

WIND AND SOLAR ELECTRICITY: CHALLENGES AND OPPORTUNITIES

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Prepared for the Pew Center on Global Climate Change

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Executive Summary

Electricity production is responsible for one third of total U.S. greenhouse gas (GHG) emissions. Therefore, the considerable reductions in U.S. GHG emissions necessary to address climate change can only be achieved through a significant shift to low- and zero-carbon sources of electricity, including renewable sources. Renewable sources currently provide only a small fraction of U.S. electricity (eight percent total including conventional hydropower; two percent excluding hydro). In the absence of significant new policies to promote renewable energy or policies that put a price on carbon, a “business-as-usual” forecast suggests that renewables will supply 14 percent of U.S. electricity by 2030, with non-hydro renewables providing only 6 percent.

This paper focuses on wind and solar as energy sources for electricity production since they have enormous resource potential, are accessible with existing technologies, are the focus of numerous current and proposed policies, and face similar challenges to widespread deployment. The three major barriers to greater use of solar and wind electricity are higher costs than many alternative electricity sources, insufficient transmission, and management of the variable electricity output from these sources.

Electricity from wind is close to cost competitive with electricity produced from natural gas—depending on natural gas prices, the availability of production tax credits, and other variables. Moreover, wind becomes more cost competitive if policies, such as cap and trade, put a price on carbon. Electricity from solar photovoltaic (PV) and concentrating solar power (CSP) power plants is significantly more expensive. These solar technologies will not achieve significant market penetration unless costs drop significantly or policies either subsidize or mandate use of these technologies. Some solar power cost reductions will occur with economies of scale in production and learning curve effects; however, breakthroughs are needed in PV cell production methods in order to allow for high-volume, low-cost PV manufacturing. Reasonably priced solar electricity could revolutionize the electricity system; however, given the enormous wind resource, other renewable energy options, and the well-documented technical and economic potential for end-use efficiency gains, the United States could reach high levels of renewable penetration even without significant solar energy deployment.

Wind power plants must be located where the wind resource is sufficient, which may be far from existing transmission lines or population centers. Significant increases in new wind electricity generation will require new transmission lines. Transmission lines are expensive to build (two to four million dollars per mile), difficult to site, and require approvals from multiple levels of government. Promising directions for addressing these problems include innovative financing approaches that clarify who pays and how much, consideration of non-wires options such as distributed storage that can reduce the need for transmission, and clarification of federal and state roles in transmission planning and siting authority.

Wind and solar power plants, unlike coal and natural gas power plants, cannot be scheduled to deliver specified amounts of power at specified times. Instead, wind and solar power plants generate electricity when the energy resources—the wind and sun—are available. Many electricity system operators see this variability as a threat to system stability and reliability. However, several electricity systems are already operating with over 10 percent of their electricity coming from wind electricity. Recent analyses suggest that 20 percent is achievable without threatening system reliability, although the added variability does impose costs.

There are three fundamental solutions to the variability challenge. The first is increasing the flexibility of electricity supply options. This includes greater use of power plants that can rapidly adjust their output as needed and contractual relationships with neighboring electricity systems for trading of electricity as needed. The second is demand flexibility—using pricing and other contractual tools to influence or control the demand for electricity. The third is physical storage of electricity and use of that stored electricity to “smooth” the output of variable electricity sources. Several physical storage technologies are under development, but costs are high and technical performance is uncertain.

Congress is considering proposals to require higher levels of renewable generation, and numerous organizations have proposed aggressive renewable generation targets. Achieving much higher levels of wind electricity, such as 20 percent by 2030 compared to less than two percent currently, would be challenging but not unachievable. It would require annual wind turbine installations at a rate about double that achieved by the wind industry in 2008. There appear to be no fundamental material, manufacturing, or labor barriers to achieving this.

Twenty percent wind by 2030 would require additional transmission spending of \$3 to \$4 billion per year, about a 40 to 50 percent increase over current transmission spending. If these costs were included in the costs of the electricity produced from wind, wind costs would need to increase by about 15 percent.

Studies suggest that the U.S. electricity grid can manage 20 percent wind penetration, although there would be costs for doing so. These costs would add four to six percent to the cost of wind electricity.

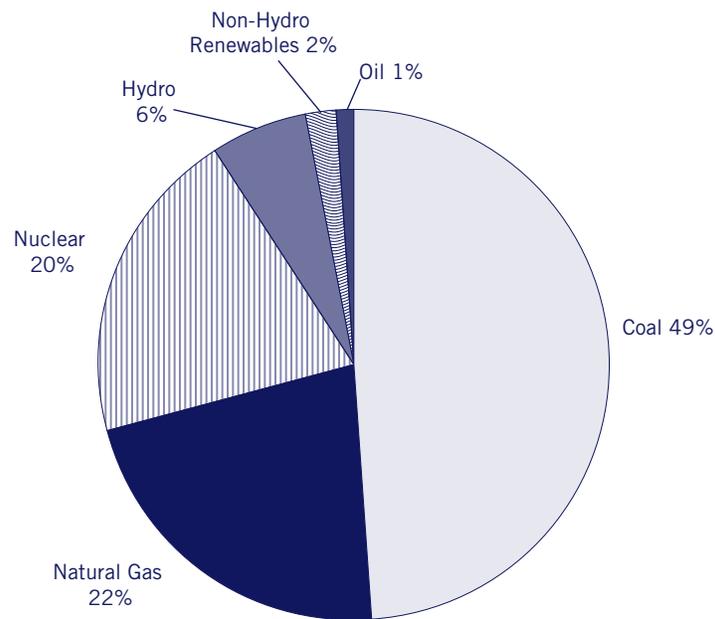
These cost estimates are uncertain, but the available evidence suggests that transmission and variability management would increase the cost of wind electricity by roughly 20 percent. This would make wind electricity generally more expensive than that from natural gas, but in many cases still less expensive than that from new nuclear or coal with carbon capture and storage (CCS) power plants. However, the relative cost of wind power and electricity from natural gas will vary with natural gas prices and with a price on carbon.

