Electricity Production Under Carbon Constraints: Implications for the Tenth District

By Mark C. Snead

Coal is the dominant fuel used to produce electricity in the United States, accounting for almost half of production. Although coal is cheap and abundant domestically, the burning of coal releases greenhouse gases (GHG) and particulates. In response, many states have increased the use of cleaner alternative fuels, primarily natural gas and renewable energy. However, roughly half of the states still rely heavily on coal to generate electricity.

In the Federal Reserve's Tenth District, six of seven states are coal-dependent, generating two-thirds or more of their electricity from coal. Coal-intensive states face regulatory risk from increased restrictions on GHG emissions. Forecasts suggest GHG restrictions would rapidly accelerate the use of cleaner fuels, but would require extensive and expensive changes in the mix of generation capacity in many states.

This article examines the potential impact of national GHG restrictions on Tenth District energy producers and consumers. The findings suggest that GHG restrictions would lead to a structural change in the mix of fuels used to generate electricity in most District states, as well as increase electricity costs to District consumers. District natural gas

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producers would benefit from increased gas consumption, but not as much as emerging natural gas producers in other areas of the country. District coal producers, particularly in Wyoming, would face sharply reduced domestic demand for coal.

The first section of the article examines trends in electricity production and fuel use in the United States and Tenth District states. The second section describes recent U.S. Department of Energy (DOE) forecasts for energy use and production, including a scenario with national GHG restrictions. The third section examines potential impacts of GHG restrictions on District electricity producers and consumers. The fourth section identifies possible spillover effects for District coal and natural gas producers.

I. U.S. AND TENTH DISTRICT ELECTRICITY FUEL USE TRENDS

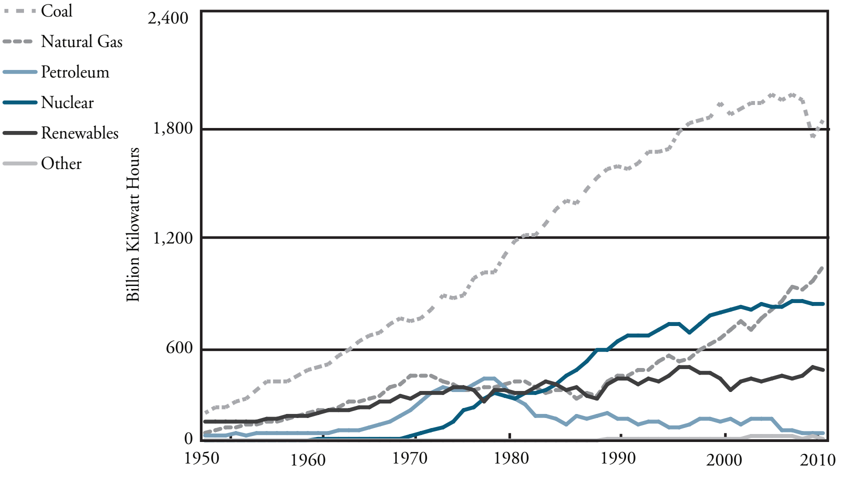
Historically, the United States has relied on coal for about half of its electricity needs, with a mix of petroleum, natural gas, nuclear power, and renewable energy accounting for the rest. Shares of these fuels have shifted over time in response to market and regulatory forces. In recent years, the growth of coal consumption has slowed and use of natural gas and renewable energy has grown. In contrast, the Tenth District continues to rely heavily on coal and much less on other fuels than the nation.[1]

Historical U.S. electricity fuel use patterns

The modern U.S. electricity fuel mix began to take shape in the late 1940s with the use of large-scale generators fired by coal, natural gas, and petroleum (Charts 1 and 2). *Coal* quickly became the dominant fuel. By the 1950s, it had captured a 50-percent share of U.S. electrical generation. Coal steadily gained share until the late 1960s when petroleum use surged and the nuclear power sector emerged. Coal use accelerated again in the 1980s, despite growing concerns about emissions (Hansen and others 1981). Coal's share peaked in 1987 at 58 percent, but has since declined steadily to around 45 percent under rising regulatory pressure. Today, coal remains inexpensive and abundant. The U.S. Energy Information Administration (EIA) estimates a domestic supply of more than 200 years at current mining rates.

Chart 1

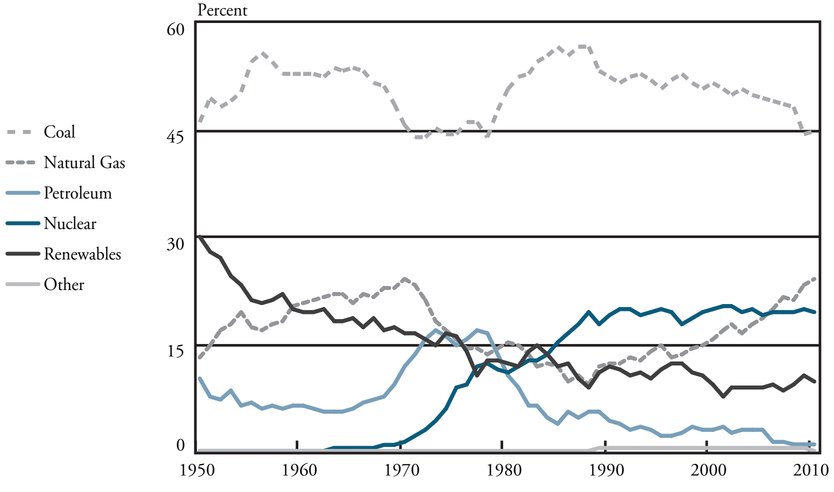
ELECTRICITY PRODUCTION BY FUEL TYPE (1950-2010)



Source: EIA, Annual Energy Outlook 2011

Chart 2

FUEL SHARE IN ELECTRICITY PRODUCTION (1950-2010)



Source: EIA, Annual Energy Outlook 2011

Petroleum-fired generation expanded rapidly in the 1940s, but quickly lost favor to cheaper coal and natural gas. Petroleum surged again in the late 1960s amid strong domestic crude oil production. That trend reversed in the 1970s as global crude prices increased and domestic production declined. By 1985, petroleum was mostly gone from the electricity fuel mix and had been redirected to meet growing demand for transportation fuels.

Natural gas use grew amid increased demand for electricity in the 1950s and 1960s. By 1970, natural gas had a share of 25 percent. But regulatory pressure, declining domestic production, and rising prices contributed to a sharp decline throughout the 1970s and 1980s.[2] By 1987, the share of natural gas bottomed at 10 percent before it rebounded as tighter emissions restrictions were placed on coal.[3] By 2010, growing domestic supplies and lower prices returned natural gas to a share of nearly 25 percent. Recent production gains from shale and tight gas formations have reduced concerns about future natural gas supplies (DOE 2011j). In fact, electricity providers recently surpassed industrial firms as the largest single end-users of natural gas in the United States (EIA 2011b).

