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THE NET BENEFITS OF LOW AND NO-CARBON ELECTRICITY TECHNOLOGIES

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Global Economy
and Development
at BROOKINGS

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Abstract:

This paper examines five different low and no-carbon electricity technologies and presents the net benefits of each under a range of assumptions. It estimates the costs per megawatt per year for wind, solar, hydroelectric, nuclear, and gas combined cycle electricity plants. To calculate these estimates, the paper uses a methodology based on avoided emissions and avoided costs, rather than comparing the more prevalent "levelized" costs. Three key findings result:

First—assuming reductions in carbon emissions are valued at $50 per metric ton and the price of natural gas is $16 per million Btu or less—nuclear, hydro, and natural gas combined cycle have far more net benefits than either wind or solar. This is the case because solar and wind facilities suffer from a very high capacity cost per megawatt, very low capacity factors and low reliability, which result in low avoided emissions and low avoided energy cost per dollar invested.

Second, low and no-carbon energy projects are most effective in avoiding emissions if a price for carbon is levied on fossil fuel energy suppliers. In the absence of an appropriate price for carbon, new no-carbon plants will tend to displace low-carbon gas combined cycle plants rather than high-carbon coal plants and achieve only a fraction of the potential reduction in carbon emissions. The price of carbon should be high enough to make production from gas-fired plants preferable to production from coal-fired plants, both in the short term, based on relative short-term energy costs, and the longer term, based on relative energy and capacity costs combined.

Third, direct regulation of carbon dioxide emissions of new and existing coal-fired plants, as proposed by the U.S. Environmental Protection Agency, can have some of the same effects as a carbon price in reducing coal plant emissions both in the short term and in the longer term as old, inefficient coal plants are retired. However, a price levied on carbon dioxide emissions is likely to be a less costly way to achieve a reduction in carbon dioxide emissions.

GLOSSARY OF TERMS

Annualized capital cost	The annual payments of interest, return on equity, and amortization of the initial capital cost required to fully amortize the capital cost per MW of capacity over the expected economic life of a power plant.
Availability factor	The percentage of time in a year during which a power plant is producing, or able to produce, at full capacity.
Avoided capacity cost	The capacity cost of a fossil fuel plant that would have been incurred had not a new plant using low or no-carbon technology been built.
Avoided emissions	The reduction in total emissions of an electricity system caused by the introduction of a new plant.
Avoided energy cost	The reduction in total energy cost of an electricity system caused by the introduction of a new plant.
Balancing costs	The costs incurred by an electrical system, such as spinning reserves, to balance supply and demand for electricity and avoid excessive voltage fluctuations.
British thermal unit (Btu)	The measurement of the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.
Capacity	The electrical producing capacity of a power plant, typically measured in megawatts (MW). A plant of one MW of capacity can produce one megawatt-hour (MWH) of electrical energy per hour when operating at full capacity.
Capacity cost	The annualized capital cost plus fixed operation and maintenance costs per year per MW of capacity, also called the fixed costs.
Capacity factor	The ratio of the actual annual megawatt hours of electrical energy production per megawatt of capacity of a power plant divided by 8,760 megawatt-hours, the total energy that could be generated by a plant of one megawatt capacity operated continuously at full capacity throughout the 8,760 hours in a year.
Combined cycle gas plant	A power plant that utilizes both a gas turbine and a steam turbine to produce electricity. The waste heat from the gas turbine burning natural gas to produce electricity is utilized to heat water and produce steam for the steam turbine to produce additional electricity.
Cost of capital	Interest payments and return on equity per dollar of investment in a new power plant.
Cycling costs	The costs incurred by an electrical system in starting up and closing down plants in order to take account of variations in the supply and demand for electricity.

Efficiency The percentage ratio between Btu's released in the burning of fuel to the Btu equivalent of electrical energy produced by a power plant.

Electricity system A system of producers and consumers of electricity connected by transmission and distribution networks.

Energy The electrical energy produced by a power plant, typically measured in megawatt-hours (MWH).

Energy cost The cost of fuel plus the variable operation and maintenance costs per MWH of energy produced, also called the variable cost per MWH produced.

Feed-in tariff A special price for electricity produced by qualified renewable energy sources.

Heat rate The number of Btu of energy in fuel required to produce one kilowatt-hour of electrical energy. The lower the heat rate of a power plant, the greater is its efficiency.

Load factor The same as the capacity factor.

Levelized cost The cost per MWH of a power plant calculated as the sum of (a) the capacity cost of a power plant divided by the number of MWH of energy produced (or expected to be produced) in a year plus (b) the energy cost per MWH.

Overnight capital cost The capital cost of a new plant per MW of capacity, excluding the cost of capital during construction.

Renewable energy certificate Certificates issued to qualified renewable energy electricity producers that electricity distributors must buy in amounts large enough to demonstrate that a specified percentage of electricity that they distribute comes directly or indirectly from renewable sources. The sale of the certificates constitutes a subsidy for qualified renewable energy producers, financed by distributors by charging higher prices to consumers.

Simple cycle gas plant A gas power plant that utilizes only a gas turbine.

Spinning reserves Potential power created by running a gas or steam turbine without producing and feeding power into the grid unless and until needed to meet a sharp increase in demand.

System Reliability The ability of an electricity system to provide a continuous flow of electricity from producers to consumers, typically measured as the inverse of the system's loss-of-load probability, the probability that during any given period of time some or all consumers will suffer a reduction or complete loss of electrical load.

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THE NET BENEFITS OF LOW AND NO-CARBON ELECTRICITY TECHNOLOGIES

Charles R. Frank, Jr.

INTRODUCTION

There are several different technologies available for reducing carbon dioxide emissions in the electricity sector. There is much debate and concern over which technologies deserve the most government policy support and what the costs and benefits are of each. In this paper we examine five different electricity technologies, wind, solar, hydroelectric, nuclear, and gas combined cycle, the first four of which are no-carbon technologies (emit no carbon dioxide) and the last of which, gas combined cycle, is a low-carbon technology, especially compared to coal and gas simple-cycle technologies.

The most common method for comparing the cost of different electricity technologies is to compute and compare the "levelized" cost of each alternative. However, Joskow (2011) argues convincingly that levelized costs are not appropriate for ranking technologies. An electricity plant that produces electricity with a relatively high levelized cost may be more valuable than a plant with a lower levelized cost if the plant with a high levelized cost delivers electricity more reliably and more cheaply when the price of electrical energy is high—that is, during periods of peak demand. For example, a high levelized-cost hydroelectric project with ample storage capacity can produce electricity at near zero marginal cost at full capacity during peak periods. While levelized costs might suggest that hydroelectric plants are higher-cost than fossil fuel plants, the hydroelectric plant may in fact be more profitable and valuable if that fossil fuel plant is burdened with a high energy cost during peak hours. Similarly, a solar plant that delivers more power during daytime (when electricity demand is at its peak) may be more valuable than a wind plant that produces more power during the night (when electricity demand is lower).

Thus, rather than using levelized costs to compare alternative technologies, one should compute the annual costs and benefits of each project and then rank those projects by net benefits delivered per megawatt (MW) of new electrical capacity. The benefits of a new electricity project are its avoided carbon dioxide emissions, avoided energy costs and avoided capacity costs.[1] The costs include its own carbon dioxide emissions, its own energy cost, and its own capacity cost. In addition, there are costs unique to certain technologies. For example, the decommissioning of a nuclear plant and disposal of its spent nuclear fuel at the end of its useful life can be very costly. Wind, solar and hydroelectric plants produce electricity intermittently and therefore generate additional system balancing and cycling costs that have to be taken into account (described in more detail later).

There is relatively little literature that analyzes benefits of low or no-carbon projects in terms of avoided emissions and avoided costs. Most of the literature that does exist focuses on avoided costs for specific electricity systems and for a limited range of technologies. For example, Gowrisankaran et al (2011) estimate the benefits and costs of solar power in Arizona. Marcantonini and Ellerman (2013) provide estimates for wind and solar in Germany. This paper estimates benefits and costs for five different technologies on a generic basis, using recently published data from the U.S. Energy Information Administration (EIA, April 2013a) on updated capital costs, operation and maintenance costs and carbon dioxide emissions. While costs can vary geographically, the market for power plant construction, operation and maintenance is global and there are few major differences in such costs among countries. The International Energy Agency also publishes cost data for construction operation and maintenance which are broadly consistent with data published by the EIA.

