9. Switch Fuels at Existing Power Plants

1. Profile

One option for reducing the carbon dioxide (CO_2) emissions from an existing electric generating unit (EGU) is to switch to a lower-emitting fuel. Fuel switching is perhaps the most familiar and most proven method for reducing greenhouse gas (GHG) emissions from existing EGUs. The technological challenges are familiar and manageable, the co-benefits can be substantial, and the costs are generally lower than for other technology options.[1]

Fuel switching can involve at least three distinct strategies. First, if an EGU is already designed and permitted to use multiple fuels, the owner or operator can reduce annual emissions by increasing the use of a lower-emitting backup fuel and decreasing the use of a higher-emitting primary fuel. For example, the EGU could reduce annual combustion of coal and increase annual combustion of natural gas. With this strategy, the hourly emissions rate of the EGU when it is burning coal would not change, and the hourly emissions rate of the EGU when it is burning gas would not change, but its annual emissions would decrease.

The second strategy is to blend or cofire a lower-emitting fuel with a higher-emitting fuel. For example, the owner or operator of the EGU could blend two different ranks of coal, or cofire a biomass fuel with coal, to reduce the emissions rate of the unit.

The third fuel-switching strategy is to repower the EGU, that is, to modify the unit or the fuel delivery system to accommodate the use of a lower-emitting fuel not previously used. For example, a coal-fired EGU might be reconstructed to burn natural gas, thus reducing the unit's emissions rate.

Switching fuels is one of the most straightforward and technologically feasible strategies for reducing emissions, but it is not a trivial undertaking. For any existing EGU, there are reasons the current fuels are used and other fuels are not used. Similarly, there are reasons the primary fuel is primary and the backup fuels are backups. These decisions are influenced by many different factors, such as delivered fuel costs, fuel handling system design, boiler design, permit conditions, emissions of criteria or toxic air pollutants, availability of natural gas pipeline capacity, and so forth.

Switching fuels will be most feasible from a technological perspective where an EGU is already designed and permitted to combust more than one type of fuel, but the current primary fuel has a higher input emissions factor than the secondary fuel. Even so, economic considerations will determine whether fuel switching is a practical option. Blending or cofiring strategies can introduce additional difficulties, as the use of blended fuel or cofiring of two fuels may affect the performance of the fuel delivery system, boiler, pollution control devices, ash handling system, and the like. Repowering projects tend to be major undertakings requiring considerable capital investment.

2. Regulatory Backdrop

With few exceptions, fuel switching has not been imposed on regulated entities as a statutory or regulatory requirement, nor has it been mandated through air pollution permitting processes. It is normally adopted by regulated entities as either an economic choice or as an optional strategy for complying with environmental requirements.

The US Environmental Protection Agency (EPA) evaluated fuel switching as a potential GHG abatement measure in conjunction with the June 2014 proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric

1 This chapter focuses exclusively on switching the fuels used (or the proportions in which they are used) at existing power plants to reduce onsite emissions without necessarily reducing electrical output. Note that Chapter 21 addresses a different strategy that is often explained in other publications using the same term "fuel switching." Chapter 21 examines the potential to reduce CO_2 emissions by less frequently dispatching (i.e., operating) higher-emitting power plants (e.g., coal units) while increasing the dispatch frequency of other, lower-emitting power plants (e.g., gas units).

Utility Generating Units. Chapter 6 of the GHG Abatement Measures Technical Support Document (TSD) is dedicated to fuel switching.[2] In the TSD, the EPA analyzed the GHG reduction potential, co-benefits, and cost-effectiveness of cofiring natural gas or biomass with coal, and of repowering a coal unit to 100 percent gas or biomass. Based on its analysis, the EPA concluded that fuel switching should not be included as part of the "best system of emissions reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities." Details of the EPA's analysis and conclusions are provided later in this chapter.

Most federal and state air pollution regulations have been implemented in a "fuel-specific" way that results in separate emissions limits, control requirements, and compliance demonstration methods for each fuel that a source is permitted to burn. The emissions limits and other applicable requirements for each fuel tend to be based on what is realistically achievable when burning that fuel.[3] Part of the explanation for this approach comes from a precedent-setting 1988 permit decision in which the EPA Administrator held on appeal that "...permit conditions that define these [control] systems are imposed on the source *as the applicant has defined it.* Although imposition of the conditions may, among other things, have a profound effect on the viability of the proposed facility as conceived by the applicant, the conditions themselves are not intended to redefine the source."[4]

In the context of the federal Prevention of Significant Deterioration (PSD) regulations, the EPA has held since that 1988 decision that control options that "fundamentally redefine the source" may be excluded from a best available control technology (BACT) analysis, but state and local permitting authorities have the discretion to engage in a broader analysis if they so desire. A number of past EPA statements in guidance documents and precedents in the case of actual permit applications indicate that requiring (for example) a coal-fired EGU to switch to natural gas as the BACT would be to "fundamentally redefine the source."[5] In summary, state and local permitting authorities have the discretion to consider fuel switching as a possible BACT option but, under current EPA policy, they are not required to do so. In practice, fuel switching has historically rarely been considered in BACT analyses.

Nearly all of the exceptions to the traditionally "fuel-specific" approach to regulation come from federal or state regulations that in some way cap annual emissions of a specified pollutant from a category of sources. Examples of such "fuel neutral" regulations include the federal Acid Rain Program, the federal Clean Air Interstate Rule (CAIR), the Cross-State Air Pollution Rule, and the Regional Greenhouse Gas Initiative (RGGI). Regulations like these that include a mass-based annual emissions cap do not force sources to switch fuels but allow for fuel switching as one of many possible compliance strategies.

Colorado's *Clean Air – Clean Jobs Act* provides a different kind of exception to the fuel-specific generalization.[6] This state statute, enacted in 2010, did not create annual mass-based emissions limits, but required the state's largest public utility to develop a coordinated plan for reducing emissions from coal-fired power plants in sufficient amounts to satisfy current *and anticipated future* Clean Air Act requirements. Here again, fuel switching was not mandated by the legislation but the reductions were targeted toward coal-fired plants, and fuel switching was specifically listed as one of the options available to the utility for inclusion in the plan.

