Synapse
Energy Economics, Inc.

Declining Markets for Montana Coal

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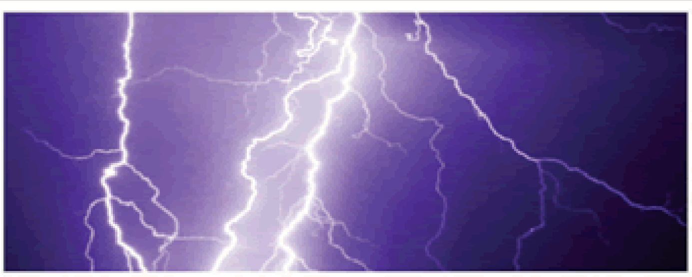
AUTHORS

Melissa Whited, David White, Sarah Jackson, Pat Knight, and Elizabeth A. Stanton, PhD



485 Massachusetts Ave.
Suite 2
Cambridge, MA 02139

617.661.3248
www.synapse-energy.com

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1. Executive Summary

Arch Coal, a global coal producer and marketer, has announced plans to develop the Otter Creek mine in the area of Ashland, Montana, and has submitted an application to the U.S. Department of Transportation's Surface Transportation Board to construct a new rail line to connect the Otter Creek mine to an existing BNSF rail line.

The Otter Creek mine claims it will produce 20 million tons of coal per year. Like other Northern Powder River Basin mines, Otter Creek coal is high in sodium, with concentrations ranging from 5.8 to 8.8 percent, much higher than the 1.2 percent typical of the Southern Powder River Basin. Because sodium causes slagging problems at power plants, demand for the coal is limited.[1] The few plants within Otter Creek's competitive area that currently accept high-sodium coal are primarily located in the upper Midwest in Minnesota, Wisconsin, and Michigan.[2]

Domestic demand for coal has declined by 14 percent since its historical peak in 2007, and the future of coal for U.S. power generation is uncertain at best.[3] According to the U.S. Energy Information Administration (EIA), only five new coal units were added in 2012, versus 50 coal unit retirements.[4] The steadily worsening outlook for coal is primarily a result of the following factors:

- **Coal has lost its cost advantage.** Falling prices of natural gas coupled with higher mining and transportation costs for coal have eroded coal's competitiveness, leading to less frequent dispatch of coal units and lower demand for coal. Over the past decade, coal's net generation decreased by ten percent, while natural gas increased by nearly 50 percent.[5] Little new coal capacity is likely to be added over the coming decades.[6]
- **Large numbers of coal plants are retiring in response to environmental regulations.** Strict new environmental regulations would require substantial new capital investments and increase operating costs for coal plants. This has led to coal plants across the country becoming uneconomic and announcing retirement, or converting to other fuel sources. Recent estimates project that a significant portion of the current coal fleet—up to 77 gigwatts—will retire by 2020.
- **Otter Creek has a limited number of potential customers, and these coal plants are becoming uneconomic.** High sodium content limits Otter Creek's customer base,[7] and many of these potential customers may retire or convert to other fuels due to the high costs of complying with new environmental regulations—in fact, several have already announced their retirements.[8] Our analysis shows that the majority of these plants will be

[1] Boiler slag is the molten bottom ash produced in wet bottom boilers.
[2] Norwest Corporation. 2006. *Otter Creek Property Summary Report.* Salt Lake City: Norwest Corporation.
[3] EIA Form 923, Schedule 5A, 2007, 2011.
[4] Based on preliminary data for 2012 from the EIA published in *Electric Power Monthly.* 24 January 2013. http://www.eia.gov/electricity/monthly/backissues.html
[5] EIA. 2001-2012. Form 923, Schedule 5A.
[6] EIA. 2012 Annual Energy Outlook. http://www.eia.gov/forecasts/aeo/MT_electric.cfm
[7] The high sodium content of Otter Creek coal (and other Northern PRB coal) causes slagging problems in boilers. See footnote 3.
[8] See footnote 35.

uneconomic compared both to the costs of operating existing natural gas plants and to the total costs of constructing and operating new natural gas plants.

- **Renewable portfolio standards, energy efficiency policies, and the likelihood of future carbon limits are reducing demand for coal.** Standards and goals for renewable energy are increasing the amount of renewables on the grid and heightening demand for natural gas as a complementary energy source due to its ability to adjust output much more quickly than coal. At the same time, increasingly aggressive energy efficiency investments are lowering energy demand across the board. Finally, a future price on carbon would drastically lower demand for coal, with generation falling to as little as 4 percent by 2040 under a carbon fee of $25.[9] Many utilities and planning commissions are already factoring carbon prices into their planning.

The long-term viability of coal is severely threatened. Demand for coal is falling across the United States, and Otter Creek's coal market is further limited by the coal's high sodium content and connection to Northern, rather than Southern rail lines. In short, it is unreasonable to expect that there will be much, if any, domestic demand for Otter Creek coal when the mine becomes operational in 2017. There is, therefore, no justification for expanding rail transportation infrastructure to connect the Otter Creek coal mine to struggling domestic markets.

2. Introduction

Domestic demand for coal has declined by 14 percent since its historical peak in 2007, and the future of coal for U.S. power generation is uncertain at best.[10] According to the U.S. Energy Information Administration (EIA), only five new coal units were added in 2012, versus 50 coal unit retirements.[11]

Several factors are reducing the nation's demand for coal. Falling costs of substitutes such as natural gas and renewable energy have eroded coal's cost advantage in much of the United States. A combination of new and more stringent environmental regulations has turned the tables on the profitability of coal plants across the nation, many of which now face difficult decisions among installing expensive environmental retrofits, converting to natural gas, or shuttering completely. On top of this, energy efficiency and the economic crisis have slowed electricity demand growth rates to a fraction of what they were during the heyday of coal plant construction. In many states, renewable portfolio standards are accelerating the transition away from coal to wind, solar, hydroelectricity, and biomass, as well as highlighting the advantages of natural gas's quick ramping ability for balancing intermittent resources. All of these factors have led to falling demand for coal and pose a serious threat to coal's long-term viability in the United States.

This report summarizes some of the key domestic energy trends and projections that are expected to challenge all U.S. coal producers in the coming decades, and highlights the obstacles facing the developers of the Otter Creek coal mine in Montana.

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[9] EIA. 2012 Annual Energy Outlook www.eia.gov/pressroom/presentations/sieminski_01142013.ppt
[10] EIA Form 923, Schedule 5A, 2007, 2011.
[11] Based on preliminary data for 2012 from the EIA published in *Electric Power Monthly.* 24 January 2013. http://www.eia.gov/electricity/monthly/backissues.html

The Otter Creek Project

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This report discusses several challenges facing the Otter Creek project, including:

- Coal electric generating capacity and generation per year will decrease in the future because of environmental costs, higher costs for coal, low natural gas prices, and, in all likelihood, greenhouse gas regulations.
- As a result, U.S domestic coal use will decline, increasing competitive pressures in the mining industry.
- Montana coal is at a relative disadvantage relative to Wyoming and other Southern Powder River Basin coals and, therefore, will likely see an even greater drop in production.

There is therefore no compelling justification for the expansion of transportation infrastructure for Montana coal based on domestic demand projections.

3. The Rapid Shift Away from Coal

U.S. coal is produced primarily for electricity generation; nearly 93 percent of coal consumed in the United States in 2011 was used by the electric power sector.[14] For many years, coal's dominant position in electricity generation was unrivaled. In the late 1990s, more than half of the electricity generated in the United States came from coal. By April 2012, this share had declined to 33 percent—nearly equivalent to that of natural gas. Figure 1 shows this decline of approximately 1 percent per year over the past decade, which began even prior to 2009 when natural gas prices were much higher. Both natural gas prices and coal use rose slightly in 2012, but have not returned to their pre-2009 levels.

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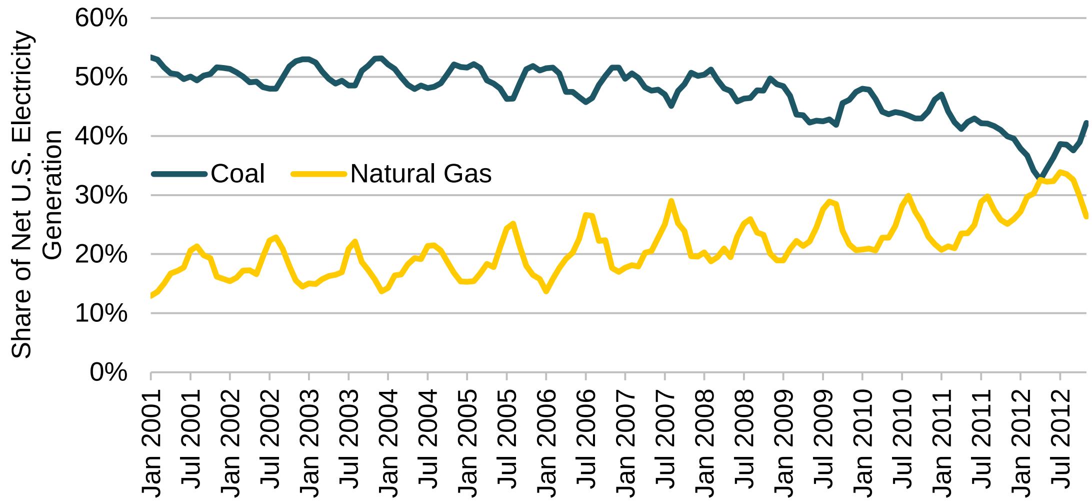
[12] Boiler slag is the molten bottom ash produced in wet bottom boilers.
[13] Norwest Corporation. 2006. *Otter Creek Property Summary Report.* Salt Lake City: Norwest Corporation.
[14] EIA. 2012. *Quarterly Coal Report: July-September 2012.* Washington, DC: U.S. Department of Energy. http://www.eia.gov/coal/production/quarterly/pdf/qcr.pdf

Figure 1. Share of Monthly Net U.S. Electricity Generation by Coal and Natural Gas, Jan. 2001 to Nov. 2012



Source: EIA Form 923, Schedule 5A, 2001 - 2012

Mining operations in the Powder River Basin, including those owned by Arch Coal, have not been impervious to this decline in coal consumption. From 2011 to 2012, the volume of coal sold by Arch Coal declined 11 percent as the company "idled equipment until coal market fundamentals improve."[15] Westmoreland Coal and Cloud Peak Energy, owners of several coal mines near the Otter Creek mine, also faced declining demand in 2012. While production steadily increased to nearly 20 million tons a year at Cloud Peak's Spring Creek mine from 2006 to 2010, mine production has declined by nearly 11 percent in the past two years.[16] Both companies cite lower natural gas prices as a primary factor driving reduced domestic demand.[17]

While coal production has declined in nearly every region of the United States over the past year, Montana coal producers have suffered a greater percentage decline in demand than the national average, and nearly twice as great a decline as that of lower-sodium Wyoming coal. In the 52 weeks ending on February 11, 2013, production declined by 8.7 percent nationally but fell by 11.4 percent in Wyoming and 21.4 percent in Montana.[18]

Coal's decline can be attributed to a number of factors, including competition from substitutes, loss of customers due to more stringent environmental regulations, policy support for renewable energy, and energy efficiency investments. These factors are discussed in greater detail below.