Similarly, markets for coal and oil are international and major price differences among countries arise largely from government trade policies. Prices for natural gas, however, are highly variable among countries because of the high cost of, and long lead times for, pipelines and liquid natural gas facilities required to transport natural gas over long distances. Also there are large differences among countries regarding capacity factors (or load factors) for renewable energy because of geographical variations in wind and solar intensity and availability of hydroelectric sites among countries. Thus this paper includes an analysis of the sensitivity of results to natural gas prices and capacity factors to demonstrate the applicability of results, or lack thereof, among countries. We also examine the implications of the analysis for government policies, including renewable incentives, taxation of carbon dioxide emissions, trading of carbon dioxide emissions allowances, and regulation of emission standards for fossil fuel electric generating facilities.

AVOIDED EMISSIONS

An important part of the value of any new plant is the avoided emissions that they generate—in other words, the reduction in carbon dioxide emissions achieved by displacing production from CO_2-emitting fossil fuel plants. The avoided emissions of any new low or no-carbon plant depend on two main factors: (1) whether the new plant displaces baseload, coal-fired electricity production or baseload, gas-fired electricity production (Fell et al, 2012), and (2) the percentage capacity factor of the new plant.

Baseload Replacement and Avoided Emissions

Avoided emissions of a new plant are much higher if it displaces a baseload coal plant rather than a baseload natural gas combined cycle plant during off-peak hours. Emissions from a baseload coal plant are much greater than emissions from a baseload gas plant using combined cycle technology. The differences in emissions between coal-fired and gas-fired plants derive from two main factors. First, coal contains more carbon per British thermal unit (Btu) than natural gas and therefore emits greater amounts of carbon dioxide per Btu. Second, coal-fired generating plants are less efficient than gas combined cycle (CC) plants in producing electricity and utilize more Btu per megawatt-hour (MWH) produced than gas CC plants.

As shown in Table 1, the difference in emissions between a new gas-fired, combined cycle plant and an old coal plant is great. Old coal plants generate 2,162.6 pounds of CO_2 emissions (nearly a metric ton) per MWH of electricity produced, nearly three times more emissions than a new gas CC plant. The EIA data are based on an energy efficiency of around 53 percent for a new combined cycle plant. However, the most modern, large-scale, combined cycle gas plants can

Table 1. CO_2 Emissions per MWH: Fossil Fuel Plants

Heat Rate (Btu/KWH)	Gas CC	Coal	Gas SC
New Plant (1)	6,430	8,800	9,750
Old Plant (2)	7,050	10,498	10,850
Efficiency			
New Plant	53.1%	38.8%	35.0%
Old Plant	48.4%	32.5%	31.5%
CO_2 Emissions: Pounds per MWH (3)			
New Plant	752.3	1,812.8	1,140.8
Old Plant	824.9	2,162.6	1,269.5
Footnotes:			
(1) EIA (April, 2013a) Table 1, p.6			
(2) EIA (April, 2013a) Table 1, p.6 for gas; EIA (December 2013a), Table 8.1 for coal			
(3) Pounds CO_2 per million Btu	*Gas*	*Coal*	
EIA (April, 2013a), Table 2-5, p. 2-10	*117.0*	*206.0*	

actually achieve an efficiency of 60 percent or more (Siemens May 2011). An old coal plant generates 3.25 times the carbon emissions of the most modern and efficient gas-fired combined cycle plant. Compared to coal, and to a simple cycle (SC) gas plant, gas CC is truly a low carbon alternative.

To put the difference in context, based on 2012 data for emissions from coal-fired plants and total emissions by the electricity sector (EIA December 2013a, Tables 3.1A and 9.1), if US coal-fired plants were replaced by the most efficient gas-fired plants, total carbon emissions from the electricity sector would decline by almost one half.

Capacity Factors

Other things equal, the higher the capacity factor of a new plant, the greater are avoided emissions per MW of new capacity. The emissions avoided by a new wind, solar or hydroelectric project during a given period of time depend on whether and to what extent the wind is blowing, the sun is shining, or the water is flowing. Wind, solar and hydro plants can only avoid emissions when they are producing electricity, which is only part of the time. Typically wind projects have a capacity factor between 20 percent and 40 percent (Renewable Energy Research Laboratory). Photovoltaic solar projects can have a capacity factor as low as 5.1 percent in 2011 in the United Kingdom (Department of Energy and Climate Change (UK), 2013, Chapter 6, Table 6.5) and as high as 19 percent in the state of Arizona (Apt, April 2008). Hydroelectric projects worldwide have an average capacity factor of 44 percent (Intergovernmental Panel on Climate Change, 2012, Chapter 5 Hydroelectric).

A nuclear plant typically has a much higher capacity factor—around 90 percent, far more than wind, solar, or hydro—and thus can avoid far more emissions per MW of capacity than wind, solar or hydro. Similarly, a baseload gas combined cycle plant can operate at a capacity factor around 90 percent. In this paper, we have used capacity factors for wind, solar, hydro and nuclear based on actual average U.S. capacity factors from 2003 to 2012 for each type of plant. We assume that a highly efficient combined cycle gas turbine can operate at a 92 percent capacity factor.

Table 2A gives avoided emissions for new plants based on the assumption that the new plant displaces coal-fired electricity production during off-peak hours. Table 2B gives avoided emissions for new plants based on the assumption that the new plant replaces gas CC electricity production during off-peak hours. Both tables are based on the assumption that the new plant displaces simple cycle gas turbines during peak hours.

As shown in Tables 2A and 2B, among the no-carbon energy alternatives, nuclear plants avoid the most emissions per MW of new capacity, simply because nuclear plants have far and away the highest capacity factor. However, a new gas combined cycle plant that displaces an old coal plant during off-peak hours is second only to a new nuclear plant in terms of avoiding carbon emissions per MW of new capacity and is superior to wind, solar and hydroelectric in that regard. A new solar plant avoids fewer emissions per MW of capacity than any other kind of new plant displacing an old coal plant. The reason is that a typical solar plant has a much lower capacity factor than any other kind of new plant.

Table 2A. Avoided Emissions per MW per Year Displacing Coal Off-Peak and Gas SC On-Peak					
Capacity Factor of New Plant	**Wind**	**Solar**	**Hydro**	**Nuclear**	**Gas CC**
Off-Peak (1)	26.1%	15.1%	33.9%	89.1%	91.6%
On-Peak (1)	20.0%	20.0%	100.0%	95.0%	96.0%
Full Year (2) (3)	25.5%	15.5%	39.9%	89.6%	92.0%
MWH per Year per MW of Capacity (4)					
Off-Peak	2,076.9	1,320.2	2,967.5	7,805.7	8,024.0
On-Peak	160.0	160.0	800.0	760.0	768.0
Full Year	2,236.9	1,359.6	3,496.5	7,852.8	8,059.2
Avoided Emissions/MW/Year Off-Peak (tons) (5)	2,041.6	1,297.7	2,917.1	7,672.9	7,887.5
Avoided Emissions/MW/Year On-Peak (tons) (6)	92.3	92.3	461.6	438.5	443.2
Total Avoided Emissions/MW/Year (tons)	**2,133.9**	**1,390.0**	**3,378.7**	**8,111.5**	**8,330.7**
New Plant Own Emissions/MW/Year (tons) (7)	0.0	0.0	0.0	0.0	(2,755.9)
Net Avoided Emissions/MW/Year (tons)	**2,133.9**	**1,390.0**	**3,378.7**	**8,111.5**	**5,574.8**

Footnotes:

(1) On-Peak Hours per Year = 800

(2) Average Capacity Factors 2002-2012 in US for wind solar, hydro and nuclear.
Source: EIA, Electric Power Annual 2012, Tables 1.2 and 4.2B

