separately or be run together using an integrating module. NEMS includes demand modules for each of the major consuming sectors in the economy, which are residential, commercial, industrial and transportation. NEMS also includes extensive detail on the supply sectors, such as electric power, natural gas, petroleum-based and alternative liquid fuels, and coal. Within the electric power sector, NEMS models several alternative types of power generation. NEMS also projects energy prices. The macroeconomic and industry components of NEMS consist of the IHS Global Insight macroeconomic and industry models.

The Inforum LIFT model is not as specialized as NEMS with regard to energy production and consumption, but includes a greater level of industry detail, and the macroeconomic and industry calculations are integrated and internally consistent. LIFT forecasts each final demand component at the industry level, including personal consumption, equipment investment, construction, government spending, exports, imports, and inventory change. Total demand by commodity is calculated using the input-output identity, and is ensured to equal total supply, defined as output plus imports less inventory change. LIFT also forecasts the major categories of income by industry, including labor compensation, corporate profits, proprietors' income, net interest, rental income, and consumption of fixed capital (depreciation). Prices by industry are forecast in a way that maintains consistency between input prices, value added, and output prices.

Submodels have been added to LIFT which link to the industry model in both directions. These submodels include:

1. An electric power sector disaggregated into 8 generation types: coal, natural gas, petroleum, nuclear, hydroelectric, solar, wind, and geothermal and other (which includes biomass).
2. A transportation module, which tracks vehicle miles traveled, fuel (including electric) efficiency, and sales and stocks of vehicles by 6 major types. The transportation module also forecasts fuel use by air, rail, water, and bus and truck transportation.
3. Biofuels module, which can be used to analyze corn and cellulosic ethanol and biodiesel.
4. Buildings module, which is used to track energy use of residential and commercial buildings.
5. Renewable power module, which models costs, efficiency, and penetration of solar and wind power.
6. Carbon emissions and carbon tax module, which relates carbon emissions to energy consumption and process emissions at the industry level, and traces the

[12] NEMS is described in detail at http://www.eia.gov/oiaf/aeo/overview/index.html.

industry price impacts of a carbon tax. This module is also used to track the "recycling" of carbon tax revenue.

Calculations native to the LIFT model are in either constant 2005 dollars or in current dollars. Prices in LIFT are price indices, equal to 1.0 in 2005. Many of the modules link energy quantities (barrels, gallons, Kwh, btus) to constant price measures in LIFT.

The general strategy of deriving a Reference case for LIFT consistent with the NEMS AEO forecast consists of a number of steps:

1. Calibrate exogenous variables, such as population and labor force, government spending, exports, and oil, natural gas, and coal prices.
2. Calibrate final demand categories, such as personal consumption, equipment investment, and construction to AEO. Demand for imports is derived from import requirements for other final demands and for intermediate consumption. Adjust imports demand to be consistent with AEO.
3. Once all final demands have been calibrated, derive the components of personal income. Change the federal and state and local tax rates to calibrate disposable income.
4. Change labor productivity by industry to calibrate to aggregate labor productivity in the AEO. Adjust employment to get close to the AEO unemployment rate forecast.
5. Calibrate energy consumption by sector by type. Energy consumption can be traced in the LIFT model at several different levels. Energy consumed in final demand includes personal consumption of gasoline, heating oil, natural gas, and electricity; government purchases of fuels and electricity, and energy consumed in building residential and nonresidential structures. Energy flows in the intermediate demand part of the model include industrial consumption of energy for space heat and light, stationary power sources, transportation fuels, and electricity for many uses. These flows also include the conversion of energy from one type to another, such as the refining of crude oil into petroleum products, and the generation of electricity from coal and other fuel sources
6. Calibrate carbon emissions at the level of major demand sector by major energy source.

LIFT was calibrated using the above procedures to the *AEO 2011* reference case. Selected tables of results of the LIFT reference case are presented and discussed in section 6.

The CUEPS model forecasts employment, output, income, and other economic variables by county. It also presents a detailed projection of electric utilities, and relates utility activity to the county markets each utility serves. The CUEPS database of results includes county data for 14 industries for 3140 counties, and utility data for 3356 utilities[13].

The Reference case for CUEPS is created using the LIFT AEO2011 reference case to obtain some variables exogenous to CUEPS, but forecasts county and utility level data endogenously. The CUEPS projection thus is consistent with the national level economic environment projected by LIFT, but relates local employment, output, and income to both local and national economic activity. CUEPS includes forecasts for about 20 aggregate county-level variables, and for about 10 economic variables at the 14-

[13] See Appendix B for a detailed description of the operation of LIFT and CUEPS.

industry level. It also includes sales, revenues, customers, and electricity rate projections for each utility.

5.3 Electricity Efficiency

The Energy Efficiency Case starts with the assumptions of the Reference case, but energy efficiency in the residential, commercial, and industrial sectors are modified to be consistent with the recommendations and findings of the ARC report *Energy Efficiency in Appalachia.*[14] While this study also assessed the effects of the policies on natural gas and petroleum based fuels, our study focuses on the electricity savings possible from this policy package.

Electricity efficiency changes were input to the LIFT model through the modification of input-output electricity coefficients in the industrial and commercial sector, and through the modification of the personal consumption equation for electricity for the residential sector. We assume that the efficiency increases occur at the national level, not just in the Appalachian region. Other assumptions that are considered in this scenario include government expenditures, subsidies, and tax breaks used to implement these policies. Other assumptions used in the LIFT model were the same as in the Reference case.

Residential Sector

The Appalachian energy efficiency study models four policy packages to encourage energy efficiency in residential buildings[15]:

1. *Model building energy codes*: Residential building energy codes define engineering and construction requirements to meet particular efficiency targets for new residential buildings. The study assumes that all Appalachian counties adopt the International Energy Conservation Codes (IECCs) with third-party verification.
2. *Expansion of the weatherization assistance program*: Weatherization programs improve the efficiency of homes for low-income persons. These programs reduce energy consumption and therefore lower energy costs while improving comfort, health, and safety. Nationally, 25 percent of households are considered to be eligible for weatherization assistance under the Weatherization Assistance Program (WAP).
3. *Existing home retrofits*: This policy element encourages homeowners to pursue existing home retrofits by reducing financial barriers. The analysis assumes the retrofit program runs as an incentive measure for 20 percent of investment cost, to accompany two other policies – home energy disclosure and on-bill financing.
4. *Super-efficient appliance deployment*: This policy element includes policies to encourage greater adoption of energy-efficient appliances and electronics. An incentive of 40 percent of the incremental cost is offered for adoption of these appliances from 2010 to 2015; from 2015 to 2020, the incentive is 20 percent of the incremental cost.

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[14] This study can be found on the ARC web site at http://www.arc.gov/assets/research_reports/EnergyEfficiencyinAppalachia.pdf.

[15] See section 3.3 of *Energy Efficiency in Appalachia* for a more detailed description of the policies targeting residential consumption.

Table 5.1 summarizes the electricity savings projected to result from these policies for selected years through 2030. Total electricity savings are estimated to be 5.4 percent by 2020, and 11.1 percent by 2030. In the current study, we model the impacts of these savings through the year 2020.

Table 5.1. Residential Electricity Savings (GWh)

	Residential Building Codes	Expanded Weatherization	Existing Home Retrofits	Super-Efficient Appliances	Total Residential Savings	Total Electricity Savings (Percent)
2010	25.2	114.0	382.0	51.0	572.2	
2013	201.2	461.5	1535.0	207.0	2404.7	
2020	1587.0	1299.6	4222.0	957.0	8065.6	5.4
2030	4888.7	2612.2	8241.0	2736.0	18477.9	11.1

Commercial Sector

The study includes four policy packages, coupled with incentives to encourage efficiency in commercial buildings[16]:

1. *Commercial building energy codes with third party verification*: As with residential buildings, the study assumes that all Appalachian counties adopt the International Energy Conservation Codes (IECCs). The savings are assumed to be made through 80 percent compliance with model building code legislation enabled by third-party verification of code compliance.
2. *Support for commissioning of existing commercial buildings*: Building commissioning is a multi-phase process to ensure building performance is as designed and that the building's operation meets the needs of its occupants. Commissioning existing buildings in the Appalachian Region could lead to immediate energy savings.
3. *Efficient commercial HVAC and lighting retrofit incentive*: A commercial retrofit program would include incentives and information to accelerate adoption of more efficient products. This type of program helps to induce stock turnover – removing the least efficient equipment, while also fostering investment in newer technology.
4. *Tightened office equipment standards with efficient use incentive*: This policy package focuses on office equipment standards for computers, copiers, printers, monitors, multi-function devices, fax machines, and scanners.

Table 5.2 summarizes the electricity savings resulting from the adoption of the above policies. The savings are substantial, especially in policy packages 2 and 3. Total energy savings are projected to be 22.3 percent by 2020, and 46.2 percent by 2030.

[16] See section 3.4 of *Energy Efficiency in Appalachia*.

Table 5.2 Commercial Electricity Savings (GWh)

	Commercial Building Codes	Commissioning of Existing Buildings	Efficient HVAC and Lighting Retrofits	Office Equipment Standards	Total Commercial Savings	Percent Savings
2010	84	213	712	387	1396	
2013	391	1868	3489	1060	6808	
2020	1551	9886	14129	4673	30239	22.3
2030	3993	26611	31661	12017	74282	46.2

Industrial Sector

The study includes 3 policy packages for the industrial sector:

1. *Expansion of industrial assessment centers (IACs):* Industrial Assessment Centers (IACs) are university-based, and teams comprised of both faculty and students perform thorough analyses at small to medium-sized industrial facilities within their local region. These assessments suggest savings improvements in energy efficiency, waste minimization, pollution prevention, and productivity. Expanding the capacity of Industrial Assessment Centers in Appalachia could greatly improve the energy efficiency of industry in the Region.
2. *Energy savings assessment (ESA) training*: There are several programs identified in the *EEA* report that support energy savings assessment and training. Details of the estimates of energy savings gained from these programs are discussed in Appendix D.2 of that study.
3. *Combined heat and power (CHP) incentives*: Combined heat and power (CHP) can offer significant energy use reductions by avoiding energy waste through heat loss. The suite of policies suggested in *EEA* includes grants, loans, special rates, and ease of interconnection with the electrical grid. Energy savings from these policies are discussed in Appendix D.3 of that study.

Table 5.3 summarizes the electricity savings estimated to be achieved through the above policies. Total energy savings are estimated to be 18 percent by 2020, and 42.4 percent by 2030.

Table 5.3. Industrial Electricity Savings (GWh)

	Expanded Industrial Assessment Center Initiative	Increasing Assessments and Training	Supporting Combined Heat and Power (CHP) with Incentives	Total Industrial Savings	Percent Savings
2010	10	106	0	116	
2013	631	914	2793	4338	
2020	3243	6422	9655	19320	18.0
2030	7261	21344	21081	49686	42.4

5.4 Carbon Mitigation

The Carbon Mitigation case examines the implications of a national greenhouse gas (GHG) price policy on electricity prices, output, and employment in Appalachia. The objective of this scenario is not to model any particular legislation, but to examine a generic GHG price scenario. Since the Reference case for this exercise is calibrated to the AEO2011 Reference case, it was convenient to calibrate the LIFT model to the AEO2011 side case "GHG Price Economywide".[17] The carbon price for this scenario is specified to begin in 2013 at $25 per metric ton CO_2, and rise to $75 per metric ton by 2035. Table 5.4 shows the carbon price assumption in both 2009$ and in nominal dollars. The average growth rate of the nominal price over this period is about 9 percent.

Table 5.4 Carbon Price

	2009$	Nominal
2012	0.00	0.00
2013	25.00	26.35
2015	29.73	32.22
2016	32.09	35.31
2020	41.55	49.58
Avg. Growth	7.26	9.03

The average electricity price is higher relative to the base case, due to the carbon costs imposed upon fossil fuels such as coal, natural gas, and petroleum. However, the AEO GHG case also includes a switch from coal to other fuel sources, which reduces the impact of the carbon tax somewhat. This switch in generation types was also adopted in the LIFT model. Table 5.5 below shows the impact on the average delivered electricity price in the Reference case and in LIFT Carbon Mitigation case.

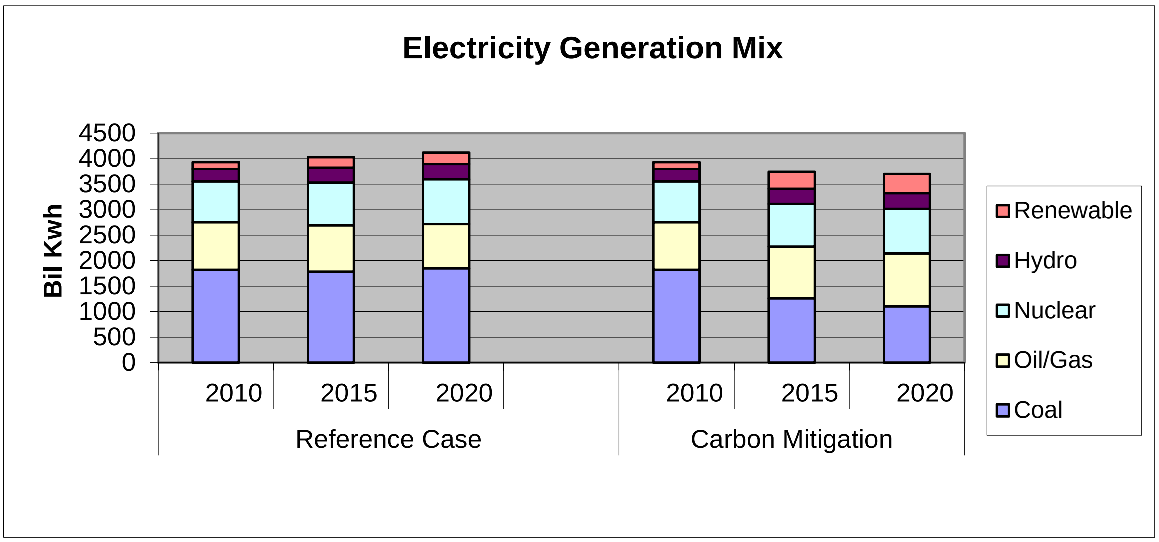
[17] The AEO 2011 was distinguished by the publication of a Reference Case and 58 side cases, described in Appendix E of the AEO document. The *Annual Energy Outlook 2011* can be accessed at http://www.eia.gov/forecasts/aeo/pdf/0383%282011%29.pdf. The full set of side cases is described in table E1 beginning on p. 214. The cases are summarized starting on p. 218. The GHG cases are described on p. 223.

Table 5.5 Electricity Price in the Carbon Mitigation Case

	Reference	GHG Price	Percent Difference
2012	9.31	9.31	
2013	9.40	10.93	16.2
2015	9.70	11.72	20.8
2020	10.68	13.46	26.0

Figure 5.1 shows the changes in nationwide electricity generation by type, and table 5.6 provides the data underlying this figure. Note that separate generation for wind, solar and geothermal and other is accounted for in LIFT, but that these have been combined into "Renewable" for this figure and table.

Figure 5.1. Generation Mix in Carbon Mitigation and Reference Cases



By 2020, generation from coal in the Carbon Mitigation case is significantly reduced (by 40.2 percent) relative to the Reference. Natural gas and Renewables are significantly higher (19 percent and 67 percent, respectively). Total electricity generation is about 10.2 percent lower in the Carbon Mitigation case, due to demand response to higher electricity prices in the residential, commercial, and industrial sectors.

Table 5.6 Electricity Generation Mix in Reference and Carbon Mitigation Cases (billions of KWh)

	Reference Case			*Carbon Mitigation*			
				Levels		Percent Difference from Reference	
	2010	2015	2020	2015	2020	2015	2020
Coal	1818	1787	1850	1266	1105	-29.2	-40.3
Oil/Gas	934	905	868	1008	1036	11.3	19.4
Nuclear	803	839	877	839	877	0.0	0.0
Hydro	240	293	301	299	306	1.8	1.6
Renewable	133	201	224	330	375	64.1	67.2
Total Generation	3929	4026	4121	3742	3699	-7.1	-10.2

5.5 Clean Energy Standard Scenario

This scenario examines possible responses to a clean energy standard, specifically the aggressive development of wind and biomass resources for electric power in the Appalachian region. The national-level scenario developed for the LIFT model draws on the recently published EIA study *Analysis of Impacts of a Clean Energy Standard*[18].

In general, a Clean Energy Standard (CES) is a policy that requires covered electricity sources to supply a specified share of their electricity sales from qualifying clean energy sources. The EIA report analyzes a version of the CES that was specified by Representative Ralph M. Hall, Chairman of the House Committee on Science, Space, and Technology. In this version, electric generators are granted clean energy credits for every megawatt-hour (MWh) of electricity produced using qualifying clean energy sources. Generators can use some combination of credits granted to their own generation of electricity, or acquire credits from other generators, to meet their CES obligations. Generators without retail customers that generate more clean energy credits than needed to meet their own obligation can sell CES credits to other companies.

Eligible generation types include hydroelectric, wind, solar, geothermal, biomass power, municipal solid waste, landfill gas, nuclear, coal-fired plants with carbon capture and sequestration (CCS), and natural gas plants with either CCS or utilizing combined cycle technology.[19] The target starts from an initial share of 44.8 percent in 2013, and rises linearly to 80 percent in 2035. Beyond 2035, the target remains at 80 percent. There is no option to purchase or sell credits to the government, and there is no banking of credits for use in future years.

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[18] *Analysis of Impacts of a Clean Energy Standard, as requested by Chairman Hall*, U.S. Department of Energy, Energy Information Administration, October 2011, at http://www.eia.gov/analysis/requests/ces_hall/.

[19] Generators earn 0.5 Mwh credit for 1 Mwh generation from natural gas combined cycle (NGCC), and 0.9 Mwh credit for 1 Mwh generated by coal or gas CCS.

The policy goal of the CES is to shift generation to a mix which generates less CO_2 and other emissions. In the scenario, there is indeed a significant shift in the generation mix. The electricity price is also significantly higher than in the Reference case.

Table 5.7 shows the impact of the CES on the delivered electricity price, in selected years.

Table 5.7 Electricity Price in CES Case

	Reference	GHG Price	Percent Difference
2012	9.31		
2015	9.70	9.82	1.2
2020	10.68	11.58	8.4

Figure 5.2 Electricity Generation Mix in Reference and CES Cases

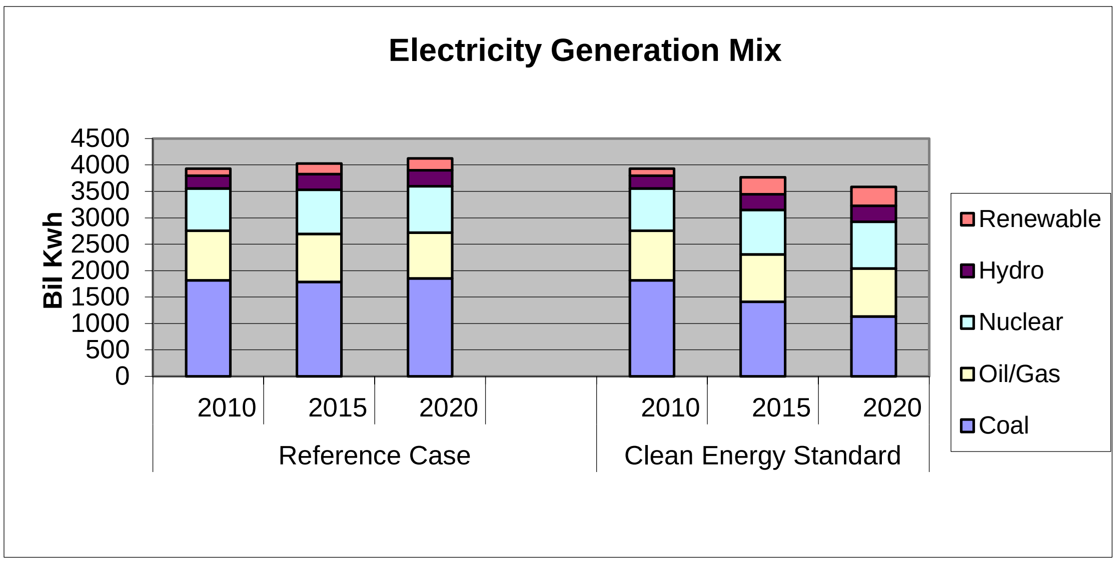


Table 5.8 Electricity Generation Mix in Reference and CES Cases

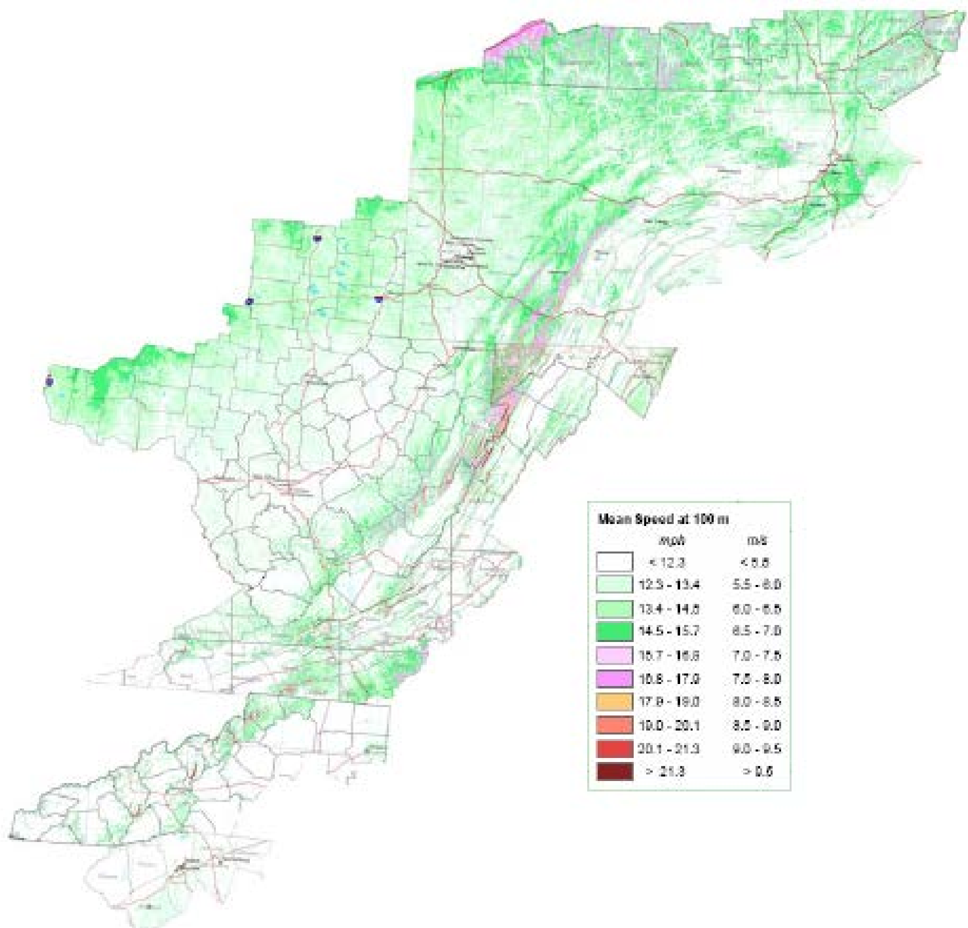
	Reference Case			*Clean Energy Standard*			
				Levels		Percent Difference from Reference	
	2010	2015	2020	2015	2020		
Coal	1818	1787	1850	1414	1135	-20.9	-38.7
Oil/Gas	934	905	868	893	903	-1.3	4.1
Nuclear	803	839	877	839	884	0.0	0.7
Hydro	240	293	301	299	306	1.8	1.6
Renewable	133	201	224	325	359	61.2	60.0
Total Generation	3929	4026	4121	3769	3587	-6.4	-13.0

Generation by coal is significantly lower in the CES Case by 2020, at a level of 1,135 billion Kwh, compared with 1,850 billion Kwh in the Reference case. Renewables are significantly higher, with generation of 359 billion Kwh compared with 224 billion Kwh in the Reference. Among the renewable sources, wind and biomass have the largest generation increases under the CES.

Wind

Since wind and biomass are two technologies that are expected to benefit from the CES, our question is: How much will these technologies expand in the Appalachian region? A study commissioned by ARC and completed in 2006 suggested that the Appalachian region had the potential of about 15,000 MW of wind capacity, with the three largest states being New York, Pennsylvania, and West Virginia.[20] The map below in Figure 5.3 shows bands of wind potential, categorized by wind speed[21].

Figure 5.3 Wind Potential in Appalachia



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[20] *Energy in Appalachia: Policy and Potential Energy Efficiency and Renewable*, July 2006, at http://www.arc.gov/assets/research_reports/arc_renewable_energy_full.pdf, pp. 3-4.
[21] This map was taken from the ARC study, and they obtained it from TrueWind Solutions, LLC.

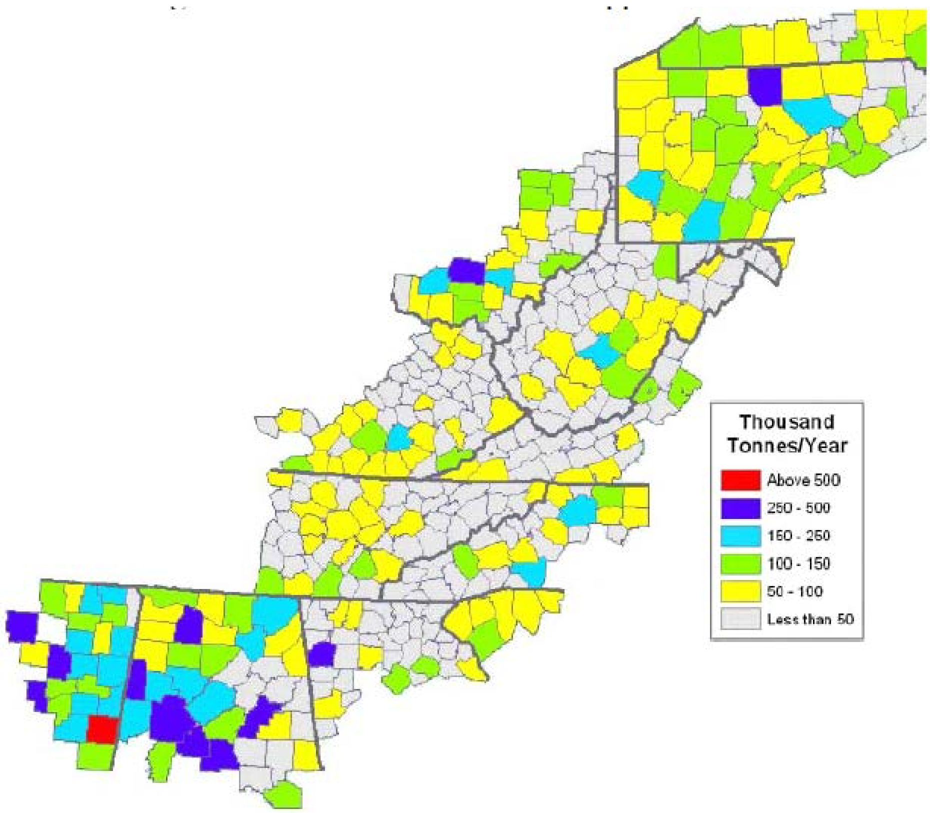
Since the earlier ARC study was published, the Eastern Wind Intregation and Transmission Study (EWITS) has published an executive summary and project overview as well as a full report[22]. This study, which is done under contract with the DOE National Renewable Energy Laboratory (NREL) is being led by Enernex, with support from Ventyx and the Midwest Independent System Operator (MISO). This study is one of the largest regional wind integration studies to date. It was initiated in 2008 to examine the operational impact of up to 20-30% wind on the power system in the Eastern Interconnect of the United States, of which the Appalachian Region is a part. An output of the study has been the valuable eastern wind dataset, which is based on three years (2004-2006) of data of 10-minute wind speed and plant output values for simulated wind plants at selected locations. This data was created by AWS-Truewind, and includes a database of selected sites for potential wind farms, with information including longitude and latitude, elevation, cost of energy, average wind speed, estimated capacity factor, size and density of the area, and total installed power potential. The derivation of the assumptions for wind capacity installation by Appalachian county are described in Appendix C.

Biomass

The other major component of the Clean Energy Standard Scenario for this project is biomass development in Appalachia. Figure 8.6 shows the map of biomass potential by county from the ARC study *Energy Efficiency and Renewable Energy in Appalachia.*

[22] These two documents, related information, maps, data and FAQs can be found at http://www.nrel.gov/wind/systemsintegration/ewits.html.

Figure 5.4 Biomass Potential in Appalachia



In this scenario, it is assumed that all coal-fired power plants retrofit in order to replace 15% of the coal that they burn with biomass by 2025. To be consistent with the EIA it was assumed upfront investments of $123 to $282 per kilowatt were needed in order to facilitate this ability. Increases in the percent of cofiring was assumed to increase linearly from the levels projected for 2012 until reaching 15% in 2025.

5.6 Expanded Natural Gas Development

This scenario explores the intensive development of natural gas resources in the region. As with the other scenarios, we first developed a national-level macroeconomic and industry context using the Inforum LIFT model, and then used geographic information to determine the impacts by county using the CUEPS model.

One of the side cases developed for the Annual Energy Outlook 2011 is called 'High Shale EUR Case'. In this scenario, the estimated ultimate recovery (EUR) per shale gas well is assumed to be 50 percent higher than in the Reference case, decreasing the per-unit cost of developing this resource. The total unproved technically available shale gas resource is currently estimated by USGS to be about 84 trillion cubic feet[23].

A LIFT model scenario was developed by calibrating LIFT to the AEO High Shale EUR case. The process was very similar to that described in section 8.1 on the Reference case. Increased supply of natural gas in the model is incorporated as higher production levels from the base case. As was shown in the AEO High Shale EUR case, there is increased supply of natural gas compared to the Reference case, which in turn leads to increased use of natural gas in electric power generation, higher gas exports and lower imports, and increased use in the residential, commercial, and industrial sectors. The gas price is also significantly reduced from the Reference case.

In developing the county level (CUEPS) assumptions for this scenario, regional changes in natural gas supply were differentiated based on regional differences in NEMS's 6 onshore and 3 offshore natural gas production regions. In all but the Northeast region, which includes all of the Appalachia counties, expanded natural gas production was shared down to the county level based on the overall size of the mining sector in each county relative to that of the region.

However, in the sixth region, the northeast, which includes all of the gas-producing Appalachian counties, the degree to which different Appalachian counties would benefit from increased production of shale gas, the modeling team used digital data published by the U.S. Geological Survey (USGS) on undeveloped shale gas resources in the Appalachian Basin. The USGS data focus on the Devonian Marcellus Shale, which stretches across parts of New York, Pennsylvania, Maryland, Virginia, West Virginia, Ohio, Kentucky, and Tennessee. The data are comprised of 21 separate shale formations within the Devonian Marcellus Shale and, among other information, include USGS estimates for the undiscovered gas resources that are likely to reside within each formation. Using GIS software, Keybridge analyzed the geographic extent of each formation relative to county boundaries in the region and generated estimates for the total amount of undiscovered shale gas in each county.