Achieving higher penetration of solar power presents different challenges. One percent solar by 2030, for example, would require annual solar installations of about 900 megawatt (MW)—two to three times higher than that seen in 2008. This would be challenging if done as PV, but possible with CSP since large (100 + MW) CSP plants have been proposed for the southwestern United States. The major challenge for PV and CSP is the first costs of the technologies themselves, which are much higher for solar than for wind.

I. Renewables' Promise and Problems

*Electricity production accounts for one-third of U.S. greenhouse gas emissions.*¹ This is because almost three quarters of electricity produced in the United States comes from fossil fuels—primarily coal and natural gas (Figure 1). These fossil fuels, particularly coal, have high “carbon intensities,” which means that they emit a large amount of carbon dioxide per unit of electricity produced.

Figure 1: U.S. electricity production (TWh/yr) by energy source, 2007 (actual)



2007 (Actual) 4,137 TWh/yr

Note: TWh/yr = terawatt-hours per year

Source: DOE, March 2009²

The U.S. electricity production system faces numerous challenges. Electricity demand continues to grow, yet building new coal-fueled power plants that do not control GHG emissions is expensive, controversial, and financially risky due largely to uncertainty over future climate policy. Increasing the use of natural gas for electricity production could increase the cost of natural gas for industrial and residential use, may be financially risky due to the volatility of natural gas prices, and raises concerns about increased dependence on imported fuels.³ Furthermore, while natural gas is a less carbon-intensive fuel than coal, increased reliance on natural

gas alone is not nearly sufficient to achieve the GHG emission reductions needed from the electric power sector to address climate change.⁴ Renewables are one of a portfolio of very low or zero-carbon technologies—which could include nuclear power, carbon capture and storage, and energy efficiency—that together can significantly reduce GHG emissions.

A. Why Renewables?

Renewable energy, including wind and solar electricity, offers several benefits compared to fossil-fueled electricity generation.

- **Zero-Carbon Electricity:** Wind and solar, in contrast to fossil fuels, produce no direct GHG emissions and, thus, offer the promise of zero-carbon electricity generation and a significant role in reducing GHG emissions to avoid climate change.⁵
- **Other Environmental Benefits:** Wind and solar avoid many non-climate-related environmental impacts associated with fossil-fueled electricity. They have no direct air emissions, they do not use large amounts of water,⁶ and they do not require environmentally degrading fuel extraction.
- **Fuel Diversification/Energy Security:** Renewable electricity generation makes the electricity generation system less reliant on coal and natural gas and thus less exposed to volatility in domestic and global fuel markets.
- **Economic Development:** Many supporters of renewable energy highlight the potential for job creation from investing in more renewable electricity generation.⁷

Although renewables, with the exception of hydropower, currently play a minor role in the U.S. electricity supply (see Figure 1), supporters have long argued that the United States can and should make a rapid transition to greater use of renewables.

This report focuses on wind and solar technologies as they have a very large remaining resource potential, are commercially available and technically proven, and are the focus of considerable policy attention.

B. Barriers to Increased Wind and Solar Electricity Generation

Given that renewables have clear environmental advantages over fossil fuels, what is holding renewables back?

It is useful to first point out factors that are *not* barriers. The United States is not significantly constrained by the technical potential of the renewable resources themselves. By one estimate, for example, the United States has more than 8,000 gigawatts (GW) of available on-shore wind power potential resource, compared to a current total U.S. electricity generating capacity of about 1,000 GW.⁸ Potential solar resources are similarly massive. In theory, solar panels covering less than 10 percent of Colorado, for example, could provide enough electricity to power the entire United States.⁹ Commercially available technologies exist that convert renewable

resources into electricity. Many of these technologies are widely available, reliable, and technically proven; although they are not necessarily cost-effective at this time (see discussion below).

The barriers are, rather, related to what can broadly be called “implementation.” Specifically, they include:

- **High costs:** Solar photovoltaic (PV) and concentrating solar power (CSP) generating plants, for example, produce electricity at costs significantly higher than for electricity produced from wind or fossil-fueled power plants.
- **Transmission:** Transmission lines carry electricity from power plants to cities, industry, and other locations where it is needed. As explained below, utility-scale wind and solar power plants are often located more remotely than fossil-fueled plants. Therefore, they require construction of new, expensive, and controversial transmission lines—and this has proven very difficult.
- **Variability/intermittency:** The wind and the sun are variable resources, meaning that their availability as an energy source fluctuates due to weather patterns, clouds, and cycles of day and night. The electricity output from power plants dependent on these variable resources varies accordingly. The demand for electricity, however, does not follow the same pattern. In the case of wind electricity, electricity generation is sometimes greatest at night when electricity demand is lowest.