(3) For gas: the capacity factor attainable by operating the plant as a baseload plant.
Source: Siemens AG Press Release, 19 May 2011

(4) Capacity factors multiplied by 8760 hours per year

(5) MWH per year multiplied by avoided emissions of old coal plant from Table 1

(6) MWH per year multiplied by avoided emissions of old gas SC plant from Table 1

(7) For gas: MWH/year multiplied by avoided emissions of new gas CC plant from Table 1

Table 2B. Avoided Emissions per MW per Year Displacing Gas CC Off-Peak and Gas SC On-Peak					
	Wind	**Solar**	**Hydro**	**Nuclear**	**Gas CC**
Avoided Emissions/MW/Year Off-Peak (tons) (1)	778.7	495.0	1,112.6	2,926.6	3,008.4
Avoided Emissions/MW/Year On-Peak (tons) (2)	92.3	92.3	461.6	438.5	443.2
Total Avoided Emissions/MW/Year (tons)	**871.0**	**587.3**	**1,574.2**	**3,365.1**	**3,451.6**
New Plant Own Emissions/MW/Year (tons) (2)	0.0	0.0	0.0	0.0	(2,755.9)
Net Avoided Emissions/MW/Year (tons)	**871.0**	**587.3**	**1,574.2**	**3,365.1**	**695.7**

Footnotes:

(1) MWH per year from Table 2A multiplied by avoided emissions of old gas CC plant from Table 1

(2) From Table 2A

AVOIDED ENERGY COST

Another important benefit of a new solar, wind or hydroelectric plant is that none have any energy cost. The energy from the wind, sun or water is free. Such a new plant displaces electricity produced by fossil fuel plants that do have an energy cost. Thus in addition to avoided emissions costs, one of the main benefits of renewable energy plants is the energy cost avoided in the displacement of fossil fuel electricity production. Nuclear plants do have an energy cost. However, the energy cost of a nuclear plant is much lower than that of a fossil fuel electricity plant that it displaces. Thus a nuclear plant also creates value in terms of avoided energy cost.

The avoided energy cost of a new plant is a function of the type of fossil fuel plant that it displaces as well as the ratio of the on-peak capacity factor to the off-peak capacity factor. Except when natural gas prices are very low, as in 2012 in the United States, the energy cost of a combined cycle gas plant is greater than that of a coal plant. A simple cycle gas plant has a very high energy cost, as shown in Table 3.

Thus a new plant that displaces gas-fired electricity production will have a higher avoided energy cost than one that displaces a coal-fired plant.

Table 3. Energy Cost per MWH: Old Fossil Fuel Plants

	Gas CC	Coal	Gas SC
Fuel Cost per mmbtu average 2013 (1)	$4.33	$2.36	$4.33
Fuel Cost per MWH from Old Plant (2)	$30.53	$24.78	$46.98
Variable O&M per MWH from Old Plant (3)	$3.60	$6.24	$15.45
Total	**$34.13**	**$31.02**	**$62.43**

Footnotes:

(1) EIA (March 2014), Table 9.9.

(2) Fuel cost per MWH multiplied by the heat rate from Table 1.

(3) Variable operation and maintenance costs from EIA (April 2013a), Table 8.1.

Avoided energy costs are higher for projects that produce energy during peak periods, when system energy costs are high because of the use of simple cycle gas turbines and diesel fuel to provide for peak load power. A project that produces energy mainly during baseload periods when system energy costs are lower will have a lower avoided energy cost. For instance, a wind plant is likely to produce more energy during non-peak periods than peak periods, and thus will have a lower avoided energy cost. In contrast, it is generally assumed that solar plant production does correlate with peak energy demands, which are likely to be greater during periods of intense sunshine. Baseload nuclear, coal, and combined cycle gas plants are likely to produce more energy during on-peak periods because scheduled maintenance is normally performed during off-peak periods.

Table 4A gives net avoided energy costs for new plants based on the assumption that the new plant displaces coal-fired electricity production during off-peak hours. Table 4B gives net avoided energy cost for new plants based on the assumption that the new plant replaces gas CC electricity production during off-peak hours. Both are based on the assumption that the new plant displaces simple cycle gas turbines during peak hours.

Table 4A. Net Avoided Energy Cost/MW/Year Displacing Coal Off-Peak and Gas SC On-Peak

	Wind	Solar	Hydro	Nuclear	Gas CC
Avoided Energy Cost/MW/Year Off-Peak (1)	$64,423	$40,949	$92,047	$242,118	$248,890
Avoided Energy Cost/MW/Year On-Peak (2)	$9,989	$9,989	$49,944	$47,447	$47,947
Total Avoided Energy Cost/MW/Year	**$74,412**	**$50,938**	**$141,991**	**$289,565**	**$296,836**
New Plant Own Energy Cost/MWH					
Fuel Cost per mmbtu average Jan-Aug 2013 (3)	$0.00	$0.00	$0.00	$0.00	$4.33
Fuel Cost per MWH from New Plant (4)	$0.00	$0.00	$0.00	$7.08	$27.84
Variable O & M per MWH from New Plant (5)	$0.00	$0.00	$0.00	$2.14	$3.27
New Plant Energy Cost/MWH	**$0.00**	**$0.00**	**$0.00**	**$9.22**	**$31.11**
New Plant Own Energy Cost/MW/Year(6)	$0	$0	$0	($72,403)	($250,737)
Net Avoided Energy Cost/MW/Year	**$74,412**	**$50,938**	**$141,991**	**$217,162**	**$46,099**

Footnotes:

(1) MWH off-peak from Table 2A multiplied by energy cost/MWH for old coal plant from Table 3.

(2) MWH on-peak from Table 2A multiplied by energy cost/MWH for old gas SC plant from Table 3.

(3) EIA (March 2014), Table 9.9.

(4) Fuel cost per mmbtu multiplied by heat rate from Table 1 for fossil fuel plants.
Fuel Cost per MWH for nuclear is the average for 2012 and taken from EIA (December 2013a), Table 8.8.

(5) EIA (April 2013a), Table 1, p. 6.

(6) Energy cost/MWH of new plant multiplied by total MWH per year from Table 2A.

Table 4B. Net Avoided Energy Cost/MW/Year Displacing Gas CC Off-Peak and Gas SC On-Peak

	Wind	Solar	Hydro	Nuclear	Gas CC
Avoided Energy Cost/MW/Year Off-Peak (1)	$70,879	$45,052	$101,271	$266,381	$273,830
Avoided Energy Cost/MW/Year On-Peak (2)	$9,989	$9,989	$49,944	$47,447	$47,947
Total Avoided Energy Cost/MW/Year	**$80,868**	**$55,041**	**$151,215**	**$313,828**	**$321,777**
New Plant Own Energy Cost/MW/Year(2)	$0	$0	$0	($72,403)	($250,737)
Net Avoided Energy Cost/MW/Year	**$80,868**	**$55,041**	**$151,215**	**$241,425**	**$71,040**

Footnotes:

(1) MWH off-peak from Table 2A multiplied by energy cost/MWH for old gas CC plant from Table 3.

(2) From Table 4A

AVOIDED CAPACITY COST

Avoided capacity costs arise from the fact that a new electric power plant can reduce the need to invest in building some other type of plant to achieve the same amount of system output and same degree of system reliability.[2] Avoided capacity costs are a function of which type of plant is displaced.

Replacement and Avoided Capacity Costs

In this paper, we assume that during off-peak periods a new plant will displace either a baseload coal plant or baseload gas combined cycle plant. During on-peak it will displace a gas simple-cycle plant, which is typically used for peaking power but has a much higher energy cost than any of the low or no-carbon alternatives. Table 5 gives estimates of the capacity costs of the plants that are displaced.

We have computed the capacity costs in Table 5 by building off of the capital costs published by the EIA, which are "overnight" cost estimates that do not take account of the cost of capital during construction. We have added an estimate of the cost of capital during construction.[3] The annualized capital cost per MW is calculated using an average cost of capital of 7.5 percent and is added to the annual fixed operation and maintenance cost to obtain the full annual capacity cost per MW.

