Displacing Coal with Generation from Existing Natural Gas-Fired Power Plants

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Summary

Reducing carbon dioxide emissions from coal plants is a focus of many proposals for cutting greenhouse gas emissions. One option is to replace some coal power with natural gas generation, a relatively low carbon source of electricity, by increasing the power output from currently underutilized natural gas plants.

This report provides an overview of the issues involved in displacing coal-fired generation with electricity from existing natural gas plants. This is a complex subject and the report does not seek to provide definitive answers. The report aims to highlight the key issues that Congress may want to consider in deciding whether to rely on, and encourage, displacement of coal-fired electricity with power from existing natural gas plants.

The report finds that the potential for displacing coal by making greater use of existing gas-fired power plants depends on numerous factors. These include:

- The amount of excess natural gas-fired generating capacity available.
- The current operating patterns of coal and gas plants, and the amount of flexibility power system operators have for changing those patterns.
- Whether or not the transmission grid can deliver power from existing gas power plants to loads currently served by coal plants.
- Whether there is sufficient natural gas supply, and pipeline and gas storage capacity, to deliver large amounts of additional fuel to gas-fired power plants.

There is also the question of the cost of a coal displacement by gas policy, and the impacts of such a policy on the economy, regions, and states.

All of these factors have a time dimension. For example, while existing natural gas power plants may have sufficient excess capacity today to displace a material amount of coal generation, this could change in the future as load grows. Therefore a full analysis of the potential for gas displacement of coal must take into account future conditions, not just a snapshot of the current situation.

As a step toward addressing these questions, Congress may consider chartering a rigorous study of the potential for displacing coal with power from existing gas-fired power plants. Such a study would require sophisticated computer modeling to simulate the operation of the power system to determine whether there is sufficient excess gas fired capacity, and the supporting transmission and other infrastructure, to displace a material volume of coal over the near term. Such a study could help Congress judge whether there is sufficient potential to further explore a policy of replacing coal generation with increased output from existing gas-fired plants.

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Purpose and Organization

Coal-fired power plants currently account for about 80% of CO_2 emissions from the U.S. electric power industry and about 33% of all U.S. CO_2 emissions.[1] Accordingly, reducing CO_2 emissions from coal plants is a focus of many proposals for cutting greenhouse gas emissions. Options include capturing and sequestering the CO_2 emitted by coal plants, and/or replacing coal-fired generation with low- and zero-carbon sources of electric power, such as wind or nuclear power.

Another option is to replace coal power with increased use of natural gas generation. Natural gas is not a zero-carbon fuel, but gas-fired power using modern generating technology releases less than half of the CO_2 per megawatt-hour (MWh) as a coal plant. Recent large increases in estimates of natural gas reserves and resources, especially from shale formations, have further fed interest in natural gas as a relatively low carbon energy option.

One proposal is that the nation can and should achieve near-term reductions in carbon emissions by making more use of existing natural gas plants. This argument was made at an October 2009 Senate Energy and Natural Resources Committee hearing on *The Role of Natural Gas in Mitigating Climate Change*. An executive for a large natural gas pipeline company stated that "Just as natural gas plays a key role in meeting U.S. energy demands, it can also play a key role in providing meaningful, *immediate*, and verifiable [CO_2] emission reductions." [2] [emphasis added] The witness for Calpine, a large operator of gas-fired power plants, stated that:

> I am here today to tell you that we could, today, simply through the increased use of existing natural-gas fired power plants, meaningfully reduce the CO_2 emissions of the power sector, *immediately* and for the foreseeable future. *In other words, a near- and medium-term solution to our climate change challenge is at hand.* No guesswork. No huge spending programs needed. That power would be reliable—available all day, every day. And if we embrace this solution with the right incentives, American business would continue to invest its own capital in existing proven technologies to build even more natural gas fired plants to dramatically further reduce emissions for the longer term. [emphasis added][3]

Both of these statements emphasize the claimed *immediate* carbon reductions that can result from increased use of natural gas. This would be accomplished by squeezing more electricity from existing gas-fired power plants, so that coal-fired plants can be operated less and CO_2 emissions quickly and substantially reduced.

[1] Energy Information Administration (EIA), *Annual Energy Review 2008*, Tables 12.1 and 12.7b, http://www.eia.doe.gov/emeu/aer/envir.html.

[2] Written testimony of Dennis McConaghy, Executive Vice President, TransCanada Pipelines, Ltd., before the Senate Energy and Natural Resources Committee hearing on *The Role of Natural Gas in Mitigating Climate Change*, October 28, 2009, p. 6, http://energy.senate.gov/public/index.cfm?FuseAction=Hearings.Hearing&Hearing_ID=788a1684-b2a2-f5bb-f574-81b9257ba5aa.

[3] Written testimony of Jack Fusco, President and CEO, Calpine Corp., before the Senate Energy and Natural Resources Committee hearing on *The Role of Natural Gas in Mitigating Climate Change*, October 28, 2009, p. 1, http://energy.senate.gov/public/index.cfm?FuseAction=Hearings.Hearing&Hearing_ID=788a1684-b2a2-f5bb-f574-81b9257ba5aa.

This report provides an overview of the issues involved in displacing coal-fired generation with electricity from existing natural gas plants. This is a complex subject and the report does not seek to provide definitive answers. The report aims to highlight the key issues that Congress may consider in deciding whether to rely on, and encourage, displacement of coal-fired electricity with power from existing natural gas plants.

The balance of the report is organized as follows:

- Background on gas-fired generation and capacity.
- Coal displacement feasibility issues.
- Policy considerations.

The report also includes two appendices. **Appendix A**, Background on the Electric Power System, may be of particular value to readers relatively new to the subject. **Appendix B** provides information on the gas-burning combined cycle generating technology discussed in the report.

Issues Not Considered in the Report

Several topics are beyond the scope of this report:

- *What would be the cost of a policy of displacing coal with natural gas?* The cost would depend on a host of uncertain variables, such as future natural gas and coal prices, any need to build additional pipeline and transmission line facilities, and the cost of carbon (if any).
- *Could natural gas be burned on a large scale in existing coal plants?* Assessing this option would require engineering analysis of the plants and determining how many coal plants have access to high capacity natural gas pipelines.
- *How will circumstances change over time?* For example, while existing natural gas plants may have enough excess capacity today to displace a material amount of coal generation, this could change in the future as load grows.
- *What kind of existing natural gas plants could be used to displace coal?* This report focuses on the potential for displacing coal generation with increased use of underutilized “combined cycle” generating plants, the most modern and efficient type of natural gas-fired power plants. Two other types of gas-fired plants have low utilization rates: peaking plants (stand-alone combustion turbines and diesel generators) and old steam-electric natural gas plants. These are not reviewed in the report because they are relatively inefficient and may not be designed or permitted for baseload operation.

Addressing these issues would require computer modeling and engineering analysis beyond the scope of this report. As noted in the concluding section of the report, these issues, if of interest to Congress, could be part of a more comprehensive review of the potential for displacing coal with natural gas.

Background on Gas-Fired Generation and Capacity

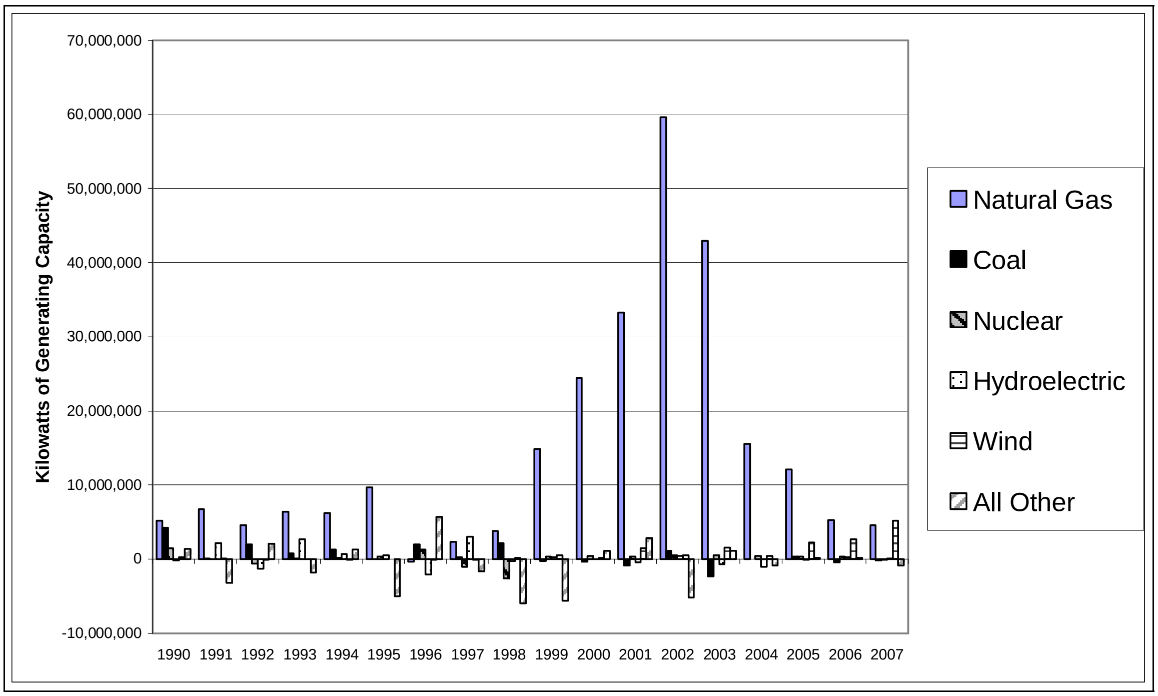
The argument for displacing coal with natural gas rests on the fact that the United States has a large base of advanced technology, underutilized, gas-burning power plants. This section of the report describes how this reservoir of underutilized natural gas combined cycle (NGCC) plants came about, and why it may represent an option for reducing the use of coal plants.

Capacity Trends

From the 1990s into this century, gas-fired power plants have constituted the vast majority of new generating capacity built in the United States. This development is illustrated by **Figure 1** for the period 1990 to 2007. Minimal new coal capacity was constructed and the growth in nuclear capacity was limited to uprates to existing plants. Only wind capacity has challenged the pre-eminence of natural gas as the source of new generating capacity, and then only in the latter part of the 2000s when total capacity additions declined sharply.

Figure 1. Net Change in Generating Capacity by Energy Source, 1990 to 2007

Net Summer Capacity



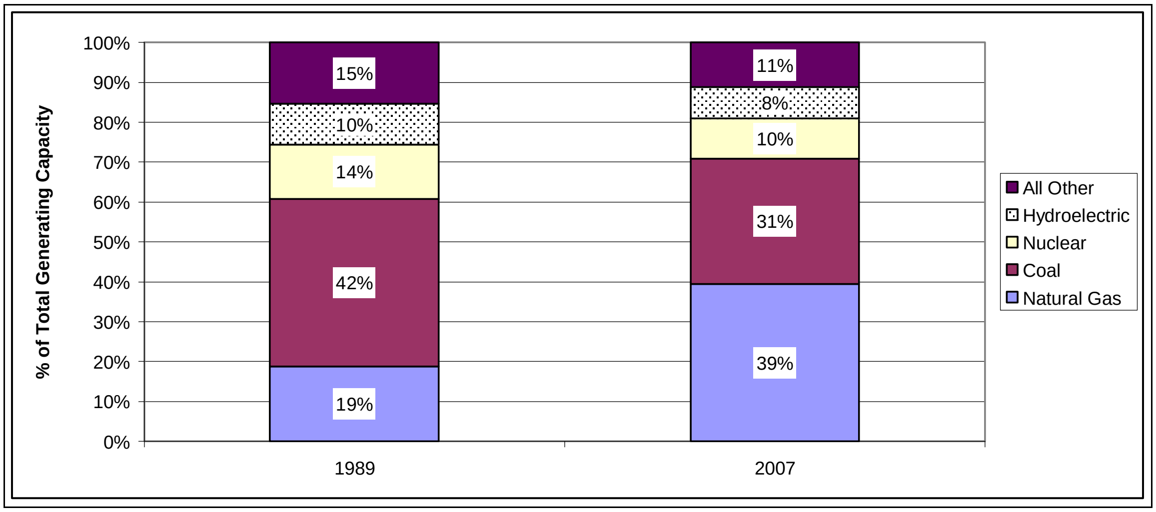
Source: Calculated from data in EIA, *Annual Energy Review 2008*, Table 8.11a, http://www.eia.doe.gov/emeu/aer/elect.html.