Nuclear power emerged in the late 1960s from technology developed during World War II. Nuclear power quickly gained share at the expense of coal and natural gas, reaching a 10-percent share by the mid-1970s. Nuclear power diversified the fuel mix amid uncertainty about energy supplies following the Arab oil embargo in 1973-74. A second wave of nuclear power plant construction pushed the nuclear share to 20 percent by 1990. Nuclear has retained that share even though no reactors have been built in the United States since 1996. Expanded use of nuclear generation faces environmental opposition and concerns about safety following accidents at Three Mile Island (1979), Chernobyl (1986), and Fukushima Daiichi (2011) in Japan. However, the Nuclear Regulatory Commission recently gave final approval to a new reactor design planned for construction in several states (Smith 2011).

Renewable energy sources transitioned from hydroelectric generation as the category's primary source in the last century to today's portfolio of wind, solar, and biofuels. Hydroelectric generation has slowly increased over time, but its share of total generation has declined steadily since the 1940s. Since 2001, hydroelectric generation has maintained its low share of 7 percent. Interest in cleaner, renewable energy sources grew in the 2000s. By 2010, the use of utility-scale wind power boosted the renewables share to nearly 11 percent. Energy from solar thermal and photovoltaic sources is coming online slowly and contributes a negligible share of total power production. Biomass generation is also early in its development, but the use of waste heat from biofuel (ethanol) production is expected to rapidly increase its share.

U.S. fuel use shifted again during the 2007-09 recession as domestic electricity consumption contracted with worsening economic conditions. Coal use fell sharply for the first time in the modern electric power era. Coal's share of less than 45 percent was the lowest since the 1970s. Power producers increasingly switched to natural gas and wind energy during the recession in response to low natural gas prices and federal wind tax incentives. Coal use has rebounded only slightly in the recovery, leaving the 2010 U.S. electricity fuel mix at approximately 45 percent coal, 24 percent natural gas, 20 percent nuclear, 10 percent renewable energy, and 1 percent other fuels.

Tenth District fuel mix

Despite pressures to replace coal with cleaner fuels, few of the recent national trends appear in the Tenth District fuel mix. Most District states are far more reliant on coal and use much less natural gas and renewable energy to generate electricity than the nation.

In 2010, almost 70 percent of electricity generated in the District was derived from coal, versus 45 percent nationally (Table 1). Only Oklahoma has reduced its reliance on coal (43.7 percent share) to near the national share. Conversely, coal is the dominant electricity fuel in Wyoming and Missouri, where their respective shares of 89.4 percent and 81.3 percent are second and eighth in the nation. Wyoming's coal dependency is the result of it being the nation's largest coal producer, coupled with low transportation costs to state power plants. Missouri recently extended its commitment to coal when it opted to add a large coal-fired generating plant to meet growing electricity demand. The remaining District states of Colorado, Kansas, Nebraska, and New Mexico still depend on coal for about two-thirds of their electricity. Kansas and Nebraska have not greatly altered their recent coal use, but Colorado and

Table 1

U.S. AND TENTH DISTRICT ELECTRICITY PRODUCTION BY FUEL TYPE (2010)

Generation by Fuel Type (Gigawatt Hours)

State	Coal	Natural Gas	Nuclear	Renewable	Petroleum	Other	Total
Colorado	34,965	11,498	0	5,089	12	91	51,656
Kansas	32,505	2,788	9,556	3,467	104	0	48,419
Missouri	75,341	4,799	8,996	3,345	128	79	92,689
Nebraska	23,340	434	11,054	882	31	66	35,807
New Mexico	25,618	8,515	0	2,083	45	33	36,294
Oklahoma	31,630	34,034	0	6,510	16	160	72,350
Wyoming	42,532	508	0	4,215	56	284	47,596
Tenth District	265,931	62,575	29,606	25,592	392	715	384,811
U.S.	1,850,750	981,815	806,968	402,548	36,925	41,022	4,120,028

Percent Share of Generation

State	Coal	Natural Gas	Nuclear	Renewable	Petroleum	Other	Total
Colorado	67.7	22.3	0.0	9.9	0.0	0.2	100
Kansas	67.1	5.8	19.7	7.2	0.2	0.0	100
Missouri	81.3	5.2	9.7	3.6	0.1	0.1	100
Nebraska	65.2	1.2	30.9	2.5	0.1	0.2	100
New Mexico	70.6	23.5	0.0	5.7	0.1	0.1	100
Oklahoma	43.7	47.0	0.0	9.0	0.0	0.2	100
Wyoming	89.4	1.1	0.0	8.9	0.1	0.6	100
Tenth District	69.1	16.3	7.7	6.7	0.1	0.2	100
U.S.	44.9	23.8	19.6	9.8	0.9	1.0	100

Source: EIA (EIA-923 Survey)

New Mexico have cut their dependency and plan to shutter older, higher emitting coal plants.

The national shift toward natural gas has been replicated in only three District states—Colorado, New Mexico, and Oklahoma. Each is a major natural gas producer and has made a commitment to greater natural gas usage. Oklahoma produced nearly half of its electricity from natural gas in 2010, surpassing coal as the state's top electricity fuel. Colorado and Nebraska each reached the national natural gas share of about 25 percent in 2010. In contrast, Wyoming, with a share of about 1 percent, is the only major natural gas producing state not to embrace its use.[4]

Like Wyoming, the remaining District states—Kansas, Missouri, and Nebraska—use very little natural gas but are the only District states with nuclear power. The share of nuclear energy in power generation ranges from 10 percent in Missouri to 30 percent in Nebraska. Kansas—with a share of 20 percent—is similar to the national average. The lack of nuclear power in other District states reflects a continued appetite for coal and natural gas, but also limited water availability and environmental opposition to nuclear power, particularly in the Mountain states of Colorado and New Mexico. The three nuclear states in the District nonetheless remain dependent on coal for an average of 70 percent of their total electricity needs.

The District share of renewable energy has long lagged the nation. Historically, this reflects a lack of significant hydroelectric generation potential. Colorado has matched the nation in achieving a 10-percent renewable share, followed by Oklahoma and Wyoming with 9-percent shares. Kansas and New Mexico have shares of 7 percent and 6 percent, respectively, while Missouri and Nebraska have shares of less than 4 percent. Despite its lag in renewable share, the District possesses high potential for wind and solar development.[5] The District also has added significant wind capacity in recent years.[6] Most of the District's wind generation capacity is in Colorado, Kansas, Oklahoma, and Wyoming, each with 1,000 megawatts to 1,500 megawatts (MW) of wind capacity.[7]

II. FORECASTS OF ELECTRICITY PRODUCTION THROUGH 2035

Given trends in the U.S. electricity fuel mix, this section examines recent DOE forecasts for electricity use and production through 2035. The forecast assumes coal use will rise long term and share roughly equally with natural gas and renewable energy in meeting future electricity demand. An alternative scenario (GHG case) evaluates the case of a national price applied to future carbon dioxide (CO_2) emissions.[8] The CO_2 price triggers a realignment of electricity fuel use and generating capacity in the United States and raises electricity prices to end users.

