750 1st St, NE
Suite 1100
Washington, DC 20002
202.682.6294 Main
202.682.3050 Fax
www.cleanskies.org

The Business Case for Integrating Clean Energy Resources to Replace Coal

By
Joel N. Swisher

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The Business Case for Integrating Clean Energy Resources to Replace Coal

By Joel N. Swisher, Ph.D., P.E.[1]

Synopsis

A confluence of factors—environmental regulation that will increase the cost of coal-fired generation; substantial underutilized natural gas-fired generation; and the mandated expansion of renewable generation—has created a historic opportunity to replace much of the obsolete coal-fired generation fleet with natural gas-fired, renewable and demand-side resources. Further extending the life of existing coal plants, moreover, will impede the flexibility needed to integrate more renewable generation and substantially reduce emissions of CO_2 and local pollutants.

On a regional basis, where there is coal-fired generation vulnerable to retirement, there is also available gas-fired capacity, as well as a mandate to increase renewable energy production. This regional alignment means that shifting generation from coal- to gas-fired units, which would increase the flexibility of the generation fleet, would coincide with the expansion of renewable generation, which in turn would demand additional flexibility. On the other hand, should the coal-to-gas shift be delayed by weak environmental enforcement or by emission control retrofits of coal-fired units, flexibility of the generation fleet will be diminished in the regions where flexibility is needed to enable renewable energy growth.

To balance renewables and reduce emissions, use of gas-fired generation will need to increase strongly in terms of capacity, but only modestly in terms of energy production, capacity factor, and fuel use. Although flexible, gas-fired resources are essential to balance the increasing share of renewable sources on the grid and reduce emissions while maintaining reliability, the financial viability of such gas-fired generators may be at risk during the transition to a cleaner generation fleet.

Adding renewable capacity to today's generation fleet will squeeze gas-fired generators between the renewable output and low-cost existing coal-fired generation, making it difficult for gas-fired units to produce revenues needed to cover their fixed costs. This short-term squeeze on the revenues of gas-fired generators, partly due to increased renewable production, could hinder the longer term integration of renewable capacity, including that which is already mandated.

To spur the needed increase in gas-fired generation, certain changes are required in the way the electric power supply system is planned and operated:

- New ancillary service products and contracts are needed for gas-fired generators to ensure that they are available to balance and firm variable resources.
- The gas-fired generation fleet needs to maintain and enhance its fast-ramping capability using state-of-the-art technology, including retrofits of existing units.
- Improved tariffs and rules are needed to align gas supply and electric generation scheduling and accommodate more flexible generation.
- Utilities need long-term natural gas contracting vehicles to mitigate gas price risk and ensure a stable cost environment.

Introduction: America's Electric Generating Mix Is on the Threshold of a Major New Frontier

Three powerful trends are converging to change the direction of the American electric power industry. We describe these trends in terms of the following new realities:

1. Environmental rules will soon make old coal-fired generators very costly to run.
2. Using available gas-fired generation to replace coal has modest costs and risks.
3. Increased gas generation enables renewable sources to replace coal on a large scale.

In response to the first new reality, some power generators are likely to resist these environmental regulations, which will significantly increase the cost of coal-fired generation. Rather than fight the imposition of such environmental costs, however, electric utilities and merchant power generators could use the avoided compliance costs as a down payment on the long-overdue modernization of the power system. Starting with the massive fleet of existing, underutilized natural gas-fired generation units, they could begin to replace much of the obsolete coal fleet with a portfolio of natural gas-fired, renewable and demand-side resources.

The essential role of existing and new natural gas-fired generation addresses several needs: directly reducing emissions compared to coal-fired generation, maintaining the resource adequacy and reliability of the power supply system, and providing the needed flexibility in the generation fleet to enable a massive scale-up of variable renewable generation from wind and solar power sources. The synergy between flexible gas-fired generation and renewable generation sources results from the need for flexible operation of generation units to balance the time-varying output of renewable sources without curtailing them.

While much of the needed gas-fired capacity exists today, and substantial growth in renewable generation is already mandated by state-level standards, several key enablers must be addressed in order to realize the potential of a renewable-rich generation fleet balanced by flexible gas-fired sources. These enablers include:

- Advancement in the flexibility and ramping ability of combined-cycle generation
- Renewed use of long-term natural gas supply contracts with electric generators
- New long-term contract vehicles to reward generators for services that enhance flexibility

The remainder of this paper discusses the new realities of the electric generation industry and their implications for the modernization of America's electric power system. This process will start with the replacement of obsolete coal plants by gas-fired generation, which in turn will catalyze the conversion of the generation fleet to one that maximizes use of renewable generation, balanced by gas-fired sources.

New Reality #1: Environmental Law Will Soon Make Old Coal-Fired Generators Very Costly to Run

Generating electric power from coal-fired steam plants, especially older units lacking up-to-date emission controls, is about to get significantly more expensive. Augmented environmental regulations, based on existing law, will compel generation owners to decide whether to invest in retrofitting out-of-compliance coal-fired plants or replace them with other generation sources such as natural gas-fired and renewable energy technology.

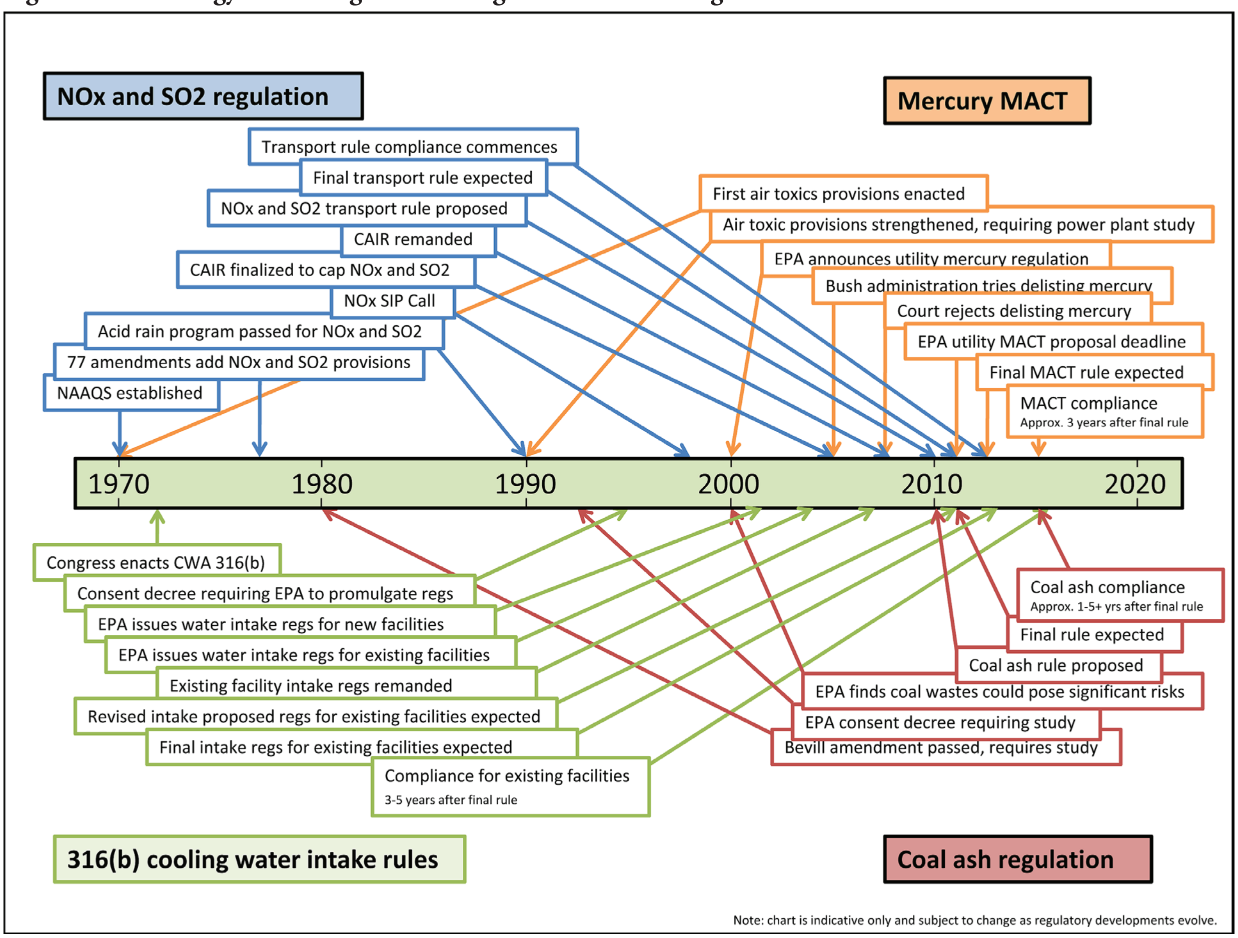
Several pending U.S. Environmental Protection Agency (EPA) regulations will affect power generation, especially from coal-fired plants:

- Adoption of limits to the emission of mercury and toxic acid gases according to Maximum Achievable Control Technology (MACT).
- New prohibitions on interstate SO_2 and NO*x* pollution under the Clean Air Transport Rule (CATR).
- Other Clean Air Act provisions controlling ozone and regional haze.
- New limits on cooling water under the Clean Water Act (CWA) Section 316(b) rulemaking, which may require cooling towers.
- CO_2 regulation under the Clean Air Act's Prevention of Significant Deterioration (PSD) program and EPA's "tailoring rule."

In addition, coal ash may be regulated as a hazardous waste.

A recent study by the American Clean Skies Foundation (ACSF) provides a detailed discussion of the regulations and their estimated public health benefits, including a chronology of their implementation (reproduced here in Figure 1).[2] Note that, while several new and amended regulations will come into force in the next few years, many of these rules have been in development and widely recognized for years or even decades, and some date back to the original Clean Air Act and Clean Water Act of the 1970s.[3] Each of these measures—divided into the general categories of traditional air quality rules, greenhouse gas rules, and water rules—is described briefly below.

Figure 1. Chronology of Existing and Pending Environmental Regulation of Power Plants



Source: ***Growing the Market for Clean Power: The EPA's New Power Plant Pegulations and What They Mean for Utilities and Public Health*. American Clean Skies Foundation, December 2010.**

Traditional Air Quality Rules

The EPA is under a court order to regulate power plant emissions of hazardous air pollutants, including mercury and acid gases, under the air toxics provisions of Section 112 of the Clean Air Act (CAA). The CAA requires these pollutants to be controlled using MACT. The MACT rulemaking for mercury emissions from coal-fired power plants was issued in March 2011. It is due to be finalized by the end of 2011, and fully enforced by the end of 2014. Natural gas-fired generators do not emit mercury and are not covered by the rule.

There is no dedicated emission control technology for mercury. The flue-gas desulfurization (FGD) units, or "scrubbers," used to control SO_2 emissions, combined with activated carbon injection and particulate filtration, are likely to qualify as MACT for mercury. It is also possible that less-expensive dry sorbent injection (DSI), using trona (a mineral often used as a source of sodium carbonate) in addition to activated carbon, will be considered sufficient to control mercury and acid gases, at least for facilities that burn Western coal.

The EPA proposed the Clean Air Transport Rule (CATR) in July 2010 to regulate SO_2 and NOx emissions in 31 (mostly Eastern) states. The goal is to maintain National Ambient Air Quality Standards (NAAQSs) under the 1990 CAA amendments for ground-level ozone and fine particulate matter. The CATR replaces the 2005 Clean Air Interstate Rule (CAIR) that was vacated by the court, which directed EPA to issue a new rule. The new rule restricts interstate emission trading to minimize the formation of local pollution "hot spots." The final rule is expected in mid-2011, with tightened SO_2 limits in force by 2014.

Control of SO_2 emissions will require scrubbers on coal-fired units that do not already have them, and NO_x control may require the installation of selective catalytic reduction (SCR) technology on some units as well. Again, DSI may be a less expensive alternative for plants using low-sulfur Western coal to control SO_2, while selective non-catalytic reduction (SNCR) is a less expensive alternative for NO_x control. Natural gas-fired generators do not emit SO_2 and are lower in NO_x and particulate emissions; therefore, they do not require scrubbers.

Clean Air Act provisions governing NAAQSs for ground-level ozone and the Prevention of Significant Deterioration (PSD) rule governing regional haze will also affect coal-fired generation, especially in the Western and South Central states. Updated rules proposed in 2011 would take effect around 2016. The ozone rule would require SCR or SNCR to control NO_x, and the haze provisions could require scrubbers on some coal-fired units.

Greenhouse Gas Rules

To date, Congress has not legislated limits on CO_2 and other greenhouse gases (GHGs). Nevertheless, in response to a 2007 Supreme Court ruling, the EPA is proceeding with GHG regulation that is authorized, and indeed required by the CAA. Although the EPA did not take action on GHG regulation during the George W. Bush administration, the administrator at that time did state that the court action, "combined with the latest science of climate change requires the Agency to propose a positive endangerment finding,"[4] which was eventually issued by the EPA under the Obama administration. The endangerment finding is a formal determination by the agency that GHGs endanger public health and welfare, and it triggers a process leading to EPA regulation of CO_2 and other GHGs under the CAA.