Notes: Capacity can decrease when retirements and deratings of units exceed capacity additions and increases. Also, in some cases the primary fuel of a unit may change, such as from wood to coal. The net change is calculated as the year over year change for each type of capacity.

As shown in **Figure 2**, this building boom doubled the natural gas share of total generating capacity between 1989 and 2007. Natural gas-fired capacity is now the largest component of the national generating fleet.

Figure 2. Shares of Total Generating Capacity by Energy Source, 1989 and 2007

Shares of Total Net Summer Capacity



Source: Calculated from data in EIA, *Annual Energy Review 2008*, Table 8.11a, http://www.eia.doe.gov/emeu/aer/elect.html.

Although natural gas is the largest source of generating capacity, it trails far behind coal as a source of actual electricity generation.[4] In 2008, coal accounted for 49% of all electricity produced, compared to 21% for natural gas, 20% for nuclear power, and 6% for hydroelectric generation.[5] The remainder of this section will explain why so much new gas-fired generation was built and why it is underutilized.

Factors Supporting the Boom in Gas-Fired Plant Construction

Natural gas was the major source of new capacity in the 1990s and early 2000s in part by default. Nuclear and coal power have been burdened with cost, environmental, and (in the case of nuclear power) safety concerns. Oil-fired generation was essentially ruled out by the costs and supply risks of petroleum supplies. This left natural gas as the energy source for new non-renewable power plants. But in addition to the negatives that surrounded alternatives, gas fired capacity also grew because of favorable technological, cost, environmental, and power market characteristics.

Technology

The new gas-fired plants constructed in the 1990s and subsequently were built around the latest design of combustion turbines—a specialized form of the same kind of technology used in a jet engine, but mounted on the ground and used to rotate a generator. Stand-alone combustion turbines were built to serve as peaking units that would operate only a few hundred hours a year. However, the most important technological development was the application of combustion

[4] "Capacity" is a measure of the potential instantaneous electricity output from a power plant, usually measured in megawatts or kilowatts. "Generation" is the actual amount of electricity produced by the plant over a period of time, usually measured in megawatt-hours or kilowatt-hours. For additional information see **Appendix A**.

[5] These four sources accounted for 96% of electricity production in 2008, which is the typical combined share going back to the 1980s. All other sources, such as wind, petroleum, and biomass, account for the remaining 4%.

turbines in modern natural gas combined cycle power plants. (For additional information see **Appendix B**.) These plants were often intended to serve as baseload generators which would operate 70% or more of the time. The NGCC has three important characteristics:

- **The technology is very efficient**, because it makes maximum use of the energy in the fuel through a two-step generating process that captures waste heat that would otherwise be lost.[6]
- **NGCC plants can be built relatively quickly and cheaply**. An NGCC plant costs roughly $1,200 per kilowatt of capacity, about half as much as for a coal-fired plant, and can be built in about two to three years from ground-breaking to operation. This compares to about to five to six years to build a coal plant. Coal plants also tend to have longer pre-construction planning and permitting phases.[7]
- **Combined cycle technology is suitable for relatively small scale and modular construction.** NGCC plants can be economically built at unit sizes of about 100 MW, and larger projects can be constructed by adding units in a building block fashion over time. Coal plants in contrast are generally economical only at a unit size of several hundred megawatts.

For the reasons discussed below, these characteristics made the NGCC an attractive technology option for the independent power producers that dominated the construction of new power plants in the 1990s and after.

Natural Gas Prices

The construction of new gas-fired capacity was also encouraged by relatively low natural gas prices in the 1990s. As illustrated by **Figure 3**, the spot price for natural gas hovered around $2.00 to $3.00 per MMBtu (nominal dollars) through the decade, and a widely held expectation was that gas prices would remain low into the future.[8]

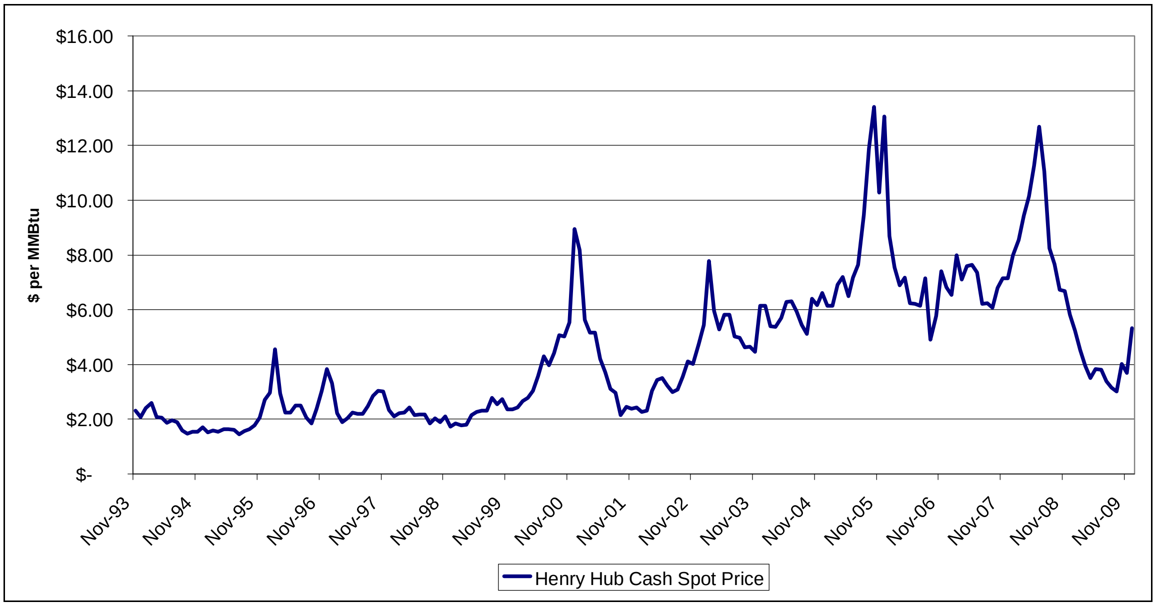
[6] By extracting the maximum energy from fuel combustion, modern combined cycles can reportedly achieve heat rates in the range of 6,752 to 6,333 btus per kwh. This compares to 9,200 to 8,740 btus per kwh for steam electric coal technology. (EIA, *Assumptions to the Annual Energy Outlook 2009*, Table 8.2, http://www.eia.doe.gov/oiaf/aeo/assumption/index.html.) This efficiency advantage can make combined cycles very economical to operate.

[7] For more information on power plant cost and construction issues, see CRS Report RL34746, *Power Plants: Characteristics and Costs*, by (name redacted).

[8] Rebecca Smith, "Utilities Question Natural-Gas Forecasting," *The Wall Street Journal*, December 27, 2004.

Figure 3. Henry Hub Cash Spot Price for Natural Gas

November 1993 to December 2009, Nominal Dollars



Source: U.S. Federal Reserve Bank of St. Louis FRED database (http://research.stlouisfed.org/fred2/series/GASPRICE?cid=98).

Carbon Dioxide Emissions

The operation of NGCC plants, and natural gas plants generally, produce fewer harmful environmental impacts than coal-fired plants, and have been much easier to site and permit than coal plants. NGCC technology has fewer air emissions than coal plants in part because of the nature of the fuel, and in part because of the greater efficiency of the technology. For example, natural gas when burned inherently emits about half as much carbon dioxide as coal.[9] However, because combined cycle plants are more efficient than typical existing coal plants in converting fuel into electricity, the difference in emissions is greater when measured in terms of CO_2 released per megawatt-hour of electricity produced. By this measure a modern combined cycle emits only about 40% of the CO_2 per MWh as a typical existing coal plant.[10]

Electric Power Industry Restructuring and Overbuilding

Restructuring of the electric power industry (beginning in the late 1970s and accelerating in the 1990s) included federal and state policies that encouraged the separation of power generation and

[9] Natural gas emits 117.08 pounds CO_2 per MMBtu burned. The comparable numbers for subbituminous, bituminous, and lignite coal are, respectively, 212.7, 205.3, and 215.4 pounds of CO_2 per MMBtu burned. EIA, *Electric Power Annual 2007*, Table A3, http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html.

[10] Other environmental advantages of combined cycle plants include minimal or zero emissions of sulfur dioxides and mercury; no solid wastes, such as ash and scrubber sludge; no coal piles with attendant fugitive dust and runoff problems; and the fuel is delivered by pipeline rather than railroad or truck. A combustion turbine burning natural gas will emit more nitrogen oxides (NOx) per MMBtu of fuel consumed than a coal-fired boiler, and depending on the location of a gas-fired plant it may have to install a low NOx combustion system and a selective catalytic reduction system to capture NOx emissions.

power plant construction from other utility functions. In the 1990s, new independent power producers (IPPs) bought power plants from utilities and constructed most of the new generating capacity. Because these companies sold power into competitive markets and did not have the security of regulated rates and guaranteed markets, they generally sought to minimize risks by constructing relatively low cost, quick-to-build, power plants.

For these reasons, independent power producers built many NGCC plants, largely to meet baseload demand. As shown in **Table 1**, between 1990 and 2007 over 168,000 MW of NGCC capacity was built at 345 plant sites. This was an enormous building program, equivalent to adding 23% to the entire national generating fleet that existed in 1990. However, the growth in generating capacity did not stop with new combined cycle plants. As also shown in **Table 1**, another 89,843 MW of less efficient stand-alone peaking turbines were constructed, plus another 56,939 MW of other generating technologies. When all of this capacity is added together, generating capacity grew by 43% between 1990 and 2007.

Table 1. Growth in Generating Capacity, 1990 - 2007

	Natural Gas Combined Cycle (NGCC)	Stand-Alone Combustion Turbine (Natural Gas)	All Other Fuel Sources and Technologies	Total
Additions to Generating Capacity, 1990 – 2007 (MW)	168,259	89,843	56,939	315,041
Additions as a Percent of Total 1990 Generating Capacity (734,100 MW)	23%	12%	8%	43%

Source: Calculated from the EIA-860 data file for 2007, http://www.eia.doe.gov/cneaf/electricity/page/eia860.html.

Notes: The capacity shown is net summer capacity. The All Other category contains 2,184 MW of gas-fired capacity, primarily in new internal combustion engines and steam turbines, and 5,432 MW of combined cycle and stand-alone combustion turbine capacity burning fuels other than natural gas (primarily stand-alone combustion turbines using distillate fuel oil).