Reference case

DOE's 2011 Annual Energy Outlook (EIA 2011b) provides a comprehensive model-based forecast of U.S. energy use and production through 2035. The reference case assumes current environmental standards and market conditions remain largely in place, and that no additional federal regulations explicitly limiting GHG emissions from power plants are enacted.[9]

In this generally stable environment, the U.S. electricity fuel mix undergoes little change through 2035 (Charts 3 and 4). Total coal usage remains flat through 2015, but then resumes steady growth through 2035, maintaining a share near 45 percent. Total natural gas usage remains near current levels through 2025 in response to rising natural gas prices, but then expands to a 25-percent share by 2035. Nuclear generation rises slightly through 2020, but declines from a 20-percent share to a 15-percent share through 2035 as additional nuclear power plants are retired. Renewable energy gains the greatest long-term share in the reference case, increasing steadily from 11 percent in 2010 to 15 percent by 2035.[10] Overall, the predicted U.S. electricity fuel mix under the reference case shifts slightly from nuclear to renewable energy through 2035, leaving the fuel mix at 44 percent coal, 25 percent natural gas, 15 percent renewable energy, 15 percent nuclear power, and 1 percent other fuels. The stable fuel mix produces little price volatility, as real electricity prices in 2009 dollars are expected to remain near 9 cents per kilowatt hour (kWh) through 2035 (Chart 5).

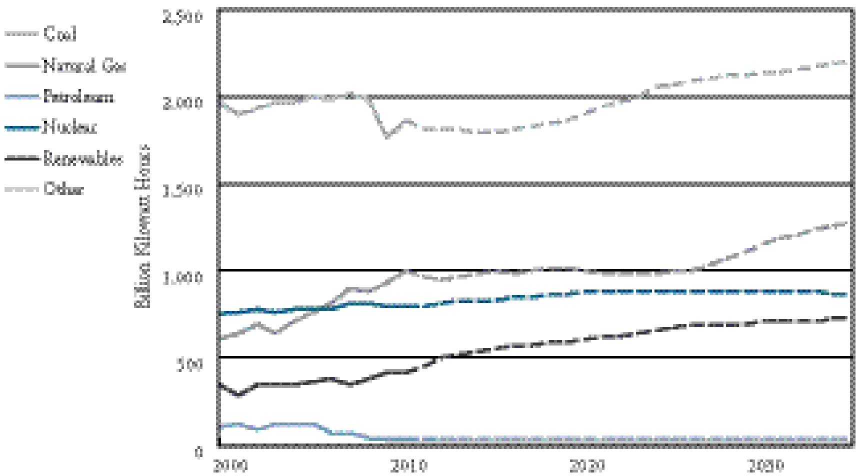
GHG case

DOE projects a dramatically different outcome for electricity producers and consumers under nationwide GHG restrictions. The scenario reflects a significant national effort to reduce GHG emissions that results in a restructuring of the U.S. electric power generation mix.[11] In the GHG case, a price of $25 per ton in 2009 dollars is applied to CO_2 emissions beginning in 2013, and increased to $77 per ton in 2035.[12] Total CO_2 emissions originating in the electric power sector decline to 45 percent of 2010 levels by 2035. The enactment of the CO_2 price is assumed to only slightly reduce the average annual growth rate in U.S. real gross domestic product (GDP) through 2035 (EIA 2011b).

In the GHG scenario, total electricity generation grows 15 percent from 2010 to 2035—a slowdown from 25 percent in the reference case. The lower production estimate reflects the response of consumers to higher electricity costs. Real electricity prices climb steadily beginning

Chart 3

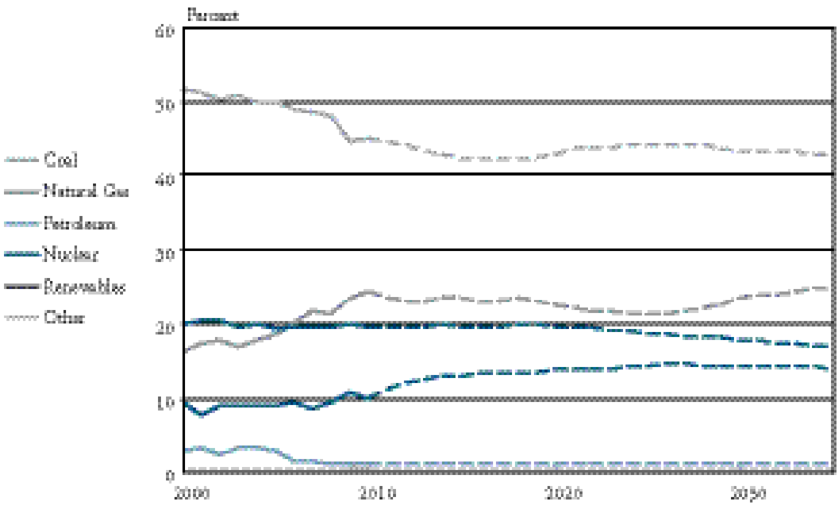
FORECAST OF ELECTRICITY PRODUCTION BY FUEL TYPE (2010-35)



Source: EIA, Annual Energy Outlook 2011

Chart 4

FORECAST OF FUEL SHARE IN ELECTRICITY PRODUCTION (2010-35)

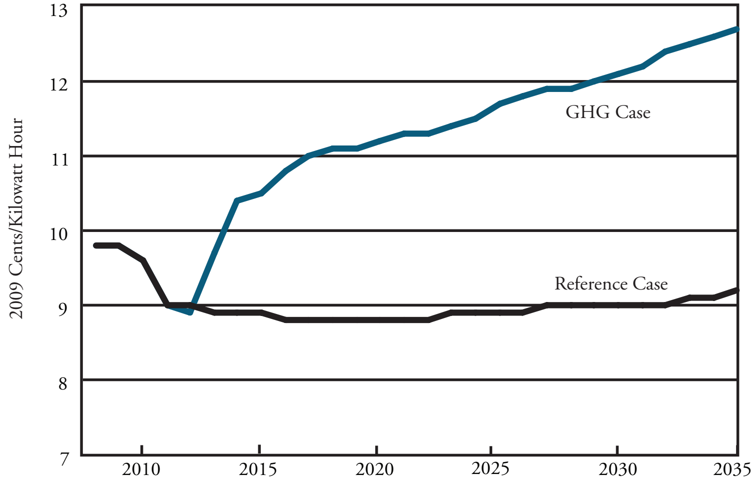


Source: EIA, Annual Energy Outlook 2011

Chart 5

FORECASTS OF REAL ELECTRICITY PRICES

Average of All Uses



2011 Reference and economy-wide greenhouse gas (GHG) cases.
Source: EIA, Annual Energy Outlook 2011

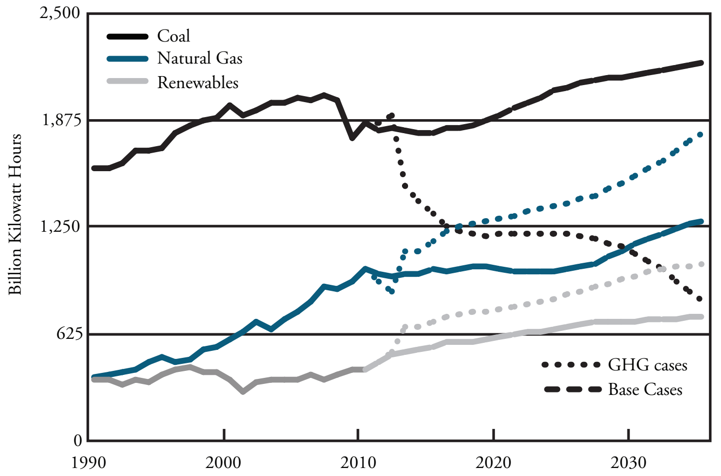
in 2013 from 9.8 cents per kWh in 2009 to 12.8 cents per kWh by 2035, an increase of roughly 30 percent (Chart 5). The price increase results from a shift by electricity providers toward more expensive fuels, the pass through of costs to alter the existing generation mix, and the price applied to CO_2 emissions.