To facilitate analysis, certain key assumptions were necessary, and some factors that are likely to affect a county's suitability for shale gas exploration were not considered. For example, due to limitations with the USGS data, each formation's estimated gas resources were assumed to be distributed evenly throughout the formation. As such, counties were allocated gas resources based on their size and the proportion of the

[23] This estimated is significantly lower than the estimate of 410 trillion cubic feet published earlier this year by the federal Energy Information Administration. The high shale case calls for an addition 3 trillion cubic feet of production by 2020. While the revised estimates are significant, drilling costs and well performance will have a larger impact on natural gas production than the size of the reserves.

county located within each formation. In addition, factors that could affect a county's capacity to extract its gas resources—for example, proximity to major urban areas, the presence of environmentally sensitive areas (e.g., national forests and parks), and the existence of ongoing drilling activities within its borders—were not included in the analysis. Moreover, the analysis is limited to the Devonian Marcellus Shale and does not include any gas resources that may be present in the Utica Shale. Although most of the attention surrounding undiscovered natural gas resources in the Appalachian Basin has centered on the Devonian Marcellus Shale, the Utica Shale is an even larger formation which, based on early testing, may also contain vast natural gas deposits.

6. Comparisons of Scenario Results

This chapter presents a comparison of the results of the scenarios implemented using the LIFT and CUEPS models. Section 6.1 compares the macroeconomic results produced using LIFT. Section 6.2 shows state summaries, which are of state level aggregates of counties within the Appalachian region. Section 6.4 shows some selected county-level results, in map form. Finally, section 6.5 shows results for certain individual counties. Tables such as those in section 6.5 could be generated for any of the 420 counties comprising Appalachia.

6.1 Macroeconomic Results

The LIFT model makes projections of final demand, value added, employment, and prices for each industry. These are summed to form the macroeconomic, energy, and emission aggregates. In this section, we first present a macroeconomic summary for each scenario. The Reference case is presented in the most detail and in a standalone table. Each other scenario is compared with respect to the Reference case. Finally, in section 6.1.5, we show global results, comparing all of the scenarios.

6.1.1 Reference Case

Table 6.1.1 shows a summary of important macroeconomic and energy-related variables for the Reference case, forecast to 2020. The table shows values for 3 selected years in the first three columns, and shows the average annual exponential growth rate of the variable in the column on the far right.

Average real GDP growth in the Reference case from 2010 to 2020 is projected to be about 3%. Personal consumption growth is expected to be somewhat slower, growing at an average rate of 2.6%. The nominal oil price is expected to reach $130.6 per barrel by 2020, an average growth of 5.1% per year. The average national electricity price is projected to grow from a value of 9.7 cents/Kwh in 2010 to 10.7 cents/Kwh in 2020, an average annual growth rate of 1.0%. Total energy consumption in Btus is expected to grow from a value of 97.8 quadrillion Btus (quads) in 2010 to 105.1 quads in 2020, an average annual growth of 0.7%. Total carbon dioxide emissions are projected to grow from 5,651 million metric tons (Mmt) in 2010 to 5791 Mmt in 2020, an average growth of 0.2%.

The policy scenarios in the next few sections are compared vis-à-vis the Reference case.

Table 6.1.1 Macroeconomic Summary Table for Reference Case

	2010	2015	2020	Growth Rate 2010-2020
GDP AND MACROECONOMIC SUMMARY				
(Billions of chained 2005 dollars)				
Gross Domestic Product	13,100	15,474	17,723	3.0
Personal Consumption Expenditures	9,346	10,673	12,147	2.6
Gross Private Fixed Investment	1,607	2,641	3,007	6.3
Exports	1,521	2,275	3,248	7.6
Imports	1,955	2,586	3,182	4.9
Government	2,569	2,547	2,694	0.5
Gross Domestic Product, bil cu$	14,578	18,486	23,233	4.7
Crude Oil Imports (mbd)	8.7	8.7	8.3	-0.5
GDP Deflator	111.3	119.5	131.1	1.6
Real Disp Income, bil 05$	9,935	11,711	13,309	2.9
ENERGY PRICES				
Crude low sulphur ($/bbl)	78.7	103.2	130.6	5.1
Average electricity (c/Kwh)	9.7	9.7	10.7	1.0
ENERGY CONSUMPTION BY SECTOR				
(quadrillion Btus)				
Residential	22.1	20.6	20.9	-0.5
Commercial	18.3	19.2	20.3	1.0
Industrial	30.0	34.5	34.8	1.5
Transportation	27.5	28.7	29.1	0.6
Total	97.8	103.1	105.1	0.7
Total electricity generation	3,929.0	4,025.6	4,120.7	0.5
CARBON DIOXIDE EMISSIONS BY SECTOR				
(million metric tons)				
Residential	339	337	333	-0.2
Commercial	214	231	235	0.9
Industrial	931	1,078	1,072	1.4
Transportation	1,859	1,925	1,922	0.3
Electric power	2,308	2,191	2,229	-0.3
Total	5,651	5,762	5,791	0.2
Carbon Dioxide Emissions				
(tons per person)	18.1	17.6	16.9	-0.7

6.1.2 Electricity Efficiency

Table 6.1.2 shows a summary of the national level macroeconomic results in LIFT for the Energy Efficiency Case. The most notable differences from the Reference case are the differences in energy consumption by sector, total electricity generation, and carbon dioxide emissions in the electric power sector. Total energy consumption rises to 100.2 quad btus in 2015, but then falls back to 97.6, slightly below the starting point of 97.8 in 2010. The biggest difference is in the commercial sector, which reached 20.3 quads by 2020 in the Reference case, but only reaches 15.77 quads in the Energy Efficiency Case. Total electricity generation actually declines to 3,426 bil Kwh by 2020 in the Energy Efficiency case, compared to a rise to 4,121 billion Kwh in the Reference case. Total carbon emissions reach 5,211 by 2020, compared to 5,791 in the Reference case.

Table 6.1.2 Macroeconomic Comparison of Electricity Efficiency Case with Reference

	Reference Case			Electricity Efficiency Case				
				Percent Differences from Reference		Levels		
	2015	2020	10-20	2015	2020	2015	2020	10-20
GDP AND MACROECONOMIC SUMMARY								
(Billions of chained 2005 dollars)								
Gross Domestic Product	15,474	17,723	3.0	0.2	0.4	15,508	17,798	3.1
Personal Consumption Expenditures	10,673	12,147	2.6	0.3	0.4	10,700	12,201	2.8
Gross Private Fixed Investment	2,641	3,007	6.3	0.5	0.6	2,653	3,024	6.3
Exports	2,275	3,248	7.6	0.1	0.4	2,276	3,259	7.5
Imports	2,586	3,182	4.9	0.3	0.4	2,593	3,193	4.9
Gross Domestic Product, bil cu$	18,486	23,233	4.7	0.1	-0.2	18,501	23,198	4.9
GDP Deflator	119.5	131.1	1.6	-0.1	-0.6	119.3	130.3	1.8
Real Disp Income, bil 05$	11,711	13,309	2.9	0.3	0.5	11,742	13,371	3.1
Average electricity price (c/Kwh)	9.7	10.7	1.0	-1.3	-3.5	9.6	10.3	0.7
ENERGY CONSUMPTION BY SECTOR								
(quadrillion Btus)								
Residential	20.65	20.94	-0.5	-2.5	-4.6	20.14	19.97	-1.0
Commercial	19.24	20.29	1.0	-8.5	-22.3	17.60	15.77	-1.5
Industrial	34.48	34.82	1.5	-2.3	-6.0	33.69	32.72	0.9
Transportation	28.73	29.08	0.6	0.0	0.0	28.74	29.09	0.6
Total Energy Consumption	103.10	105.13	0.7	-2.8	-7.2	100.18	97.55	0.0
Total electricity generation (bil Kwh)	4,026	4,121	0.5	-6.7	-16.9	3,755	3,426	-1.3
Total carbon dioxide emissions (MMT)	5,762	5,791	0.2	-3.9	-10.0	5,537	5,211	-0.8
(tons per person)	17.6	16.9	-0.7	-3.9	-10.0	16.9	15.2	-1.7

6.1.3 Carbon Mitigation

Table 6.1.3 is the macroeconomic summary for the Carbon Mitigation case. By 2020 GDP is slightly lower than in the Reference case, a difference of about 0.9 percent. Exports decline by about 3.4 percent relative to the base by 2020 due to an increase in the relative domestic to foreign price. Total carbon tax revenue collected in 2020 is $248 billion. In the LIFT scenario, we have rebated two-thirds of this tax in the form of a lump sum personal tax rebate. One-third has been rebated to the corporate sector through a reduction in corporate income taxes. Total energy consumption in Btus reaches 99.95 quads by 2020, compared with 105.1 in the Reference case, a decline of 4.9 percent. Total carbon dioxide emissions reach a total of 5,048 by 2020, compared with 5,791 in the Reference case, a decline of about 13 percent. This decline is due partly to reduced energy consumption, but more importantly from a switch away from coal in electricity generation.

Table 6.1.3 Macroeconomic Comparison of Carbon Mitigation Case with Reference

	Reference Case			Carbon Mitigation Case				
				Percent Differences from Reference		Levels		
	2015	2020	10-20	2015	2020	2015	2020	10-20
GDP AND MACROECONOMIC SUMMARY								
(Billions of chained 2005 dollars)								
Gross Domestic Product	15,474	17,723	3.0	-0.4	-0.9	15,414	17,569	3.1
Personal Consumption Expenditures	10,673	12,147	2.6	-0.2	-0.2	10,656	12,119	2.8
Gross Private Fixed Investment	2,641	3,007	6.3	-0.7	-2.0	2,622	2,947	6.3
Exports	2,275	3,248	7.6	-1.9	-3.4	2,232	3,137	7.5
Imports	2,586	3,182	4.9	-0.8	-1.2	2,565	3,145	4.9
Gross Domestic Product, bil cu$	18,486	23,233	4.7	1.6	2.5	18,775	23,816	4.9
GDP Deflator	119.5	131.1	1.6	2.0	3.4	121.8	135.6	1.8
Real Disp Income, bil 05$	11,711	13,309	2.9	-0.2	-0.3	11,690	13,265	3.1
Average electricity price (c/Kwh)	9.7	10.7	1.0	20.8	26.0	11.7	13.5	0.7
ENERGY CONSUMPTION BY SECTOR								
(quadrillion Btus)								
Residential	20.65	20.94	-0.5	-6.8	-8.3	19.24	19.20	-1.0
Commercial	19.24	20.29	1.0	-3.2	-5.3	18.62	19.22	-1.5
Industrial	34.48	34.82	1.5	-4.9	-5.7	32.78	32.84	0.9
Transportation	28.73	29.08	0.6	-0.9	-1.4	28.47	28.68	0.6
Total Energy Consumption	103.10	105.13	0.7	-3.9	-4.9	99.10	99.95	0.0
Total electricity generation (bil Kwh)	4,026	4,121	0.5	-7.1	-10.2	3,742	3,699	-1.3
Total carbon dioxide emissions (MMT)	5,762	5,791	0.2	-9.6	-12.8	5,207	5,048	-0.8
(tons per person)	17.6	16.9	-0.7	-9.6	-12.8	15.9	14.7	-1.7

6.1.4 Clean Energy Standard

The main impacts of the Clean Energy Standard (CES) are on the choice of electric power generation by type, which result in only a slight increase (1.3%) in the electricity price by 2015, and a larger increase (8.5%) by 2020. GDP and its components are hardly affected, with only a 0.1% decline in GDP relative to the Reference case by 2020. Energy consumption is down more than would be warranted by the electricity price alone. This case was calibrated to the CES case published by DOE, which also showed an increase in natural gas prices due to demand pressure from electric power producers switching out of coal into natural gas. Total energy consumption reaches 100 quads by 2020, compared with 105.1 in the Reference case, a difference of -4.9%. Total carbon emissions are 12.4% lower than the Reference by 2020, due both to reduction in consumption as well as the greener mix of electric power production.

Table 6.1.4 Macroeconomic Comparison of Clean Energy Standard with Reference

	Reference Case			Clean Energy Standard				
				Percent Differences from Reference		Levels		
	2015	2020	10-20	2015	2020	2015	2020	10-20
GDP AND MACROECONOMIC SUMMARY								
(Billions of chained 2005 dollars)								
Gross Domestic Product	15,474	17,723	3.0	0.0	-0.1	15,472	17,697	3.0
Personal Consumption Expenditures	10,673	12,147	2.6	0.0	-0.1	10,672	12,130	2.6
Gross Private Fixed Investment	2,641	3,007	6.3	0.0	-0.2	2,640	3,001	6.2
Exports	2,275	3,248	7.6	0.0	-0.1	2,275	3,243	7.6
Imports	2,586	3,182	4.9	0.0	-0.1	2,585	3,177	4.9
Gross Domestic Product, bil cu$	18,486	23,233	4.7	0.0	0.1	18,481	23,253	4.7
GDP Deflator	119.5	131.1	1.6	0.0	0.2	119.4	131.4	1.7
Real Disp Income, bil 05$	11,711	13,309	2.9	0.0	-0.2	11,710	13,289	2.9
Average electricity price (c/Kwh)	9.7	10.7	1.0	1.3	8.5	9.8	11.6	1.8
ENERGY CONSUMPTION BY SECTOR								
(quadrillion Btus)								
Residential	20.65	20.94	-0.5	-8.9	-17.3	18.81	17.32	-3.2
Commercial	19.24	20.29	1.0	-1.2	-1.9	19.01	19.90	0.8
Industrial	34.48	34.82	1.5	-2.1	-3.1	33.76	33.73	1.2
Transportation	28.73	29.08	0.6	0.0	-0.1	28.72	29.05	0.6
Total Energy Consumption	103.10	105.13	0.7	-2.7	-4.9	100.30	100.00	0.0
Total electricity generation (bil Kwh)	4,026	4,121	0.5	-6.4	-13.0	3,769	3,587	-1.4
Total carbon dioxide emissions (MMT)	5,762	5,791	0.2	-7.1	-12.4	5,354	5,072	-1.4
(tons per person)	17.6	16.9	-0.7	-7.1	-12.4	16.4	14.8	-2.4

6.1.5 Expanded Natural Gas Development

This scenario is characterized by an aggressive development of natural gas from shale. As a result, gas prices are 15.5% lower than the Reference in 2015, and 16.1% lower in 2020, reaching a level of 5.2 $/tcf instead of 4.2 $/tcf in the Reference case. The electricity generation mix shifts in favor of the cheaper natural gas and the overall electric power price declines 3.4% by 2020. Residential consumption actually decreases relative to the base in 2020, but all other sectors expand slightly, due to the lower prices. The net effect on carbon emissions is a difference of -4.9% relative to the Reference case by 2020.

Table 6.1.5 Macroeconomic Comparison of Expanded Natural Gas with Reference

	Reference Case			Expanded Natural Gas Development				
				Percent Differences from Reference		Levels		
	2015	2020	10-20	2015	2020	2015	2020	10-20
GDP AND MACROECONOMIC SUMMARY								
(Billions of chained 2005 dollars)								
Gross Domestic Product	15,474	17,723	3.0	0.1	0.1	15,488	17,744	3.0
Personal Consumption Expenditures	10,673	12,147	2.6	0.1	0.0	10,679	12,153	2.6
Gross Private Fixed Investment	2,641	3,007	6.3	0.0	0.2	2,641	3,014	6.3
Exports	2,275	3,248	7.6	0.3	0.5	2,283	3,263	7.6
Imports	2,586	3,182	4.9	0.1	0.2	2,588	3,187	4.9
Gross Domestic Product, bil cu$	18,486	23,233	4.7	-0.3	-0.3	18,427	23,160	4.6
GDP Deflator	119.5	131.1	1.6	-0.4	-0.4	119.0	130.5	1.6
Real Disp Income, bil 05$	11,711	13,309	2.9	0.1	0.1	11,721	13,325	2.9
Natural gas ($/tcf)	4.9	6.2	4.5	-15.5	-16.1	4.2	5.2	3.9
Average electricity price (c/Kwh)	9.7	10.7	1.0	-3.9	-3.4	9.3	10.3	0.7
ENERGY CONSUMPTION BY SECTOR								
(quadrillion Btus)								
Residential	20.65	20.94	-0.5	-5.1	-10.9	19.60	18.67	-2.4
Commercial	19.24	20.29	1.0	-0.1	1.0	19.23	20.49	1.1
Industrial	34.48	34.82	1.5	-0.3	1.3	34.39	35.27	1.6
Transportation	28.73	29.08	0.6	0.0	0.1	28.74	29.09	0.6
Total Energy Consumption	103.10	105.13	0.7	-1.1	-1.5	101.96	103.52	0.4
Total electricity generation (bil Kwh)	4,026	4,121	0.5	-5.0	-8.2	3,825	3,785	-0.8
Total carbon dioxide emissions (MMT)	5,762	5,791	0.2	-3.4	-4.9	5,565	5,506	-0.5
(tons per person)	17.6	16.9	-0.7	-3.4	-4.9	17.0	16.1	-1.5

6.1.6 Comparisons of All Scenarios

Figures 6.1.1 through 6.1.4 compare 4 selected macroeconomic variables across the 5 cases: Real GDP, total employment, energy intensity (btus/GDP), and CO_2 emissions. The biggest negative impact to real GDP and employment is in the Carbon Mitigation case. The efficiency and gas development cases have higher GDP than the Reference and the CES is very close to the Reference.

Figure 6.1.1 Comparison of Real GDP

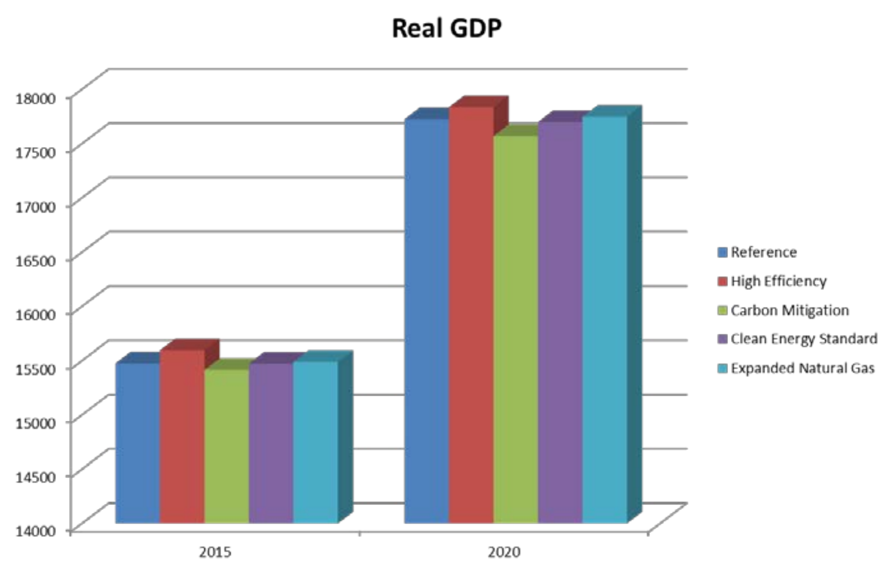
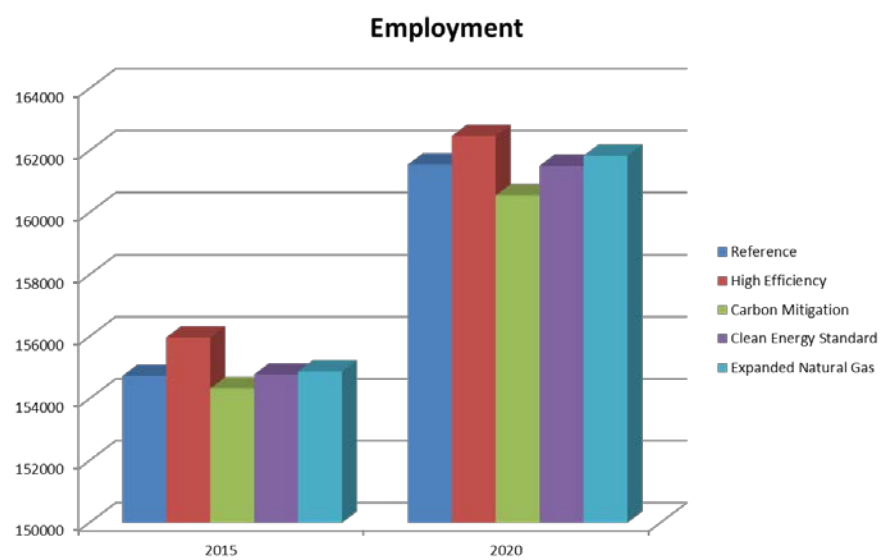


Figure 6.1.2 Comparison of Employment



In terms of total economy-wide energy intensity, all scenarios are somewhat more efficient than the Reference case. The biggest increase in efficiency is in the electricity efficiency case. Carbon emissions are reduced the most in the Carbon Mitigation case, followed by the Clean Energy Standard. However, by 2020, the efficiency case also has significant carbon reductions.

Figure 6.1.3 Comparison of Energy Intensity

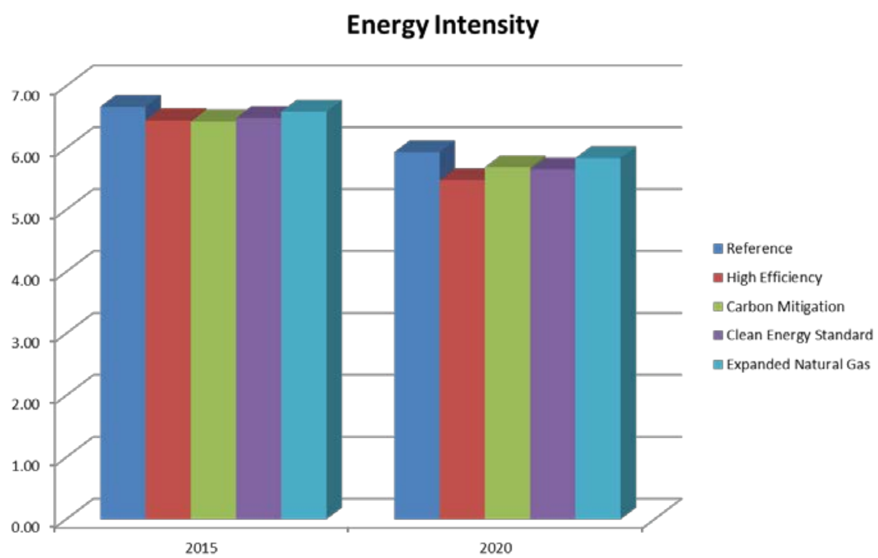
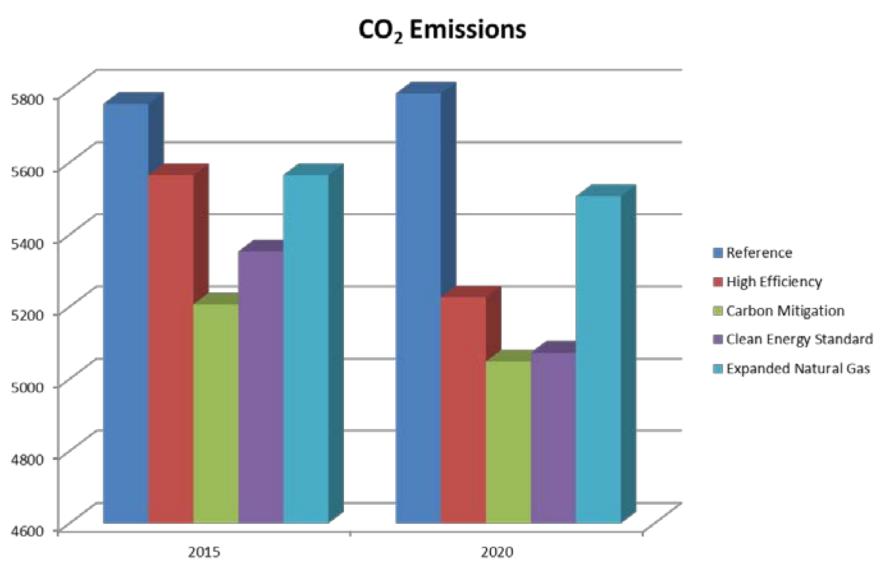


Figure 6.1.4 Comparison of CO_2 Emissions



6.2 Appalachia and State-Level Summaries

The CUEPS model makes projections for 3140 counties and 3356 utilities. To make sense of this mass of detail it is necessary to aggregate. In the following sections, we present results at the Appalachia 420 county level, and for state-level aggregates of Appalachian counties. In the following section, results are presented in maps of all Appalachian counties for selected variables in the model.

6.2.1 Reference Case

The projections in table 6.2.1 are aggregated from the county level. There are 420 counties comprising the Appalachian region, scattered across 13 states. Real personal income in the aggregate Appalachian region is about $723.8 billion (2005$) in 2010, growing to $1,031.7 billion by 2020. Per capita real income is about $28.8 thousand in 2010, growing to about $38.1 thousand by 2020. Employment in the region is 12.9 million jobs in 2010, growing to about 16 million by 2020.

Table 6.2.1 Appalachia Summary for the Reference Case

			Levels		Growth rate
	Units	2010	2015	2020	10-20
County Economic Variables					
Real personal income	Millions of 2005$	723,817	858,671	1,031,721	3.5
Per capita	Thousands of 2005$	28.76	32.89	38.09	2.8
Employment	Thousand jobs	12,885	14,530	16,044	2.2
Electric Utility Variables					
Electricity sales	Thousand Mwh	389,502	453,021	508,445	2.7
Sales per customer	Mwh				
Residential		12.64	13.02	12.92	0.2
Commercial		63.36	62.86	60.93	-0.4
Industrial		2,180.52	1,945.93	1,752.04	-2.2
Electricity revenues	Millions of dollars	30,411	35,611	44,125	3.7
Revenues per customer	Thousands of dollars				
Residential		1.21	1.25	1.37	1.2
Commercial		5.14	5.15	5.53	0.7
Industrial		119.41	107.21	106.38	-1.2
Electricity rate	Dollars/Kwh				
Residential		0.096	0.096	0.106	1.0
Commercial		0.081	0.082	0.091	1.1
Industrial		0.055	0.055	0.061	1.0

The data for electricity sales, revenues, customers, and rates is originally projected by utility, and then converted to the county level using the county-utility bridge which relates county economic activity to each utility’s market. Total electricity sales in Appalachia is 389.5 million Mwh in 2010, and grows to 508.4 million Mwh by 2020, an average annual growth of about 2.7 percent. Sales per customer is obtained by dividing total sales by market (residential, commercial, and industrial) by the number of customers projected in each market. The Reference case projection includes a slight increase in residential sales per customer (0.22 percent growth), but for slightly declining commercial sales per customer (-0.39 percent), and fairly strong declines in industrial sales per customer (-2.2 percent). The different absolute sizes of the sales per customer number are typical of the database, although a few large industrial customers bring up the industrial average considerably.

Total electricity revenues in the Appalachian region in the Reference case are $30.4 billion in 2010 and are projected to grow to $44.1 billion by 2020, an average growth rate of 3.7 percent. This overall revenue growth is a combination of the growth in electricity sales (Mwh), electricity rate, and the growth in the number of customers, which are projected for each market. The electricity rate is highest in the residential sector, at 9.6 cents/Kwh in 2010. The commercial rate is slightly lower, at 8.1 cents/Kwh, and the industrial rate is the lowest, at 5.5 cents/Kwh. All of the electricity prices are projected to grow at between 1 percent and 1.1 percent over the period.

6.2.2 Electricity Efficiency

Table 6.2.2 presents results at the all Appalachia level for the Electricity Efficiency case. The most important driver of this simulation is the reduction in electricity use. The reduction in demand pressure also causes the electricity price to grow somewhat more slowly. Electricity sales by 2020 are 15.6 percent below the Reference case, as shown in the fifth column. Electricity revenues are 17.6 percent below the Reference case. Both personal income and employment are somewhat higher than the Reference case, due both to improvements in efficiency and the slight reduction in the electricity price.

Table 6.2.2 Appalachia Comparison for the Electricity Efficiency Case

	Reference Case			Electricity Efficiency Case				
	Levels		Growth rate	Percent Differences from Reference		Levels		Growth rate
	2015	2020	10-20	2015	2020	2015	2020	10-20
County Economic Variables								
Real personal income	858,671	1,031,721	3.5	0.1	0.3	859,283	1,035,120	3.6
Per capita	32.89	38.09	2.8	0.1	0.3	32.92	38.21	2.8
Employment	14,530	16,044	2.2	0.2	0.4	14,559	16,113	2.2
Electric Utility Variables								
Electricity sales	453,021	508,445	2.7	-5.7	-15.6	427,337	428,961	1.0
Electricity revenues	35,611	44,125	3.7	-6.5	-17.6	33,312	36,376	1.8
Electricity rate								
Residential	0.096	0.106	1.0	-1.3	-3.5	0.095	0.102	0.7
Commercial	0.082	0.091	1.1	-1.3	-3.5	0.081	0.088	0.8
Industrial	0.055	0.061	1.0	-1.3	-3.5	0.054	0.059	0.7

6.2.3 Carbon Mitigation

Table 6.2.3 presents results at the all Appalachia level for the Carbon Mitigation case. The economic results for Appalachia are mixed. By 2020, employment is down by 0.3 percent relative to the Reference case. Revenue from the carbon tax is recycled to consumers, so there is some benefit to real personal income, an increase of 1.2 percent relative to the Reference case in 2020.

The carbon charge has a large impact on electricity prices, with an increase of 26 percent over the Reference case by 2020. There is a reduction of electricity sales of 7.9 percent by 2020, relative to the Reference case. Revenues (which include the tax) actually increase, since the decline in sales is not as large as the increase in price.

Table 6.2.3 Appalachia Comparison for the Carbon Mitigation Case

	Reference Case			Carbon Mitigation Case				
	Levels		Growth rate	Percent Differences from Reference		Levels		Growth rate
	2015	2020	10-20	2015	2020	2015	2020	10-20
County Economic Variables								
Real personal income	858,671	1,031,721	3.5	0.6	1.2	863,895	1,044,059	3.7
Per capita	32.89	38.09	2.8	0.6	1.2	33.09	38.54	2.9
Employment	14,530	16,044	2.2	-0.1	-0.3	14,515	15,991	2.2
Electric Utility Variables								
Electricity sales	453,021	508,445	2.7	-6.3	-7.9	424,525	468,453	1.8
Electricity revenues	35,611	44,125	3.7	13.3	16.3	40,360	51,308	5.2
Electricity rate								
Residential	0.096	0.106	1.0	20.8	26.0	0.116	0.134	3.3
Commercial	0.082	0.091	1.1	20.8	26.0	0.099	0.114	3.4
Industrial	0.055	0.061	1.0	20.8	26.0	0.067	0.076	3.3

6.2.4 Clean Energy Standard

In the Clean Energy Standard scenario, electricity prices also increase, though not by as much as in the Carbon Mitigation case. Electricity prices increase by 8.5 percent relative to the Reference by 2020. Sales decline by 4 percent, with the result that revenues increase by 4.4 percent. Macroeconomic and income effects are negligible, with an increase of 0.1 percent in real personal income by 2020.

Table 6.2.4 Appalachia Comparison for the Clean Energy Standard Case

	Reference Case			Clean Energy Standard				
	Levels		Growth rate	Percent Differences from Reference		Levels		Growth rate
	2015	2020	10-20	2015	2020	2015	2020	10-20
County Economic Variables								
Real personal income	858,671	1,031,721	3.5	0.0	0.1	858,609	1,032,632	3.6
Per capita	32.89	38.09	2.8	0.0	0.1	32.89	38.12	2.8
Employment	14,530	16,044	2.2	0.1	0.0	14,540	16,050	2.2
Electric Utility Variables								
Electricity sales	453,021	508,445	2.7	-1.2	-4.0	447,667	488,051	2.2
Electricity revenues	35,611	44,125	3.7	0.3	4.4	35,702	46,086	4.1
Electricity rate								
Residential	0.096	0.106	1.0	1.3	8.5	0.098	0.115	1.8
Commercial	0.082	0.091	1.1	1.3	8.5	0.083	0.098	1.9
Industrial	0.055	0.061	1.0	1.3	8.5	0.056	0.066	1.8

6.2.5 Expanded Natural Gas Development

In this scenario, use of natural gas increases and coal decreases. The net effect on Appalachian counties depends partly on the relative size of the impact on the natural gas industry versus the coal and electric power sectors. Personal income is 0.3 percent lower than the Reference case and employment is up slightly, by 0.1 percent. Electricity prices are lower than the Reference by 3.4 percent in 2020. Electricity sales are up by 0.6 percent in 2015, but about the same as the Reference case by 2020.