A new plant that displaces a coal plant has a much higher avoided capital cost than a new plant that displaces either gas combined cycle or gas simple cycle.

Avoided capacity costs are also a function of the capacity factor of the new plant. For example, a nuclear plant or gas combined cycle plant can replace a coal-fired baseload plant and operate at about the same

Table 5. Capacity Cost per Year per MW: New Fossil Fuel Plant

Capital Cost per Year per MW	Gas CC	Coal	Gas SC
"Overnight" Capital Cost per KW (1)	$1,023	$2,934	$676
Years for Construction (2)	2.5	4.0	1.5
Cost of Capital during Construction (3)	$130	$440	$42
Total Capital Cost	$1,153	$3,374	$718
Expected Economic Life	30	30	30
Capital Cost per Year per MW	$97,663	$285,689	$60,815
Fixed O&M Cost per Year per MW (1)	$15,370	$31,180	$7,040
Total Capacity Cost per Year per MW	**$113,033**	**$316,869**	**$67,855**

Footnotes:

(1) Energy Information Administration (April 2013a) Table 1, p.6

(2) International Energy Agency (2011), Executive Summary

(3) Weighted Average Cost of Capital = 7.5%

capacity factor as a coal-fired baseload plant. Thus each megawatt of a nuclear or gas CC plant can replace one megawatt of a coal plant and avoid the capital cost associated with a coal plant. However, a wind, solar or hydro plant can operate only at a fraction of the capacity of a coal plant. All other things equal, a wind plant that operates at a capacity factor of 30 percent can replace only a third of a megawatt of a coal plant operating at a 90 percent capacity factor.

Reliability and Avoided Capacity Costs

However, all other things are not equal. Wind, solar, and hydroelectric plants without storage are inherently less reliable, not because they are mechanically more prone to forced outages, but because the availability of wind, sun or water is highly variable. In order to maintain system reliability, additional investments in capacity are required. Thus a wind plant with a 30 percent capacity factor can actually replace only less than a third of a coal plant with a 90 percent capacity factor, if system reliability is to be maintained. In theory one can overcome the problem of variability of wind, solar and hydro with adequate storage of electricity produced during off-peak periods and released during on-peak hours. Practically, however, the technology for electricity storage is not yet developed enough to make it economical without government subsidies.

If all power plants were equally reliable, then one could calculate avoided capacity costs by taking the ratio of capacity factors between the new plant and the plant to be replaced and multiplying it by the capacity cost of the plant to be replaced. The challenge is to deduce avoided capacity costs for a new plant that is less reliable than the plant that it replaces. The capacity factors have to be adjusted to take account of differing reliability.

In this paper, we have addressed this challenge by estimating a 99 percent confidence level capacity factor (the adjusted capacity factor) for the new plant and for the plant that it replaces. For example, as shown in Table 6A, we have estimated that for a wind plant that operates off-peak on average with a 26.1 percent capacity factor, the probability is 99 percent that in any given year it will operate with a capacity factor of 20.4 percent or higher.[4] For the baseload coal plant with a 89.5 percent off-peak capacity factor that it displaces during off-peak hours, we estimate that in any given year the probability is 99 percent that the coal capacity factor will be 87.5 percent or higher. Thus a wind plant of 1 MW capacity can only replace 0.233 MW (the ratio of 20.4 to 87.5) of a baseload coal plant with the same degree of reliability each year. In other words, it takes 4.28 MW of wind capacity to produce the same amount of electricity with the same degree of reliability as 1 MW of off-peak coal plant capacity.[5] Similarly, it takes 7.30 MW of solar capacity to produce the same amount of electricity with the same degree of reliability as 1 MW of off-peak coal plant capacity.

Table 6A is based on the assumption that a new no or low-carbon plant displaces a coal baseload plant during off-peak hours. Since the capacity cost of a gas CC plant is substantially less than that of a coal plant, the avoided capacity cost is lower by a factor of two or three if gas CC rather than coal capacity is displaced, as shown in Table 6B.

The size of the investment required to maintain system reliability when a new plant replaces a baseload plant depends on a number of factors other than the variance of the capacity factor of the new plant. It depends on the degree of covariance between the capacity factor and the demand for electricity. A plant with a high capacity factor during peak periods is more capable of maintaining system reliability than a plant with a low capacity factor during peak

Table 6A. Avoided Capacity Cost: Coal Baseload Production Displaced					
Baseload	**Wind**	**Solar**	**Hydro**	**Nuclear**	**Gas CC**
Off-Peak Capacity Factor (1)	26.1%	15.1%	33.9%	89.1%	91.6%
Adjusted Capacity Factor (2)	20.4%	12.0%	28.4%	87.1%	89.6%
Coal Baseload Capacity Replaced (MW) (3)	0.233	0.137	0.325	0.996	1.024
Coal Baseload Capacity Cost Avoided (4)	$73,967	$43,404	$102,877	$315,451	$324,476
Peak Load					
On-Peak Capacity Factor (1)	20.0%	20.0%	100.0%	95.0%	96.0%
Adjusted Capacity Factor (2)	15.7%	15.9%	98.0%	93.0%	94.0%
Gas SC Capacity Replaced (MW) (5)	0.169	0.171	1.054	1.000	1.011
Less: Coal Capacity Replaced	(0.233)	(0.137)	(0.325)	(0.996)	(1.024)
Net Peak Load Capacity Avoided	(0.065)	0.034	0.729	0.004	(0.013)
Gas SC Capacity Cost Avoided (4)	($4,398)	$2,298	$49,473	$304	($899)
Total Capacity Cost Avoided	**$69,570**	**$45,702**	**$152,350**	**$315,755**	**$323,577**

Footnotes:

(1) From Table 2A

(2) Capacity factor above which the probability is 99%.

(3) The ratio of: (a) the off-peak adjusted capacity factor of the new plant to (b) the adjusted capacity factor of a baseload coal plant.

(4) Capacity costs of coal and gas SC from Table 5 times coal baseload capacity or gas SC peak load capacity replaced.

(5) The ratio of: (a) the on-peak adjusted capacity factor for the new plant to (b) the on-peak adjusted availability factor of a peak load gas SC plant.

Table 6B. Avoided Capacity Cost: Gas CC Baseload Production Displaced					
Baseload	**Wind**	**Solar**	**Hydro**	**Nuclear**	**Gas CC**
Gas CC Capacity Replaced (1)	0.228	0.134	0.317	0.972	1.000
Gas CC Baseload Capacity Cost Avoided (2)	$25,767	$15,120	$35,838	$109,889	$113,033
Peak Load					
Gas SC Capacity Replaced (MW) (3)	0.169	0.171	1.054	1.000	1.011
Less: Gas CC Capacity Replaced	(0.228)	(0.134)	(0.317)	(0.972)	(1.000)
Net Peak Load Capacity Avoided	(0.059)	0.037	0.737	0.028	0.011
Gas SC Capacity Cost Avoided (2)	($4,026)	$2,516	$49,989	$1,887	$730
Total Capacity Cost Avoided	**$21,741**	**$17,636**	**$85,827**	**$111,776**	**$113,762**

Footnotes:

(1) The ratio of: (a) the off-peak adjusted capacity factor for the new plant to (b) the off-peak adjusted capacity factor for a baseload gas CC plant.

(2) Capacity costs of gas CC and gas SC from Table 5 times coal baseload capacity replaced.

(3) The ratio of: (a) the on-peak adjusted capacity factor for the new plant to (b) the on-peak adjusted availability factor for a peak load gas SC plant.

demand. If the capacity factor during peak hours is high enough, no new investment in peaking capacity may be required, even if the new plant is less reliable than the coal plant that it displaces. For example, a hydroelectric plant that has adequate water storage capability can reliably operate close to or at a capacity factor of 100 percent during peak hours. While the year-round capacity factor of a hydro plant may be a fraction of its total capacity and highly variable, its ability to operate at a much higher and more reliable capacity factor during peak hours can enable investments in peaking capacity to be reduced rather than increased while still maintaining the same degree of system reliability. Solar plants tend to have higher capacity factors during peak hours because peak loads are more likely to occur when the sun is shining. Nuclear and gas CC have higher capacity factors during peak hours because preventative maintenance is normally performed during off-peak hours. Thus in Tables 6A and 6B, hydro, solar, nuclear and gas CC have positive avoided capacity costs associated with peak periods. Wind, which is assumed to have a lower capacity factor during peak and off-peak periods, has negative peak period avoided capacity cost.

