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Energy Economics, Inc.

Economic Impacts of Restricting Mountaintop/Valley Fill Coal Mining in Central Appalachia

August 25, 2009

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1. Introduction

This report focuses on the potential economic impacts of restrictions on mountaintop/valley fill coal mining in Central Appalachia, consistent with the subject of the 2003 draft Environmental Impact Statement (EIS).[1] While this issue has been examined previously in the draft EIS and elsewhere, prevailing economic conditions have changed dramatically over the course of the decade. A number of trends are affecting and will continue to affect the outlook for coal in general, including lower than previously expected natural gas prices, high risk associated with investments in new coal-fired power plants, expanded investments for energy efficiency and renewable resources, and federal regulation of greenhouse gas emissions.

This report does not seek to evaluate the costs and benefits of coal or of coal mining in general. As a starting point, this report recognizes that the nation obtains a large portion of its energy supply from coal, and that shifting to other energy sources will take time. Rather, it explores how electricity markets and regional economies would be affected by restrictions on a specific type of coal mining—mountaintop/valley fill mining. We find that alternative sources of electricity and alternative sources of coal are economic and available for serving electric load in the East. In the short run, a decrease in coal production in Central Appalachia will lead to an increase in mining elsewhere. However, all sources of coal are facing a decline in the demand for coal in the coming months and years. For these and other reasons, we expect that the impact on regional electricity markets is likely to be relatively small, although modeling is needed to pinpoint the magnitude of these impacts.

The net effect of restrictions on mountaintop removal on the Central Appalachian economy is uncertain, but a growing body of evidence suggests that the region's dependence on coal for jobs has not proved a boon. Economic diversification in Central Appalachia would promote a healthier, more stable economy. Research continues to shed more light on the economic and health costs of coal mining.

This study does not attempt to conduct a full accounting of the costs and benefits of mountaintop/valley fill coal mining techniques in Central Appalachia. Instead, this report seeks to identify costs and benefits that should be analyzed or re-analyzed in the context of the current economic and political reality facing the coal industry, and the communities dependant on coal mining employment. These realities suggest, however, that allowing the continued extraction of coal

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1 While mountaintop removal has been the focus of previous research, we consider all surface mining methods consistent with data availability from EIA and because, to varying degrees, all of the surface methods have large amounts of overburden that is frequently disposed of in valleys and waterways.
The emphasis on mountaintop/valley fill mining should not be construed to mean that other mining techniques are socially desirable or have positive net economic benefits when climate change impacts, damage to water resources, worker health costs, air emissions from coal mining and combustion, foregone alternative land uses, among other costs, are considered. We have not assessed the costs and benefits of other mining techniques.

using extremely environmentally-destructive mining techniques would be highly inconsistent with the Obama administration's stated policy of reducing greenhouse gas emissions and would be unwise given impending carbon regulations.

2. Impacts of Regulation of Carbon Dioxide on the Demand for Coal

A comprehensive system for federal regulation of carbon dioxide (CO_2) and other greenhouse gas emissions is inevitable, and it is generally expected that steep emissions reductions will be required over the coming decades. There are two likely avenues for this federal regulation of greenhouse gases. Congress could pass legislation, or the U.S. Environmental Protection Agency could adopt regulations to limit greenhouse gas emissions. Both paths are currently under active consideration.

Leaders in both the House and Senate are pursuing plans for aggressive legislative action on climate change during this session. To date, the most substantive legislative proposal is the Waxman-Markey bill that was recently approved by the House of Representatives. This bill would mandate the following greenhouse gas reduction targets:

- 2020 – 83 percent of 2005 emission levels
- 2050 – 17 percent of 2005 emission levels

While Congress debates climate change legislation, the EPA is poised to take the next step towards regulating greenhouse gases (GHG) under the Clean Air Act. In 2007, the U.S. Supreme Court determined that carbon dioxide is an "air pollutant" under the Clean Air Act, and that EPA has the authority to regulate it.[2] The EPA has now circulated its draft finding, for public comment, that greenhouse gas emissions endanger public health and welfare.[3] The EPA recently indicated that permits for new and modified power plants could set limits on GHG emissions as soon as March 2010, based on EPA's pending rule on vehicular GHG emissions that defines these gases as regulated under the Clean Air Act.[4] The Obama Administration has stated its preference for a legislative solution to addressing climate change; however, EPA's regulatory authority provides an alternate option should Congress fail to act.

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2 In this case, Massachusetts and 11 other states sued the US EPA for failing to regulate greenhouse gas emissions from the transportation sector. The Court found that EPA has the authority and the obligation to regulation greenhouse gas emissions. The court found that EPA's refusal to do so or to provide a reasonable explanation of why it could not regulate was arbitrary, capricious and otherwise not in accordance with law. The Supreme Court also found that the "harms associated with climate change are serious and well recognized."

3 "White House begins review of EPA endangerment proposal," Greenwire, March 23, 2009.

4 "EPA Vehicle Rule to Trigger Stationary Source GHG Limits," CantorCO2e, August 25, 2009.

The Obama Administration indicated in its recently released Federal budget that it would seek to establish a cap-and-trade system to reduce greenhouse gas emissions to 14 percent below 2005 levels by 2020 and to 83 percent below 2005 levels by 2050. These levels are comparable to the reductions that would be mandated under the Waxman-Markey bill passed by the House of Representatives.

It is reasonable to expect that these reductions in allowed CO_2 emissions will lead to reduced burning of coal, the most carbon intensive fuel, absent development of carbon capture and sequestration technology as a "silver bullet" that could allow the continued burning of coal at or near current levels. For example, a study of the Waxman-Markey bill for the National Mining Association reported that even under a set of "optimistic" assumptions that minimized the impact of the Waxman-Markey bill on the coal industry, the use of coal would decline by more than 10-15 percent from today's coal use by 2030; under a more "pessimistic" set of assumptions, the use of coal would decline to less than 25 percent of today's levels by 2030.[5]

3. Electricity Market Impacts from Restricting Surface Mining in Central Appalachia

There is no evidence that eliminating surface-mining of Central Appalachian coal will cause the lights to go out or electricity prices to significantly increase in the east. In fact:

- the demand for coal for electricity generation is likely to decrease in the short and long run, and
- there are economically attractive alternatives to burning Appalachian mountain top/valley fill mined coal for electricity supply.

Projected Demand for Coal

The demand for coal for electricity generation is likely to decrease in both the short and long run. In the short term, because gas prices are low, gas-fired generating units are being run more frequently and are displacing coal-fired plants, especially in the southeast. As reported in a Market Commentary in *Coal & Energy Price Report*:

> "It's clear what people are doing. They are basically turning off coal-fired stations and running combined cycle turbine units because gas is so cheap, and they don't need coal stations to run better than 50-60 percent, so they are turning the whole thing off."[6]

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5 http://www.nma.org/pdf/062409_2454.pdf.

6 *Coal & Energy Price Report*, Volume 11, No. 106, June 2, 2009.

The same June 2009 Market Commentary also quoted an unnamed source as believing that the displacement of coal by gas has been greater than many in the industry believe:

> "It's replacing coal," the source said. "These utilities must be doing it every which way but Sunday. No one will confirm it. No one will quantify it."

The U.S. Department of Energy has agreed:

> Over the last year, the price of natural gas delivered to electric generators has fallen dramatically. Current natural gas prices now present increased potential for displacing coal-fired electricity generation with natural gas-fired generation.[7]

This displacement of coal plants by gas-fired units can be expected to continue because gas prices are projected to remain reasonably low for the foreseeable future. Indeed, a growing number of utilities and forecasts have noted a structural change in the natural gas markets over the last year. For example, Entergy Louisiana, in announcing that it was suspending construction of a new coal-fired power plant, explained in some detail the structural changes in the natural gas market that had led to the expectation that future gas prices would be much lower than previously anticipated:

> Until very recently, natural gas prices were expected to increase substantially in future years. For the decade prior to 2000, natural gas prices averaged below $3.00/mmBtu (2006$). From 2000 through May 2007, prices increased to an average of about $6.00/mmBtu (2006$). This rise in prices reflected increasing natural gas demand, primarily in the power sector, and increasingly tighter supplies. The upward trend in natural gas prices continued into the summer of 2008 when Henry Hub prices reached a high of $131.32/mmBtu (nominal). The decline in natural gas prices since the summer of 2008 reflects, in part, a reduction in demand resulting from the downturn in the U.S. economy.
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> However, the decline also reflects other factors, which have implications for long-term gas prices. During 2008, there occurred a seismic shift in the North American gas market. "Non-conventional gas" – so called because it involves the extraction of gas sources that previously were non-economic or technically difficult to extract – emerged as an economic source of long-term supply. While the existence of non-conventional natural gas deposits within North America was well established prior to this time, the ability to extract

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[7] *The Implications of Lower Natural Gas Prices for the Electric Generation Mix in the Southeast*, U.S. Energy Information Administration, May 2009. Available at www.eia.doe.gov.