Along a similar vein, in 2011 the State of Washington enacted a law that imposes a GHG emissions performance standard for the two boilers at an existing coal-fired power plant. The law does not require fuel switching per se, but the standards are sufficiently stringent that the source is

2 US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units—GHG Abatement Measures.* Office of Air and Radiation. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents.

3 During the permitting process, regulators occasionally find that a source will be unable to meet all applicable requirements while burning a particular fuel. In such cases, the owner of the source might opt to switch to a different fuel in order to obtain the permit, or accept limitations on the quantity of the problematic fuel that will be combusted, but the regulator will not unilaterally mandate fuel switching.

4 In re Pennsauken County, N.J., Resource Recovery Facility, 2 E.A.D. 667 (Adm'r 1988) (emphasis added).

5 *See, e.g.,* In re Old Dominion Elec. Coop., 3 E.A.D. 779 (Adm'r 1992), in which the EPA found no error in a state's determination that it could not require a proposed new coal-fired EGU to instead fire natural gas.

6 Colo. Rev. Stat. §§ 40-3.2-201 to 40-3.2-210.

Table 9-1

Compliance Methods Used in Phase 1 of the Acid Rain Program

Compliance Method	Number of Generators	Average Age[a] (years)	Affected Nameplate Capacity (megawatts)	Allowances[b] (per year)	1985 SO_2 Emissions (tons)	1995 Emissions (tons)	Percentage of Total Nameplate Capacity Affected by Phase I	Percentage of SO_2 Emission Reductions in 1995[c]
Fuel Switching and/or Blending	136	32	47,280	2,892,422	4,768,480	1,923,691	53	59
Obtaining Additional Allowances	83	35	24,395	1,567,747	2,640,565	2,223,879	27	9
Installing Flue Gas Desulfurization Equipment (Scrubbers)	27	28	14,101	923,467	1,637,783	278,284	16	28
Retired Facilities	7	32	1,342	56,781	121,040	0	2	2
Other	8	33	1,871	110,404	134,117	18,578	2	2
Total	**261**	**32**	**88,989**	**5,550,821**	**9,301,985**	**4,444,432**	**100**	**100**

widely expected to either shut down or repower by 2025. The installation of carbon capture and storage technology might provide a third compliance option that allows for continued use of coal.[7]

Fuel switching strategies may have permitting implications for existing sources. In cases in which an EGU is already permitted to burn more than one fuel, it will often be the case that the source can increase its use of a lower-emitting fuel without requesting any changes to its operating permit because the emissions rates will not change. There may be exceptional cases in which a source that has a limit on annual or monthly mass emissions or hours of operation will need to request a permit revision in order to increase its use of a fuel for which it is already permitted. If the owner of an EGU wishes to switch to a fuel that the source was already capable of burning but was not permitted to burn (i.e., a switch that does not require a physical change to the source), it will be necessary to obtain a revised operating permit. Finally, if the source will be repowered, it may require a new source construction permit and a revised operating permit.

3. State and Local Implementation Experiences

As noted earlier in this chapter, there are virtually no examples of state or local governments that have instituted fuel switching through a mandatory statute or regulation. However, there are abundant examples from virtually all states in which fuel switching has been implemented by sources as a Clean Air Act compliance strategy or for economic reasons (with emissions reductions as a co-benefit). One such example can be found in a 1997 US Energy Information Administration (EIA) review of the compliance strategies adopted by regulated units during the first phase of the Acid Rain Program.[8] As shown in Table 9-1, fuel switching and fuel blending were the chosen strategies for more than half the affected sources, and those strategies accounted for nearly 60 percent of the sulfur dioxide (SO_2) emissions reductions.

An EIA 2012 survey of generators identified over 3600 EGUs that were operable at that time and had the regulatory permits needed to burn multiple fuels.[9] Multi-fuel facilities were operating in every state. With so many EGUs already designed and permitted to burn multiple fuels, the strategy of switching between primary and backup fuels to reduce emissions will be familiar to many power plant owners and state regulators. This is especially true in ozone non-attainment areas that have been subject to seasonal nitrogen oxides (NO_x) emissions limits. It is quite common in such cases for regulated entities to switch to burning natural gas, normally a backup fuel, to meet seasonal limits. Similar strategies have also been used by owners of Acid

7 The possibilities for reducing CO_2 emissions from existing power plants through carbon capture and storage technologies are addressed in Chapter 7.

8 US EIA. (1997, March). *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update.* Washington, DC.

9 US EIA. (2013, December 4). Form EIA-860 detailed data for 2012 retrieved from the EIA website: http://www.eia.gov/electricity/data/eia860/index.html.

Rain units (as already noted) and EGUs subject to CAIR in order to comply with annual SO_2 emissions limits. In fact, more than half of the coal-fired EGUs in the Acid Rain and CAIR programs have not installed SO_2 emissions controls, but have complied using fuel switching or other strategies such as allowance trading.[10]

In 2012, electric power industry analysts at the firm SNL Energy reported the results of their review of recent fuel switching at multi-fuel facilities.[11] SNL Energy looked at reported fuel use data to identify power plants capable of burning both coal and natural gas. Overall, 197 facilities (many with multiple EGUs) with a total generating capacity of 78,544 megawatts (MW) were identified as burning both coal and natural gas for electricity generation during at least one month between 2008 and 2012. SNL Energy reported that the volume of gas burned at those plants increased 11 percent in 2011 compared to 2008, whereas the volume of coal burned fell nine percent. These data offer a clear indication that substantial levels of fuel switching can occur at multi-fuel facilities over a relatively short period of time (years rather than decades). What is not quite as clear is how much *additional* fuel switching, beyond what already happened in 2012, is still possible for existing multi-fuel facilities.