There are other barriers as well, including siting and permitting challenges for the renewable power plants themselves and for the transmission lines that connect them to the grid, higher perceived technical risk, high ratio of capital to operating costs, and policy uncertainty. However, the three barriers noted above—higher costs, the need for new transmission capacity, and variability of output—are currently the most significant and thus are the focus of this report.

II. Wind and Solar Electricity Generating Technologies

Wind and solar are quite different in terms of current market penetration and costs (Table 1). This section summarizes the current status, costs, and challenges for wind and for two distinct solar technologies: photovoltaics (PV) and concentrating solar power (CSP).

Table 1: Wind and solar technology summary, plus natural gas for comparison

Technology	U.S. capacity, 2007 (GW)	U.S. generation, 2007 (TWh/yr)	Representative cost (LCOE, in ¢/kWh) *	Challenges/constraints
Wind	16	32	9-12	Variability, Transmission access
Concentrating Solar	<1	<1	24-29	High price, Variability, Transmission access
Utility-Scale Solar Photovoltaic (20 MW+)	<1	<1	28-42	High price, Variability, Transmission access
Distributed Solar Photovoltaic (< 10 kW)	<1	<1	46-59	High price, Variability
Natural Gas	395	685	5-10	Fuel price volatility, Carbon emissions

* The approximate levelized cost of electricity based on electricity generated from a new plant built today. Does not include/reflect the production tax credit (PTC) or investment tax credit (ITC). See *Box: Measuring and Comparing Costs of Electricity Production* and *Appendix 1: Cost Assumptions and Calculations* for details.

Notes: TWh/yr = terawatt-hours per year. ¢/kWh = cents per kilowatt-hour. LCOE = levelized cost of electricity.

Sources: Generation and capacity from U.S. Department of Energy (DOE).¹⁰ Cost assumptions detailed in Appendix 1.

Measuring and Comparing Costs of Electricity Production

There are many ways to measure costs; all are imperfect. This report defines cost of electricity production as the “levelized cost of electricity” (LCOE), in units of cents per kilowatt-hour (¢/kWh). This can be thought of as a price per kWh that covers both the first costs of the technology itself, as well as the ongoing fuel as well as operations and maintenance (O&M) costs of keeping the technology operating. As such, it allows for direct comparisons across generating technologies. This report excludes from the LCOE calculation the many “soft” costs that typically vary dramatically by project, such as land acquisition and permitting costs. Also excluded are subsidies such as the production tax credit (PTC) or the investment tax credit (ITC), as they are policy-dependent and distort cost comparisons. Finally, excluded as well are the costs of new transmission that might be needed to accommodate the plant, as well as any variability-related costs the plant might impose on the electricity system. (These costs however are estimated separately; see discussion below).

LCOE is a useful metric that allows for comparisons across generating technologies. It does however need to be used carefully, as it is not a direct measure of “value.” For example, a kWh from a natural gas plant might be perceived as having greater value to the electricity system than a kWh from a wind turbine because it is dispatchable—able to be turned on and off as needed. Similarly, a kWh from a wind turbine may be seen as more valuable as there is no CO₂ resulting from the generation of that kWh.

The specific assumptions and calculations for the LCOE estimates shown in Table 1 are detailed in *Appendix 1: Cost Assumptions and Calculations*.

A. Wind Electricity

In recent years, wind electricity has seen a phenomenal boom. In 2008 alone, 8.5 GW of wind power were installed in the United States, representing a 50 percent increase in U.S. wind capacity.¹¹ After many years in which the technical and environmental promise of wind clearly exceeded the commercial reality, wind has turned the corner and is now a commercially proven, reliable, and cost-competitive option¹² for producing utility-scale electricity.

Large wind turbines typically start producing electricity when wind speeds reach about nine miles per hour (mph) (four meters per second [m/s]) and reach their rated output at wind speeds of about 33 mph (15 m/s). Therefore, any area with sustained wind speeds of greater than 10 to 15 mph may be able to support a wind turbine. Such sites are surprisingly prevalent. Currently, 35 of the 50 U.S. states have installed utility-scale wind turbines.¹³

The 25 GW of currently installed (end of 2008) wind capacity in the United States exploits a trivial fraction of the total U.S. wind resource. A U.S. Department of Energy study¹⁴ estimates that the United States has the technical potential for 8,000 GW of onshore wind and 4,000 GW of offshore wind.¹⁵ Just 12 percent of this would provide enough electricity to meet the entire U.S. electricity demand.¹⁶

1. Wind Electricity Costs

How much does wind electricity cost? This report estimates the cost of wind electricity, excluding the production tax credit (PTC),¹⁷ at nine to 12 ¢/kWh (see Table 1 and Box: *Measuring and Comparing Costs of Electricity Production*). It is critical to note that this price is “typical” or “representative,” and that a specific project’s costs may fall outside this range.

It is likely that any future wind electricity cost reductions will be modest. Wind turbine technology is close to mature, and it already benefits from the inherent efficiencies of large-scale production. Although wind turbines will continue to be refined and improved, costs reflect in large part the raw materials and construction/assembly requirements, which cannot be further reduced significantly.¹⁸

2. Wind’s Strengths and Weaknesses

All electricity sources, renewable and nonrenewable, have strengths and weaknesses. Ideally, these factors would be reduced to costs and benefits and could be combined to yield a final total or “societal” benefit-cost assessment. In reality, however, it is often impossible to reduce these factors to financial terms, as their valuation can be subjective and situation dependent. These factors are therefore discussed here separate from costs.