By the mid-2000s it was apparent that the combined cycle building boom had resulted in excess and underutilized generating capacity. Too many plants were built, in part because of questionable investment decisions by independent developers operating in an immature restructured power market. The capacity glut was compounded by a dramatic increase in gas prices after 2000. (See **Figure 3**.) Even the high efficiency of the combined cycle plants could not compensate for gas prices that at times peaked above $10.00 per MMBtu, compared to $2.00 to $3.00 per MMBtu prices (nominal dollars) in the 1990s.

The consequence of the combined cycle building boom and bust is that the fleet of NGCC plants has a large amount of unused generating capacity, as illustrated in **Table 2** for a "study group" of large combined cycle plants defined for this report.[11] Baseload operation can be reasonably

[11] The study group of combined cycle plants consists of plants with the following characteristics: minimum net summer (continued...)

defined as operation at an annual capacity factor of 70% or greater. As shown in **Table 2**, only 13% of combined cycle capacity in the study group operated in this range in 2007. A third of the combined cycle capacity had a utilization rate of less than 30%; that is, the plants were the equivalent of idle more than 70% of the time.

Table 2. Utilization of Study Group NGCC Plants, 2007

Capacity Factor Category	Net Summer Megawatts	Percent of Total NGCC Megawatts	Number of NGCC Plants	Percent of Total NGCC Plants
70% and Greater	22,151	13%	42	13%
Under 70% to 50%	40,103	24%	68	22%
Under 50% to 30%	50,711	30%	90	29%
Under 30%	57,662	34%	114	36%
Total	170,627	100%	314	100%

Source: Calculated from the EIA-860 and EIA-906/920 databases for 2007 (http://www.eia.doe.gov/cneaf/electricity/page/data.html).

Notes: Detail many not add to total due to rounding. For information on the characteristics of the power plants selected for the study group, see footnote 11.

In 2007 the study group of NGCC plants had an average capacity factor of 42%.[12] In contrast, the study group of coal plants had an average capacity factor of 75%.[13] It is this mismatch between combined cycle and coal plant operating patterns—the former, low carbon emitting but underutilized; the latter, high carbon emitting and highly utilized—that creates the interest and perceived opportunity for displacing coal power with gas generation from existing plants.

(...continued)

capacity of 100 MW; the plant operated at some point in time during 2007 and was in operational condition at the end of 2007; the plant's primary fuel was natural gas; and the plant's primary purpose was to sell power to the public. (This last criterion excludes industrial and commercial cogenerators who operate a power plant primarily to provide electricity and steam to a single business establishment.) A total of 314 combined cycle plants with total capacity of 170,627 MW met these criteria. The study group of coal plants had the same criteria except that the capacity floor was 250 MW and the primary fuel had to be coal or waste coal. A total of 298 coal plants with total capacity of 284,646 MW met these criteria. CRS identified the plants and extracted the data from the EIA-860 and EIA-906/920 databases for 2007 (http://www.eia.doe.gov/cneaf/electricity/page/data.html). The 2007 generation from the plants in the combined cycle study group (630.4 million MWh) accounted for 98% of all gas-fired combined cycle generation in the electric power sector in 2007. Similarly, the generation from the coal plants in the study group (1,870.6 million MWh) accounted for 95% of all coal-fired generation in the electric power sector.

[12] Capacity factor is a measure of the actual utilization of a power plant compared to its hypothetical maximum utilization. For additional information see **Appendix A**.

[13] For information on the study group of coal plants see footnote 11. Capacity factors were calculated using the EIA-906/920 generation and EIA-860 generating capacity databases (http://www.eia.doe.gov/cneaf/electricity/page/data.html).

Coal Displacement Feasibility Issues

Estimates of Displaceable Coal-Fired Generation and Emissions

The maximum coal-fired generation and emissions that may be displaceable by existing NGCC plants is estimated in **Table 3** and **Table 4**. As noted above, the plants in the NGCC study group had an average capacity factor of 42% in 2007. As shown in the tables, if the utilization of this capacity could be essentially doubled to 85%, it would generate additional power equivalent to 32% of all coal-fired generation in 2007, and could displace about 19% of the CO_2 emissions associated with coal-fired generation of electricity. Although these calculations suggest that at most about a third of current (2007) coal-fired generation could be displaced by existing NGCC plants, it is unlikely that this maximum could actually be achieved.

Table 3. Approximation of the Maximum Displaceable Coal-Fired Generation, Based on 2007 Data

(1)	(2)	(3)	(4)	(5)
Actual NGCC Generation, 2007 (MWh)	Hypothetical NGCC Generation at an 85% Capacity Factor (MWh)	Hypothetical Surplus Generation Available for Coal Displacement (MWh) (2) – (1)	Actual Coal-Fired Generation in 2007 (MWh)	Hypothetical Surplus NGCC Generation as a Percentage of Coal Generation (3) / (4)
630,358,373	1,270,487,153	640,128,780	2,016,456,000	32%

Source: CRS estimates based on EIA-906/920 and EIA-860 electric power databases, and EIA, *Electric Power Annual 2007*, Table ES1, http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html.

Notes: The generation in column 1 is for the 314 NGCC plants included in the study group defined for this report. For additional information see footnote 11. As discussed in the main body of the report, several factors, such as transmission system limitations, will tend to drive actual displacement below the maximum potential. Also, this estimate is for 2007, and in other years the amount of surplus gas generation and the amount of coal generation will likely vary from 2007 values.

Table 4. Approximation of Maximum Displaceable CO_2 Emitted by Coal-Fired Generators, Based on 2007 Data

(1)	(2)	(3)	(4)	(5)	(6)
Estimated Hypothetical Coal Generation Displaced by Natural Gas (MWh)	Estimated CO_2 Emissions from Displaced Coal Generation (Million Metric Tons)	Estimated CO_2 Emissions From NGCC Generation Used to Displace Coal (Million Metric Tons)	Net Reduction in Emissions of CO_2 by Natural Gas Displacement of Coal (Million Metric Tons)	Total CO_2 Emissions from Coal for Power Generation, 2007 (Million Metric Tons)	Hypothetical Net Reduction in CO_2 Emissions as a Percentage of 2007 Total Electric Power Coal Emissions of CO_2
			(2) – (3)		(4) / (5)
640,128,780[a]	635.7[b]	253.6[c]	382.1	2,002.4	19%

Source: CRS estimates based on: EIA-906/920 database (http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html); EIA, *Electric Power Annual 2007*, Table A3, http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html; EIA, *Annual Energy Review 2008*, Table 12.7a, http://www.eia.doe.gov/emeu/aer/envir.html.

Notes: As discussed in the main body of the report, several factors, such as transmission system limitations, will tend to drive actual displacement below the maximum potential. Also, this estimate is for 2007, and in other years the amount of surplus gas generation and the amount of coal generation will likely vary from 2007 values.

a. From Table 3, column 3.

b. In 2007, total coal generation was 2,016,456,000 MWh (Table 3, column 4) and total CO_2 emissions from coal were 2,002.35 million metric tons. This equates to 0.993 metric tons of CO_2 per MWh of coal generation (the comparable value for a modern NGCC plant is about 0.4 metric tons of CO_2 per MWh). Therefore, the estimated CO_2 emissions from the displaced coal is 640,128,780 MWh x 0.993005 metric tons of CO_2 per MWh = 635.651 million metric tons of CO_2.

c. Actual study group NGCC generation in 2007 was 630,358 MWh (Table 3, column 1). This generation consumed 4,702,226,931 MMBtus of natural gas, or 7.4596 MMBtus of gas per MWh. At this average heat rate, it would take 4,775,104,647 MMBtus of gas to displace 640,128,780 MWh of coal generation. This much gas burn would release 253.6 million metric tons of CO_2, using an emissions factor of 117.08 pounds of CO_2 per MMBtu of natural gas consumed and 2,204.6 pounds per metric ton.

This section of the report will discuss issues that relate to the feasibility of actually displacing coal with gas from existing power plants. The issues are:

- Transmission system factors;
- System dispatch factors;
- Natural gas supply and price; and
- Natural gas transportation and storage.

Transmission System Factors

If an NGCC generating unit is located at the same plant site as a coal-fired generating unit, it is probably fair to assume that the NGCC unit can use the same transmission lines as the coal unit and can transmit its power to any load the coal unit is used to meet. However, in most cases coal units and NGCC units are built at separate locations and rely on different transmission paths to move their power. This means that there is no guarantee that the NGCC plant can send its power to the same loads as the coal plant and by doing so displace coal-fired generation.

Even on a regional level, coal and NGCC plants are not necessarily located in the same areas. The maps in **Figure 4** and **Figure 5** show, respectively, the location of large coal and NGCC plants in the conterminous states. The maps show that in some cases coal and NGCC plants are in the same regions, such as east Texas. On the other hand, California has many NGCC plants and no coal plants, while the Ohio River valley has a dense concentration of coal plants and only a handful of NGCC plants.

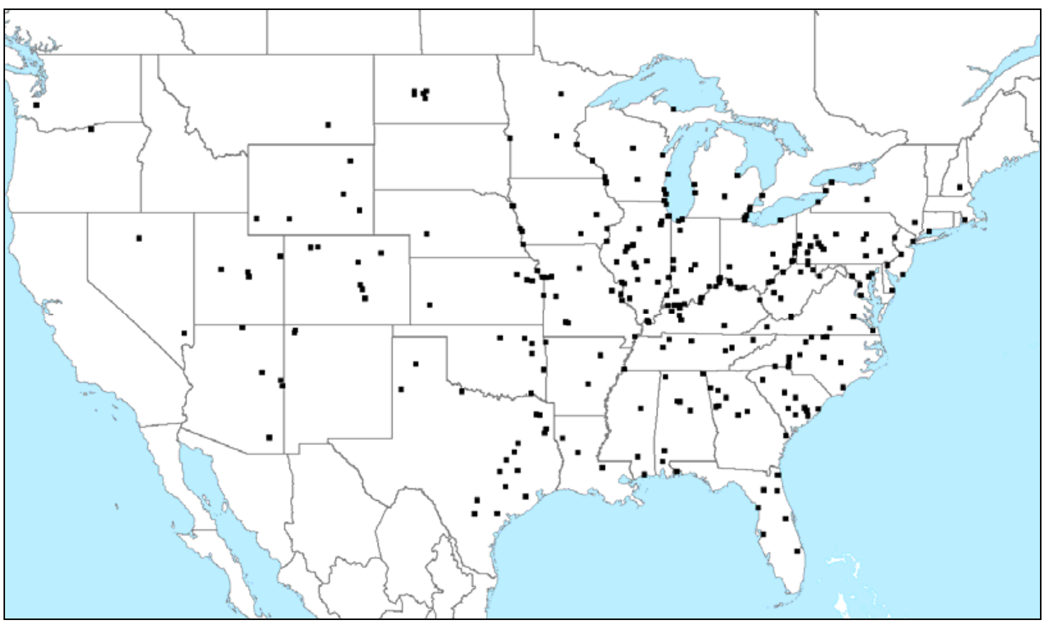
This section of the report will discuss three types of transmission system constraints that can prevent one power plant from meeting the load currently served by another plant. These limits on the "transmission interchangeability" of coal and NGCC plants are:

- Isolation of the Interconnections;
- Limited long-distance transmission capacity; and
- Transmission system congestion.