As shown in Tables 6A and 6B, wind and solar plants have the lowest avoided capacity cost (save less in capacity cost) and nuclear and gas CC have the highest avoided capacity cost (save more in capacity cost). The main reasons why wind and solar have such low avoided capacity costs per MW is their low capacity factors and low reliability compared to nuclear and fossil fuel plants. If unadjusted capacity factors are used, it takes 3.43 MW of wind and 5.94 MW of solar capacity to produce the same output of a 1 MW of coal baseload capacity. When capacity factors are adjusted to take account of reliability, it takes 4.28 MW of wind and 7.30 MW of solar capacity to produce the same output with the same degree of reliability as 1 MW of capacity of a baseload coal plant.[6]

Another important determinant of system reliability is the degree of correlation in the capacity factor of a new plant during any given time period with the overall system availability. If there is a high degree of positive correlation between the capacity factor of a new plant and the system availability factor, then the new plant's ability to contribute to peak loads is much less than if the correlation were zero or negative. The wind or solar plant capacity factor of a new plant tends to be positively correlated with capacity factors of existing wind and solar plants in the geographic area served by an electricity system. Thus as the degree of wind and solar penetration in a system increases, new wind and solar plants contribute increasingly less to system reliability.

CAPACITY COSTS

The benefits of a new plant are the value of avoided emissions, net avoided energy cost and avoided capacity costs (or savings in emissions, energy cost and capacity cost). The costs of a new project tend to be dominated by capacity costs of the project itself. Table 7 shows the capacity cost on an annual basis per MW for each of the four types of no-carbon plant.

Table 7. Capacity Cost per MW per Year: New No-Carbon Electricity Plants				
Baseload	**Wind**	**Solar**	**Hydro**	**Nuclear**
"Overnight" Capital Cost per KW (1)	$2,213	$3,873	$2,936	$5,530
Years for Construction (2)	1.5	1.5	5.0	5.0
Cost of Capital during Construction (3)	$138	$242	$551	$1,037
Total Capital Cost	$2,351	$4,115	$3,487	$6,567
Expected Life	20	40	50	40
Annualized Capital Cost per Year per MW	$230,645	$326,737	$268,713	$521,412
Fixed O & M per Year per MW (1)	$39,550	$24,690	$14,130	$93,280
Total Annual Capacity Cost per MW	**$270,195**	**$351,427**	**$282,843**	**$614,692**
Footnotes:				
(1) Energy Information Administration (April 2013a) Table 1, p.6				
(2) International Energy Agency 2011, Executive Summary				
(3) Weighted Average Cost of Capital = 7.5%				

Nuclear plants have far and away the highest capacity cost. Gas combined cycle plants have far and away the lowest capacity cost (see Tables 5 and 7).

Much has been made about the recent rapid decline in price of solar photovoltaic (PV) panels, especially from Chinese manufacturers. The EIA has taken this decline in price into account in its 2013 capital cost estimate of a solar plant of $3,873, shown in Table 6. This represents a 22 percent decrease from the EIA 2010 estimates for PV solar plants (EIA April 2013a, Table 2, p. 7). Furthermore, the cost of PV panels as a percentage of the total 2013 capital cost estimate is less than 43 percent of the total capital cost of a solar PV plant (EIA April 2013a, p. 24-3). An additional 50 percent reduction in the current price of PV panels would result in less than a 22 percent reduction in the future total capital cost.

OTHER COSTS INCURRED

In addition to the capacity cost of a renewable energy project, wind and solar projects have additional system costs. Since both wind and energy are highly variable over time, such projects impose additional "balancing costs"—costs of balancing the periodic fluctuations with spinning reserves in order to avoid excessive voltage fluctuations. Using wind and solar also causes non-renewable energy production facilities to start up and shut down more frequently, reducing the energy efficiency of the non-renewable units and increasing the cost of repair and maintenance, known as "cycling costs." However, the effect of cycling and balancing costs is quite small. A study by Ellerman and Marcantonini (May, 2013) found that balancing costs are around 2 euros per MWH for wind. Van Bergh and others (2013) show that variability in renewable energy production adds little to the normal variability of residual electricity demand, suggesting that the cycling and balancing costs are quite modest.

Nuclear plants also have additional costs, including nuclear decommissioning, spent fuel disposal costs and disaster insurance. The average cost of decommissioning a nuclear plant is approximately $300 to $400 million according to the U.S. Nuclear Regulatory Commission (July 2013) and the cost of disposing of spent fuel is another $100 million according to the Nuclear Energy Institute (2013). On an annualized basis, this works out to an annual cost of $2,200 per MW.

According to the Nuclear Regulatory Commission (March 2012) the cost of private disaster insurance per year per MW is $830,000 per reactor. However, the Price-Anderson Act, which was renewed in 2005 for another 20 years, provides government insurance that is available once the private insurance limit of $375 million is reached. The provisions of the act amount to a government subsidy, which has been estimated by Heyes and Heyes (2000) to be in the order of $2.2 million per reactor.

Table 8 summarizes the annual other costs per MW of a new nuclear plant:

Table 8. Other Costs for Nuclear Plants	
Decommissioning and Spent Fuel Disposal	
Cost per Plant ($million) (1)	$500
MW per plant	1,000
Number of years before decommissioning and waste fuel disposal	40
Present Value of decommissioning and disposal cost per MW	$27,710
Annual cost of decommissioning and disposal per MW	($2,200)
Insurance Costs	
Average annual premium for $375 million coverage per reactor (2)	($830,000)
Annual premium per MW	($830)
Subsidy element of Price-Anderson Act per plant ($million)	$2.2
Subsidy element per MW (3)	($2,200)
Cost of Nuclear Disaster insurance per MW	($3,030)
Total Other Costs per Year per MW	**($5,230)**
Footnotes:	
(1) Nuclear Regulatory Commission (July 2013) and Nuclear Energy Institute 2013	
(2) Nuclear Regulatory Commission (March 2012)	
(3) Heyes and Heyes (2000)	

NET BENEFITS

The benefits of a new plant are the value of its avoided emissions, its avoided energy cost, and its avoided capacity costs (savings in emissions, energy cost and capacity cost). The costs of a new plant include the value of its carbon dioxide emissions, its capacity cost, its energy costs and other costs pertaining to solar, wind and nuclear. The net benefits are the difference between the two, as shown in Tables 9A and 9B.

Table 9A. Net Benefits per Year per MW: Displacement of Coal Baseload Production					
Benefits per MW per Year	**Wind**	**Solar**	**Hydro**	**Nuclear**	**Gas CC**
Avoided Emissions (1)	$106,697	$69,502	$168,934	$405,574	$416,534
Avoided Energy Cost (2)	$74,412	$50,938	$141,991	$289,565	$296,836
Avoided Capacity Cost (3)	$69,570	$45,702	$152,350	$315,755	$323,577
Costs per MW per Year:					
New Plant Emissions (1)	$0	$0	$0	$0	($137,796)
New Plant Energy Cost (2)	$0	$0	$0	($72,403)	($250,737)
Capacity Cost Incurred (3)	($270,195)	($351,427)	($282,843)	($614,692)	($113,033)
Other Costs (4) (5)	($5,816)	($3,535)	$0	($5,230)	$0
Total Net Benefits	**($25,333)**	**($188,820)**	**$180,432**	**$318,569**	**$535,382**
Footnotes:					
(1) Avoided and new plant emissions from Table 2A have been valued at $50 per ton.					
(2) Avoided and new plant energy costs are from Table 4A.					
(3) Avoided and new plant capacity costs are from Tables 6A and 7.					
(4) Other costs for nuclear are from Table 8.					
(5) Wind and solar other costs are based on Ellerman and Marcantonini (May, 2013)					

New hydroelectric, nuclear or gas combined cycle plants are much more beneficial per MW of capacity than wind or solar plants, with a gas combined cycle plant being the most beneficial.