> supplies economically in large volumes was not. The recent success of non-conventional gas exploration techniques (e.g., fracturing, horizontal drilling) has altered the supply-side fundamentals such that there now exists an expectation of much greater supplies of economically priced natural gas in the long-run….
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> *   *   *   *
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> Of course, it should be noted that it is not possible to predict natural gas prices with any degree of certainty, and [Entergy Louisiana] cannot know whether gas prices may rise again. Rather, based upon the best available information today, it appears that gas prices will not reach previous levels for a sustained period of time because of the newly discovered ability to produce gas through non-traditional recovery methods…[8]

Entergy's conclusion that there has been a recent seismic shift in the domestic natural gas industry was confirmed in early June 2009 by the release of a report by the Potential Gas Committee, the authority on gas supplies. This report concluded that the natural gas reserves in the United States are 35 percent higher than previously believed. The new estimates show "an exceptionally strong and optimistic gas supply picture for the nation," according to a summary of the report.[9] The existence of higher reserves and the new recovery techniques discussed by Entergy support the conclusion that future natural gas prices should not be nearly as high as was forecast last year or even earlier this year.

Over the longer term, as discussed above, coal demand is likely to be reduced as greenhouse gas emissions reductions are mandated. At the same time, new coal plants are increasingly seen as risky investments.[10] In fact, more than 90 proposed coal plants have been cancelled, extensively delayed or have been rejected by state regulatory commissions since 2002 due to concerns over construction costs and the impending federal regulation of greenhouse gas emissions. The lower natural gas prices, discussed above, are another recent development that has pushed utilities to cancel or delay proposed coal plants and to instead build new gas-fired units instead.

For example, in February 2009, NV Energy, Inc. announced the postponement, due to increasing environmental and economic uncertainties, of its plans to construct a coal-fired power plant in East Nevada. The company has said that it will not proceed with construction of the coal plant until the technologies that will capture and store greenhouse gasses are commercially feasible, which it believes is not likely before the end of the next decade.[11] Similarly, in early

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8 Id, at pages 17, 18 and 22.

9 *Estimate Places Natural Gas Reserves 35 percent Higher*, New York Times, June 9, 2009.

10 *Don't Get Burned: The Risks of Investing in New Coal Plants*, February 2008*. Available at www.synapse-energy.com.*

11 http://www.lasvegassun.com/news/2009/feb/09/nv-energy-postponing-big-coal-fired-plant-near-ely/.

March 2009, Alliant Energy cancelled its plan to build a proposed 649 MW coal-fired plant in Marshalltown, Iowa. According to Alliant, the decision to cancel the project was based on a combination of factors including "the current economic and financial climate; increasing environmental, legislative and regulatory uncertainty regarding regulation of future greenhouse gas emissions" and the terms placed on the proposed power plant by regulators.[12]

State regulators have cited several reasons for rejecting permits and rate recovery for proposed coal plants. For example, the July 2007 decision of the Florida Public Service Commission denying approval for the 1,960 MW Glades Power Project was based on concern over the uncertainties of plant construction costs, coal and natural gas prices, and future environmental costs, including carbon allowance costs.[13]

In April of 2008, the Virginia State Corporation Commission rejected rate recovery for a proposed coal plant citing uncertainties of costs, technology, and unknown federal mandates.[14] The Commission concluded that "… [Appalachian Power Company] has no fixed price contract for any appreciable portion of the total construction costs; there are no meaningful price or performance guarantees or controls for this project at this time. This represents an extraordinary risk that we cannot allow the ratepayers of Virginia in [Appalachian Power Company's] service territory to assume."[15] The Commission also noted the uncertainties surrounding federal regulation of carbon emissions, and carbon capture and sequestration technology and costs, and observed that the Company was asking for a "blank check."[16] On this basis, the Commission concluded that "We cannot ask Virginia ratepayers to bear the enormous costs – and potentially huge costs – of these uncertainties in the context of the specific Application before us."[17]

In November 2008, the Public Service Commission of Wisconsin rejected the proposed 300 MW (net) Nelson E. Dewey CFB coal-fired power plant. The Commission decided that the $1.26 billion project was too costly when weighing it against other alternatives such as natural gas generation and the possibility of purchasing power from existing sources.[18] The Commission also said that "Concerns over construction costs and uncertainty over the costs of complying with future possible carbon dioxide regulations were all contributing factors to the denial."[19]

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12 http://www.alliantenergy.com/Newsroom/RecentPressReleases/023120.

13 Florida Public Service Commission, Order No. PSC-07-0557-FOF-EI, Docket No. 070098-EI, July 2, 2007.

14 Final Order in Case No. PUE-2007-00068, April 14, 2008. Available at http://scc.virginia.gov/newsrel/e_apfrate_08.aspx.

15 Id, at page 5.

16 Id, at page 10.

17 Id, at page 10.

18 The estimated cost of the proposed coal plant was $1.26 billion for a 326 MW facility.

19 *PSC Rejects Wisconsin Power & Light's Proposed Coal Plant*, issued by the Public Service Commission of Wisconsin on November 11, 2008.

At the same time that investments in new coal plants have become more risky, an increasing number of states have adopted renewable portfolio standards and energy efficiency goals that will further dampen the demand for power from coal-fired power plants. For example, the State of New York is implementing a "15 by 15" Clean Energy Plan to reduce energy consumption in 2015 by 15 percent to be achieved by energy efficiency alone.[20] The State also has adopted a plan to obtain 25 percent of its electricity from renewable resources by 2013.[21]

In summary, then, it is reasonable to expect that the demand for coal will decrease during future years due to federal regulation of greenhouse gas emissions, lower than previously expected natural gas prices, the riskiness of investments in new coal-fired power plants, and expanded investments for energy efficiency and renewable resources.

Coal Cost Impact on Wholesale Electricity Prices

Quantifying the impact of prohibiting mountaintop/valley fill mining in Central Appalachia on the price of coal and wholesale power prices is beyond the scope and capability of a limited assessment like this. A detailed simulation model, such as the U.S. Department of Energy's NEMS model with its coal database, is needed. Previous attempts to quantify the magnitude of these effects are outdated, and these studies have unresolved methodological issues. It is worth noting, however, that a thorough (but flawed) attempt to analyze these impacts for the 2003 EIS found that coal prices in the study region (Eastern KY, VA, and WV) would be only 5% higher in the case with restrictions on valley fill to watersheds of less than 75 acres versus the base case in 2010, at the end of the 10 year period of analysis.[22]

The impact of such an increase in the price of some of the coal mined in Appalachia would vary depending on whether plants can find alternative sources of coal and on whether the plant is located in areas of the nation where wholesale electricity markets have been deregulated.