Most of the emissions reductions are achieved through a shift from coal to natural gas and renewable energy (Charts 6 and 7). The shift from coal is rapid and substantial. Total coal use falls one-third below 2010 levels by 2018, and ultimately falls more than 60 percent below 2010 levels by 2035 (Chart 6). To offset the decline in coal, natural gas use increases by about one-third by 2017 and replaces coal as the dominant electricity fuel as early as 2015. By 2035, total natural gas and renewable energy use increase by 80 percent and 150 percent, respectively. Natural gas reaches a 38-percent share of electricity generation and renewables reach a 22-percent share, both well above coal's eventual 17-percent share in 2035. Nuclear energy's share is assumed to increase slightly through 2035, mostly due to nuclear generation capacity added after 2030. Overall, U.S. electricity generation is substantially less carbon-intensive in the GHG case, having shifted to 38 percent natural

Chart 6

FORECASTS OF ELECTRICITY PRODUCTION BY FUEL TYPE (2010-35)

Base and GHG Cases

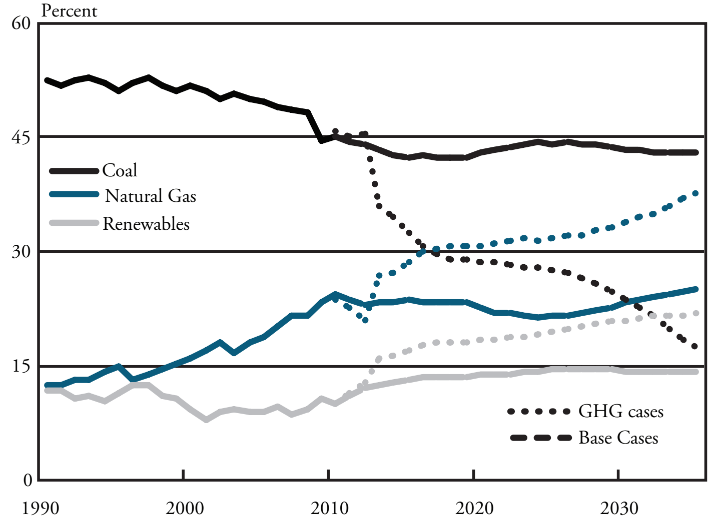


Source: EIA, Annual Energy Outlook 2011

Chart 7

FORECASTS OF FUEL SHARE BY FUEL TYPE (2010-35)

Base and GHG Cases



Source: EIA, Annual Energy Outlook 2011

gas, 22 percent renewable energy, 22 percent nuclear power, 17 percent coal, and 1 percent other fuels by 2035.

Projected changes in generation capacity in the GHG case

To accommodate DOE's projected shift in fuel mix in the GHG case, U.S. power producers must substantially restructure the existing mix of generation capacity. Total generating capacity is roughly unchanged through 2035. However, a sharp reduction in coal-fired capacity is offset by increased use of renewable energy and modern natural gas combined-cycle (NGCC) plants capable of base load generation.[13]

DOE projects that U.S. coal capacity will decline 40 percent from 2009 levels by 2016, mostly through a surge in retirements of existing coal plants. These retirements would eliminate 12 percent of total capacity and reduce coal's share from 30 percent to 18 percent by 2035. An equivalent 40-percent reduction in District coal capacity would require the retirement of 18 percent of total District capacity. For the District to achieve the projected U.S. coal share of 18 percent, more than 60 percent of existing District generating capacity would have to be retired.

Most coal-intensive states would face a similar prospect of retiring half or more of their existing coal-fired capacity to match the projected U.S. coal share. Nonetheless, the realized impact of coal plant retirements would likely be eased by the age of the existing coal-fired fleet. Nearly two-thirds of national and District coal generating capacity is at least 30 years old and approaching the end of its useful economic life (EIA 2011d).

Reductions in coal capacity in the GHG case are largely offset by a 16-percent (65,000 MW) increase in capacity at modern NGCC plants. This added capacity is about 40 percent of the NGCC capacity added in the past decade. Recent DOE estimates suggest that a typical advanced NGCC generator with a rated capacity of 400 MW has an estimated "overnight capital cost" of roughly $1 million per MW (EIA 2010).[14] Based on these specifications, the GHG case suggests a need for 160 new advanced NGCC systems nationally at an estimated cost of $400 million each. The added plants would raise the national share of NGCC generation to the projected 21-percent level.[15] Utilization rates at existing NGCC plants would also rise with their share of base load generation.

At the District level, the current share of natural gas capacity (37.5 percent) is only slightly below the national share (39.2 percent). However, only a little more than half of the natural gas capacity added in the District since 1990 is at NGCC plants. To match the projected 21 percent U.S. share, District power producers would need an additional 8,000 MW of NGCC capacity (a 72-percent increase). This is equivalent to about 20 additional NGCC plants in the District.

Renewable energy capacity is projected to increase 67 percent (from 122,400 MW to 203,300 MW) by 2035, ultimately accounting for 20 percent of capacity.[16] Nearly all of the projected renewable capacity is wind generation and would approximately triple existing wind capacity in the United States.

Although the Tenth District currently has nearly double the U.S share of wind capacity (6.1 percent versus 3.3 percent), achieving the 20 percent national renewable share would require slightly more than a tripling of current District wind capacity. The District would have to add about 12,500 MW, or 8,300 wind turbines, based on the historical District average capacity of 1.5 MW per turbine.[17] DOE estimates that a standard onshore wind generator with a rated capacity of 1 MW has an estimated overnight capital cost of roughly $2.4 million (EIA 2010).

III. IMPACTS ON DISTRICT POWER PRODUCERS AND CONSUMERS

Predicted shifts in the U.S. electricity mix under the GHG scenario raise concerns for District electricity producers and consumers. Sharp reductions in coal use would require substantial restructuring of the electricity generation mix in most District states. DOE projections also suggest that average electricity prices nationally would increase to levels near current prices in states that use the least coal. High coal dependency among District states suggests the possibility of rapid and substantial increases in electricity prices.