Table 6.2.5 Appalachia Comparison for the Expanded Natural Gas Development Case

	Reference Case			Expanded Natural Gas Development				
	Levels		Growth rate	Percent Differences from Reference		Levels		Growth rate
	2015	2020	10-20	2015	2020	2015	2020	10-20
County Economic Variables								
Real personal income	858,671	1,031,721	3.5	-0.3	-0.3	856,119	1,029,095	3.5
Per capita	32.89	38.09	2.8	-0.3	-0.3	32.79	37.99	2.8
Employment	14,530	16,044	2.2	0.1	0.1	14,539	16,067	2.2
Electric Utility Variables								
Electricity sales	453,021	508,445	2.7	0.6	0.0	455,567	508,665	2.6
Electricity revenues	35,611	44,125	3.7	-3.2	-3.1	34,464	42,749	3.4
Electricity rate								
Residential	0.096	0.106	1.0	-3.9	-3.4	0.093	0.102	0.7
Commercial	0.082	0.091	1.1	-3.9	-3.4	0.079	0.088	0.8
Industrial	0.055	0.061	1.0	-3.9	-3.4	0.053	0.059	0.8

6.2.6 Comparisons of All Scenarios by State

Table 6.2.5 shows a comparison of total employment in each Appalachian state across the Reference case and the four policy scenarios. The units are thousands of jobs. The first two columns show the values in the Reference case for 2010 and 2020. The next 4 groups of 2 columns each show the levels of employment in each policy scenario in 2020, and the percentage difference from the Reference case in 2020.

The Efficiency case has the largest positive impacts on employment by 2020, with an average increase relative to the Reference case of 0.43 percent within all Appalachia. Results by state vary from an increase of 0.30 percent in Kentucky, to 0.47 percent in Maryland, North Carolina, and South Carolina. The Expanded Natural Gas case also shows positive employment impacts, with an average increase of 0.15 percent for all Appalachia, and increases ranging from 0.13 percent in several states, to 0.18 percent in Ohio. Results for the Clean Energy Standard are mixed, and with a wide variation across states. The average impact across all Appalachia is nearly zero (0.04 percent), with results ranging from -0.03 percent in Kentucky to 0.24 percent in New York. Finally, the Carbon Mitigation case shows consistently negative employment impacts relative to the Reference case by 2020 with an average of -0.33 percent across all Appalachia, and a range of -0.31 percent to -0.40 percent across the state aggregates.

Table 6.2.5 Employment

	Reference		Efficiency		Carbon Mitigation		Clean Energy Standard		Expanded Natural Gas	
			Level	% Diff.	Level	% Diff.	Level	% Diff.	Level	% Diff.
	2010	2020	2020	2020	2020	2020	2020	2020	2020	2020
Appalachia	12,885	16,044	16,113	0.43	15,991	-0.33	16,050	0.04	16,067	0.15
Alabama	1,591	1,970	1,979	0.45	1,963	-0.34	1,970	0.00	1,973	0.13
Georgia	1,356	2,568	2,579	0.46	2,559	-0.32	2,568	0.02	2,571	0.14
Kentucky	513	604	606	0.30	601	-0.40	604	-0.03	605	0.16
Maryland	135	167	168	0.47	166	-0.33	167	0.17	167	0.14
Mississippi	305	340	342	0.40	339	-0.40	340	0.08	341	0.13
New York	556	586	589	0.44	585	-0.30	588	0.24	587	0.16
North Carolina	889	1,105	1,110	0.47	1,102	-0.26	1,106	0.04	1,107	0.13
Ohio	914	1,069	1,073	0.41	1,065	-0.38	1,069	-0.01	1,071	0.18
Pennsylvania	3,184	3,513	3,529	0.45	3,502	-0.31	3,515	0.06	3,518	0.15
South Carolina	648	772	776	0.47	769	-0.34	772	0.01	773	0.14
Tennessee	1,515	1,912	1,921	0.45	1,906	-0.33	1,913	0.03	1,915	0.14
Virginia	387	424	426	0.36	422	-0.38	424	0.07	425	0.13
West Virginia	893	1,014	1,017	0.32	1,010	-0.33	1,014	0.02	1,015	0.16

Units: Thousands of jobs

Table 6.2.6 has the same format as the employment table, but shows aggregates of real personal income. It provides a somewhat different picture of the changes across the scenarios by state. For example, from the perspective of real income, the improvement in the Efficiency case is larger than employment, with an average improvement in all Appalachia of 0.91 percent by 2020. This increase in real income is due to two factors: the additional efficiency stimulates additional economic activity; and the overall price level is also reduced. Since real income is calculated as nominal income divided by the price level, the reduction in the price level implies this makes real income higher than it would be otherwise. Similarly, in the Carbon Mitigation case, the negative impacts on real income are larger than on employment because of the higher GDP price in the Carbon Mitigation case. The average reduction of real income across all Appalachia is -2.14 percent by 2020, compared to an employment difference of -0.33 percent. Whereas the employment effects of the Clean Energy Standard are mixed, the real income effects are all slightly negative, since the overall price level is slightly higher than the Reference case. Personal income impacts in the Expanded Natural Gas case are mixed, due to the countervailing effects of increased natural gas production combined with decreases in coal production. The negative impacts on income are largest in West Virginia, with a 0.31 percent difference from the Reference case.

Table 6.2.6 Real Personal Income

	Reference		Efficiency		Carbon Mitigation		Clean Energy Standard		Expanded Natural Gas	
			Level	Perc. Diff.	Level	Perc. Diff.	Level	Perc. Diff.	Level	Perc. Diff.
	2010	2020	2020	2020	2020	2020	2020	2020	2020	2020
Appalachia	722,664	1,030,727	1,040,110	0.91	1,008,712	-2.14	1,029,259	-0.14	1,032,584	0.18
Alabama	92,476	133,874	135,168	0.97	131,020	-2.13	133,646	-0.17	134,118	0.18
Georgia	82,522	173,145	174,761	0.93	169,232	-2.26	172,926	-0.13	173,702	0.32
Kentucky	27,047	36,077	36,328	0.69	35,298	-2.16	35,972	-0.29	36,035	-0.12
Maryland	7,271	10,506	10,607	0.96	10,281	-2.14	10,505	-0.01	10,533	0.25
Mississippi	15,187	19,328	19,492	0.85	18,887	-2.28	19,308	-0.10	19,376	0.25
New York	30,377	37,171	37,536	0.98	36,373	-2.15	37,171	0.00	37,259	0.24
North Carolina	47,894	68,057	68,718	0.97	66,613	-2.12	67,980	-0.11	68,257	0.29
Ohio	52,807	69,714	70,302	0.84	68,096	-2.32	69,585	-0.19	69,862	0.21
Pennsylvania	187,174	237,444	239,618	0.92	232,591	-2.04	237,170	-0.12	237,804	0.15
South Carolina	32,928	45,230	45,674	0.98	44,271	-2.12	45,175	-0.12	45,365	0.30
Tennessee	77,853	111,578	112,612	0.93	109,209	-2.12	111,442	-0.12	111,876	0.27
Virginia	20,015	25,720	25,928	0.81	25,166	-2.16	25,672	-0.19	25,709	-0.05
West Virginia	49,114	62,884	63,366	0.77	61,676	-1.92	62,709	-0.28	62,688	-0.31

Units: Millions of 2005$

The final table shown at the aggregate Appalachian state level is 6.2.7, which compares electricity sales the Reference case with the four policy scenarios. This table demonstrates clearly the differences in electricity demand due to each set of policy assumptions. The largest decrease is in the Efficiency case, with an average of 15.63 percent decline relative to the Reference across all Appalachia by 2020. The demand effect in the Carbon Mitigation case is price induced, with an average 7.87 percent decline relative to the Reference. The demand effect in the Clean Energy Standard case is also price induced, with an average 4 percent decline relative to the Reference. There is a slight electricity price reduction in the Expanded Natural Gas case, with a resulting slight increase in demand, about 0.04 percent for total Appalachia.

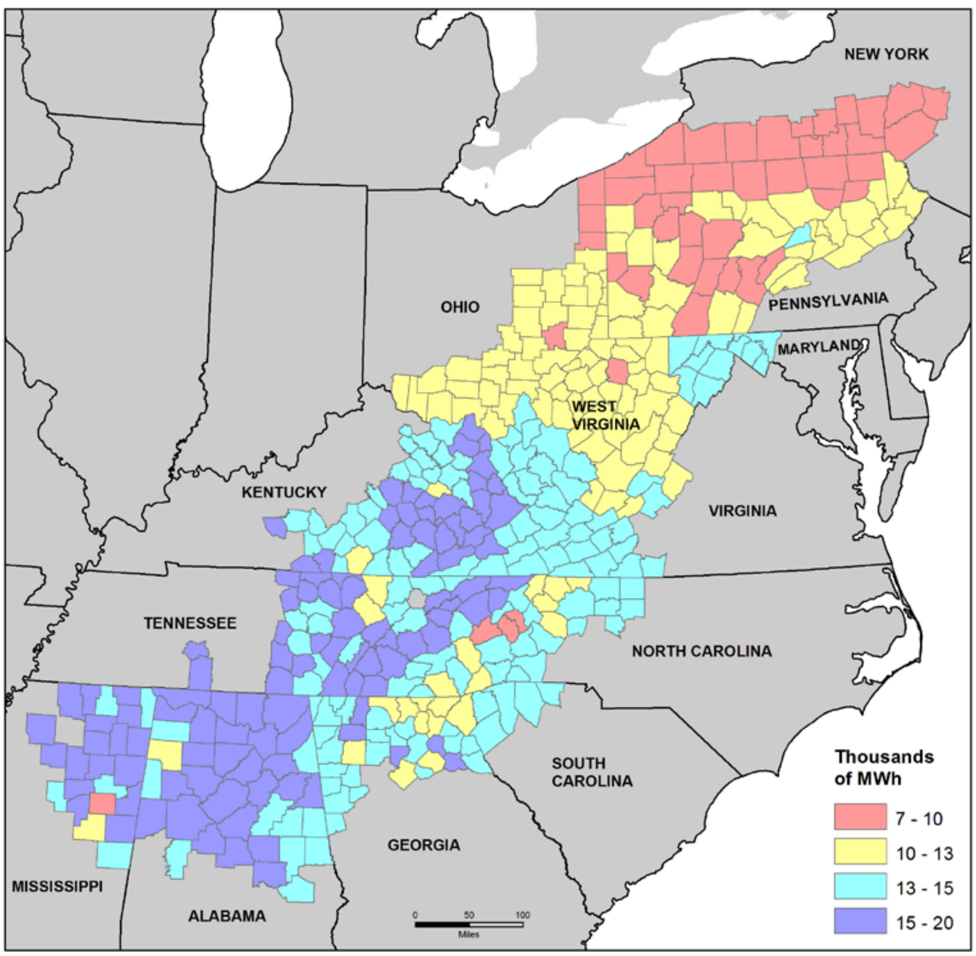
Table 6.2.7 Electricity Sales

	Reference		Efficiency		Carbon Mitigation		Clean Energy Standard		Expanded Natural Gas	
			Level	Perc. Diff.	Level	Perc. Diff.	Level	Perc. Diff.	Level	Perc. Diff.
	2010	2020	2020	2020	2020	2020	2020	2020	2020	2020
Appalachia	389,502	508,445	428,961	-15.63	468,453	-7.87	488,051	-4.01	508,665	0.04
Alabama	52,803	67,530	57,210	-15.28	62,198	-7.90	64,815	-4.02	67,513	-0.02
Georgia	41,382	66,252	55,789	-15.79	61,228	-7.58	63,828	-3.66	66,379	0.19
Kentucky	19,048	22,899	19,607	-14.37	21,036	-8.14	21,926	-4.25	22,917	0.08
Maryland	3,907	5,594	4,790	-14.37	5,163	-7.70	5,390	-3.64	5,607	0.25
Mississippi	8,719	10,665	9,113	-14.55	9,844	-7.69	10,265	-3.75	10,679	0.14
New York	9,431	11,396	9,659	-15.24	10,528	-7.61	10,981	-3.64	11,434	0.33
North Carolina	23,847	32,945	27,888	-15.35	30,432	-7.63	31,737	-3.67	33,016	0.21
Ohio	31,547	41,381	34,719	-16.10	38,126	-7.87	39,709	-4.04	41,418	0.09
Pennsylvania	71,858	88,071	74,089	-15.87	81,213	-7.79	84,634	-3.90	88,238	0.19
South Carolina	19,474	26,794	22,630	-15.54	24,750	-7.63	25,810	-3.67	26,851	0.21
Tennessee	63,561	81,384	68,213	-16.18	74,707	-8.20	77,682	-4.55	81,042	-0.42
Virginia	13,834	16,961	14,320	-15.57	15,602	-8.01	16,247	-4.21	16,957	-0.02
West Virginia	30,091	36,575	30,933	-15.43	33,624	-8.07	35,028	-4.23	36,613	0.10

6.3 Selected County-Level Results

Figure 6.3.1 shows electricity sales per customer, in thousands of Mwh. Regional influences appear very strongly here. Higher demand characterizes southern regions, which require more air conditioning. Intensity of usage is also related to average price and average income, but the location effect is most important.

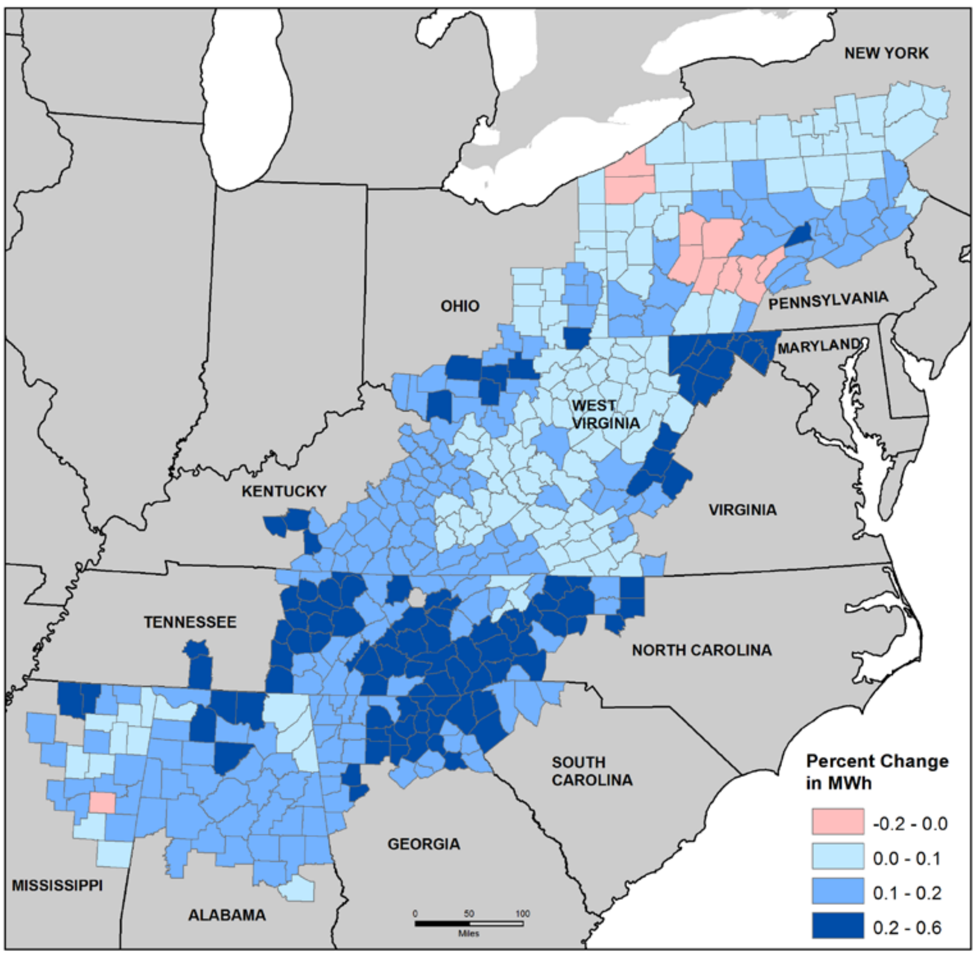
Figure 6.3.1 Electricity Sales per Customer, Residential, 2020, Reference Case



Map Title: Electricity Sales Per Customer, Residential, 2020: Reference Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Figure 6.3.2 displays the growth of electricity sales per customer in the Reference case. Residential efficiency is projected to improve over time, so these growth rates are fairly low. The pattern of growth is related in adjoining regions, showing that price and demand indicator patterns in adjoining regions are similar. The area of fastest sales growth is concentrated in the south.

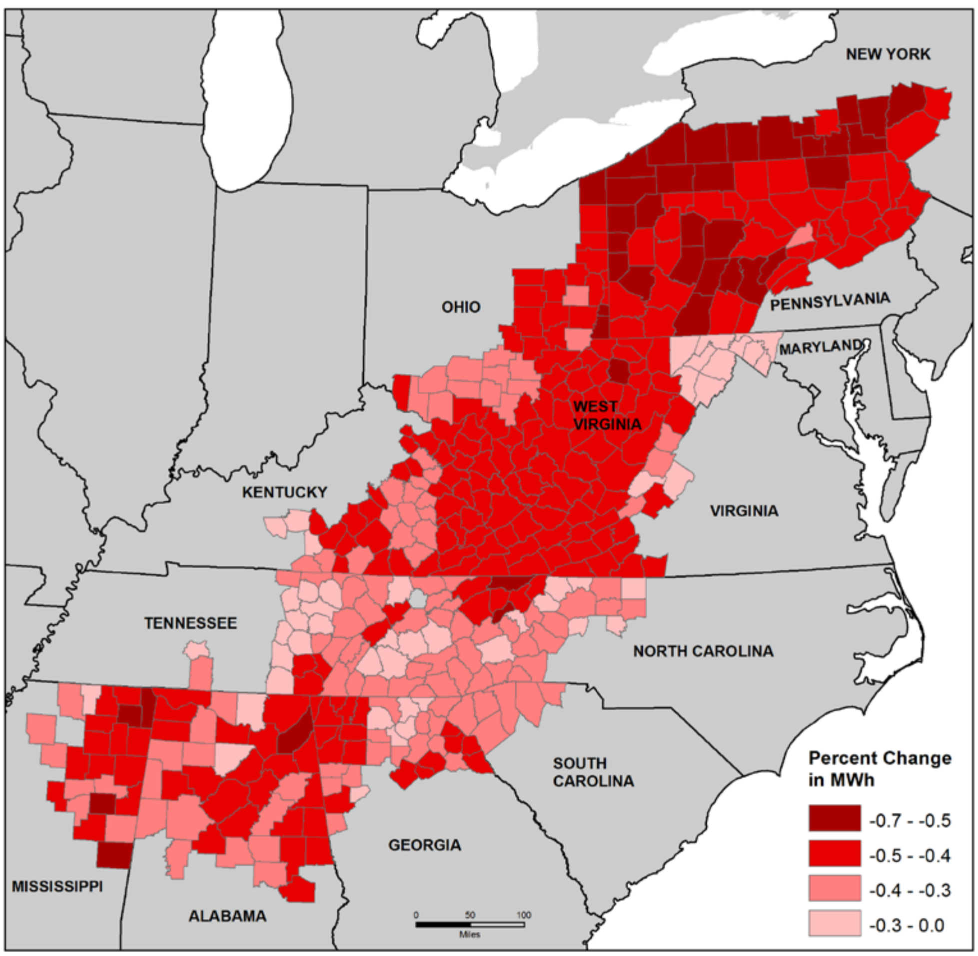
Figure 6.3.2 Electricity Sales per Customer, Residential, 2010-2020 Growth Rate, Reference Case



Map Title: Electricity Sales Per Customer, Residential, 2010-2020 Growth Rate: Reference Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Figure 6.6.3 shows the growth rates by county of residential sales per customer for the Efficiency case. The Efficiency case assumes reductions in electricity use of up to 16% by 2020, relative to the Reference case. This results in absolute declines in per residential customer use, of up to -0.7 percent annual growth. The greatest declines are in the northern region of Appalachia, in New York, Pennsylvania, and West Virginia. Declines in the high consumption regions of the south are not as big.

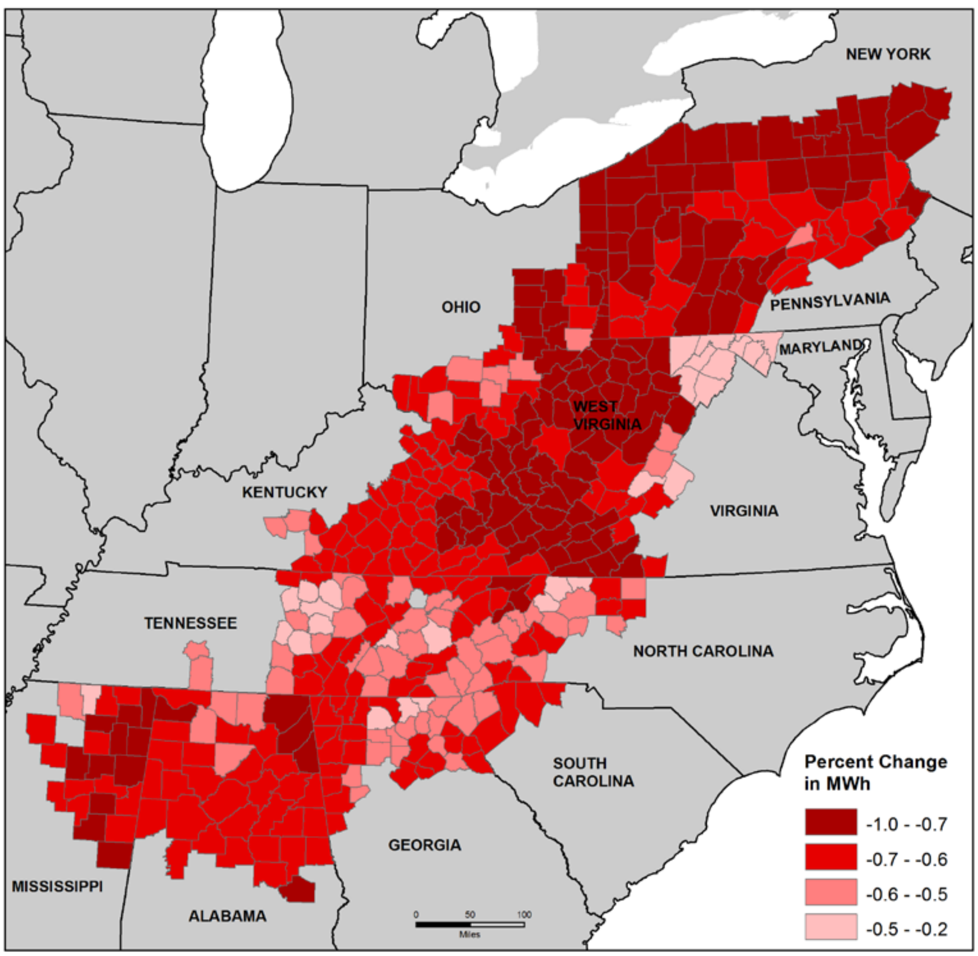
Figure 6.3.3 Electricity Sales per Customer, Residential, 2010-2020 Growth Rate, Electricity Efficiency Case



Map Title: Electricity Sales Per Customer, Residential, 2010-2020 Growth Rate: High Efficiency Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Figure 6.3.4 shows the growth rates by county of residential sales per customer for the Carbon Mitigation Case. In this case, residential electricity consumption per customer declines in response to the electricity price increase. In some counties is larger than in the high efficiency case. Since the proportion of the price increase is very similar across counties, and the assumed price response is also the same, the patterns of change are similar, but with the largest declines still concentrated in the northern and central areas of Appalachia.

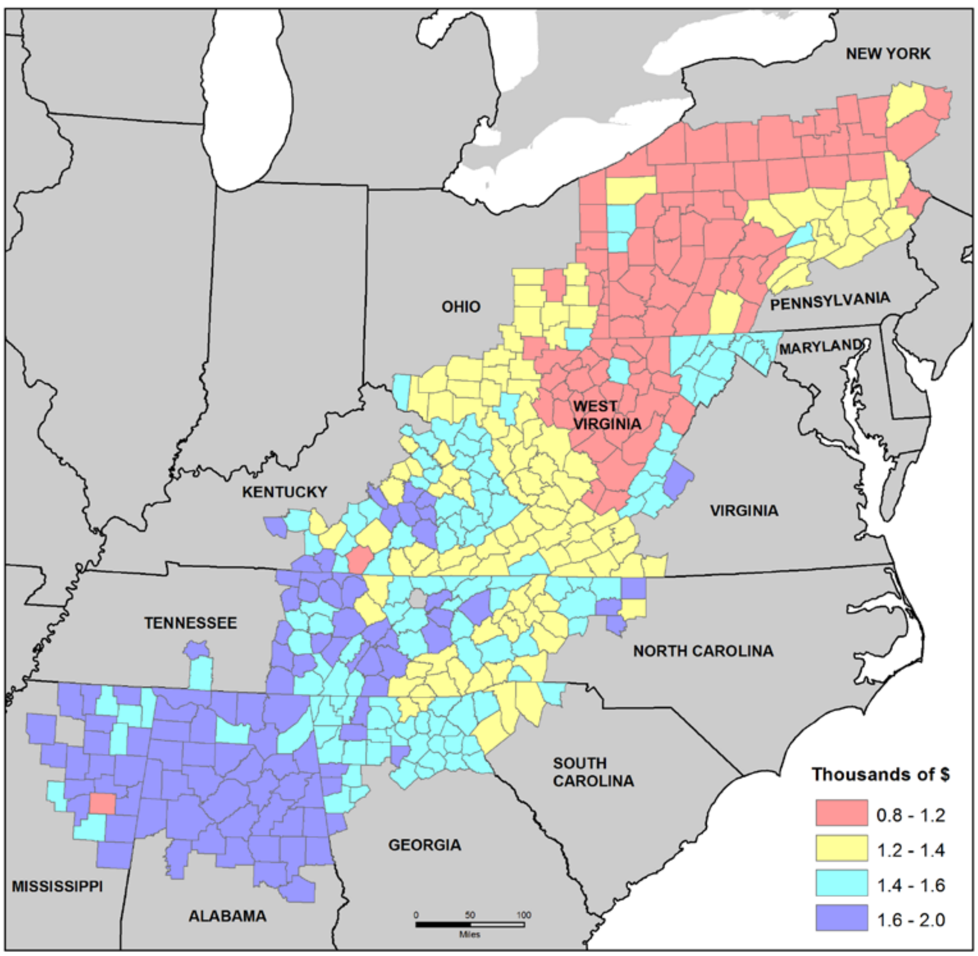
Figure 6.3.4 Electricity Sales per Customer, Residential, 2010-2020 Growth Rate, Carbon Mitigation Case



Map Title: Electricity Sales Per Customer, Residential, 2010-2020 Growth Rate: Carbon Mitigation Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Figure 6.3.5 shows revenues per customer, which can be thought of as the product of Mwh sales per customer times the electricity price for each region. Higher revenues are still concentrated in the southern counties, as with sales. Note that large pockets of West Virginia and western Pennsylvania have low revenues per customer, whereas most of Appalachian Alabama has higher than average revenues.

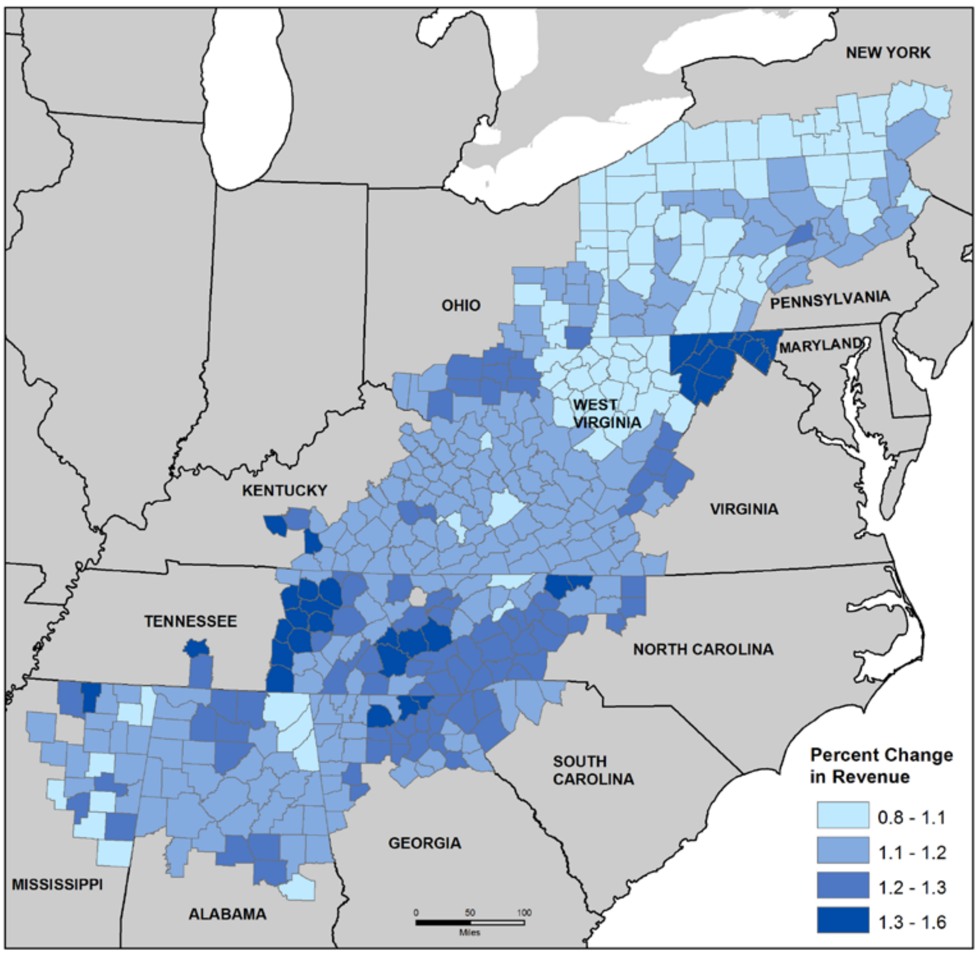
Figure 6.3.5 Revenues per Customer, Residential, 2020, Reference Case



Map Title: Revenues Per Customer, Residential, 2020: Reference Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

The growth rate in revenues per customer is the growth rate in sales per customer plus the growth in prices. Figure 6.3.6 shows the growth in the Reference case. Since the percentage growth in prices is assumed to be the same across counties, this map is essentially reflecting differences in the growth rates of sales. This growth is partly related to overall economic growth in each county, but also to changes in the number of households.