The concluding part of this section presents an analysis of potential coal displacement by gas using the proximity of coal and existing NGCC plants as a proxy for transmission interchangeability.

Figure 4. Location of Large Coal-Fired Power Plants in the Conterminous States

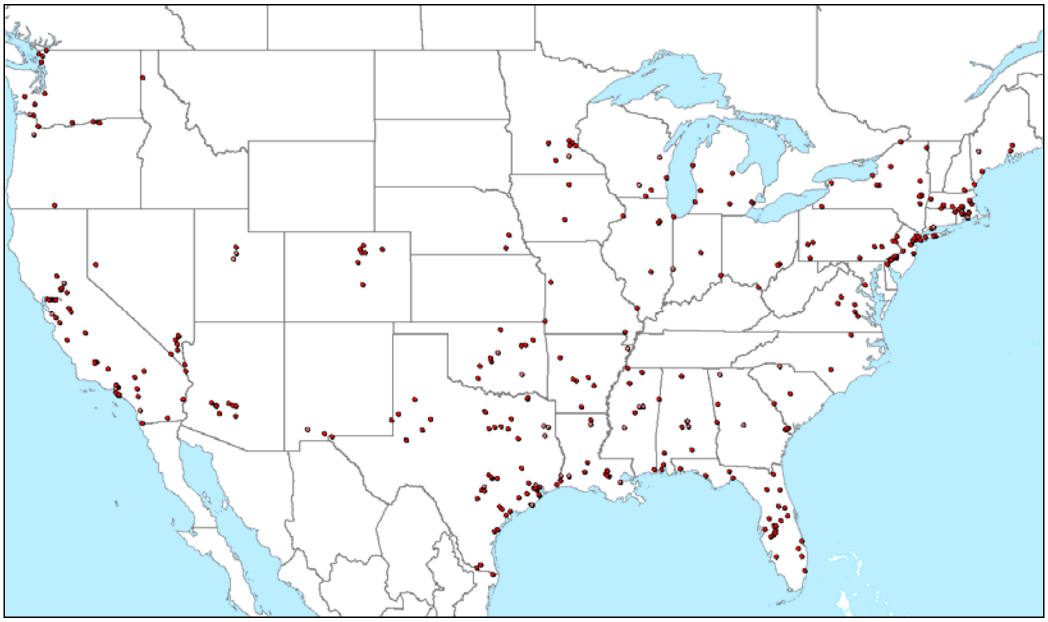
250 Megawatt and Greater Net Summer Capacity



Source: Platts Powermap (fourth quarter 2009 database).

Figure 5. Location of Large NGCC Power Plants in the Conterminous States

100 Megawatt and Greater Net Summer Capacity

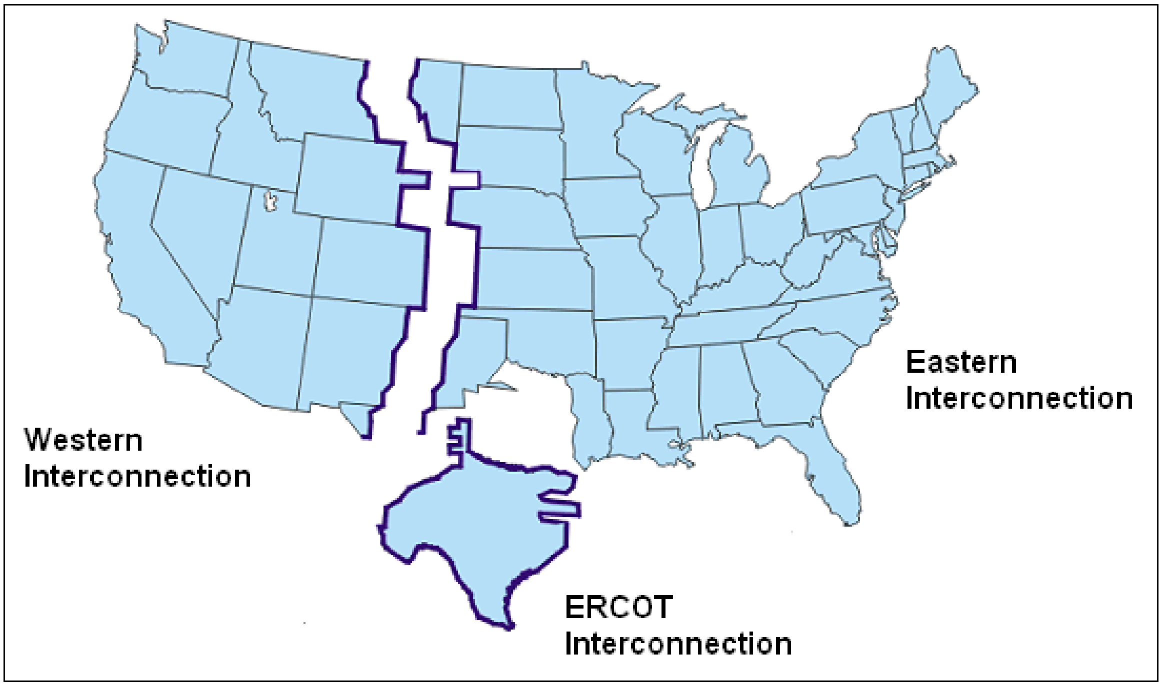


Source: Platts Powermap (fourth quarter 2009 database).

Isolation of the Interconnections

The electric power grid covering the conterminous states is divided into three "interconnections," Eastern, Western, and the ERCOT Interconnection that covers most of Texas (**Figure 6**). These three interconnections operate in most respects as independent systems. There are only a handful of limited, low capacity links between the interconnections. Consequently, surplus capacity in one interconnection cannot be used to meet load in another interconnection.

Figure 6. United States Power System Interconnections



Source: adapted from a map located on the Energy Information Administration website at http://www.eia.doe.gov/cneaf/electricity/page/fact_sheets/transmission.html.

Notes: ERCOT = Electric Reliability Council of Texas.

To illustrate with a hypothetical example, assume 1,000 MW of surplus NGCC capacity in the northern part of the ERCOT Interconnection, and a desired use for that capacity to displace coal in Oklahoma, which is in the Eastern Interconnection. Although the regions are adjacent, from the standpoint of the power grid they are electrically isolated from each other because, with very limited exceptions, the ERCOT and Eastern Interconnections are not linked. Therefore the displacement cannot take place.

Limited Long-Distance Transmission Capacity

Within each interconnection the network of power lines, generating plants, and electricity consumers are linked together. The grid operates in some respects like a single giant machine in which, for example, a disturbance in the operation of the transmission system in Maine is detectible by system monitors in Florida.

Although all generators and loads within an interconnection are linked by the grid, the power grid is not designed to move large amounts of power long distances. The grid was not built in accordance with a "master plan," analogous to the Interstate Highway System. Transmission lines were first built in the early 20th century by single utilities to move electricity to population centers from nearby power plants. As generation and transmission technology advanced, the distances between power plants and loads increased, but the model of a single entity building lines within its service territory to supply its own load still predominated.

Over time the local grids began to interconnect, due to utilities building jointly owned power plants and because power companies began to grasp the economic and reliability benefits of being able to exchange power. Nonetheless, this pattern of development did not emphasize the construction of very long-distance inter-regional lines. Consequently, the capacity to move power long distances within interconnections is limited. For example, while a generator in Maine and a load in Florida are connected by the grid, it is not feasible to send power from Maine to Florida because the transmission lines do not have enough capacity to move the electricity.

Additionally, over distances of hundreds of miles, losses occur with transmission of electricity, making the transfer uneconomic.[14] Power can be moved long distances most efficiently by the highest voltage transmission lines, but only a small portion of the national grid consists of these types of lines.[15] Much of the debate over the proposed increased use of renewable power involves how to build and pay for the new transmission lines that would be needed to move wind and solar power from remote locations to population centers, in part to displace fossil-fueled power plants. Coal displacement by existing gas-fired generators is a similar type of problem. If the existing transmission network does not have sufficient capacity in the right places, then it may not be practical to move gas-powered electricity to loads currently served by coal plants without investing in upgraded or new power lines.

Transmission System Congestion

Even across relatively short distances, options for moving power can be restricted by transmission line congestion. Transmission congestion occurs when use of a power line is limited to prevent overloading that can lead to failure of the line. Congestion can occur throughout a power system:

- Regional congestion: for example, power flows are limited between the eastern and western parts of the PJM power pool (covering much of the Midwest and middle Atlantic regions) by congestion.[16] In the western states, examples of congested links include power flows between Montana and the Pacific Northwest, and between Utah and Nevada.[17]

[14] Line loss is the loss of electrical energy due to the resistance of the length of wire in a circuit. Much of the loss is thermal in nature. (This definition is a composite created from the glossaries at http://www.eia.doe.gov/glossary/glossary_l.htm and http://www.ewh.ieee.org/sb/srisairamec/glossary/k-lglos.htm.)

[15] Most of the transmission grid uses alternating current (AC) technology which is prone to line losses. By using transmission lines with higher kilovolt (kV) ratings, more power can be transported long distances with fewer losses. The highest capacity AC lines currently in use in the United States have a rating of 765 kV, but according to DOE these lines make up less than 2% of the grid. An alternative, direct current (DC) technology, can move large amounts of power long distances with minimal losses. However, DC lines are in only limited use (about 2% of the grid) because they are more difficult and expensive to integrate into the grid than AC lines. Proposals have been made to upgrade the AC network by building more 765 kV lines and lines using even high capacity AC technology (referred to as ultra high voltage transmission), and to build more DC lines. These proposals are generally focused on moving renewable power long distances. For example, see American Electric Power, *Interstate Transmission Vision for Wind Integration*, undated, http://www.aep.com/about/i765project/docs/WindTransmissionVisionWhitePaper.pdf, and the Joint Coordinated System Plan proposal at http://www.jcspstudy.org/. (The transmission line statistics cited in this footnote are from DOE, *National Transmission Grid Study*, May 2002, p. 3, http://www.ferc.gov/industries/electric/indus-act/transmission-grid.pdf.)

[16] Ventyx Corp., *Major Transmission Constraints in PJM*, 2007, http://www1.ventyx.com/pdf/wp07-transmission-constraints.pdf.

[17] Western Electric Coordinating Council, *2008 Annual Report of the Transmission Expansion Planning Policy Committee, Executive Summary*, March 31, 2009, p.9, http://www.wecc.biz/committees/BOD/TEPPC/Shared%20Documents/TEPPC%20Annual%20Reports/2008/CoverLetter_Exec_Summary_Final_.pdf.

- State-level congestion: for example, congestion restricts power flows into and out of southwestern Connecticut.[18]
- Local congestion: These are "load pockets" with limited ability to import power. New York City is an example of a load pocket.

Transmission congestion can increase costs to consumers by forcing utilities to depend on nearby inefficient power plants to meet load instead of importing power from more distant but less costly units. Studies suggest that the annual costs of transmission congestion range from the hundreds of millions to billions of dollars.[19] However, for the purposes of this report the key aspect of transmission system congestion is not the cost impact, but the restrictions it imposes on power flows. Because of congestion, it may not be possible to ship power from an underutilized NGCC plant to a load served by coal power, because the transmission path available to the combined cycle is too congested to carry the electricity.

The solution for congestion is not necessarily massive transmission construction. For example, DOE found that in the Eastern Interconnection "a relatively small portion of constrained transmission capacity causes the bulk of the congestion cost that is passed through to consumers. This means that a relatively small number of selective additions to transmission capacity could lead to major economic benefits for many consumers."[20] However, in the absence of this construction, congestion remains a constraint on the choice of power plants available to meet a load.