Wind electricity’s major strength is that it is a zero-carbon energy source¹⁹ with a per-kilowatt-hour cost that is close to that of new fossil fuel-fired generation. Wind electricity has other attractive features as well:

- Utility-scale wind farms can be sized from about 10 MW to up to hundreds of megawatts,²⁰ and additional capacity can easily be added in stages.
- Wind electricity has no emissions, little noise, and no waste products, and it is compatible with many land uses, including agriculture and grazing.
- Wind farms can be built quickly—in less than a year, typically.

Wind electricity also has some significant problems, notably:

- The wind resource overall is very large; however, wind farms must be sited where wind is sufficient, which may be very far from population centers or transmission lines.
- There can be local opposition to siting of wind farms, primarily due to visual impacts.
- The electricity production from wind turbines is variable (see discussion below).
- As with any form of development, wind farms can have negative impacts on wildlife and natural habitat. Moreover, wind farms require more area per MWh than many other electricity generation technologies.

3. *Wind's Future*

With a large and untapped wind resource, wind electricity per-kWh costs falling closer to that of new fossil-fueled electricity, and an environmentally friendly image, wind electricity has a promising future. Most projections of renewable electricity generation find wind to be a primary source of expanded renewable generation.

B. Photovoltaics

Photovoltaics (PV) use various materials—most frequently silicon—to convert sunlight directly into electricity. PVs are quiet, have no moving parts, can be installed very quickly, and can be sized to power anything from a single light to an entire community. However, they are quite expensive, with current costs ranging from 28 to 42¢/kWh for large grid-connected systems (see Table 1). Although costs have come down considerably in recent years and will continue to drop, PVs are currently nowhere near cost-competitive with fossil fuels in the vast majority of circumstances.

U.S. installed PV capacity at the end of 2008 was about 800 MW,²¹ which generates roughly the same amount of electricity as one mid-size natural gas power plant. Although PV installations are growing rapidly, photovoltaics currently supply much less than one percent of U.S. electricity consumption.

The solar resource is huge and could technically supply U.S. electricity needs many times over. For example, as noted above, solar panels covering an area equal to less than 10 percent of Colorado could provide enough electricity to power the entire United States. Such a system, however, would be immensely impractical for numerous reasons, including that it would not generate electricity at night and that it could require massive construction of new transmission lines.

1. *Photovoltaic Costs*

One sees widely varying costs for PV-sourced electricity, for several reasons:

- *How cost is defined.* Calculation of cost per watt includes only first (initial) costs and does not include operating and maintenance costs. Calculation of cost per kilowatt-hour, in contrast, does incorporate these factors but also requires assumptions about lifetimes and discount rates.
- *What's included.* A complete PV system requires not just the photovoltaic cells but also many other components such as inverters, transformers, and wiring.²²
- *Whether it is an actual or projected cost.* There can be a large difference between what costs might be in the future and what they really are today.
- *The size and application of the system.* In general, the larger the system, the lower the per-kilowatt and per-kilowatt-hour cost.

- *Where it is located.* Although photovoltaics will operate anywhere, the more sunlight, the lower the per-kilowatt-hour cost. A PV system located in the southwestern United States, for example, can produce up to twice as much electricity as the same system located in the northeastern United States.²³
- *What technology was used.* There are several different types of PV cells, and each has different costs and performance characteristics.
- *Whether the price reflects or includes subsidies.* There is currently a federal investment tax credit for PV systems,²⁴ and several states provide significant subsidies as well.

This report estimates the costs of a utility-scale (20 MW) PV power plant at 28 to 42 ¢/kWh, not including the federal investment tax credit (ITC) (See Table 1). Smaller (less than 10 kW) distributed PV systems have somewhat higher costs which are estimated as 46 to 59 ¢/kWh, again excluding the ITC. PV cost estimates that reflect the ITC will be considerably lower.

PV system costs overall decreased 3.5 percent per year from 1999 to 2007.²⁵ Almost all of this cost reduction was in non-module costs; the PV modules themselves showed little cost reduction.²⁶ This does not mean that module costs will not decrease in the future. There is currently considerable private-sector investment in photovoltaics, and there are a number of promising approaches to producing PV cells at lower costs. At least one manufacturer is claiming they can produce PV modules for under \$1/watt²⁷—compared with the \$4/watt average module costs for installed U.S. systems in 2007.²⁸ It is certainly possible, but by no means assured, that PV costs could drop significantly in the future.

2. Photovoltaics' Strengths and Weaknesses

Photovoltaic cells are noiseless and require little maintenance. They can be placed on rooftops or integrated into building materials, and thus they raise few visual concerns. They can be sized to fit any application, from a wristwatch to a multi-megawatt utility-scale system. Although their output will vary depending on the amount of sunlight they receive, they can be installed anywhere the sun shines. The question of whether photovoltaics will “work” in a specific geographical location is one of economics and cost-effectiveness, not technical feasibility. And PVs, when used on rooftops and other distributed applications, can postpone the need for transmission and distribution system upgrades.