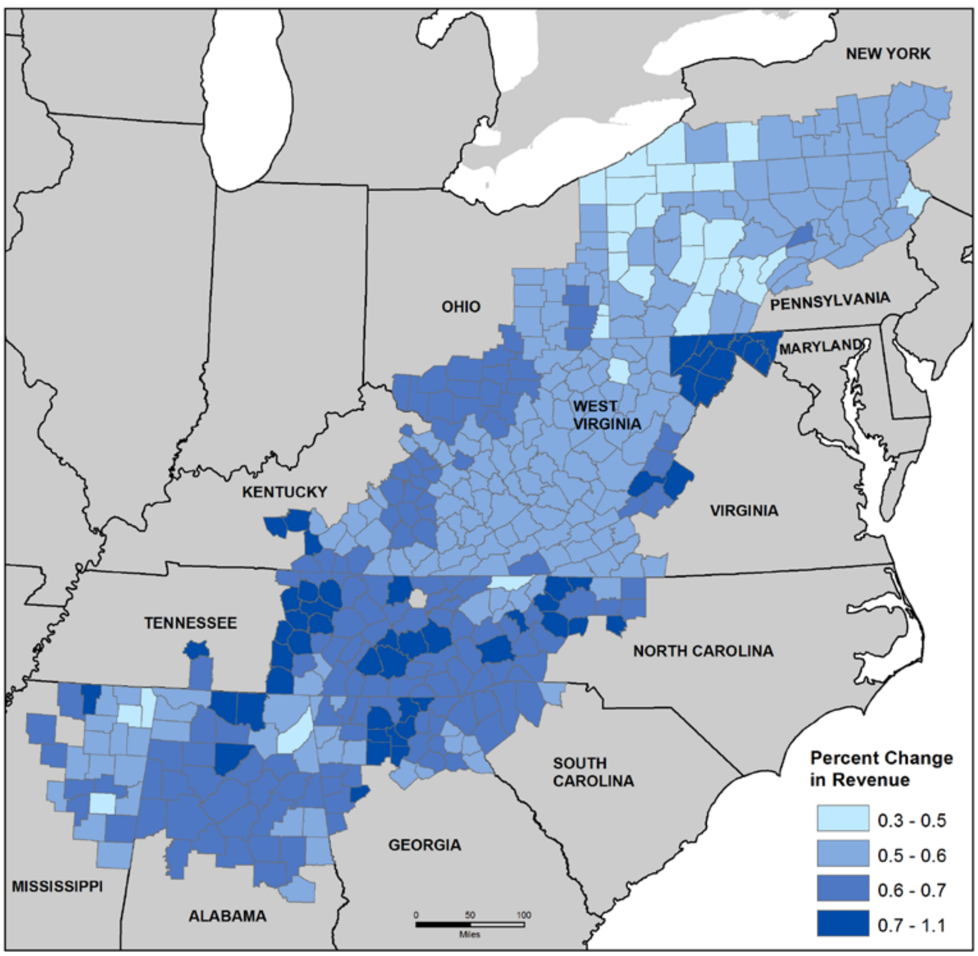
6.3.6 Revenues per Customer, Residential, 2010-2020 Growth Rate, Reference Case



Map Title: Revenues Per Customer, Residential, 2010-2020 Growth Rate: Reference Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Figure 6.3.7 shows the same data for the High Efficiency Case. The growth rates of residential revenues per customer are much lower overall than in the Reference case.

6.3.7 Revenues per Customer, Residential, 2010-2020 Growth Rate, Efficiency Case



Map Title: Revenues Per Customer, Residential, 2010-2020 Growth Rate: High Efficiency Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Figure 6.3.8 shows the increase in revenues per customer for the Carbon Mitigation Case. As we saw in the map for Mwh sales, sales growth in this case is lower than the Reference case, in response to the higher price due to the carbon cost. However, the growth rates of residential revenues per customer are higher overall than in the Reference case in response to higher electricity prices.

6.3.8 Revenues per Customer, Residential, 2010-2020 Growth Rate, Carbon Mitigation Case

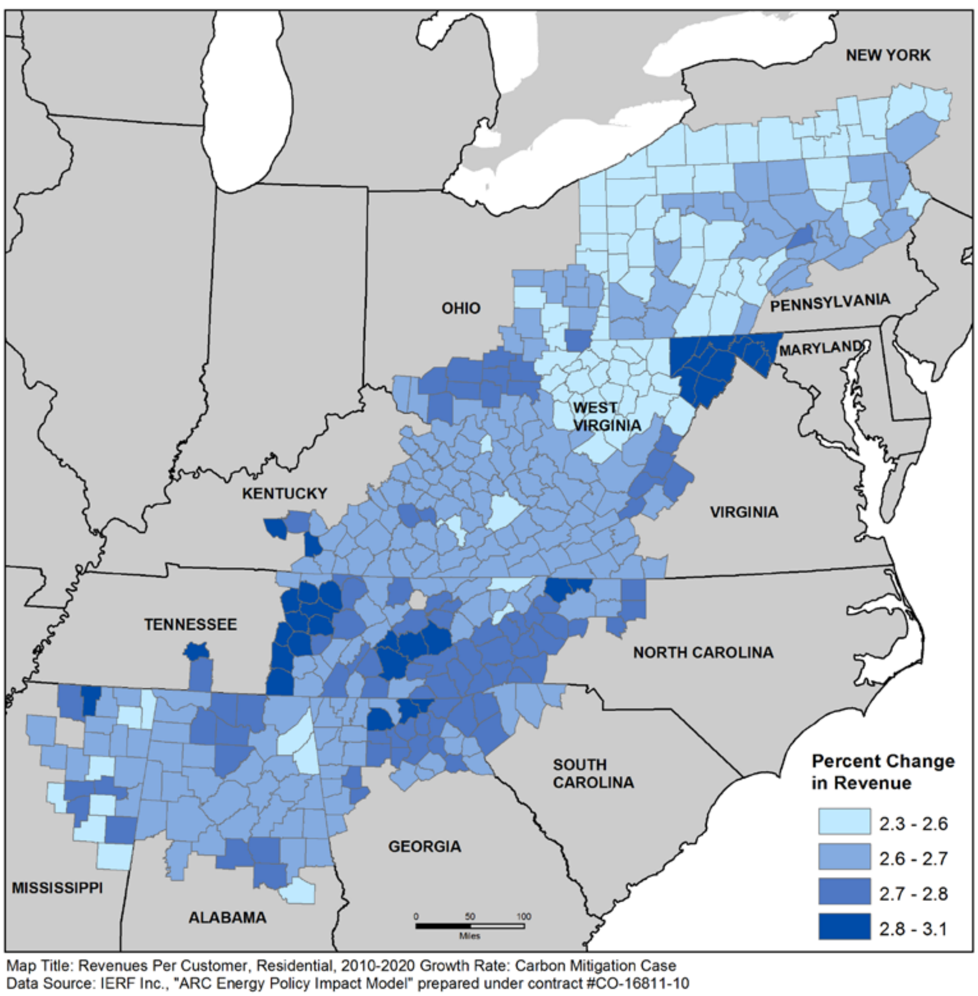
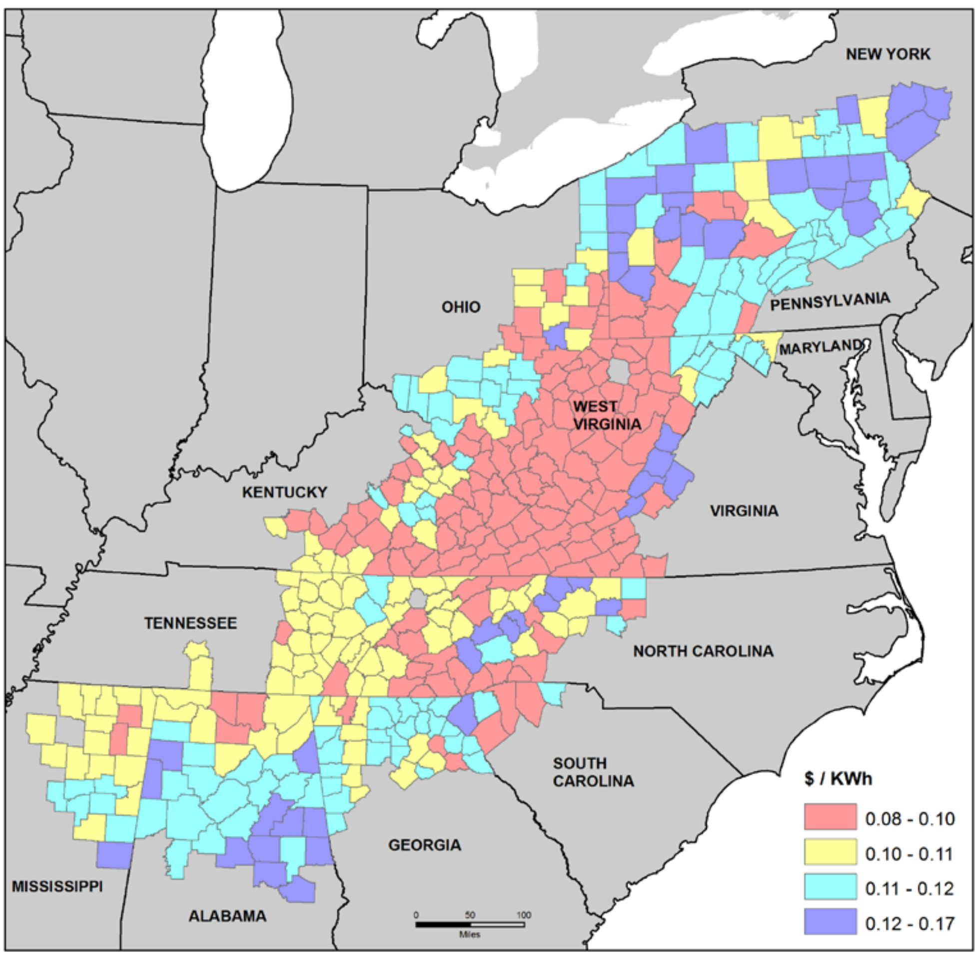


Figure 6.3.9 shows the distribution of electricity prices by county. These county prices are calculated by starting with the average electricity rates by utility, and distributing them to the counties they serve based on the county-utility bridge. The lowest rates are concentrated in West Virginia, western Virginia, and eastern Kentucky. The highest price regions are New York, Pennsylvania, and areas of Alabama and Georgia. This map is identical for the efficiency case, as we assumed no change in rates for that case.

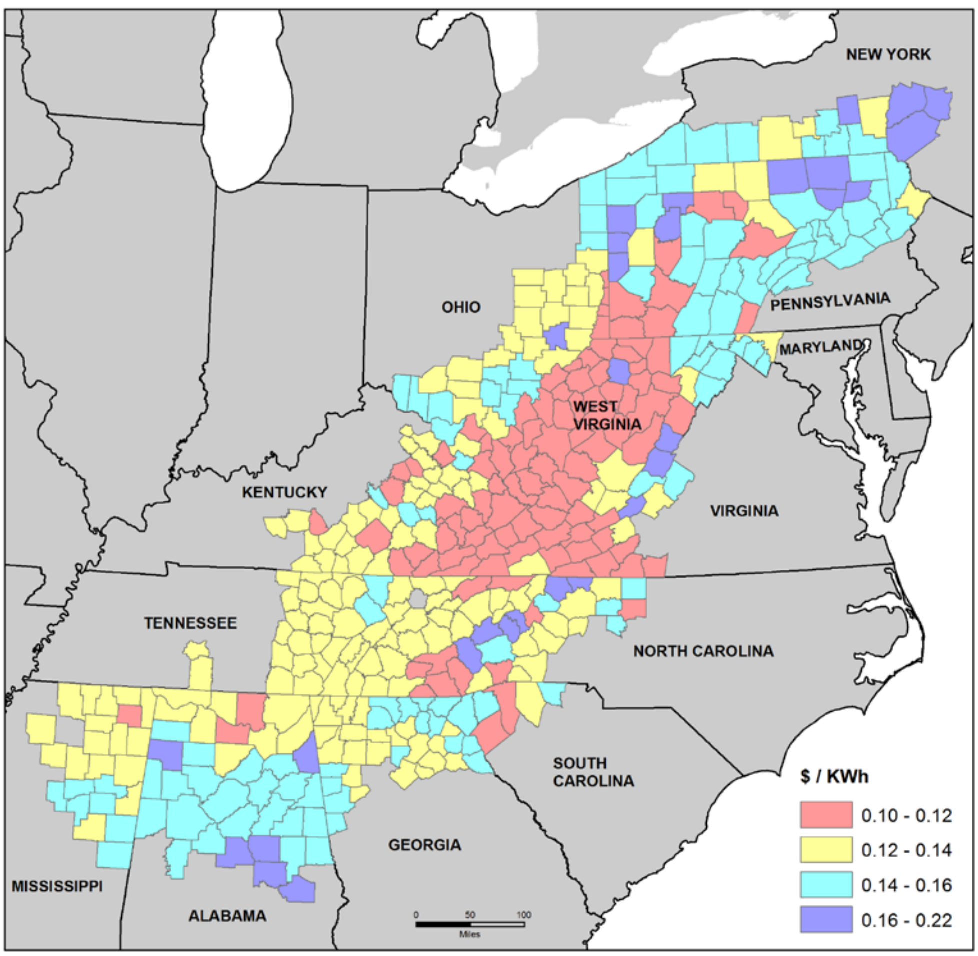
6.3.9 Residential Rate, 2020, Reference Case



Map Title: Residential Electricity Rate, 2020: Reference Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Figure 6.3.10 shows the residential rate by county for the Carbon Mitigation Case, where all electricity prices are about 25% higher than the Reference case by 2020. The higher electricity cost does have a significant impact on rates, although counties appear to preserve their relative standing.

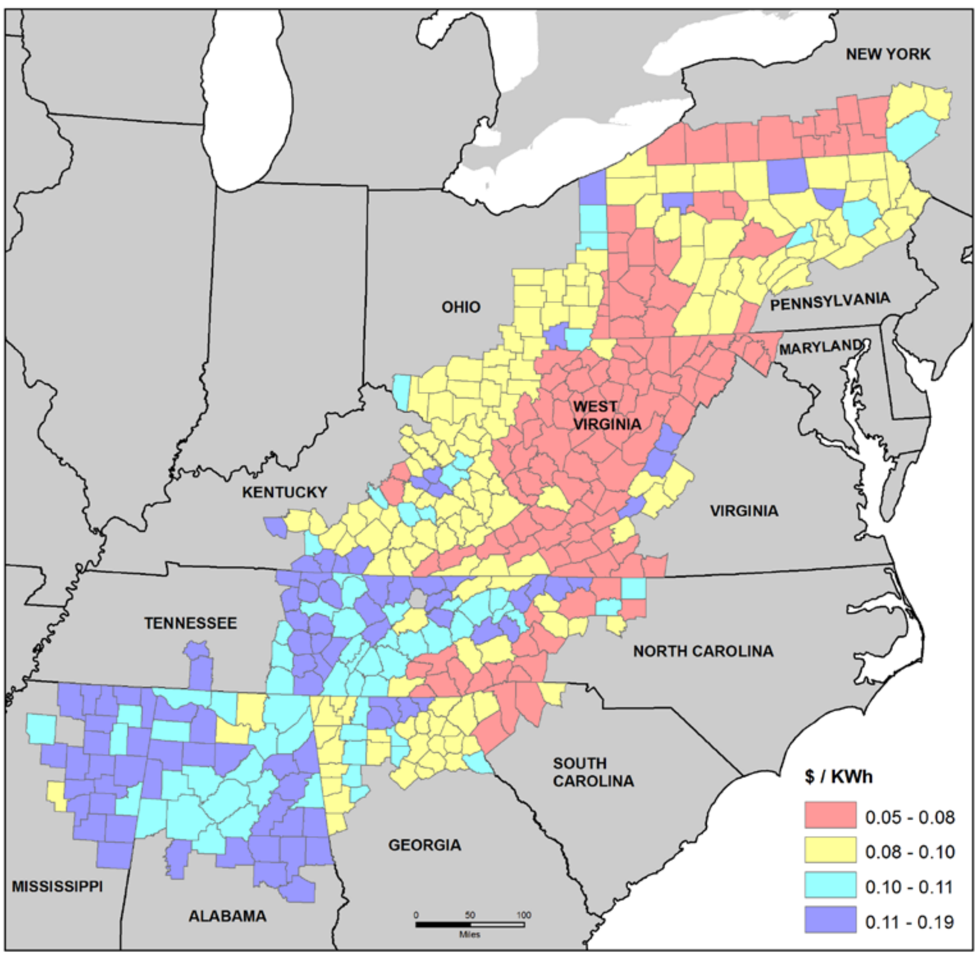
6.3.10 Residential Rate, 2020, Carbon Mitigation Case



Map Title: Residential Electricity Rate, 2020: Carbon Mitigation Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Figure 6.3.11 shows the distribution of commercial electricity rates by county in 2020 in the Reference case. While highly correlated with the distribution of residential rates, the distribution is not identical. Although commercial rates are lower than residential rates, they are not lower by the same percentage in every utility and county. This map also applies to the Efficiency case, as there was no change in rates.

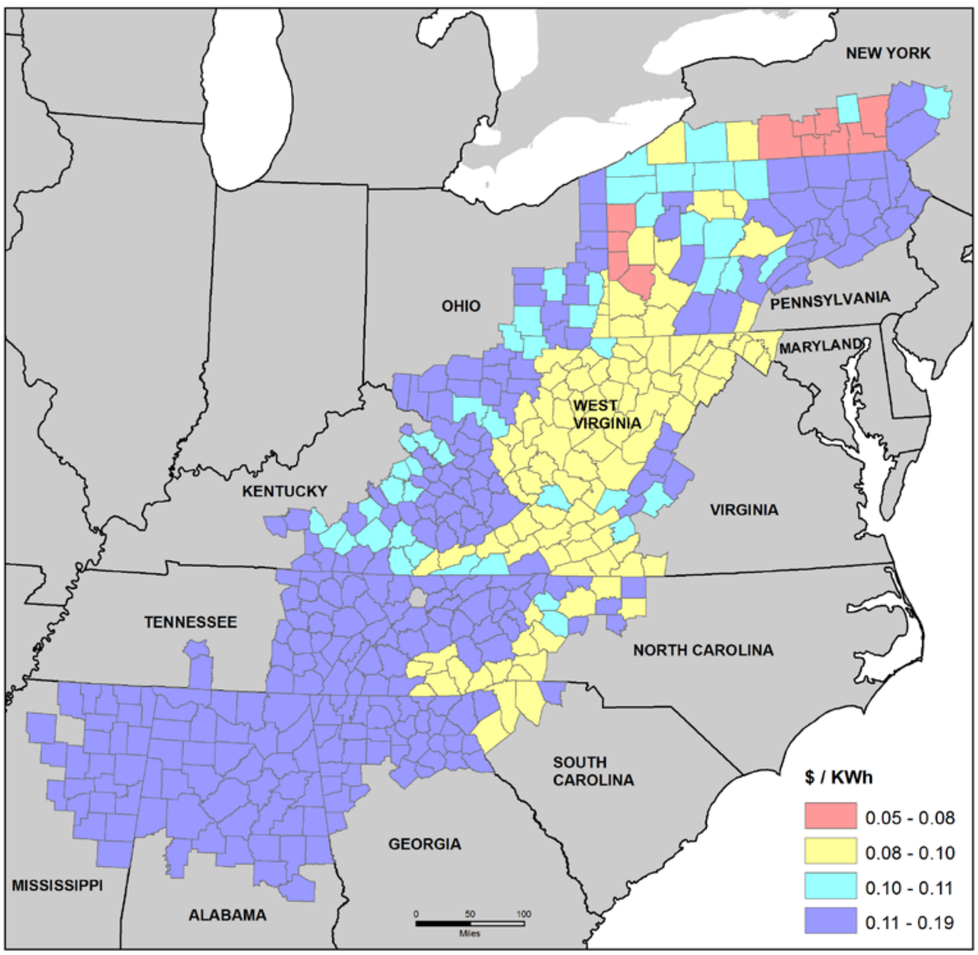
6.3.11 Commercial Rate, 2020, Reference Case



Map Title: Commercial Electricity Rate, 2020: Reference Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Figure 6.3.12 shows the distribution of commercial rates in the Carbon Mitigation Case in 2020. The areas of highest commercial rates continue to be the southern region of Appalachia, with scattered pockets elsewhere. The lowest commercial rates are in northern West Virginia.

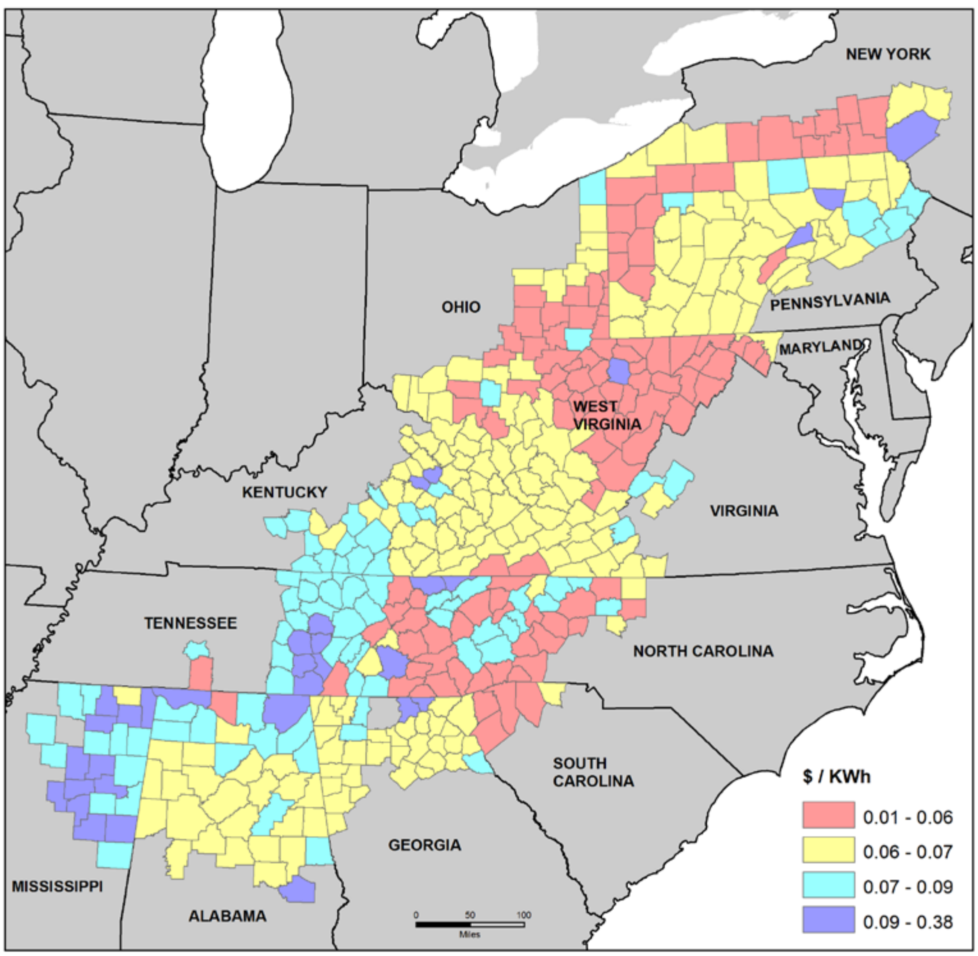
6.3.12 Commercial Rate, 2020, Carbon Mitigation Case



Map Title: Commercial Electricity Rate, 2020: Carbon Mitigation Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Figure 6.3.13 shows the distribution of industrial rates in the Reference case in 2020. These tend to be substantially lower than residential or commercial rates, as industrial users buy in bulk and also tend to use more off-peak power. The area centered on West Virginia and Virginia still has the lowest rates, with the southern regions generally paying higher industrial prices. Note that this map is also valid for the Efficiency Case, where there were no changes in rates.

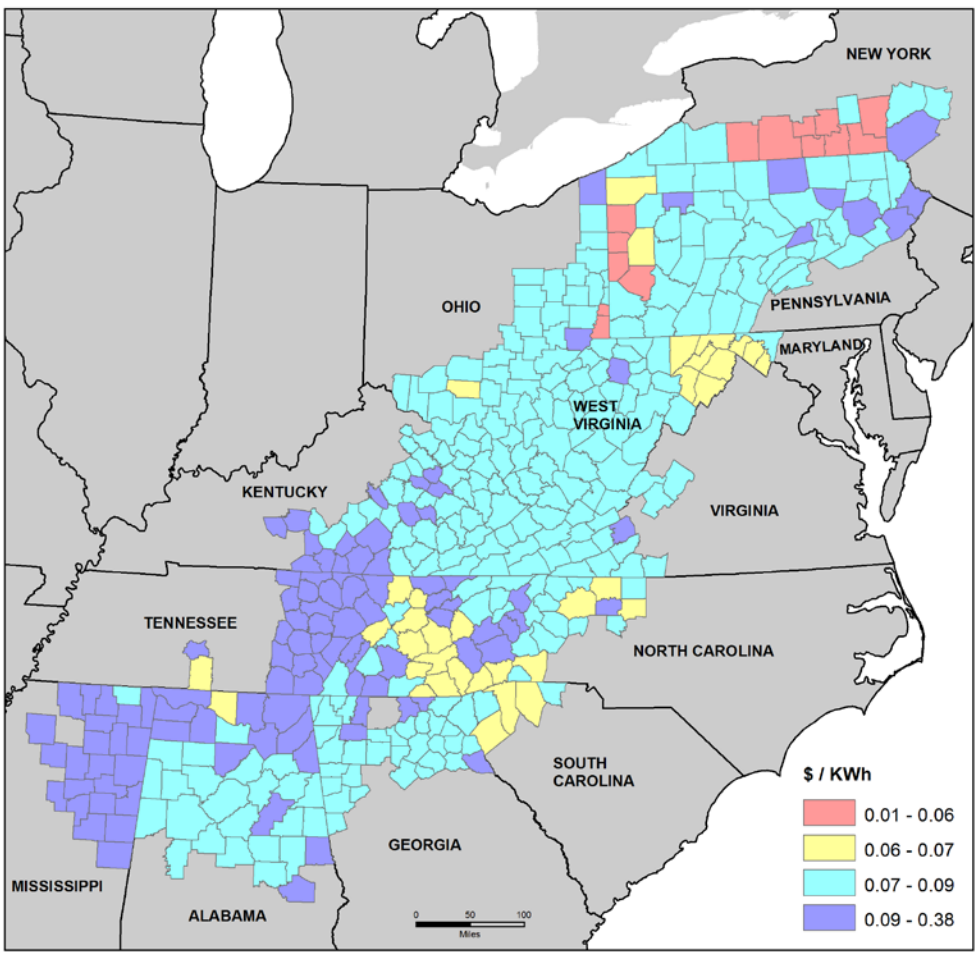
6.3.13 Industrial Rate, 2020, Reference Case



Map Title: Industrial Electricity Rate, 2020: Reference Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

This figure shows the distribution of industrial electricity rates by county in 2020, in the Carbon Mitigation Case. The relative standing of the counties is similar to that in Figure 6.3.13.

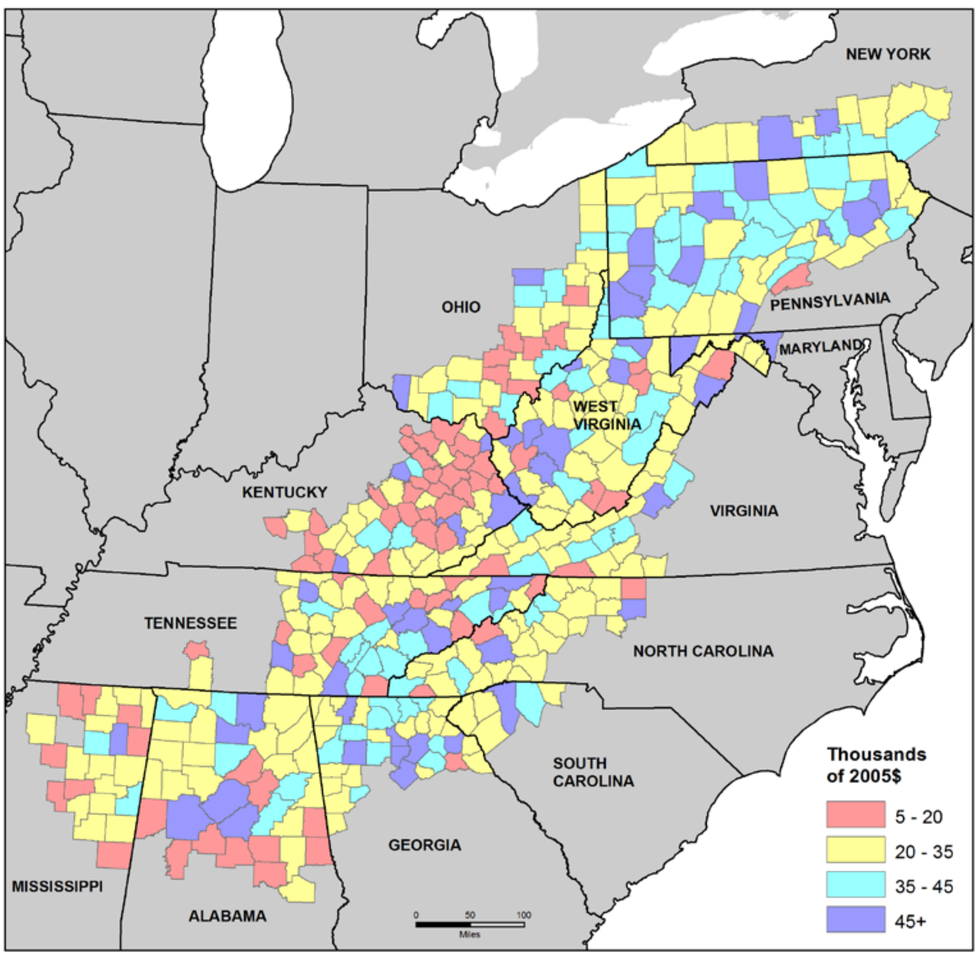
6.3.14 Industrial Rate, 2020, Carbon Mitigation Case



Map Title: Industrial Electricity Rate, 2020: Carbon Mitigation Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Figure 6.3.15 shows the distribution of per capita real Gross Regional Product (GRP) in 2020. GRP can be high due either to higher incomes or to higher industrial output per person. This map shows quite a variation in distribution of GRP across counties. An area with highly valued production will show higher GRP per capita, but not necessarily higher incomes. The reverse is also true.