Fuel blending has also been a common Acid Rain and CAIR compliance strategy. Many boiler owners in the United States have routinely blended lower-sulfur sub-bituminous coal with higher-sulfur bituminous coal to reduce annual SO_2 emissions while meeting other performance and cost objectives. Unfortunately, most of the analyses of Acid Rain and CAIR compliance strategies have conflated fuel blending with other forms of fuel switching, so it is difficult to quantify how much fuel blending has occurred.

Cofiring is yet another variation on fuel switching. The Electric Power Research Institute (EPRI) published a technical report in 2000 that assessed five proven technologies and one experimental technology for cofiring natural gas with coal at EGUs.[12] EPRI closely examined over 30 full-scale installations of these technologies that had been installed across the entire range of coal-fired boiler types in use in the United States: tangentially fired boilers, wall-fired boilers, cyclone boilers, and turbo-fired boilers. The technologies and installations reviewed are summarized in Table 9-2; for complete descriptions refer to the EPRI report.

The 2012 EIA survey data cited above offers a more recent and comprehensive look at cofiring capabilities in the United States across all technologies and fuels. The EIA

Table 9-2

Cofiring Technologies Reviewed in EPRI Study
(Circa 2000)

Technology	Number of Installations
Supplemental Gas Cofiring (simultaneous firing of both fuels through separate burners in boiler's primary combustion zone)	10
Gas Reburning (in secondary combustion zone)	11
Fuel Lean Gas Reburning	6
Advanced Gas Reburning	2
Amine-Enhanced Fuel Lean Gas Reburning	2
Coal/Gas Cofiring Burners	0

data indicate that 1980 of the multi-fuel generating EGUs in the United States have cofiring capability and the necessary regulatory approvals. Although the earlier EPRI report focused only on cofiring coal and gas, the EIA data show that the most common configuration among these units is the ability to cofire oil with gas, as shown in Figure 9-1.

Repowering of existing EGUs is the last type of fuel switching examined in this chapter. In recent years, dozens of repowering projects have been undertaken, announced, or proposed for United States power plants. Most of these projects involve repowering existing coal units to burn natural gas, but there are also several examples involving a switch from coal to biomass. An example of a coal plant that has already been converted to natural gas can be found at Dominion Virginia Power's 227-MW Bremo Power Station in Bremo Bluff, Virginia. Examples of completed coal to biomass repowering projects include

10 US EPA. (2013). *Clean Air Interstate Rule, Acid Rain Program, and Former NOx Budget Trading Program: 2012 Progress Report.* Available at: http://www.epa.gov/airmarkets/progress/ARP-CAIR_12_downloads/ARPCAIR12_01.pdf.

11 SNL Energy reports are available only to subscribers but are frequently cited in trade media accounts. For example, the data reported here appeared in *Coal Age News* (http://www.coalage.com/features/2386-us-power-plants-capable-of-burning-coal-and-natural-gas.html) in October 2012.

12 EPRI. (2000). *Gas Cofiring Assessment for Coal-Fired Utility Boilers.* Palo Alto, CA.

Figure 9-1

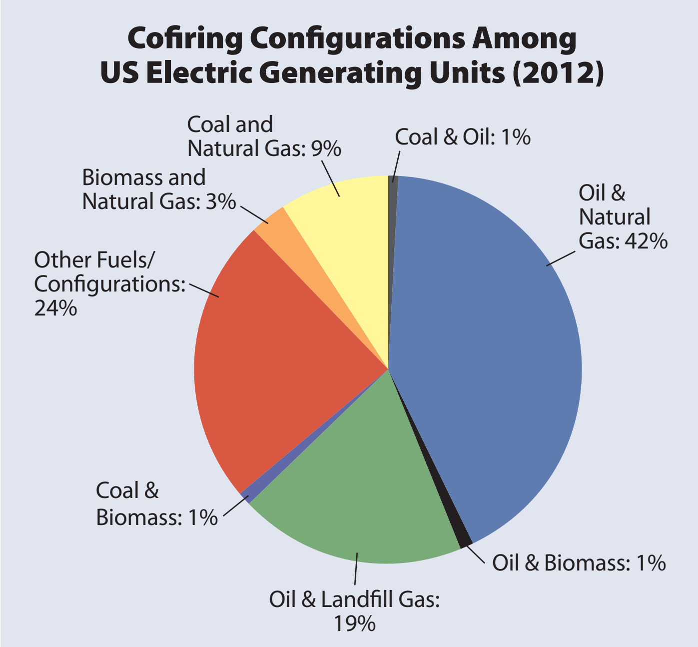
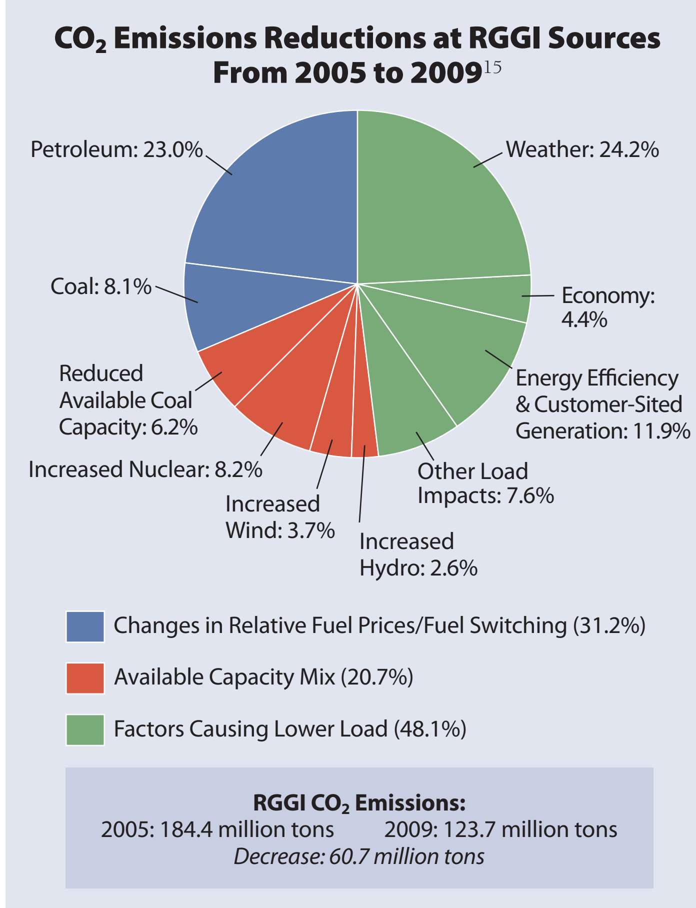


Figure 9-2



DTE Energy Services' 45-MW power plant at the Port of Stockton in California and a 50-MW unit at Public Service of New Hampshire's Schiller Station in Portsmouth, New Hampshire.