In June 2010, the EPA issued its "tailoring rule," which provides for permitting of GHG sources under the PSD provisions of the CAA.[5] The agency issued guidance documents in November 2010, which indicated that PSD regulation of CO_2 emissions from large stationary sources would begin in January 2011.

The PSD rules require that new or substantially modified sources limit emissions according to the Best Available Control Technology (BACT), which the EPA tends to define on a case-by-case basis. In December 2010, the EPA entered into a settlement agreement with 11 states and several other parties to issue rules for emissions of CO_2 and other GHGs from power plants and refineries. The rules for power plants, which are to be proposed by July 2011 and to be finalized by May 2012, would set New Source Performance Standards (NSPSs) for certain new and existing fossil fuel-fired power plants.[6] Unlike MACT rules, which provide for case-by-case determinations, NSPSs are across-the-board emission standards, although the EPA has broad latitude to make the standards flexible and cost-effective.

Meanwhile, at the regional level, ten Northeastern states operate the Regional Greenhouse Gas Initiative (RGGI), which is a cap-and-trade program to limit CO_2 emissions from the power sector. California also has issued rules for a statewide cap-and-trade program to limit CO_2 and other GHG emissions under the state's 2006 Global Warming Solutions Act, Assembly Bill 32. Implementation of AB-32, which is scheduled to begin in 2012, was challenged by a November 2010 ballot initiative that would have delayed the regulations taking effect. California voters defeated this initiative, and the state's Air Resources Board is moving forward with implementation.

For coal-fired generators, state and federal regulation of CO_2—even in the absence of comprehensive federal climate legislation—has the potential to impose additional compliance costs that will be high enough to make many legacy coal-fired generation plants no longer viable to operate, especially for merchant generators. Since there is no off-the-shelf CO_2 scrubber or emission control device, and carbon capture with geologic sequestration is still in the research and demonstration phase, compliance with CO_2 regulation would likely entail energy efficiency or fuel switching to reduce coal-fired generation, or the purchase of emission allowances or offsets that effectively pay others to make such reductions.

Water Quality and Waste Management Rules

Section 316(b) of the Federal Water Pollution Control Act, better known as the Clean Water Act, governs discharges, including waste heat, into water bodies from power plants and other large facilities. The EPA has recently issued a new rule to be finalized by July 2012; it will take effect in 2016 or 2017.

This Section 316(b) rulemaking could force generators, particularly nuclear and coal-fired steam plants, to replace once-through cooling with cooling towers. Retrofitted cooling towers entail a large capital expenditure, as well as a performance penalty in terms of both power output capacity and fuel efficiency. Natural gas-fired plants would also be subject to the rule, but their cooling requirements are substantially less than coal plants, and the impact of the regulations on power output, fuel efficiency and cost would be lower for gas.

Coal-fired power plants also may be subject to hazardous waste regulation for coal combustion residuals, or ash, of which some 130 million tons are produced annually in the U.S. In May 2010, the EPA proposed two regulatory options: One would treat coal ash as hazardous waste under the Resource Conservation and Recovery Act (RCRA) and require closure of surface ash impoundments in lieu of regulated landfills; the other would treat ash as non-hazardous waste and require installation of liners on impoundment ponds and monitoring systems to protect groundwater. Even the latter, less stringent rule would require substantial expenditures for compliance. The final rule is expected in 2011 or 2012, and would take effect by 2016. Note that gas-fired plants produce no ash.

Impacts on Coal-Fired Generation

It is difficult to predict whether all of the environmental regulations listed above will be strictly enforced according to their current timetables. However, the total of the pending regulations and their potential compliance costs makes it clear that a significant number of coal-fired generation units could face prohibitive compliance costs in the near future. These soon-to-be unviable coal plants will tend to be older (>50 years), smaller (<100 MW), and thus expensive to retrofit. We estimate the cost of installing scrubbers and SCR at about $800/kW (see below), but this value could be substantially higher for units of less than 100 MW capacity. Moreover, control technology such as scrubbers for air emissions and cooling towers for water recycling tends to reduce generation capacity and adds to a plant's fuel cost and CO_2 emissions.

Facing such costs, electric utilities and merchant generators relying on coal can be expected to argue against the enforcement of these new regulatory burdens.[7] Before accepting such arguments, however, it is helpful to first explore the technical options and business case for retiring old coal plants. The most immediate issues are the extent to which retirement of a significant number of coal-fired generation units would compromise power system reliability, and the availability of other generation sources to replace the retired coal plants.

Retiring out-of-compliance coal plants does not risk system reliability, according to several studies that address this question and consider retirement scenarios that range between 30,000 and 100,000 MW of retirements.[8] As the assumed quantity of retirements increases, of course, more caution will be required in implementing the environmental rules and in planning for replacement power supplies.

New Reality #2: Using Available Gas-Fired Generation to Replace Coal has Modest Costs and Risks

The first question raised by the potential retirement of the most obsolete segment of the coal-fired generation fleet is how its power output will be replaced. Will there be enough capacity to ensure power grid reliability, and what will the replacement energy cost?

The short answer to the question of replacement generation is natural gas, at least in the near term. But will the supply be adequate to increase power generation? Will the fuel cost and risk of future price spikes be manageable? There appears to be a range of views among utility executives. While Duke Energy's CEO Jim Rogers has characterized natural gas as "the crack cocaine of the power industry," Exelon's CEO John Rowe recently referred to natural gas as "a genuine elixir that will deliver the cleaner energy we need to compete in the world."[9] For his part, President Obama called for a national Clean Energy Standard in his State of the Union address and said recently that "by 2035, 80% of our electricity needs to come from a wide range of clean energy sources—renewables like wind and solar, and efficient natural gas."[10]

A great deal of existing gas-fired capacity can be more fully employed, and new capacity would need to be added if the higher retirement scenarios are realized (discussed further below). In the longer term, a more diverse portfolio of updated gas-fired generation, renewable sources and demand-side resources, as explained later, will be required and can be expected to fill the gap left by the retirement of today's most obsolete coal-fired units.

Efficiency and Emissions Advantages of Gas-Fired Generation

To replace out-of-compliance coal-fired generation, the least-cost, short-run option is generally to dispatch existing, underutilized gas-fired generation capacity. The existing fleet of gas-fired generation stations has an average capacity factor of only 33%.[11] The reason much of the gas-fired capacity is idle much of the time is that its variable cost, basically the cost of fuel to generate one kilowatt-hour (kWh), is typically somewhat higher than that of competing coal-fired generation.[12] Moreover, past spikes in natural gas prices and the accompanying price volatility has led some power sector planners to conclude that gas-fired generation is inherently expensive and risky compared to coal.

Looking forward, however, increased gas-fired generation to replace coal appears to have rather moderate costs and risks. One advantage of gas-fired generation is that it produces essentially no mercury or SO_2 emissions and will have little difficulty, and therefore cost, to comply with the tightening EPA regulations discussed above. Rather, the capital cost of emission control retrofits on coal-fired units, plus the additional fuel costs due to resulting efficiency penalties, will translate into a cost advantage for gas-fired generation.

The efficiency penalty of emission control retrofits only adds to the fuel efficiency disadvantage of coal-fired generation compared to gas. Gas-fired combined-cycle gas turbine (CCGT) generators have relatively low heat rates, which translate into high fuel efficiency.[13] The heat rates for existing CCGT plants are between 6,000 and 9,000 Btu/kWh (38-57% efficiency), with an average around 7,500 Btu/kWh (45% efficiency), while the heat rates for coal-fired steam plants are between 9,500 and 12,000 Btu/kWh (28-36% efficiency), with an average around 10,500 Btu/kWh (32% efficiency).[14]

Lower heat rates and higher efficiencies mean lower CO_2 emissions for gas-fired plants. In addition to the roughly 35% average efficiency advantage, natural gas contains about 40% less carbon per unit energy than coal. The direct CO_2 emissions per kWh for coal-fired power are therefore more than twice as high on average (0.99 kg-CO_2/kWh) than for power from a gas-fired CCGT (0.41 kg-CO_2/kWh). In addition to direct CO_2 emissions from fossil fuel combustion, the GHG impact of a fuel includes emissions of methane and other GHGs during combustion and upstream in the fuel supply chain.[15] The non-CO_2 GHGs such as methane and N_2O are more powerful greenhouse gases than CO_2, and this effect is expressed in terms of total GHG emissions as CO_2 equivalents.[16] After accounting for upstream and non-CO_2 GHG emissions, gas-fired generation is still less than half as GHG intensive, in CO_2-equivalent terms, at 0.51 kg-CO_2e/kWh, than coal, at 1.03 kg-CO_2e/kWh. Table 1 compares the full fuel chain GHG emissions of coal- and gas-fired generation with average generation efficiency (heat rate)

Generation Plant Type	Fuel Carbon Intensity (kg-CO_2/MMBtu)	Fuel-Based GHG Intensity (kg-CO_2e/MMBtu)	Heat Rate (Btu/kWh)	Electricity-Based GHG Intensity (kg-CO_2e/kWh)
New Gas-Fired Combined Cycle	53.2	65.6	6,500	0.427
Average Existing Gas-Fired Unit	53.2	65.6	7,700	0.505
New Coal-Fired Steam Unit	95.3	99.4	9,000	0.895
Average Existing Coal-Fired Unit	95.3	99.4	10,350	1.029
Older, At-Risk Coal-Fired Unit	95.3	99.4	11,750	1.168

Table 1. Full Fuel Chain GHG Emissions by Generation Unit Type and Fuel

values, as well as new, more efficient generation units, and also for older coal-fired plants at risk of retirement due to the cost of compliance with pending environmental regulations.

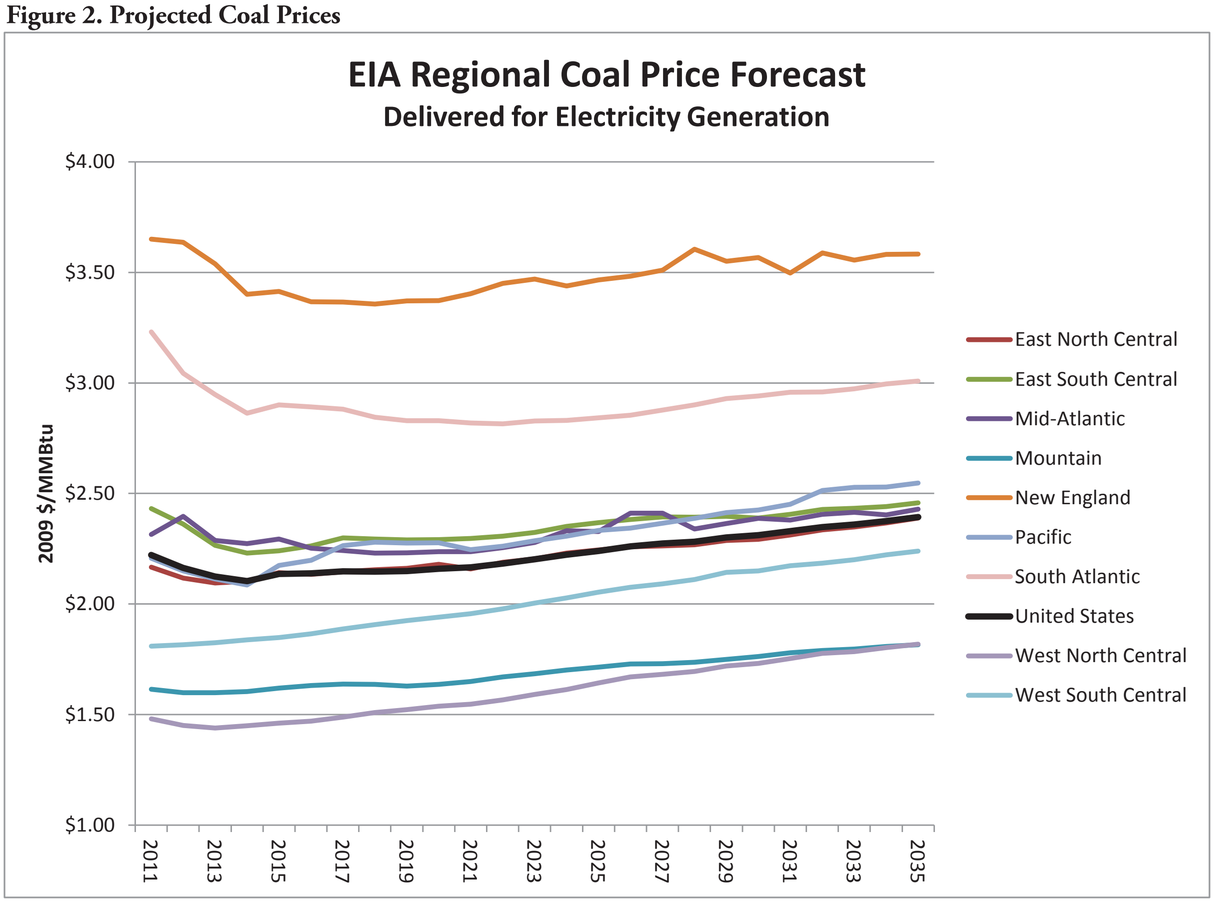
Costs of Retrofitting Coal-Fired Generation

The CO_2e emissions from generating one kWh at a coal-fired power plant are over 100% higher, on average, than from a gas-fired CCGT plant. However, the older coal plants that are likely candidates for retirement due to environmental regulation, as discussed above, are not average plants. Their heat rates are higher—we estimate an average of about 11,750 Btu/kWh, although others have suggested much higher values[17]—which make their emission rate about 1.16 kg-CO_2e/kWh, 130% higher than an average gas-fired CCGT plant.[18]

Coal-fired generation units that are retrofitted in response to tightened environmental regulation will likely be newer and have lower heat rates (higher efficiency) than plants that are retired. On the other hand, emission control retrofits can be expected to degrade the efficiency and raise the CO_2 emissions of the retrofitted coal-fired units. If greenhouse gas regulation leads to a future carbon price of $20/tonne-$CO_2$, the difference in emission cost between these coal plants and the average gas-fired CCGT would be about 1.3 cent/kWh. This added cost alone would more than compensate for the current variable cost difference between CCGT and coal-fired generation.