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[15] Arch Coal. 2013. 10-K Filing to the Securities and Exchange Commission. http://www.sec.gov/

[16] According to Cloud Peak Energy's 2013 10-K Filing to the Securities and Exchange Commission (http://www.sec.gov/), annual production at the Spring Creek mine declined from 19.3 million tons in 2010 to 17.2 million tons in 2012.

[17] Westmoreland Coal. 2012. 10-Q: For the Quarterly Period Ended September 30, 2012. http://www.westmoreland.com/library/2012_SEC_Filings/Westmoreland_Coal_Co_September_10-Q_as_filed_November_8_2012.pdf; Cloud Peak Energy. 2013. 10-K to the Securities and Exchange Commission. http://www.sec.gov/

[18] EIA. February 14, 2013. Weekly U.S. Coal Production Overview (DOE/EIA 0218/06). http://www.eia.gov/coal/production/weekly/

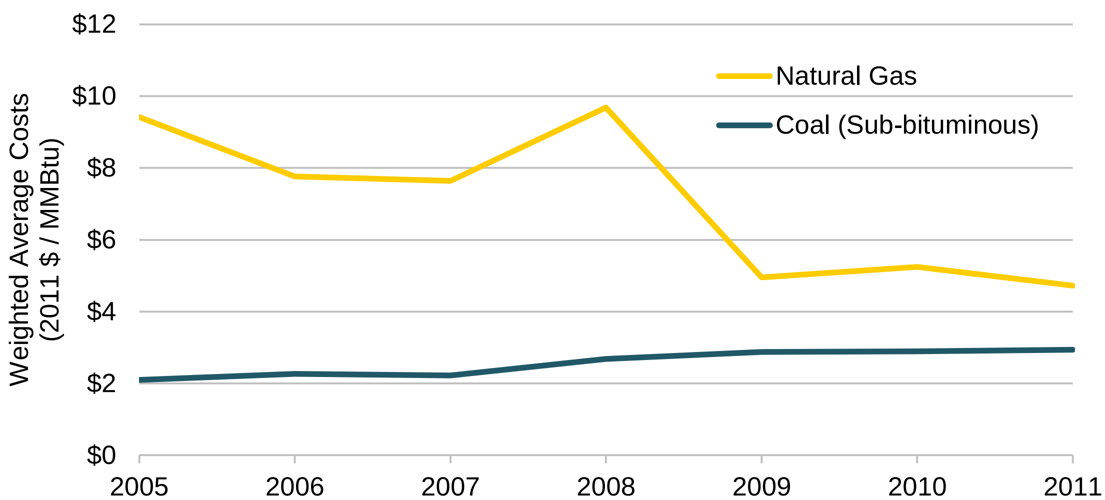
4. Coal's Disappearing Cost Advantage

Although once considered among the most inexpensive energy sources, in recent years the delivered price of coal has risen while the cost of substitutes—particularly natural gas and wind energy—has declined precipitously.

The rise of natural gas

More efficient natural gas extraction techniques, particularly hydraulic fracturing, have enabled the extraction of large reserves of shale gas that were previously uneconomic. Since 2007, shale gas production has risen rapidly—from less than 5 billion cubic feet per day, to more than 25 billion cubic feet per day.[19] Natural gas prices have fallen correspondingly, while the average price of subbituminous coal (primarily from Western basins) has slowly risen, as displayed in **Error! Reference source not found.**.

Figure 2. Weighted Average Real Natural Gas and Subbituminous Coal Prices per MMBTU for the Electric Power Industry, 2005 to 2011



Source: EIA, Electric Power Annual 2011, Table 7.4, http://www.eia.gov/electricity/annual/html/epa_07_04.html

These low natural gas costs have had a dramatic impact on the dispatch order of existing power plants, as reflected in the relative monthly net generation values of coal and natural gas in Figure 1. For power plants that purchase their coal from higher-cost or geographically distant regions, natural gas has become more economic than coal.

Historically, natural gas plants have functioned primarily as load-following peaker plants—operating only at times of peak demand—due to higher fuel costs. As fuel costs decline, however, natural gas plants are transitioning to serving more baseload (i.e., operating during more hours of the year), enabled in part by the large amount of existing, under-utilized generating capacity at natural gas power plants.

[19] EIA. 2013. Natural Gas Weekly Update: Monthly Dry Shale Gas Production. Washington, DC: U.S. Department of Energy.

In 2011, the United States had 457 gigawatts (GW) of natural gas nameplate capacity.[20] If one assumes a 90 percent capacity factor (that is, that on average natural gas plants were to be in operation 90 percent of the time), today's natural gas plants have the potential to produce more than 3.6 million gigawatt-hours (GWh)

. Yet in 2011, natural gas generated only 1 million GWh—just 28 percent of their potential.[21] This mismatch between capacity and generation is partially the result of the rapid build-out of gas plants during the late 1990s and early 2000s when gas prices were low.[22]

Electricity generators are now beginning to more fully utilize that capacity, repurposing natural gas plants to serve baseload, or in some cases even converting coal plants to natural gas boilers. These impacts are clearly apparent in the change in share of net generation by fuel type from 2002 through 2011: the total electricity generated from coal declined by 10 percent, while the total electricity generated from natural gas increased by 46 percent in this period (see Figure 1).[23]

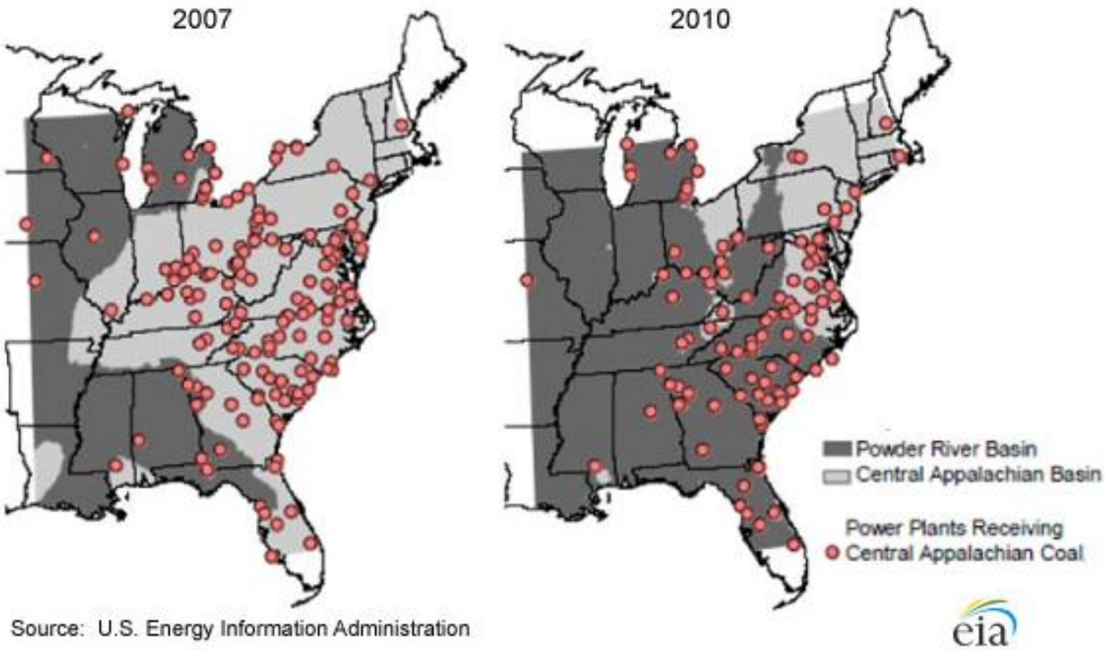
Escalating coal transport costs

The locus of U.S. coal production has been moving westward for decades as Western coal production rapidly increased, overtaking Appalachian production levels in the late 1990s. Appalachian coal reached its zenith around 1990 and has been generally declining ever since, primarily due to increasingly adverse mining conditions and rising costs.

As Appalachian coal prices shot upward, Powder River Basin coal became competitive in eastern markets—despite the vast physical distance and transportation costs. A recent EIA analysis found that for the majority of power plants receiving Central Appalachian coal in 2007, Powder River Basin coal had become the lowest-cost option by 2010 (Figure 3).

[20] EIA. 2011. Form 860.
[21] EIA. 2011. Form 923.
[22] From 2000 to 2011, natural gas generating capacity in the United States increased by 85 percent—from 220 GW to 457 GW—while net generation from natural gas increased by only 59 percent. EIA. 2001-2011. Form 860.
[23] EIA. 2001-2012. Form 923, Schedule 5A.

Figure 3. EIA Analysis of Lowest Delivered Cost of Coal by Coal Basin, 2007 and 2010



Note: Dark grey shading indicates that for plants in these areas, Powder River Basin coal has the lowest delivered cost. Light grey shading indicates that for plants in these areas, Central Appalachian Basin coal has the lowest delivered cost. Red circles indicate plants receiving Central Appalachian Basin coal.
Source: EIA. July 2013. Coal Transportation to the Electric Power Sector.
http://www.eia.gov/coal/transportationrates/

Yet, while Powder River Basin coal is clearly winning the competition with Central Appalachian coal in the East, both are losing ground in the wider U.S. domestic marketplace. From 2010 to 2012, both basins' production levels fell by nearly 10 percent, as other fuels became increasingly economic, displacing coal altogether.[24]

One major factor affecting coal's competitiveness is the cost of transportation. Transportation costs accounted for nearly 60 percent of the delivered cost of Powder River Basin coal in 2010.[25] That is, on average, the transportation cost of Powder River Basin coal is typically greater than the cost of coal itself, and these costs have increased significantly since 2001. Appalachian and Illinois Basin coal have experienced the highest increases in transportation costs; increases in real, inflation-adjusted transportation costs for Powder River Basin coal, however, have also been significant, rising 14 percent from 2001 to 2010 (see Figure 4).