Looking ahead, an April 2014 review by SNL Energy found that utilities and merchant power plant owners have announced plans to repower 7600 MW of current coal-fired generating capacity with other fuels, and an additional 3600 MW of coal capacity is slated for either repowering or retirement, with those decisions to come at a later date.[13]

4. GHG Emissions Reductions

To date, switching fuels at existing facilities has occurred primarily in response to criteria pollutant and air toxics regulations and as an economic choice driven by low natural gas prices. However, in nearly all parts of the country, federal GHG regulations for existing sources could conceivably provide the impetus for additional fuel switching beyond what has already happened and what is already planned.

Most of the state experience to date with mandatory CO_2 emissions limits for existing sources comes from the states participating in RGGI.[14] One analysis by the New York State Energy Research and Development Authority (NYSERDA), summarized in Figure 9-2, found that sources regulated under RGGI reduced their CO_2 emissions by 60.7 million tons (33 percent) between 2005 and 2009, and 31 percent of the reductions could be attributed to fuel switching. This underscores two facts: that significant CO_2 emissions reductions are achievable over a short time period, and that fuel switching can be a preferred option for reducing CO_2 emissions.

13 As reported in *Coal Age News* at http://www.coalage.com/61-uncategorised/3572-coal-unit-conversions.html.

14 The nine states currently participating in RGGI are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. New Jersey was previously a participant. California, like the RGGI states, has enacted a mandatory CO_2 cap-and-trade program for existing sources including but not limited to power plants. But in the case of California, similar data on emissions reductions and the factors causing them are not yet available because 2013 was the first year for enforceable compliance obligations. California regulators expect fuel switching to play a relatively smaller role than it has in the RGGI states because most of that state's generating fleet is already gas-fired.

15 NYSERDA. (2010, November 2). *Relative Effects of Various Factors on RGGI Electricity Sector CO_2 Emissions: 2009 Compared to 2005.* Available at: http://www.rggi.org/docs/Retrospective_Analysis_Draft_White_Paper.pdf.

At a theoretical or hypothetical level, the output emissions rate of any combustion unit can be determined as follows:

E = EF * HR where
E = output emissions rate (lbs CO2/MWh[16]gross);
EF = input emissions factor (lbs CO2/MMBTU[17]); and
HR = heat rate (MMBTU/MWhgross).

The input emissions factor is a function of the carbon and heat content inherent in the chemical and physical composition of any given fuel; it varies across fuel types and even within fuel types, as shown in Table 9-3. One option for reducing the CO_2 emissions from an existing EGU is to switch to a fuel that has a lower input emissions factor. (Another but very different option, discussed in Chapter 1, is to improve the heat rate of the unit.)

The data in Table 9-3 suggest the levels of emission reductions that are at least hypothetically possible from fuel switching. To begin with, it should be noted that there is a range of emissions factors within most coal ranks. This suggests the possibility that some sources may be able to reduce their output emissions rate by a small amount, but probably no more than five percent, simply by obtaining coal of the same rank that has a lower input emissions factor. Significantly greater reductions are possible if a source switches to an entirely different fuel. For example, switching from lignite coal to natural gas could cut an EGU's output emissions rate nearly in half.

One fuel switching option that has received considerable attention is the option of blending or cofiring biomass or waste-derived fuels with coal, or completely repowering a coal-fired unit to burn only biomass. Table 9-3 does not show input emissions factors for biomass, biogas, or municipal solid waste fuels. This is because there is significant ongoing debate and controversy about whether or to what extent to treat such fuels as "carbon neutral" (i.e., attribute no net CO_2 emissions to these fuels). The scientific arguments in that debate are beyond the scope of this document, but the salient point is that the regulatory treatment of GHG emissions from biomass and waste-derived fuels remains uncertain at this time and is likely to strongly influence the demand for biomass fuels.[19]

Table 9-3

Average Input Emissions Factors of Various US Fuels[18]

Fuel Type	Input Emissions Factor (lbs CO_2/MMBTU)
Coal – Anthracite	227
Petroleum Coke	225
Coal – Lignite	212 to 221
Coal – Sub-bituminous	207 to 214
Coal – Bituminous	201 to 212
Residual Oil	174
Distillate Oil	161
Natural Gas	117

If biomass fuels are ultimately treated by regulators as fully or partially carbon neutral, biomass utilization at existing coal-fired power plants could potentially play a role in reducing CO_2 emissions. At least two published papers have concluded that a five-percent reduction in CO_2 emissions from the North American electric power sector (roughly 100 Mt[20]/year) could be achieved solely by cofiring biomass with coal at existing EGUs.[21,22] Analysts

16 Megawatt hour.

17 MBTU stands for one million BTUs, which can also be expressed as one decatherm (10 therms). MBTU is occasionally expressed as MMBTU, which is intended to represent a thousand thousand BTUs.

18 US EPA. (2010, October). *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-fired Electric Generating Units.* Office of Air and Radiation. Available at: http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf.

19 In July 2011, the EPA decided to temporarily defer the application of PSD and Title V permitting requirements to CO2 emissions from biogenic stationary sources while it studied whether and how to regulate such emissions. However, that decision was vacated by the US Court of Appeals for the District of Columbia Circuit (DC Circuit) in July 2013. From a regulatory standpoint, the GHG reductions that may be achievable by switching to these fuels are thus uncertain.