The main problem with photovoltaics is their expense. As discussed above, their cost per unit of electricity output is currently much higher than that of fossil-fueled generation and wind. In addition, their electrical output is variable, meaning that their electricity production varies with the sunlight.

3. Photovoltaics' Future

Photovoltaics' high costs mean that they will supply only a small fraction of U.S. electricity needs, unless those costs come down significantly or policies promote greater PV deployment via large subsidies or mandates. As noted above, there is considerable private investment in new PV technologies, and the needed cost

reductions *may* occur. The future for this technology is uncertain and hinges on technical advancements that would allow significant cost reduction (see discussion below).

C. Concentrated Solar Power (CSP)

Concentrated solar power plants (sometimes called “solar thermal” plants) concentrate the sun’s energy onto a liquid carrier fluid (such as oil) and then use that hot fluid to heat water into steam and drive a turbine. This approach to producing electricity is currently used at only a handful of locations worldwide; however, some see it as a promising approach once the technology is refined and costs drop. The United States currently has 419 MW of CSP capacity. Most of this—354 MW—was built in California prior to 2000.²⁹

1. CSP Costs

Only one utility-scale CSP plant has been built in the United States since 2000 (although several additional plants are planned). This makes cost estimates highly uncertain. This report estimate the costs (LCOE) of electricity from a CSP plant built today to be in the range of 24¢ to 29¢/kWh, excluding the investment tax credit (see Table 1). These costs would decrease if more such plants were built, due to learning curve effects and economies of scale in production.

2. CSP’s Strengths and Weaknesses

CSP plants can be built to provide dispatchable electricity (that is, electricity that can be produced when it is needed rather than only when the sun provides sufficient energy), and can therefore be used to meet peak demands. This can be done two ways. First, solar energy can be stored in the form of hot fluid for up to several hours, and this fluid can then be used to generate electricity when needed. No currently operating plants in the U.S. have this capability; nevertheless it is technically feasible. Alternatively, CSP plants can use natural gas to heat the fluid when the sun is not available. This of course increases the carbon footprint of the plant.

CSP’s major weakness is its high costs, which stem from its technical complexity and need for large reflective surfaces/areas. It also requires high sunlight levels, and therefore is geographically limited to the U.S. Southwest. Therefore, significant new transmission would be required to deliver CSP electricity from the Southwest to other parts of the country.

3. CSP’s Future

A number of CSP plants have been announced or planned in the U.S. Southwest, but it is not yet clear how many (if any) of those plants will actually be built since high costs and transmission issues remain. If costs come down, CSP could play a significant role in the Southwest (including the very large California market).

III. Barriers to Increasing Wind and Solar Electricity Generation

As noted above, there are three principal barriers to greater use of wind and solar electricity: high costs, transmission availability, and variability of output. This section explains these challenges in further detail; the next section outlines some solutions.

Who Decides What New Power Plants Get Built?

Changing how the United States generates electricity requires an understanding of how decisions are made about what types of new power plants are built, and who makes those decisions.

The U.S. electricity system is a mix of regulation and competition.³⁰ Most states have a traditionally regulated system, in which regulated utilities generate, transmit, distribute, and sell electricity. State regulators oversee major decisions by these utilities—including decisions to build, or buy the output from, new power plants.

When considering new power plants, many state regulators use a “least-cost” process, in which the various options (such as natural gas, coal, wind, and energy efficiency) undergo a detailed economic analysis to determine which will provide the lowest-cost means of meeting electricity demand. In the regulated system, it is the state regulators and the utility that most strongly influence new generation decisions.

Some states use a more competitive system, in which utilities are not vertically integrated, and generating companies compete with one another to sell electricity to distributors and end users. Some of this electricity is sold in short-term bidding markets, while some is sold via longer-term bilateral contracts. In this system, market prices for electricity play a larger role in determining new generation decisions.

A. Cost of Wind and Solar Energy Relative to Other Electricity Sources

The greatest single barrier to significant market penetration for solar PV and CSP is their high costs. As shown in Table 1, there is a very large gap between the levelized costs of these technologies and those of natural gas power plants, even if one assumes a high natural gas price.

As discussed above (see Box: *Measuring and Comparing Costs of Electricity Production*), levelized technology cost ($\text{\$/kWh}$) is only one way to measure costs. A true societal cost that captured environmental and other costs and benefits not captured in price might show a different pattern. However, investment and purchase decisions are made largely on market costs, not societal costs. Therefore, solar PV and CSP will not achieve significant market penetration unless first costs drop significantly, policies subsidize or mandate the use of these technologies, or climate policies put a high price on carbon.

Costs are not as much of a barrier for wind turbines. As shown in Table 1, wind turbines can produce electricity at a per-kWh cost much below that of PV and CSP. And, depending on prevailing natural gas prices and other factors, wind electricity's cost can be close to that of electricity from natural gas.

B. Transmission Availability

The U.S. electricity system was built to accommodate large, centrally located power plants and to provide reliable, low-cost electricity to users. High-voltage transmission lines carry electricity from power plants to large demand centers, transformers then reduce the voltage, and the electricity is then delivered to users via distribution lines.