Table 9A is based on the assumption that a new low or no-carbon plant displaces a coal plant during off-peak periods. Table 9B is based on the assumption that the new plant displaces a baseload combined cycle gas plant.

If the new plant replaces a gas CC plant rather than a coal plant, net benefits are substantially reduced. Only hydro, and a new gas combined cycle plant that replaces an old, less efficient, more emissions-intensive gas combined cycle plant, show positive net benefits. A new nuclear plant falls from second to third in the ranking by net benefits, the result of its extremely high capacity costs.

Table 9B. Net Benefits per Year per MW: Displacement of Gas CC Baseload Production					
Benefits per MW per Year	**Wind**	**Solar**	**Hydro**	**Nuclear**	**Gas CC**
Avoided Emissions (1)	$43,552	$29,365	$78,712	$168,257	$172,580
Avoided Energy Cost (2)	$80,868	$55,041	$151,215	$313,828	$321,777
Avoided Capacity Cost (3)	$21,741	$17,636	$85,827	$111,776	$113,762
Costs per MW per Year:					
New Plant Emissions (1)	$0	$0	$0	$0	($137,796)
New Plant Energy Cost (2)	$0	$0	$0	($72,403)	($250,737)
Capacity Cost Incurred (3)	($270,195)	($351,427)	($282,843)	($614,692)	($113,033)
Other Costs (4) (5)	($5,816)	($3,535)	$0	($5,230)	$0
Total Net Benefits	**($129,852)**	**($252,920)**	**$32,911**	**($98,465)**	**$106,554**
Footnotes:					
See footnotes to Table 9A substituting Tables 2B, 4B, and 6B for Tables 2A, 4A, and 6A.					

Table 9C. Net Benefits with More Favorable Assumptions for Wind and Solar					
Benefits per MW per Year	**Wind**	**Solar**	**Hydro**	**Nuclear**	**Gas CC**
Avoided Emissions (1)	$284,526	$185,338	$337,867	$811,148	$833,069
Avoided Energy Cost (2)	$98,925	$67,732	$141,680	$288,746	$295,994
Avoided Capacity Cost (3)	$70,482	$46,425	$116,816	$240,284	$246,215
Costs per MW per Year:					
New Plant Emissions (1)	$0	$0	$0	$0	($275,592)
New Plant Energy Cost (2)	$0	$0	$0	($72,403)	($250,737)
Capacity Cost Incurred (3)	($162,867)	($181,434)	($195,058)	($455,843)	($87,574)
Other Costs (4) (5)	($7,755)	($4,713)	$0	($7,169)	$0
Total Net Benefits	**$283,311**	**$113,349**	**$401,306**	**$804,763**	**$761,375**
Footnotes:					
(1) Avoided emissions from Table 3 have been valued at $100 per ton.					
(2) Wind and solar other costs are based on Ellerman and Marcantonini (May, 2013)					

The results shown in Tables 9A and 9B are very robust if we change some key assumptions to favor wind and solar. For example, if we increase the price of carbon to $100 per ton, reduce the cost of capital to 5 percent, and reduce the capital cost and increase the capacity factor of solar and wind by one-third, we get the results shown in Table 9C.

A new nuclear plant becomes the most favored alternative. Wind and solar continue to rank fourth and fifth among all the alternatives, mainly because of the very high capacity cost and the very low capacity factors. Furthermore, capacity factors in the United States are much higher than those in some other countries, suggesting that in those countries wind and solar are even less economical. For example, in Germany the average capacity factors for wind and solar between 2006 and 2010 were 18 percent and 8.1 percent, respectively, compared to 25.5 percent and 15.5 percent, respectively, in the United States (Federal Ministry for the Environment Nature Conservation and Nuclear Safety (Germany) 2012). In the U.K., wind capacity factors are about the same as in the United States, but the average capacity factor for solar between 2008 and 2012 was only 8.3 percent, little more than half of that in the United States (Department of Energy and Climate Change (UK), Chapter 6, Table 6.4).

DISPLACEMENT OF BASELOAD PRODUCTION

The net benefits of the various technologies are very sensitive as to whether a new plant displaces a coal plant or a gas CC plant. If a coal plant is shut down, the avoided emissions and the avoided capacity costs are greater than if a gas plant is shut down. The avoided energy costs are less, but the value of the avoided emissions and the avoided capacity costs outweigh the energy cost benefits.

The decision as to whether to shut down or reduce the output of a coal plant or a gas plant depends on the price of natural gas relative to the price of coal and the price attached to carbon dioxide emissions. The decision also has a short-term and a long-term dimension. A new plant may replace gas-fired production in the short term and coal-fired production in the longer term. In the short term, the choice between coal-fired or gas-fired production is based on short-term marginal cost, or the cost of producing energy from an existing plant, the costs of which have already been incurred. In the longer term, the choice between an investment in a coal plant or a gas plant is governed by relative total cost, both capacity cost and energy cost.

Break-even Carbon Price in the Short Term

Net benefits in the short term depend on how various plants within the system are chosen to be utilized, or dispatched. Whether the dispatch system is "command and control" or is determined by market supply and demand for electricity, the dispatch of a particular plant depends on the energy cost of electricity produced by the plant (where the energy cost is the sum of the fuel cost per MWH plus variable operation and maintenance cost per MWH). Wind, solar and hydro plants have zero energy cost per MWH and therefore are always likely to be dispatched, provided the wind is blowing, the sun is shining or the water is flowing. Nuclear plants have always had energy costs much lower than those of fossil-fuel plants. Therefore a nuclear plant is also always likely to be dispatched. In recent years, nuclear plants have been running at a capacity factor of about 90 percent (EIA 2009, Table 5.2, p. 148). Thus variations in the demand for electricity typically have been met by variations in the dispatch of fossil-fuel plants, not wind, solar, hydro, or nuclear plants that are likely already to be utilized.

What matters most is which kind of fossil fuel plant is dispatched—one powered by coal or one powered by natural gas. Historically gas prices per Btu have been much higher than coal prices. Thus a coal plant has been more likely to be dispatched than a gas-fired plant. Under these circumstances, a new electricity plant is less likely displace a high carbon emission coal plant and more likely to displace a much lower carbon emission gas CC plant. This perverse result from an emissions standpoint can be remedied by a carbon tax or a price for carbon emission allowances as shown in Table 10A.

Without any cost of carbon emissions, and a natural gas price of $3.40 per million Btu as in the United States in 2012, the energy cost per MWH of a gas CC plant ($27.57) is less than that of coal ($31.02). However, the gas price in the United States in 2012 was atypically low. At higher gas prices in the United States, the U.K., Germany and Japan, the energy cost of a coal plant is much lower than that of a gas CC plant. Thus most typically the energy cost of coal is less than that of gas and a new low-carbon plant will normally replace a gas CC plant. However, if a price is attached to carbon dioxide emissions, the energy

Table 10A. Short-term Break-even Carbon Price: Sensitivity to Natural Gas Prices						
	Gas Price	Energy Cost/MWH		CO_2	Adjusted Energy Cost	
	Mmbtu	Gas CC	Coal	Price/Ton	Gas CC	Coal
United States 2012 (1)	$3.40	$27.57	$31.02	$0.00	$27.57	$31.02
United States 2013 (1)	$4.33	$34.13	$31.02	$5.11	$36.04	$36.04
UK Heren NPB Index 2012 (2)	$9.46	$70.29	$31.02	$64.59	$94.51	$94.51
German Import Price 2012 (2)	$11.08	$81.71	$31.02	$83.37	$112.97	$112.97
Japan cif 2012 (2)	$16.75	$121.69	$31.02	$149.11	$177.59	$177.59
Footnotes:						
(1) Gas prices paid by U.S. utilities, EIA (March 2014), Table 9.9.						
(2) BP 2013, p.27						

cost of coal, adjusted to take account of the CO_2 price, will be greater than that of gas and a new plant will replace a coal-fired baseload plant. For example, at a carbon price greater than $64.59 in the U.K., a new plant would displace a coal plant in the short term as shown Table 10A.