20 Mt is defined as millions of tons.

21 Robinson, A., Rhodes, J. S., & Keith, D. W. (2003). Assessment of Potential Carbon Dioxide Reductions Due to Biomass-Coal Cofiring in the United States. *Environ Sci Technol.* 37 (22), 5081-5089. Available at: http://pubs.acs.org/doi/pdf/10.1021/es034367q.

22 Zhang, Y., McKechnie, J., Cormier, D., Lyng, R., Mabee, W., Ogino, A., & Maclean, H. L. (2010). Life Cycle Emissions and Cost of Producing Electricity from Coal, Natural Gas, and Wood Pellets in Ontario, Canada. *Environ Sci Technol.* 44 (1), 538–544.

at McKinsey & Company offer a different estimate of the potential for reducing CO_2 emissions in the United States through biomass cofiring, putting the number at 50 Mt in the year 2030.[23] The biggest difference between these two assessments appears to be that McKinsey assumes that other, less costly CO_2 abatement measures would be implemented prior to 2030 that would lead to the retirement of large amounts of coal capacity and thus a reduced potential to cofire biomass with coal.

In the previously cited GHG Abatement Measures TSD, the EPA separately assesses the emissions reduction potential of fuel switching from coal to gas and from coal to biomass.[24] With respect to gas, the EPA concludes that emissions are reduced in direct proportion to the amount of gas cofired. Cofiring 10 percent gas with 90 percent coal will reduce GHG emissions four percent relative to firing 100 percent coal. Switching to 100 percent gas reduces GHG emissions 40 percent. WIth respect to biomass, the EPA found that stack CO_2 emissions can increase or decrease relative to firing 100 percent coal, depending on the amount and type of biomass fired, and the extent to which biomass-related GHG emissions are treated by regulators as "carbon neutral."

5. Co-Benefits

Most of the future fuel switching that will occur as a response to GHG regulations will likely involve a switch from coal (or possibly oil) to natural gas or biomass. In addition to the CO_2 emissions reductions noted above, fuel switching is likely to result in reduced emissions of other regulated air pollutants. The extent of the reductions will depend on the fuels burned before and after the fuel switch.

According to the EPA, the average natural gas-fired EGU emits just 28 percent as much NO_X as the average coal-fired EGU on an output (lb/MWh) basis, or 43 percent as much NO_x as the average oil-fired EGU, whereas emissions of particulate matter (PM), SO_2, and mercury are orders of magnitude lower for gas than for coal or oil. For repowering projects, the effects on NO_x emissions may be greater than these averages would suggest because new gas-fired EGUs are likely to be more efficient and have lower emissions than the average of gas-fired units already in place. In the GHG Abatement Measures TSD, the EPA presents information on avoided emissions of SO_2, NO_X, and $PM_{2.5}$ for a hypothetical coal plant switching to natural gas at either a ten-percent cofiring rate or at 100 percent gas.[25] For ten-percent cofiring, SO_2 emissions are reduced by 0.3 lbs/net MWh, NOx by 0.2 lbs/net MWh, and $PM_{2.5}$ by 0.02 lbs/net MWh. If 100-percent gas is fired, the reductions are 3.1 lbs/net MWh for SO_2, 2.04 lbs/net MWh for NO_x, and 0.2 lbs/net MWh for $PM_{2.5}$.

The previously cited EPRI report on cofiring natural gas with coal summarized the expected impacts of each cofiring technology on emissions of NO_x, SO_2, and CO_2. With respect to SO_2 and CO_2, EPRI reports that emissions are reduced roughly in proportion to the differences in emissions factors between natural gas and coal, and the extent to which gas is burned in lieu of coal. The effect on NO_x emissions depends on the cofiring technology used. Supplemental gas cofiring (i.e., simultaneously firing both fuels through separate burners in the boiler's primary combustion zone) can reduce NO_x emissions 10 to 15 percent, whereas the various reburn technologies, which were developed specifically for the purpose of reducing NO_X emissions, can reduce NO_X emissions by 30 to 70 percent across a range of boiler types.

In the GHG Abatement Measures TSD, the EPA does not provide avoided criteria pollutant emissions data for cofiring of biomass as it does for cofiring natural gas. Biomass fuels come in so many varieties that it is much harder and less meaningful to discuss average emissions, but the EPA notes elsewhere that in general the emissions of SO_2, NO_X, and mercury will be lower for biomass fuels than for coal, because biomass contains much less sulfur, nitrogen, and mercury than coal does. For example, Peltier reports that the repowered biomass EGU at Public Service of New Hampshire's Schiller Station emits about 75 percent less NO_X, 98 percent less SO_2, and 90 percent less mercury than before the repowering project, when the unit burned coal.[26]

When biomass and coal are cofired there is some evidence of interactive effects between the products of combustion that makes it harder to predict the resulting

23 McKinsey & Company. (2007, December). Reducing US Greenhouse Gas Emissions: How Much at What Cost? Available at: http://www.mckinsey.com/client_service/sustainability/latest_thinking/reducing_us_greenhouse_gas_emissions.

24 Supra footnote 2.

25 Ibid.

26 Peltier, R. (2007). PSNH's Northern Wood Power project repowers coal-fired plant with new fluidized-bed combustor. POWER. Available at: http://www.powermag.com/psnhs-northern-wood-power-project-repowers-coal-fired-plant-with-new-fluidized-bed-combustor/

impact on non-GHG emissions. The literature on this subject, as summarized by Robinson et al, consistently reports SO_2 emissions reductions, but there are some indications that a 10-percent/90-percent cofiring of biomass/coal (for example) can produce a greater than ten-percent reduction in SO_2 emissions. The majority of studies also report modest NO_X reductions, but some studies report no NO_X benefit and one study found that biomass reburning in a secondary combustion zone can reduce NO_X emissions by 60 percent.[27] Aerts & Ragland, on the other hand, reported the results of one test in which cofiring 10 percent switchgrass with 90 percent coal reduced NO_x emissions by 17 to 31 percent.[28]

The full range of co-benefits that can be realized through fuel switching is summarized in Table 9-4. In this table, "utility system" benefits are those that are shared between the owners of power plants and their customers.