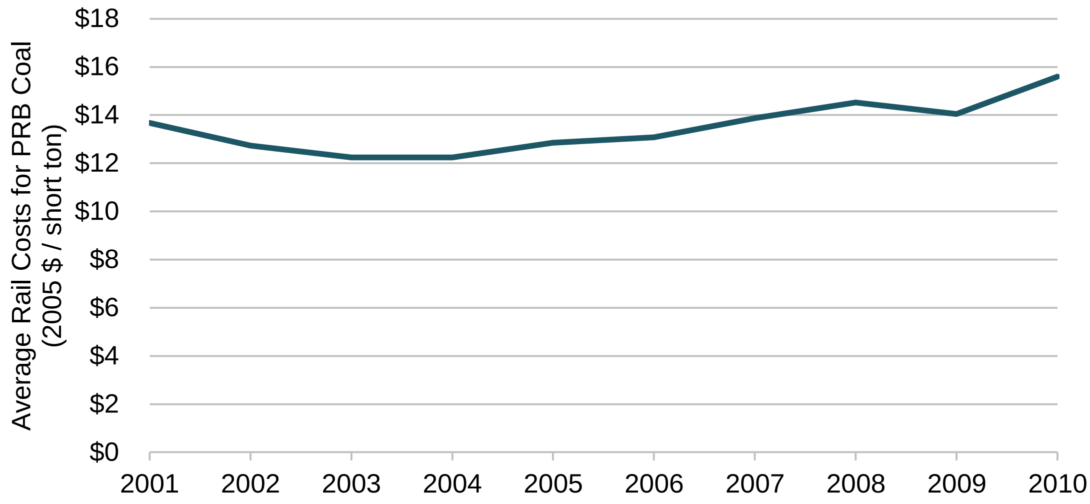
For all U.S. coal, high-and-rising transportation costs are harming the fuel's competitiveness with natural gas (which is transported domestically by pipelines at a much cheaper rate), and wind power, which is very nearly costless to operate (although it does have fixed, capital costs). Rising

[24] EIA. 2013. Monthly Coal Production Forecast January 2002 - January 2013. http://www.eia.gov/coal/production/weekly/forecast/monthprodforecast2002.xls

[25] EIA. 2012. "Cost of Transporting Coal to Power Plants Rose almost 50 Percent in Decade." *Today in Energy*, November 19, 2012. http://www.eia.gov/todayinenergy/detail.cfm?id=8830

transportation costs are contributing to coal's decline, and will certainly hinder the ability of Otter Creek and other Powder River Basin coal to expand in eastern markets.

Figure 4. Real Average Transportation Costs of Powder River Basin Coal, 2001 to 2010



Source: EIA, Coal Transportation Rates to the Electric Power Sector, Trends 2001-2010, Table 7, http://www.eia.gov/coal/transportationrates/excel/table7_PRB_Averages.xls

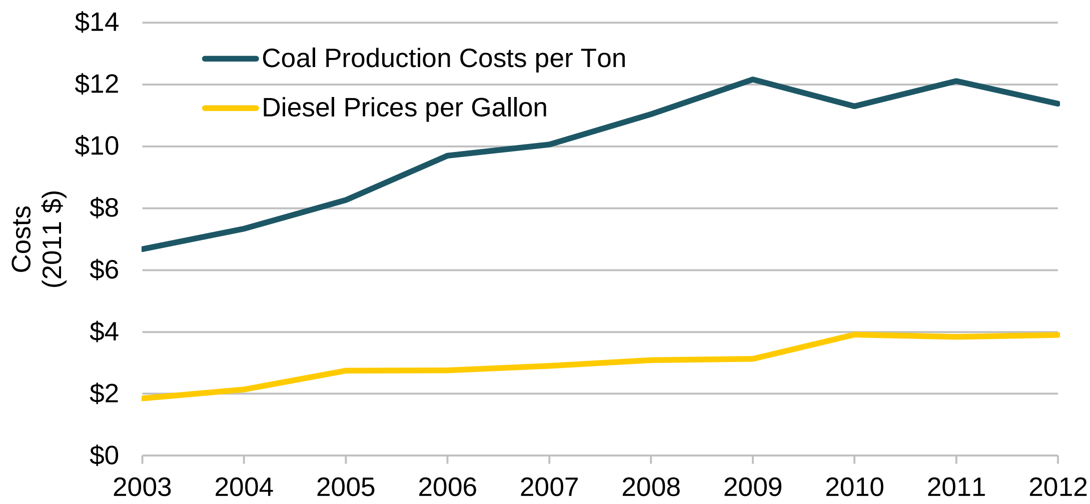
Mining costs on the rise

Higher mining costs, too, have eaten into coal's once-significant cost advantage. Coal producers in the Powder River Basin were hit especially hard by skyrocketing oil and steel prices during the 2000s due to their dependence on diesel fuel to power earth-moving equipment and their dependence on steel for the manufacture of mine supports. Arch Coal's Powder River Basin production costs have escalated at an average annual rate of nearly 7 percent since 2003.[26]

As shown in Figure 5, diesel prices in particular have increased rapidly over the past few years, with real prices rising by an average annual rate of more than 8 percent from 2003 to 2012.[27] Arch Coal explicitly notes its exposure to fuel prices in its 10-K filings, stating, "Our coal mining operations use significant amounts of steel, diesel fuel, explosives, rubber tires and other mining and industrial supplies.... We also use significant amounts of diesel fuel and tires for the trucks and other heavy machinery we use, particularly at our Black Thunder mining complex. If the prices of mining and other industrial supplies, particularly steel-based supplies, diesel fuel and rubber tires, increase, our operating costs could be negatively affected."

[26] Arch Coal. 2013. 10-K Filing to the Securities and Exchange Commission. http://www.sec.gov
[27] EIA. 2013. *Short-Term Energy Outlook - Annual Average Diesel Price.* Washington, DC: U.S. Department of Energy. http://www.eia.gov/forecasts/steo/

Figure 5. Arch Coal Production Costs and Diesel Fuel Prices, 2003 to 2012



Source: Arch Coal 10-K 2013 Filing, EIA Diesel Fuel Prices (AEO 2012).

The EIA's 2012 *Annual Energy Outlook* reference case projects that oil prices will increase at an average annual rate of 2.5 percent (after correcting for inflation) from 2013 to 2035, which may lead to a continuing rise in mining costs over time.[28] Clearly substitution to other fuels and more efficient technologies will mitigate some of the effect on coal production costs, but recent experience has highlighted coal producers' vulnerability to rising commodity costs.

Coal is no longer competitive

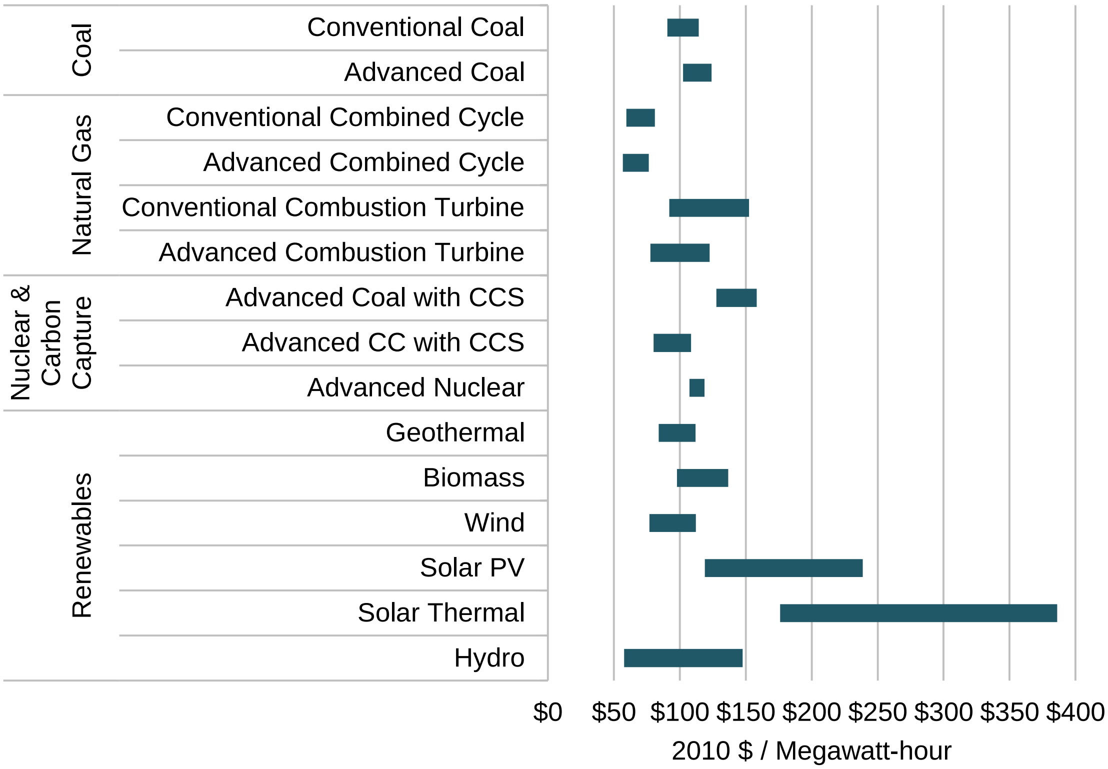
Natural gas electricity generation costs have fallen below those of coal. Coal also faces competition from existing renewable energy sources, such as solar and wind, which, of course, have no fuel costs.

Coal's market position is even more precarious, however, when analyzed in terms of the total levelized cost of energy for newly constructed plants. Levelized costs are a convenient way of comparing various energy technologies by looking at the cost per megawatt hour (in real dollars) of construction and operation over the entire life of a plant, taking into account capital costs, fuel costs, operating and maintenance costs, financing costs, and an assumed utilization rate.