Break-even Carbon Price in the Longer Term

Net benefits in the longer term depend on whether the new low-carbon plant displaces investment in new coal-fired plants or investment in new gas-fired plants. In the short term the choice between a gas CC plant and a coal plant depends on relative energy cost. In the longer term the investment decision depends on relative total cost—both the capacity cost and the energy cost.

The longer-term break-even carbon price is much lower than the short-term break-even price. For example, the U.K. short-term break-even price is $64.59 (Table 10A), while its long-term break-even price is only $11.97 (Table 10B). This is because the capacity cost of a coal plant is much higher than the capacity cost of a gas CC plant, making the coal plant more costly as a long-term investment decision than as a short-term dispatch decision.

Table 10B. Longer Term Break-even Carbon Price: Sensitivity to Natural Gas Prices				
	Gas Price	Carbon	Total Cost/MWH	
	Mmbtu	Price/Ton	Gas CC	Coal
United States 2012 (1)	$3.40	$0.00	$39.16	$65.43
United States 2013 (1)	$4.33	$0.00	$45.14	$65.43
UK Heren NPB Index 2012 (2)	$9.46	$11.97	$87.13	$87.13
German Import Price 2012 (2)	$11.08	$21.79	$104.93	$104.93
Japan cif 2012 (2)	$16.75	$56.18	$167.26	$167.26
Footnotes:				
See footnotes to Table 10A				

Sensitivity to Carbon Prices

In Tables 9A and 9B, the net benefits for both wind and solar are negative. However, if the carbon price is increased from $50 to $61.87 or above, then the net benefits of wind are positive (as shown in Table 11). Above $185.84, the net benefits of solar are also positive. This result is broadly consistent with the results of Marcantonini and Ellerman (2013) for Germany. They estimated that for 2006-2010 the cost of CO_2 emission abatement for wind was 43 euros higher and for solar 537 euros higher than the European Trading System carbon price. Solar is less economical in Germany than in the United States as German capacity factors are well below those in the United States.

Table 11. Sensitivity of Net Benefits to Carbon Dioxide Prices (1)					
CO_2	Net Benefits of:				
Price	Wind	Solar	Hydro	Nuclear	Gas CC
$50.00	($25,333)	($188,820)	$180,432	$318,569	$535,382
$61.87	$0	($172,318)	$220,541	$414,863	$601,562
$185.84	$264,539	$0	$639,385	$1,420,420	$1,292,650
Footnotes:					
(1) Displacement of Coal-Fired Baseload Plants and Gas Price of $4.33/mmbtu					

Sensitivity to Natural Gas Prices

The results in Tables 9A and 9B are highly sensitive to natural gas prices, which have been highly variable, both over time and geographically. In the United States, the average annual cost of natural gas to electricity producers reached a high of $9.01 per million Btu in 2008. The average monthly cost reached a low of $2.68 in April 2012 (EIA, November 2013, Table 9.10.). The variation among countries, and the effect on net benefits, is illustrated in Table 12.

At any price of natural gas below $16 per million Btu, wind and solar rank fourth and fifth among the five alternatives. At the Japanese price of $16.75, however, natural gas CC ranks fourth. Regardless of the price of natural gas, nuclear and hydro rank above wind and solar and the net benefits of solar power are even negative.

Table 12. Sensitivity of Net Benefits to Natural Gas Prices (1)						
	Gas	Net Benefits				
	Price (2)	Wind	Solar	Hydro	Nuclear	Gas CC
United States Henry Hub	$2.76	($28,058)	($191,546)	$166,804	$305,623	$603,658
UK Heren NPB Index	$9.46	($16,427)	($179,914)	$224,960	$360,871	$312,289
German Import Price	$11.08	($13,615)	($177,102)	$239,022	$374,229	$241,839
Japan cif	$16.75	($3,772)	($167,259)	$288,237	$420,984	($4,737)
Footnotes:						
(1) Displacement of Coal-Fired Baseload Plants and $50 CO_2 Price *(2) 2012 average prices: BP 2013, p.27*						

IMPLICATIONS FOR CO_2 EMISSION REDUCTION POLICIES

Governments in both Europe and the United States have instituted CO_2 emission reduction policies of three different types. First, they have adopted a wide variety of renewable energy incentives such as feed-in tariffs, production and investment tax credits, grants and loan subsidies for renewable energy projects, renewable energy targets, and tradable renewable energy certificates. Second, they have introduced carbon trading systems designed to produce a market-driven price for carbon dioxide emissions based on government imposed emissions targets. Third, they have instituted, or are in the process of instituting, tighter regulations on emissions standards for coal-fired generating plants.

Renewable Incentives

Renewable incentives in the United States and Europe are available for wind, solar, small-scale hydro, biomass and other renewable energy sources. Generally, no incentive policies are available for other low or no-carbon alternatives such as nuclear, large-scale hydro, or gas combined cycle. Yet the results of this paper demonstrate clearly that these three alternatives (assuming the price of gas is $16 per million Btu or less) are far more cost effective per MW of capacity in reducing carbon dioxide emissions than wind or solar. In both the United States and Europe, there is political opposition to all three of these alternatives on environmental and safety grounds, despite their superiority in reducing carbon dioxide emissions.

Renewable incentives in both Europe and the United States rarely, if at all, make distinctions among renewable projects based on avoided emissions. For example, auction awards for feed-in tariffs could be based not just on cost but on cost less the value of avoided emissions. Renewable Energy Certificates could be granted not on the basis of MWH produced but on the basis of avoided carbon dioxide emissions. These incentive programs would then become more effective in reducing carbon emissions.

Carbon Trading Systems

There are two generally recognized methods of introducing a price for carbon dioxide emissions: (1) a carbon tax, and (2) a cap-and-trade system for enforcing carbon dioxide emissions reduction targets. There is relatively little support for a carbon tax in both Europe and the United States. The European Union has established a European Trading System for carbon dioxide emission permits. In the United States, there has been little progress in establishing a country-wide carbon emission trading system, but a group of states in New England and the state of California have been successful in establishing regional carbon emission trading systems.

The price of carbon emissions on the European Trading system (ETS) reached a peak of 30 euros in 2006 and was trading below 5 euros at the end of 2013, far too low to make gas production more profitable than coal production of electricity. The reduction in the ETS carbon emissions price, along with increases in the price of natural gas in Europe, has made coal more attractive as an energy source. The experience in the U.K. reflects this trend. Between 2009 and 2012, U.K. natural gas prices almost doubled (BP 2013, p. 27). Between 2011 and 2012 alone, the natural gas share of electricity production fell from 40 percent to 28 percent, and the coal-fired share increased from 30 percent to 39 percent. As a result, carbon dioxide emissions from the power generation sector in the U.K. increased by 7.62 percent, despite the economic recession and despite increased renewable energy production (Department of Energy and Climate Change 2013, Table 5.1.2 and Department of Energy and Climate Change, March 28, 2013, Table 17).

The need for a carbon price in the United States has been less than in Europe in part because of lower natural gas prices in the United States. Between 2008 and 2012 U.S. natural gas prices decreased by 68.9 percent; coal production decreased from 48.2 percent to 37.4 percent; gas production increased from 21.4 percent to 30.3 percent; and emissions from the electricity sector declined by 13.2 percent (BP 2013, p. 27 and EIA 2013a, Tables 3.1A and 9.1). The increase in natural gas prices in 2013 and 2014, however, makes gas less attractive than coal as a baseload production alternative and could put an end to the increasing share of natural gas in U.S. electricity production.

Prices in the California carbon market in 2013, its first year of operation, ranged between $12 and $20, enough to make natural gas more attractive than coal, at least in California. Prices in the Regional Greenhouse Gas Initiative (RGGI) carbon market, however, have been consistently lower, less than or a little more than $3 a ton since the first carbon allowance auction in September 2008. However, in January 2014, RGGI announced a 45 percent reduction in the target emissions level for 2014 to 91 million tons and further annual reductions of 2.5 percent a year until 2020, all of which should substantially increase future RGGI auction prices. If gas prices in the United States continue to increase, higher carbon prices will be necessary to keep carbon emissions from rising in the RGGI region and California.