6. Costs and Cost-Effectiveness

In virtually all cases, fuel switching will increase operations and maintenance (O&M) costs above the status quo, or require a capital investment, or both. Where neither type of cost increase is necessary, fuel switching will usually have already occurred for economic reasons. In the context of mandatory GHG regulations for existing sources, the relevant question will not be whether fuel switching increases capital or operating costs but whether it costs less than other compliance options. This question can only be answered on a case-by-case basis for each EGU, but some useful general observations can be gleaned from the literature.

The previously cited NYSERDA report on CO_2 emissions reductions in the RGGI states does not delineate the costs of fuel switching as an emissions reduction strategy, but it does offer a few insights into the economic drivers for fuel switching. NYSERDA found that switching from petroleum and coal generation to natural gas "was caused in large part by the decrease in natural gas prices relative to petroleum and coal prices... Natural gas prices decreased by 42 percent from 2005 to 2009, while both petroleum and coal prices increased. Through 2005, natural gas prices were generally higher than No. 6 oil prices (dollars per MMBTU); beginning in 2006, natural gas prices have been lower than No. 6 oil prices... The price gap between US natural gas and coal decreased by 61 percent, from $6.72 per MMBTU in 2005 to $2.62 per MMBTU in 2009... The changing fuel price landscape has resulted in dual fuel units

Table 9-4

Types of Co-Benefits Potentially Associated With Fuel Switching

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
NO_x	Yes
SO_2	Yes
PM	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Maybe
Coal Ash Ponds and Coal Combustion Residuals	Maybe
Employment Impacts	No
Economic Development	No
Other Economic Considerations	No
Societal Risk and Energy Security	Maybe
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	No
Avoided Production Energy Costs	No
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	No
Avoided Line Losses	No
Avoided Reserves	No
Avoided Risk	Maybe
Increased Reliability	No
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand-Response-Induced Price Effect	Yes; could be positive or negative
Other	

27 Robinson et al., at supra footnote 21.

28 Aerts, D. & Ragland, K. (1997). *Switchgrass production for biomass.* Research Brief No. 51: University of Wisconsin, Madison, WI. Available at: http://www.cias.wisc.edu/switch-grass-production-for-biomass/.

burning natural gas rather than oil."[29]

The observations in the NYSERDA report are likely to hold true for multi-fuel facilities everywhere, although the fuel price differentials may vary geographically. In some cases, other operational cost impacts of fuel switching, such as reduced ash handling costs when gas use displaces coal, may factor into compliance decisions. Over the longer term, maintenance costs may vary somewhat based on how much of each type of fuel is used, and those costs could affect compliance decisions as well.

It is more difficult to assess costs and cost-effectiveness when cofiring or repowering strategies are used, but this question has been tackled head-on in some of the relevant literature. With respect to cofiring coal and natural gas, the previously cited EPRI report examined case studies of actual cofired EGUs.[30] In several of these cases, supplemental gas cofiring was used either to allow use of an alternate coal or to reduce fly ash carbon levels. EPRI found that in these applications, "gas cofiring improved the combustion characteristics of an alternate coal or reduced the existing carbon levels in the fly ash, but was not sufficient to produce a payback. Either carbon in the fly ash remained above three percent, making it unsalable as a high-priced cement additive, or alternate coal combustion characteristics were not improved sufficiently to provide added boiler flexibility." However, EPRI also found examples where cofiring with gas corrected problems that had led to a derate of the EGU. Eliminating the derate made cofiring a cost-effective choice. Finally, EPRI found that gas re-burn technologies were cost-effective means of reducing NO_x emissions, relative to installing pollution control devices, and supplemental gas cofiring was similarly cost-effective for reducing NO_x in some but not all cases. More recent studies from the engineering firm Black & Veatch indicate that capital costs for cofiring gas with coal can range from $10 to $100 per kilowatt (kW).[31]

Robinson et al offer a number of insights into the economics of cofiring biomass with coal.[32] Their analysis assigns a 5- to 15-percent premium on the nonfuel O&M costs for biomass fuels relative to coal, depending on the cofire rate. Biomass fuel costs are much more variable. Fuel costs can be zero or even negative in cases where onsite or local biomass sources exist, especially if the biomass fuel is a waste-derived fuel that would otherwise have to be landfilled. But in general, they found that the fuel costs of biomass on a BTU basis can be up to four times the cost of coal. Finally, in terms of the capital costs necessary to enable cofiring, their model assumes that biomass can be cofired at up to two percent of total energy input without any modifications to the coal handling and combustion systems. Higher rates of biomass cofiring require a capital investment on the order of $50/kW to $300/kW, depending on the cofire rate. Compiling all of these data along with the potential for cofiring at existing US coal EGUs, the authors found that cofiring with biomass could reduce CO_2 emissions from the coal-fired electricity generation sector by ten percent at a carbon price of about $50 per metric ton. The previously cited analysis by McKinsey & Company cited a lower CO_2 abatement cost, on the order of about $30 per metric ton.[33]

The last fuel switching option to consider is repowering. In a recent study of options for repowering existing steam plants with combined-cycle technology, EPRI found that repowering could cost about 20 percent less than building a completely new combined-cycle plant on a capacity ($/kW) basis, and 5 percent less on a cost-of-electricity ($/MWh) basis.[34] Other analysts have placed the cost of converting an existing coal-fired boiler to natural gas at just 15 to 30 percent of the cost of a new gas boiler.[35] Black & Veatch analysts estimate that the capital costs of repowering from coal to gas range between $100/kW and $250/kW, or higher if a new combined-cycle gas turbine is installed.[36] These costs compare quite favorably to the EIA's estimated cost for a new conventional natural gas combustion turbine of $973/kW or a new conventional natural gas combined-

29 Supra footnote 15.

30 Supra footnote 12.

31 Nowling, U. (2013, October 1). Utility Options for Leveraging Natural Gas. *POWER*. Available at: http://www.powermag.com/utility-options-for-leveraging-natural-gas/?pagenum=1.