Historically, coal has maintained low levelized costs by balancing its large capital outlays with lower fuel costs, but this is no longer the case. Natural gas plants are much less expensive to build, can be built quickly, and possess much faster ramp rates that enable them to provide back-up generation for variable energy sources such as wind.[29] In the EIA's recent projection of 2017 average levelized costs for various energy technologies, natural gas combined-cycle plants clearly outperformed conventional and advanced coal, and natural gas combustion turbines exhibited nearly equivalent costs to coal, but with a wider range of costs due to regional variation in local labor markets, and the cost and availability of fuel (see Figure 6).

[28] EIA. 2012. Annual Energy Outlook 2012. Washington, DC: U.S. Department of Energy.
[29] Higher ramping rates allow natural gas plants to quickly increase and decrease electricity output to match offset fluctuations in variable energy sources such as wind.

Figure 6. Levelized Cost of Energy for Various Technologies, 2017



Note: Assumed capacity factors are: coal = 85%, combined cycle = 87%, combustion turbines = 30%, nuclear = 90%, geothermal = 91%, biomass = 83%, wind = 33%, solar PV = 25%, solar thermal = 20%, and hydro = 53%.
Source: Levelized Cost of New Generation Resources in the Annual Energy Outlook 2012, Table 2, http://www.eia.gov/forecasts/aeo/electricity_generation.cfm

It comes as no surprise, then, that few coal plants are being proposed or constructed (see the section below on 'The Future of U.S. Coal-Powered Electric Generation'). Natural gas is simply more economic, better suited for the integration of renewable energy, and not as susceptible to costly environmental retrofits as coal plants.

5. Regulation favors shift away from coal

New, stricter environmental regulations are adding to the costs of operating coal-fired power plants. Many of the nation's aging coal plants are widely expected to retire over the next few decades, to be replaced by natural gas, renewables, and energy efficiency measures.[30] This section describes each of the federal environmental regulations affecting coal plants in turn.[31]

National Ambient Air Quality Standards

National Ambient Air Quality Standards (NAAQS) set maximum air quality limitations that must be met at all locations across the nation. Compliance with the NAAQS can be determined through air quality monitoring stations, which are stationed in various cities throughout the United States, or through air quality dispersion modeling. States with areas found to be in "nonattainment" of a particular NAAQS are required to set enforceable requirements to reduce emissions from sources contributing to nonattainment such that the NAAQS are achieved and maintained. The U.S. Environmental Protection Agency (EPA) has established NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen dioxides (NO_2), carbon monoxide (CO), ozone, particulate matter (measured as particulate matter less than or equal to 10 micrometers in diameter (PM10) and particulate matter less than or equal to 2.5 micrometers in diameter (PM2.5)), and lead.

In nonattainment areas, coal plants and other sources must comply with emission reduction requirements known as "Reasonably Available Control Technology" (RACT) to bring the areas into attainment of the NAAQS. New major sources, including major modifications at existing sources, must comply with very strict emissions reductions consistent with "lowest achievable emissions reductions" (LAER) as well as obtain emission offsets.

EPA is currently in the process of drafting new, more stringent NAAQS for SO_2, PM2.5, and ozone.

- On June 22, 2010, EPA revised[32] the standard for SO_2 by establishing a new 1-hour standard at a level of 75 parts per billion (ppb) in place of the existing annual and 24-hour standards for SO_2. EPA plans to make area designations for the new SO_2 standard by June 3, 2013, and compliance would be required in 2017.
- On December 14, 2012, EPA strengthened the annual PM2.5 standard from 15 µg/m3 to 12 µg/m3, and retained the current 24-hour standard at 35 µg/m3. EPA will make final area designations for the new standard by December 2014. Once designations are made, states with non-attainment areas will have to develop a State Implementation Plan within three years outlining how they will reduce pollution to meet the standard by 2020.
- In March 2008, EPA strengthened the 8-hour ozone standard from 84 ppb to 75 ppb. On September 16, 2009, EPA announced that because the 2008 standard was not as protective as recommended by EPA's panel of science advisors, it would reconsider the 75 ppb standard. In 2010, EPA proposed lowering the 8-hour ozone standard from 75 ppb to between 60 and 70 ppb, and September 2, 2011, the Administration announced that EPA would not finalize its proposed reconsideration of the 75 ppb standard ahead of the regular 5-year NAAQS review cycle. The next 5-year review for 8-hour ozone is expected

[30] Elliott, Gold, and Hayes. August 2011. Avoiding a Train Wreck: Replacing Old Coal Plants with Energy Efficiency. ACEEE White Paper. http://aceee.org/files/pdf/white-paper/Avoiding_the_train_wreck.pdf

[31] For more detailed information on up-coming environmental regulations see Miller. January 2013. A Primer on Pending Environmental Regulations and their Potential Impacts on Electric System Reliability. NESCAUM. http://www.nescaum.org/

[32] 75 Fed. Reg. 35520 (June 22, 2010)

in 2013. Compliance with the upcoming standard would likely be required in the 2019-2020 timeframe.

Cross State Air Pollution Rule

The Cross State Air Pollution Rule (CSAPR) was finalized in 2011, establishing the obligations of each affected state to reduce emissions of NO_x and SO_2 that significantly contribute to another state's PM2.5 and ozone non-attainment problems. The rule targets coal and other electric generating units, and uses a cap and-trade approach to limit each state to emissions below a level that significantly contributes to non-attainment in downwind states.

On August 21, 2012, CSAPR was vacated by the U.S. Court of Appeals for the District of Columbia. EPA has filed a petition for *en banc* rehearing of that decision; even if EPA fails to salvage CSAPR through the courts, however, the Agency must still promulgate a replacement rule to implement Clean Air Act requirements to address the transport of air pollution across state boundaries. In the meantime, the court left the requirements of the 2005 Clean Air Interstate Rule in place.

Regional Haze Rules

One of the national goals set out in the Clean Air Act is reducing existing visibility impairment from human-made air pollution in all "Class I" areas (e.g., most national parks and wilderness areas).[33] EPA's Regional Haze Rule—issued in 1999, and revised in 2005—requires states to create plans to significantly improve visibility conditions in Class I areas with the goal of achieving natural background visibility conditions by 2064. These requirements are implemented through state plans with enforceable reductions in haze-causing pollution from individual sources and with other measures to meet "reasonable further progress" milestones.[34] The first progress milestone is 2018.

A key component of this program is the imposition of air pollution controls on coal plants and other existing facilities that impact visibility in Class I areas. Specifically, the rules require installation of "best available retrofit technology" (BART) that is developed for such facilities on a case-by-case basis. In addition, EPA's BART determinations specify particular emission limits for each BART-eligible facility. EPA evaluates BART for the air pollutants that impact visibility in our national parks and wilderness areas – namely SO_2, PM, and nitrogen oxides (NO_x). Under the Clean Air Act, states develop Regional Haze requirements, but EPA approves state plans for compliance. If EPA finds the plans are not consistent with the Clean Air Act, it adopts a federal plan with BART and reasonable progress requirements. Affected facilities must comply with the BART determinations as expeditiously as practicable but no later than five years from the date EPA approves the state plan or adopts a federal plan.[35]

[33] 42 U.S.C. § 7491(a)(1)
[34] 40 C.F.R. §51.308-309
[35] EPA's regulations allow certain states in the "Grand Canyon Visibility Transport Region" to participate in an SO_2 trading program in lieu of adopting source-specific SO_2 BART requirements, if the trading program will result in greater reasonable progress toward attaining the national visibility goal than source-specific BART. Although nine states were originally eligible to participate, today only three states are opting to participate in this program – New Mexico, Utah, and Wyoming. These states agreed to a gradually declining cap on SO_2 emissions from all emission sources. If the declining caps are exceeded in any year, then even greater SO_2 emission reductions have to be

Mercury and Air Toxics Standards

In 2000, EPA determined it was appropriate and necessary to regulate toxic air emissions (or hazardous air pollutants) from coal and other steam electric generating units. As a result, EPA adopted strict emission limitations for hazardous air pollutants that are based on the emissions of the cleanest existing sources.[36] These emission limitations are known as Maximum Achievable Control Technology (MACT). The final MATS rule, approved in December 2011, sets strict stack emissions limits for mercury, other metal toxins, other organic and inorganic hazardous air pollutants, as well as acid gasses. Compliance with MATS is required by 2015, with a potential extension to 2016.

Coal Combustion Residuals Disposal Rule

Coal-fired power plants generate a tremendous amount of ash and other residual wastes, which are commonly placed in dry landfills or slurry impoundments. The risk associated with wet storage of coal combustion residuals (CCR) was dramatically revealed in the catastrophic failure of the ash slurry containment at the Kingston coal plant in Roane County, Tennessee in December 2008, releasing over a billion gallons of slurry and sending toxic sludge into tributaries of the Tennessee River.

On June 21, 2010, EPA proposed to regulate CCR for the first time either as a Subtitle C hazardous waste or Subtitle D solid waste under the Resource Conservation and Recovery Act. The current rulemaking is 30 years overdue. If the EPA classifies CCR as hazardous waste, a cradle-to-grave regulatory system would apply to CCR, requiring regulation of the entities that create, transport, and dispose of the waste. Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required; in addition, the EPA would implement minimum requirements for dam safety at impoundments. Under a solid waste Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install liners, and require standards for long-term stability and closure care.

The EPA is currently evaluating which regulatory pathway will be most effective in protecting human health and the environment. In 1999, EPA released a series of technical papers to Congress documenting cases in which damages are known to have occurred from leakages and spills from coal ash impoundments.[37] In the current proposed rule, the EPA recognizes a substantial increase in the types and quantities of potentially toxic CCR caused by air pollution control equipment.

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achieved—although the reductions can be met through emissions trading, rather than imposition of specific emission limitations on any one facility. This program is called the Backstop Trading Program. As of the date of this testimony, EPA has not yet approved the Backstop Trading Program to meet Regional Haze requirements in any of the three states' Regional Haze plans, so the trading program is not yet federally enforceable.