This system worked well for large (200 MW and larger) power plants and traditionally regulated, vertically integrated utilities, but it is now showing its age. The introduction of competition in generation markets increased the demand for longer-distance and interstate movements of electricity—something not foreseen, or always easily accommodated, in our current transmission system. States have regulatory power over utilities operating within their borders and have been unenthusiastic about interstate transmission lines (particularly if these lines mean that low-cost electricity would be exported). And in restructured states (that is, states without traditionally regulated, vertically integrated utilities), there has been little incentive for the private sector to invest in new transmission lines.

In addition to these issues, utility-scale new wind and solar plants present particular challenges to the transmission system. One is that wind and solar power plants must be located where the renewable resource is sufficient—and this location may be far from any existing transmission lines and far from electricity users. This is in contrast to fossil-fueled power plants, for example, which can be sited near existing transmission and/or electricity users.

Another challenge is that wind and solar produce fewer kWh per kW of capacity (that is, they have lower capacity factors) than many fossil fuel power plants. In other words, a wind or solar power plant will provide less electricity per unit of generation capacity. So pricing transmission use by capacity means that wind may pay more per unit of electricity delivered (kWh) than a fossil-fueled power plant. Whether or not such pricing is discriminatory is a contentious issue; nevertheless, pricing of transmission by capacity, rather than generation, can make it challenging for wind or solar to compete financially. Similarly, if a wind or solar power plant must

pay to reserve space on a transmission line, but is then unable to use that space because the wind is not blowing or the sun is not shining, then that payment is lost. Dispatchable and baseload power plants do not suffer from this form of risk.

The end result is a risk that existing wind projects will be unable to get their electricity to market and that proposed projects will be unable to proceed due to the unavailability of transmission.

Clearly, new transmission lines would enable greater use of renewable energy. Why then are they not being built? Barriers to new construction include:

- *Jurisdictional conflicts and overlaps:* Cities and counties control land use, states control intrastate electricity, and the federal government controls interstate electricity. This makes for complex and time-consuming permitting and paperwork requirements.
- *Public opposition:* Some see new transmission lines as ugly, environmentally damaging, and unsafe. This leads to blocking of new line projects at the local and regional levels.
- *High first costs:* New transmission lines typically cost \$2 million to \$4 million per mile,³¹ or more if lines are underground or very high voltage. Construction of new lines takes several years, at best. Revenues, however, don't start flowing until the line is operating, and these revenues are uncertain and depend in part on state and federal-level regulators' decisions on how transmission use is paid for. This makes building transmission capacity a high-risk proposition—one that few, if any, private-sector companies will take on without significant risk sharing or other government support.

Significant increases in new renewable electricity generation will require new transmission lines,³² and it is very difficult to get these lines built. This is not a technology issue; rather, the problem is a complex one of incentives, jurisdiction, and cost sharing.

Who Owns Transmission Lines?

In traditionally regulated states (see Box: *Who Decides What New Power Plants Get Built?*), vertically integrated utilities generate, transmit, and distribute electricity. Those utilities usually own and operate their own transmission lines. In other states, ownership varies. In many cases, a single company owns and operates transmission and distribution systems. These companies are typically under state regulation, although that regulation is limited to intrastate activities. The Federal Energy Regulatory Commission (FERC) regulates interstate transmission of electricity through existing power lines; however, siting of these lines is largely a local and regional matter. There are alternative, although less-common, transmission ownership structures. A regulated company can provide transmission only, without generation or distribution. In this structure, a separate regulated company provides distribution, while either competitive companies or a single regulated company can provide generation. Alternatively, a “merchant” company can own and operate transmission services.³³ These companies typically do fall under FERC regulation, but can be given leeway to charge rates based on market forces.³⁴ Finally, some public utilities (such as local government utilities and federal power administrations) own transmission lines.

C. Variability of Wind and Solar Electricity

When electricity users flip on the light switch, they expect the lights to come on. This expectation, combined with the fact that it is very difficult to store electricity, means that utilities are left with the challenging task of always producing exactly as much electricity as is demanded.

One essential tool utilities and electricity system operators use to ensure electricity supply equals electricity demand is “dispatch,” meaning turning power plants up or down as needed. Many types of power plants—natural gas and hydroelectric, for example—are “dispatchable.” Wind and PV, unfortunately, are not. Therefore, from the perspective of the utility, wind or solar electricity may not be as valuable, or useful, as that from dispatchable power plants, because utilities cannot necessarily depend on wind and solar plants to produce electricity when it is needed. How much less valuable, how to measure that loss of value, and how much wind and solar can contribute to total electricity needs are contentious questions.

Until recently, wind and solar energy provided such a small fraction of total electricity that their effects on the electricity system were not noticeable. In the past few years, however, as wind electricity generation has increased, concern over the effects of variable (also called intermittent) electricity sources has grown. Recent research, coupled with accumulating experience, has shown the following:

- Wind electricity does not require 100 percent backup with dispatchable generation. That is, having 100 MW of wind electricity does not mean that one needs 100 MW of natural gas-powered generation

ready to go in case the wind suddenly stops. The wind is somewhat predictable, and the latest research shows that wind does have some “capacity value,” meaning that it can provide some level of reliable electricity.³⁵ PV, too, has some capacity value. CSP with storage can have considerable capacity value—in some cases, close to that of traditional fossil-fired power plants.