Regulated Markets

If the plant is located in a region in which wholesale electricity markets have not been deregulated, the coal price increases are likely to be passed along to consumers whenever the plant's owner next seeks a rate increase or through an automatic fuel adjustment clause. However, any coal price increase will be blended in with increases and decreases in the prices of other fuels and/or other operating expenses and capital expenditures. Moreover, the plant at which the higher cost coal is being burned will be only one of the plants in the region being used to generate power – thus the utility or regional fuel mix will be important in

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20 Remarks by Governor Eliot Spitzer. "15 by 15": A Clean Energy Strategy for New York. 19 Apr 2007. Found at: http://www.state.ny.us/governor/keydocs/0419071_speech.html

21 Available from http://www.ny.gov/governor/press/lt_conservation.html.

22 Hill & Associates. Final Report on the Coordinated Review of Mountaintop Mining/Valley Fill EIS Economic Studies. Jan 13, 2003.

determining the impact of a coal price increase on power prices. Consequently, any increase in some coal prices (as a result of the prohibition of mountaintop/valley fill mining in Appalachia), can reasonably be expected to result in a substantially smaller overall price increase for consumers. The 2003 Hill & Associates sensitivity analysis projected that the weighted average wholesale electricity price in Eastern KY, VA, and WV (which remain regulated) would be only a fraction of a percent higher in the case with restrictions on valley fill to watersheds of less than 75 acres versus the base case. Also, the cost of fuel is only a modest component in the total cost of electricity paid by the end-users, typically less than half. Thus any percentage increase in the cost of coal will be a much smaller percentage increase in the cost of electricity.

Deregulated Markets

Translating any increase in the price of coal into an impact on the price of power in a deregulated market environment (such as in PJM, the Midwest ISO, New York and New England) is more complicated than in a regulated environment. In a deregulated wholesale electricity market, the impact of an increase in the cost of power from coal plants depends on how often these units have the highest accepted bid, thereby setting the price of electricity for all units that are providing power to loads in the market in that time interval. The unit(s) that set the price of electricity are referred to as “marginal” units, or units that are “on the margin”. Although the extent to which fuel prices will impact wholesale electricity prices requires unit dispatch modeling, it is very unlikely that the entire increase in the cost of power from coal plants will flow through to electricity consumers via wholesale electricity prices. A non-coal-fired unit may have costs that are just higher than the previously-marginal coal plant’s costs but lower than the previously-marginal coal plant’s costs would be after the fuel price increase. When operating, this other unit would emerge as the marginal unit during the time intervals that the coal unit would have been on the margin but for the increase in coal prices. Again, the wholesale electricity cost only represents about half of the price paid by consumers, so any percentage increases will be smaller.

To shed light on whether Central Appalachian mountaintop/valley fill mined coal is being burned at plants that are on the margin in these ISOs, we reviewed coal receipt data from the U.S. Energy Information Administration’s (EIA) utility and non-utility fuel receipts database. Form EIA-923 is mandatory for grid-connected electric power plants and combined-heat-and-power plants with a total generator nameplate capacity of 1 megawatt (MW) or greater, although individual reporting is incomplete in some cases. Because changes in dispatch can have substantial impacts on the price of electricity, a thorough analysis of the likely changes in dispatch should be conducted using an integrated dispatch model. It also is important to note that the data in the EIA fuel receipts database do not distinguish between different forms of surface mining. In this report, data on all surface mined coal is used to estimate the maximum number of generating units that could be impacted by eliminating mountaintop/valley fill mining.

PJM

In PJM, we estimate that plants that received Central Appalachian surface-mined and mixed surface- and underground-mined coals were only on the margin between 10% and 15% of the time in 2008.[23] The low end of the range (10%) reflects known receipts of surface-mined or mixed-mined Central Appalachian coal, by units for which operating data exist in EPA's Clean Air Markets database (CAMD) and could be matched to plants in the EIA 923 fuel receipts database.[24] The high end of the range includes estimated hours for units that do not appear in EIA's fuel receipts database, as well as for plants in PJM that have coal receipts that are not distinguished by mining method and/or mine source in the EIA data. The high end of the range, 15%, is very unlikely, because it assumes that *all* coal receipts without an identified source and/or method in the EIA data, *and, all* records from the EIA database that could not be matched to CAMD data, represent Central Appalachian surface-mined coal.

ISO New England

In ISO New England, coal units were on the margin on 11% of the time in 2006.[25] Generation by units burning Central Appalachian coal represent only a subset of that 11%, and surface-mined Central Appalachian coal represents an even smaller number. EIA's utility and non-utility fuel receipts data for 2008 contain no records of receipts of Central Appalachian surface mined coal by plants in ISO New England.[26] If we assume that all coal receipts by ISO New England plants for which no state of origin was identified comes from Central Appalachia, between 9% and 14% of all coal receipts (by weight) by these plants *could conceivably* be from Central Appalachian mines, either surface or deep.[27] Thus,

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23 For this analysis, units were identified as being on the margin based on their operational behavior during 2008. Methodology for approximating which units are marginal (i.e., "load-following") are discussed in Ezra D. Hausman, Jeremy Fisher, and Bruce Biewald, *Analysis of Indirect Emissions Benefits of Wind, Landfill Gas, and Municipal Solid Waste Generation*, July 23 2008.
Many of the fuel purchases in the EIA 923 database report a blend of underground and surface mined coals. EIA assumes that that the ratio for blends reported as Surface/Underground ("SU") and Underground/Surface ("US") is 0.67/0.33. To be conservative, in this report blended purchases have been included in surface mined coals to ascertain the high end of possible impacts. Because some amount of underground-mined coal was included in the blended purchases, the marginal plant estimate of 10% is likely higher than in reality. (U.S. Energy Information Administration Form EIA-923. Power Plant Operations Report Instructions. http://www.eia.doe.gov/cneaf/electricity/forms/eia923.pdf)

24 Small units (<40 MW) are not included in the Clean Air Markets database.
As of the writing of this report, EIA fuel receipts data for 2008 are preliminary. These data do not yet include fuel receipts by units only subject to annual report requirements. Form EIA-923 is also not required for electric power plants and CHP plants that have a total generator nameplate capacity (sum for generators at a single site) of less than 1 megawatt (MW); or for units that are not connected to the local or regional electric power grid. While there is no way to tell whether their sources of coal would differ from the monthly reporters in any systematic way, these units are smaller and would be unlikely to affect the results significantly. (See U.S. Energy Information Administration Form EIA-923. Power Plant Operations Report Instructions. http://www.eia.doe.gov/cneaf/electricity/forms/eia923.pdf)

25 ISO New England Inc., *2006 New England Marginal Emission Rate Analysis*. September 2008.

26 EIA-923 (Schedule 2) - Monthly Utility and Nonutility Fuel Receipts and Fuel Quality Data, 2008 (preliminary). http://www.eia.doe.gov/cneaf/electricity/page/eia423.html

27 The low end of the range (9%) includes receipts with unknown sources that are likely to be from Central Appalachia, based on supplier. Suppliers considered likely to be obtaining/deriving coal from Central Appalachia include Alpha Coal, Central Appalachia Mining, and Pocohontas/Consol PA Company. The

the plants that could possibly be burning Central Appalachian coal in 2008 were probably on the margin—and setting electricity prices— only a very small portion of the time.[28]

New York ISO

While coal-fired power plants generate much of the electricity in New York State (NY), natural gas and oil units are usually the marginal source of generation and set market clearing prices.[29] Coal or hydro units are more likely to be on the margin in Western NY, where prices are considerably lower than in the load pockets of New York City and Long Island. Based on EIA's utility and non-utility fuel receipts data, the only receipts of Central Appalachian surface mined coal in 2008 for generating units in NY were by Dynegy for its Danskammer Generating Station in Newburgh.[30] The Central Appalachian surface mined coal receipts by Danskammer comprised only 1% of total coal receipts for NY electricity plants. Receipts of coal for which no specific mine source was identified, excluding coal known to be from underground mines, comprise 6% of all reported coal receipts for NY plants, putting the upper bound at 7%. Considering that coal units are infrequently on the margin in NY ISO, the plants that could conceivably have been burning Central Appalachian coal in 2008 were probably on the margin for only a small fraction of the year.

Alternatives to Burning Appalachian Mountaintop/valley fill-mined Coal

There are a number of economically attractive alternatives to combusting Central Appalachian mountaintop/valley fill-mined coal for electricity generation, including energy efficiency, renewable energy, Central Appalachian coal mined using underground methods, and coal from other regions.