[36] Clean Air Act §112(d)

[37] EPA. March 15, 1999. Technical Background Document for the Report to Congress on Remaining Wastes from Fossil Fuel Combustion: Potential Damage Cases.
http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ffc2_397.pdf

Use of more advanced air pollution control technology reduces air emissions of metals and other pollutants in the flue gas of a coal-fired power plant by capturing and transferring the pollutants to the fly ash and other air pollution control residues. The impact of changes in air pollution control on the characteristics of CCRs and the leaching potential of metals is the focus of ongoing research by EPA's Office of Research and Development.[38]

Steam Electric Effluent Limitation Guidelines

Following a multi-year study of steam-generating units across the country, EPA found that coal-fired power plants are currently discharging a higher-than-expected level of toxic-weighted pollutants into waterways. Current effluent regulations were last updated in 1982 and do not reflect the changes that have occurred in the electric power industry over the last thirty years, and do not adequately manage the pollutants being discharged from coal-fired generating units. Coal ash ponds and flue gas desulfurization systems used by such power plants are the source of a large portion of these pollutants, and are likely to result in an increase in toxic effluents in the future as environmental regulations are promulgated and pollution controls are installed. No new rule has yet been proposed, but EPA is under a court order to issue the proposed regulation by April 19, 2013 and a final rule in May 22, 2014.[39] New requirements will be implemented in 2014 to 2019 through the five-year National Pollutant Discharge Elimination System permit cycle.[40]

Clean Water Act Cooling Water Intake Structure Rule

On March 28, 2011, the EPA proposed a long-expected rule implementing the requirements of Section 316(b) of the Clean Water Act at existing power plants.[41] Section 316(b) requires "that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." Under this new rule, EPA set new standards reducing the impingement and entrainment of aquatic organisms from cooling water intake structures at new and existing electric generating facilities.

The rule provides that:

- Existing facilities that withdraw more than two million gallons per day are subject to an upper limit on fish mortality from impingement, and must implement technology to either reduce impingement or slow water intake velocities.
- Existing facilities that withdraw at least 125 million gallons per day are required to conduct an entrainment characterization study to establish a "best technology available" for the specific site.

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[38] 75 Fed. Reg. 35139 (June 21, 2010).
[39] *See* U.S. Environmental Protection Agency website. Accessed February 21, 2013. Available at: http://water.epa.gov/scitech/wastetech/guide/steam-electric/amendment.cfm
[40] *See* U.S. Environmental Protection Agency. *Steam Electric ELG Rulemaking*. UMRA and Federalism Implications: Consultation Meeting. October 11, 2011. http://water.epa.gov/scitech/wastetech/guide/upload/Steam-Electric-ELG-Rulemaking-UMRA-and-Federalism-Implications-Consultation-Meeting-Presentation.pdf
[41] 33 U.S.C. § 1326.

Title V Greenhouse Gas Tailoring Rule

Under EPA's Greenhouse Gas Tailoring Rule, coal plants and other large sources of greenhouse gas emissions are subject to permitting requirements. A "large source" is a new facility with emissions of at least 100,000 tons per year of carbon dioxide equivalent (CO_2e) or an existing facility that emits at least 100,000 tons per year CO_2e and is making changes that would increase greenhouse gas emissions by at least 75,000 tons per year CO_2e. These sources are required to obtain permits under the New Source Review Prevention of Significant Deterioration and Title V Operating Permit programs and must install Best Available Control Technology (BACT) for greenhouse gases. The BACT requirement only applies, however, if the project also increases emissions of at least one non-greenhouse-gas pollutant.

New Source Performance Standards

Under Section 111 of the Clean Air Act, EPA sets technology-based standards for new sources on a category-by-category basis. These standards are set based on the best demonstrated available technology (BDAT) and apply to all new sources built or modified following promulgation of the standard.

On March 27, 2012, EPA proposed[42] New Source Performance Standards for greenhouse gas emissions from new electric generating units, such as coal-fired power plants. The standard was set at 1,000 lbs CO_2e/MWh, which is equivalent to the emission rate that a combined-cycle natural gas unit can achieve. A new coal plant would have to employ carbon capture and sequestration (CCS) technology with the capability of removing 50 percent of CO_2 emissions in order to meet the standard. The rule also allows a unit's emissions to be averaged over 30 years to achieve an annual average emission rate of 1,000 lbs CO_2e/MWh. This option allows the phase-in of CCS within the first 10 years of operation.

While New Source Performance Standards apply only to new facilities, Section 111(d) of the Clean Air Act requires states to develop plans for *existing* sources of any non-criteria pollutants (i.e., a pollutant for which there is no NAAQS) and non-hazardous air pollutant whenever EPA promulgates a standard for a new source. These plans are subject to EPA review and approval, similar to state implementation plans under the NAAQS program.

The implications of forthcoming environmental regulations for coal plants

EPA's increasingly stringent environmental regulations will have substantial impacts on the coal industry. Many coal plants will require retrofits to comply with the regulations, and a significant number of plants may be retired as they become too expensive to operate.[43] Further detailed analysis of these impacts is discussed in the following section.

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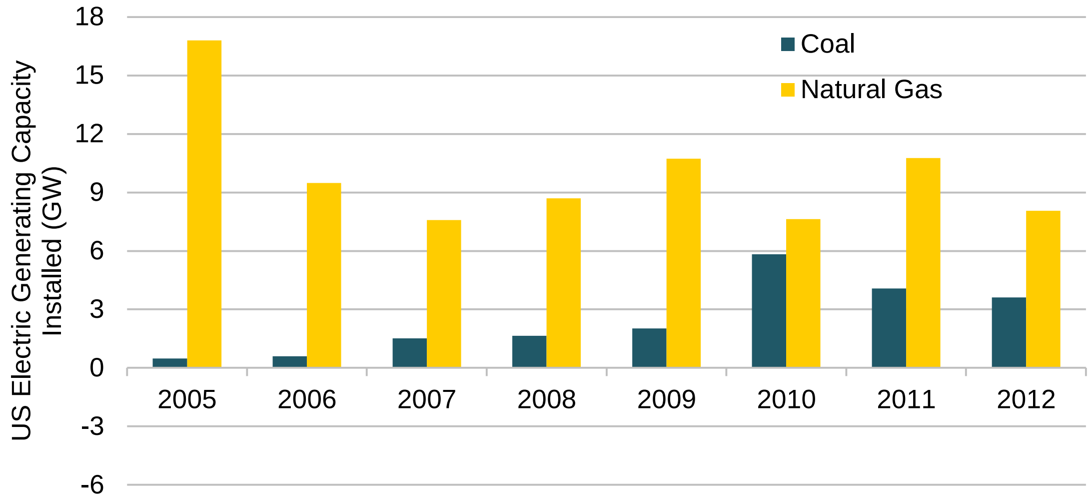
[42] 77 Fed. Reg. 22392 (April 13, 2012)

[43] EPA performed an analysis of the costs of compliance with each of the four major rules expected to impact the electric industry. Annual compliance costs are projected to total $10.2 billion for MATS, $853 million for CSAPR, $600 million to $1.5 billion for CCR depending on which option is finalized, and $397 million for 316(b). Source: U.S. Government Accountability Office, July 2012. *EPA Regulations and Electricity: Better Monitoring by Agencies could Strengthen Efforts to Address Potential Challenges*. http://www.gao.gov/assets/600/592542.pdf

6. The Future of U.S. Coal-Powered Electric Generation

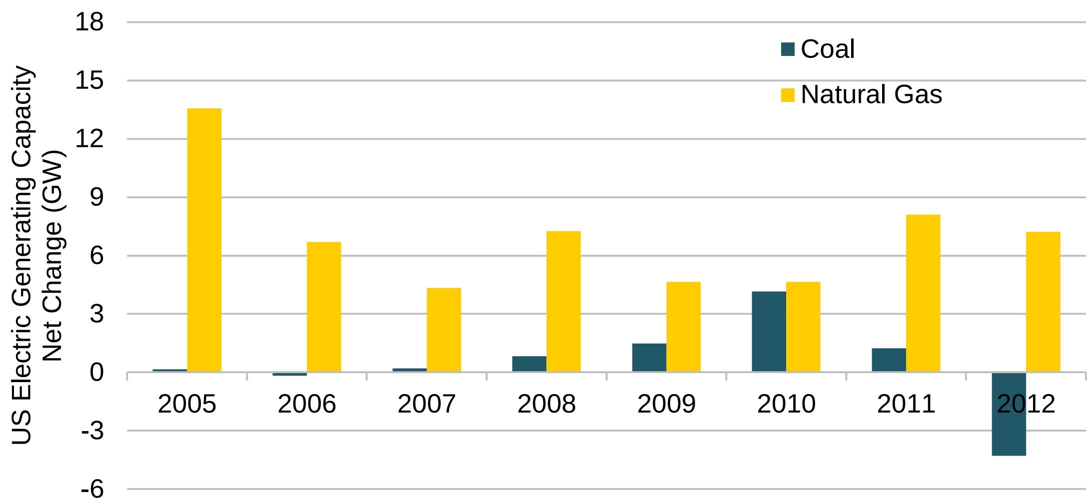
Competition from other generation technologies and forthcoming environmental regulations are pushing much of the existing U.S. coal fleet into retirement, and few coal plant additions are expected. Newly installed electric generating facilities are dominated by natural gas (see Figure 7), and the net change in generating facilities (new installations less retirements) favors natural gas over coal even more strongly (see Figure 8).