In general, the variable cost of generation, consisting mostly of fuel costs, determines which combination of existing generation units are operated, or dispatched, and when and how much they operate during the year. Today, the

Figure 2. Projected Coal Prices



Source: Data from U.S. Energy Information Administration. *Annual Energy Outlook 2011*.

variable cost comparison favors coal-fired power, but only slightly (see Figure 2).[19] Both the current and forecasted coal price is about$2.25/MMBtu on a national average, while the natural gas price is $4.25/MMBtu (17 May 2011) and forecasted at $5.60/MMBtu (see Figure 3). However, the superior efficiency of gas-fired generation can narrow this gap.[20]

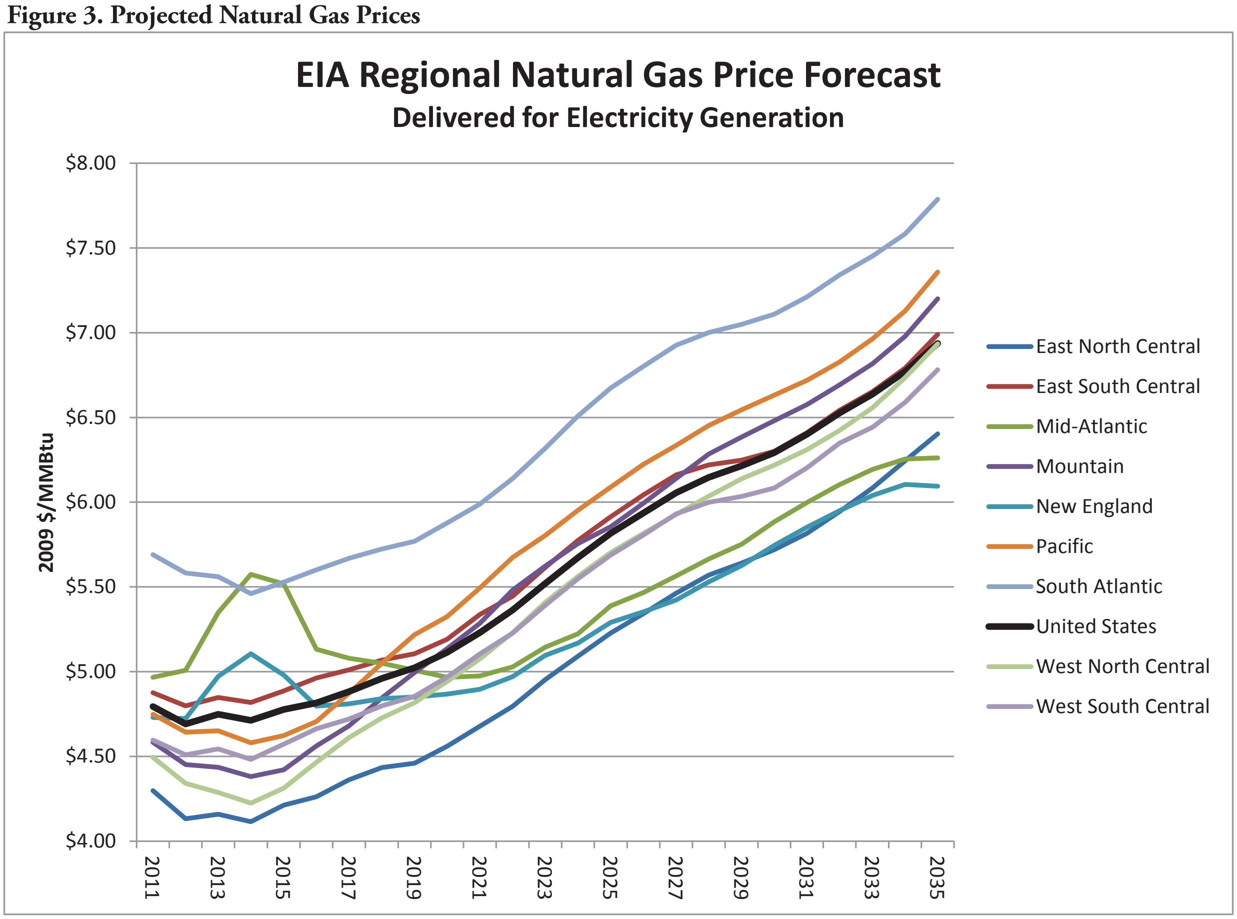
A useful measure of the economics of different generation options is the breakeven natural gas price. Given the expected coal price, capital costs and heat rates, how low do gas prices need to be for power from a CCGT to be competitive with power from retrofitted coal plants? Does the breakeven natural gas price suggest that gas-fired generation will be competitive based on the forecasted trajectory of future gas prices? Below we estimate this breakeven gas price for a number of different cases, which are summarized in the text box.

The breakeven natural gas price, at which the variable costs of power generated from gas-fired CCGT and coal-fired units are equal, is currently about $3.60/MMBtu, assuming average heat rates for each type of unit. If we focus on the coal-fired units likely to face retrofit or retirement with a heat rate around 11,750 Btu/kWh, then the breakeven gas price rises to $4.10/MMBtu, only slightly below today's spot price.

To avoid retirement, these out-of-compliance coal plants will require significant capital investment to retrofit emission controls. How do these costs affect the gas-vs.-coal economics? If we consider a range of compliance scenarios for coal-fired generation, and include the levelized cost of emission control retrofits, we can estimate the resulting breakeven gas prices.

One plausible scenario would involve retrofit of flue-gas desulphurization (scrubbers)

Figure 3. Projected Natural Gas Prices



Source: Data from U.S. Energy Information Administration. *Annual Energy Outlook 2011.*

to control SO_2 and mercury and selective catalytic reduction (SCR) units to control NO_x and ozone. A more expensive scenario would add ash control and cooling towers, for Clean Water Act compliance, to the retrofit of SCR and scrubbers. On the other hand, a less expensive scenario, which might prove to be a viable alternative for plants using low-sulfur Western coal, would be dry sorbent injection (DSI) to control SO_2 and mercury and selective non-catalytic reduction (SNCR) for NO_x and ozone.

We estimate the capital cost of each retrofit scenario as follows:

- Inexpensive — DSI and SNCR: 102.5 +/- 22.5 $/kW
- Baseline — Scrubbers and SCR: 800 +/- 400 $/kW
- Expensive — Scrubbers, SCR, ash control and cooling towers: 1200 +/- 600 $/kW

Summary of Economic Comparisons of Retrofitted Coal vs. Gas-Fired Generation

Today's breakeven natural gas price, at which the variable costs of power from gas-fired CCGT and coal-fired units are equal, is currently about $3.60/MMBtu (average heat rates: 7,500 Btu/kWh for CCGT, 10,500 Btu/kWh for coal).

Against the coal-fired units likely to face retrofit or retirement (heat rate ~11,750 Btu/kWh), the breakeven gas price is ~$4.10/MMBtu, slightly below today's price.

Taking the central estimate of the capital costs, and assuming a heat rate for the retrofitted units of 11,750 Btu/kWh, we estimate breakeven natural gas prices as:

- Inexpensive retrofits: $5/MMBtu breakeven gas price
- Baseline retrofits: $6/MMBtu breakeven gas price
- Expensive retrofits: $7/MMBtu breakeven gas price

For the same coal plant retrofit costs, assuming a heat rate for the retrofitted units of 11,750 Btu/kWh, we estimate breakeven gas prices for new CCGT generation as:

- Inexpensive retrofits: $4/MMBtu breakeven gas price
- Baseline retrofits: $5.5/MMBtu breakeven gas price
- Expensive retrofits: $6.5/MMBtu breakeven gas price

Taking the central estimate of the capital cost for each scenario, and assuming a heat rate for the retrofitted units of 11,750 Btu/kWh, we estimate breakeven natural gas prices as:

- Inexpensive retrofits: $5/MMBtu breakeven gas price
- Baseline retrofits: $6/MMBtu breakeven gas price
- Expensive retrofits: $7/MMBtu breakeven gas price

Viability of Out-of-Compliance Coal-Fired Generators

The economics of each individual generation station is different. In general, though, these calculations indicate that, at today's gas prices or those projected in the future, many out-of-compliance coal plants are not competitive with existing gas-fired generation. Varying assumptions about retrofit costs and relative heat rates does not change this result.

The only variable that could change the game and make gas-fired CCGT less competitive would be a return to higher and volatile natural gas prices. As discussed below, a return to long-term contracting for gas supplies could mitigate this risk. Several recent studies have evaluated the economics of out-of-compliance coal plants on a plant-by-plant basis, and each has concluded that strict enforcement of the pending EPA regulations could make about 60,000 MW of generation capacity uneconomic to keep in service.[21] The retirement estimates from each of these studies are shown as the "moderate" retirement estimates in Table 2.

Some of the studies also have "low" estimates based on less aggressive environmental enforcement, while some also have "high" estimates based on the combined impact of Clean Water Act and multiple Clean Air Act rules. Most of these studies highlight the older and smaller plants as especially expensive to retrofit and thus vulnerable to retirement.[22] Some also note that plants using relatively costly Appalachian coal supplies are likely to more vulnerable than plants using Western coal.[23]

Study	Low Estimate of Retirements (GW)	Moderate Estimate of Retirements (GW)	High Estimate of Retirements (GW)
Bernstein Research		65	
Brattle Group	40	66	
Charles River Associates	35		
Credit Suisse	35	60	103
Deutsche Bank		60	
MJ Bradley & Associates	30	60	
NERC	33	67	104

Table 2. Estimated Coal-Fired Generation Capacity Retirements in Response to Pending Environmental Regulations, According to Several Recent Studies

They also distinguish between merchant generation plants and plants owned by regulated utilities, including investor-owned and public utilities. The economic analysis by the Brattle Group, in particular, concludes that the majority of merchant coal-fired generation units nationwide would become uneconomic and face retirement, while regulated utilities would find it cost-effective to retrofit most of their coal-fired generation.[24] Other studies find that regulated utilities would retire substantial coal-fired generation, particularly older, smaller units in response to tightened environmental standards.

The future trajectory of natural gas prices is the input assumption to which all these studies' results are most sensitive. To the extent that natural gas prices remain moderate and stable, the retirement of coal-fired capacity appears more cost-effective and less risky. In addition, the availability of continued or increased gas supplies in North America affects the future price trajectory, as well as the reliability of the gas-fired generation fleet.

Availability of Existing Gas-Fired Generation

The available gas-fired generation capacity in the U.S. appears adequate to replace much of the out-of-compliance coal-fired capacity that might face retirement. The merchant power building boom in 2000-2004 added over 150,000 MW of gas-fired CCGT generation. The national fleet of gas-fired CCGT generation units has a total rated capacity of 225,000 MW, and a summer peak capacity of 194,000 MW.[25] In 2008, this fleet was operated with a capacity factor of 33%, which indicates that its average output was only 74,000 MW. The remainder of the CCGT fleet's generation capacity was mostly idle or on standby status.

The main reason these gas-fired units run as little as they do is that coal-fired generation units are prioritized to dispatch ahead of them, based on the lower variable cost of coal-fired power. If, for example, the existing CCGT plants with heat rates below 9,000 Btu/kWh (efficiency above 38%) are operated with an average capacity factor of 60%,[26] the fleet average capacity factor would climb from 33% to 55%. The increased output of 430 million MWh would replace the total annual output of 60,000 MW of coal-fired baseload units operating at 80% annual capacity factor. This increment of available generation is more than the total annual output of the roughly 60,000 MW of out-of-compliance coal-fired generation that is vulnerable to shutdown in response to tightened EPA regulations.[27]

The geographic distribution of this available CCGT capacity is rather well aligned with the location of many of the vulnerable coal-fired generation units. On a regional basis, we can compare the distribution of the available CCGT capacity to potential coal retirements using the regional definitions from the North American Electric Reliability Corporation (NERC). In Table 3, we compare available CCGT generation to the potential coal retirements according to the NERC study of the impact of pending EPA regulations. We use the NERC assumptions for their strict Clean Air Act regulation case and moderate Clean Water Act regulation.