Energy Efficiency and Renewable Resources

Energy efficiency has significant potential to help meet energy needs both inside and outside of Central Appalachia. A recent study commissioned by the Appalachian Regional Commission found that "an ambitious package of energy-efficiency policies implemented throughout Appalachia in 2010 could result in

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higher end of the range *excludes* receipts from suppliers that obtain/derive coal from other regions of the US or world. These suppliers include CMC (from Columbia, South America), Colorado Coal, Drummond (Columbia and Alabama), Glencore (South Africa, Australia, Canada, and Columbia), Loveridge, Mina Norde and Pasa Diablo (Venezuela), PT Adaro Indonesia and the Bailey mine. There were no reported receipts of underground-mined coal with an unknown source by plants in New England.

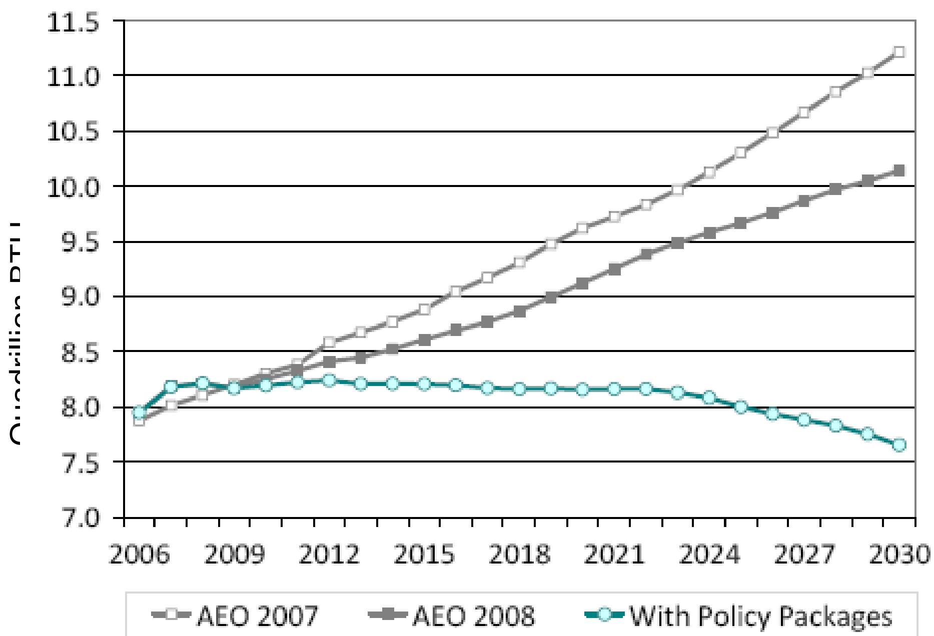
28 If the plants burning coal that does not have an identified source are no more likely to be on the margin in ISO NE than the plants that have identified the specific mine, then the plants that could possibly be burning Central Appalachian coal in 2008 were price-setting for less than 2%of the time. Also, this calculation assumes that New England plants burning Central Appalachian coal were on the margin the same proportion of the time as other New England coal plants. These assumptions are unlikely to have much of an impact on our conclusion that an increase in the cost of power from plants burning Central Appalachian coal would have little effect on overall electricity prices.

29 Potomac Economics, Ltd. *New York ISO 2007 State of the Market Report.*

30 EIA-923 (Schedule 2) - Monthly Utility and Nonutility Fuel Receipts and Fuel Quality Data, 2008 (preliminary). http://www.eia.doe.gov/cneaf/electricity/page/eia423.html

significant energy savings", an estimated 11% in 2020 and 24% in 2030, relative to the EIA "business-as-usual" forecast and "more than offsetting the forecast growth in energy use." Figure 1 shows impacts on energy consumption in Appalachia from implementation of energy efficiency programs and measures, including efficiency in residential and commercial buildings, in industry, and in transportation.[31] On the state level, West Virginia's Division of Energy published a strategic energy plan for the state in December, 2007, stating that "we believe we can become 30% more energy efficient in all sectors by 2030."[32] Renewable resources, including wind along the eastern mountain ridges, low-impact small hydroelectric and forest residue biomass, are likewise underdeveloped.[33]

Figure 1. Potential Displacement of Appalachian Energy Consumption by Cost-Effective Efficiency Resources



Central Appalachian Coal from Underground Mines

Central Appalachian coal mined using underground methods has the potential to replace some of the coal currently mined using mountaintop/valley fill methods. However, the impact on the price of coal from putting an end to Central Appalachian mountaintop/valley fill mining is difficult to estimate, because of the way transportation and sulfur content factors into the delivered price of coal from

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31 According to the study, 68 percent of energy savings potential in Appalachia consists of electricity system efficiency, while motor gasoline consumption by vehicles accounts for 17 percent and natural gas savings potential in the commercial, residential, and industrial sectors accounts for 12 percent. (Marilyn A. Brown, John A. Laitner, Sharon Chandler, Elizabeth D. Kelly, Shruti Vaidyanathan, Vanessa McKinney, Cecelia Logan, and Therese Langer. *Energy Efficiency in Appalachia: How Much More Is Available, at What Cost, and by When?* March 2009. http://www.seealliance.org/pdf/ARC_Final_March09.pdf)

32 West Virginia Division of Energy. *West Virginia Energy Opportunities: A Blueprint for the Future.* http://www.energywv.org/community/EOD.pdf

33 Marshall University Center for Business and Economic Research, *Energy Efficiency and Renewable Energy in Appalachia: Policy and Potential*. August 28, 2006.

alternative sources. Projecting changes in the cost of Central Appalachian deep-mined coal (or coal from other locations, discussed below) and in the cost of electricity in this case would require detailed analyses of the cost of coal from individual mines (which is often not publically available), fuel transportation costs, ability of individual electric plants to switch to coals with different sulfur contents, sulfur dioxide and carbon allowance prices, changes in the price of other generation fuels (largely natural gas), and the extent to which a restriction on mountaintop/valley fill mining would cause a shift to deep mining, among other things.[34] These analyses should estimate impacts on generation dispatch, preferably with a model that considers these interrelated factors simultaneously.

Nevertheless, there are considerable economic deep coal reserves in the region, suggesting that alternative coal sources will emerge to meet coal demand without a substantial increase in electricity prices. For WV as a whole, 2007 estimated recoverable reserves by underground mining are 15,395 million short tons, while surface mining estimated recoverable reserves are only 2,274 million short tons.[35] These reserves have the cost advantage of being close to market, and of having infrastructure already in place.

Coals from other parts of Appalachia, such as Northern Appalachia, represent economically attractive alternatives for many of the power plants serving the load centers in the east. The EIA's Annual Energy Outlook forecasts that demand for Appalachian coal will fall and shift to lower cost production in the northern part of the basin. Indeed, a large percentage of coal received by generators in the East North Central, Middle Atlantic, and South Atlantic already comes from Northern Appalachia. Table 1 shows coal receipts by origin of coal and state of receiving electric plant. Table 2 further breaks down Central Appalachian coal receipts by mine type. Coal mined using mountaintop/valley fill is a subset of surface-mined, surface/underground blended, and underground/surface blended coal.