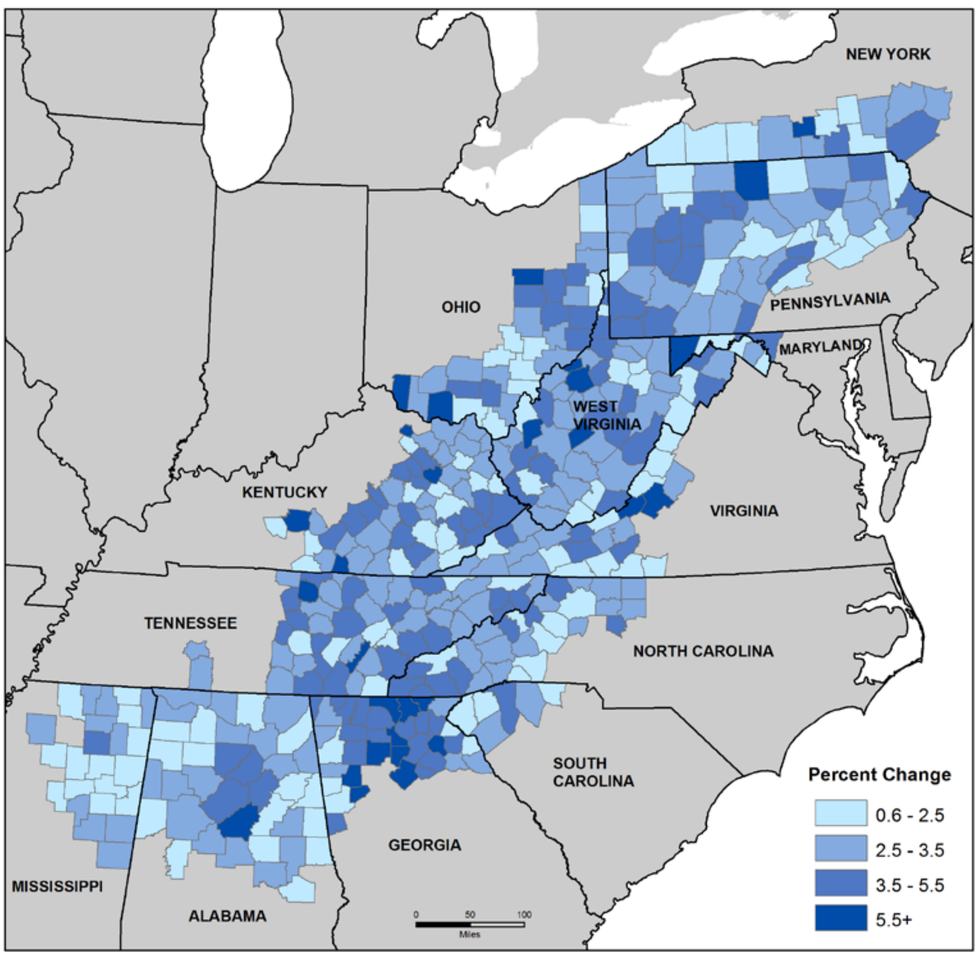
6.3.15 Per Capita Real Gross Regional Product, 2020, Reference Case



Map Title: Per Capita Real GRP for 2020: Reference Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Reference case GRP growth rates, shown in Figure 6.3.16, can be traced back to the growth of industrial output in each county. In general, the Appalachian counties of north Georgia grow the fastes. There are other pockets of high growth scattered throughout Appalachia. Keep in mind that high growth does not necessarily imply high GRP, as the county may be starting from a lower base in 2010.

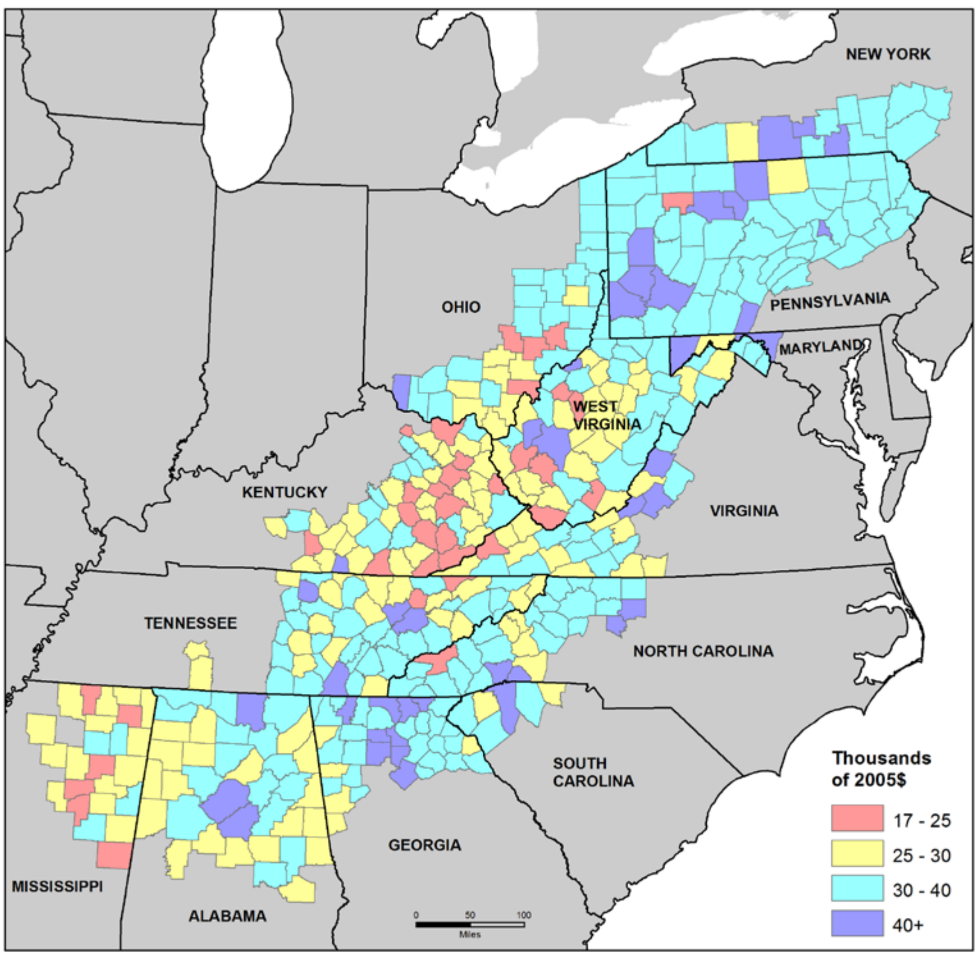
6.3.16 Per Capita Real Gross Regional Product, 2010-2020 Growth Rate, Reference Case



Map Title: Per Capita Real GRP, 2010-2020 Growth Rate: Reference Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Levels of per capita real income in 2020 are projected to follow similar relative patterns to those of today. Large pockets of relatively high personal income can be found in near metro areas in north Georgia, parts of central and north Alabama, southwestern Pennsylvania, West Virginia, North Carolina, and Tennessee. Only two counties are projected to have average income below $20 thousand in 2020.

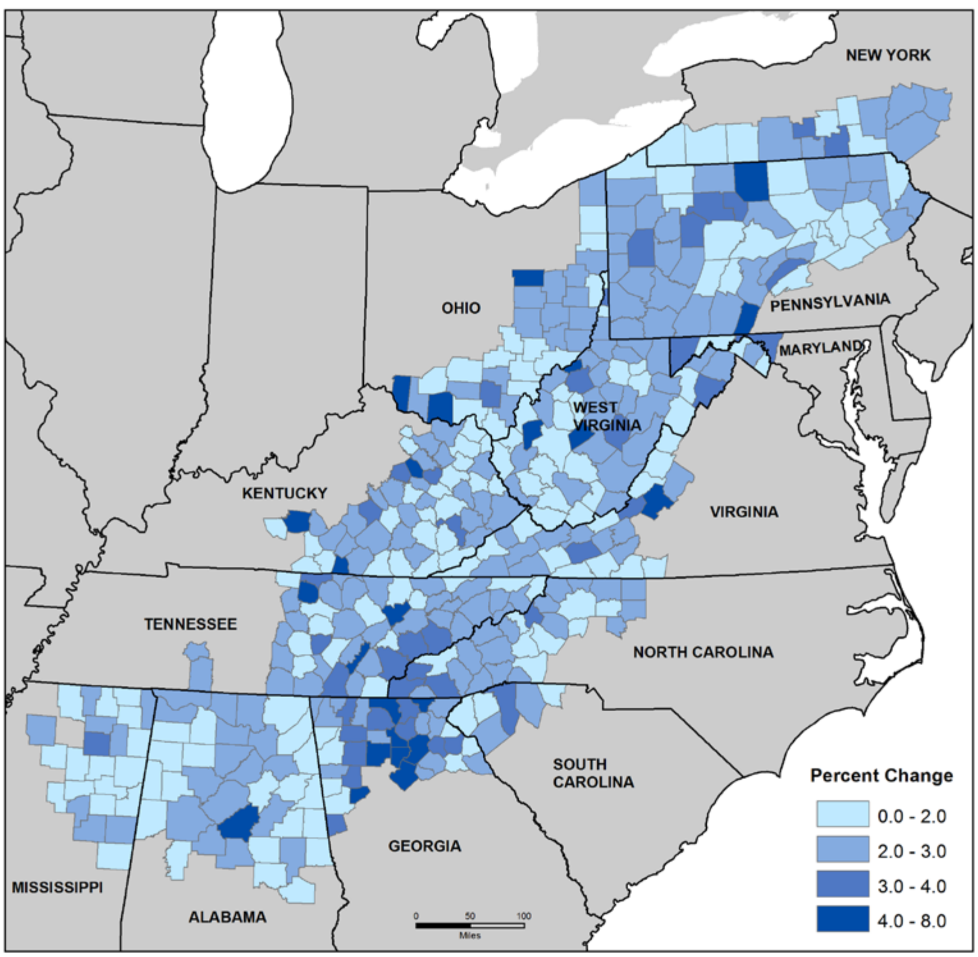
6.3.17 Per Capita Real Personal Income, 2020, Reference Case



Map Title: Per Capita Real Personal Income for 2020: Reference Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Per capita income growth varies widely across the region, with north Georgia being the strongest. Pockets of high growth and low growth are fairly well dispersed.

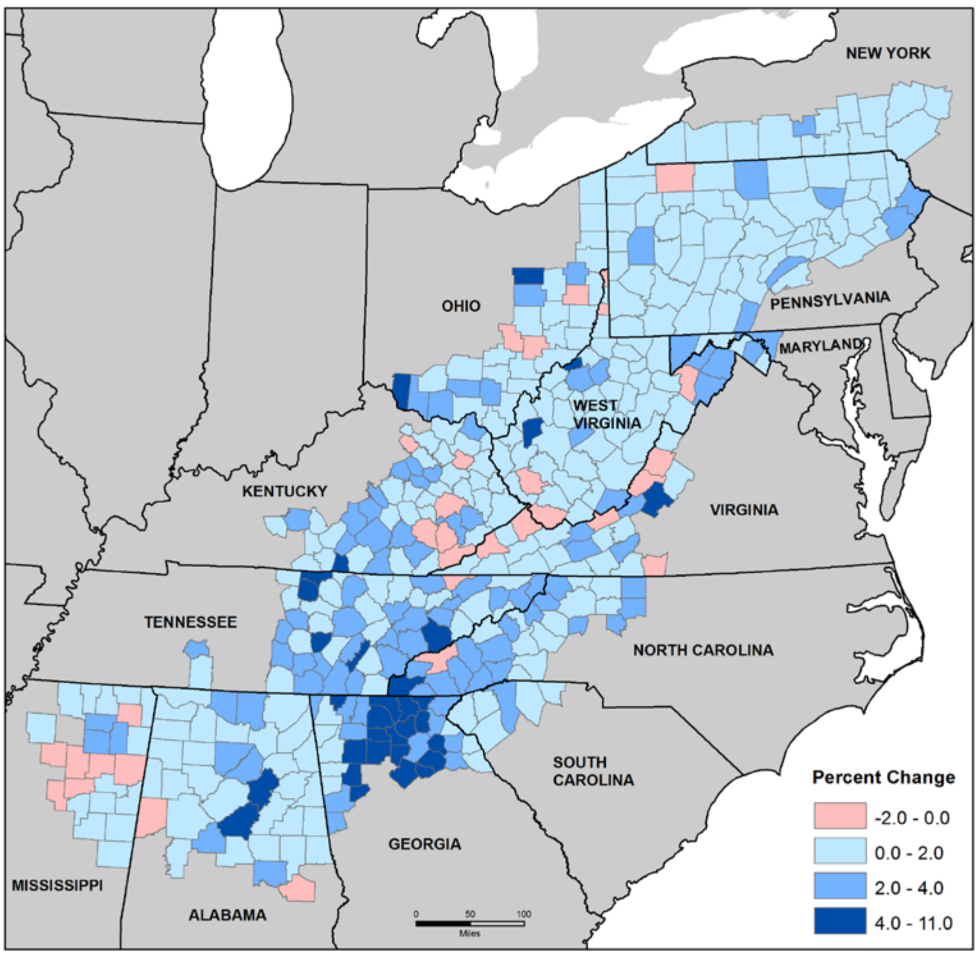
6.3.18 Per Capita Real Personal Income, 2010-2020 Growth Rate, Reference Case



Map Title: Per Capita Real Personal Income 2010-2020 Growth Rate: Reference Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

The strongest employment growth is projected in north Georgia, but there are also pockets of high growth in western North Carolina and east Tennessee.

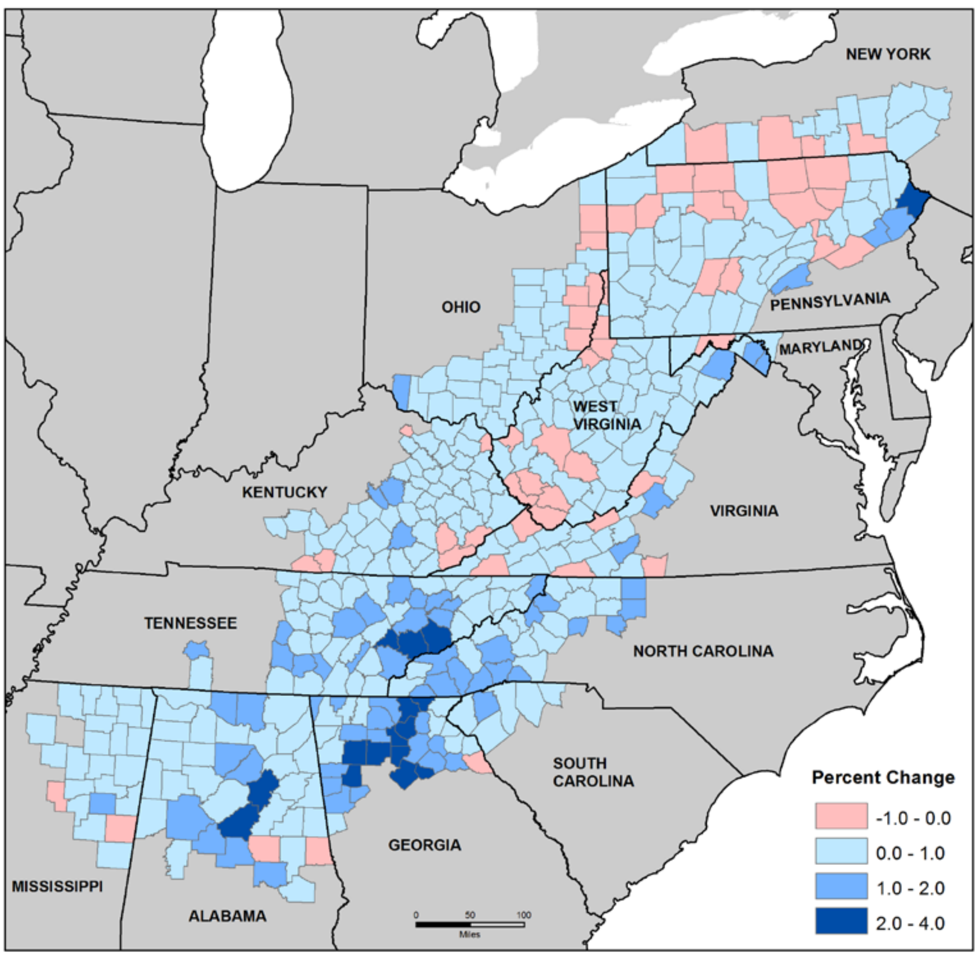
6.3.19 Employment, 2010-2020 Growth Rate, Reference Case



Map Title: Employment, Projected Growth Rate for 2010-2020: Reference Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Population growth is projected to be most rapid in certain relatively urban counties in Georgia and Alabama. Regions of northern Pennsylvania, southwestern New York, and parts of West Virginia and Ohio are projected to experience the slowest growth.

6.3.20 Population, 2010-2020 Growth Rate, Reference Case



Map Title: Population, Projected Growth Rate for 2010-2020: Reference Case
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

6.4 Sample Individual County Results

This section explores a sampling of simulation results at the county level. Here we give a flavor for the capabilities of the model, as well as what is happening in each of the four alternate policy simulations.

Table 6.4.1 is a comparison table of Kanawha county West Virginia. The first two columns show the values in the Reference case for 2010 and 2020. The next 4 groups of 2 columns each show the levels of variables in each policy scenario in 2020 and the percentage difference from the Reference case in 2020. The units of each variable are shown in parenthesis next to the title.

West Virginia is at the center of our analysis, being a state wholly contained within the Appalachian region, and experiencing intimately the interplay of coal, wind, biomass, and natural gas issues in the region. Kanawha is the largest county in West Virginia, both in population and in income.

In the efficiency case, employment increases relative to the Reference case by 0.35 percent, which is higher than the West Virginia average of 0.33, but lower than the Appalachian average of 0.43 (see table 6.2.5). Real personal income increases by 0.77 percent. This is the same percentage as the West Virginia average, but lower than the Appalachia average of 0.91 percent. Total real output is up by 0.10 percent. The results for the electric power sector are in line with the rest of West Virginia.

In the Carbon Mitigation case, employment is down by 0.23 percent, not as much as the West Virginia average of 0.33 percent. This is most likely due to the fact that Kanawha is a large and diversified county, with a strong service sector and government presence. Real personal income is down 1.34 percent, also less than the West Virginia average of 1.92 percent, and less than the overall Appalachia average of 2.14 percent.

In the CES case, employment is down relative to the base by 0.14 percent, compared with 0.02 percent for all West Virginia, and .04 percent for all Appalachia. Personal income is down by 0.55 percent, which is more than the West Virginia average (-0.28 percent) or the all Appalachia average (0-.14 percent).

In the Expanded Natural Gas cases employment shows almost no change relative to the Reference case, but real personal income is down by 0.93 percent. These results relate to the relative strength of coal and natural gas in this county's economy.

Table 6.4.1 Kanawha, West Virginia

	Reference		Efficiency		Carbon Mitigation		Clean Energy Standard		Expanded Natural Gas	
			Level	Perc. Diff.	Level	Perc. Diff.	Level	Perc. Diff.	Level	Perc. Diff.
	2010	2020	2020	2020	2020	2020	2020	2020	2020	2020
Total employment (thous)	131,738	142,421	142,920	0.35	142,091	-0.23	142,216	-0.14	142,405	-0.01
Real personal income (mil 2005$)	6,716	7,788	7,848	0.77	7,683	-1.34	7,745	-0.55	7,715	-0.93
Real output (mil 2005$)	12,796	16,879	16,895	0.10	16,743	-0.81	16,810	-0.41	16,895	0.10
Household consumption (mil $)	6,276	7,985	7,997	0.14	8,215	2.88	7,961	-0.31	7,869	-1.46
Total earnings (mil $)	6,131	9,164	9,185	0.23	9,321	1.72	9,136	-0.30	9,088	-0.82
Sales (Mwh)	3,057	3,648	3,097	-15.10	3,355	-8.03	3,496	-4.17	3,651	0.08
Revenue ($)	217	285	236	-17.20	331	16.03	297	4.19	276	-3.15
Rate ($/Kwh)	0.07	0.08	0.08	-2.48	0.10	26.15	0.09	8.73	0.08	-3.23

Table 6.4.2 is a similar table for Allegheny, Pennsylvania. This county is the largest in Appalachia, both in terms of personal income and population. The county has both coal and gas resources, but they are not huge in proportion to the county economy. This county benefits to a greater extent than Kanawha from the Efficiency scenario, with a 0.57 percent increase in employment and a 1.12 percent increase in real income. Impacts on the electric power sector are similar to those of Kanawha county. With regard to the Carbon Mitigation case, the negative impacts are proportionally smaller than those on Kanawha, while the effects on real income are larger. The Clean Energy Standard scenario has much smaller negative employment and income impacts than Kanawha. This is partly due to the fact that Allegheny has both wind and biomass development contributing positive impacts. Over the course of the scenario, we assume that 161 MW of wind capacity gets built in this county at a cost of $338 million. This county also benefits from biomass development. Finally, in the Expanded Natural Gas scenario, this county experiences a small improvement relative to the base, both in employment and in income.

Table 6.4.2 Allegheny, Pennsylvania

	Reference		Efficiency		Carbon Mitigation		Clean Energy Standard		Expanded Natural Gas	
			Level	Perc. Diff.	Level	Perc. Diff.	Level	Perc. Diff.	Level	Perc. Diff.
	2010	2020	2020	2020	2020	2020	2020	2020	2020	2020
Total employment (thous)	861,355	923,233	928,452	0.57	921,748	-0.16	923,387	0.02	924,445	0.13
Real personal income (mil 2005$)	52,660	66,734	67,480	1.12	65,611	-1.68	66,643	-0.14	66,828	0.14
Real output (mil 2005$)	89,866	128,766	129,516	0.58	127,992	-0.60	128,722	-0.03	129,096	0.26
Household consumption (mil $)	49,211	68,419	68,754	0.49	70,146	2.52	68,489	0.10	68,152	-0.39
Total earnings (mil $)	48,447	72,048	72,430	0.53	73,164	1.55	72,084	0.05	71,881	-0.23
Sales (Mwh)	13,341	16,372	13,594	-16.97	15,137	-7.55	15,767	-3.70	16,409	0.23
Revenue ($)	828	1075	901	-16.20	1253	16.59	1128	4.95	1045	-2.77
Rate ($/Kwh)	0.06	0.07	0.07	0.93	0.08	26.10	0.07	8.98	0.06	-2.99

Figure 6.4.1 shows a graphical comparison of employment in the High Efficiency case with the Reference case in 2020. Consistent with the previous table, Kanawha county has an increase of 0.35 percent in employment relative to the Reference case. There are four counties which suffer employment declines relative to the base from -0.66 to -0.3 percent. Those counties are Calhoun, Boone, Mingo, and McDowell. Table 6.4.3 shows how dependent these counties are on the mining sector, which includes a large share of coal in these counties. In Calhoun county, 23.5 percent of all employment is in this sector, making it very susceptible to reductions in coal consumption.

Figure 6.4.1 Comparison of Employment in West Virginia: High Efficiency vs. Reference

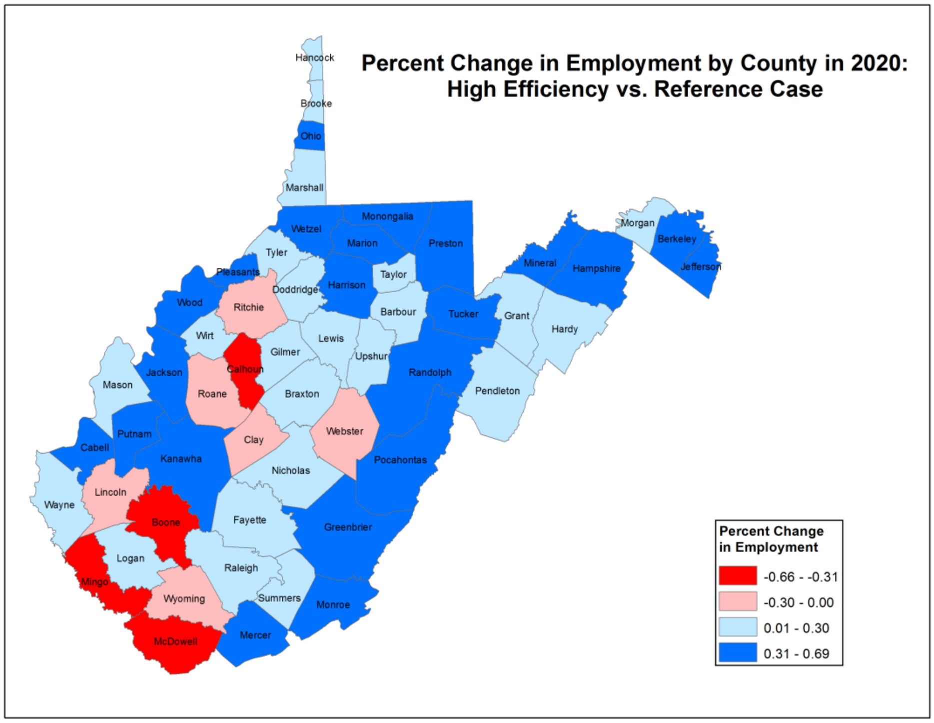


Table 6.4.3 Mining Share of Employment in West Virginia, 2009

County	Percent
54013 Calhoun, WV	23.2
54005 Boone, WV	22.5
54047 McDowell, WV	20.4
54059 Mingo, WV	20.3
54015 Clay, WV	18.6
West Virginia Average	3.0

7. Conclusions

For this study, we have constructed a new economic modeling system and used that system to set up a Reference case and then to explore the impacts of four alternative policy scenarios on the U.S. and the Appalachian region. The focus has been on the electric power sector, which is particularly important in this region. We have chosen the policy scenarios to encompass a range of policy and technology outcomes which we anticipate may be likely to occur in the next ten to fifteen year period. These outcomes include:

- Increases in end-use electricity efficiency in the residential, commercial, and industrial sectors.
- A carbon mitigation policy, which creates a market for carbon emissions or through the imposition of a tax.
- A Clean Energy Standard or similar policy which encourages development of renewables, nuclear, and to some extent gas combined cycle generation.
- Expanded and accelerated development of shale gas resources.

The actual evolution of policy and the economy may include some mix of these outcomes, and there may well be other policy scenarios well worth investigating with this modeling system.

This study also contributes a review of the broader policy environment described in Chapter 2 to put the current study in context. Chapter 3 reviews literature on policy choices, economic models and modeling exercises, and discusses assumptions that are typically used in energy/environmental modeling.

A brief review of the components of the EPIM (Economic Policy Impact Model) is given in Chapter 4 and is supplemented by additional detailed information in Appendices A and B. Chapter 5 reviews the assumptions and techniques used to develop the Reference case and each policy scenario. Results are summarized and sampled in the various sections of Chapter 6 at the national, Appalachian state, and Appalachian county level.

7.1 Main Findings from the Scenarios

Results for selected key macroeconomic variables are summarized in table 7.1.1. For each variable, the first line shows the value of that variable in the Reference case in 2015 and 2020. The other lines show the differences from the Reference for each of the policy cases.

Several main conclusions stand out at the macroeconomic level:

1. The High Efficiency case shows by far the largest positive impact. Gains from increases in electricity efficiency are significant, whether we use GDP, real income or employment for our criteria. Policy actions that can be taken to accelerate increases in the development of efficient technologies or to provide incentives for the adoption of existing technologies have a high payoff and may justify public expenditures either from direct subsidies, public assistance, or tax credits. By 2020, the High Efficiency case shows real GDP higher by 75 billion

(2005$), with real Disposable income up by $61 billion. Total employment is higher by 526 thousand jobs. Note that the High Efficiency case also shows the largest reduction in aggregate energy intensity of all the scenarios examined and also manages to reduce total CO2 emissions by 580 MMT by 2020.

2. The Carbon Mitigation case shows the largest negative impact. Although it is the most effective scenario at reducing carbon emissions (742 MMT reduction by 2020), it does so at the cost of lower GDP, employment, and real income. Aggregate energy intensity is reduced, but not by as much as the High Efficiency scenario.
3. The Clean Energy Standard is a highly effective way of reducing carbon emissions, without a large cost to GDP, real income or employment. Although the changes in these three variables are all slightly negative with respect to the Reference case, the differences are not large in percentage terms.
4. Expanded Natural Gas Development is somewhat positive for aggregate GDP and real income, significantly positive for employment, and with measurable reductions in carbon emissions (285 MMT reduction by 2020).

Table 7.1.1 Macroeconomic Summary of Key Variables Across Scenarios

		2015	2020
Real Gross Domestic Product (bil 2005$)	Reference	15,474	17,723
	High Efficiency	34	75
	Carbon Mitigation	-60	-154
	Clean Energy Standard	-2	-26
	Expanded Natural Gas	14	21
Real Disposable Income (bil 2005$)	Reference	11,711	13,309
	High Efficiency	31	61
	Carbon Mitigation	-21	-45
	Clean Energy Standard	0	-20
	Expanded Natural Gas	10	15
Employment (thousands)	Reference	154,733	161,550
	High Efficiency	320	526
	Carbon Mitigation	-401	-999
	Clean Energy Standard	49	-39
	Expanded Natural Gas	147	284
GDP Deflator (2005 = 1.0)	Reference	1.19	1.31
	High Efficiency	0.00	-0.01
	Carbon Mitigation	0.02	0.04
	Clean Energy Standard	0.00	0.00
	Expanded Natural Gas	0.00	-0.01
Energy Intensity (btus/GDP)	Reference	6.66	5.93
	High Efficiency	-0.20	-0.45
	Carbon Mitigation	-0.23	-0.24
	Clean Energy Standard	-0.18	-0.28
	Expanded Natural Gas	-0.08	-0.10
Total CO2 Emissions (million metric tons)	Reference	5,762	5,791
	High Efficiency	-225	-580
	Carbon Mitigation	-555	-742
	Clean Energy Standard	-408	-718
	Expanded Natural Gas	-197	-285

Line 1 is reference case value
Other lines are differences from reference

These national level results are fully consistent with our findings at the Appalachia state and county levels. However, we find greater differences in impact at this level due to different distributions of production and employment by industry, as well as differences in the distribution of coal and natural gas resources, and in the availability of biomass and wind development in the Clean Energy Standard scenario.

As we saw in section 6.4, several West Virginia counties suffer from declines in employment and output in the High Efficiency case, even though this scenario shows strong positive effects at the national level. This is due to the fact that more than half the electric power generation in the West Virginia territory is coal-based and the coal consumed by power generation supports the local mining industry. As electricity efficiency increases, coal consumption decreases, with resulting decreases in coal industry employment.

In fact, all of the policy scenarios imply a reduction in electric power generation from coal. Table 7.1.2 summarizes the production of electricity by eight different generation types across the Reference case and the four policy scenarios. In the Reference case, total generation rises to 4,121 billion Kwh by 2020, with 1,850, or about 45 percent, from coal. In the High Efficiency case, total generation is 16.9 percent lower by 2020, at 3,426 billion Kwh. Our simulation rule was to take the reduction in fossil fuels, so coal, gas and petroleum based generation were all cut by the same percentage of 25.1. In the Carbon Mitigation case, coal takes a much bigger hit, -40.3 percent. Total generation declines by 10.2 percent. Gas, wind, and geothermal and other increase in this scenario. In the CES scenario, there is a 13 percent reduction in total generation, but nearly 39 percent reduction in coal generation, with increases in gas, nuclear, hydro, wind, and geothermal and other. Finally, the expanded natural gas case has more gas (8.4 percent), but not quite as much more as the Carbon Mitigation case, which had an increase of 20.6 percent.[24]

Table 7.1.2 National Electric Power Generation by Type Across Scenarios

	Reference		Efficiency		Carbon Mitigation		Clean Energy Standard		Expanded Natural Gas	
			Level	Perc. Diff.	Level	Perc. Diff.	Level	Perc. Diff.	Level	Perc. Diff.
	2010	2020	2020	2020	2020	2020	2020	2020	2020	2020
Production by Type										
Coal	1,818	1,850	1,386	-25.1	1,105	-40.3	1,135	-38.7	1,485	-19.7
Natural gas	895	829	621	-25.1	1,000	20.6	871	5.0	899	8.4
Petroleum	39	39	29	-25.1	36	-6.5	32	-17.0	35	-9.9
Nuclear	803	877	877	0.0	877	0.0	884	0.7	859	-2.1
Hydro	240	301	301	0.0	306	1.6	306	1.6	301	-0.1
Wind	91	143	143	0.0	186	29.8	186	29.8	120	-15.8
Solar	1	3	3	0.0	3	0.0	3	0.0	3	0.0
Geothermal & other	41	78	65	-16.9	186	138.2	170	117.7	82	5.5
Total	3,929	4,121	3,426	-16.9	3,699	-10.2	3,587	-13.0	3,785	-8.2

Units: Billions of Kwh

In section 6.2.6 we presented some comparisons at the aggregate state level across scenarios. Some of the main conclusions from these comparisons were:

1. Consistent with the U.S. national results, the High Efficiency case shows the most positive impacts on employment and real income. The Carbon Mitigation case shows the largest negative impacts. Results for the CES are mixed, but small, and the Expanded Natural Gas case has slightly positive impacts.