In each region, the available CCGT generation is equal to or exceeds the generation from potential retirements, based on the NERC scenario described above. Some studies that have identified potential coal retirements found an

NERC Region (*see* Appendix 1)	A. 2008 CCGT Total Annual Generation (million MWh)	B. Potential Additional Generation (million MWh)	C. Equivalent Baseload Capacity (thousand MW) of "B."	D. Potential Retired Coal Generation Capacity (thousand MW)	E. Production during 2008 (million MWh) from "D."
ERCOT	114	36	5.1	4.8	21
FRCC	86	22	3.1	1.6	7
MRO	6	18	2.5	4.2	18
NPCC	72	32	4.5	7.1	31
RFC	56	108	15.4	16.9	74
SERC	86	121	17.2	21.7	95
SPP	39	35	5.0	1.9	8
WECC	187	59	8.4	8.6	37
Total:	648	430	61.4	66.9	292

Table 3. Geographic Distribution, by NERC Region, of Available CCGT Generation and Coal-Fired Generation Vulnerable to Retirement. The data in each column are as follows:

A. The energy generated by CCGT units
B. Additional energy that could be generated each year if CCGT units with heat rates below 9000 Btu/kWh were operated at 60% capacity factor
C. The amount of baseload capacity (assuming 80% capacity factor) that would be needed to produce the same amount of energy as "B.," the incremental energy that could be generated by operating CCGT units with heat rates below 9000 Btu/kWh at 60% capacity factor
D. Estimated out-of-compliance coal-fired capacity that is vulnerable to retirement
E. The energy generated by "D.," the out-of-compliance coal-fired capacity that is vulnerable to retirement

even greater concentration of vulnerable coal-fired generation in the RFC (Great Lakes to Mid-Atlantic) and SERC (Southeast) regions where, as shown in Table 3, available CCGT generation is most concentrated.[28]

Other recent studies reach similar results. The Congressional Research Service estimated that increasing gas-fired CCGT capacity factors to about 72% (85%, based on summer capacity, the practical maximum) could produce an additional 640 million MWh, and that 28% of this generation would occur within 25 miles of a coal-fired power plant.[29] A 2010 MIT study made a similar calculation after comparing potential gas-fired generation to generation from relatively old (pre-1987), inefficient (heat rate above 10,000 Btu/kWh) coal-fired plants that would be candidates for retirement. The MIT study observed that the production from such vulnerable coal plants was comparable to the potential production from gas-fired generation in the Southeast and Southwest, while it was substantially more than gas-fired potential in the Midwest and Mountain states, and much less than gas-fired potential in the Northeast and West Coast.[30]

The calculation above shows that the energy produced from today's out-of-compliance coal-fired generation could be replaced by existing, underutilized gas-fired CCGT units. However, power system reliability depends even more essentially on ensuring sufficient supply capacity, especially during summer peak demand periods. Existing gas-fired capacity is already counted as part of the generation capacity reserve margin that is needed for reliability, so it cannot also replace retiring coal-fired capacity for reliability purposes.

Reliability and Replacement Generation Capacity

Recent studies vary substantially in their assessment of the impact of potential coal unit retirements on regional reserve margins. Some of this disagreement results from the NERC's multiple definitions of capacity reserve margins.[31] The Bernstein Research study finds reserve margins falling unacceptably low in the SERC (Southeast),[32] SPP (south Central) and MRO (Upper Midwest) regions, while the Brattle Group study highlights reliability concerns in the RFC (Great Lakes to Mid-Atlantic) and ERCOT (Texas) regions.[33] On the other hand, a recent study by M.J. Bradley and Associates finds that reserve margins would remain above in NERC targets in all regions, even with as much as 100,000 MW of retirements.[34]

Coal-fired generation retirements can be balanced mostly by existing gas-fired capacity without compromising reliability. Moreover, coal unit retirements will also free up transmission capacity that is now reserved, but not fully used, by the legacy coal-fired generators. This available transmission can support grid reliability, harness existing and new CCGT gas-fired capacity, and enable connection of renewable sources. It is also important to note that none of the studies cited above consider the effect of renewable energy standard or renewable portfolio standard (RES/RPS) requirements on capacity requirements and transmission planning.

Should additional generation capacity be needed to ensure power system reliability, gas-fired CCGT capacity is the least-cost option to displace new, environmentally compliant coal-fired generation. Today's CCGT technology has much lower capacity costs than new coal-fired capacity with the needed emission controls.[35] Gas-fired CCGT generators have very low heat rates (high efficiency) and very low CO_2 emissions, even compared to new coal plants.[36] Assuming no cost of CO_2 emissions, new CCGT capacity is competitive with new coal-fired generation as long as natural gas prices are around \$6.20/MMBtu or lower.[37]

New gas-fired capacity can also be competitive with existing out-of-compliance coal plants. The capital costs of new CCGT units are only moderately higher than the retrofit costs of scrubbers and SCR, and they are likely lower than the capital cost of retrofits that include ash control and cooling towers to bring old coal-fired plants into Clean Water Act compliance. Given the CCGT's very low heat rates (high efficiencies) and very low CO_2 emissions, especially in comparison with old coal plants, it can be cost effective to replace certain older coal plants with new CCGT units.

For the coal plant retrofit cost scenarios described earlier, assuming a heat rate for the retrofitted units of 11,750 Btu/kWh, we estimate breakeven natural gas prices for new CCGT generation as:

- Inexpensive retrofits: $4/MMBtu breakeven gas price
- Baseline retrofits: $5.5/MMBtu breakeven gas price
- Expensive retrofits: $6.5/MMBtu breakeven gas price

Prospects for Future Natural Gas Prices

At the current price of natural gas or at prices projected in the future, both existing gas-fired CCGT generation and new CCGT units can replace out-of-compliance coal generation, meet customer demand, and maintain system reliability. With economics that are competitive or nearly so with existing out-of-compliance coal plants, reliance on gas-fired CCGT need not incur a significant cost penalty.[38] Moreover, new CCGT plants are economically competitive with new coal-fired units, should new capacity be needed for reliability.

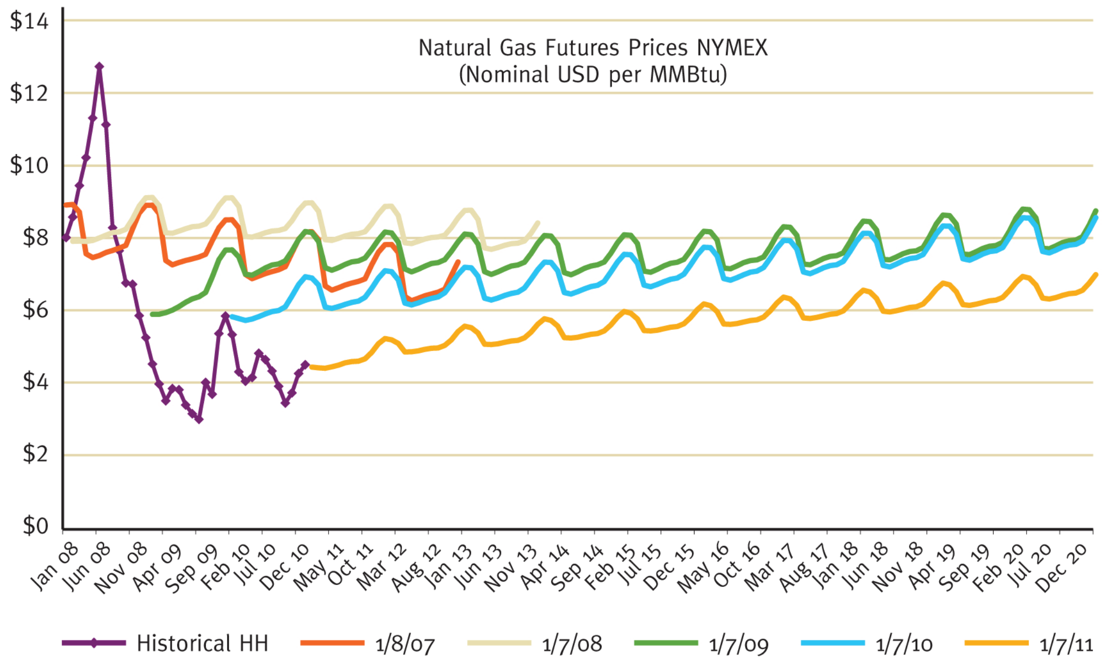
In a stabilized gas price environment, a gas-intensive generation fleet will be less expensive and less financially risky than most industry experts believed until recently. The conventional wisdom has been that future gas price risk is high, making greater reliance on gas-fired generation risky and investments in new CCGT capacity particularly so. The attractive picture that we draw above, of the economics of gas-fired generation, depends critically on future gas prices remaining lower and less volatile than they were in much of the past decade.

The expectation of a stable gas price regime is realistic, as suggested by the moderating of gas futures prices over the past few years (see Figure 4).[39] This new regime results from the current expansion and huge potential of on-shore unconventional natural gas supply. For example, according to an authoritative 2010 MIT study, in addition to conventional supplies, "assessments of the recoverable volumes of shale gas in the U.S. have increased dramatically over the last five years. The current mean projection of the recoverable shale gas resource is approximately 650 trillion cubic feet (Tcf)... approximately 400 Tcf could be economically developed with a gas price at or below $6/MMBtu."[40]

The domestic supply figure of 400 Tcf alone represents about 18 years' total national usage. Global potential is even greater. The MIT study concludes that about 80 years' worth of present global natural gas demand could be developed at $4/MMBtu. These important additions to the domestic and international gas supply resources can be expected to limit future natural gas prices in the $4-6/MMBtu range, with greater price stability than the recent experience.[41]

Increased North American supply, together with ongoing demand-side efficiency gains in the use of natural gas in buildings and industry, should reduce the risk of supply-demand imbalances and resulting price excursions. Customer energy efficiency programs administered by utilities have been expanding in recent years, spreading from mostly electric utility territories into gas utilities as well, and from a few states to throughout the U.S.[42] By helping gas customers save energy wherever it is less costly than buying new supply, these programs help moderate demand and thereby limit future prices.

Figure 4. Natural Gas Future Prices — 2008 to 2020



Source: ***Task Force on Ensuring Stable Natural Gas Markets.***
Bipartisan Policy Center and the American Clean Skies Foundation, March 2011.

The Need for Long-Term Supply Contracts

Regardless of the future natural gas price regime, there is still a critical need for electric utilities and merchant generators to address gas price volatility and reduce perceived price risk. Before deregulation of the natural gas industry in the 1980s, gas producers sold forward production to large customers such as power generators under long-term contracts, but this practice mostly stopped following deregulation, subjecting generators to market price volatility, from which they benefitted initially. Today, following a period of price spikes from 2000 to 2008, a return to long-term forward contracting for natural gas supply to utilities and other generators is needed. The ability to lock in a future fuel supply price is essential for utilities to base their resource planning and procurement on gas-fired generation sources.

Oddly, this sort of conservative fiscal management is especially difficult to apply in the context of regulated utilities, whose revenue model is based on cost recovery of capital investments and approved expenses. Fuel (and emissions) costs represent an expense that is typically passed through from the utility to the customer, who implicitly bears the risk of price volatility. A utility that tries to protect its customers from such risks, for example, by buying a fuel price hedge, stands to gain little direct benefit from successfully hedging this risk. On the other hand, should fuel prices remain stable or decline, making the hedge unnecessary, the utility faces the risk that recovery of the cost of the hedge might be denied by regulators who could rule the expenditure, in hindsight, to be not "prudent."

Such treatment of risk by regulators creates a perverse incentive for utilities to pass known risks along to customers without hedging or other risk management. It also forces utilities to treat future gas price risk very conservatively in the planning and procurement stage, because the eventual cost recovery of future fuel prices is not assured. This uncertainty, which is especially unwelcome in the cautious arena of utility financial management, tends to discourage investments in new gas-fired generation.

Utilities need long-term natural gas contracting vehicles to mitigate gas price risk and ensure a stable cost environment. Merchant generators might choose to maintain some exposure to market prices, but they would also benefit from the ability to stabilize or hedge at least some of their future fuel costs. To be useful, long-term contracts need to cover five to twenty years' supply and provide a transparent price trajectory. There are a number of possible structures for a future escalation clauses or price floors and ceilings, but the main requirement is predictability, avoiding a simple index to, for example, NYMEX spot prices.

One useful example of such a contract is the recently concluded, 10-year natural gas supply contract between Xcel Energy and Anadarko. The contract is part of a new resource plan and the accompanying legislation (HB-10-1365), which will enable Xcel Energy to close four coal-fired units in the Denver region, switch one unit to natural gas, and build a new gas-fired CCGT plant to meet federal emission standards by cutting nitrogen oxides (NO_x) by over 80%.[43] The plan, including the fuel supply contract, had to be approved by the Colorado Public Utilities Commission (PUC) and, in particular, it provides for cost recovery of payments under the contract regardless of the future gas price trajectory. The result is a stable price and steady supply of fuel to protect Xcel's Colorado customers from gas market price volatility.

Xcel solicited proposals for five- to ten-year natural gas supply contracts to complement the proposed emissions reduction plan. The winning contract, negotiated with Anadarko, contains a fixed price with an annual escalation adjustment. The details are confidential, but Xcel provided a public estimate of $5.48/MMBtu over the ten years as the average nominal cost of the gas supply.[44] This represents a premium over the prevailing spot market price at the time (about $4.25/MMBtu), but somewhat less than the longest future contract price ($5.75/MMBtu for December 2015).[45]

The price premium compensates Anadarko for sharing in the future price risk and enabling Xcel to lock in a predictable fuel supply cost for their planned generation fleet. This is a useful model for future generator fuel supply contracts. Another option is joint venture relationships, where the gas customer invests in natural gas development and receives part of the production, as in a recent agreement between gas producer Encana and Northwest Natural Gas Co. of Oregon.[46]

New Reality #3: Increased Gas Generation Enables Renewables to Replace Coal on a Large Scale

The Xcel Energy shift to gas-fired generation in Colorado is part of the solution to the local ozone pollution and NO_x emissions problem. Compared to coal-fired generation, CCGTs emit far less NO_x, essentially no SO_2 or mercury and less than half as much CO_2. However, the shift to gas provides another important environmental and resource planning advantage: By increasing the share of gas-fired generation in the fleet, a utility can enable greater usage of renewable energy, with no emissions or fuel costs.