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[34] The Hill & Associates study cites confidential industry sources as supporting a claim that a decrease in surface mining could make some deep mining uneconomic, because of shared transportation, blending of different coal qualities (e.g., sulfur content, heat rate), and, to a lesser extent, other shared site development costs (e.g., washing facilities). (See Mark Burton, Michael Hicks and Calvin Kent, *Coal Production Forecasts and Economic Impact Simulations in Southern West Virginia*, June 2000, which concludes that these "economies of scope" exist.) However, from a review of literature, we were unable to find studies on the magnitude of these economies of scope; most likely, such a study does not exist, because mining companies treat the data needed to conduct such a study as confidential. Even if mining costs increase, however, it is reasonable to expect that restrictions on surface mining would lead to increases in deep mining. Discussing the flip side of surface mine permitting delays, Patriot Coal's Senior Vice President Mark Schroeder recently noted that the company has "wonderful underground reserves that are out there, some of which are ready to go." Furthermore, differences in the characteristics and quality of surface- and underground-mined coal does not appear to be a problem for Patriot: "The coal out there in many of the properties is interchangeable, and we typically in our contracts have the ability to substitute from one mine to another mine." ("Q2 2009 Patriot Coal Corporation Earnings Conference Call," July 28, 2009. http://phx.corporate-ir.net/phoenix.zhtml?c=216060&p=irol-eventDetails&EventId=2333204# accessed Aug 25, 2009)

[35] The Annual Coal report does not provide data on estimated economic reserves for northern West Virginia, which is in Northern Appalachia, versus southern West Virginia, in Central Appalachia. (EIA, *2007 Annual Coal Report*, Table 15)

Table 1. Electric Plant Receipts by Coal Source and Destination Eastern State (East of the Mississippi River), 2008 (million tons)

Location of Generating Units	Coal Sources							
	Appalachia			Interior▲	Western♦	Imported	Unknown origin	Grand Total
Plant census region/state	Central‡	Northern*	Southern^					
East North Central	**20.5**	**26.1**	**0.8**	**42.4**	**134.1**	**0.0**	**12.2**	**236.1**
	9%	*11%*	*0%*	*18%*	*57%*	*0%*	*5%*	*100%*
IL	0.0	0.0	0.6	3.9	53.1	0.0	0.9	
IN	2.0	2.0	0.0	33.6	20.7	0.0	1.7	
MI	5.6	0.7	0.0	0.0	25.1	0.0	4.6	
OH	13.0	23.3	0.2	4.8	10.6	0.0	4.9	
WI	0.0	0.1	0.0	0.1	24.6	0.0	0.1	
East South Central	**18.8**	**4.6**	**0.5**	**31.8**	**24.4**	**1.0**	**33.6**	**114.7**
	16%	*4%*	*0%*	*28%*	*21%*	*1%*	*29%*	*100%*
AL	0.3	0.0	0.2	2.5	6.3	0.7	25.7	
KY	9.9	3.7	0.0	19.9	5.3	0.0	2.1	
MS	1.1	0.0	0.3	2.4	0.0	0.3	5.6	
TN	7.6	0.9	0.0	7.0	12.7	0.0	0.2	
Middle Atlantic	**2.7**	**36.6**	**0.1**	**0.1**	**5.2**	**2.3**	**13.3**	**60.3**
	4%	*61%*	*0%*	*0%*	*9%*	*4%*	*22%*	*100%*
NJ	0.8	1.9	0.1	0.0	0.1	1.4	0.1	
NY	0.4	2.9	0.0	0.0	3.6	1.0	0.5	
PA	1.5	31.8	0.0	0.1	1.6	0.0	12.7	
New England	**0.2**	**0.6**	**0.0**	**0.0**	**0.0**	**3.0**	**3.6**	**7.4**
	2%	*8%*	*0%*	*0%*	*0%*	*41%*	*49%*	*100%*
CT	0.2	0.5	0.0	0.0	0.0	1.4	0.0	
MA	0.0	0.0	0.0	0.0	0.0	1.4	2.2	
ME	0.0	0.0	0.0	0.0	0.0	0.2	0.1	
NH	0.0	0.1	0.0	0.0	0.0	0.0	1.3	
RI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
VT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	

Location of Generating Units	Coal Sources							
	Appalachia			Interior▲	Western♦	Imported	Unknown origin	Grand Total
Plant census region/state	Central‡	Northern*	Southern^					
South Atlantic	**76.0**	**25.9**	**0.4**	**4.0**	**7.3**	**6.1**	**50.9**	**170.6**
	45%	*15%*	*0%*	*2%*	*4%*	*4%*	*30%*	*100%*
DE	1.4	0.0	0.0	0.0	0.3	0.0	0.4	
FL	8.4	0.0	0.0	3.7	0.3	4.9	5.0	
GA	5.3	0.0	0.3	0.0	3.6	0.2	30.0	
MD	4.3	5.8	0.0	0.0	0.3	0.3	0.2	
NC	27.5	1.5	0.0	0.0	0.0	0.4	0.0	
SC	12.4	2.4	0.1	0.0	0.0	0.4	0.2	
VA	3.8	0.0	0.0	0.0	0.2	0.0	9.1	
WV	13.0	16.1	0.0	0.3	2.4	0.0	5.9	
Unknown destination state	**1.0**	**0.3**	**0.0**	**3.6**	**0.8**	**1.1**	**0.4**	**7.2**
Grand Total	**119.3**	**94.0**	**1.8**	**81.9**	**171.8**	**13.6**	**114.0**	**596.4**

‡ Consistent with EIA's definitions of coal producing regions, Central Appalachia includes Eastern Kentucky, Virginia, Southern West Virginia, and the Tennessee counties of: Anderson, Campbell, Claiborne, Cumberland, Fentress, Morgan, Overton, Pickett, Putnam, Roane, and Scott. Eastern Kentucky is defined as the counties of Bell, Boyd, Breathitt, Carter, Clay, Clinton, Elliot, Estill, Floyd, Greenup, Harlan, Jackson, Johnson, Knott, Knox, Laurel, Lawrence, Lee, Leslie, Letcher, Lewis, Magoffin, Martin, McCreary, Menifee, Morgan, Owsley, Perry, Pike, Powell, Pulaski, Rockcastle, Rowan, Wayne, Whitley, and Wolfe. Southern West Virginia includes Boone, Cabell, Clay, Fayette, Greenbrier, Kanawha, Lincoln, Logan, Mason, McDowell, Mercer, Mingo, Nicholas, Pocahontas, Putnam, Raleigh, Summers, Wayne, and Wyoming counties.

*** Northern Appalachia consists of Maryland, Ohio, Pennsylvania, and Northern West Virginia, including the West Virginia counties of Barbour, Brooke, Braxton, Calhoun, Doddridge, Gilmer, Grant, Hancock, Harrison, Jackson, Lewis, Marion, Marshall, Mineral, Monongalia, Ohio, Pleasants, Preston, Randolph, Ritchie, Roane, Taylor, Tucker, Tyler, Upshur, Webster, Wetzel,Wirt, and Wood.**

^ Southern Appalachia consists of Alabama, and the Tennessee counties of: Bledsoe, Coffee, Franklin, Grundy, Hamilton, Marion, Rhea, Sequatchie, Van Buren, Warren, and White.

▲ The Interior Region (with Gulf Coast) consists of Arkansas, Illinois, Indiana, Kansas, Louisiana, Mississippi, Missouri, Oklahoma, Texas, and Western Kentucky, including the Kentucky counties of Breckinridge, Butler, Caldwell, Christian, Crittenden, Daviess, Edmonson, Grayson, Hancock, Hart, Henderson, Hopkins, Logan, McLean, Muhlenberg, Ohio, Todd, Union, Warren, and Webster. The Illinois Basin is a subregion of the Interior and consists of Illinois, Indiana, and Western Kentucky.

♦ The Western Region consists of Alaska, Arizona, Colorado, Montana, New Mexico, North Dakota, Utah, Washington, and Wyoming. The Western Region includes the Powder River Basin, which consists of the Montana counties of Big Horn, Custer, Powder River, Rosebud, and Treasure and the Wyoming counties of Campbell, Converse, Crook, Johnson, Natrona, Niobrara, Sheridan, and Weston.