- Wind electricity can provide a significant fraction of total electricity without a reduction in system reliability. In a number of U.S. states, and other countries, wind plays a major role in the overall electricity mix (Table 2)—and those electricity systems are stable and reliable.
- Managing wind’s variability does add costs; however, these costs are modest. Many studies have assessed the costs of managing wind’s variability and have found that wind imposes costs of 0.1¢ to 0.5¢/kWh on the system as long as wind accounts for about 30 percent or less of total system capacity.³⁶

Table 2: Wind penetration rates

State or region	Percentage of in-state or in-region generation that comes from wind, 2007
Minnesota	7.5%
Iowa	7.5%
Colorado	6.1%
South Dakota	6.0%
Denmark	20%
Spain	12%
Portugal	9%
Ireland	8%

Source: U.S. DOE, 2008.³⁷

Nonetheless, variability is a legitimate concern. The high (over 10 percent) wind penetration rates for European countries, shown in Table 2, are made possible in part through cross-border transmission links.³⁸ The studies showing modest costs imposed by higher levels of wind are estimates, not actual measured costs. There is very little real-world experience with high penetration rates of variable electricity resources.

IV. Overcoming Barriers to Wind and Solar Electricity

In order to ensure greater generation of wind and solar energy, they must be cost-competitive, transmission constraints need to be resolved, and solutions to the variability of these renewable resources need to be developed.

A. Make Wind and Solar Cost-Competitive

As noted above, wind electricity's cost (LCOE, see Table 1 and Box: *Measuring and Comparing Costs of Electricity Production*) is close to that of electricity from natural gas, depending on prevailing natural gas prices and other factors. The principal barriers to greater use of wind electricity are instead primarily transmission availability and output variability.

This is not true for either photovoltaics or concentrated solar power. As summarized in Table 1, utility-scale photovoltaics can provide electricity at a levelized cost of 28 to 42¢/kWh, whereas concentrated solar power costs 24 to 29¢/kWh. Neither of these is price-competitive with natural gas or wind, which are at 5 to 10¢/kWh and 9 to 12¢/kWh respectively. (These cost estimates exclude major tax credits, see Appendix 1 for details.)

Decisions about new electricity generating technologies are driven in large part by costs. Solar is still a niche technology because it is so expensive. It will remain a niche technology unless: (a) the costs of solar come down significantly; (b) the costs of fossil-based electricity go up significantly (for example, due to regulations that put a high price on carbon); or (c) solar is mandated through, for example, solar set-asides in renewable portfolio standards (RPSs) or feed-in tariffs. These three options are discussed separately, below.

How are price reductions in new technologies achieved? One path is through continual refinements in production processes and assembly methods. This typically occurs when production volumes increase and competitive market forces provide financial incentives for price reductions. Wind turbines are a useful example of this process. Wind turbines in 1980 were produced by a small number of small companies, the turbines produced relatively expensive electricity (~40¢/kWh), and turbines were not always reliable or well engineered. The transition to today's low-cost and technically sophisticated turbines was not the result of any one technical breakthrough but, rather, a long series of improvements, refinements, and advances.

This process only works, however, when one is essentially refining existing technologies, rather than coming up with new ones. It is useful, therefore, to break the solar cost reduction challenge into two parts: refining existing technologies and inventing new ones.

1. Refine Existing Technologies

Photovoltaics' first costs (also called "initial" or "capital" costs) are typically \$5,000 to \$9,000/kW (see Appendix 1). These first costs break down into two, roughly equal components: the PV modules themselves, and the rest of the system—wires, support structures, inverters, and so on—commonly called "balance of system" (BOS) components.³⁹ It is likely that these BOS components would see significant reductions if the number of installations increased significantly. Currently, many PV systems are custom-designed, and assembled and installed by small companies that do not have time or money to invest in research to fine-tune them. These BOS components fall into the "refining existing technologies" category, and cost reductions will likely occur if production volumes increase.

Similarly, CSP systems make use of existing technologies and have considerable potential for large cost reductions without the need for fundamental advances. This is not to minimize the challenge; CSP is not a simple technology, and it will require considerable technical development to yield the needed cost reductions. However, there is no "show-stopper," and it is likely that these cost reductions would occur, given the right incentives to the industry.

2. Invent New Technologies

The PV modules themselves, in contrast, are in need of some fundamental advances. The majority of PVs sold today are "crystalline silicon"—a technology that requires considerable amounts of expensive processed silicon, a complex and costly production process, and the need to wire individual cells together, which further increases costs and complexity. Recent analyses of PV cost data show that module costs—predominantly crystalline silicon—were essentially flat from 1998 to 2007.⁴⁰ It is not clear that PV systems made with crystalline silicon cells can achieve the cost reductions needed to become economically competitive with natural gas or wind-based electricity.

A much more promising approach is "thin-film," in which a very thin layer of photovoltaic material is applied directly on a backing material (typically glass or steel). This process uses much less PV material, lends itself to continuous manufacturing (thin-film PV can be produced in a continuous sheet for potentially lower manufacturing costs than crystalline silicon PV), and may be able to be applied directly to windows, roofing and siding materials, and other surfaces. There are a number of promising thin-film technologies and approaches, some in commercial use, and more under development. More research, however, is needed to refine thin-film production methods with the goal of low-cost, high-volume manufacturing of reliable and durable PV cells.