The Need for Flexibility to Balance Renewable Generation

Unlike a coal-fired steam plant, which is designed to run constantly as a baseload power source, CCGTs and simple-cycle combustion turbines (CTs) can ramp their output up or down faster and with less cost and efficiency penalty. Their dispatch flexibility is far superior to coal-fired steam plants, which have slow ramping rates, minimum output levels of 35-50% of maximum and relatively high costs to shut down and start up. Moreover, cycling coal-fired plants to balance renewable sources can negate much of their emission savings, because the coal units operate at an elevated heat rate (lower efficiency), increasing their emission intensities.[47]

The flexibility of gas-fired generation is useful in load following, i.e., changing output to fit the changing time-profile of customer demand, and it also makes CCGTs and CTs complementary to variable renewable power sources such as solar power and especially wind power. Thus, flexible gas-fired generation is the key to reducing power sector CO_2 emissions, partly due to its low carbon intensity compared to coal, but especially because its flexibility enables carbon-free variable renewable sources.

To understand the synergy between renewable and gas-fired generation, it is important to distinguish between the total annual energy (in kWh or MWh) supplied by a generation source and the instantaneous capacity (in kW or MW) that source can supply. In the short term, the first impact of adding renewable energy to the generation fleet is to replace incremental energy, which would otherwise be supplied mostly from gas-fired units as the dispatchable, load-following generation source. In essence, the renewable source is a negative load on the power supply system. From this perspective, it is commonly thought that the main result of installing renewable generation is to replace gas-fired generation, but this is a misleading result.

In the longer term, as the share of generation from renewables increases, as indeed it is mandated to do in many jurisdictions, gas-fired ramping capacity is needed to balance, or "firm," the time-variable renewable sources. Thus, to balance an increasing share of renewable generation and reduce emissions, the generation fleet might experience a decrease in energy from gas-fired sources initially, and a significant increase in capacity required from gas-fired sources over time. Thus, balancing a large contribution from variable renewable sources may require dramatic increases in gas-fired generation in terms of capacity, but more modest increases in terms of energy and fuel use.

Development of Renewable Generation Capacity

The importance of gas-fired generation to balance renewable sources depends on the future share of renewables. This share is growing at a dramatic rate and can be expected to continue to grow, including in regions where there has been little development to date. At the beginning of 2011, 29 States plus the District of Columbia have some form of mandated renewable energy standard or renewable portfolio standard (RES/RPS). These standards require utilities to produce or purchase, on behalf of their customers, electricity generated from new, renewable sources to meet or exceed the standard, which is usually expressed as a share of total electricity sales.[48]

Existing RES/RPS rules mandate over 40,000 MW of new renewable power by 2020, and over 60,000 MW by 2025.[49] These increments are additions to about 35,000 MW of renewable capacity existing in 2010.[50] Because of the present cost advantage of wind power compared to solar and other non-hydro renewable sources, most renewable energy production to achieve RES/RPS targets will be from wind turbines.

Some states have specific portions of their RES/RPS requirement set aside for solar power. These will require over 1,000 MW of solar generation by 2020 and close to 2,000 MW by 2025.[51] Some states have voluntary standards or targets, such as California's "Million Solar Roof" program, that could result in the installation of additional solar capacity. If solar costs continue to fall to the point where a kWh of solar generation is closer in cost to one from wind, then some share of the RES/RPS compliance could shift from wind to solar power.[52]

The RES/RPS projections represent new renewable generation capacity that has been mandated to date. The total production would represent about 4% of total US electricity generation by 2020. To meet broader national energy goals or targets from recently introduced (but not yet enacted) legislation, even larger quantities of renewable power would be needed. A 20% national renewable energy target, for example, would demand expansion of renewable capacity, at almost five times the rate needed to fulfill present RES/RPS requirements, continuing steadily through 2030.[53] Another indication of the potential growth of renewable generation is that about 350,000 MW of wind and solar projects are reported to be in transmission interconnection queues.[54]

The already-mandated growth of renewable generation is shown in Table 4, which gives a regional breakdown of the capacity required by 2020 under existing RES/RPS rules, not counting voluntary targets. Mandated renewable generation in each region is also compared with available CCGT generation and potential coal retirements according to the NERC study of the impact of pending EPA regulations (from Table 3).

At least on a regional basis, where there is out-of-compliance coal-fired generation vulnerable to retirement, there is also available gas-fired capacity, as well as a mandate to increase renewable energy production (compare columns C, D and E in Table 4). The exception, where mandated renewable growth far exceeds available CCGT capacity and potential coal retirements, (column E is much greater than columns C and D in Table 4) is the WECC (Western) region. The WECC already has a large fleet of existing gas-fired generation capacity, as well as hydropower, which can support

NERC Region (*see* Appendix 1)	A. 2008 CCGT Total Annual Generation (million MWh)	B. Potential Additional Generation at 60% Capacity Factor (million MWh)	C. Equivalent Baseload Capacity (thousand MW) of "B."	D. Potential Retired Coal Generation Capacity (thousand MW)	E. Mandated Renewable Generation (thousand MW)
ERCOT	114	36	5.1	4.8	3.8
FRCC	86	22	3.1	1.6	0
MRO	6	18	2.5	4.2	5.8
NPCC	72	32	4.5	7.1	5.6
RFC	56	108	15.4	16.9	18.6
SERC	86	121	17.2	21.7	13.9
SPP	39	35	5.0	1.9	2.9
WECC	187	59	8.4	8.6	14.3
Total:	648	430	61.4	66.9	64.8

Table 4. Geographic Distribution, by NERC Region, of Available CCGT Generation, Coal-Fired Generation Vulnerable to Retirement, and New, Renewable Generation Mandated by Existing RES/RPS. The data in each column are as follows:

A. The energy generated by CCGT units
B. Additional energy that could be generated each year if CCGT units with heat rates below 9000 Btu/kWh were operated at 60% capacity factor
C. The amount of baseload capacity (assuming 80% capacity factor) that would be needed to produce the same amount of energy as "B.," the incremental energy that could be generated by operating CCGT units with heat rates below 9000 Btu/kWh at 60% capacity factor
D. Estimated out-of-compliance coal-fired capacity that is vulnerable to retirement
E. Estimated new renewable capacity that is mandated to be built by 2025 under existing RES/RPS rules

the integration of renewable sources under existing RES/RPS rules. Individual states such as California are studying integration issues for renewable power contributions of 33%.[55]

This regional alignment means that the potential need to shift generation from coal-fired units to gas-fired CCGT units, which would increase the flexibility of the generation fleet, would coincide with the expansion of renewable generation, which in turn would demand additional flexibility. On the other hand, should the coal-to-gas shift be delayed by weak environmental enforcement or by emission control retrofits of coal-fired units, flexibility of the generation fleet will be diminished in the regions where flexibility is needed for renewable energy growth.

Flexibility in the Existing Generation Fleet

The flexibility needed to enable the growth of renewable generation, including that already mandated by state-level standards, depends on the generation planning decisions that will be made in response to present environmental regulations. In the power industry today, the need for flexible ramping and firming capacity to balance variable renewable generation sources is generally thought to limit their contribution.

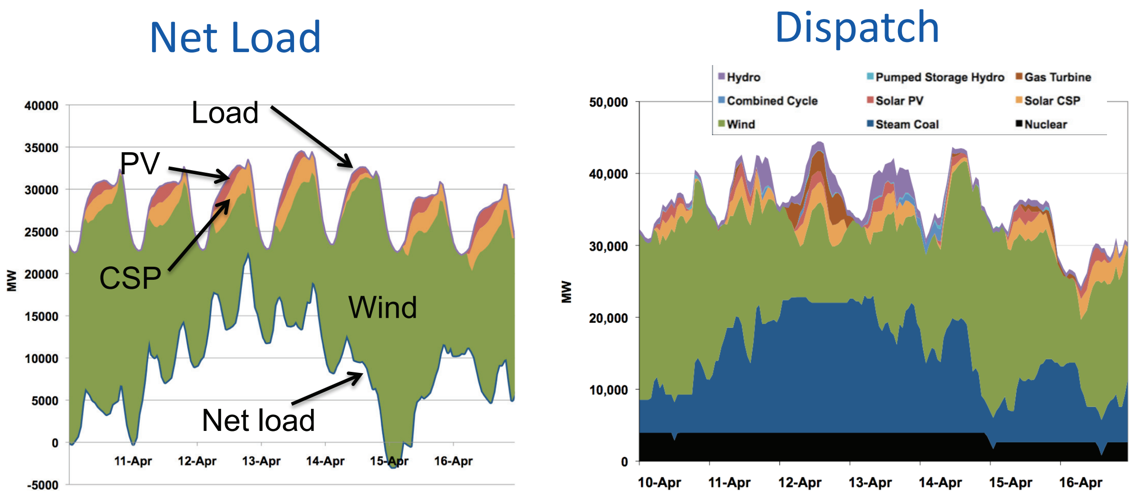
Already, wind generators are sometimes curtailed due to "over-generation" in some regions, especially where coal plants are the dominant off-peak source. Wind curtailment has been most frequent in the ERCOT (Texas) region, which currently produces about 7% of its electricity from wind. In 2009, 17% of Texas' potential wind generation was reported as curtailed.[56] The specific conditions causing curtailment in Texas are partly related to transmission constraints, but the curtailment events occur when the system is operating at its minimum output level and baseload generation (mostly nuclear and coal-fired) cannot be ramped down further.

Higher penetrations of coal and nuclear steam plants reduce the flexibility of the generation fleet and increase integration problems for new renewable sources. Lack of flexibility increases the likelihood of having to curtail clean renewable power or risk operational problems or costly shut-downs of baseload generation plants. If the situation were reversed, with a large share of incumbent renewable generation, it would be difficult to add baseload steam plants, because their lack of flexibility would not be compatible with the existing, renewable-rich generation fleet. More flexible generation would be preferable.

For example, Figure 5 shows the simulated generation dispatch, for a "difficult week" (low load, high wind) in the challenging Texas market (large share of inflexible nuclear and coal-fired steam plants in the generation fleet), with 30% wind penetration (and 5% solar), from the GE/NREL Western Wind and Solar Integration Study.[57] The net load falls so low that all the gas-fired sources, much of the coal, and even some nuclear generation would not be needed, highlighting the tension between adding variable renewable and maintaining baseload generation.

While baseload steam plants increase the difficulty of integrating renewable sources, replacing coal-fired generation with flexible gas-fired sources inherently enables better integration of renewable sources. In the future, a high renewable penetration in the generation fleet, in response to RES/RPS rules, CO_2 emission limits or simple economics, will therefore require increased gas capacity, supplemented by additional transmission capacity and other enablers.

Figure 5. Simulated Generation Dispatch with 30% Wind Penetration in Texas



Source: ***How Do High Levels of Wind and Solar Impact the Grid? The Western Wind and Solar Integration Study.*** **National Renewable Energy Laboratory, December 2010.**

Summary of Power Plant Types and Their Dispatch

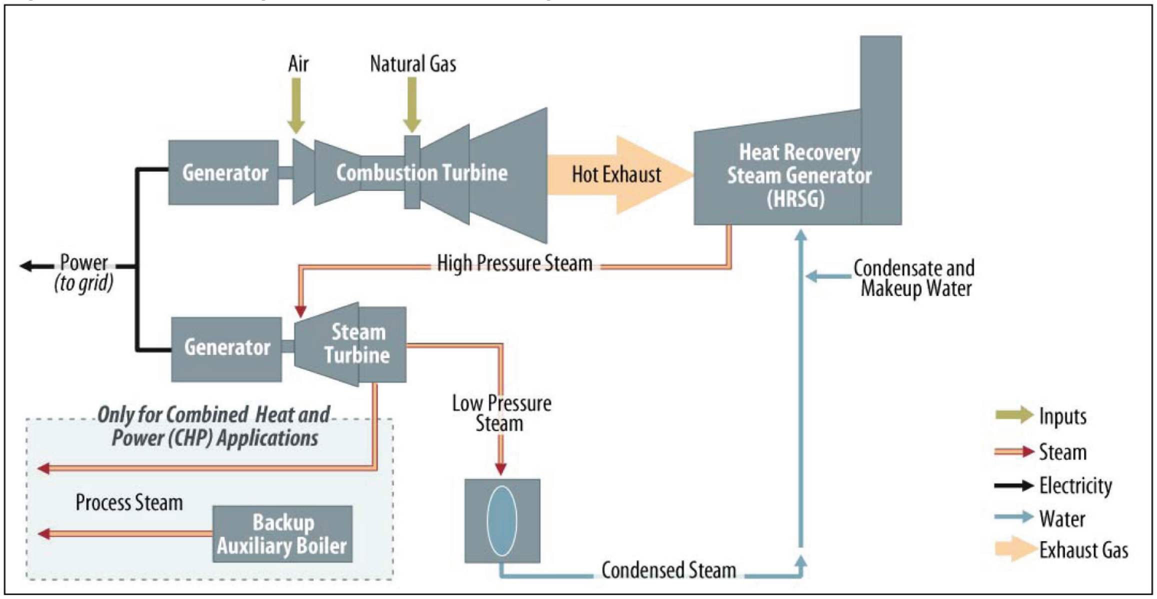
Electric power production is generally adjusted continuously to meet the variation in customer loads or, as shown in Figure 5, the loads net of renewable energy output. Different types of generation units are typically used to meet this varying demand, and the choice of plant type depends on the amount of time the plant is needed--measured by the capacity factor, which is the ratio of the plant's average production to its rated output.