[24] Note that these generation shares are a result of our calibrations to AEO 2011 side cases, and to a special study on the CES done by EIA.

2. However, there is a significant degree of variation within the states, which is reflective of an even greater variation at the county level. For example, although all states benefit in the High Efficiency scenario, the benefit to Kentucky and West Virginia is not nearly as large, since these are states more heavily dependent on coal mining. The state and county impacts in the CES case are a mix of positive impacts from Wind and Biomass, countered by negative impacts from reductions in coal. Kentucky and Ohio stand out with negative employment changes relative to the Reference case. The Expanded Natural Gas case shows states like Ohio, New York, and Pennsylvania benefitting more than the average, as these states contain some of the richer shale resources.

7.2 Policy Conclusions

This study has developed alternative scenarios to aid in the analysis of likely policy outcomes. The scenario choice, as stated above, was informed by decisions of likely outcomes, but also guided by the strategic objectives as outlined in the ARC Regional Energy Blueprint. Our goal has been to contribute to the dialogue surrounding these objectives by providing quantitative, scenario-based analysis. The modeling system used provides comprehensive national level summaries of policy impacts, as well as economic and electric power sector impacts at the county level.

Some main policy conclusions which we can draw from this quantitative analysis are:

1. Energy Efficiency stands out as an extremely effective policy to pursue, and may in fact pay for itself in terms of higher GDP, employment, and government revenue. It benefits the economy in terms of increasing aggregate multifactor productivity, reducing prices, and increasing employment and real incomes. However, certain localities that are dependent on coal are likely to have lower employment and income.
2. Natural gas from shale is a very promising avenue for stimulating employment and income growth in the northern Appalachian region, as well as contributing to a smaller carbon footprint.
3. Wind resources in Appalachia, though important, are not huge. Wind should be relied upon as one component of strategy for economic development of the region. According to our estimates, total potential wind capacity in the entire Appalachian region is about 16.6 GW, implying a total investment of about $34 billion (2009$), spread over a period of eight years. Wind capacity will most likely be concentrated in Pennsylvania and New York.[25]
4. Biomass resources are also important. If biomass resources are aggressively developed, we expect a total contribution of $10 billion to the Agriculture, and forestry sector, as well as a contribution of about $5 billion to the Transportation sector over the period until 2020,
5. Carbon mitigation strategies would accomplish important objectives through the reduction of a large share of U.S. carbon emissions which are generated from coal burned by electric utilities. However, unless accompanied by other strategies that stimulate development in the Appalachian region, several Appalachian counties would be hurt disproportionately.

[25] See Appendix C for detail on the derivation of assumptions for Wind in the CES case.

7.3 Extensions of This Research

A key contribution of this study, in addition to the development of the EPIM modeling system, has been the framing of policy scenarios to explore likely outcomes for Appalachia. Another valuable contribution has been the detailed study of the electric power sector in Appalachia, including how the power sector relates to the economies of the Appalachian counties. Finally, a significant effort was invested in obtaining detailed information about coal, natural gas, wind, and biomass resources at the detailed county level for Appalachia.

Several extensions of this research could benefit the Appalachian Regional Commission:

1. The exploration of further policy scenarios, particularly along the lines of the CES scenario used in this study, where a particular concrete policy proposal was evaluated. The availability of analysis from the Department of Energy EIA NEMS model is always particularly valuable for this type of exercise. The results from EPIM can be considered to be an extension of the NEMS results in the direction of industry level detail at the national level, and county level detail for Appalachia.
2. Further research on shale gas potential in the region and the likely course of development. Such analysis could look at key uncertainties affecting shale gas development, such as environmental constraints imposed by potential water supply degradation.
3. Further research on biomass development by county, also examining key constraints which may slow the development of the region’s biomass resources.
4. More detailed examination of the simulation results for particular counties and regions. Stakeholders in this analysis may be interested to have a more comprehensive view of the local impacts.

The Inforum LIFT model is continuously updated, and each year we make a new calibration to the latest Annual Energy Outlook.[26] We have also started to update the county level economic data used in the CUEPS database.

Energy and environmental issues will become an ever larger issue for the counties in Appalachia, no matter what the economic and policy environment may bring. The modeling system and strategies presented in this study should continue to contribute to the understanding of these issues.

[26] The AEO for 2012 will be published in March, 2012.

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Appendix A. Data Documentation

A.1 County Economic Data

County level data are derived primarily from data published by the Bureau of Economic Analysis (BEA), and include data or estimates for employment, earnings, output, value added, costs and capital income by industry. In addition, aggregate data on personal income and its components, population, number of households are compiled from BEA sources. A small (14x14) IO table consistent with the national level detailed table has been compiled to calculate electricity demands for the industrial and commercial sectors.

The CEDDS 2011[27] data was obtained from Woods & Poole, and this was used to update the county level economic data in CUEPS. This data is now available with historical economic data through 2009. Projections of population and other variables are available as far out as 2040, at five-year intervals. These projections are used to compare with the results of CUEPS projections.

Data from CEDDS were incorporated and updated for the following variables by county:

1. Population
2. Total employment
3. Personal income
4. Total earnings
5. Wages and salaries
6. Other labor income
7. Proprietor income
8. Dividends interest and rental income
9. Transfer payments
10. Social insurance contributions
11. Residence adjustment
12. Gross regional product
13. Number of households
14. Employment for 14 NAICS industries (11 private and 3 government)
15. Earnings for 14 industries

Historical data by county were then estimated for the following variables by county:

1. Real and nominal output for 14 industries
2. Personal consumption expenditures by 14 industries
3. Capital type income by 14 industries
4. Indirect taxes by 14 industries
5. Electricity use in dollars by 14 industries
6. Electricity use in Mwh by 14 industries

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[27] *The Complete Economic and Demographic Data Source,* Woods & Poole Economics, Washington, D.C.

Historical data for many economic variables were also allocated to the respective utilities serving the county areas by using the county utility bridge. The following are some of the economic variables are allocated to electric utility service areas:

1. Population
2. Personal income
3. Employment
4. Personal consumption
5. Current and constant price output
6. Households

Demand indicators are developed for each major utility market. The residential demand indicator is moved by the number of households. The industrial and commercial demand indicators are moved by the growth of real output in the industrial or commercial sectors.

A.2 Electric Utility Data

EIA-861 Data

The EIA-861 is an electric utility data file that includes such information as peak load, generation, electric purchases, sales, revenues, customer counts and demand-side management programs, green pricing and net metering programs, and distributed generation capacity. The data source is the survey Form EIA-861, *Annual Electric Power Industry Report*. The EIA-861, along with the EIA-923, and several other data files, are the main sources of information for EIAs *Electric Power Annual* and *Electric Power Monthly*.

The data are distributed in zipped executable files. For example, the file F861yr09.exe is a file of data collected on the Form EIA-861, *Annual Electric Power Industry Report*, for the reporting period, calendar year 2009. The zipped .exe file contains 11 .xls files and one Word file describing the tables and file layout, and a .pdf of the Form EIA-861. The complete set of data is described in table A-1:

Table A-1. Data available from EIA-861

File	Description of Contents
File1	Aggregate operational data on energy balance, and revenue information from each electric utility, including power marketers and Federal power marketing administrators.
File1_cao	(2005 forward) Data on control area operators
File1_a	(2007 forward) Data on the types of activities each utility engages in, the NERC regions of operation, whether the utility generates power, and if it operates alternative-fueled vehicles.
File2	Retail revenue, sales and customer counts, by state and class of services, for each distribution utility or energy service provider.
File3	Information on demand-side management programs.
File3a	(2007 forward) Cost percentages by state of energy efficiency and load management programs
File4	Names of the counties, by state, in which each respondent has equipment for the distribution of electricity to ultimate consumers
File5	Aggregate data of the number of customers by state and customer class for Green Pricing and net Metering programs.
File6	Information on utility or customer-owned distributed and dispersed generation such as the number, capacity and types of generators.
File7	(2007 forward) Data on mergers and acquisitions
File8	(2007 forward) Data on advanced meters.

The main data file used in the CUEPS model is File 2. These data on revenues, sales, customers and electricity rates by utility, for each major market from File 2 have been combined across the years 1999 to 2009. There are 3356 utilities in this database. A bridge was also constructed that maps the utility service regions to the counties comprising each service region. The mapping weights are numbers of households. File 4 was also used in the construction of the county-utility bridge. This file shows the counties in which each utility has equipment for the distribution of electricity to the ultimate consumers.

File 1 of the database includes data on net generation, wholesale purchases, electricity exchanged/received, exchanged/delivered, wheeled/received, wheeled/delivered, total sources, retail sales, sales for resale, and other information.

EIA-923 Data

For this study, the 2008 and 2009 files of the EIA-923 data were used[28]. This dataset identifies generation by type, and consumption of fuels, as well as dollar values of various costs by electric generating unit (EGU).

The form EIA-923 Preliminary 2010 is published in spreadsheet format. We have worked with the tab entitled Generation and Fuel Consumption. Other data in the file include Fuel Stocks, Boiler Fuel Data, Generator Data, Fuel Receipts and Cost Data, Combustion By-Products Disposition and Costs, and operational data for Cooling Systems, NOX control, FGP control, and FGD control.

The generation and fuel consumption table has 9927 rows, each representing a separate generating unit. Monthly data and some other fields that are not used were removed from this table, leaving the following fields:

[28] Before 2008, the format of the data files was different. Since we are interested in generator characteristics in a forecasting framework, we find that the 2008-9 data is sufficient to establish generation characteristics for the near future.

Table A-2 – Characteristics in the Generation and Fuel Consumption Database

Fld#	Description
1	Plant ID
2	Combined Heat & Power Plant
3	Nuclear Unit I.D.
4	Plant Name
5	Operator Name
6	Operator ID
7	State
8	Census Region
9	NERC Region
10	NAICS Code
11	EIA Sector Number
12	Sector Name
13	Reported Prime Mover
14	Reported Fuel Type Code
15	AER Fuel Type Code
16	Physical Unit Label
17	TOTAL FUEL CONSUMPTION QUANTITY
18	ELECTRIC FUEL CONSUMPTION QUANTITY
19	TOTAL FUEL CONSUMPTION MMBTUS
20	ELEC FUEL CONSUMPTION MMBTUS
21	NET GENERATION (megawatthours)
22	Year

The first task was to check that rollups of the data corresponded to tables published in the *Electric Power Annual, 2009* (EPA). The data were cross-tabbed by state, and the results put into a table showing total generation by state. The results of this crosstab for 2009 are shown in table A-3. This table corresponds with the map on page 27 of the *Electric Power Annual 2009*.

Table A-3. Net Generation by State, 2009

State	Generation (Mwh)	State	Generation (Mwh)
Alabama	143,255,557	Montana	26,712,736
Alaska	6,702,159	Nebraska	34,001,893
Arizona	111,971,251	Nevada	37,705,133
Arkansas	57,457,739	New Hampshire	20,164,122
California	204,776,132	New Jersey	61,811,239
Colorado	50,565,952	New Mexico	39,674,339
Connecticut	31,206,222	New York	133,150,550
Delaware	4,841,563	North Carolina	118,407,402
District of Columbia	35,499	North Dakota	34,196,467
Florida	217,952,309	Ohio	136,090,225
Georgia	128,698,377	Oklahoma	75,066,810
Hawaii	11,010,533	Oregon	56,690,856
Idaho	13,100,152	Pennsylvania	219,496,144
Illinois	193,864,358	Rhode Island	7,696,824
Indiana	116,670,280	South Carolina	100,125,487
Iowa	51,860,063	South Dakota	8,196,531
Kansas	46,677,308	Tennessee	79,716,889
Kentucky	90,630,427	Texas	397,167,910
Louisiana	90,993,676	Utah	43,542,946
Maine	16,349,849	Vermont	7,282,348
Maryland	43,774,832	Virginia	70,082,066
Massachusetts	38,966,651	Washington	104,470,132
Michigan	101,202,606	West Virginia	70,782,514
Minnesota	52,491,848	Wisconsin	59,959,060
Mississippi	48,701,484	Wyoming	46,029,212
Missouri	88,354,271		
		Total U.S.	**3,950,330,932**

The data were also cross-tabbed by generation type, using the AER Fuel Type Code. The results were compared with the top part of table 2.1 on page 26, and these also checked out.

The table A-4 shows how generation was allocated to each type of production, based on the AER code.

Table A-4. – Correspondence Between AER Fuel Type and Production Type

Production by Type	AER Fuel Type Code	AER Description
Coal	COL	Coal
	WOC	Waste Coal
Petroleum	DFO	Distillate Petroleum
	WOO	Waste Oil
	PC	Petroleum Coke
	RFO	Residual Fuel Oil
Natural Gas	NG	Natural Gas
Other Gases	OOG	Other Gases

Nuclear	NUC	Nuclear
Hydroelectric Conventional	HYC	Hydroelectric Conventional
Other Renewables	GEO	Geothermal
	SUN	Solar PV and Thermal
	WND	Wind
	ORW	Other Renewables
	WWW	Wood and Wood Waste
	MLG	Biogenic Municipal Solid Waste and Landfill Gas
Hydroelectric Pumped Storage	HPS	Hydroelectric Pumped Storage
Other	OTH	Other (including nonbiogenic MSW)

Table A-5 summarizes the production by type in 2009.

Table A-5 Electricity Generation by Type

Type	Generation (Mwh)
Coal	1,755,904,256
Petroleum	38,936,515
Natural Gas	920,978,681
Other Gases	10,632,107
Nuclear	798,854,585
Hydroelectric Conventional	273,445,094
Other Renewables	144,278,704
Hydroelectric Pumped Storage	(4,627,345)
Other	11,928,335
Total	3,950,331,136

The EIA-923 data is a database on generating units. The database of electric utilities in EIA-861 is by sellers of electricity. Some of these sellers are generators as well. However, many of them are transmitting and distributing electricity generated by others. Some are power marketers, buying and reselling electricity. There is difficulty in determining from these two databases the generating source of the power which is ultimately sold at the residential, commercial or industrial market. Even if this is not possible, our goal is to determine the average content by production type in any given market. We can make some simplifying assumptions to assist in solving this problem.

We first performed a matching exercise on the utility IDs in the 923 and 861 databases. A simple tally was made to see how many records, and how much net generation were in the utility IDs that match those in the model database. Out of 9927 records for 2009, only 4429 records are matched in the utility key, and 5498 are not. Of the total net generation of 3950 million Mwh, 2247 is accounted for by matched utility IDs, and 1703 is not.

The next step is to find a link from the generators to the sellers. The objective will be to maintain one database of generators, and compile the information needed by generator. Then, we construct a bridge matrix between the generator list and the seller list. Except for the direct matches, this is done on the basis of judgment.

Here are the steps:

1. Build the generator list
2. Build a link from the generators to sellers, where the ID is the same.
3. Use information provided by ARC on the generator characteristics of electricity by seller.
4. Use geographic location (state) to match up others not identified above.

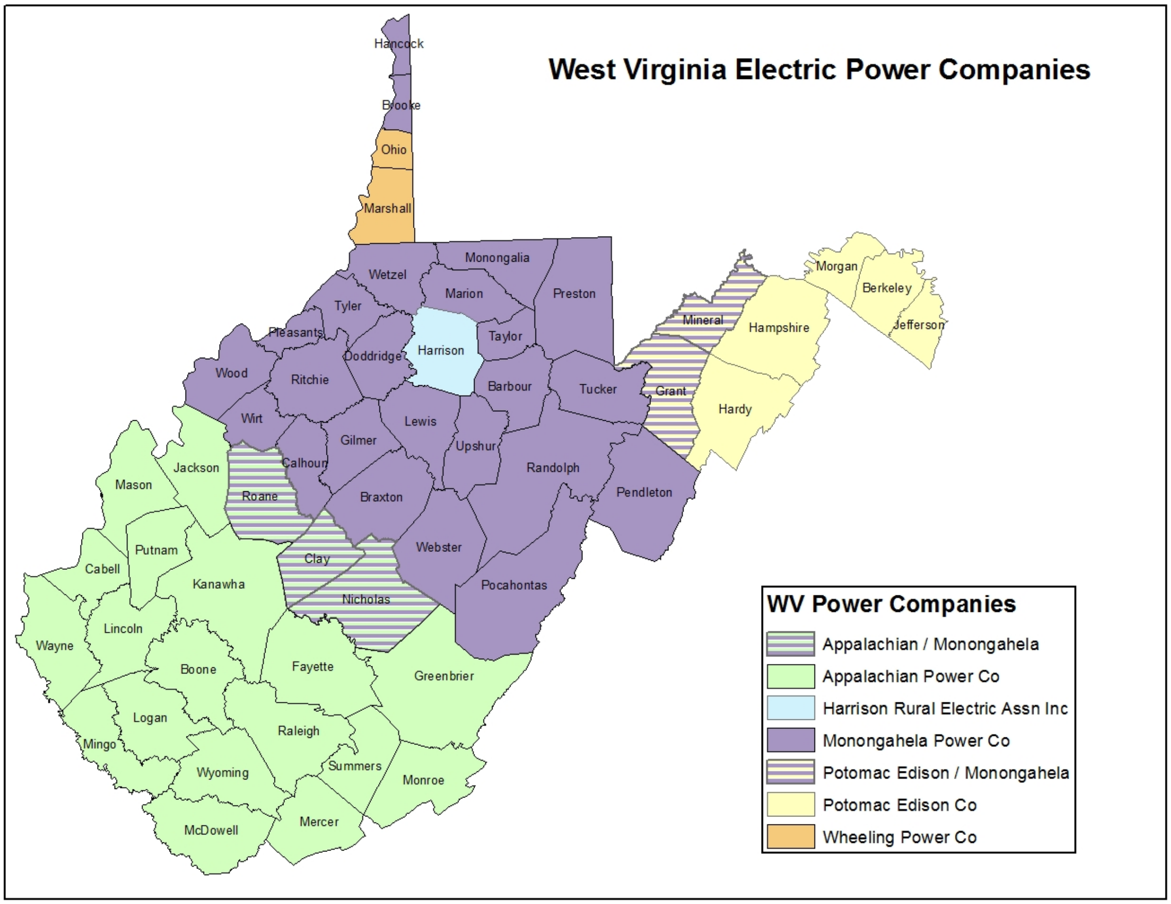
We have linked these data with existing data in CUEPS from the EIA-861. We use these data in modeling the effects of fuel costs and taxes on electricity prices.

A.3 County Utility Bridge

An immediate problem that arises is that of relating economic activity in a given county to demand for a utility, as well as relating utility prices of a given utility to demand for electricity in a county. The solution to this problem was the development of a county-utility bridge matrix, which is a crucial component of the model. The bridge is used to convert data available by county to data by utility, and vice versa. The rows of this bridge matrix correspond to the 3140 counties, and the columns to the 3356 utilities. The bridge was initially filled with some data that could be used to relate utility service area to counties. For this purpose, we have used the number of households (meters) served. Although the matrix is quite large, only the nonzero cells are stored, of which there are at present only about 8000 out of a total possible of 11.4 million. This bridge is conceptually similar to the product-industry bridge, used in the Inforum *LIFT* model, which distributes value added by industry to value added by product, and vice-versa.

Figure A.3.1 shows the mapping of utilities to counties in West Virginia by the county utility bridge.

Figure A.1 County Utility Bridge Relationships in West Virginia



Appendix B. Model Documentation

B.1 The LIFT Model

The Inforum *LIFT* (Long-term Interindustry Forecasting Tool) model is unique among large-scale models of the U.S. economy in that it is based on an input-output (IO) core, and builds up macroeconomic forecasts from the bottom up. In fact, this characteristic of *LIFT* is one of the principles that has guided the development of Inforum models from the beginning. This is in part because the understanding of industry behavior is important in its own right, but also because this parallels how the economy actually works. Investments are made in individual firms in response to market conditions in the industries in which those firms produce and compete. Aggregate investment is simply the sum of these industry investment purchases. Decisions to hire and fire workers are made jointly with investment decisions with a view to the outlook for product demand in each industry. The net result of these hiring and firing decisions across all industries determines total employment, and hence the unemployment rate. In the real world economy pricing decisions are made at the detailed product level. Modeling price changes at the commodity level certainly captures the price structure of the economy better than an aggregate price equation. In *LIFT*, prices and incomes are forced into consistency through the fundamental input-output identity, and the aggregate price level is determined as current price GDP divided by constant price GDP.

Despite its industry basis, *LIFT* is a full macroeconomic model, with more than 1200 macroeconomic variables determined either by econometric equation, exogenously or by identity. The econometric equations tend to be those where behavior is more naturally modeled in the aggregate. Many aggregates are formed the sum of industry detail, such as total corporate profits. An equation for the effective corporate tax rate is used to determine total profits taxes, which is a source of revenue in the Federal government account. Equations for contribution rates for social insurance programs and equations for transfer payments out of these programs can be used to study the future solvency of the trust funds. Certain macrovariables provide important levers for studying effects of government policy. Examples are the monetary base and the personal tax rate. Other macrovariables, such as potential GDP and the associated GDP gap provide a framework for perceiving tightness or slack in the economy.

Since its inception, *LIFT* has continued to develop and change. We have learned much about the properties of the model through analytical studies and simulation tests. We have learned about the behavior of the general Inforum type of model, from work with Inforum partners in other countries, including China, Japan, Germany and Italy.

In the last several years, the *LIFT* model has been extended through the incorporation of several modules that can be used to study energy demand and supply, and the implications of energy use on carbon emissions.

B.1.1 An Overview of the LIFT Model

We first focus on the "real side" of the model, where the expenditure components of GDP are calculated in constant prices. First personal savings are determined, which affect how much of real disposable income will result in total expenditures on consumption. Personal consumption is modeled in the PADS (consumer demand system) function to get consumption by category. PADS allows the classification of consumption goods into related expenditure groups, for example food, transportation or medical care. In PADS, motor vehicles prices affect the demand for public transportation, since motor vehicles and public transport are substitutes.

Exports by commodity may be determined outside the model, from the Inforum bilateral trade model (BTM) or by equations use information from BTM in the form of weighted foreign demands and foreign prices. The equipment investment equations are based on a Diewert cost function, that models the substitution (or complementarity) of equipment capital with labor and energy. The equations use a cost of capital measure that includes real interest rates, present value of depreciation, investment tax credit and corporate profits tax. The construction equations are for the roughly 20 categories of private construction. Though each has a different form, common variables are interest rates, disposable income and sectoral output.

Federal and state and local consumption and investment expenditures are specified exogenously in real terms, but *LIFT* allows for detailed control of these expenditures. For example, defense purchases of aircraft can be specified independently of missiles, ships or tanks.

The input-output solution solves jointly for output, imports and inventory change. Note that the IO matrix coefficients are specified to change over time, according to trends for each row. However, individual coefficients can also be fixed, to model changes in price or technology.

Labor productivity equations are used to determine the ratio of output to hours worked by industry. Average hours equations determine the average hours per employed person per year. Together, the productivity, average hours and output forecast generate employment by industry in the private sector. Adding in exogenous projections of government and domestic employment, total civilian employment is obtained. Subtracting total employment from projected labor force yields unemployment, and the unemployment rate, which is a pivotal variable in the model.

Prices in LIFT are determined as a markup over unit intermediate and labor costs. However, all components of value added are calculated first. Some are then scaled so that value added by commodity and prices are consistent. The largest component of value added is labor compensation by industry, which we call simply the "wage rate", although it also includes supplements. The "wage" equations relate the growth of the wage rate to growth in the ratio of M2 to GDP, expected inflation, and the growth in labor productivity. Multiplying the wage rate by the total hours worked per industry gives total labor compensation per industry.

It is also important to determine the components of capital income. Such items as Corporate profits, proprietors' income and capital consumption allowances are calculated in LIFT by industry. The value added relationships not only play a role in the determination of prices, but are also needed to be able to calculate corporate profits taxes, and retained earnings and capital consumption allowances are the large components of business savings, which is an important part of the savings-investment identity. Furthermore, dividends, proprietors' income, interest income and rental income all contribute to personal income.

Finally, there is a block of the model called "the Accountant", which is a large set of equations and identities that aggregate industry and commodity level variables up to the aggregate level, and calculate many of the main variables in the National Income and Product Accounts (NIPA). Part of the job of the accountant is to estimate all of the components of national income, personal income and disposable income. It also calculates federal and state and local government receipts and expenditures, as well as transfer payments and social insurance contributions. All of the fundamental national accounts identities are also calculated by the Accountant.

The standard solution interval for *LIFT* has recently been to 2030. For the calibration to the *2010 Annual Energy Outlook*, the solution interval will be extended to 2035. Note that we have also developed special versions of *LIFT* that forecast to 2050 (for carbon emissions modeling) or to 2085 (for long-term health care projects).

B.1.2 The Use of LIFT for Energy Modeling

As described above, *LIFT* is an interindustry macroeconomic (IM) model. Price and quantity calculations are grounded in the IO relationships. To a large extent, the macroeconomic forecasts are aggregates of detailed industry equations. The *LIFT* model embodies industry and interindustry detail for about 90 commodities, as well as a full set of NIPA (national accounts) variables. While not an energy model *per se*, LIFT maintains detail for the following energy industries:

3. Coal
4. Natural gas extraction
5. Crude petroleum
24. Petroleum refining
25. Fuel oil
66. Electric utilities
67. Natural gas distribution

LIFT shows constant and current price sales of these industries to all other industries and to final demand, as well as showing the purchases of these industries from other industries in the economy.

The calculation of prices in *LIFT* is also based on IO relationships. Prices are based on the prices of domestic and imported inputs, and the value added generated in production, including labor compensation, gross operating surplus and indirect taxes. Energy taxes, such as those analyzed in this study, are implemented as an indirect tax, which affects the price of the target industry directly, and the prices of all other industries indirectly.

Residential energy demand, and household transportation are modeled as part of a system of personal consumption expenditure equations. These consumption equations respond to disposable income, relative prices and other variables. Industrial, commercial and non-household transportation energy demand is modeled via IO relationships. The IO relationships are not static, but may be modeled to incorporate efficiency improvements, price-induced substitution, or changes in structure due to technological change. The structure of the electric power generating industry is represented as a disaggregation into the following list of 8 separate components, based on the technology or fuel type:

Types of Electricity Generation

1. Coal
2. Natural gas
3. Petroleum
4. Nuclear
5. Hydro
6. Wind
7. Solar
8. Geothermal, biomass and other

Additional modules have been attached to *LIFT*, which perform side calculations. These modules take output, price and other variables from the model, solve, and then provide variables to feed back to the main model. Examples of modules now functioning with *LIFT* include:

- Biofuels
- Light-duty vehicles
- Building efficiency
- CCS
- Renewable power (wind and solar)
- Nuclear power
- Carbon and carbon tax calculator
- Electricity generation by type

A module such as the building efficiency or light duty vehicles calculates variables such as residential and commercial energy demand for which *LIFT* would normally use the personal consumption equations or the IO coefficients. With the addition of the module, these default calculations are either replaced or modified. Personal consumption expenditures on gasoline may then be calculated as the sum of fuels of vehicles of different types, based on MPG and vehicle miles traveled instead of the default equations which rely on income and price. Changes in commercial energy demand coming through building or vehicle efficiency are implemented as changes in IO coefficients.

Producing Sectors of the LIFT Model of the U.S. Economy

1 Agriculture, forestry, and fisheries

Mining
2 Metal mining
3 Coal mining
4 Natural gas extraction
5 Crude petroleum
6 Non-metallic mining

Construction
7 New construction
8 Maintenance & repair construction

Non-Durables
9 Meat products
10 Dairy products
11 Canned & frozen foods
12 Bakery and grain mill products
13 Alcoholic beverages
14 Other food products
15 Tobacco products
16 Textiles and knitting
17 Apparel
18 Paper
19 Printing & publishing
20 Agricultural fertilizers and chemicals
21 Plastics & synthetics
22 Drugs
23 Other chemicals
24 Petroleum refining
25 Fuel oil
26 Rubber products
27 Plastic products
28 Shoes & leather

Durable Material and Products
29 Lumber
30 Furniture
31 Stone, clay & glass
32 Primary ferrous metals
33 Primary nonferrous metals
34 Metal products

Non-Electrical Machinery
35 Engines and turbines
36 Agriculture, construction, mining & oilfield equipment
37 Metalworking machinery
38 Special industry machinery
39 General and miscellaneous industrial machinery
40 Computers
41 Office equipment
42 Service industry machinery

Electrical Machinery
43 Electrical industrial apparatus & distribution equipment
44 Household appliances
45 Electric lighting and wiring equipment and misc. electrical supplies
46 TV's, VCR's, radios & phonographs
47 Communication equipment
48 Electronic components

Transportation Equipment
49 Motor vehicles
50 Motor vehicle parts
51 Aerospace
52 Ships & boats
53 Other transportation equipment

Instruments and Miscellaneous Manufacturing
54 Search & navigation equipment
55 Medical instruments & supplies
56 Opthalmic goods
57 Other instruments
58 Miscellaneous manufacturing

Transportation
59 Railroads
60 Trucking, highway passenger transit
61 Water transport
62 Air transport
63 Pipeline
64 Transportation services

Utilities
65 Communications services
66 Electric utilities
67 Gas utilities
68 Water and sanitary services

Trade
69 Wholesale trade
70 Retail trade
71 Restaurants and bars

Finance and Real Estate
72 Finance & insurance
73 Real estate and royalties
74 Owner-occupied housing

Services
75 Hotels
76 Personal and repair services, exc. auto
77 Professional services
78 Computer & data processing
79 Advertising
80 Other business services
81 Automobile services
82 Movies and amusements
83 Private hospitals
84 Physicians
85 Other medical services & dentists
86 Nursing homes
87 Education, social services, membership organizations

Miscellaneous
88 Federal & state and local government enterprises
89 Non-competitive imports
90 Miscellaneous tiny flows
91 Scrap and used goods
92 Rest of the world industry
93 Government industry
94 Domestic servants
95 INFORUM statistical discrepancy
96 NIPA statistical discrepancy

97 Chain weighting residual

B.2 The CUEPS Model

B.2.1 Elements of the CUEPS Database

The *CUEPS* database consists of national level data from the Inforum *LIFT* model, aggregated to the 14 sector level, county level data, based on the Regional Economic Information System (REIS) from the U.S. Bureau of Economic Analysis, and electric utility data from the Energy Information Administration (EIA).

The 14 sectors used in *CUEPS* are listed in table B-1. The data from *LIFT* include output in current and constant dollars, prices, employment, productivity, labor compensation, proprietors' income, other return to capital, indirect business taxes, total value added, personal consumption expenditures, federal defense expenditures, federal nondefense expenditures, state & local government expenditures and total final demand.

Data for the 3140 counties comprising the U.S. include population, employment, total earnings, number of households, total wages and salaries, other labor income, proprietors' income, dividends, interest and rental income, transfer income, social insurance contributions, and a residence adjustment.[29] Data for earnings and employment are available from each county for the 14 sectors listed in table A-1. In addition to these data, estimates were made for current and constant dollar output, return to capital, and indirect business taxes. Table X-X shows a sample of the 3140 counties.

The electric utility data is available from EIA for a set of 3356 utilities, derived from the EIA-861 and EIA-860 datasets. These data consist of sales in megawatt hours (Mwh), revenue, and number of customers, for five markets: Residential, Commercial, Industrial, Public and Other. Table B-2 shows a sample of the list of utilities.