Figure 7. Newly Installed Generating Capacity by Year, 2005 to 2012



Source: EIA Form 860, 2005–2012

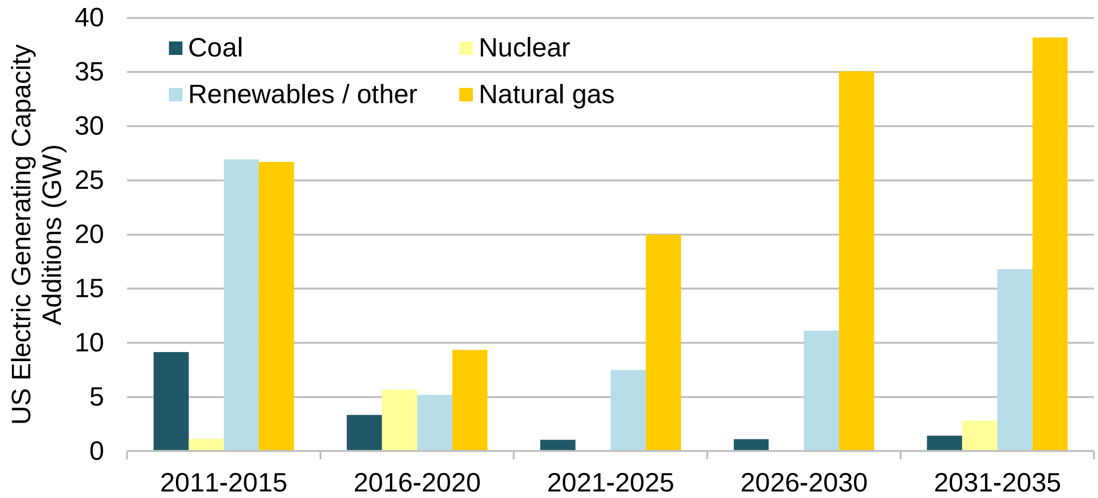
Figure 8. Net Change in Generating Capacity by Year, 2005 to 2012



Source: EIA Form 860, 2005-2012

EIA's *2012 Annual Energy Outlook* reference case projects very little new coal capacity to be added over the next twenty years, while large amounts of capacity are projected to soon retire. As Figure 9 demonstrates, most new capacity is expected to be a mixture of natural gas and renewables, not coal.

Figure 9. Electricity generation capacity additions by fuel type, including combined heat and power, 2011 to 2035 (GW)



Source: EIA. 2012 Annual Energy Outlook. *http://www.eia.gov/forecasts/aeo/MT_electric.cfm*

At the same time that little new coal capacity is expected to be added, significant amounts may soon be retired. Already, plants totaling 30 GW of coal capacity have announced their retirements by 2016. The Brattle Group's most recent forecast of likely coal retirements in response to tightening environmental regulations was 59 to 77 GW.[44] As of February 2013, Black & Veatch estimates that nearly 62 GW of coal capacity will be retired by 2020, up slightly from what the company estimated in mid-2012.[45]

Coal plant retirements include many of Otter Creek's potential customers

Coal plant retirements will make it increasingly difficult for Otter Creek coal to find buyers for its high-sodium coal. Already several of the ten coal plants identified as the initial target market for the mine's coal have announced their retirement or conversion to natural gas or biomass.[46] It is reasonable to expect that many more of the potential customers for Otter Creek coal will be retired in the near future as units face escalating costs of environmental upgrades.

Costs of operating electric generating units include both fixed and variable components. Fixed costs are invariant to the amount of generation (e.g. investment capital, property taxes, and fixed operation and maintenance expenses). Variable, or "running," costs strongly depend on the

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[44] The Brattle Group. October 2012. *Potential Coal Plant Retirements: 2012 Update*. http://www.brattle.com/_documents/UploadLibrary/Upload1082.pdf

[45] Maloney, Peter. 2013. Black & Veatch Updates Coal-fired Power Plant Retirement Estimates. Platts.

[46] Conversion of Hoot Lake to natural gas by 2020 was approved by the Minnesota Public Utilities Commission in January 2013 (http://minnesota.publicradio.org/display/web/2013/01/31/business/hoot-lake-plant-stop-burning-coal), several units of Syl Laskin will switch to natural gas (http://fresh-energy.org/2013/01/news-release-clean-air-victory-in-northern-minnesota-as-minnesota-power-announces-phasing-out-coal-at-two-minnesota-plants/), while Bayfront will be converted to biomass (http://www.jsonline.com/blogs/business/68594702.html ; http://www.woodbioenergymagazine.com/magazine/2012/1012/article-old-pro-excel.php).

amount of generation (e.g. fuel costs, emissions costs, and variable operation and maintenance expenses).

Pollution control technologies affect the forward-going cost of a unit in several ways. First, these technologies require investment capital and increase the fixed costs at a unit in a given year, which depend, in part, on the size of the unit; smaller units are more expensive to retrofit on a dollar per kilowatt basis. Second, emission control equipment requires electricity to run—called the "parasitic load"—reducing the net output of a generating unit; in other words, the same fuel usage results in less electricity output. Finally, many emission controls also require the use of a chemical reagent, purchase of which increases variable operation and maintenance costs.[47]

The dispatch order of generation units—which units are called upon to generated electricity in a given hour and which are not—is driven by unit variable costs, but the decision to construct a new plant or retrofit a plant with new environmental controls is based on the combination of the additional fixed costs of the environmental controls and the variable costs. Together these constitute the "forward-going operating costs."

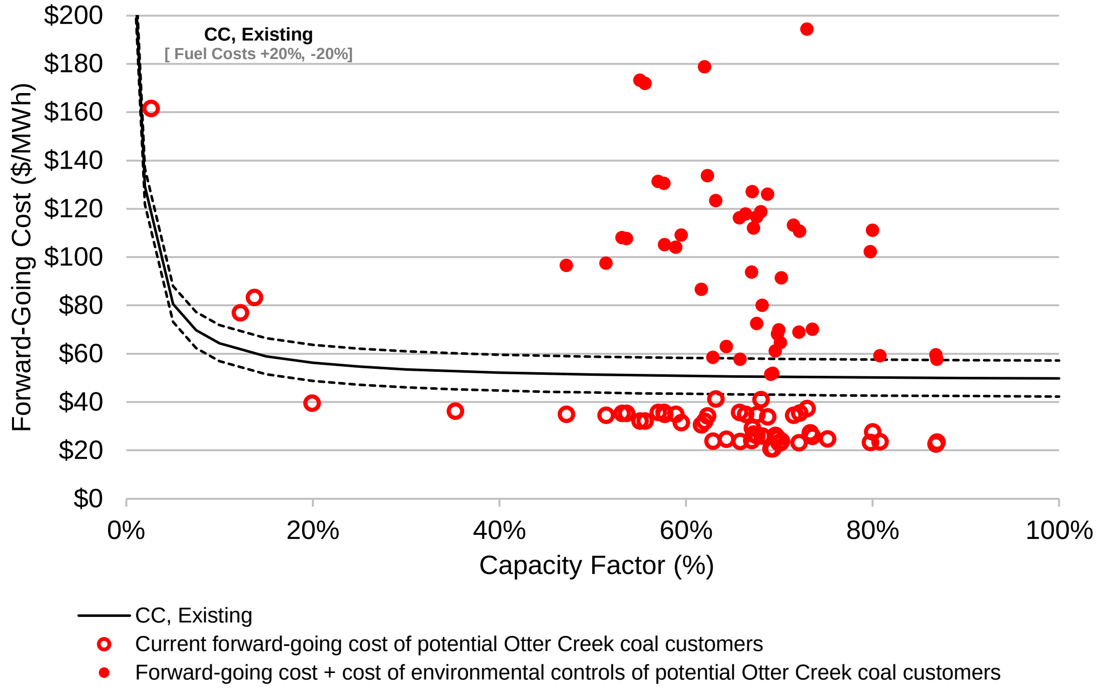
Synapse Energy Economics performed an analysis of the 52 units identified by Norwest as potential Otter Creek customers, based on each unit's operating characteristics and estimated capital expenditures for the specific environmental upgrades that would be needed to comply with EPA regulations assuming a $15 per ton CO_2 carbon price. The coal fuel costs used for this analysis conservatively assume that the current cost of delivered coal remains the same, ignoring the likelihood that these costs will increase due to higher transportation and mining costs over the next decade.[48]

Figure 10 displays the forward-going operating costs of these coal units, first without any carbon price or environmental upgrades (the hollow red circles) and then with both an approximately $15 per ton carbon price and the specific environmental technologies that each plant would need to be in compliance with federal law (the solid red circles). The solid circles are the relevant costs that will be considered when deciding whether to retire a unit or retrofit it with new environmental controls.

[47] Wilson, Rachel. July 23, 2012. "Direct Testimony of Rachel S. Wilson." *Case No. 2012-00063, Application of Big Rivers Electric Corporation, Befor the Public Service Commission of Kentucky.*

[48] Estimated from EIA. 2010. Form 923.

Figure 10. Forward-going costs of existing coal units by capacity factor ($/MWh) relative to the total levelized cost of an existing natural gas combined cycle unit



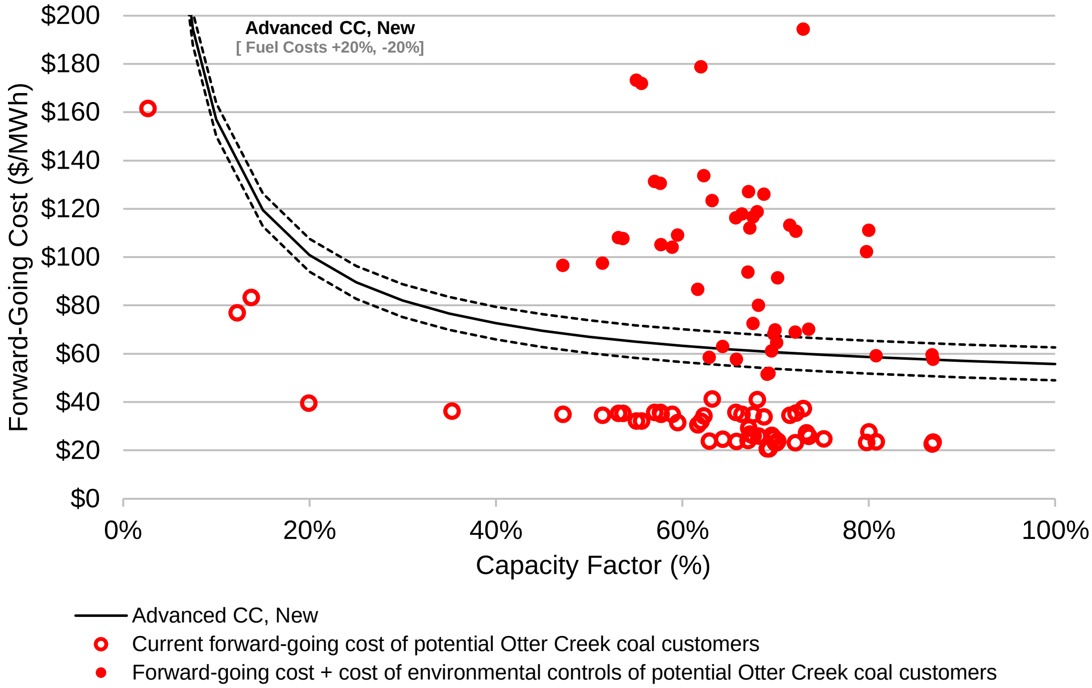
Source: Authors' calculations.