Tighter regulations

The United States has failed to adopt a national carbon emissions trading system because of political opposition in the U.S. Congress. However, the U.S. Environmental Protection Agency (EPA) has been formulating tougher regulations under the Clean Air Act of 1990, affecting mainly coal-fired electric generating plants.

Some of the new regulations do not directly affect the carbon dioxide emissions of fossil fuel plants, but will increase the cost of electricity produced by coal-fired plants. These new proposed regulations include those that would reinstate EPA control of interstate sulfur dioxide and nitrous oxide emissions, after the U.S. Supreme Court in April 2014 overruled the earlier decision of the U.S. Circuit Court of Appeals for the District of Columbia that held such regulations to be unconstitutional. Other regulations would include standards for mercury and other air toxics; waste water quality; and disposal of coal ash. The proposed regulations would, in effect, have some of the same impact on coal-fired plants as a carbon price (Beasley and Morris, 2012).

On January 8, 2014, the EPA published in the U.S. Federal Register a new set of much more radical proposed regulations, directly aimed at establishing new standards for carbon dioxide emissions from new fossil-fuel fired electricity generating plants. The new standards would require that new coal plants emit no more than 1,100 pounds of CO_2 per MWH and new large gas combined cycle plants to emit no more than 1,000 pounds of CO_2 per MWH. New combined cycle gas plants can easily meet the new proposed standard (as shown in Table 1). New coal plants, however, cannot possibly meet the new standard without investments in carbon capture and sequestration (CCS).

CCS is very costly according to EIA cost estimates—the capital cost of a coal CCS plant is 60 percent greater and its fuel efficiency more than 33 percent less than a conventional advanced pulverized coal plant, excluding the cost of sequestration. The technology is unproven. If the CO_2 captured is close to an oil field being exploited using enhance oil recovery techniques, then captured carbon has a ready use. Without nearby enhanced oil recovery, the CO_2 must be sequestered in very deep geologic formations with specific characteristics. There is no certainty that the CO_2 from these formations will not eventually leak into the atmosphere. The transportation of the captured CO_2 to such geologic formations requires new pipelines that are expensive and difficult to permit. As a practical matter, the implementation of the new proposed EPA regulations would result in very few new coal-fired electricity generation plants.

It is likely to be far less costly to achieve reductions in carbon dioxide emissions through an effective carbon trading system that allows the market to determine the most effective way to reduce emissions rather than through establishment of EPA standards for emissions. For example, a new coal plant with 38.8 percent efficiency that replaces an old coal plant with 32.5 percent efficiency generates more avoided emissions per MW per year than a solar plant, and more net benefits than either solar or wind when the carbon dioxide emission price is $50. The new proposed EPA regulations would exclude this option from the electricity portfolio mix.

SUMMARY AND CONCLUSIONS

Assuming that reductions in carbon dioxide emissions are valued at $50 per metric ton and the price of natural gas is not much greater than $16 per million Btu, the net benefits of new nuclear, hydro, and natural gas combined cycle plants far outweigh the net benefits of new wind or solar plants. Wind and solar power are very costly from a social perspective because of their very high capacity cost, their very low capacity factors, and their lack of reliability.

For example, adjusting U.S. solar and wind capacity factors to take account of lack of reliability, we estimate that it would take 7.30 MW of solar capacity, costing roughly four times as much per MW to produce the same electrical output with the same degree of reliability as a baseload gas combined cycle plant. It requires an investment of approximately $29 million in utility-scale solar capacity to produce the same output with the same reliability as a $1 million investment in gas combined cycle. Reductions in the price of solar photovoltaic panels have reduced costs for utility-scale solar plants, but photovoltaic panels account for only a fraction of the cost of a solar plant. Thus such price reductions are unlikely to make solar power competitive with other electricity technologies without government subsidies.

Wind plants are far more economical in reducing emissions than solar plants, but much less economical than hydro, nuclear and gas combined cycle plants. Wind plants can operate at a capacity factor of 30 percent or more and cost about twice as much per MW to build as a gas combined cycle plant. Taking account of the lack of wind reliability, it takes an investment of approximately $10 million in wind plants to produce the same amount of electricity with the same reliability as a $1 million investment in gas combined cycle plants.

Renewable incentives work best if electricity producers face an internalized price for natural gas emissions sufficiently high to discourage the use of coal both for short-term and longer-term investment horizons. Since a highly efficient gas combined cycle plant produces one-third of the emissions of a coal plant per MWH, replacement of coal-fired production by gas-fired plants can substantially reduce carbon dioxide emissions. However, carbon dioxide emissions prices are too low in both Europe and in the Regional Greenhouse Gas Initiative in the United States to encourage the use of natural gas rather than coal. As a result, for example, coal-fired electricity production and emissions have increased in the U.K., despite substantial reliance on renewable incentives.

Increasing regulation by the U.S. Environmental Protection Agency of mercury, sulfur dioxide and nitrous oxide emissions, waste water disposal, and ash disposal will increase the cost of operating coal plants. This regulation, combined with direct regulation of carbon dioxide emissions from new and existing coal-fired plants, as proposed or contemplated by the EPA, can have some of the same effects as an internalized carbon price. However, a carbon dioxide emissions trading system with effective limits and adequate carbon prices is likely to be much less costly to electricity producers and consumers than direct regulation of carbon dioxide emissions.

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ENDNOTES

1. It is sometimes difficult to think of avoided costs as a benefit. It may be easier to think of "avoided" emissions, energy costs and capacity costs as "savings" in emissions, energy costs, and capacity costs.
2. There exists an extensive literature on the capacity credit for a new solar or wind plant (Garver 1966, Lannoye et al 2007, Milligan and Parsons 2007, Milligan and Porter 2008). The capacity credit is estimated using a model of the electrical system to calculate an expected load carrying capacity (ELCC). The new solar or wind capacity allows some increase in the load on the system without any decrease in reliability. The capacity credit is the ratio of the allowed increase in system load to the name-plate capacity of the new plant.
3. We assume that the capital costs are incurred on a straight-line basis, that is, the portion of the capital cost incurred each month during construction is the same each month.
4. To calculate the adjusted capacity factors for wind, solar and off-peak hydroelectric technologies, we first calculated the mean and variance in annual capacity factors using 10 years of data from the EIA. With the estimates of mean and variance, we were able to calculate the parameters required to make an estimate of the 99 percent confidence level using a Beta distribution. The Beta probability distribution was used rather than the normal distribution because the Beta distribution is for random variables that are restricted between zero and one. For a discussion of the properties and application of the Beta distribution see Gupta (2004). Ideally, estimates of the 99 percent confidence level capacity factors should be based on the variance of capacity factors over a much shorter period than a year—hourly or less. The variance would be greater for wind, solar and hydro and the avoided capacity costs would be lower if shorter time periods were used to make the estimates. However, we do not have access to such short-term data.
5. The calculations for on-peak avoided capacity costs are slightly different than those for off-peak avoided capacity costs. Instead of using the ratio of the adjusted capacity factor of the new plant to the adjusted capacity factor for an on-peak gas simple cycle plant, we use the ratio of the adjusted capacity factor of the new plant to the estimated adjusted availability factor of the on-peak gas simple cycle plant. An on-peak gas simple cycle plant is valuable not because of the electrical energy that it actually produces, but because of its availability to produce power to meet peak-loads when needed.
6. The cost of the lack of reliability for wind and solar is probably underestimated here. As noted in footnote 5 above, the data used to calculate the variance in wind and solar capacity factors is not fine enough and better data is likely to increase the estimated variance. Furthermore, more work needs to be done in estimating 99 percent confidence level capacity factors for nuclear and fossil fuel plants. Our estimates here are based on the author's experience in financing power plants but are not backed up by hard data. If anything the author believes that better data would increase the adjusted capacity factors for nuclear and fossil fuel plants.

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