Residential customers are defined as household establishments that consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking and clothes drying. Commercial actually includes both commercial and industrial establishments which have demands generally less than 1000 kilowatt hours (kW). Industrial includes commercial and industrial establishments which have demands generally greater than 1000 kW. Public is energy supplied to ultimate consumers for public street and highway lighting. Other includes any customers not included in the other four categories, and is primarily for agricultural use. Average price data were also calculated by dividing revenue by megawatt hour sales in each market, by utility.

B.2.2 Demand Indicators

The demand indicators are variables constructed for the regression equations of electricity demand (in Mwh sales) by major sector. The demand indicators are calculated based on sectoral outputs and the national input-output coefficients for

[29] The residence adjustment accounts for individuals who live in one county or area, but earn their income in another. The earnings variable includes them in their county of employment, but the personal income variable includes them in the county of residence.

electricity consumption. For example, the demand indicator for industrial electricity consumption is formed as:

$$D_{Industrial} = \sum_{j \in Industrial} A_{6j} q_j$$

where:

A is the national input-output direct coefficients matrix, aggregated to 14 sectors

q is real sectoral output

the "industrial" group is mining, construction, manufacturing, and transportation, communication and public utilities, except electric utilities

Sector 6 is the electric utilities sector

The interpretation of this demand indicator is the amount of electricity input in constant dollars that would be needed in a certain county, given the levels of sectoral outputs of each buying sector, and the input-output relationships that we observe at the national level. The demand indicator is necessarily imperfect since the national input-output matrix is only an approximate measure of electricity use per sector at the county level. However, the demand indicator constructed in this way gives a better measure than the sum of sectoral outputs for how electricity demand should change with changes in outputs, especially if the composition of outputs is changing within the industrial group.

The demand indicator for the commercial group is formed in the same way, but using the I-O coefficients and output levels of the agricultural services, wholesale trade, retail trade, finance insurance and real estate, and services sectors.

The demand indicator for "other" is simply the output of the agricultural industry. The demand indicator for the government sector is total government spending in the county.

Before they can be used in the demand regression equations described below, the demand indicators are converted to the utility basis using the county-utility bridge matrix.

B.2.3 The Cross-Sectional Electricity Demand Equations

To relate demand by market to electricity price changes, cross-sectional demand regressions were estimated for each of the five markets, using the EIA utility data described above. The quantity variable used was Mwh sales, and the price variable was the average utility rate per Kwh by market. Demographic data were also used in the residential regressions. Finally, the demand indicators described above were bridged to the utility level to adjust for demand differences.

The Commercial Sector

Of the total of roughly 3356 utilities in the database, only about 1840 had enough variables present to be included in the regressions for commercial and industrial. The final estimated equation for the commercial sector was:

LSALECOM = C - 0.87*LRATECOM + -.09*LDEMCOM + 0.92*LCUSTCOM

where: *C* = function of state dummies and ERS Beale codes.
LSALECOM = log of utility sales to the commercial sector
LRATECOM = log of utility rate per Kwh for the commercial sector
LDEMCOM = log of demand indicator for the commercial sector
LCUSTCOM = log of number of commercial utility customers

The constant term *C* is consists of the actual constant term of the equation plus two dummy variable effects, and thus varies by utility. The meaning of the state dummies is clear. The ERS Beale codes are classifications for the rural/urban classification of the county, and are defined in table 3.[30]

The omitted state dummy is for Alaska, and the omitted ERS Beale code was 0. The coefficient on *LRATECOM* (0-0.87) can be interpreted as the long run price-elasticity. Both the demand indicator and number of customers were included as demand variables. Each customer (utility meter) accounts for some fixed amount or minimum of electricity consumption, and the demand variable picks up electricity consumption that varies with economic activity. In the case of commercial customers, the bulk of the demand is estimated to arise from the customers variable. This makes sense, since most commercial use is for lighting, air-conditioning, computers and registers.[31] The sum of the elasticities of sales with respect to the demand indicator and number of customers is approximately one, which is in accord with our *a priori* expectation. The fit of this equation was rather good for a cross-sectional regression, with an R-squared of .915.

The Industrial Sector

The final estimated equation for the industrial sector was:

LSALEIND = C -2.58*LRATEIND + 0.34*LDEMIND + 0.48*LCUSTIND

where the variables are defined just as in the commercial sector. The estimated price elasticity for this equation is rather high. Some plotting and scanning of the price and sales data verified that the coefficient reflected the patterns observed in the data. However, this elasticity may be partly due to location decisions of industrial firms, rather than being a true price elasticity. In other words, firms that anticipate that they will have a high share of electricity cost will tend to locate in areas where electricity is relatively cheap. This phenomena will bias our coefficient upwards for use in time-series forecasting. We are considering constraining this elasticity to a smaller number. The industrial equation allocates a larger share of demand to the demand indicator variable than the commercial equation. Industrial customers' consumption of electricity is driven by electric motors, electro-chemical process needs, welding, and other production activities, which vary with the level of output. However, there are still space heat, lighting and air-conditioning requirements, so the number of customers is still important. The total of the demand indicator and customers elasticities was 0.82. This is smaller than our *a priori* elasticity of 1.0, but it could be there are more significant economies of scale in electricity use in the industrial sector. The fit of this equation was also quite good, with an R-squared of .761.

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30 The ERS is the U.S. Department of Agriculture, Economic Research Service.

31 Ideally, one would like to obtain data on number of square feet of space. However, this data was not available to us.

The Residential Sector

For the residential sector, 2240 utilities had sufficient data to be included in the regression. The estimated equation is:

LSALERES = C -0.35*LRATERES + 0.71*HIAGESHARE + 0.13*LCUSTMI

where LSALERES = log of sales to the residential sector
LRATERES = log of utility rate per Kwh for the residential sector
HIAGESHR = share of over 65 population
LCUSTMI = log of customers per mile

The price elasticity estimated for the residential sector is -.35, much lower than that of the commercial or industrial sector. After performing several exploratory regressions, the share of elderly and the population density were chosen as useful non-price explainers of the variation of electricity demand by utility. Note that no measure of number of customers was used in this regression, nor was the left-hand side variable put in per-capita form. The residential demand equations were much harder to fit than the commercial or industrial equations. The R-squared of the final equation used was only .387.

The Other Sector

As described above, this sector is comprised mostly of agriculture. In the total sample, 1408 observations had the necessary data to be included in this regression. The final estimated equation for the other sector was:

LSALEOTH = C - 1.35**LRATEOTH* + .27**LDEMOTH* + .47**LCUSTOTH*

where: C = ERS Beale codes
LSALEOTH = log of utility sales to the other sector
LRATEOTH = log of utility rate per Kwh for the other sector
LDEMOTH = log of demand indicator for the other sector
LCUSTOTH = log of number of utility customers (meters) in the other sector

Note that state dummies were not used in this regression, as they did not add much to the explanatory power. The estimated price elasticity in this sector of -1.35 is between that of industrial and commercial. As in the commercial sector, the elasticity of demand with respect to the demand indicator variable was significantly less than 1.0 (.27). Even the sum of the demand indicator elasticity and the elasticity with respect to the number of customers (.47) was less than 1.0 (.74). This equation should be revisited, as it implies significant economies of scale in electricity use in the agriculture sector, which may not be realistic.

The Public Sector

The public sector regression followed the form of the other sector, i.e.:

LSALEPUB = C - .79**LRATEPUB*+ .46**LCUSTPUB*

where: C = State dummies and ERS Beale codes
LSALEPUB = log of utility sales to the public sector
LRATEPUB = log of utility rate per Kwh for the public sector
LCUSTPUB = log of number of utility customers (meters) in the public sector

The price elasticity for the public sector is reasonable (-.79). The elasticity with respect to number of customers is significantly less than one.

B.2.4 The Structure of CUEPS

The construction of the County Utility Policy Simulator was done in two stages. In the first stage, historical data at the local level was estimated based on national relationships. This data set was then used as the historical starting point for making model projections.

B.2.4.1 Estimation of County Historical Data

The step of estimating data not available from the county or utility database is done by a program that works like a model, but over the historical interval (1980 to 2009)

The first step of this program is to reads data from the national model LIFT, aggregate that data, and insert it into the model database. These variables include the A-matrix, or direct coefficients matrix, output in constant and current prices, domestic prices, employment, labor productivity (output/employment), personal consumption by commodity in constant and current prices, total final demand, labor compensation, proprietors' income, total earnings (labor compensation plus proprietors' income), total return to capital, indirect business taxes, total value added, total federal government final demand, and total state & local government final demand. This data is used to form other variables described below. In running the simulator, the forecast data is in many cases calculated in the same way as the historical data.

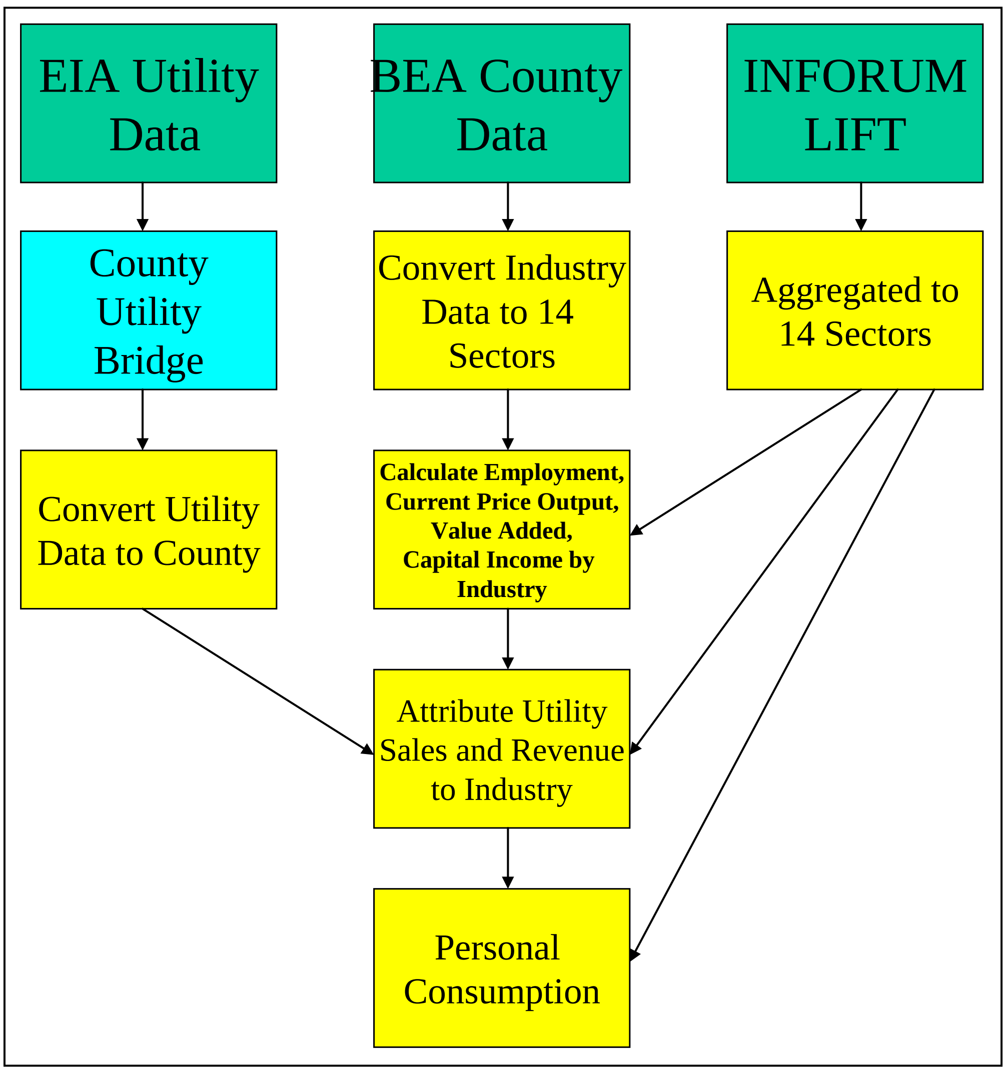
After filling the historical data file with 14-sector national data, the program converts the revenue and sales data by utility to county level, using the county-utility bridge. With total electric utility revenue by county in hand, the sector Transportation, communication and public utilities (TCPU) can be split into two parts. First, total revenue for the group as a whole is estimated by multiplying the ratio of current price output to employment at the national level by employment at the county level. Then, the share of electric utility revenue to this total is used to split employment and constant price output. In a few cases, electric utility revenue obtained by passing through the bridge was greater than current price output in the original TCPU sector. In these cases, we used the national shares of the two industries to do the split.

Constant and current price output for the other 12 sectors is obtained by multiplying the national ratio of these variables to employment by the employment by county by industry. Indirect business taxes by industry are derived as a share of current price output equal to that of the national data, for each industry. Capital type income by industry is calculated as a ratio to total earnings (labor compensation plus proprietors' income) equal to that of the national data for each industry. Total value added is then the sum of earnings, return to capital and indirect business taxes. In a small number of cases, the value added so estimated is larger than nominal output. In these cases, nominal output is set equal to total value added.

Electric utility sales (Mwh) and revenue by the five market areas are then distributed to the 14 industry sectors, using shares of intermediate sales of electricity in the national 14 sector I-O table to do the distribution. The link to the twelve industries and to consumption is as described in table 2. Note that Residential revenue is defined to be equal to personal consumption of Electric utilities in current prices.

Next, total consumption by county is estimated by applying the ratio of personal consumption to personal income at the national level to personal income by county. Personal consumption of electricity in current prices is set equal to residential consumption of electricity, derived above. Consumption of the other commodities is then determined by using the national shares of the non-electric part of current price consumption by commodity. Figure B-1 summarizes the historical data flow.

Figure B.1 Historical Data Flow



B.2.4.2 The County Utility Policy Simulator (CUEPS) Program

Like the historical data program CUEPS first collects and aggregates various data from LIFT which are used both as driver variables and allocator variables. Particularly important is sectoral output, since regressions have been developed by 14 sectors that relate county output to national output.

The model starts by making a first pass estimate of personal income by county. This estimate is made by growing lagged personal income by county by the growth rate of personal income at the national level. The model iteration loop begins by figuring how much of personal income is personal consumption, using the national share of personal consumption in personal income. Then the first pass estimate of the electricity share in that total consumption is calculated by moving the lagged share by the growth of the national share. That share is then used to derive consumption of electricity, in current prices. Personal consumption of the non-electricity commodities is obtained by sharing out the non-electricity consumption by county by the corresponding national shares.

Next, output by industry for each county is estimated using estimated output regressions. These are of two types. “National” industries are related to the national output of the same industry. “Local” industries, which include Retail trade, Construction, Services and State & local government, are related to total personal consumption in each county. Federal government output is moved forward by the growth rate of the total national federal government spending. Current price output by industry is derived by multiplying the national price level for that industry by the constant price output estimate.

Next, demand indicators for each major market are derived by county, and then converted to demand indicators by utility using the bridge matrix. Electricity prices by market by utility are moved forward by the growth rate of the national electricity price. The number of customers by utility is set to grow at the same rate as the demand indicator, but this can be changed by the user of the model.

Once the price, demand indicators and customers variables have been calculated, the electricity demand equations described above are calculated. The result of these equations is Mwh sales of electricity by market, by utility. These sales are then converted back to the county level using the bridge. Total utility revenue by market is calculated by multiplying the Mwh sales by the price per Mwh. Mwh sales by county by market are aggregated to a total for each county, and this figure is used to move the estimate of the electric utility industry output.

Employment by industry is formed using national employment/output ratios times sectoral constant price output. Total earnings are formed by first growing the earnings/employment ratio by county by the national growth rate in employment to earnings for each industry, and then multiplying by employment. Current price output by industry is formed simply by multiplying constant price output by industry by the national price index. Value added by industry is calculated based on the national ratio of value added to current price output, and capital income is formed as the difference of total value added and total earnings by industry. Population in each county is assumed to move in step with employment. This assumes a constant jobs/population ratio in each county.

Finally, personal income by county is formed by moving the lagged value forward by the growth in total earnings. The model compares the personal income vector with the last guess of personal income, and returns to the top of the model loop if they are not sufficiently close. Several iterations are usually required before the model reaches convergence.

Many of the variables in the model can be fixed exogenously by the user. These fixes may be overrides, indexes, growth rates, add-factors or multiplication factors. By changing the path of certain variables, we can investigate the effects of these variables on other variables, either for an individual county, or a set of counties grouped by some criterion.

Figure B.2 Flow of the County Utility Policy Simulator

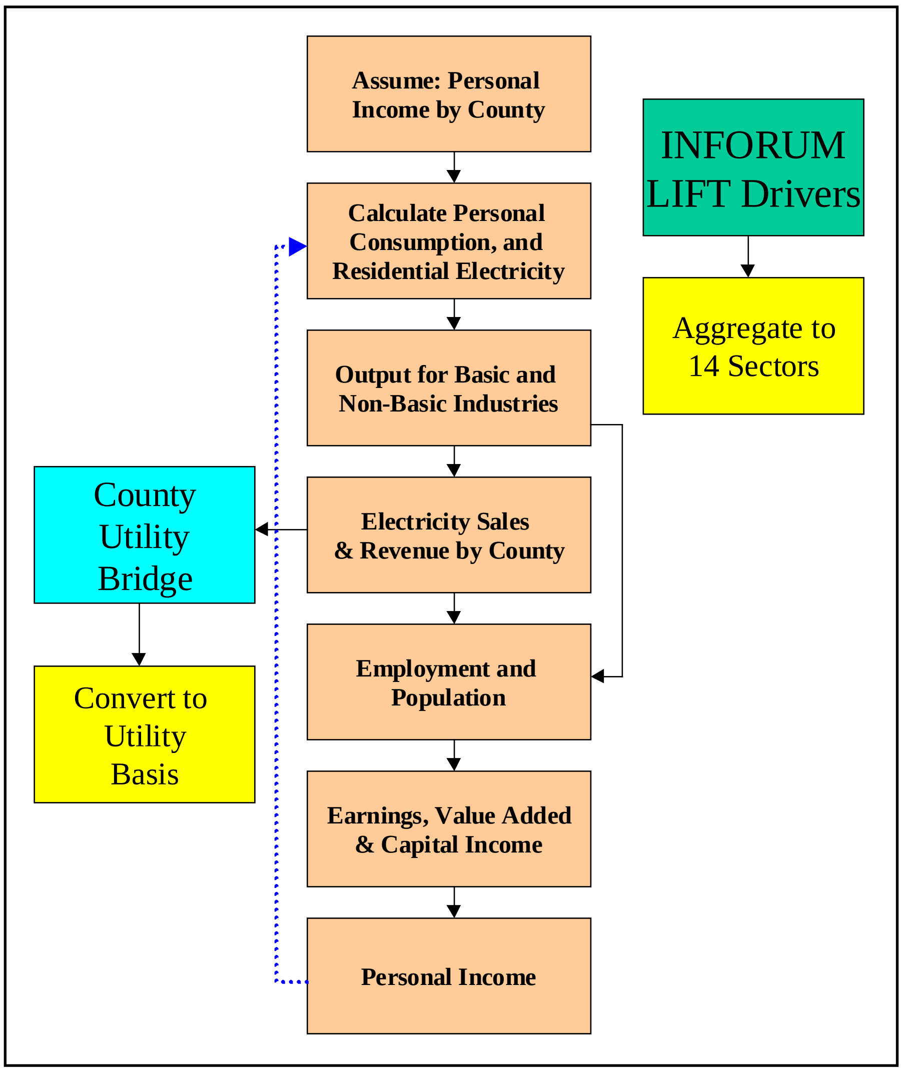


Table B-1: Industry and Government Sectors in CUEPS

#	*Industry Title*	*NAICS Definition*
1	Farming	111, 112
2	Agricultural services, forestry, fisheries	113, 114, 115
3	Mining	21
4	Construction	23
5	Manufacturing	31, 32, 33
6	Electric Utilities	2211
7	Transportation, communications, and public utilities, except electric utilities	48, 49, 513, 2212, 2213
8	Wholesale trade	42
9	Retail trade	44, 45
10	Finance, insurance and real estate	52, 53
11	Services	51, 54, 55, 56, 61, 62, 71, 72, 81
12	Federal civilian	N/A
13	Federal military	N/A
14	State & local	N/A

Table B-2: Correspondence of 5 EIA Market Categories to 14 Sectors and Personal Consumption

Market	*Sectoral Correspondence*
Residential	Personal consumption of electricity
Industrial	Mining, Construction, Manufacturing, Transportation, communication and public utilities, except electric
Commercial	Wholesale trade, Retail trade, Finance, insurance and real estate, Services
Public	Federal government, State & local government
Other	Agriculture, agricultural services, forestry and fisheries

Table B-3: ERS Beale Codes and Their Definitions

ERS Beale Code	*Definition*
	METROPOLITAN COUNTIES (0-3)
0	Central counties of metropolitan areas of 1 million population or more
1	Fringe counties of metropolitan areas of 1 million population or more
2	Counties in metropolitan areas of 250 thousand to 1 million population
3	Counties in metropolitan areas of less than 250 thousand population
	NONMETROPOLITAN COUNTIES (4-9)
4	Urban population of 20 thousand or more, adjacent to a metropolitan area
5	Urban population of 20 thousand or more, not adjacent to a metropolitan area
6	Urban population of 2,500 to 19,999, adjacent to a metropolitan area
7	Urban population of 2,500 to 19,999, not adjacent to a metropolitan area
8	Completely rural (no places with a population of 2,5000 or more, adjacent to a metropolitan area
9	Completely rural (no places with a population of 2,5000 or more, not adjacent to a metropolitan area

Appendix C. Wind and Biomass Potential

C.1 Derivation of Wind Assumptions

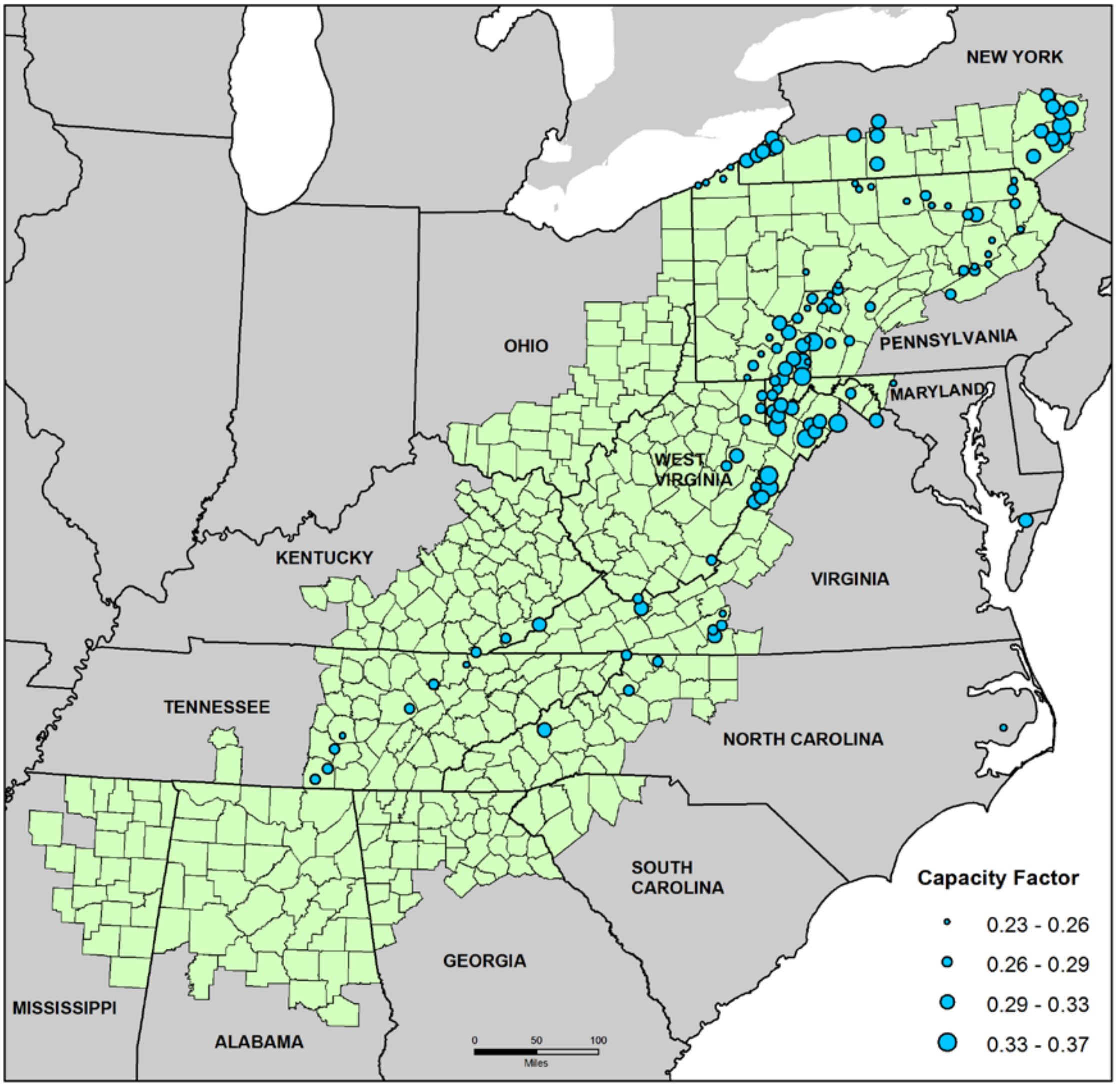
The Eastern Wind Intregation and Transmission Study (EWITS) has published an executive summary and project overview as well as a full report[32]. This study, which is done under contract with the DOE National Renewable Energy Laboratory (NREL) is being led by Enernex, with support from Ventyx and the Midwest Independent System Operator (MISO). This study is one of the largest regional wind integration studies to date. It was initiated in 2008 to examine the operational impact of up to 20-30% wind on the power system in the Eastern Interconnect of the United States, of which the Appalachian Region is a part. An output of the study has been the valuable eastern wind dataset, which is based on three years (2004-2006) of data of 10-minute wind speed and plant output values for simulated wind plants at selected locations. This data was created by AWS-Truewind, and includes a database of selected sites for potential wind farms, with information including longitude and latitude, elevation, cost of energy, average wind speed, estimated capacity factor, size and density of the area, and total installed power potential.

For the current study, we isolated the locations that fell within the Appalachian area. Figure C.1 shows the locations pinpointed as circles, proportional to capacity factor. The capacity factor is defined as the ratio of actual energy produced in a given period to the maximum attainable energy, running full time at the rated power of the wind turbine. Since wind is intermittent, and wind speeds vary greatly over time, the capacity factor for wind is generally less than 40 percent. The capacity factor is thus an indicator of how much energy potential wind turbines would have in a given location.

The EWITS database also shows the total power generation potential in each location, based on estimates of optimal wind farm size and other factors. Figure C.2 shows a map of counties by potential total installed power generation potential.

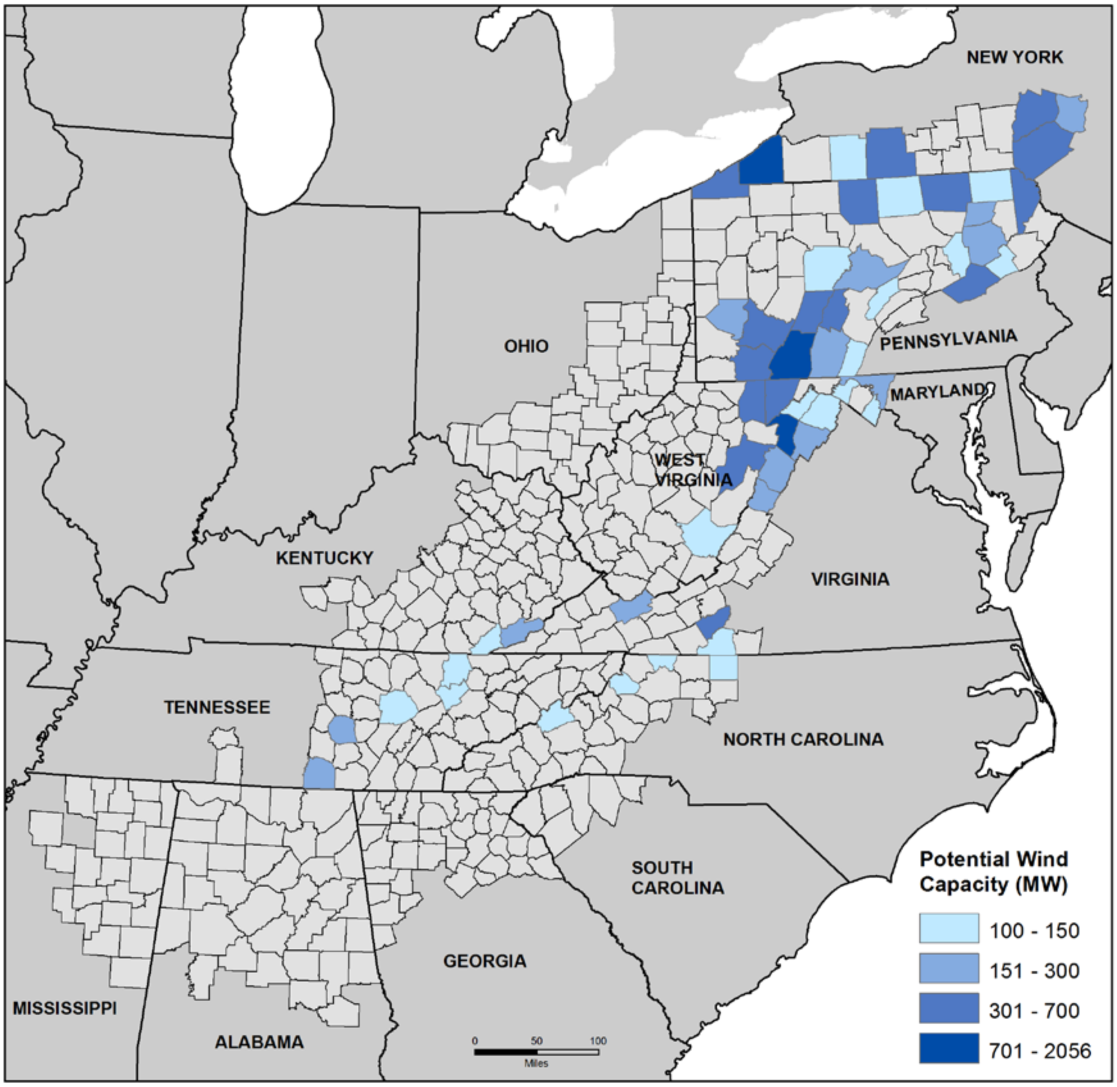
[32] These two documents, related information, maps, data and FAQs can be found at http://www.nrel.gov/wind/systemsintegration/ewits.html.

Figure C.1 Wind Potential in Appalachia Rated by Capacity Factor



Map Title: Wind Power Capacity Factor
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Figure C.2 Wind Capacity Potential by County



Map Title: Potential Wind Capacity (MW)
Data Source: IERF Inc., "ARC Energy Policy Impact Model" prepared under contract #CO-16811-10

Table C.1 summarizes the wind capacity potential, calculated investment cost, and generation potential by county and state. The states within the Appalachian region that have the largest wind potential are Pennsylvania (6.7 GW), New York (3.9 GW) and West Virginia (2.3 GW).

The estimated cost of construction of new wind capacity used for our calculations was 1.9 million 2009 dollars per MW of generation capacity, and an additional 0.2 million 2009 dollars per MW of transmission capacity.[33] These data are summarized by county and state in column 4 of table 8.15. Total estimated investment requirements in Pennsylvania amount to 13.3 billion 2009 dollars.