Table 2. Electric Plant Coal Receipts of Coal from Central Appalachia, Unknown sources, and Other Regions by Mining Type and Plant State (East of the Mississippi River), 2008 (million tons)

	Central Appalachia‡						Unknown Origin						Imported & Other Sources	All Reported Receipts
Plant census region/ state	Surface	Surface/ Under-ground Blend	Under-ground	Under-ground/ Surface Blend	Unknown	Total	Surface	Surface/ Under-ground Blend	Under-ground	Under-ground/ Surface Blend	Unknown	Total	Total	Total
East North Central	**5.0**	**5.8**	**7.7**	**0.1**	**1.9**	**20.5**	**5.2**	**0.1**	**1.4**	**0.0**	**5.5**	**12.2**	**203.4**	**236.1**
	2%	2%	3%	0%	1%	9%	2%	0%	1%	0%	2%	5%	86%	100%
IL	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.2	0.0	0.2	0.9	57.5	58.5
IN	1.1	0.0	0.8	0.0	0.0	2.0	0.2	0.0	0.0	0.0	1.5	1.7	56.3	60.0
MI	0.1	1.1	4.3	0.1	0.0	5.6	3.6	0.0	0.8	0.0	0.2	4.6	25.8	36.0
OH	3.8	4.6	2.7	0.0	1.8	13.0	0.9	0.1	0.4	0.0	3.5	4.9	38.9	56.7
WI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	24.9	25.0
East South Central	**9.8**	**1.9**	**6.8**	**0.1**	**0.3**	**18.8**	**12.3**	**10.7**	**3.5**	**0.0**	**7.1**	**33.6**	**62.3**	**114.7**
	9%	*2%*	*6%*	*0%*	*0%*	*16%*	*11%*	*9%*	*3%*	*0%*	*6%*	*29%*	*54%*	*100%*
AL	0.2	0.0	0.0	0.0	0.0	0.3	9.3	10.2	2.5	0.0	3.7	25.7	9.8	35.7
KY	6.4	0.5	3.0	0.0	0.0	9.9	0.1	0.1	0.0	0.0	1.9	2.1	28.9	40.9
MS	0.0	0.6	0.4	0.0	0.0	1.1	2.8	0.3	1.0	0.0	1.4	5.6	3.0	9.7
TN	3.1	0.7	3.3	0.1	0.3	7.6	0.1	0.1	0.0	0.0	0.0	0.2	20.6	28.4
Middle Atlantic	**0.6**	**0.6**	**1.5**	**0.0**	**0.0**	**2.7**	**0.0**	**0.0**	**0.0**	**0.0**	**13.3**	**13.3**	**44.3**	**60.3**
	1%	*1%*	*3%*	*0%*	*0%*	*4%*	*0%*	*0%*	*0%*	*0%*	*22%*	*22%*	*74%*	*100%*
NJ	0.0	0.3	0.5	0.0	0.0	0.8	0.0	0.0	0.0	0.0	0.1	0.1	3.4	4.3
NY	0.0	0.1	0.3	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.5	0.5	7.4	8.3
PA	0.5	0.2	0.7	0.0	0.0	1.5	0.0	0.0	0.0	0.0	12.7	12.7	33.5	47.7

	Central Appalachia‡						Unknown Origin						Imported & Other Sources	All Reported Receipts
Plant census region/ state	Surface	Surface/ Under-ground Blend	Under-ground	Under-ground/ Surface Blend	Unknown	Total	Surface	Surface/ Under-ground Blend	Under-ground	Under-ground/ Surface Blend	Unknown	Total	Total	Total
New England	**0.0**	**0.0**	**0.2**	**0.0**	**0.0**	**0.2**	**1.3**	**0.0**	**0.0**	**0.0**	**2.3**	**3.6**	**3.6**	**7.4**
	0%	*0%*	*2%*	*0%*	*0%*	*2%*	*18%*	*0%*	*0%*	*0%*	*31%*	*49%*	*49%*	*100%*
CT	0.0	0.0	0.2	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	1.9	2.0
MA	0.0	0.0	0.0	0.0	0.0	0.0	1.3	0.0	0.0	0.0	0.9	2.2	1.4	3.7
ME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2
NH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	1.3	0.2	1.5
South Atlantic	**22.5**	**24.8**	**21.4**	**7.0**	**0.3**	**76.0**	**14.9**	**2.5**	**21.1**	**0.0**	**12.4**	**50.9**	**43.7**	**170.6**
	13%	*15%*	*13%*	*4%*	*0%*	*45%*	*9%*	*1%*	*12%*	*0%*	*7%*	*30%*	*26%*	*100%*
DE	0.2	0.2	0.8	0.0	0.2	1.4	0.0	0.0	0.0	0.0	0.4	0.4	0.4	2.2
FL	2.6	3.4	2.3	0.0	0.0	8.4	0.2	0.0	1.8	0.0	2.9	5.0	8.9	22.3
GA	1.6	1.2	2.4	0.0	0.0	5.3	12.7	2.5	9.5	0.0	5.3	30.0	4.2	39.4
MD	1.9	1.0	1.4	0.0	0.0	4.3	0.0	0.0	0.0	0.0	0.1	0.2	6.4	10.9
NC	6.2	16.4	3.9	1.0	0.0	27.5	0.0	0.0	0.0	0.0	0.0	0.0	1.9	29.4
SC	0.3	1.7	4.4	5.9	0.0	12.4	0.0	0.0	0.1	0.0	0.1	0.2	2.9	15.4
VA	1.1	0.9	1.8	0.0	0.0	3.8	1.6	0.0	5.5	0.0	2.1	9.1	0.2	13.2
WV	8.5	0.0	4.4	0.0	0.0	13.0	0.4	0.0	4.1	0.0	1.5	5.9	18.9	37.8
Unknown destination state	**0.2**	**0.6**	**0.1**	**0.0**	**0.1**	**1.0**	**0.0**	**0.1**	**0.0**	**0.0**	**0.3**	**0.4**	**5.7**	**7.2**
Grand Total	**38.1**	**33.6**	**37.8**	**7.2**	**2.5**	**119.3**	**33.8**	**13.4**	**26.0**	**0.0**	**40.8**	**114.0**	**363.1**	**596.4**

See Table 1 for definitions for coal producing regions.

Other Coal Producing Regions

Interior region coal, including the Illinois basin, generally has a high sulfur content (requiring air emissions controls) but is less expensive at the mine than Appalachian coal. Depending on transportation costs and the price of sulfur dioxide air emissions allowances or the cost of sulfur air emissions controls, Illinois basin coal can be an economically attractive alternative to Appalachian coal. With permitted coal production in the Illinois Basin quickly rising, from 98 million tons in 2008 to 167 million tons in 2010, supply will almost certainly increase.[36]

Power plants in the east can and do burn high sulfur coal, and the number of plants with scrubbers is increasing. In fact, an increasing number of existing coal-fired power plants have announced plans to install scrubbers to satisfy federal clean air requirements and to enable the units to economically burn higher sulfur coal blends. Examples of plants with plans to install scrubbers and related equipment include the Merrimack Plant in New Hampshire, the Edgewater 5 and Columbia Units 1 and 2 plants in Wisconsin and the White Bluffs plant in Arkansas.

Networks exist for transporting Illinois basin coal to eastern plants. EIA's 2005 Annual Coal Report maintained that there are no problems with Interior region coal transportation networks. In addition, railroads are discussing proposals for enhancing their capacity to bring Midwestern and Western coal to power plants in the East and the Southeast. For example, two railroads, CN (Canadian National) and Norfolk Southern have announced a new rail corridor to speed up coal movements between the Midwest and the Southeast:

> "In what looks, potentially, to be a creative effort to establish new coal traffic patterns, CN and Norfolk Southern launched an initiative to create a "MidAmerica Corridor" in which the railroads will share track between Chicago, St. Louis, Kentucky, and Mississippi to establish shorter and faster routes for coal traffic moving between the Midwest and Southeast.
>
> This initiative, when finalized through definitive agreements, will have three components. First, NS will haul CN freight between Chicago and St. Louis, reducing the distances between these points for CN shipments by 60 miles and providing improved connections to other rail carriers through the St. Louis gateway.
>
> Second, NS will use CN's routes between St. Louis and Fulton, KY, as part of a new, more efficient route from the Midwest to the Southeast, saving more than 50 miles on NS shipments. Third, CN will haul NS freight between Chicago and Fulton, shortening NS's Chicago-to-Birmingham route by almost 100 miles.

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[36] *Coal & Energy Price Report.* Vol 11, No. 113. Jun 11, 2009.

As part of the Mid-America Corridor, CN and NS plan to create a new coal gateway at Corinth, MS, to better link NS-served Southeastern utility plans with CN-served Illinois Basin coal producers.