32 Robinson et al., at supra footnote 21.

33 Supra footnote 23.

34 EPRI. (2012, August 8). *Repowering Fossil Steam Plants with Gas Turbines and Heat Recovery Steam Generators: Design Considerations, Economics, and Lessons Learned.*

35 Ingraham, J., Marshall, J., Flanagan, R. (2014, March 1). Practical Considerations for Converting Industrial Coal Boilers to Natural Gas. *POWER*. Available at: http://www.powermag.com/practical-considerations-for-converting-industrial-coal-boilers-to-natural-gas/.

36 Supra footnote 31.

cycle unit of $917/kW.[37]

A 2012 case study analysis by Reinhart et al considered the relative costs of five different strategies for reducing emissions from a hypothetical coal-fired power plant.[38] The options considered included full repowering of the existing boiler and turbine to natural gas; modifications of the existing equipment to allow cofiring of natural gas with coal; installation of emissions control equipment without other changes; repowering the existing steam turbine to operate in combined-cycle mode; and full replacement of the existing unit with a combined-cycle natural gas unit. The authors concluded that the least-cost option varied depending on assumptions about future fuel prices, the service life of the unit, and future capacity factors of the unit. Modifying the unit to allow cofiring was not the least-cost option in any of the examined scenarios, but each of the other options was least-cost in at least one scenario. The conclusion one can draw from this paper is that the relative merits of different fuel-switching options depend in part on variables that are generally location- and case-specific.

In the GHG Abatement Measures TSD, the EPA published its own review of the costs and cost-effectiveness of repowering an existing coal boiler to be able to fire gas or biomass.[39] For a typical 500-MW pulverized coal boiler, total capital costs for repowering to gas were estimated to be $237/kW, which would add about $5/MWh to levelized costs of generation. The EPA further estimated that fixed O&M costs would decline by 33 percent, whereas variable O&M costs would drop 25 percent owing to reduced waste disposal, reduced auxiliary power requirement, and miscellaneous other costs. Fuel costs, on the other hand, were expected to double – adding $30/MWh to levelized costs. Putting these factors together, the EPA estimated that the average cost of repowering to gas would be $83/metric ton of CO_2 reduction for 100-percent gas firing, or $150/metric ton for ten-percent gas cofiring.

The EPA estimated that the capital cost associated with adding ten-percent biomass cofiring capability to a 500-MW coal unit would be $20/kW. Fixed O&M costs in this case were estimated to increase by ten percent, while variable O&M costs remained constant. The EPA found that the fuel cost of biomass is highly site-specific. Putting these factors together, the EPA estimated that the cost per metric ton of CO_2 reduction would likely fall between $30 and $80 for biomass cofiring, if the biomass-related emissions were treated as carbon-neutral.

Although the EPA acknowledged in the GHG Abatement Measures TSD that some coal plant owners are engaging in repowering projects, the agency concluded that this kind of fuel switching will be on average more expensive than other available options, such as constructing a new natural gas combined-cycle unit. Because gas and biomass cofiring options were found to be relatively expensive when national average cost data were used, the EPA declined to include fuel switching as part of the "best system of emissions reduction" in its proposed emissions guidelines.

7. Other Considerations

Where physical modifications of a power plant are necessary to facilitate fuel switching, the owner of the power plant will generally not want to make such modifications unless he or she has a reasonable expectation that the capital costs of the project can be recovered from the sale of energy to wholesale markets, a purchasing utility, or retail ratepayers. (Exceptions to this general rule may exist where the owner has a compliance obligation and less costly options are not feasible.) In the case of a power plant owned by an investor-owned utility, the utility will further expect to realize a profit for shareholders. This concern with cost recovery (and profit) is likely to be even more pronounced in regions of the country that have adopted competitive wholesale markets. In those regions, the owners of power plants have no guarantee that their assets will clear the energy market over any given operating period, be dispatched, and earn revenue. Thus, they have no guarantee that the considerable costs associated with repowering an EGU, or even the lesser costs of modifying an EGU to allow cofiring of different fuels, will be recovered. Still, where the owner sees a reasonable expectation of reward to accompany this risk, fuel switching may be an attractive option.

One potential regulatory issue that is often cited by regulated entities as a concern is the possibility that a repowering project could trigger federal New Source Review, PSD, or New Source Performance Standard (NSPS)

37 US EIA. (2013, April). *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants.* Available at: http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf.

38 Reinhart, B., Shah, A., Dittus, M., Nowling, L., & Slettehaugh, B. (2012). *A Case Study on Coal to Natural Gas Fuel Switch.* Retrieved from the Black & Veatch website: http://bv.com/Home/news/solutions/energy/paper-of-the-year-a-case-study-on-coal-to-natural-gas-fuel-switch.

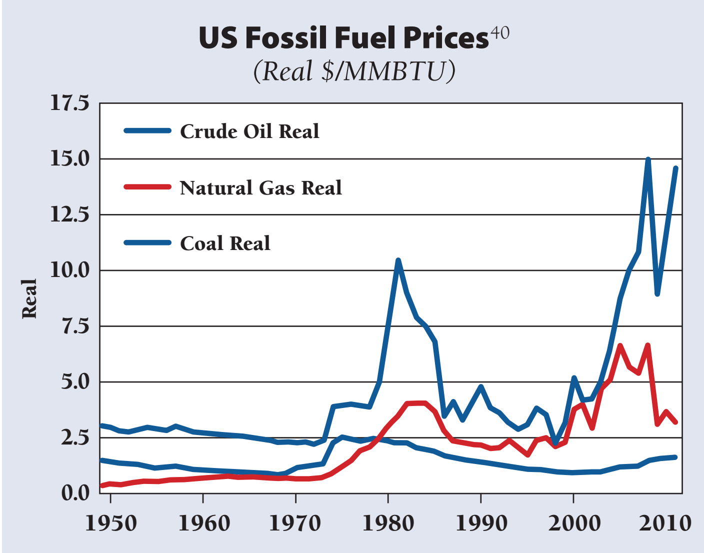
39 Supra footnote 2.