Impact of fuel mix changes on Tenth District capacity

The projected shift from coal to natural gas and renewable energy will require substantial changes in the District's generation mix. Table

Table 2

TENTH DISTRICT GENERATING CAPACITY BY FUEL TYPE (2009)

Megawatts, Summer Nameplate Capacity

	Percent Share of Generating Capacity by Fuel Type					
State	Coal	Natural Gas	Nuclear	Renewable	Petroleum	Other
Colorado	38.4	41.0	0.0	19.0	1.4	0.1
Kansas	41.3	36.8	9.3	8.1	4.5	0.0
Missouri	53.9	26.9	5.7	7.3	6.1	0.0
Nebraska	49.8	24.1	16.1	4.9	5.0	0.1
New Mexico	49.8	41.3	0.0	8.5	0.4	0.1
Oklahoma	25.6	63.0	0.0	10.8	0.3	0.4
Wyoming	78.4	1.6	0.0	18.6	0.1	1.4
Tenth District	44.7	37.5	4.0	10.8	2.8	0.2
U.S.	30.5	39.2	9.9	13.2	5.3	1.9
U.S. GHG Case (2035)	18.0	45.3	12.7	19.5	2.4	2.1

Source: EIA (EIA-860 Survey and 2011 Annual Energy Outlook)

2 compares the current share of generation capacity by fuel type for each District state to projected U.S. fuel shares in 2035. The data show District states would face challenges in altering their existing capacity to match predicted changes in the national generation mix. Concerns include a high share of coal capacity, a lack of existing NGCC capacity, and limited renewable energy potential.

Among District states, only Oklahoma (25.6 percent) is near the projected 18 percent national coal share of capacity for 2035. Meeting the U.S. share would require the retirement of relatively few Oklahoma coal plants. The remaining District states, however, have significant excess coal capacity relative to the U.S. Coal's share in Missouri, Nebraska, and New Mexico is about 50 percent. In Colorado and Kansas, the share is near 40 percent. The coal share in those states is more than double the projected national share in the GHG case. Wyoming's coal share of nearly 80 percent is more than four times the projected national share. Retiring a large number of coal plants would be needed to meet the projected national share in Missouri, Nebraska, New Mexico, Colorado, Kansas, and Wyoming.

Heavy investment in modern natural gas-fired plants would also be required in most District states. Of the District's 11,000 MW of NGCC capacity added since 1990, half is in Oklahoma.[18] These additions place Oklahoma above the projected U.S. share of 21 percent for NGCC generation. Matching the projected national share would require more than doubling NGCC capacity in Missouri and a fourfold increase in Nebraska. Both Kansas and Wyoming would face significant costs to install the required NGCC capacity. Wyoming has little installed natural gas capacity of any type.

The ability of District states to meet the projected 20 percent renewable share of capacity in the GHG case also is mixed. Colorado and Wyoming already have high renewable shares near 20 percent. However, the remaining District states would have to increase their renewable capacity twofold to fourfold to achieve the projected U.S. share of 20 percent in 2035. Wind generation potential in the District is adequate to match the projected U.S. renewable share, but the potential is not equal across the states. Almost 80 percent of the District's installed wind capacity is in Colorado, Kansas, Oklahoma, and Wyoming.[19] These states each have between 1,000 MW and 1,500 MW of installed wind capacity, or 650 to 1,000 wind turbines.

District state shifts

Predicting each District state's adjustment to GHG restrictions is complicated by the lack of an existing national framework to govern energy production and delivery. Such a framework could be used to allocate the projected national capacity changes and carbon reductions among the states.[20] The existing state and regional regulatory framework sheds little light on how DOE's GHG case would be implemented. Nevertheless, an overview of the current fuel mix and existing generation portfolio suggests the potential ability of each District state to adapt to GHG constraints.

Colorado is highly coal intensive relative to national standards but already has redirected some electricity production to natural gas and renewable energy. Its coal share is now only slightly above the national share, but producers still generate two-thirds of the state's electricity with coal. Modern NGCC plants comprise 14 percent of generating capacity, and renewable energy mandates have helped Colorado far exceed the national share of renewable capacity. There is large untapped potential for wind and solar in Colorado, particularly wind potential along the Front Range and in the eastern plains. Although coal remains important in power generation, Colorado is relatively well positioned to adapt to future GHG constraints.

Kansas must balance excess coal capacity and limited NGCC capacity with strong wind potential and existing nuclear power. Coal is more than 40 percent of generating capacity and fuels two-thirds of the electricity generated statewide. Kansas has significant existing natural gas capacity but none is modern NGCC generation. Although the renewable share of generating capacity in Kansas is well below the national share, western Kansas has widespread areas well suited for future utility-scale wind generation. The 10 percent nuclear share gives Kansas another option for low-carbon electricity going forward. Continued high coal use and lack of NGCC capacity will challenge Kansas.

More than half of **Missouri's** generating capacity is coal-fired, which could leave the state saddled with significant excess coal-fired capacity under national GHG constraints. Missouri also generates more than 80 percent of its electricity from coal and has recently expanded its coal capacity. The state also has only half the national share of NGCC generating capacity. Missouri uses very little renewable energy and has relatively little future wind and solar potential. The lack of renewable potential is partly offset by nuclear power, which gives the state an additional low-carbon option in the future. Overall, Missouri is among the group of states that would likely face the most substantial challenges under GHG restrictions.

Nebraska's advantage under GHG constraints is that it generates 30 percent of its electricity from carbon-free nuclear power. However, 65 percent of the state's electricity is still derived from coal. Similar to Missouri and New Mexico, roughly half of Nebraska's generating capacity remains coal-fired, and the state could be left with significant excess coal-fired capacity under GHG constraints. Generation from modern NGCC plants and renewable energy each accounts for only 5 percent of generation. Nebraska uses relatively little renewable energy despite widespread areas with moderate wind generation potential. Nuclear power would aid Nebraska's adjustment to emission constraints, but high coal usage suggests that the state would face considerable challenges.

New Mexico remains coal-intensive, with 70 percent of its electricity production coal-fired. However, like Colorado, the state has already opted to close some of its highest emitting coal plants. The state has also made a considerable commitment to natural gas generation, with current NGCC capacity at 17.5 percent of total capacity. The overall renewable share in New Mexico is currently below the national share, but there is substantial untapped solar and wind generation potential across the state. New Mexico's existing NGCC capacity and renewable potential leave the state relatively well positioned to reduce its coal usage under GHG constraints.

Overall, **Oklahoma** is best positioned among the District states to adapt to projected capacity changes under GHG constraints. Coal represents only 25 percent of total generating capacity in the state, well below the national share. Oklahoma already has a large installed base of NGCC plants and ready access to local sources of natural gas. Nearly half of the state's electricity is currently generated from natural gas. The state's renewable share of capacity is near the national share, and the western portions of Oklahoma will support substantially more utility-scale wind generation. Oklahoma's transition would likely mirror the overall national shift as projected in DOE's GHG case.

Wyoming remains the most coal-dependent state in the District and one of the most coal-dependent states nationally. The state's electricity base lacks diversification, with wind the only other major source of generating capacity in the state. The large base of wind generation gives Wyoming a renewable energy share well above the nation, and the state is home to some of the nation's best onshore wind generation potential. However, Wyoming has negligible installed natural gas capacity of any type despite being a major natural gas producer. Wyoming's near exclusive dependence on coal suggests that its electricity producers would face substantial hurdles in adapting the state's generation base to national GHG constraints.