Baseload units run almost all the time at nearly constant output.[58] All nuclear and many coal-fired steam plants are operated as baseload plants because it is difficult and expensive to ramp such plants up and down or to start and stop them. Much of the daily variation in load (or net load) is met with intermediate generation units. These units can be coal-fired steam plants, which typically have limited ramping ability, or either hydroelectric plants where available or natural gas-fired combined-cycle gas turbine (CCGT) plants. Hydro and CCGT units are typically more flexible and can ramp faster than coal-fired steam plants. Maximum loads are served by peaking units, which are usually simple-cycle combustion turbines (CTs) that are highly flexible and able to ramp quickly and start and stop as needed.

The most efficient thermal power plants are gas-fired CCGT units, which join combustion turbine technology with a steam turbine. As shown in Figure 6, a typical configuration takes the hot exhaust from the CT, after extracting power from it, and uses the remaining heat energy to produce steam that drives a steam turbine, from which additional power is taken, resulting in high overall efficiency.

Simple-cycle CT "peakers" are highly flexible generation sources, although not as efficient as CCGTs. While CCGTs are more flexible than coal-fired units and other steam plants, their ability to ramp and cycle varies widely. Planners tend to assume a ramp rate of 1.5-2%/minute.[59] Newer CCGT plants have faster ramping ability than older plants, and existing units can be retrofitted for faster ramping and lower part-load emissions. Moreover, new technology is emerging for highly efficient "fast-ramp" CCGT technology.[60]

Figure 6. Schematic diagram of a combined-cycle gas turbine (CCGT) power plant[61]



Source: ***Displacing Coal with Generation from Existing Natural Gas-Fired Power Plants.*** **Congressional Research Service, January 2010.**

Supplying Natural Gas for Flexible Generation

In order to increase the ability of CCGT units to ramp and cycle in response to time variations in load and renewable production, it will also be necessary to ensure sufficient natural gas delivery capacity and storage to fuel fast-ramping generation sources. One existing barrier is that the gas-scheduling "day" and electricity-scheduling "day" do not match, and gas supplies must be scheduled early in the day ahead of usage, before the electric generation dispatching needs are determined. This mismatch limits the flexibility of gas-fired generators to ramp production up and down, and it imposes additional cost penalties when they do. Improved tariffs and rules are needed to accommodate more flexible generation, and one example where such innovations have been implemented is in the province of Ontario, Canada.[62]

A significant quantity of natural gas storage is contained in the variable pressure and volume (or "line pack") in the gas transmission grid. Ability to vary pipeline pressure, in order to charge or withdraw from the stored gas volume, is an important resource to harness in the process of ramping CCGT units to balance variable loads and renewable output while maintaining reliability. To date, gas pipelines and compressor stations have not been configured to support fast-ramping generation units particularly, and their contractual incentives can discourage such usage. However, both the technical and contractual details can be adjusted to make fuller use of line pack storage for fast-ramping generators, and these changes would help enable the expansion of renewable generation.[63]

One recent study analyzed the technical and regulatory impact of balancing renewable power with gas-fired generation and identified potential limitations regarding natural gas pipelines.[64] Based on an assumed 88,000 MW of new wind capacity to be built by 2025, it estimated that some 33,000 MW of gas-fired generation capacity would be needed, running at about a 20% average capacity factor, to balance variations in wind production. The magnitude of the resulting load on pipeline capacity and how much could be met via more pro-active management of line pack are under debate,[65] which highlights the importance of gas supply considerations.

Financing Flexible Generation

In the short term, as noted earlier, the initial effect of adding renewable generation is to replace incremental energy that would be supplied mostly from gas-fired units, while in the longer term, additional gas-fired capacity is needed to balance variable renewable sources. It is important to focus on the short run perspective, however, because the financial viability of gas-fired generators may be at risk, at least during a transitional time period. Adding renewable capacity to today's generation fleet will squeeze gas-fired generators between the free (in variable cost terms), must-run renewable output and low variable-cost coal-fired generation, potentially making it ever more difficult for gas-fired units to get into the dispatch queue and produce revenues needed to cover their debt service and other fixed costs.

However, these flexible, gas-fired resources are essential in the longer term to balance the increasing share of renewable sources on the grid and reduce emissions while maintaining reliability. The short-term squeeze on the revenues of merchant gas-fired generators, partly due to the increased penetration of renewable sources, paradoxically could make it more difficult to integrate additional renewable capacity, including that which is already mandated by RES/RPS rules, in the near future.

To bolster the financial health of flexible gas-fired generators, and to ensure their availability when needed to balance variable renewable sources, new ancillary services products and contracts may be needed.[66] Of the ancillary services typically provided by reserve generation capacity, the fast-response regulation services appear to be most likely to be stressed as renewable sources are added, rather than the slower unit commitment and hourly load following services, which can be partly managed by improving forecast methods.[67] In addition, the overall range and rate of generation ramping, in response to time variations in load and renewable production, may become a reliability constraint in a renewable-rich power system, and serving this need may require a new ancillary service product.[68]

Fast-acting regulation services and fast-ramping capability will have greater value in a renewable-rich power system than in today's system. In the meantime, however, there is a need to begin recognizing this value, in order to create incentives to supply the needed flexibility services, or at least not to retire generators that could provide them. In regions where ancillary services are bid competitively into wholesale markets, there may be a need for new products, such as fast-ramping capacity, or simply a greater demand for familiar regulation services, to prepare for greater reliance on renewable sources.[69] To provide a market signal to provide these services, it may be necessary to require generation buyers to include fast-ramping and firming services, from flexible generation sources, in the portfolio of ancillary services they buy.

In regions where regulated utilities produce or procure ancillary services, the procurement planning procedures may need to provide specifically for fast-ramping generation capacity as part of their integrated resource planning (IRP) process. Such utilities' resource adequacy requirements may need short-term adjustment, in order to ensure that flexible generation units' fixed costs are covered, at least until fast-ramping and firming services are fully recognized as part of the ancillary services mix. Current generation planning does not yet recognize this value. Therefore, to provide the needed fast-ramping and firming services, flexible generation sources will probably need a new type of long-term contract for such capacity.[70]

At the national level, the Federal Energy Regulatory Commission (FERC) has started to address the integration of variable renewable sources in a recent Notice of Proposed Rulemaking (NOPR), in which the FERC proposed that transmission grid operators allow scheduling in 15-minute intervals and that variable generators provide meteorological data to forecasters.[71]

At the regional level, more dynamic resource planning and market processes are needed to enable the power generation fleet to adapt to changing conditions, including environmental regulation, renewable generation growth, and demand-side programs. As noted earlier, existing procedures may allow some existing coal-fired plants to remain cost-effective to operate if grid operators determine they are essential for reliability.[72]

Instead of determining the need for specific generation units to support reliability separately from least-cost planning or market processes, grid operators or state regulators could make these processes more dynamic by accounting explicitly for reliability needs and policy mandates such as RES/RPS. This approach can enable the determination of the least-cost resource mix to achieve needed reliability criteria, while it can also reduce the frequency and duration with which uneconomic generation units are kept in service.[73]

A Flexible, Integrated Utility Resource Portfolio

Increased availability of flexible, gas-fired generation makes it possible to combine a wide range of supply and demand-side resources into a diversified portfolio that can balance variable renewable sources and match their combined output to customer load.[74] There is considerable potential for energy from renewable resources to be balanced using the geographic diversity of the resources themselves.[75] The idea of harnessing geographically diverse renewable resources to balance and firm one another has long been theorized,[76] but it is beginning to be recognized as a viable approach, provided that system planners and operators can rely on improved forecasting, upgraded transmission, balancing area expansion, and other improvements to the grid.[77]

Besides flexible generation and expanded regional transmission capacity on the supply side, demand-side resources can provide reliable ramping and firming by decreasing or postponing power demand when needed. Moreover, some demand-side resources can also provide flexible load to increase demand when needed to avoid curtailment of renewable sources, such as the case of wind in Texas, mentioned earlier. Recent studies of wind integration options find that, for example, "responsive load would be easily justified as an economic option to help manage variability."[78] A more cautious view of demand-side resources, however, reveals that these resources have a wide variety of capabilities, some of which fit the need for renewable integration better than others.

We can characterize the renewable integration problems in terms of under-generation (too little wind and solar resource relative to load), over-generation (too much wind or solar resource relative to load), and ramping rates (too fast a change in load net of renewable production). The under-generation problem is handled well by ordinary demand response programs, where customer load is reduced by some combination of manual, automated or pricing-based adjustment of demand, when called by the utility. Solar under-generation tends to occur during warm summer evenings, while wind under-generation is most likely during calm summer afternoons. Reducing air-conditioning loads through demand response programs or demand-side thermal storage can offset these problems.[79]

The over-generation problem can be more complex. Solar over-generation tends to occur during sunny spring or early summer mornings, while wind over-generation is most likely during windy nights in the late winter or spring. At these times, demand response programs would have difficulty increasing loads as needed. However, demand-side thermal storage can address these problems, by using electricity to charge the thermal battery, provided that the corresponding thermal loads (heating or cooling) occur sometime during the day (but not necessarily during the over-generation event). The controllable, two-way load shifting ability of thermal storage is key.

The ramping rate problem is also complicated. The need for ramping upward tends to peak during late afternoons in winter, when load increases as solar and wind resources diminish. Ramping downward tends to peak during autumn evenings, when load decreases as wind accelerates.[80] Ramping upward would be difficult for most demand-side resources to provide, although some demand response programs might be suitable. Like over-generation, ramping downward can be handled by demand-side thermal storage, but not readily by conventional demand response. It is unclear, however, whether large numbers of thermal storage devices can be aggregated and dispatched fast and precisely enough to provide adequate ramping services.

Other demand-side resources can contribute to a robust resource portfolio. Any load that has built-in electric or thermal energy storage properties can be useful to balance a renewable-rich generation fleet. For example, the potential to connect millions of plug-in vehicles to the grid will add a significant new electric load, but it will also add a substantial quantity of battery storage capacity that will be parked 95% of the time.

With smart control technology and incentives, this battery resource could be harnessed to help balance variable renewable generation, under part of a so-called "Smart Garage" strategy.[81] Plug-in vehicles would also enable electric utilities to increase their total load, and thus their revenues, in an environmentally benign way, since any emissions associated with the power generation to supply plug-in vehicles would be more than offset by the CO_2 and local emission savings from replacing gasoline-powered driving.[82]

Summary: The Obsolescence of Today's Generation Fleet as a Catalyst to Building Tomorrow's

The synergy between flexible natural gas-fired generation and renewable generation can benefit utilities' generation portfolios and allow generators to avoid high compliance costs of continued reliance on coal. Today, the cost-risk profile for natural gas supplies is much improved compared to a decade ago, and the prospect of renewed use of long-term gas supply contracts by power generators provides additional gas price risk mitigation. Moreover, the fact that renewable sources have zero fuel cost, with no volatility or emissions cost exposure, helps to moderate and hedge potential fuel-related price risk.

Utilization of flexible gas-fired sources to balance variable renewable generation enables the maximum use of the least expensive renewable technologies such as wind. Moreover, it allows the maximum use of variable renewable sources as must-run generation, rather than having to curtail these sources at times. Running renewable generation at maximum output will tend to moderate the total production, capacity factor, fuel use and emissions from the gas-fired units that provide ramping and firming.

It is difficult to estimate the quantity of installed gas-fired capacity that will be required to balance and firm each increment of variable renewable capacity. We can bound the problem using the capacity values for renewable energy, which are typically 10-15% for wind, 25-30% for rooftop solar, and over 90% for concentrating solar with thermal storage.[83] An NREL analysis of high wind-solar scenarios estimated a combined capacity value of about 18%.[84] This value suggests that as much as 0.8 MW of flexible generation capacity could be needed to firm each MW of variable renewable capacity, which should be viewed as a worst-case criterion, as we can expect that progress in using the geographic diversity of wind and solar resources to reduce firming requirements. To the extent that dedicated gas-fired capacity is required to firm renewable generation, we can estimate that is would only need to produce about 30-40% of its rated output on average, corresponding to less than half the capacity factor of a baseload plant.

Thus, to balance renewables and reduce emissions, the increase in gas-fired generation will be substantial in terms of capacity, but modest in terms of energy and fuel use. A modest resulting increase in gas demand is also consistent with moderate and stable future gas prices, especially in the presence of the expected supply increases and demand-side efficiency gains discussed earlier. For the gas-fired generation fleet, operation at moderate capacity factors will limit exposure to fuel prices and emission cost risks, but it also limits the revenues available to cover debt service and other fixed costs of the gas-fired capacity.