The West Tennessee Railroad between Fulton and Corinth, which will be upgraded to handle heavier shipments and additional rail traffic, is a key component of the new initiative…."[37]

Transportation networks have also expanded in the last couple of decades to allow delivery of Western coal to eastern power plants.[38] Interior and Western coals are competitive with eastern coal, and public service commissions in the east expect utilities to consider the economics of different coal types and sources. For example, the FL PSC held Progress Energy Florida accountable for not obtaining a permit to burn Western coal when it received bids that were "extremely competitive" with eastern coals.[39]

4. Macroeconomic Impacts of Restricting Mountaintop/valley fill Mining in Central Appalachia

The practice of mountaintop/valley fill mining has economic costs to society, such as increased mortality and morbidity of miners and surrounding communities, reduced property values associated with mining activities, and extensive damage to natural resources. Its economic benefits include jobs, low electricity rates and tax revenue. The question of whether eliminating mountaintop/valley fill mining in Central Appalachia would have net positive or net negative impacts to society as a whole has not been adequately addressed. For one, deep mining will continue to be a source of employment in the region and may expand, to the extent that Central Appalachian deep mined coal remains competitive (given its lower transportation costs and higher quality). Indeed, a shift to deep mining has the potential to bring an increase in employment, because, per ton of production, deep mining employs more miners than surface mining.[40]

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37 *Coal & Energy Price Report*, Volume 11, No. 29, February 11, 2009, at page 3.

38 In the 1990s, sub-bituminous Powder River Basin (PRB) coal became available to Midwestern and southeastern utilities at delivered costs lower than the delivered costs of eastern bituminous coal, and numerous utilities modified their units to burn PRB coal. For example, Alabama Power dramatically increased PRB burn at its Miller plant from 1995 to 1997; Georgia Power switched to 100% PRB coal for its Scherer Units 3 & 4 in 1993; since 1994, Plant Daniel (partly owned by Gulf Power) in Mississippi has burned PRB sub-bituminous coal extensively; and Tampa Electric switched the Gannon coal-fired units to a PRB blend. (Florida Citizen's Petition for Order Requiring Progress Energy Florida, inc. to Refund to Customers $143 Million, Representing Past Excessively High Fuel Costs Stemming from Failure to Utilize the Most Economical Sources of Coals for Crystal River Units 4 and 5. Docket No. 060001-E1. Aug 10 2006. http://www.psc.state.fl.us/library/filings/06/07207-06/07207-06.pdf)

39 Florida Public Service Commission, Order No. PSC-07-0816-FOF-EI. Oct 10, 2007.

40 Productivity, i.e. average production per employee per hour, was much higher for surface mining (3.74) than for deep mining (2.29) in Central Appalachia in 2007 according to the 2007 Annual Coal Report. Thus, deep mining requires more worker hours per ton of coal production. (EIA, 2007 Annual Coal Report. February 2009.) The difference in productivity of underground mining methods and mountaintop removal is likely to be even greater. In the 2003 EIS, the productivity of the sample mountaintop removal mine was 7.25. (U.S. EPA, Mountaintop Mining / Valley Fill DEIS, Section III, Table III.L-5)

Secondly, there is a growing body of evidence that, on balance, mining is a net cost to Appalachia. A 2009 study by Michael Hendryx and Melissa Ahern suggests that the costs of coal mining are in excess of five times higher than its economic benefits, when the value of premature deaths attributable to the mining industry is considered. Hendryx and Ahern's analysis omitted a number of costs and benefits—mostly costs—including reduced employment productivity resulting from medical illness, increased public expenditures for programs such as food stamps and Medicaid, and costs of natural resource destruction.[41] As another example, a Kentucky-specific study finds a net negative economic impact on the state's budget, even without accounting for coal-related costs of healthcare, illness-related reductions in productivity, water treatment, environmental remediation and pollution control, social spending associated with declines in coal employment and related economic hardships of coalfield communities.[42]

History shows that the transition from deep to surface mining devastated the region economically, and that the prosperity of mining companies has not gone hand in hand with the economic welfare of coal mine workers.[43] A report by the Appalachian Regional Commission found that Central Appalachia has suffered from current and persistent economic distress, and that this distress "has been associated with employment in the mining industry, particularly coal mining." The report further explains that,

> "As employment in Central Appalachia's mining sector has declined over time, with levels of employment in the mining industry being 10 percent in 1960 and declining to only 2 percent in 2000, many counties that were already typically experiencing relatively poor and tenuous economic circumstances in the past have been unable to successfully adapt to changing economic conditions…
>
> "The counties that have emerged from distress in the region have consistently had fewer jobs in mining and a greater number of jobs in manufacturing when compared to the counties that have remained persistently distressed."[44]

Regardless of mountaintop/valley fill mining regulation, jobs from coal mining have been declining, even as coal production has increased or stagnated. Coal mining employment is projected to continue to decline.[45] Figures 2, 3, and 4 show historical Kentucky coal mining employment, historical Kentucky coal production, and historical West Virginia coal mining employment and production, respectively. As noted above, carbon regulations are likely to further reduce the

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41 Ken Ward Jr. *Coal's costs outweigh benefits, WVU study finds.* Charleston Gazette. June 20, 2009.

42 Melissa Fry Konty, Ph.D. and Jason Bailey, *The Impact of Coal on the Kentucky State Budget.* Jun 25, 2009.

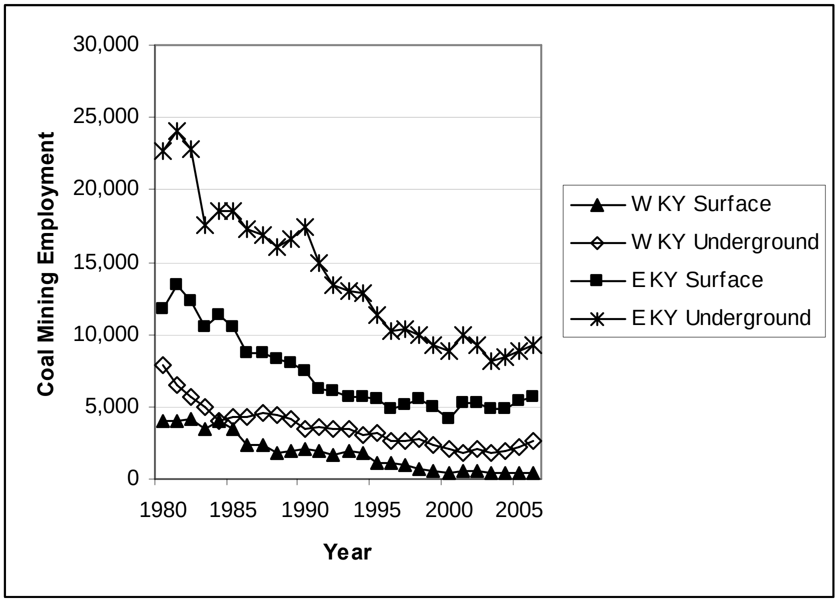
43 Economic Development Research Group, Inc. 2007. *Sources of Regional Growth in Non-Metro Appalachia.* Prepared for the Appalachian Regional Commission.

44 Wood, Lawrence E. *Trends in National and Regional Economic Distress: 1960-2000.* April 2005. Prepared for the Appalachian Regional Commission. http://www.arc.gov/index.do?nodeId=2958

45 U.S. EPA, Mountaintop Mining / Valley Fill DEIS, §III, Q-1; Hill & Associates. *Final Report on the Coordinated Review of Mountaintop Mining/Valley Fill EIS Economic Studies.* Jan 13, 2003.