Power Plant Proximity Analysis

Transmission system limitations on coal displacement can be rigorously analyzed using sophisticated computer models. Such an analysis is beyond the scope of this report. However, a first approach to the significance of transmission factors can be made by examining how close coal plants are to existing NGCC plants. The assumption behind such a "proximity analysis" is that the closer an NGCC plant is to a coal plant, the more likely that the NGCC plant will connect to the same transmission lines as the coal plant. If the NGCC plant has this comparable transmission access—that is, the combined cycle is "transmission interchangeable" with the coal plant—it potentially could serve the same load as the coal plant and supplant the coal generation.

CRS performed a proximity analysis for the coal plants and NGCC plants in the study groups defined for this report. The analysis was conducted as follows, in all cases using 2007 data (the most recent pre-recession year for which complete data were available):

(1) Study groups of large coal plants and NGCC plants were defined. The plants in these groups accounted for the great majority of power plant coal generation and NGCC generation in 2007.[21]

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[18] Connecticut General Assembly, Office of Legislative Research, *Factors Behind Connecticut's High Electric Rates*, August 5, 2008, No. 2008-R-0452, http://www.cga.ct.gov/2008/rpt/2008-R-0452.htm.

[19] Bernard Lesieutre and Joseph Eto, *Electricity Transmission Congestion Costs: A Review of Recent Reports*, Lawrence Berkeley National Laboratory, p. 2, http://certs.lbl.gov/pdf/54049.pdf, and U.S. Department of Energy, *National Transmission Grid Study*, May 2002, pp. 16–18, http://www.pi.energy.gov/documents/TransmissionGrid.pdf.

[20] U.S. DOE, *National Electric Transmission Congestion Study*, August 2008, p. 28, http://www.pi.energy.gov/documents/TransmissionGrid.pdf. Emphasis in the original not shown.

[21] The study group of combined cycle plants includes 314 larger plants that accounted for 98% of combined cycle (continued...)

(2) The latitude and longitude of each plant (provided by EIA) was entered into a geographical information system (GIS).

(3) The GIS was used to identify all coal plants with one or more existing NGCC plants within a ten mile radius. The hypothetical surplus generation for each NGCC plant within the ten-mile radius was calculated and assumed to displace generation from the coal plant.[22] If one NGCC plant was within ten miles of two or more coal plants, it was allocated first to the coal plant with the largest estimated CO_2 emissions in 2007.[23]

(4) A second version of Step 3 was performed which included all NGCC plants within 25 miles of a coal plant.

The maps in **Figure 7** and **Figure 8** show the locations of the coal plants assumed to have generation displaced by existing NGCC plants.[24]

(...continued)

generation in the electric power sector in 2007. The study group of coal plants includes 298 larger plants that accounted for 95% of coal-fired generation in the electric power sector in 2007. For additional information on the characteristics of the study groups see footnote 11.

[22] Actual generation in 2007 is from the EIA-906/920 database. Capacity factors were computed using this generation data and each plant's capacity as reported in the EIA-860 database. An NGCC plant was assumed to have surplus generation if its annual capacity factor in 2007 was less than 85%; that is, the hypothetical surplus generation available to displace coal was the difference between the NGCC plant's actual generation in 2007 and the electricity it could have produced at an 85% utilization rate. A few NGCC plants had capacity factors of 85% or greater in 2007 and were therefore assumed to have no surplus generation available for coal displacement. The EIA databases are available at http://www.eia.doe.gov/cneaf/electricity/page/data.html.

[23] CO_2 emissions were estimated for each coal plant based on the type and volume of coal consumed. Fuel consumption in MMBtus was taken from the EIA-906/920 database and used to calculate CO_2 emissions using the emission factors in EIA, *Electric Power Annual 2007*, Table A3, http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html. The same data sources were used to calculate CO_2 emissions for combined cycles.

[24] The maps only show coal plants assumed to have had generation displaced, and the existing NGCC plants responsible for the displacement. If a coal plant had an NGCC plant with the ten or 25 mile radius, but the NGCC plant was assumed to be unavailable to displace coal (for example, because it had a capacity factor in 2007 of 85% or higher) no coal is assumed to have been displaced and the coal plant is not shown on the map.

Figure 7. Coal Plants with Hypothetical Generation Displaced by a NGCC Plant Within 10 Miles

Source: CRS estimates, mapped using the Platts Powermap system.

Notes: The maps only show coal plants assumed to have had generation displaced. If a coal plant has an NGCC plant with the ten mile radius, but the NGCC plant was assumed to be unavailable to displace coal (for example, because it had a capacity factor in 2007 of 85% or higher) the coal plant is not shown on the map.

Figure 8. Coal Plants with Hypothetical Generation Displaced by a NGCC Plant Within 25 Miles

Source: CRS estimates, mapped using the Platts Powermap system.

Notes: The maps only show coal plants assumed to have had generation displaced. If a coal plant has an NGCC plant with the 25 mile radius, but the NGCC plant was assumed to be unavailable to displace coal (for example, because it had a capacity factor in 2007 of 85% or higher) the coal plant is not shown on the map.

This analysis is not a forecast. It is a first approach to estimating coal displacement potential based on one factor, the proximity of coal and existing NGCC plants. Many other factors, including, for example, how utility systems are dispatched, the configuration and capacity of the electric power transmission system, fuel cost and availability, natural gas transportation capacity, and power system reliability requirements, would influence actual coal displacement potential. These other factors could increase or decrease the potential displacement.

Table 5, which gives the results of the proximity analysis, shows in column 4 that existing NGCC plants located near coal plants might be able to achieve 15% to 28% of the potential maximum coal generation and CO_2 emissions displacement. However, the *displaceable* coal generation and emissions (see **Table 3** and **Table 4**) are only a fraction of *total* U.S. coal generation and CO_2. As shown in **Table 5**, column 5, the hypothetical displaced coal generation and emissions are equivalent to 5% to 9% of *total* U.S. coal generation, and 3% to 5% of the associated CO_2 emissions.

Given its limitations, the analysis suggests that existing NGCC plants near coal plants may be able to account for something on the order of 30% or less of the displaceable coal-fired generation and CO_2 emissions. Greater displacement of coal by existing NGCC plants would depend on more distant NGCC plants which would be less clearly “transmission interchangeable” with coal plants. This emphasizes the importance that the configuration and capacity of the transmission system will likely play in determining the actual potential for displacing coal with power from existing NGCC plants.

Table 5. Hypothetical Estimates of the Displacement of Coal Generation and Emissions by Existing NGCC Plants Based on Proximity

Based on 2007 Data

Case (1)	Category (2)	Amount Displaced (3)	Amount Displaced as a % of the Maximum Potential Displacement of Coal by Existing NGCC Plants[a] (4)	Amount Displaced as a % of Total Electric Power Sector Coal MWh and Associated CO2 Emissions[b] (5)
Generation and CO_2 Displaced for Coal Plants within 10 Miles of a NGCC Plant[c]	Generation	101.8 Million MWh	16%	5%
	CO_2 Emissions	58.1 Million Metric Tons	15%	3%
Generation and CO_2 Displaced for Coal Plants within 25 Miles of a NGCC Plant[c]	Generation	181.5 Million MWh	28%	9%
	CO_2 Emissions	104.8 Million Metric Tons	27%	5%

Source: CRS estimates primarily based on EIA data. See the main text of the report for more information. For detailed backup, such as lists of plants, contact the author.

Notes: This is not a forecast; it is a rough approximation of coal displacement potential based on one factor, the proximity of coal and existing NGCC plants. Many other factors, including, for example, how utility systems are dispatched, the configuration and capacity of the electric power transmission system, fuel cost and availability, natural gas transportation capacity, and power system reliability requirements, would influence actual coal displacement potential. These other factors could increase or decrease the potential displacement. MWh = Megawatt-hours; NGCC = natural gas combined cycle.

a. The values in this column are calculated using column 3; Table 3, column 3; and Table 4, column 4.

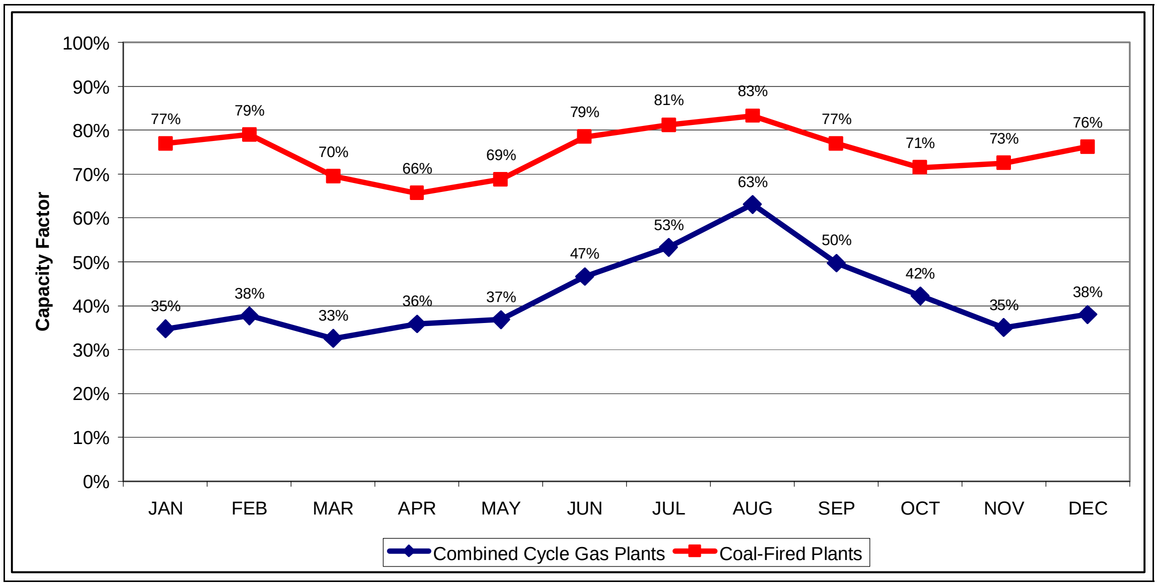
b. The values in this column are calculated using column 3; Table 3, column 4; and Table 4, column 5.

c. The study group included 298 coal-fired plants. In the ten-mile radius case, coal is displaced in whole or part at 35 of these plants (11.7% of the plants). In the 25-mile radius case, coal is displaced in whole or part at 60 of these plants (20.1%).

System Dispatch Factors

System dispatch refers to the pattern in which power plants are turned on and off, and their power output ramped up and down, to meet changing load patterns. (For additional discussion, see **Appendix A**.) The concept of displacing coal generation with power from existing NGCC plants assumes that the NGCC plants are underutilized or idle when coal plants are operating. However, this is not necessarily the case. This can be illustrated by examining the monthly utilization of the coal and gas-fired plants in the study groups (**Figure 9**). As shown in the figure, the utilization of coal and combined cycle plants follows a similar pattern: utilization is highest in the summer and, to a lesser degree, in the winter, and lowest in the "shoulder" months of the spring and fall. The figure illustrates that when coal plant operation is at its highest and the most coal power can be displaced, NGCC plant operation is also at its highest and surplus gas-fired generation is therefore at its lowest.

Figure 9. Monthly Capacity Factors in 2007 for Study Group Coal and NGCC Plants



Source: Calculated by CRS from the EIA-906/920 and EIA-860 databases.