requirements. Satisfying New Source Review, PSD, or NSPS requirements could require the installation of new pollution control devices and add considerably to the cost of such a project, perhaps to the point at which it is no longer economically justifiable to the source owner. But in general, repowering projects will reduce not just CO_2 emissions rates (per MWh), but also the emissions rates of other regulated air pollutants, and this potential problem for source owners is unlikely to materialize. Exceptions may arise in which a repowering project opens the door to greater utilization of the EGU. This could happen, for example, if the repowered unit will have significantly lower operating costs than the existing EGU. If the unit then increases its annual hours of operation, its annual emissions of one or more pollutants could conceivably increase by an amount large enough to trigger other regulations. There may also be cases in which the capital cost of a repowering project exceeds 50 percent of the capital cost that would be required to construct a comparable new facility, thus meeting the Clean Air Act definition of "reconstruction" and triggering NSPS requirements.

The most obvious opportunities to reduce emissions through fuel switching are found at power plants that burn coal or oil as a primary fuel. However, the availability of firm natural gas pipeline capacity may in some cases create limitations on the potential for fuel switching. The most obvious limitation arises where a power plant is not connected to a natural gas pipeline. Extending a pipeline to reach such a power plant requires a significant capital investment, over and above any costs of modifying the power plant itself, as well as a lengthy permitting and construction process. But even where the power plant is already connected to a gas pipeline, there may be limitations. The capacity of gas pipelines relative to peak customer demand varies regionally. During a prolonged cold spell in the winter months of 2014, many power plants in the Northeastern United States found that they could not obtain gas because they did not have firm delivery contracts, and those that did have firm contracts were using nearly all of the existing pipeline capacity. This is not an insurmountable problem; it can be alleviated by adding gas pipeline capacity or by changing contract terms. But it does potentially limit the ability of some sources to reduce CO_2 emissions through fuel switching.

Historically, oil and natural gas prices have been more volatile than coal prices, as shown in Figure 9-3. Owners of coal-fired generation may be reluctant to depend on fuel switching as the means to meet mandatory CO_2 emissions

Figure 9-3



limitations because of the perception, backed by history, that using other fossil fuels increases uncertainty about future fuel costs. Recent advances in production techniques (hydraulic fracturing, principally) have reduced short-term domestic gas prices considerably, but it remains to be seen if these techniques will have an impact on the long-term volatility of prices.

The potential for emissions reductions described earlier in this chapter assumes that the operating capabilities of an EGU will not be affected by fuel switching. In practice, this may not always be the case. The capacity of an EGU can be uprated or derated depending on the heat content of the fuels used, if the rate at which the fuels are consumed remains constant. So, for example, consider the case in which a boiler burns a coal with a high input emissions factor at some maximum rate based on the design of the fuel delivery system and burners. If this coal is then blended with a different rank of coal that has a lower heating value, but the maximum rate that the blended fuel is consumed remains unchanged, then the capacity of the EGU will decrease. Any owner of an EGU will be concerned about a derate of its capacity.

Any fuel switching project that requires an EGU to go offline for an extended period of time may raise concerns about reliability impacts. The likelihood of such impacts will vary with the size (i.e., capacity) of the EGU, the duration of the scheduled downtime, and the amount of

40 US EIA. (2012, September). *Annual Energy Review 2011*. Available at: http://www.eia.gov/totalenergy/data/annual/pdf/aer.pdf.

excess capacity available to meet load during the scheduled downtime.

Power plants that have not previously utilized biomass or biogas fuels may encounter significant challenges in securing reliable fuel supplies and a supply chain that can reliably deliver the fuel. This can present a classic chicken-and-egg dilemma, wherein generators will not switch fuels until they are certain a reliable fuel supply and supply chain exists, but a supply chain will not materialize until there is sufficient demand for the fuel. Onsite storage of solid biomass fuels can also pose problems in terms of storage space, fire risks, or fugitive dust concerns. These same concerns are present at coal-fired power plants, so they are not novel issues when it comes to fuel switching to biomass. Just as there are techniques to deal with these issues at coal plants, there are similar techniques to deal with them at biomass plants.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on fuel switching:

- Black, S., & Bielunis, D. (2013, August). *Challenges when Converting Coal-Fired Boilers to Natural Gas.* Babcock Power Inc. Available at: http://www.babcockpower.com/pdf/RPI-TP-0232.pdf.
- EPRI. (2000, August). *Gas Cofiring Assessment for Coal Fired Utility Boilers.* Palo Alto, CA.
- EPRI. (2012, August 8). *Repowering Fossil Steam Plants with Gas Turbines and Heat Recovery Steam Generators: Design Considerations, Economics, and Lessons Learned.*
- Nicholls, D., & Zerbe, J. (2012, August). *Cofiring Biomass and Coal for Fossil Fuel Reduction and Other Benefits—Status of North American Facilities in 2010.* General Technical Report PNW-GTR-867. US Department of Agriculture, Forest Service, Pacific Northwest Research Station.
- US EPA. (2010, October). *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-fired Electric Generating Units.* Office of Air and Radiation. Available at: http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf.
- US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units—GHG Abatement Measures.* Office of Air and Radiation. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents.

9. Summary

Fuel switching in its various forms offers a proven emissions reduction strategy that will be feasible to a lesser or greater extent for many covered sources. Literally thousands of EGUs in the United States already have the capability to fire multiple fuels, and many more could be candidates for a repowering project. The primary limitation on this strategy is not technical but economic. Most EGUs that are not already using low-emitting fuels as a primary energy source are using higher-emitting fuels for economic reasons. Fuel switching could increase the operating costs, and possibly add capital costs, for these sources. However, the underlying economics will change when new mandatory CO_2 emissions limits are in place. Generation owners will then want to reconsider the relative costs of different fuels and determine if fuel switching is their best compliance option.