The last column of table 8.15 shows total power generation potential based on the capacity factor and potential installed capacity at each location. The formula used to make this conversion was:

$$G = CF * C * 365.25 * 24/1000$$

Where G is total potential generation in millions of KWh, CF is the capacity factor, C is the capacity in GW, and the constants 365.25 and 24 refer to the average number of days in a year, and the number of hours in a day. According to these calculations, total potential wind generation attainable in Pennsylvania would be 14.9 billion KWh.

For the CUEPS Clean Energy Standard Scenario, we assume that all of the capacity listed in Table C.1 will be built. Two major questions to address at this point are:

What is the time period over which construction can be expected to occur?

How much local impact will the construction have on the local economies?

We have decided to assume a five-year construction period, lasting from 2013 to 2020, at which point the capacity listed in table is assumed to be in place.

A tool for determining the output and job impacts from wind turbine farm construction is the Jobs and Economic Development Impact (JEDI) models, supported and maintained by the National Renewable Energy Laboratory.[34]

At this stage, we are exploring the JEDI module for the analysis of local impacts of wind power construction. Our next step will be the integration of the outputs of JEDI as assumptions on output and employment changes by county in the CUEPS model.

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[33] These figures are an average of estimates from several sources, including the NEMS documentation for the Renewable Fuels Module in the *Assumptions to the Annual Energy Outlook 2011* (at http://38.96.246.204/forecasts/aeo/assumptions/pdf/0554%282011%29.pdf), p. 168, the EWITS Executive summary, and *Wind Power: Performance and Economics*, Fact Sheet #2 at the Renewable Energy Research Laboratory, at http://www.umass.edu/windenergy/publications/published/communityWindFactSheets/index.html.

[34] The home page for JEDI is http://www.nrel.gov/analysis/jedi

Table C.1. Wind Potential by County and State

State	County	Potential Wind Capacity (MW)	Investment Requirements (Mil. 2009$)	Potential Generation (mil KWh)
Kentucky				
	Bell	100	209	239
	Harlan	200	421	511
		300	630	750
Maryland				
	Garrett	634	1332	1577
	Washington	155	326	348
		789	1658	1925
New York				
	Allegany	127	266	340
	Chautauqua	2056	4317	5384
	Delaware	643	1351	1736
	Otsego	464	974	1318
	Schoharie	222	466	622
	Steuben	376	790	994
		3888	8164	10393
North Carolina				
	Alleghany	100	209	247
	Hyde	127	267	278
	Madison	100	210	276
	Stokes	114	240	269
	Watauga	100	209	230
		541	1136	1300
Pennsylvania				
	Allegheny	161	338	346
	Bedford	154	323	357
	Blair	332	697	829
	Bradford	325	683	751
	Cambria	593	1246	1386
	Carbon	100	210	218
	Centre	150	316	339
	Clearfield	100	210	217
	Columbia	100	210	233
	Erie	580	1217	1266
	Fayette	539	618	622
	Fulton	136	286	312
	Luzerne	199	419	431
	Mifflin	100	420	452
	Potter	301	631	660
	Schuylkill	355	746	805
	Somerset	1220	2562	3238
	Susquehanna	145	304	352
	Tioga	100	210	220
	Wayne	426	895	952
	Westmoreland	316	663	780
	Wyoming	255	536	644
		6687	13285	14937

Table C.1 Wind Potential by County and State (continued)

State	County	Potential Wind Capacity (MW)	Investment Requirements (Mil. 2009$)	Potential Generation (mil KWh)
Tennessee				
	Anderson	114	239	268
	Campbell	100	211	223
	Cumberland	100	210	232
	Franklin	256	537	602
	Warren	216	454	493
		786	1650	1818
Virginia				
	Accomack	111	234	291
	Floyd	572	1201	1337
	Highland	212	444	586
	Patrick	100	210	280
	Tazewell	201	421	490
		1397	2934	3562
West Virginia				
	Grant	710	1490	1994
	Greenbrier	100	211	245
	Hampshire	100	211	268
	Hardy	300	629	889
	Jefferson	102	213	286
	Mineral	114	452	598
	Morgan	127	267	320
	Pendleton	200	420	619
	Preston	423	889	1034
	Randolph	302	633	763
		2275	4778	6152
Appalachia Total		**16663**	**34235**	**40837**

C.2 Derivation of Biomass Assumptions

In the Clean Energy Standard scenario, the modeling team adopted national biomass power generation assumptions from the EIA's *Analysis of Impacts of a Clean Energy Standard as requested by Chairman Hall*. In this analysis, EIA assumes virtually no increase in the construction of or power generation from dedicated biomass power plants. They do, however, project a major increase in the cofiring of biomass with coal at the nation's coal-fired power plants. Overall, they project the most co-fired power plants will be fueled by a 15% biomass/85% coal fuel mixture, a level that is broadly considered the maximum biomass content that could be burned efficiently at those plants without dramatically increasing the associated investment costs that would be needed at a plant in order to facilitate biomass co-firing.

Based on these projections, the biomass portion of the fuel mix at existing coal-fired power plants is projected to grow to 11% by 2020 and reach 15% in 2025. It was also assumed that coal-fired power plants would need to invest $200 per kW of capacity between now and 2025 in order to facilitate biomass co-firing, based on the EIA's cost estimates of $123 to $282 per kilowatt.

County-level biomass supplies were estimated by using the county-level data from the Department of Energy's *Billion Ton Study Update*[35]. Non-cellulosic resources such as grains, animal fat, and animal wastes were assumed to be used for other purposes and cellulosic mill residues were assumed to be used for power production by end users such as paper manufacturers. The remaining biomass resources that were assumed to be available for either cellulosic biofuels production or electricity production include annual energy crops, perennial grasses, other woody agricultural crops, forestry resources, urban wood waste, and agricultural residues such as corn stover. County-level supplies were then calculated by summing all of the cellulosic biomass resources available in each county in for all years from 2012-2030 at $10 per ton increments from $10 to $200, with more and more resources becoming accessible at higher biomass price levels. The county-level biomass resource estimates were summed for 22 regions that correspond to NEMS's Electricity Market Module (EMM) regions. Because these regions do not align with state borders, the modeling team used GIS software in order to approximate which counties are within each region.

Demand in each of these 22 regions was then calculated using the regional cellulosic ethanol production and biomass electricity projections from the 2011 AEO Reference case and a few core assumptions. The assumptions included:

1. Each ton of biomass had energy content of biomass equal to 16 mmBtus, the assumption used in the *Billion Ton Study Update,* and
2. Coal-fired power plants could convert biomass into electricity with an efficiency of nearly 33%, the average efficiency used by the EIA in their analyses.

After calculating demand for biomass in each of the 22 regions, the modeling team determined the price at which each region could supply sufficient biomass resources for each year and then reduced the amount of biomass resources estimated to be available for cellulosic ethanol production.

[35] See https://bioenergykdf.net/content/billiontonupdate

The remaining amounts of biomass available were then summed for each price level and year and compared with the amount of biomass needed to produce cellulosic ethanol at the levels projected in the AEO Reference case. The demand from the ethanol industry assumed a conversion efficiency from cellulosic biomass feedstock into ethanol of 28 percent, the same efficiency assumption that the EIA uses. The modeling team then estimated the lowest biomass price at which the remaining biomass resources would be sufficient to supply the cellulosic ethanol industry and further reduced available biomass supplies by that amount in the EMM regions that were able to provide resources at that price. In addition an average biomass transportation cost of $18 per ton was added to the biomass price in each region to account for the transportation of biomass within a region.

Some EMM regions were estimated to be unable to produce sufficient biomass resources to supply electric power sector demand for biomass in the region at a reasonable price. The modeling team assumed that these regions could obtain fill the gap between biomass demand and supply by purchasing excess biomass resources from other regions but that they would have to pay an additional $30 per ton of biomass for the additional cost of transporting the resources to the region. The regions that were able to contribute still more biomass resources at the lowest prices were then assumed to export the resources to the EMM regions that were unable to supply their own power sectors.

Revenues from biomass production were then calculated by multiplying the regional price, which varied from $30 to $70 per metric ton in the Reference case, and the amount supplied by each region. These amounts were summed to reflect the biomass revenues collected by the agriculture and forestry industry at the national level. The amounts were also shared down to the county level based on the available supplies in each county at the projected county-level biomass price.

These same calculations were repeated for the clean energy standard scenario, which, as explained above, includes significantly more biomass co-firing at coal-fired power plants than the Reference case does. This drives the demand for biomass resources up significantly as well as the price of biomass in many regions. The resulting increases in biomass production and prices were modeled as transfers from the utility industry to the agriculture and forestry industries. Transportation costs were represented as transfers from the utility sector to the trucking and rail industries.

Figures C.3 to C.6 show the estimated biomass potential by Appalachian county at different biomass prices, from $20/ton to $200/ton.

Figure C.3 Biomass Potential at $20/ton

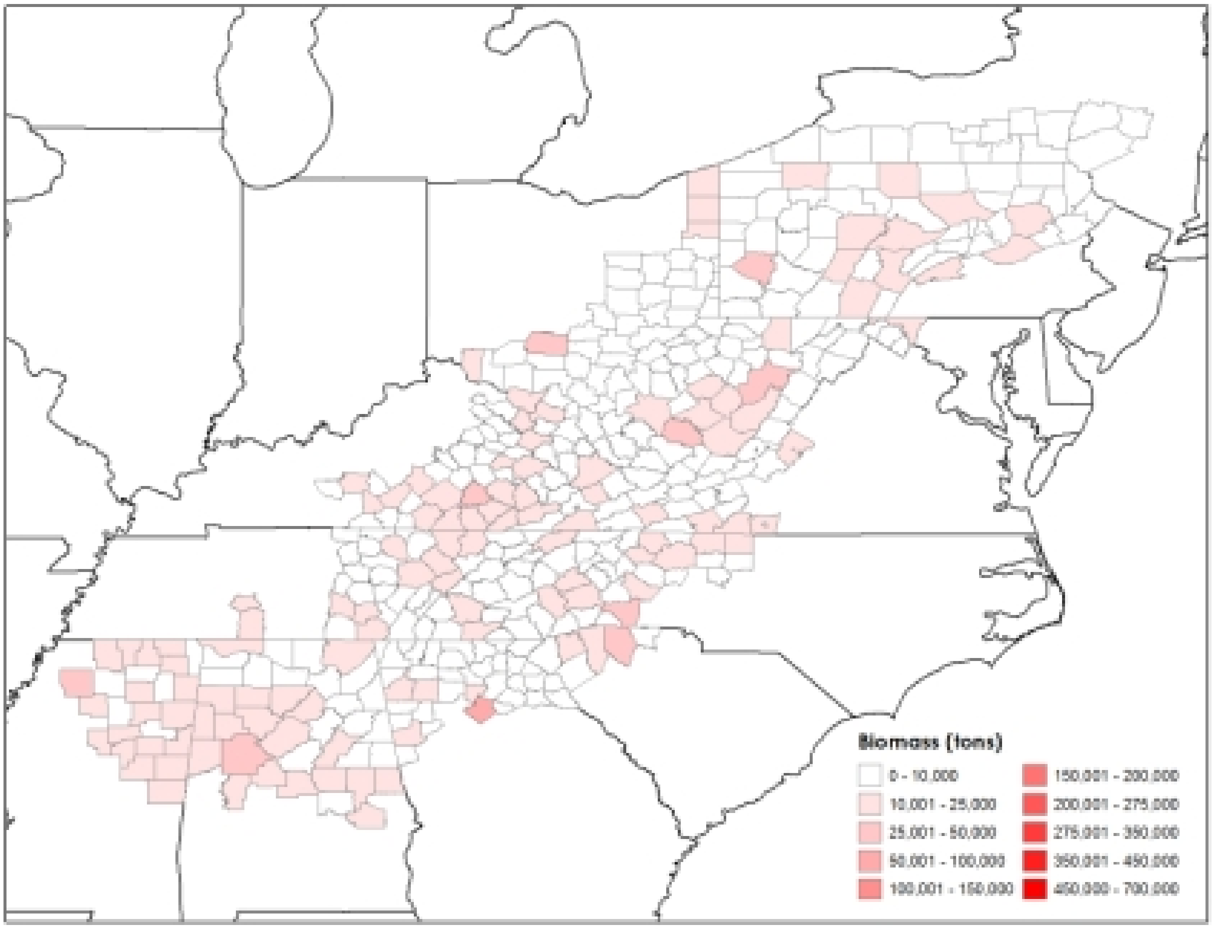


Figure C.4 Biomass Potential at $60/ton

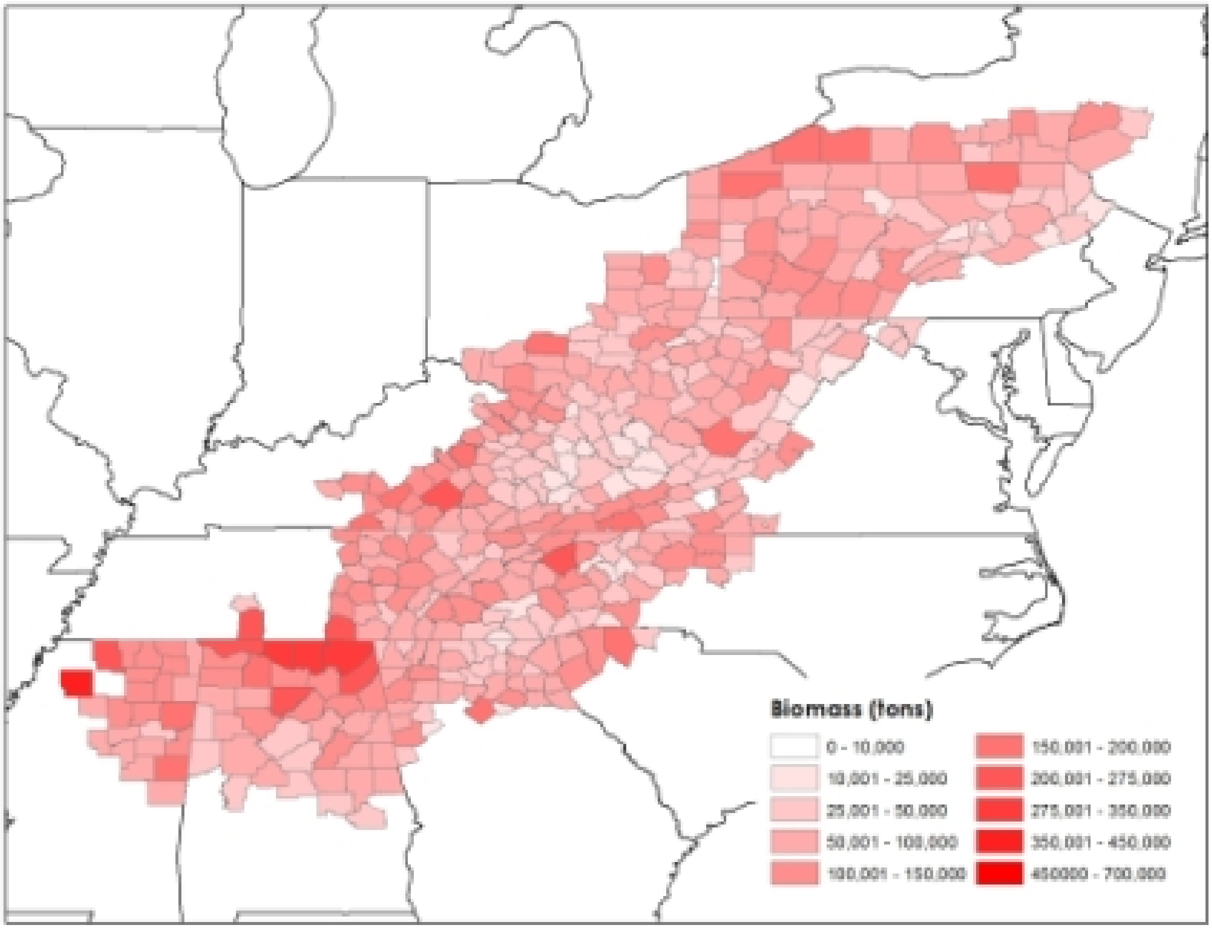


Figure C.5 Biomass Potential at $100/ton

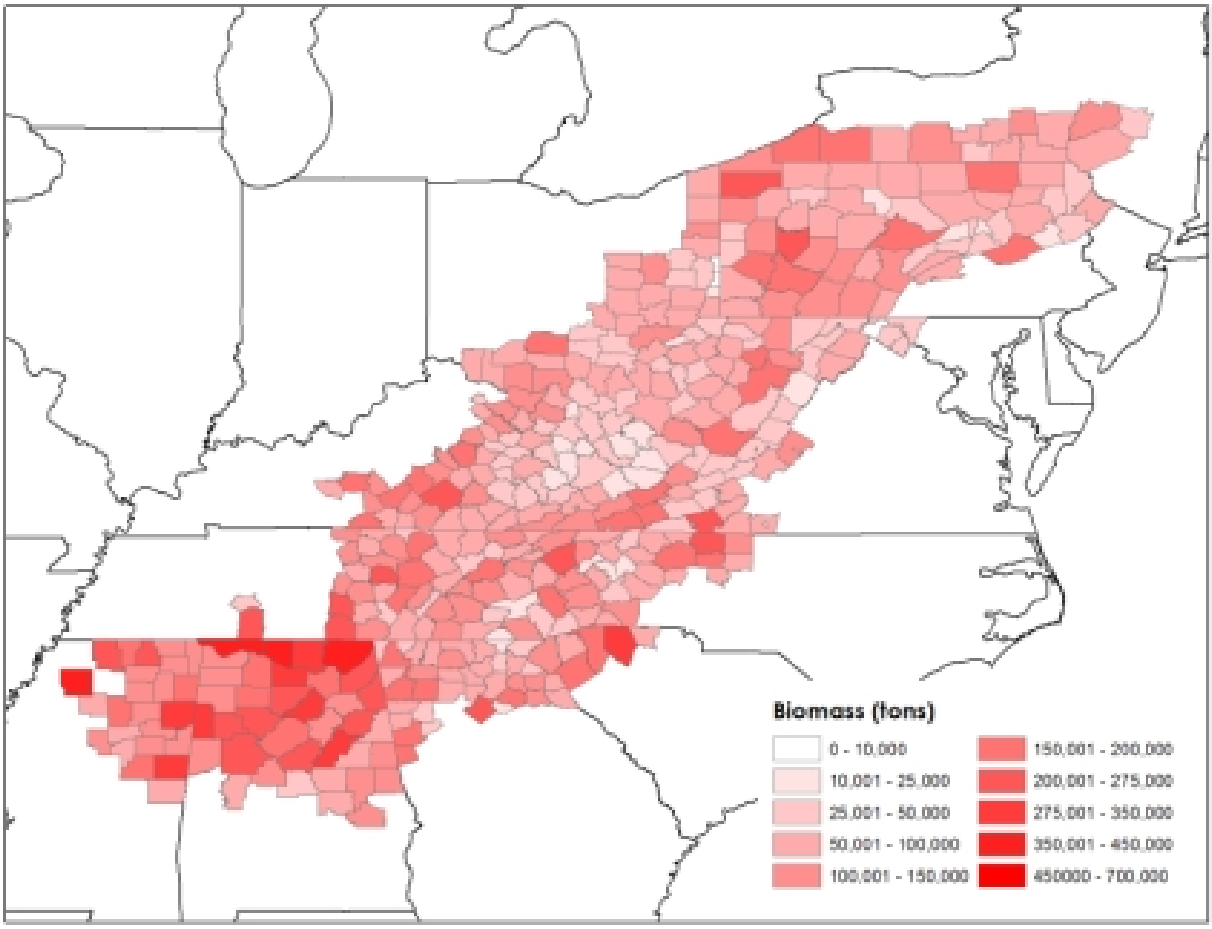
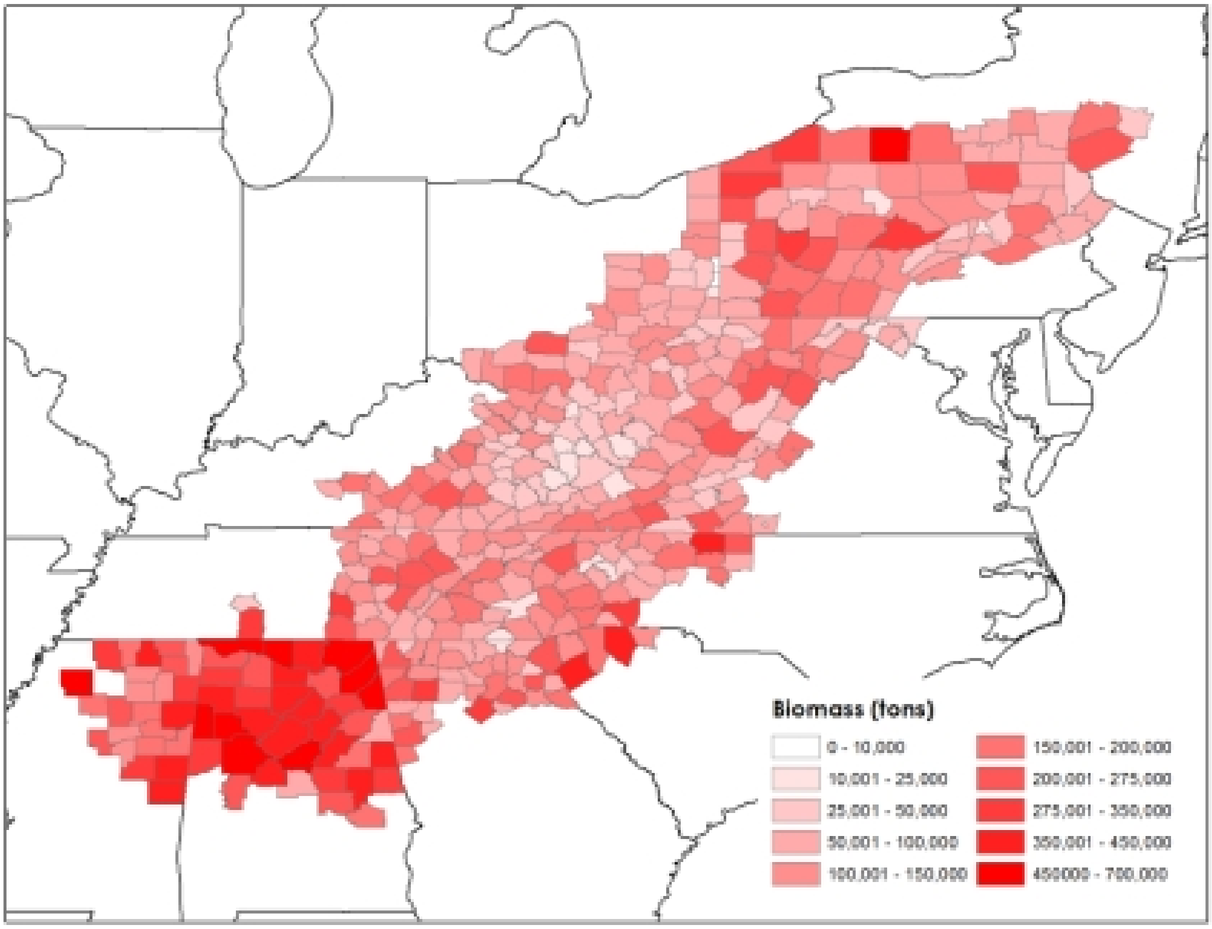


Figure C.6 Biomass Potential at $200/ton



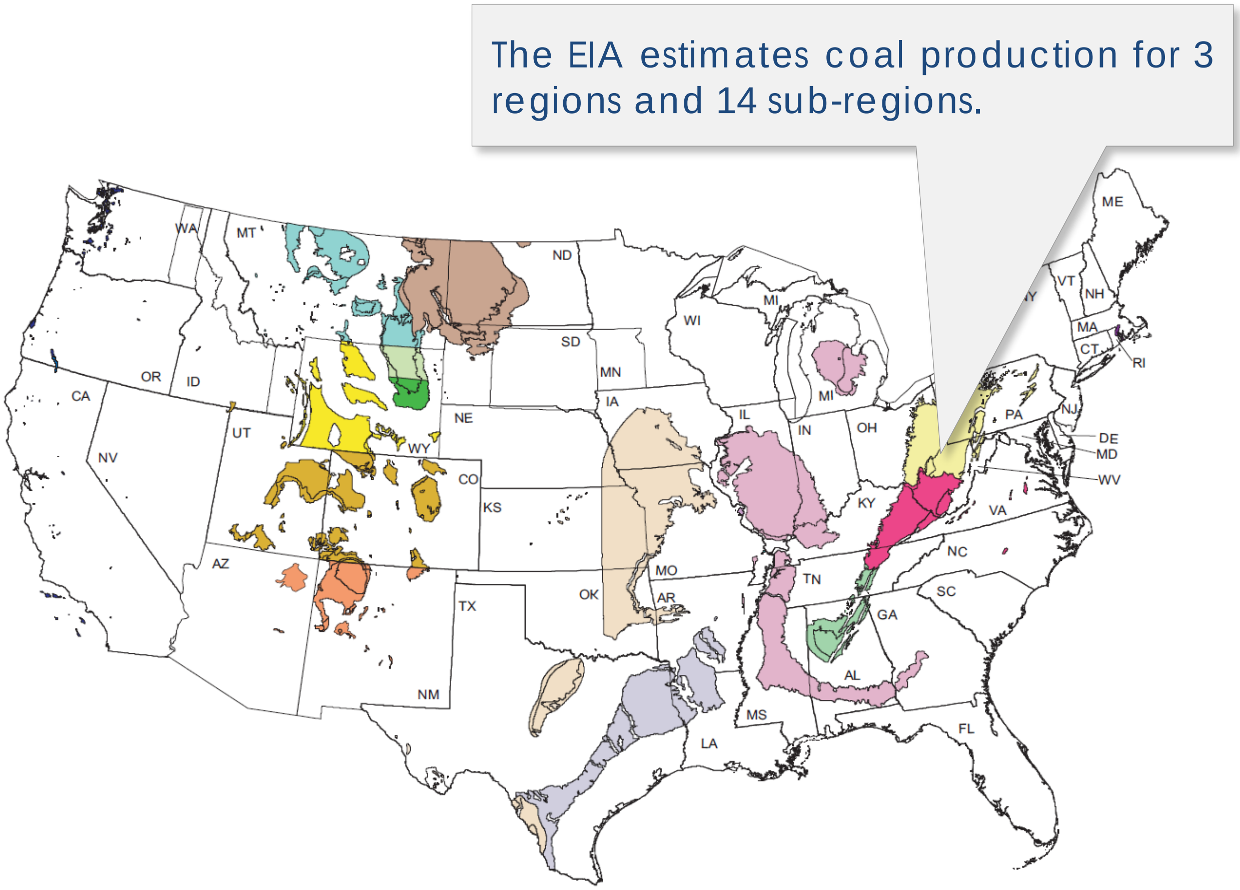
Appendix D. Coal Estimates for Appalachia

Like other variables, coal production in the Reference case was calibrated to the levels projected in the EIA's 2011 Annual Energy Outlook Reference case. The EIA divides coal production into three coal producing regions and various sub-regions. Based on these regions and sub-regions, CUPS assigns coal-producing counties to one of 5 regions/sub-regions: Northern, Central, and Southern Appalachia, Interior U.S. (includes the Great Plains non-Appalachian parts of the Midwest and South), and Western U.S.. Coal production for all counties in each of these five regions was calibrated to equal the total in the AEO Reference Case and, within those regions, shares of those totals were estimated using 2009 county-level coal production data from the EIA.

In the alternative scenarios it was assumed that additional electricity production from alternative resources – efficiency, wind, biomass, and gas – would displace coal-fired power production. The impact on coal production was estimated by using projections from the EIA's Analysis of Impacts of a Clean Energy Standard as requested by Chairman Hall. Elasticities of coal fired power production in regional electricity markets to regional coal production were calculated from the EIA's Reference and CES-Hall scenarios and then applied in CUPS. Important regional differences in the EIA's projected impacts on coal production were then captured within CUPS.

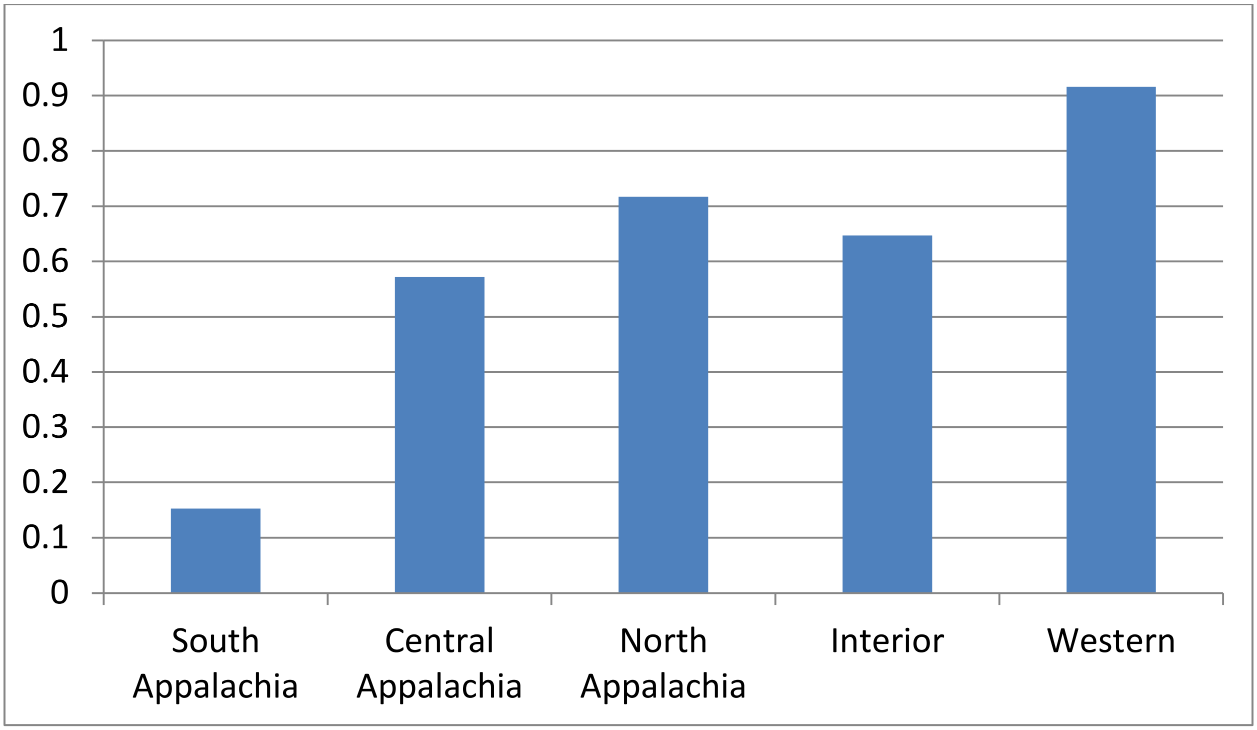
In particular, the EIA estimates that reductions in coal demand from the power sector would have milder economic impacts on the Appalachian coal industry than it would have on the Western coal production. This is driven by the fact that much of the coal produced in Appalachia's is metallurgical coal that is either used in the domestic steel industry or exported. The EIA estimates that production of this type of coal would be largely unaffected by a domestic policy aimed at the power sector. The EIA's projections are that Southern Appalachian coal production would be the least impacted by reductions in demand from the power sector, followed by Central Appalachia, the Interior, Northern Appalachia, and Western U.S.

Figure D.1 EIA Coal Estimates



EIA's modeling results provided a basis for differentiating coal production by region, with Southern Appalachian production being the least impacted.

Figure D.2 Coal Production by Region



Regional coal impacts were then further broken down to the county level using 2009 county-level production data.

Figure D.3 County Level Coal Production