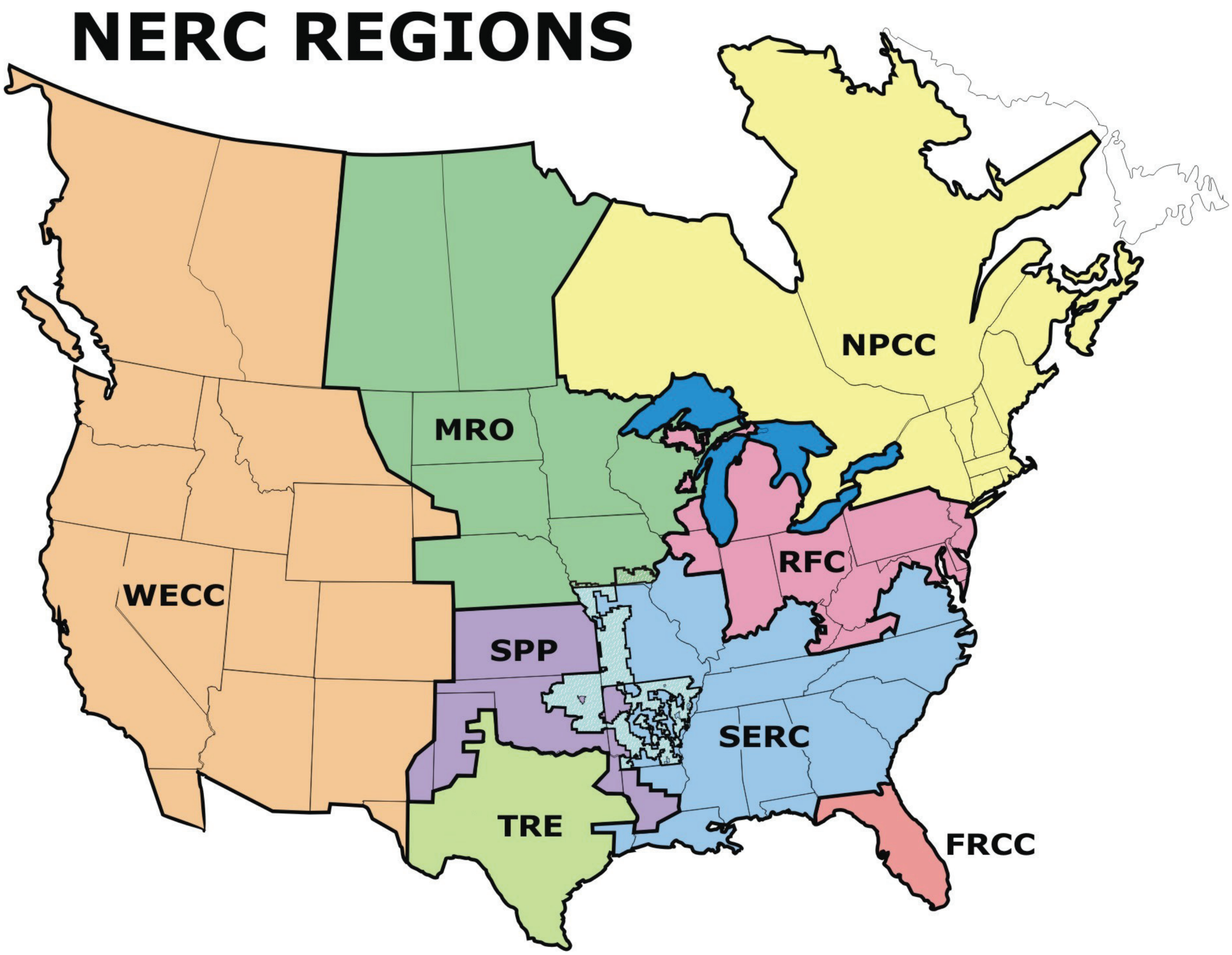
As noted earlier, operation at moderate capacity factors is not ideal for the financial health of gas-fired generators, as the value of their flexibility and fast-ramping ability is not recognized by either competitive power markets or utility planners. It is therefore necessary to design new approaches, to both power markets and utility planning and procurement practices, to ensure that the fixed costs of flexible generation sources can be covered. New types of long-term capacity contracts are needed, to cover the fixed costs and provide incentives for flexible generation sources that deliver fast-ramping and firming services, as the share of renewable generation rises.

All in all, given the prospect of compliance with the full spectrum of pending EPA regulations, existing and potential CO_2 emission limits, and spreading RES/RPS requirements, extending the life of obsolete coal-fired steam plants would be a step in the wrong direction. All of these present and future trends demand much greater use of renewable generation, which in turn demands greater flexibility in the generation fleet, not less, and therefore greater reliance on gas-fired generators to reduce emissions and balance the growing share of renewable sources in the generation fleet.

The power sector is truly at a crossroads, facing mutually exclusive paths forward. Coal-fired generation is about to get significantly more expensive. Extending the life of out-of-compliance coal plants, by retrofitting or delaying environmental enforcement, will impede the flexibility needed to integrate an increasing share of renewable generation. It would also impose unnecessary economic, environmental and/or health costs.

Rather than fight the imposition of new such costs, power generators have the historic opportunity to replace much of the obsolete coal-fired generation fleet with a portfolio of renewable and demand-side resources, together with sufficient natural gas-fired generation to ensure reliability. This gas-fired capacity will provide the flexibility needed to integrate a portfolio of clean energy resources and enable substantial reductions in local and regional pollution. Deploying these resources now will also simplify and accelerate the process of cutting CO_2 emissions.

Appendix 1: Map of the NERC Regions



Endnotes

1. Joel N. Swisher is a Consulting Professor at Stanford University and former Technical Director, Camco International. A prior version of this paper was delivered at the February 2011 Clean Energy Regulatory Forum at Wye River, MD, which was sponsored in part by the American Clean Skies Foundation.

2. Staple, G., and C. Carr, 2010. *Growing the Market for Clean Power: The EPA's New Power Plant Regulations and What They Mean for Utilities and Public Health*, American Clean Skies Foundation. The figure shows all the areas of environmental regulation addressed here, with the exception of the regulation of CO_2 and other greenhouse gases under the Clean Air Act and EPA's endangerment finding.

3. World Resources Institute (WRI), *Response to EEI's Timeline of Environmental Regulation*, November 2010, http://pdf.wri.org/factsheets/factsheet_response_to_eei_timeline.pdf

4. Johnson, S., *EPA Administrator letter to President Bush*, 31 January 2008. Mr. Johnson also writes that "a finding is required by the Supreme Court case, and the state of the latest climate change science does not permit a negative finding, nor does it permit a credible finding that we need to wait for more research."

5. Environmental Protection Agency, Final Rule, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*, http://www.epa.gov/nsr/documents/GHGTailoringProposal.pdf

6. *See* http://www.eenews.net/assets/2010/12/23/document_gw_02.pdf.

7. *See* Edison Electric Institute (EEI), *An Exchange on Change, Electric Perspectives*, October-November 2010, http://www.eei.org/magazine/EEI%20Electric%20Perspectives%20Article%20Listing/2010-09-01-EXCHANGE.pdf, for example, in which utility executives refer to EPA mandates as a "train wreck," and a critique of EEI's view in WRI, 2010, *op. cit.*

8. *See,* for example, M.J. Bradley & Associates, *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability*, August 2010, http://www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf; Charles River Associates, http://crai.com/uploadedFiles/Publications/CRA-Reliability-Assessment-of-EPA's-Proposed-Transport-Rule.pdf; North American Electric Reliability Corporation (NERC), *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*, October 2010, http://www.nerc.com/files/EPA_Scenario_Final.pdf.

9. Rowe, J. *Energy Policy: Above All, Do No Harm*, speech to American Enterprise Institute, Washington DC, 8 March 2011. The Rogers quote has appeared in numerous public forums.

10. President Barack Obama, *Remarks by the President on America's Energy Security*, Georgetown University, Washington DC, 30 March, 2011.

11. Power plant data are from US Department of Energy, Energy Information Administration EIA Forms 860 and 923. A power plant's capacity factor is the average power production divided by rated power output.

12. The variable cost of generation, which determines the dispatch priority of existing generation units, is the sum of operation and maintenance costs and fuel costs, which depend on the fuel price and the unit's heat rate (efficiency).

13. The heat rate is the amount of fuel energy in Btu required to generate 1 net kWh of power.

14. Average values represent weighted average according to amount of power generated by each plant. U.S. Energy Information Administration (EIA), *Average Operating Heat Rate for Selected Energy Sources*, 2009, available at: http://www.eia.doe.gov/cneaf/electricity/epa/epat5p3.html

15. There has recently been controversy about the impact of upstream emissions on the GHG intensity of natural gas compared to other fuels, based on an EPA report, *Technical Support Document: Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry*, EPA-HQ-OAR-2009-0923-3610, at http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_TSD.pdf. The EPA modified its methodology for estimating some sources of fugitive methane emissions from natural gas production systems. In particular, the EPA increased the estimated emissions from gas well cleanups by more than 20 times and added emissions due to gas well completions and workovers that involve hydraulic fracturing, which is used to extract natural gas from shale gas deposits. As a result, the 2009 inventory (and the revised 2008 inventory) shows natural gas upstream emissions as about 20% of combustion emissions, which is about double the ratio (around 10%) shown in the original 2008 inventory. We have reflected the EPA's updated GHG emission factors in our calculations that compare the GHG intensity of coal- and gas-fired generation, and the results still show a substantial advantage for natural gas. Anecdotally, some recent reports seem to exaggerate the impact of the EPA's modified methodology on the overall GHG intensity of natural gas, by suggesting that the updated emissions are twice the previous estimates (*see*, for example, Lustgarten, A., 2011. *Climate Benefits of Natural Gas May Be Overstated*, Propublica.org, 25 January 2011, at http://www.propublica.org/article/natural-gas-and-coal-pollution-gap-in-doubt). This interpretation confuses the change in the upstream and non-combustion emissions (which are indeed doubled) with the change in total GHG emissions (which increase about 10%). It also omits the important point that upstream GHG emissions from coal mining must be included for consistent comparison, and that these upstream emissions from coal production still represent about half of the revised, higher upstream emissions from gas production.

16. Tons of CO_2e are the emissions of all greenhouse gases, accounting for the varying atmospheric lifetimes and radiative forcing power of the gases including CO_2, N_2O, methane (CH_4) and others, expressed as the equivalent number of tons of CO_2 alone that would cause the same total radiative forcing, integrated over a 100-year time horizon. The CO_2e emissions estimates for natural gas include methane losses from the production and transportation system (adding 17% to natural gas's CO_2e), methane and N_2O emissions from stationary combustion (adding very little), and CO_2 losses from production (adding 3%). The CO_2e emissions estimates for coal include methane losses from mining (adding 3% to coal's CO_2e), and methane and N_2O emissions from stationary combustion (adding 1%). All values are taken from US EPA, 2011. *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2009*, EPA-430-R-11-005, http://www.epa.gov/climatechange/emissions/usinventoryreport.html. Because we use the more recent *IPCC Fourth Assessment Report* (2007) data (in which the GWP for methane is 25) rather than the *Second Assessment Report* (1995) data used in EPA's national GHG inventory (in which the GWP for methane was 21) our estimates of the CO_2e values for methane are about 20% higher than those reported in the EPA documents cited here. Values for N_2O are nearly unchanged between the two sources.

17. For example, one study estimates 16,990 Btu/kWh for 62 GW of most obsolete coal plants. *See* Deutsche Bank Group, *Natural Gas and Renewables: A Secure Low Carbon Future Energy Plan for the United States*. November 2010, http://www.dbcca.com/dbcca/EN/_media/NaturalGasAndRenewables.pdf.

18. The output-weighted average of coal-fired units built before 1970, and operated at less than 50% capacity factor in 2008, was 12,500 Btu/kWh. To be conservative, we use an estimated value of 11,750 Btu/kWh.

19. IEA, *Annual Energy Outlook 2011*.

20. IEA, *Natural Gas Weekly Update*, 18 May 2011, and *Annual Energy Outlook 2011*. Constant 2009 dollars.

21. Bernstein Research. *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vise of EPA Regulation; Who Wins and Who Loses?* October 2010. http://207.114.134.6/coal/oh/downloads/bernstein-report.pdf; Celebi, M., *Potential Coal Plant Retirements Under Emerging Environmental Regulations*. December 2010. The Brattle Group. http://www.brattle.com/_documents/UploadLibrary/Upload898.pdf; Shavel, I., and B. Gibbs, *A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT*, December 2010, Charles River Associates, http://crai.com/uploadedFiles/Publications/CRA-Reliability-Assessment-of-EPA's-Proposed-Transport-Rule.pdf; Credit Suisse, *Growth From Subtraction: Impact of EPA Rules on Power Markets*. September 2010, http://epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=b42de70d-b814-4410-831d-34b180846a19; DB Climate Change Advisors, *Natural Gas and Renewables: A Secure Low Carbon Future Energy Plan for the United States*. November 2010. Deutsche Bank Group, http://www.dbcca.com/dbcca/EN/_media/NaturalGasAndRenewables.pdf; M.J. Bradley & Associates, *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability*, August 2010, http://www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf; North American Electric Reliability Corporation (NERC), 2010 S*pecial Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*, October 2010, http://www.nerc.com/files/EPA_Scenario_Final.pdf.