Shown also on Figure 10 is the fixed plus variable cost of a typical existing combined-cycle natural gas plant with the $15 per ton carbon price included. The dashed lines above and below the natural gas line combined cycle cost represent 20 percent higher and lower fuel costs, with natural gas fuel costs derived from *Annual Energy Outlook* projections through 2022.

While the majority of the coal plants identified as potential Otter Creek customers were more economic to operate than an existing combined-cycle natural gas plant prior to the environmental upgrades and carbon price, this is no longer the case once the environmental costs are factored in. Our analysis estimates that these units face environmental control capital expenditures ranging from $141 million to $822 million. The decision of whether to retrofit these units, convert them to natural gas, or retire them will be based on each unit's variable costs, plus the environmental capital costs, the carbon price, and reduced efficiency due to the parasitic load. It is reasonable to expect that many units will find it difficult to justify their continued operation and will likely retire rather than bear the expense of an environmental retrofit.

Figure 11 presents the same analysis, but this time in comparison to the higher costs of an advanced new combined-cycle gas plant, including the cost to construct the plant itself. The results are striking: After complying with environmental regulations, the majority of Otter Creek's potential customers' costs will be higher than the cost of building and operating a new combined-cycle natural gas plant.

Figure 11. Forward-going costs of existing coal units by capacity factor ($/MWh) relative to the total levelized cost of new advanced natural gas combined cycle unit



Source: Authors' calculations.

7. Other Policies Reducing Demand for Coal

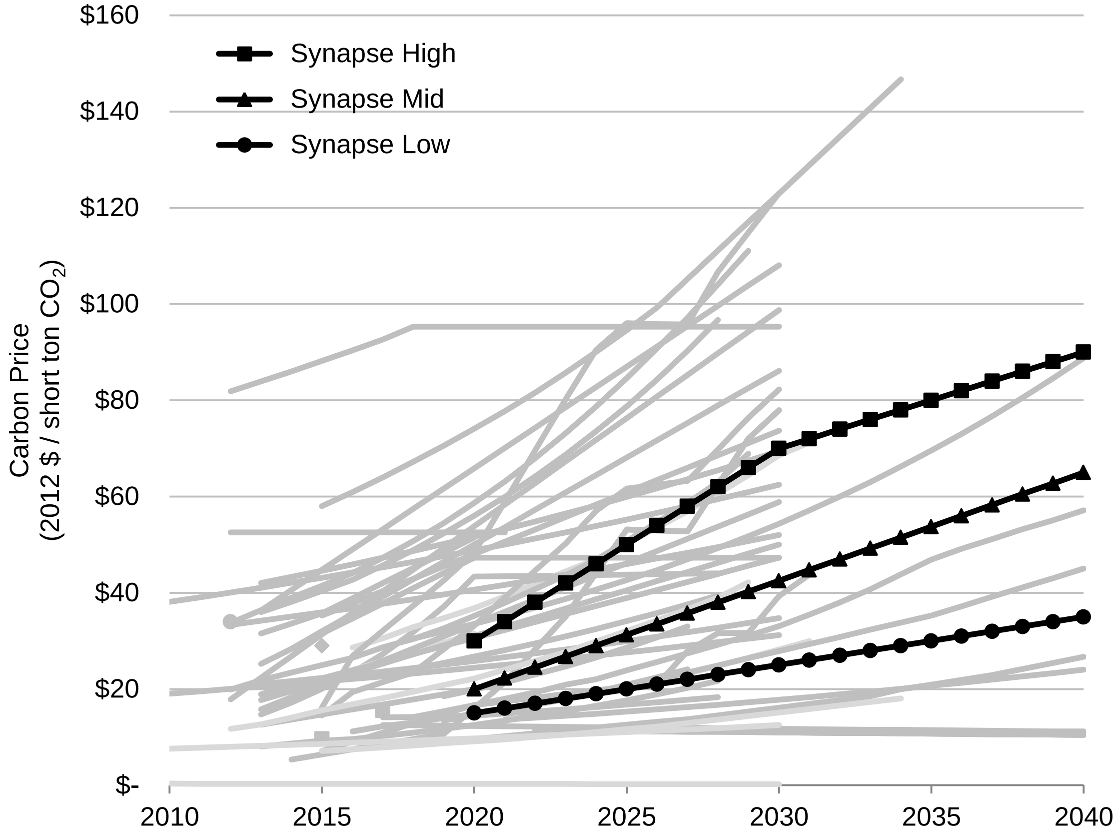
Several other categories of energy and environmental policies, at both the federal and state levels, are likely to have the effect of reducing domestic demand for U.S. coal. The sections below discuss the expected impact of carbon policies, renewable portfolio standards, and energy efficiency measures.

Future carbon policy favors shift away from coal

While there is not currently a federal law or proposed rulemaking requiring a carbon control technology, cap-and-trade program, or tax on emissions of CO_2, discussions at the EPA and at the Congressional level are ongoing. Due to coal's high rate of carbon emissions, demand for this fuel would be impacted significantly by a national or regional carbon policy.

Based on a review of more than 40 current carbon price estimates and related analyses, including CO_2 price estimates used by electric utilities in planning, Synapse Energy Economics developed low, mid, and high estimates of future carbon prices for the period 2020 to 2040. Synapse's 2020 carbon price projections range from $15 to $30 per ton of CO_2, with a mid-case of $20 per ton of CO_2. The Synapse carbon price projections are compared to the range of utility carbon price forecasts in Figure 12.

Figure 12. Synapse CO_2 price forecasts compared to the range of utility forecasts

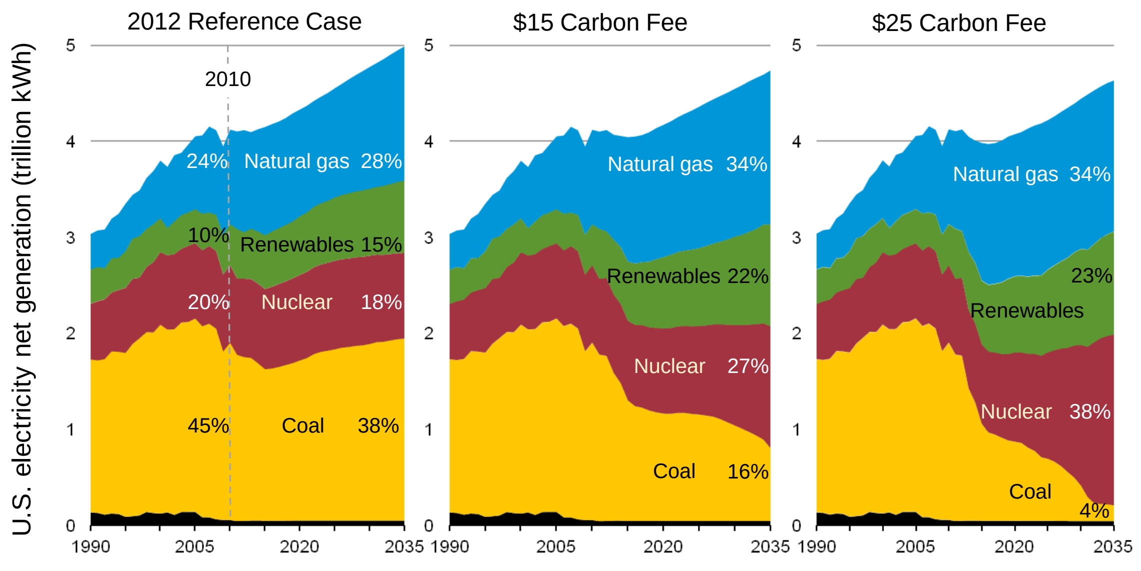


Source: Wilson, Rachel, Patrick Luckow, Bruce Biewald, Frank Ackerman, and Ezra Hausman. 2012. 2012 Carbon Dioxide Price Forecast. *Cambridge: Synapse Energy Economics, Inc. http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf*

The EIA's *2012 Annual Energy Outlook* reports the projected impact of $15 and $20 per ton CO_2 emissions fees starting in 2013[49] (similar to Synapse's low and mid cases) on net electricity generation in the United States. Figure 13 below shows EIA's reference case with no CO_2 emissions fee on the left, a $15 per ton case in the center, and a $20 per ton case on the right. In all three cases, coal declines from 45 percent of net generation in 2010, but the decline is much more pronounced in the carbon fee scenarios. Under a $15 per ton CO_2 fee, coal declines to 16 percent of generation by 2035, while under a $25 per ton CO_2 fee, coal declines to just 4 percent of generation by the end of the period modeled.

[49] AEO CO_2 prices escalate 5 percent each year through 2035.

Figure 13. U.S. Electricity Net Generation (Trillion kWh) under Reference, $15, and $25 Carbon Fee Scenarios



Source: EIA. Annual Energy Outlook 2012. www.eia.gov/pressroom/presentations/sieminski_01142013.ppt

EIA's projections highlight the vulnerability of coal demand to carbon policy, even at a low carbon price. As outlined in the Synapse Energy Economics *2012 Carbon Dioxide Price Forecast* report, federal legislation requiring reductions in carbon dioxide emissions is likely to occur in this decade prompted by one or more of the following factors:[50]

- Technological opportunity;
- A patchwork of state emission targets for 2020, spurring industry demand for federal action;
- A U.S. Supreme Court decision to allow nuisance lawsuits to go ahead, resulting in a financial threat to energy companies; and
- Increasingly compelling evidence of climate change.

Such policy will certainly reduce demand for coal nationally, as the costs of carbon adds significantly to the overall cost of energy produced by coal. Capturing and storing carbon emissions at the smokestack (i.e. carbon capture and sequestration) is not yet economic (see Figure 6), and coal will likely continue to face significant competition from low-cost natural gas and renewable resources for the foreseeable future.