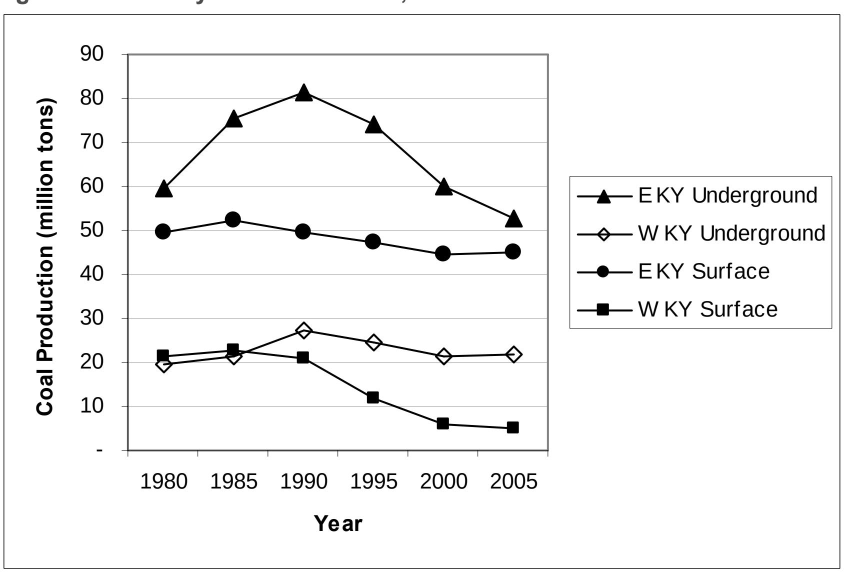
competitiveness of coal, resulting in a further decrease coal mining employment, and any impacts from mountaintop/valley fill mining restrictions are likely to be far overwhelmed by impacts resulting from reductions in the demand for coal due to carbon regulations and lower natural gas prices.

Figure 2. Kentucky Coal Mining Employment, 1980—2006



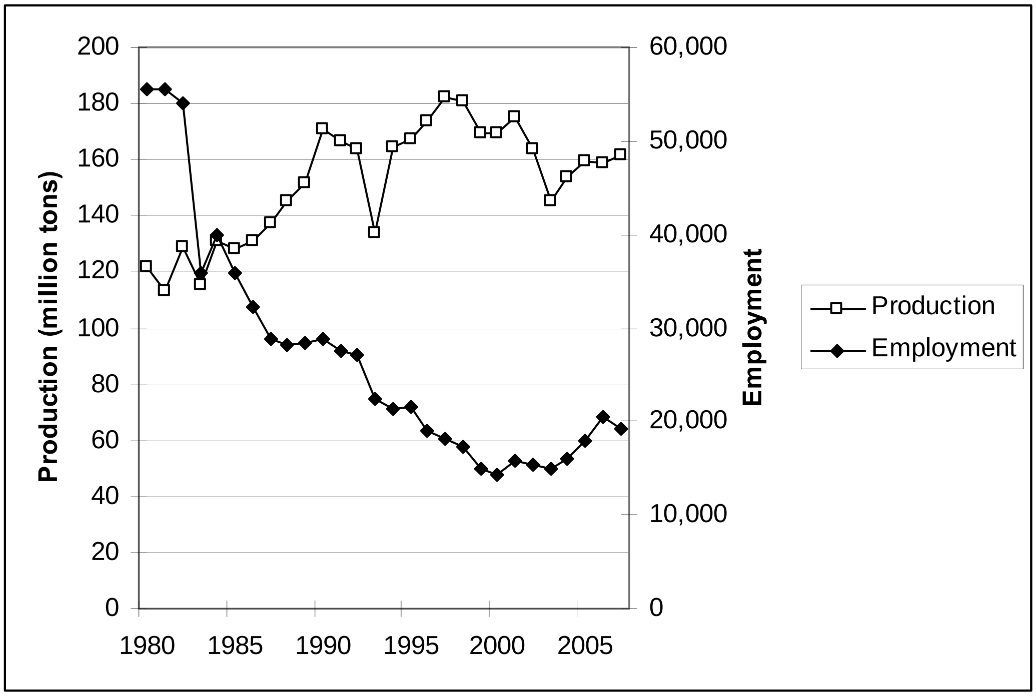
Source: Kentucky Office of Energy Policy and the Kentucky Coal Association, 2007-2008 Kentucky Coal Facts

Figure 3. Kentucky Coal Production, 1980—2005



Source: KY Coal Facts - KY Production.
http://www.coaleducation.org/Ky_Coal_Facts/production/ky_production.htm

Figure 4. West Virginia Coal Production and Employment, 1980—2007



Source: West Virginia Coal Association, Coal Facts 2008. http://www.wvcoal.com/resources/coal-facts.html

The region's continued dependence on extractive industries has hindered development of a resilient economy. Economic diversification, fostered by regional and national policy, can alleviate the boom-bust cycles associated with heavy dependence on employment in extractive industries and help prepare the region for the reality of a carbon constrained economy.

An Appalachian Regional Commission/Southeast Energy Efficiency Alliance report released in March illustrates that other sectors can have a much greater impact on the economy as a whole. Economic multipliers for industries in Appalachia are shown in Table 3. It is evident from this table that the job multipliers are much smaller for energy extraction/mining and refining than for many other sectors.[46]

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46 Marilyn A. Brown, John A. Laitner, Sharon Chandler, Elizabeth D. Kelly, Shruti Vaidyanathan, Vanessa McKinney, Cecelia Logan, and Therese Langer. *Energy Efficiency in Appalachia: How Much More Is Available, at What Cost, and by When?* March 2009. http://www.seealliance.org/pdf/ARC_Final_March09.pdf, page F-2

Table 3. Appalachia Economic Multipliers by Sector

SECTOR	Type I Multiplier Jobs (per million $ of final demand)	Type I Multiplier Compensation (per dollar of final demand)	Type I Multiplier Value-Added (per dollar of final demand)
Agriculture	21.5	0.224	0.646
Oil and Gas Extraction	5.1	0.167	0.742
Coal Mining	6.0	0.335	0.712
Other Mining	7.6	0.365	0.740
Construction	13.3	0.429	0.720
Manufacturing	8.3	0.338	0.630
Petroleum Refining	2.6	0.095	0.311
Electric Utility Services	5.3	0.285	0.818
Natural Gas Utility Services	3.7	0.204	0.552
Transportation Other Public Utilities	11.0	0.418	0.747
Wholesale Trade	15.3	0.461	0.863
Services	14.1	0.415	0.834
Financial Services	8.6	0.385	0.828
Governmental Services	19.7	0.885	0.974

Economic development can focus on a number of areas. For example, increased development of energy efficiency resources can lead to both consumer savings but also a net increase in jobs, because jobs in efficiency are more labor-intensive than extractive industries. Manufacturing of components for renewable electricity generation, such as wind turbines and photovoltaics, would likewise provide more jobs per million dollars of spending than extractive industries.[47] A study by Downstream Strategies finds that over the long run, a scenario in which the wind industry is aggressively developed in the Coal River Mountain area would provide more cumulative jobs than a scenario in which the mountain is mined using mountaintop removal techniques. It is worth noting that wind farm development, and by extension development of local wind industry, could be hindered or even precluded by mountaintop removal, as is demonstrated for Coal River Mountain.[48]

Another area identified for economic diversification is cultural and ecological asset-based development. With implementation of joint government-community initiatives, development of these assets can produce permanent jobs in the non-

47 Ibid.

48 Evan Hansen, Alan Collins, Michael Hendryx, Fritz Boettner, and Anne Hereford. *The Long-Term Economic Benefits of Wind Versus Mountaintop Removal Coal on Coal River Mountain, West Virginia.* Dec 2008. http://www.coalriverwind.org/wp-content/uploads/2008/12/coalvswindoncoalrivermtn-final.pdf

metropolitan Appalachian region and "has the potential to be central to the Appalachian regional development as the area has rich natural, cultural, and human assets "sleeping" in the mountains."[49] Technology, sustainable timber, and small-scale agriculture also have significant economic development potential.[50]

5. Conclusions

It has been clearly demonstrated elsewhere that mountaintop removal and other mountaintop/valley fill mining techniques have had devastating and irreversible impacts on the environment in Central Appalachia. The major outstanding question, then, is the impact on jobs and electricity prices from ending mountaintop/valley fill mining in the region. The prevailing economic conditions that existed when previous modeling was done in 2001-2003 no longer apply—the nation is transitioning into an economy in which the externalities of GHG emissions are being internalized, and the outlook for coal fired generation is drastically different than projected in the past.

[49] Economic Development Research Group, Inc. 2007. *Sources of Regional Growth in Non-Metro Appalachia.*

[50] Ken Ward Jr. *Coal's costs outweigh benefits, WVU study finds.* Charleston Gazette. June 20, 2009.