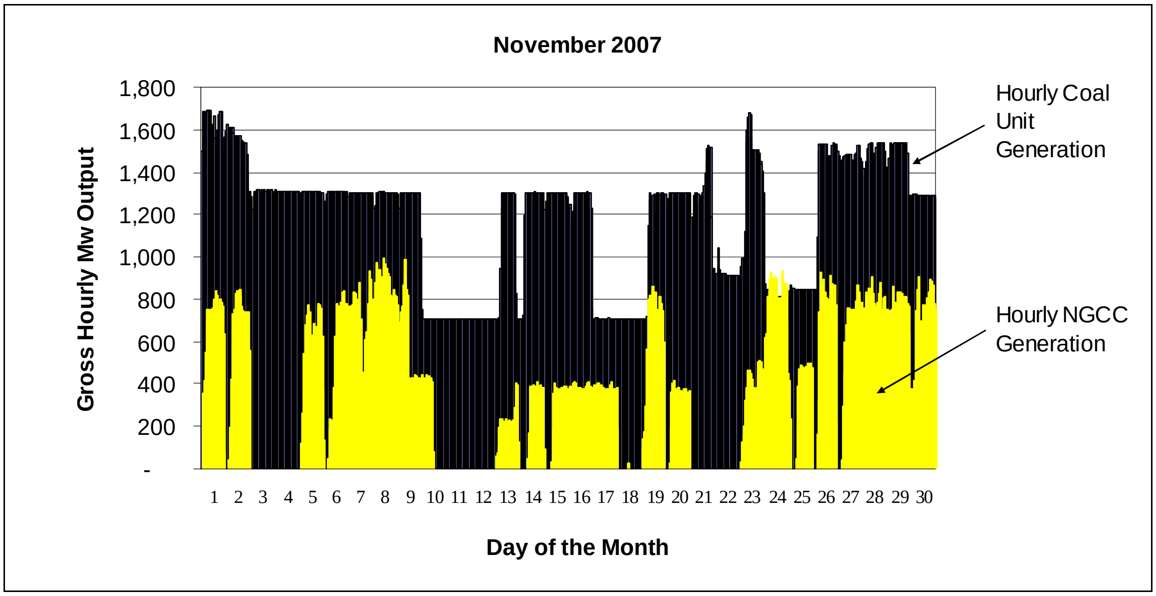
Notes: For information on the study groups of coal and NGCC plants, see footnote 11. NGCC= natural gas combined cycle.

Figure 9 is a national, monthly picture of power plant dispatch. System dispatch actually takes place moment-to-moment, and at this level of detail the complexities in displacing coal with gas become further evident. **Figure 10** graphically illustrates *hourly* dispatch at Plant Barry, a power plant in Alabama that has both coal and NGCC units at the same site. The data is for November 2007, the month in which the NGCC units at Plant Barry had their lowest generation for the year and therefore, in principle, the most excess capacity available to displace coal.[25] However, the graphic illustrates that even during this low utilization month for the NGCC units, there are still periods when the units were running near maximum output[26] (e.g., November 6 to 9, and 27 to 30). While there were periods when coal plant output was high and the NGCC units were shut down (e.g., November 4), creating the maximum opportunity to displace coal with gas, there were also periods when the NGCC units were available but potential coal displacement was reduced by limited operation of the coal units (e.g., November 18). These examples illustrate the level of detailed analysis required to realistically estimate the potential for changing plant dispatch to displace coal with natural gas.

[25] According to U.S. EPA data, the gross output of the NGCC units at Plant Barry was 288,726 MWh in November 2007. In comparison, the highest output was 532,040 MWh in August. The data was downloaded from the EPA website at http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.prepackaged_select.

[26] The NGCC units at Plant Barry have, according to the Platts Powermap database, a nominal total net winter capacity of 1,090 MW. However, the maximum output achievable at any point in time will vary with the ambient air temperature, which affects the density of the air flow into the combustion turbine units of a NGCC.

Figure 10. Hourly Coal and Combined Cycle Generation at Plant Barry



Source: Data downloaded from the EPA website at http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.prepackaged_select.

Natural Gas Supply and Price

Large scale displacement of coal-fired generation by existing NGCC plants could result in a significant increase in U.S. gas demand. **Table 6** compares the actual demand for natural gas for all purposes in 2007 with an illustrative estimate of the additional gas supplies needed if all of the displaceable coal-fired generation (see **Table 3**) were actually replaced by existing NGCC plants. As discussed above, this maximum displacement of coal by existing NGCC plants may be unachievable, so results are also shown for a half and a quarter of the maximum.

Table 6. Illustrative Estimates of Increased Natural Gas Demand For Coal Displacement Compared to Total National Demand

Based on 2007 Data

	Hypothetical Maximum Displacement of Coal by Existing NGCC Plants (2007 data and 85% capacity factor)	Half of Hypothetical Maximum Displacement	One Quarter of Hypothetical Maximum Displacement
1. Additional MWh of NGCC Generation Needed to Displace Coal	640,128,780	320,064,390	160,032,195
2. Required Additional Natural Gas in Trillion Btus (Tbtus)	4,775	2,388	1,194
3. Additional Gas as a Percentage of 2007 Gas Consumed for All Purposes in the U.S.[a]	20%	10%	5%

Source: Table 3 and EIA, *Annual Energy Review 2008*, Tables 6.1 and A4 (http://www.eia.doe.gov/emeu/aer/contents.html).

Notes: Total gas consumption in 2007 of 23,047 billion cubic feet was converted to TBtus using a conversion factor of 1.028 (see Table A4 in the *Annual Energy Review*, cited immediately above). The MWh of additional gas-fired generation was converted to TBtus using a heat rate of 7.4596 MMBtus of fuel input per MWh. This is the 2007 average annual heat rate for the study group of 314 combined cycle plants, calculated using the generation and fuel input reported in the EIA 906/920 database (http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html).

a. Total gas consumption in 2007 for all residential, commercial, industrial, electric power, and transportation purposes was 23,692 Tbtus. The percentages shown in Line 3 are calculated by dividing this number into the values shown on line 2.

Total U.S. natural gas demand in 2007 was the third highest on record. The illustrative estimates of increased gas demand for coal displacement would increase the already high level of demand in 2007 by another 5% to 20% (**Table 6**, line 3).

This increased demand might be met with a combination of increased domestic production, pipeline imports from Canada, Alaskan supplies if the trans-Alaskan gas pipeline is built, and imports of liquefied natural gas by tanker from overseas. For example, one reason for the interest in coal displacement by gas is the recent increase in natural gas available from shale formations and other "unconventional" sources of gas.[27] The combination of higher production (up a projected 3.7% for 2009) and reduced demand due to the 2008-2009 recession has contributed to a sharp decline in gas prices from the peaks experienced earlier in the 2000s (see **Figure 3**).[28] For the longer term, there is widespread optimism concerning the gas supply and price outlook. An example is a late 2009 assessment by the Federal Energy Regulatory Commission (FERC):

> The long-term [gas production] story is one of abundance. In June, the Potential Gas Committee, an independent group that develops biennial assessments of gas resources, raised

[27] For additional information see CRS Report R40894, *Unconventional Gas Shales: Development, Technology, and Policy Issues*, coordinated by (name redacted); and FERC, *State of the Markets Report 2008*, August 2009, Section 2, http://www.ferc.gov/market-oversight/st-mkt-ovr/2008-som-final.pdf.

[28] EIA, *Short-Term Energy Outlook*, December 2009, pp. 4 – 6, http://www.eia.doe.gov/emeu/steo/pub/dec09.pdf.

> its estimate to over 2 quadrillion cubic feet, one-third more than its previous level and almost 100 years of gas production at current consumption levels. The large increase is almost entirely due to improvements in our ability to harvest gas from shale and get it to markets at a reasonable cost…. As we have indicated before, gas production is becoming more like mining and manufacturing with high probability of production from each well drilled. This environment should have profound effects on the traditional boom and bust cycle of gas production.[29]

EIA's most recent long-term forecasts of natural gas wellhead prices for 2020 and 2030 have dropped, respectively, 13% and 11% from its prior forecast, "due to a more rapid ramping up of shale gas production, particularly after 2015. [The forecast] assumes a larger resource base for natural gas, based on a reevaluation of shale gas and other resources…."[30]

Even with the current optimism concerning natural gas supplies and prices, it is important to note that natural gas markets have historically been exceptionally difficult to forecast. According to an EIA self-assessment of its long-term projections, "The fuel with the largest difference between the projections and actual data has generally been natural gas."[31] In the 1990s gas prices were expected to be low; by 2004 prices were much higher than expected and major gas buyers were reported to be "increasingly critical of the nation's system for forecasting natural gas supply and demand."[32] Subsequently, as shown in **Figure 3**, prices plummeted. In the October 2009 Senate hearing on natural gas, a cautionary note was sounded by the witness for Dow Chemical Company:

> Although increased supply from shale gas appears to have changed the production profile, we have seen similar scenarios occur after past spikes. In 1998, significant new imports from Canada came on line; in 2002-2003, there were new supplies from the Gulf of Mexico and in 2005, new discoveries in the Rockies were brought into play. In each case, the initial hopes were too high and production increases were not as large as initially expected.[33]
>
> In 2009, as in 2002, 2004 and 2006, drilling has declined dramatically as price has fallen. After each trough, natural gas demand and price rise once the economy turns, signaling the production community to increase drilling. During the lag between the pricing signals and new production, only one mechanism exists to rebalance supply and demand: demand destruction brought about by price spikes. Demand destruction is an antiseptic economic term for job destruction.[34]

Although multiple options may exist to meet the additional natural gas demand created by a coal displacement policy, the significance of the potential increase in demand should not be

[29] FERC, *Winter 2009/2010 Energy Market Assessment*, November 19, 2009, p. 3, http://www.ferc.gov/EventCalendar/Files/20091119102759-A-3-final.pdf. For additional information on the findings of the Potential Gas Committee, see the press release at http://www.energyindepth.org/wp-content/uploads/2009/03/potential-gas-committee-reports-unprecedented-increase-in.pdf.

[30] EIA, *Annual Energy Outlook 2010 Early Release Overview*, pp. 3, 4, 12, http://www.eia.doe.gov/oiaf/aeo/pdf/overview.pdf.

[31] EIA, *Annual Energy Outlook Retrospective Review: Evaluation of Projections in Past Editions (1982-2008)*, September 2008, p. 2, http://www.eia.doe.gov/oiaf/analysispaper/retrospective/pdf/0640%282008%29.pdf.

[32] Rebecca Smith, "Utilities Question Natural-Gas Forecasting," *The Wall Street Journal*, December 27, 2004.

[33] Statement for the Record of Edward Stones, Director of Risk Management, Dow Chemical Co., before the Senate Energy and Natural Resources Committee hearing on *The Role of Natural Gas in Mitigating Climate Change*, October 28, 2009, p. 4, http://energy.senate.gov/public/_files/StonesTestimony102809.pdf.

[34] Ibid., p. 3.

underestimated. The lowest level of increased gas demand shown in **Table 6**, 1,194 trillion Btus (TBtus), would raise total demand to 24,886 TBtus. In its most recent Reference Case forecast, the U.S. Energy Information Administration (EIA) does not envision this demand level being reached until after 2028. The middle estimate of increased gas demand shown in **Table 6** would raise total gas demand to 26,080 TBtus, which is larger than EIA's forecast for 2035.[35] A policy of rapid change from coal to gas could therefore involve a significant acceleration of gas demand growth compared to EIA's current estimates.