Substitution due to renewable mandates

Volume I of Norwest's *Otter Creek Summary Report* describes the limited market for Montana Powder River Basin coal with high sodium content.[51] Montana coal will have difficulty competing

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[50] Wilson, Rachel, Patrick Luckow, Bruce Biewald, Frank Ackerman, and Ezra Hausman. 2012. 2012 Carbon Dioxide Price Forecast. Cambridge: Synapse Energy Economics, Inc. http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf

[51] Norwest Corporation. 2006. *Otter Creek Property Summary Report.* Salt Lake City: Norwest Corporation.

with Wyoming coal due to both the high sodium characteristics of the coal and higher transportation costs for all but a few regions of the United States. The Norwest report lists ten plants that are willing to accept high-sodium coal and which constitute the likely initial market for Otter Creek coal, all located in Minnesota, Michigan, or Wisconsin. An additional fourteen plants are then listed as potential customers. These plants are located in North Dakota, West Virginia, Montana, Arizona, Washington, and Kansas.

All of the states that represent potential markets for Otter Creek coal, with the exceptions of West Virginia and North Dakota, have mandatory renewable portfolio standards requiring that their electric utilities deliver set shares of electricity from renewable or alternative energy sources. North Dakota has a voluntary renewable energy target. While these policies vary in their requirements and goals, as shown in Table 1, taken together they indicate that renewable energy generation will constitute a growing share of the electricity delivered in the states where Arch Coal hopes to market coal from the Otter Creek mine.

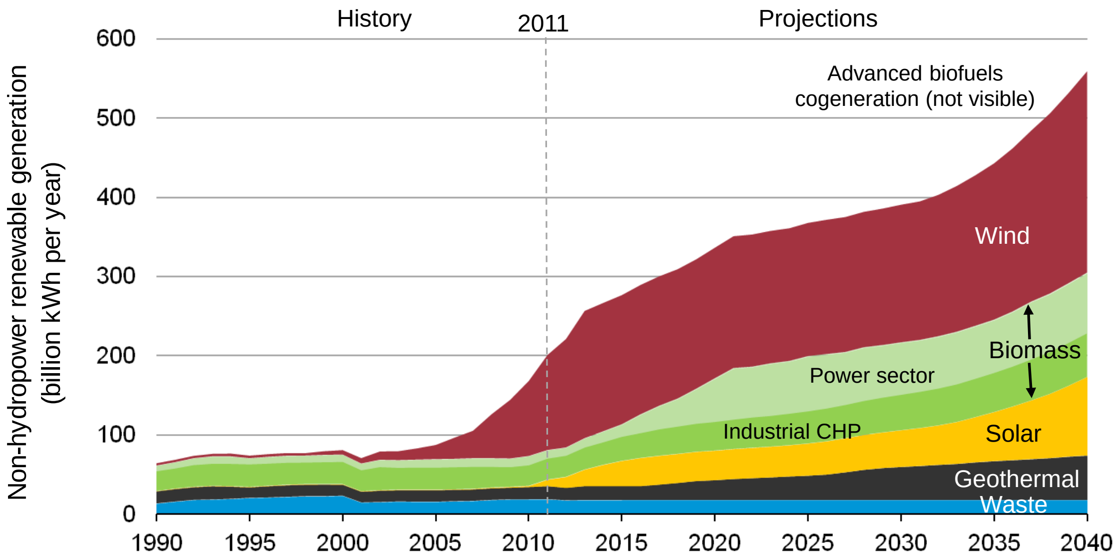
Table 1. State renewable energy requirements

State	Requirement
Mandatory RPS Requirement	
Arizona	15% by 2025
Kansas	20% by 2020
Michigan	10% by 2020
Minnesota	30% by 2020
Montana	15% by 2015
Washington	15% by 2020
Wisconsin	10% by 2015
Voluntary Goals	
North Dakota	10% by 2015

Source: Database of State Incentives for Renewables and Efficiency, January 2013.
http://www.dsireusa.org/rpsdata/RPSspread011113.xlsx

Nationwide, EIA projects that non-hydroelectric renewable generation will more than double between 2011 and 2040, partially as a result of state or national policies favoring renewable energy (Figure 14). These policies will further squeeze national demand for coal and contribute to increasing competition among coal suppliers.

Figure 14. Non-hydro renewable generation, 2011 to 2040 (thousand GWh)

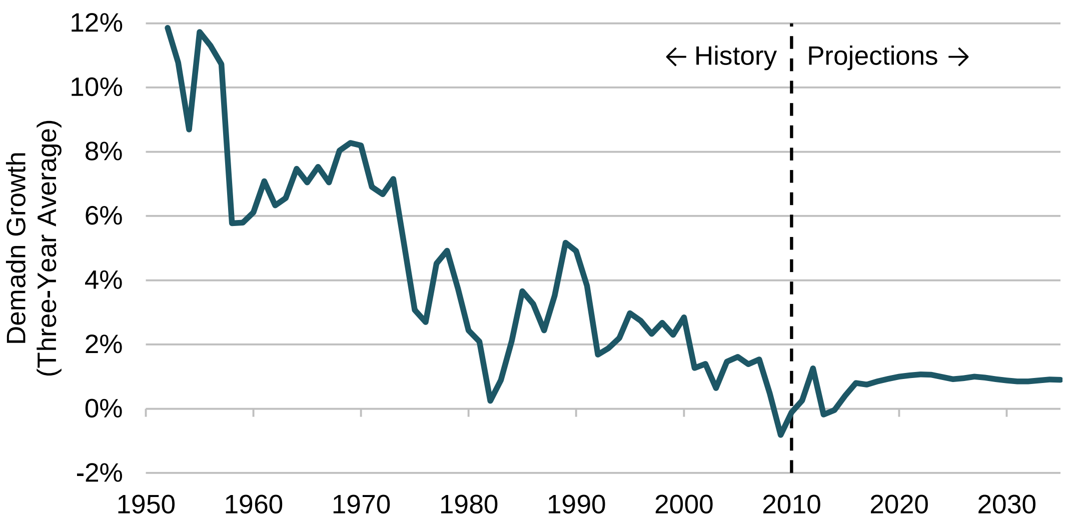


Source: EIA. Annual Energy Outlook 2012. www.eia.gov/pressroom/presentations/sieminski_01142013.ppt

Demand reduction due to energy efficiency

The growth rate of electricity demand has declined precipitously over the past sixty years, from 9.8 percent annually during the 1950s to only 0.7 percent per year during the past decade.[52] As displayed in Figure 15, the EIA projects that the pace of growth of electricity demand will remain very slow through 2035 due to new appliance standards and investments in energy-efficient equipment.

Figure 15. Growth in U.S. electricity demand, 1950 to 2035



Source: EIA, 2012 Annual Energy Outlook http://www.eia.gov/forecasts/aeo/MT_electric.cfm

[52] EIA. 2013. Annual Energy Outlook 2012.

EIA's regional projections show Otter Creek's prospective Midwestern, Kansas, and North Dakota customers with even lower electricity demand growth rates, ranging from 0.1 to 0.3 percent per year for the period 2010 to 2035, likely as the result of reduced economic growth and aggressive energy efficiency policies.[53] According to the American Council for an Energy-Efficient Economy, the Midwestern states that Norwest identifies as Otter Creek's initial market, together with Montana and Arizona, rank among the 20 states with the highest incremental energy savings as a percent of retail electricity sales.[54]

Slow electricity demand growth, renewable portfolio standards, and competition from low-cost natural gas suggest that Montana coal will find it challenging to maintain its current sales, much less expand sales in the future.

8. Conclusions

Domestic demand for coal is in decline, and this is especially true for Otter Creek's particular type of high-sodium coal. The steadily worsening outlook for coal is primarily a result of the following factors:

- **Coal has lost its cost advantage.** Falling prices of natural gas coupled with higher mining and transportation costs for coal have eroded coal's competitiveness, leading to less frequent dispatch of coal units and lower demand for coal. Over the past decade, coal's net generation decreased by ten percent, while natural gas increased by nearly 50 percent.[55] Little new coal capacity is likely to be added over the coming decades.[56]
- **Large numbers of coal plants are retiring in response to environmental regulations.** Strict new environmental regulations would require substantial new capital investments and increase operating costs for coal plants. This has led to coal plants across the country becoming uneconomic and announcing retirement, or converting to other fuel sources. Recent estimates project that a significant portion of the current coal fleet—up to 77 GW—will retire by 2020.
- **Otter Creek has a limited number of potential customers, and these coal plants are becoming uneconomic.** High sodium content limits Otter Creek's customer base,[57] and many of these potential customers may retire or convert to other fuels due to the high costs of complying with new environmental regulations—in fact, several have already announced their retirements.[58] Our analysis shows that the majority of these plants will be uneconomic compared both to the costs of operating existing natural gas plants and to the total costs of constructing and operating new natural gas plants.

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53 EIA. 2013. 2012 Annual Energy Outlook. http://www.eia.gov/forecasts/aeo/er/index.cfm

54 Foster, Ben, et al. 1012. The 2012 State Energy Efficiency Scorecard. American Council for an Energy-Efficient Economy. http://www.aceee.org/research-report/e12c

55 EIA. 2001-2012. Form 923, Schedule 5A.

56 EIA. 2012 Annual Energy Outlook. http://www.eia.gov/forecasts/aeo/MT_electric.cfm

57 The high sodium content of Otter Creek coal (and other Northern PRB coal) causes slagging problems in boilers. See footnote 3.

58 See footnote 35.

- **Renewable portfolio standards, energy efficiency policies, and the likelihood of future carbon limits are reducing demand for coal.** Standards and goals for renewable energy are increasing the amount of renewables on the grid and heightening demand for natural gas as a complementary energy source due to its ability to adjust output much more quickly than coal. At the same time, increasingly aggressive energy efficiency investments are lowering energy demand across the board. Finally, a future price on carbon would drastically lower demand for coal, with generation falling to as little as 4 percent by 2040 under a carbon fee of $25.[59] Many utilities and planning commissions are already factoring carbon prices into their planning.

The long-term viability of coal is severely threatened. Demand for coal is falling across the United States, and Otter Creek's coal market is further limited by the coal's high sodium content and connection to Northern, rather than Southern rail lines. In short, it is unreasonable to expect that there will be much, if any, domestic demand for Otter Creek coal when the mine becomes operational in 2017. There is, therefore, no justification for expanding rail transportation infrastructure to connect the Otter Creek coal mine to struggling domestic markets.

[59] EIA. 2012 Annual Energy Outlook www.eia.gov/pressroom/presentations/sieminski_01142013.ppt