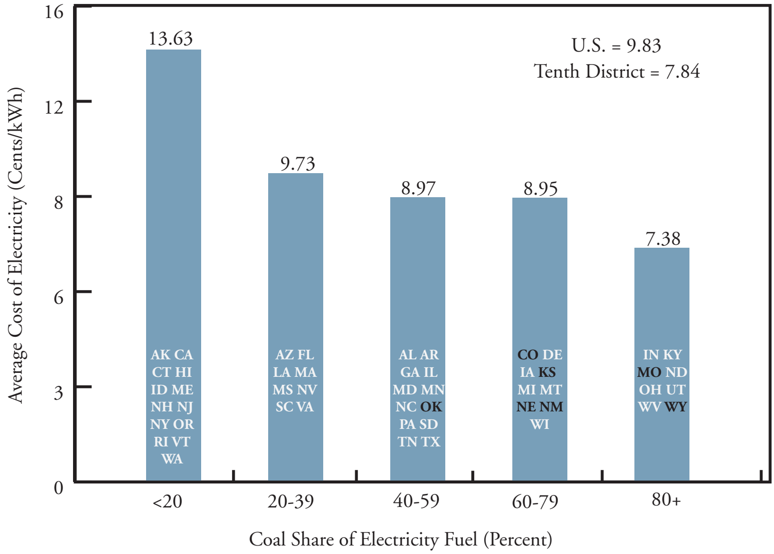
Cost of electricity

The shift from coal in the GHG case is expected to significantly increase average electricity prices. Historically, electricity prices have depended on coal's share in the generation fuel mix, with the most coal-intensive states generally having the lowest electricity costs. Chart 8 shows the general inverse relationship between coal share and electricity price across states.

The eight states with a coal share of 80 percent or more had an average cost of only 7.38 cents per kWh, 25 percent below the 9.83 cents per

Chart 8

COST OF ELECTRICITY BY SHARE OF COAL GENERATION (2010)



Note: Tenth District states highlighted in black.
Source: EIA

kWh price nationally. This group of highly coal-intensive states includes the District states of Missouri and Wyoming. Wyoming generated 89 percent of its electricity from coal in 2010 and had the lowest electricity cost among the group at 6.20 cents per kWh—almost 40 percent below the U.S. average. Across all Tenth District states, the price of electricity averaged only 7.84 cents per kWh in 2010, 20 percent less than the U.S. average. Electricity prices increase to approximately 9 cents per kWh for the two groups of states using 40 percent to 59 percent and 60 percent to 79 percent coal, and rise rapidly again as the share of coal falls below 40 percent. The average cost in those states using 20 percent to 39 percent coal in 2010 was 9.73 cents per kWh—32 percent higher than the most coal-intensive group (80 percent or more).

The comparatively high price paid for electricity in the 13 states using less than 20 percent coal provides insight into expected prices under GHG restrictions for the most coal-intensive states. Electricity averaged 13.63 cents per kWh in these states in 2010, almost 40 percent higher than in states using 20 percent to 39 percent and nearly double the average cost paid in the most coal-intensive group.[21] These low-coal states currently pay the highest electricity costs but already closely approximate the projected generation mix under the GHG case. They are significantly less carbon-intensive overall and release at least one-third less CO_2 per capita than the nation as a whole (Snead and Jones 2010). Excluding Alaska and Hawaii, the remaining 11 states in the low-coal group rank among the 14 lowest emitting states based on CO_2 emissions per capita. New York, the least carbon-intensive state with only about half the CO_2 emissions per capita of the nation, had average electricity costs of 16.41 cents per kWh in 2010.

The cost of electricity in the low-coal (less than 20 percent share) states also provides a reasonableness test for DOE's projected 30 percent increase in real electricity costs from 2009 to 2035. DOE's inflation-adjusted price of 12.8 cents per kWh in 2035 is only slightly below the current average price of 13.63 cents per kWh in the low-coal states. The current price in these states, given their low share of coal generation, provides another indication that coal-dependent states can expect considerable price increases under GHG restrictions.

IV. IMPACT ON DISTRICT COAL AND NATURAL GAS PRODUCERS

The Tenth District is home to the largest coal producing state (Wyoming) and four of the six major natural gas producing states (Colorado, New Mexico, Oklahoma, and Wyoming). Predicted shifts in the U.S. electricity fuel mix under the GHG case present clear challenges for District coal producers but possible opportunities for District natural gas producers. The projected sharp decline in coal consumption by the power sector would hurt District coal producers, while increased domestic natural gas production and higher prices would benefit District natural gas producers.

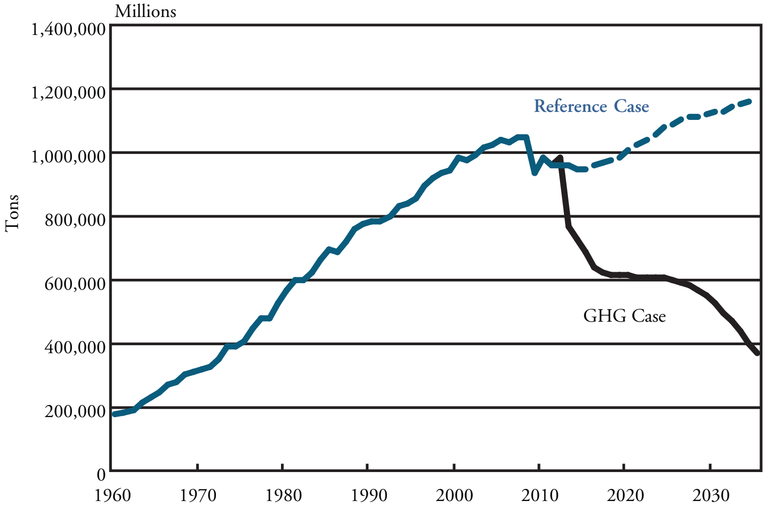
District coal producers

The magnitude of the predicted reduction in coal use in the GHG case presents a considerable challenge for District coal producers. Annual coal consumption declines by more than 60 percent—from 935 million tons in 2010 to 370 million tons in 2035 (Chart 9). Two-thirds of the decline occurs very rapidly, by 2018. The total projected decline

Chart 9

COAL CONSUMED BY THE ELECTRIC POWER SECTOR

Reference and GHG Cases



Source: EIA: 2011 Annual Energy Outlook, State Energy Data System

through 2035 reduces coal consumption in the power sector to roughly 1975 levels.