22. The NERC study highlights the potential impact of the Clean Water Act section 316(b) requirements, and finds that, in addition to coal-fired plants, substantial amounts of nuclear and oil- and gas-fired steam plants would be vulnerable to retirement.

23. Bernstein Research, 2010, *op. cit.*

24. Celebi, 2010, *op. cit.*

25. Based on EIA Form-860, 2008 (plant-level capacity data) and Form-923, 2008 (plant-level energy data). Note that the output capacity of a combustion turbine is sensitive to the density of the intake air. As air temperature increases in the summer, air density falls and causes a resulting decline in the turbine capacity.

26. 70% based on summer peak capacity.

27. These vulnerable coal plants currently operate at an average capacity factor of less than 50%.

28. *See* Celebi, 2010, *op. cit.,* and Bernstein Research, 2010, *op. cit.* The main difference is in ERCOT.

29. Kaplan, S.M., 2010. *Displacing Coal with Generation from Existing Natural Gas-Fired Power Plants*, Congressional Research Service report for Congress, http://assets.opencrs.com/rpts/R41027_20100119.pdf.

30. MIT Energy Initiative, 2010. *The Future of Natural Gas*, http://web.mit.edu/mitei/research/studies/report-natural-gas.pdf.

31. *See*, for example, North American Electric Reliability Corporation (NERC). *2010 Long-Term Reliability Assessment*, 2010.

32. Bernstein Research, 2010, *op. cit.*

33. *See* Celebi, 2010, *op. cit.*

34. Bradley & Associates, 2010, *op. cit.*

35. According to the *EIA Annual Energy Outlook 2011*, capacity costs for new coal generation with scrubbers are over $2000/kW, while gas-fired CCGT capital costs are around $900/kW.

36. *Ibid.*, new coal generation with scrubbers: heat rate 9200 Btu/kWh (emissions 0.89 kg-CO2e/kWh); gas-fired CCGT: heat rate 6400 Btu/kWh (emissions 0.38 kg-CO2e/kWh).

37. Our analysis does not vary coal prices. Rather we adopt the EIA forecast, in which coal prices remain stable below $2.40/MMBtu (constant 2009 dollars) through 2030. *See* IEA, *Annual Energy Outlook 2011*.

38. Assuming that out-of-compliance coal plants are required to expend the costs to achieve compliance. Note, however, that some existing coal-fired plants could remain cost-effective to operate, regardless of the cost to customers, if system operators determine that they are essential for reliability and award the plants "reliability must run" (RMR) contracts. Several such occurrences are documented in Synapse Energy Economics, 2010, *Public Policy Implications on Transmission Planning*, http://www.synapse-energy.com/Downloads/SynapseReport.2010-12.EJ.Public-Policy-Impacts-on-Transmission.10-064.pdf.

39. *Final Report of the Bipartisan Center and American Clean Skies Foundation Task Force on Ensuring Stable Natural Gas Markets*, March 2011, http://www.cleanskies.org/pricestabilitytaskforce/63704_BPC_web.pdf.

40. MIT Energy Initiative, 2010, *op. cit.*

41. *Ibid.*

42. Friedrich, K. and M. Eldridge, 2009. *Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved through Utility-Sector Energy Efficiency Programs*, American Council for an Energy Efficient Economy, http://www.aceee.org/files/pdf/conferences/eer/2009/4C_Friedrich_Eldridge.pdf.

43. The Denver Post, "Colorado PUC Adopts Plan to Switch Denver-area Power Plants to Natural Gas," 10 December 2010.

44. State of Colorado, 2010. House Bill 10-1365 *Clean Air-Clean Jobs Act*, Fact Sheet, available at http://rechargecolorado.com/images/uploads/pdfs/Colorado_Clean_Air_Clean_Jobs_Act_GEO_White0Paper.pdf.

45. EIA, *Natural Gas Weekly Update*, 15 December 2010.

46. Reuters, "EnCana, Northwest Natural Form Jonah Joint Venture," 25 February 2011.

47. For a worst-case example, *see* Bentek Energy, LLC, 2010. *How Less Became More: Wind, Power and Unintended Consequences in the Colorado Energy Market*. http://www.wind-watch.org/documents/wp-content/uploads/BENTEK-How-Less-Became-More.pdf.

48. *See*, for example, Wiser, R. and G. Barbose, 2008. *Renewable Portfolio Standards in the U.S., Lawrence Berkeley National Laboratory*, LBNL-154e, http://eetd.lbl.gov/EA/EMP/reports/lbnl-154e-revised.pdf, and up-to-date tabulations at http://www.pewclimate.org/sites/default/modules/usmap/pdf.php?file=5907 and http://www.ferc.gov/market-oversight/othr-mkts/renew.asp.

49. Some RES/RPS rules include allowances for energy efficiency and other non-fossil resources, which have been subtracted out to obtain our estimate of mandated new renewable capacity.

50. Wiser, R. and M. Bolinger, 2010. *2009 Wind Technologies Market Report*, Lawrence Berkeley National Laboratory, LBNL-3716e, http://eetd.lbl.gov/EA/EMP/reports/lbnl-3716e.pdf.

51. Wiser, R., G. Barbose and E. Holt, 2010. *Supporting Solar Power in Renewables Portfolio Standards: Experience from the U.S.*, LBNL-3984e, http://eetd.lbl.gov/EA/EMP/reports/lbnl-3984e.pdf.

52. If so, the total renewable generation capacity would have to increase to account for the lower annual capacity factor (average power output / rated output) of solar compared to wind.

53. US Department of Energy and National Renewable Energy Lab, 2008. *20% Wind Energy*

by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply, http://www.nrel.gov/wind/systemsintegration/pdfs/2008/20_percent_wind.pdf.

54. Wiser, R. and M. Bolinger, 2010, *op. cit.*

55. California Independent System Operator, 2010. *ISO Study of Operational Requirements and Market Impacts at 33% RPS*, http://www.cpuc.ca.gov/NR/rdonlyres/AE1D8F17-A92C-435D-829D-97244F391CE4/0/CAISOPresenatationonTechnicalAppendicesRelevantto33IntegrationStudy.pdf.

56. Wiser, R. and M. Bolinger, 2010, *op. cit.*

57. GE Energy, 2010. *Western Wind and Solar Integration Study*, NREL/SR-550-47781, at http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf.

58. Utility generation fleets typically include a variety of different types of generation sources. Sources that have low variable costs such as nuclear and coal-fired units (with low fuel costs but generally high initial capital costs) are generally operated as much of the time as possible and are referred to as *baseload* sources. Baseload sources are not expected to vary in their output or have ability to ramp production up or down in response to time variation in loads (or production of other generators such as wind turbines). Sources that vary their output, or that start and stop as needed, in response to load variations, are *intermediate* load units, and gas-fired CCGT units are preferred for this part of the portfolio due to their flexibility and moderate capital costs and variable costs. Extreme peak loads are met by *peaking* sources, which operate relatively few hours per years and are typically simple-cycle combustion turbines with high variable costs but very low initial capital costs. Hydropower is exceptional in that it typically includes energy storage capacity (water in the reservoir) and can be dispatched as needed, as baseload, intermediate or peaking capacity.

59. California Independent System Operator (ISO), 2010. *Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS*, California ISO, August 31, 2010, http://www.caiso.com/2804/2804d036401f0.pdf.

60. For example, Alstom's Low Load Operation Capability system for its combined-cycle power plants allows the plant to operate at loads less than 25% while maintaining operation of the steam side of the plant with reasonable plant efficiency, with the ability to "achieve over 95% of combined-cycle baseload output in less than 20 minutes from the 'parked' condition of 20% load." (3+%/minute), *see* http://www.powermag.com/gas/Flexible-Turbine-Operation-Is-Vital-for-a-Robust-Grid_2955.html. Similarly, Siemens' Hot Start on the Fly CCGT product, which consists of unrestricted gas turbine startup, with parallel steam turbine start-up, can be applied as a retrofit, and it can ramp to full load in about 30 minutes (3+%/minute), *see* http://www.energy.siemens.com/hq/pool/hq/energy-topics/pdfs/en/combined-cycle-power-plants/OperationalFlexibilityEnhancementsofCombinedCyclePowerPlants.pdf. GE has also announced that a new, highly flexible gas turbine will be available for the European market to foster greater grid integration of renewables. No comparable North American product has been announced yet, however *see* "GE Says New Gas Turbine Works in Conjunction with Wind, Solar Gear," Wall Street Journal, May 24, 2011.

61. From Congressional Research Service (Kaplan, 2010, *op. cit.*)

62. Aspen Environmental Group, July 2010, *Implications of Greater Reliance on Natural Gas for Electricity Generation*, http://www.publicpower.org/files/PDFs/ImplicationsOfGreaterRelianceOnNGforElectricityGeneration.pdf.

63. Rigos, D., B. Shapiro, and R. Levitan, *Leaning on Line Pack*, *Public Utilities Fortnightly*, January 2001, pp. 18-26.

64. ICF International, 2011. *Firming Renewable Electric Power Generators: Opportunities and*

Challenges for Natural Gas Pipelines, http://www.ingaa.org/cms/31/7306/9622.aspx.

65. Schutt, B., 2011. "AWEA sees 'flawed' study driving wedge between gas, wind industries," SNL, March 21, 2011, http://www.snl.com/InteractiveX/ArticleAbstract.aspx?id=12508329.

66. Ancillary services are the electric system services provided by power producers and, increasingly, demand-side resources that support the reliability of system in ways other than delivering bulk electric energy. Ancillary services include providing reserve capacity for day-ahead generation unit commitment, hourly load following to correct energy imbalances, fast-acting regulation and frequency response, as well as voltage support and reactive power.

67. Lew, D., 2011. *Finding Flexibility in the Existing Grid, Grid Integration of Renewables* Workshop, Stanford University, 13 January 2011. http://tomkat.stanford.edu/docs/Lew.pdf.

68. *See* Denholm, P.; E. Ela; B. Kirby; M. Milligan, 2010. *The Role of Energy Storage with Renewable Electricity Generation*, National Renewable Energy Lab, NREL/TP-6A2-47187.

69. Puga, N., 2010. *The Importance of Combined Cycle Generating Plants in Integrating Large Levels of Wind Power Generation*. The Electricity Journal, http://www.bateswhite.com/media/pnc/4/media.344.pdf.

70. *Ibid.*

71. Federal Energy Regulatory Commission (FERC), *Integrating Variable Energy Resources*, Notice of Proposed Rulemaking (NOPR), 133 FERC ¶ 61,149. 18 November 2010. The rule also proposes that grid operators offer regulation reserves, which are needed to balance variable output, to generators that export to other regions, just as for generators selling within the same network. Although generators can buy such ancillary services on their own, grid operators also must offer these services. Operators can recover the cost of ancillary services directly from the variable generators, either by contract or through a tariff.

72. *See* Synapse Energy Economics, 2010, *op. cit.*, which documents cases where uneconomic units are awarded "reliability must run" (RMR) contracts, at considerable cost to customers, because the market-clearing process does not optimize for the need to retain certain generation sources for reliability purposes.

73. *Ibid.*

74. Swisher, J., K. Wang, and L. Hansen, *Changing Course: Envisioning a New Electric Utility Paradigm*, Power-Gen Renewable Energy & Fuels Conference, Las Vegas, February 19-21, 2008.

75. For example, if it is windy in the Dakotas when it is calm in Kansas, sunny in Nevada when it is cloudy in California, or sunny in Texas when it is calm there.

76. *See*, for example, http://www.claverton-energy.com/common-affordable-and-renewable-electricity-supply-for-europe-and-its-neighbourhood.html.

77. *See*, for example, Milligan, M., et al, 2009. *Large-Scale Wind Integration Studies in the United States: Preliminary Results*, 8th International Workshop on Large Scale Integration of Wind Power, Bremen, Germany, http://www.nrel.gov/wind/systemsintegration/pdfs/2009/milligan_large_integration_studies.pdf.

78. *Ibid.*

79. For information on leading practitioners of demand response and demand-side thermal storage, respectively, *see* www.enernoc.com and www.ice-energy.com.

80. Lew, D., et al, 2009. *How Do High Levels of Wind and Solar Impact the Grid? The Western Wind and Solar Integration Study*, 8th International Workshop on Large Scale Integration of Wind Power, Bremen, Germany, http://www.nrel.gov/wind/systemsintegration/pdfs/2010/lew_wwsis_grid_impact.pdf.

81. On the "Smart Garage" strategy, *see* Swisher, et al, 2008, *op. cit.*

82. *See* Electric Power Research Institute (EPRI) and Natural Resources Defense Council, 2007. *Environmental Assessment of Plug-in Hybrid Electric Vehicles*, EPRI report 1015325.

83. Capacity value is the quantity of capacity a given generator adds to the electric supply system, as compared to a fossil fuel-fired conventional generator that would add the same level of system reliability. For a resource with a capacity value of 50%, one MW would provide the same contribution to system reliability as 0.5 MW of conventional generation capacity.

84. Lew et al., 2009, *op. cit.*