Natural Gas Transportation and Storage

Gas-fired power plants and other gas consumers receive fuel through a vast national pipeline network. At the end of 2008 the network consisted of 293,000 miles of interstate and intrastate pipelines with the capacity to move up to 215 billion cubic feet (BCF) of gas daily.[36] The capacity of this system is sized to meet peak loads, such as during the winter residential heating season. Peak demands are also supported by a system of natural gas storage facilities connected to the pipeline network. These storage facilities hold gas which is produced during lower demand periods until it is needed to meet peak demand.

It seems unlikely that on a national, aggregate scale, pipeline capacity would be a constraint on coal displacement by existing NGCC plants. The natural gas consumption required for the maximum potential coal displacement by existing NGCC plants (see **Table 3**) equate to about 15 BCF per day of natural gas, or about 7% of existing pipeline capacity.[37] A 7% increase in peak demand would appear manageable given the planned expansions to the pipeline system (see below). But irrespective of national system-wide capacity, a different question is whether increased use of gas-fired plants could overstress the specific pipelines and storage facilities that serve those plants. This may be an important issue because the increase in gas demand from existing NGCC plants for coal displacement could be large relative to the amount of gas currently used for power generation. As shown in **Table 7**, illustrative estimates of this increase range from 16% to 66%, which means that the facilities serving those plants could have to handle a material increase in gas demand.

A balancing factor is that the natural gas industry has been effective at adding large amounts of capacity to the pipeline system. Capacity additions in 2007 and 2008 were, respectively, 14.9 and 44.6 BCF per day, and as of mid-2009, 31.9 BCF per day was under construction or approved for construction and completion in 2009. Another 62.1 BCF per day of capacity additions are

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[35] EIA's Annual Energy Outlook 2010 backup spreadsheet for Table 13, located at http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html. Values were converted from cubic feet to Btus using a conversion factor of 1.028. This is the Reference Case forecast, which assumes no changes to current law or regulations.

[36] The interstate portion of the system consists of 217,000 miles of pipeline with a capacity of 183 BCF per day. The interstate portion consists of 76,000 miles of pipeline with a capacity of 32 BCF per day. EIA, *Expansion of the U.S. Natural Gas Pipeline Network: Additions in 2008 and Projects through 2011*, September 2009, p. 3, http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2009/pipelinenetwork/pipelinenetwork.pdf.

[37] As shown in **Table 3**, the maximum potential increase in existing NGCC generation to displace coal is 640,128,780 MWh. This number assumes an annual average capacity factor of 85%, but on a given day the existing NGCC plants could be running at full load to displace coal, which is 640,128,780 MWh ÷ 0.85 ÷ 365 days = 2,063,268 MWh per day. The average heat rate for combined cycles in the study group is 7.4596 MMBtus per MWh and the conversion factor from MMBtus of thousands of cubic feet is 1.028, so the daily gas demand can be calculated as 2,063,268 MWh x 7.4596 MMBtus per MWh ÷ 1.028 ÷ 1,000,000 = 15 BCF per day.

planned for 2010 and 2011,[38] which is equivalent to almost 30% of current capacity. It appears that, given sufficient lead time, the natural gas industry has the ability to install large amounts of additional transportation capacity to meet increased demand.

Table 7. Illustrative Estimates of Increased Natural Gas Demand Relative to Electric Power Demand, Based on 2007 Data

	Hypothetical Maximum Displacement of Coal by Existing NGCC Plants (2007 data and 85% capacity factor)	Half of Hypothetical Maximum Displacement	One Quarter of Hypothetical Maximum Displacement
1. Additional MWh of Existing NGCC Generation	640,128,780	320,064,390	160,032,195
2. Required Additional Natural Gas in Trillion Btus (Tbtus)	4,775	2,388	1,194
3. Required Additional Gas as a Percentage of Actual Gas Used for Power Generation in 2007[a]	66%	33%	16%

Source: Table 6 and EIA, *Annual Energy Review 2008*, Tables 8.4a (http://www.eia.doe.gov/emeu/aer/contents.html).

Notes: The MWh of additional gas-fired generation was converted to TBtus using a heat rate of 7.4596 MMBtus of fuel input per MWh. This is the 2007 average annual heat rate for the study group of 314 combined cycle plants, calculated using the generation and fuel input reported in the EIA 906/920 database (http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html).

a. Electric power gas consumption in 2007 was 7,288 Tbtus. The percentages shown in Line 3 are calculated by dividing this number into the values shown on line 2.

Policy Considerations

As discussed in this report, the potential for displacing coal consumption in the power sector by making greater use of existing NGCC power plants depends on numerous factors. These include:

- The amount of excess NGCC generating capacity available;
- The current operating patterns of coal and NGCC plants, and the amount of flexibility power system operators have for changing those patterns;
- Whether or not the transmission grid can deliver power from existing NGCC plants to loads currently served by coal plants; and
- Whether there is sufficient natural gas supply, and pipeline and gas storage capacity, to deliver large amounts of additional fuel to gas-fired power plants; and consideration of the environmental impacts of increasing gas production.

[38] EIA, *Expansion of the U.S. Natural Gas Pipeline Network: Additions in 2008 and Projects through 2011,* September 2009, Table 2, http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2009/pipelinenetwork/pipelinenetwork.pdf.

All of these factors have a time dimension. For example, while existing NGCC plants may have sufficient excess capacity today to displace a material amount of coal generation, this could change in the future as load grows. Therefore a full analysis of the potential for gas displacement of coal must take into account future conditions, not just a snapshot of the current situation.

There is also the question of cost which, as discussed in the introduction, is beyond the scope of this report. Clearly, the cost of a coal displacement by gas policy is highly uncertain, and depends on such factors as future natural gas and coal prices, any need to build additional pipeline and transmission line facilities, and the cost of carbon (if any). The economic impacts of a coal displacement by gas policy could also spill over to other parts of the economy. For example, increased power sector demand could drive up the price of natural gas, to the detriment of other residential, commercial, and industrial users. Decreased production of coal and increased production of natural gas would pose varying costs and benefits for states and regions.

As a step toward addressing these questions, Congress may consider chartering a rigorous study of the potential for displacing coal with power from existing gas-fired power plants. Such a study would require sophisticated computer modeling to simulate the operation of the power system, to determine whether there is sufficient excess gas fired capacity and the supporting transmission and other infrastructure to displace a significant volume of coal over the near term. This kind of study might also estimate the direct costs of a gas for coal policy, such as the impact on electric rates. Because of the large number of uncertainties, such as the future price of natural gas, the study would have to consider several scenarios. Such a study could help Congress judge whether there is sufficient potential to further explore a policy of replacing coal generation with increased output from existing gas-fired plants.

Congress may also consider chartering an analysis of the potential for directly using gas in existing coal-fired plants, either as a supplemental or primary fuel. As noted in the introduction, large scale use of gas in coal plants raises engineering issues and the question of how many coal plants have adequate pipeline connections. However, burning gas in coal plants would make it possible to displace coal while still using existing transmission lines to meet load, which could be a significant advantage.[39]

[39] Many coal plants use natural gas as a startup fuel and for flame stabilization during normal operations. However, this is different from running the plant primarily or largely on natural gas. In addition to the engineering issues, even if a coal plant currently uses natural gas as a startup fuel, its existing natural gas pipeline connection may not have sufficient capacity to provide enough gas for full load (or even large partial load) operation on gas. There are examples of coal units switching to natural gas for environmental reasons ("Marketwatch: Public Service Electric & Gas of New Jersey," *Platts Coal Week*, June 22, 1992; "Ill. Power to Shift Vermilion to Gas; Phase I Decision Kills Coal Solicitation," *Platts Coal Week*, October 10, 1994; "PEPCO Mulls NOx Ozone Season's Effect on Coal, Gas, Oil Use," *Platts Coal Week*, October 25, 1999.

Appendix A. Background on the Electric Power System

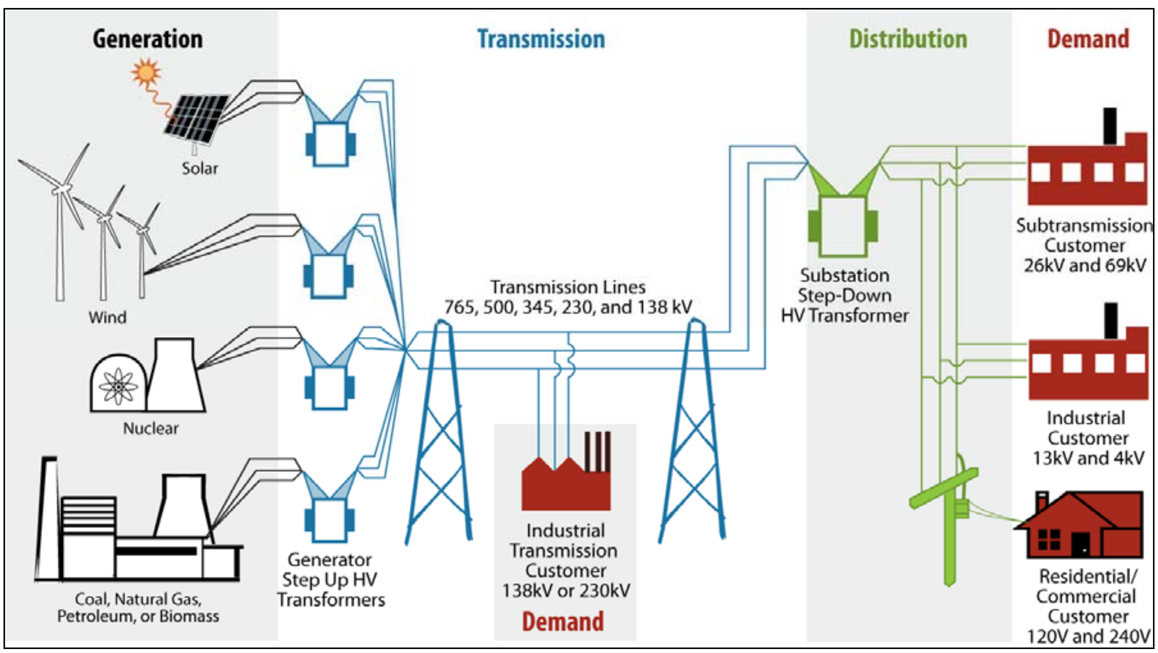
This appendix provides background on the components and operation of the electric power system. Readers familiar with these topics may wish to skim or skip this appendix.

Power Plants and Power Lines

Power plants, transmission systems, and distribution systems constitute the major components of the existing electric power system, as briefly described and illustrated below (**Figure A-1**):

- *Generating plants* produce electricity, using either combustible fuels such as coal, natural gas, and biomass; or non-combustible energy sources such as wind, solar energy, or nuclear fuel.
- *Transmission lines* carry electricity from power plants to demand centers. The higher the voltage of a transmission line the more power it can carry and the fewer the line losses during transmission. Current policy discussions focus on the high voltage network (230 kilovolts (kV) rating and greater) used to move large amounts of power long distances.
- Near customers a step-down transformer reduces voltage so the power can be carried by low voltage *distribution lines* for final delivery.

Figure A-1. Elements of the Electric Power System



Source: CRS.