As the nation's largest coal supplier, Wyoming producers would clearly be at greatest risk under national GHG restrictions. Wyoming produced 45 percent (424 million tons) of all coal used in the U.S. power sector in 2010, including 85 percent of the coal used for electricity generation in the Tenth District (Table 3).[22] Wyoming coal is a major export product for the District, with two-thirds of the production shipped to states outside the District. At a 2010 price of $13 per ton, the annual value of Wyoming coal production reached $5.5 billion, or nearly 15 percent of state GDP. If the projected reduction in national coal use is borne heavily by Wyoming, alternative markets for coal would have to be sought to avoid a sharp blow to the state's economy.[23]

Reduced coal consumption could potentially impact District coal-producing states other than Wyoming. Six of seven District states (not Nebraska) produced coal for electricity generation in 2010 (Table 3). Production in these states totaled 41.7 million tons in 2010, about 10 percent of Wyoming's output. New Mexico produced nearly all of its own coal for electricity generation and exported substantial quantities

Table 3

COAL SUPPLY AND PURCHASES FOR ELECTRICITY PRODUCTION BY REGION (IN TONS)

Purchasing Region	Supplying Region: Colorado	Kansas	Missouri	New Mexico	Oklahoma	Wyoming	District	Non-District	Total
Colorado	8,882,867					8,544,409	17,427,276	0	17,427,276
Kansas			293,144			20,210,342	20,503,486	0	20,503,486
Missouri		74,319	52,933			42,957,263	43,084,515	1,148,787	44,233,302
Nebraska						13,788,290	13,788,290	0	13,788,290
New Mexico				14,411,710		28,968	14,440,678	0	14,440,678
Oklahoma		51			405,175	19,119,152	19,524,378	90,746	19,615,124
Wyoming						24,628,091	24,628,091	0	24,628,091
District	8,882,867	74,370	346,077	14,411,710	405,175	129,276,515	153,396,714	1,239,533	154,636,247
Non-District	10,368,752	0	0	7,164,504	0	294,350,575	311,883,831	469,737,758	781,621,589
Total	19,251,619	74,370	346,077	21,576,214	405,175	423,627,090	465,280,545	470,977,291	936,257,836

Source: EIA (EIA-923 Survey)

outside the District. Kansas and Missouri engaged in a small amount of cross-border coal trade, but both imported the bulk of their coal from Wyoming. Colorado produced about half of the coal it used in electricity generation and imported the other half from Wyoming. But Colorado exported more coal outside the District than it retained for use in-state.

Relative to Wyoming, the other coal-producing states in the District face little economic risk from GHG restrictions. New Mexico and Colorado both produced only about 20 million tons of coal in 2010, with the output in both states valued at approximately $700 million annually at recent prices. This production represents about 1.0 percent of total GDP in New Mexico and 0.3 percent in Colorado. The elimination of coal production in either state would likely have only localized impacts with little effect on overall state economic performance. In Kansas, Missouri, and Oklahoma, coal production is a very minor industry, and reduced coal usage would have few spillovers.

District natural gas producers

The District is also a major natural gas-producing region and would potentially benefit from increased natural gas usage by electricity producers. In the GHG case, added demand for natural gas by power producers is met by a projected 40 percent increase in output from 21.5 quadrillion Btu in 2009 to 30.23 quadrillion Btu in 2035 (Table 4). This estimate is 12 percent higher than projected output of 27.0 quadrillion Btu in 2035 under the reference case.

The projected rise in natural gas output is near the high end of the range of DOE production forecasts through 2035. The greatest production gains are expected in shale and tight gas formations. Production from these formations has increased by nearly 50 percent annually between 2006 and 2010 (EIA 2011j). The production gains also assume the continued use of horizontal drilling and hydraulic fracturing techniques.

The gains in production will be accompanied by rising natural gas prices (Table 4). The path of natural gas prices in 2009 dollars tracks only slightly above that in the reference case, rising steadily from $3.71 per thousand cubic feet (Mcf) in 2009 to $6.44 per Mcf in 2035. Despite recent production gains and large upward revisions in domestic natural gas reserves (Potential Gas Committee 2011), some researchers remain

Table 4
NATURAL GAS PRODUCTION AND PRICE FORECAST SCENARIOS

		2009	2015	2020	2025	2030	2035
Natural Gas Production (Quadrillion Btu)	Reference	21.50	23.01	24.04	24.60	25.75	27.00
	GHG	21.50	23.34	25.58	26.68	27.78	30.23
Wellhead Price of Natural Gas (2009 Dollars per Mcf)	Reference	3.71	4.24	4.59	5.43	5.81	6.42
	GHG	3.71	4.52	5.32	6.08	6.30	6.44

Source: EIA, 2011 Annual Energy Outlook

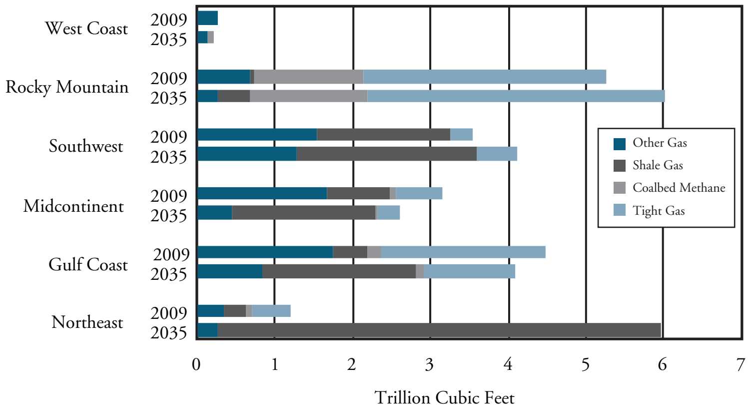
skeptical of the potential to maintain recent production gains without even higher natural gas prices (NETL 2008; and Berman 2009).

Assuming the natural gas production gains in the GHG case are realized, which producing regions of the country will benefit the most from added natural gas demand? Chart 10 summarizes DOE forecasts of domestic onshore natural gas production through 2035 by producing region and formation type. The Tenth District states are primarily located in the Rocky Mountain (Wyoming, Colorado, and western New Mexico) and Midcontinent (Kansas, Missouri, Nebraska, and Oklahoma) regions.[24]

The estimates suggest that most natural gas-producing regions of the country will benefit from added demand and higher prices, but the gains will not be evenly distributed. Most of the projected gains are in shale formations, which comprise a comparatively small share of production in the Rocky Mountain region and a rapidly growing but small share of Midcontinent production. District states are projected to participate in a 0.8 trillion cubic feet (Tcf) gain in annual output in the Rocky Mountain region through 2035, primarily from increased tight gas production. However, this gain is largely offset by an expected 0.5 Tcf decline in annual production in the Midcontinent region.

On balance, District producers should benefit from increased demand and higher prices for natural gas, but the region will not be the primary beneficiary. Most of the production gains are instead projected for the Northeast, primarily due to a near 500-percent increase in shale gas output projected for the Marcellus formation through 2035.

Chart 10
LOWER 48 ONSHORE NATURAL GAS PRODUCTION BY REGION, 2009 AND 2035



Source: EIA: 2011 Annual Energy Outlook

V. CONCLUSION

Recent forecasts of energy use and production under GHG restrictions highlight concerns for Tenth District electricity producers and consumers. National emission restrictions would accelerate the shift under way from coal to natural gas and renewable energy sources. Most District states have a coal-intensive electricity fuel mix and are not well prepared for national emissions restrictions. District coal and natural gas producers could also be impacted by any resulting shifts in the electricity fuel mix.

The article finds that District electricity producers would be required to make substantial shifts in fuel mix and generation capacity in order to match projected U.S. electricity generation trends under GHG restrictions. Oklahoma would have the easiest transition, followed by Colorado and New Mexico. These states have already made a major commitment to cleaner, modern natural gas-fired plants and have strong renewable energy potential. The remaining District states, especially coal-dependent Wyoming, would face substantial challenges in matching the projected U.S. shift in capacity.