Capacity and Energy

Capacity is the potential instantaneous output of a generating or storage unit, measured in watts. Energy is the actual amount of electricity generated by a power plant or released by a storage device during a time period, measured in watt-hours. The units are usually expressed in thousands (kilowatts and kilowatt-hours) or millions (megawatts and megawatt-hours). For example, the maximum amount of power a 1,000 megawatt (MW) power plant can generate in a year is 8.76 million megawatt-hours (MWh), calculated as: 1,000 MW x 8,760 hours in a year = 8.76 million MWh.

Capacity Factor

Capacity factor is a standard measure of how intensively a power plant is utilized. It is the ratio of how much electricity a power plant produced over a period of time, typically a year, compared to how much electricity the plant could have produced if it operated continuously at full output. For example, as shown in the prior paragraph, the maximum possible output of a 1,000 MW power plant in one year is 8.76 million MWh. Assume that during a year the plant actually produced only 7.0 million MWh. In this case the plant's capacity factor would be 7.0 million MWh ÷ 8.76 million MWh = 81%.

Generation and Load

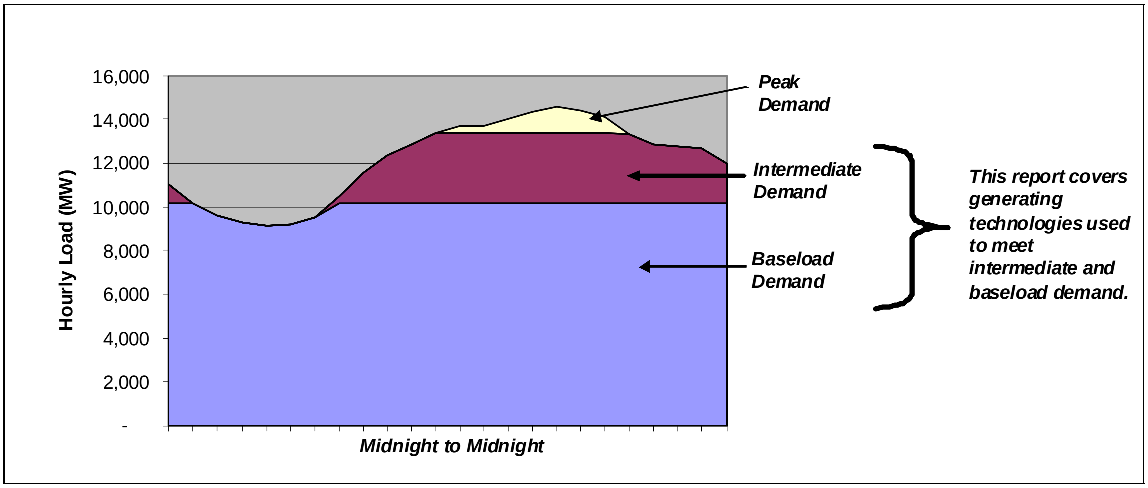
The demand for electricity ("load") faced by an electric power system varies moment to moment with changes in business and residential activity and the weather. Load begins growing in the morning as people waken, peaks in the early afternoon, and bottoms-out in the late evening and early morning. **Figure A-2** shows an illustrative daily load curve.

The daily load shape dictates how electric power systems are operated. As shown in **Figure A-2**, there is a minimum demand for electricity that occurs throughout the day. This base level of demand is met with "baseload" generating units which have low variable operating costs.[40] Baseload units can also meet some of the demand above the base, and can reduce output when demand is unusually low. The units do this by "ramping" generation up and down to meet fluctuations in demand.

The greater part of the daily up and down swings in demand is met with "intermediate" units (also referred to as load-following or cycling units). These units can quickly change their output to match the change in demand (that is, they have a fast "ramp rate"). Load-following plants can also serve as "spinning reserve" units that are running but not putting power on the grid, and are immediately available to meet unanticipated increases in load or to back up other units that go off-line due to breakdowns.

[40] Variable costs are costs that vary directly with changes in output. For fossil fuel units the most important variable cost is fuel. Solar and wind plants have minimal or no variable costs, and nuclear plants have low variable costs.

Figure A-2. Illustrative Daily Load Curve



Source: CRS.

The highest daily loads are met with peaking units. These units are typically the most expensive to operate, but can quickly start up and shut down to meet brief peaks in demand. Peaking units also serve as spinning reserve and as "quick start" units able to go from shutdown to full load in minutes. A peaking unit typically operates for only a few hundred hours a year.

Economic Dispatch and Heat Rate

The generating units available to meet system load are "dispatched" (put on-line) in order of lowest variable cost. This is referred to as the "economic dispatch" of a power system's plants.

For a plant that uses combustible fuels (such as coal or natural gas) a key driver of variable costs is the efficiency with which the plant converts fuel to electricity, as measured by the plant's "heat rate." This is the fuel input in British Thermal Units (btus) needed to produce one kilowatt-hour of electricity output. A lower heat rate equates with greater efficiency and lower variable costs. Other things (most importantly, fuel and environmental compliance costs) being equal, the lower a plant's heat rate, the higher it will stand in the economic dispatch priority order. Heat rates are inapplicable to plants that do not use combustible fuels, such as nuclear and non-biomass renewable plants.

As an illustration of economic dispatch, consider a utility system with coal, nuclear, geothermal, natural gas combined cycle, and natural gas peaking units in its system:

(1) Nuclear, coal, and geothermal baseload units, which are expensive to build but have low fuel costs and therefore low variable costs, will be the first units to be put on-line. Other than for planned and forced maintenance, these baseload generators will run throughout the year.

(2) Combined cycle units, which are very efficient but use more expensive natural gas as a fuel, will meet intermediate load. These cycling plants will ramp up and down during the day, and will be turned on and off dozens of times a year.

(3) Peaking plants, using combustion turbines,[41] are relatively inefficient and burn natural gas. They run only as needed to meet the highest loads.[42]

An exception to this straightforward economic dispatch are "variable renewable" power plants—wind and solar—that do not fall neatly into the categories of baseload, intermediate, and peaking plants. Variable renewable generation is used as available to meet demand. Because these resources have very low variable costs they are ideally used to displace generation from gas-fired combined cycle plants and peaking units with higher variable costs. However, if wind or solar generation is available when demand is low (such as a weekend or, in the case of wind, in the evening), the renewable output could displace coal generation.

Power systems must meet all firm loads at all times, but variable renewable plants do not have firm levels of output because they depend on the weather. They are not firm resources because there is no guarantee that the plant can generate at a specific load level at a given point in time.[43] Variable renewable generation can be made firm by linking wind and solar plants to electricity storage, but with current technology, storage options are limited and expensive.

[41] A combustion turbine is an adaption of jet engine technology to electric power generation. A combustion turbine can either be used stand-alone as a peaking unit, or as part of a more complex combined cycle plant used to meet intermediate and baseload demand.

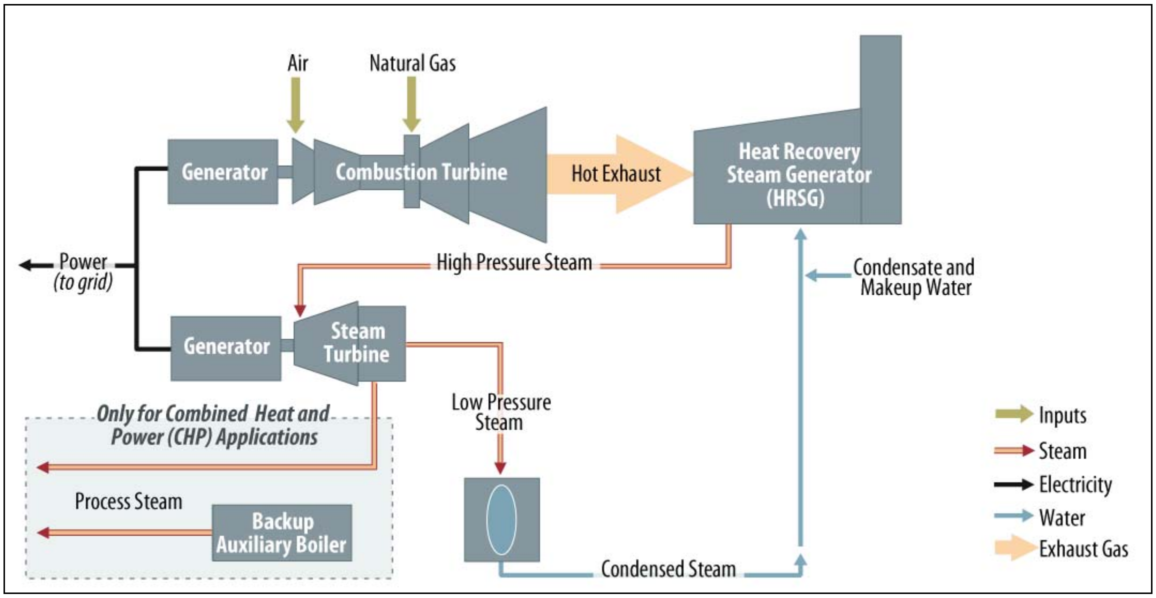
[42] This alignment of generating technologies is for new construction using current technology. The existing mix of generating units in the United States contains many exceptions to this alignment of load to types of generating plants, due to changes in technology and economics. For instance, there are natural gas and oil-fired units built decades ago as baseload stations that now operate as cycling or peaking plants because high fuel prices and poor efficiency has made them economically marginal. Some of these older plants were built close to load centers and are now used as reliability must-run (RMR) generators that under certain circumstances must be operated, regardless of cost, to maintain the stability of the transmission grid.

[43] Hydroelectric generation is a special case. Hydro generation is very low cost and is firm, dispatchable capacity to the degree there is water in the dam's reservoir. However, operators have to consider not only how much water is currently available, but how much may be available in upcoming months, and competing demands for the water, such as drinking water supply, irrigation, and recreation. These factors can make hydro dispatch decisions very complex. In general hydro is used to meet load during high demand hours, when it can displace expensive peaking and cycling units, but if hydro is abundant it can also displace baseload coal plants.

Appendix B. Combined Cycle Technology

The combined cycle achieves a high level of efficiency by capturing waste heat that would otherwise be lost in the generating process. As shown in **Figure B-1** for a combined cycle unit fueled by natural gas, the gas is fed into a combustion turbine which burns the fuel to power a generator. The exhaust from the combustion turbine is then directed to a specialized type of boiler (the heat recovery steam generator or HRSG) where the heat in the exhaust gases is used to produce steam, which in turn drives a second generator. In combined heat and power (CHP) applications, part of the steam is used to support an industrial process or to provide space heating, further increasing the total energy efficiency of the system.

Figure B-1. Schematic of a Combined Cycle Power Plant



Source: CRS, based on a Calpine Corp. illustration.

Combined cycles are built in different configurations, depending in part on the amount of capacity needed. **Figure B-1** illustrates a configuration in which one combustion turbine feeds one HRSG; this is referred to as "1x1" design. In higher capacity 2x1 or 3x1 designs, multiple combustion turbines feed a single HRSG. These options illustrate the modular (or "building block") nature of combined cycles, which facilitates rapid and flexible construction of new generating units to match changes in demand.

In the United States the predominant fuel used in combined cycle plants is natural gas. Combined cycles can also be designed to use fuel oil as a primary or backup fuel. Gasified coal can also be used as the fuel in an integrated gasification combined cycle (IGCC) plant. There are currently two prototype IGCC plant operating in the United States and a commercial-scale unit is under construction in Indiana.

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