The projected shift away from coal would translate into higher average electricity prices in most District states. Current electricity costs in the least coal-intensive states provide a useful benchmark for possible price increases in the most coal-intensive states. Based on this benchmark, the most coal-intensive states would be subject to the largest price increases.

District coal producers could face a sharp decline in coal demand under GHG restrictions. Wyoming, in particular, would face a large potential hit to economic activity. The added demand for natural gas by power producers under GHG restrictions is expected to produce strong gains in domestic natural gas production. However, District gas producers are expected to benefit less than other emerging gas-producing regions, particularly those in the Northeast.

ENDNOTES

[1]The Tenth District of the Federal Reserve comprises the states of Colorado, Kansas, Nebraska, Oklahoma, and Wyoming, as well as northern New Mexico and western Missouri.

[2]The Powerplant and Industrial Fuel Use Act of 1978 discouraged the use of natural gas and petroleum for electricity generation.

[3]Natural gas releases an average of 45 percent less CO_2 than coal under stationary combustion (EIA 2011n). However, the full life-cycle emissions of producing, transporting, and burning natural gas may be greater than implied by DOE combustion-based emissions estimates (Jaramillo and others 2007; Howarth and others 2011).

[4]The natural gas-producing states of Texas and Louisiana have shares of about 40 percent.

[5]Wind capacity maps are at DOE (2011). Wind and solar potential maps are at NREL (2011).

[6]Most District states have policies that mandate or encourage minimum levels of renewable fuels in future electricity production. Colorado, Kansas, Missouri, and New Mexico have enforceable mandates, and Oklahoma has a non-enforceable statewide renewable energy goal. Wyoming and Nebraska have no mandates or goals.

[7]Wind generation remains a minor share of total electricity production capacity in these states. District wind capacity reached 6,720 MW in June 2011, or 16 percent of total U.S. wind capacity. Wind capacity of 1,000 MW is roughly equal to the generation capacity of one large modern coal-fired electric plant, though wind generators generally operate at much lower utilization rates.

[8]The reference case assumes some market reaction to potential future GHG regulation. A 300 basis point increase in the cost of capital is assumed for investments in new coal-fired power plants if they do not employ carbon capture and sequestration technology. The same cost of capital assumption was justified in the GHG case evaluated in DOE's 2009 Annual Energy Outlook (EIA 2009a): "Although the 3-percentage-point adjustment is somewhat arbitrary, its impact in levelized cost terms is similar to that of a $15 fee per metric ton of CO_2 for investments in new coal-fired power plants without Carbon Capture and Storage (CCS)—well within the range of the results of simulations that utilities and regulators have prepared."

[9]There are two separate environmental concerns surrounding electric power emissions—noncarbon particulates such as mercury, nitrogen oxides (NOx), and sulfur dioxide (SO_2) emissions; and GHG emissions, primarily CO_2. Federal and state regulations have long addressed the impacts of particulates such as NOx and SO_2, and a number of federal efforts are under way to reduce these harmful noncarbon emissions. These programs include the Clean Air Mercury Rule

(CAMR) and the Clean Air Interstate Rule (CAIR). CAMR mandates reductions in mercury in electricity production. CAIR is a cap-and-trade program in the electric power sector that would reduce NOx and SO_2 emissions.

[10]Wind installations in the United States are expected to slow dramatically as federal tax credits expire at the end of 2012. Despite wind's rapid growth the last decade, it accounted for only slightly more than 3 percent of total electricity produced in the first half of 2011.

[11]The carbon price imposed in the GHG case is intended to achieve CO_2 reductions similar to those in the proposed American Clean Energy and Security Act of 2009. The act seeks to reduce GHG emissions to 17 percent below 2005 levels by 2020 and to 83 percent below 2005 levels by 2050. The legislation was passed by the House of Representatives but failed to move beyond debate in the Senate.

[12]The scenario does not include provisions for carbon offsets, bonus allowances, targeted allowance allocations, or increased efficiency mandates.

[13]Natural synergies exist between natural gas and renewable generation, particularly wind and solar power. These renewable sources generally require significant amounts of coal- or natural gas-fired generation on ready reserve, and faster ramp-up times for natural gas generators relative to coal make them more compatible with the intermittent nature of the sun and wind.

[14]From EIA (2011b): " 'Overnight cost' is an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through completion could be accomplished in a single day. The cost estimates for each technology were developed for a generic facility of a specific size and configuration, and assuming a location without unusual constraints or infrastructure needs. This concept is useful to avoid any impact of financing issues and assumptions on estimated costs."

[15]EIA (2011e) provides estimates of historical capacity factors by fuel source. Wind turbines operate at roughly 35 percent utilization rates and solar at 18 percent to 25 percent. Geothermal and biomass tend to produce 80 percent to 90 percent utilization rates, while hydroelectric plants operate at approximately 50 percent utilization rates. NGCC and coal-fired plants used for base load generation maintain approximately 85 percent utilization rates.

[16]Significant new biomass generation is assumed in the GHG case, primarily from the use of waste heat from biofuel (ethanol) production. However, this is not considered additional renewable capacity. Solar thermal and photovoltaic (PV) energy contributes a minor share of renewable power production.

[17]At the end of 2009, the District had nearly 3,700 wind turbines with a rated summer capacity of almost 5,500 MW.

[18]Colorado and Missouri have each added NGCC capacity of 1,850 MW since 1990; New Mexico has added 1,400 MW; and Nebraska 400 MW.

[19]Installed wind capacity was 42,432 MW in the United States and 6,720 MW in the Tenth District as of June 30, 2011 (DOE 2011). MW capacity by

District state: Colorado 1,299; Kansas 1,074; Missouri 459; Nebraska 294; New Mexico 700; Oklahoma 1,482; and Wyoming 1,412.

[20]The Tenth District stretches across four of the eight operating regions served by the North American Electric Reliability Corp. (NERC), the entity that assures reliability of the national electric system (NERC 2011). Hence, any change in the capacity mix in an individual District state must also take into consideration the overall load characteristics of the broader NERC region.

[21]Most of these low-coal states use significant amounts of relatively more expensive natural gas and nuclear generation, but also low-cost hydroelectric power. After removing the low-cost hydroelectric states—Idaho, Oregon, and Washington—from the group of states using less than 20 percent coal, the price of electricity for this group increases to 15.64 cents per kWh.

[22]Wyoming's coal output is three times higher than West Virginia, the second-ranked coal producer. However, the low energy content, or "heat rate," of Wyoming coal may lead to an overstatement of production as measured by power generation. Because Wyoming subbituminous coal has only about 70 percent of the energy per pound of Eastern coal, power producers must burn nearly 50 percent more Wyoming coal to produce the same power output as Eastern coal.

[23]Wyoming coal, especially from the Powder River Basin, could remain highly competitive relative to Eastern coal due to its low sulfur content. Sulfur dioxide emissions from coal-fired power plants are heavily regulated, and Wyoming coal contains only 0.35 percent sulfur by weight, versus 1.6 percent sulfur for Eastern coal. The favorable sulfur content per Btu and a lower price for Wyoming coal compensate for the fact that it has lower energy content.

[24]Eastern New Mexico is in the Southwest region.

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