Given the enormous solar energy resource and thus the long-term potential for solar electricity to provide substantial zero-carbon electricity, policies to promote or subsidize PV research and development (R&D) are well justified. As the private sector is already engaged, such policies should focus not on fundamental/theoretical research but, rather, on building on the applied research already under way. Policy options include expanded R&D tax credits and greater funding of university/industry research collaborations. These policies should focus on research into methods to manufacture low-cost PVs at high volumes. Deployment policies, in contrast, raise questions as to the degree to which they are subsidizing higher-priced technologies that may not achieve economic competitiveness.

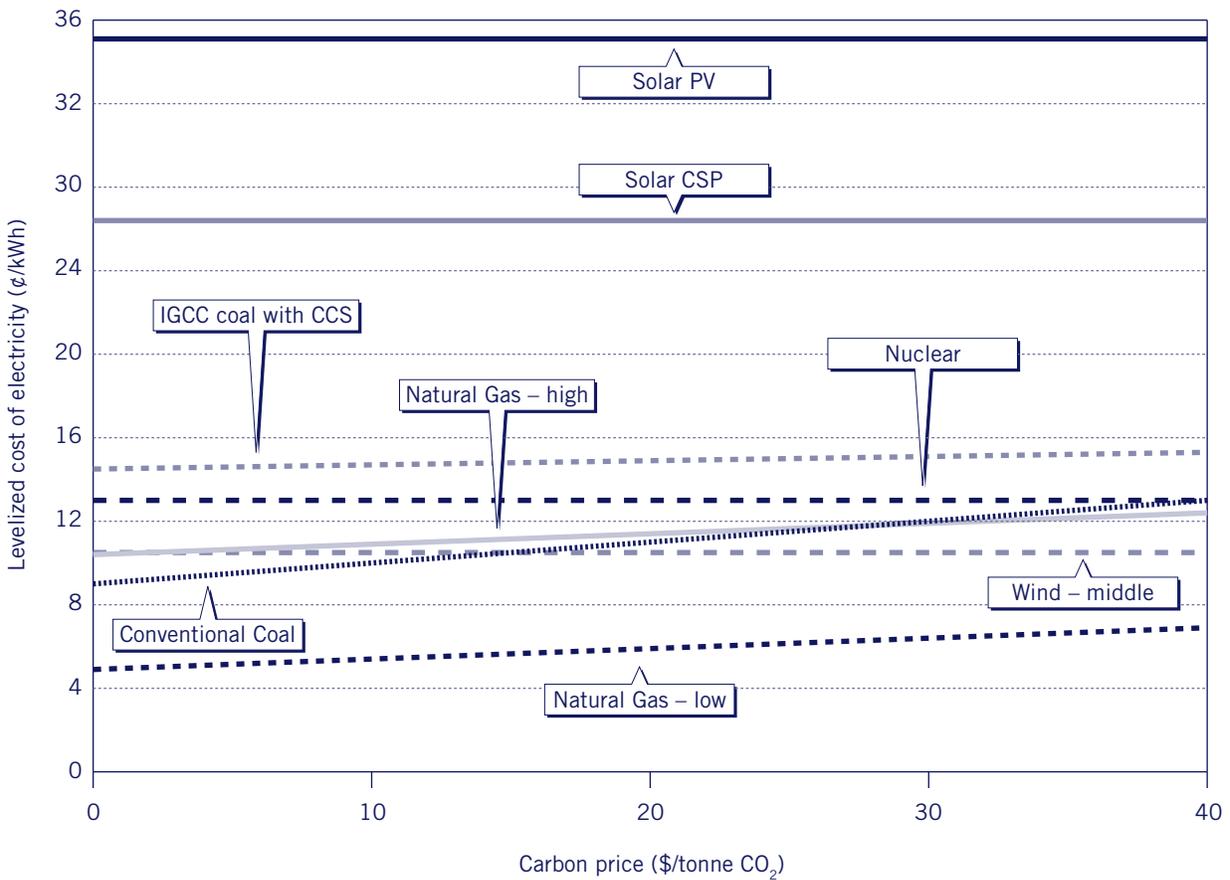
3. Putting a Price on Carbon

Putting a price on carbon emissions (such as via a cap-and-trade program) would raise the costs of traditional fossil-fueled electricity, thereby increasing the cost-competitiveness of low-carbon alternatives. A clear externality of fossil-fueled electricity is carbon: coal-fired power plants emit about one metric ton (tonne) of CO₂/MWh, and natural gas power plants emit about 0.5 tonnes of CO₂/MWh. Wind and solar power plants, in contrast, emit no CO₂. In addition to any policies to promote renewable energy, reductions in greenhouse gas emissions from across the economy can be achieved by putting a price on carbon as a carbon cap-and-trade system or a carbon tax would do.^{41, 42}

The degree to which a cap-and-trade system promotes renewables depends largely on where the cap is set, how much the cap is decreased per year, and the resulting price on carbon. Putting a price on carbon makes renewable electricity more competitive with electricity from coal and natural gas. A price on carbon could make wind electricity less expensive than natural gas electricity, but it is unlikely to make solar a least-cost generation option unless significant progress is made in reducing the cost of solar electricity. As shown in Figure 2, even at a \$50/tonne CO₂ price, electricity from solar PV and solar CSP have higher costs (levelized cost of electricity, LCOE) than electricity from other sources.

In interpreting Figure 2, one should note that it considers only the LCOE (see box above explaining what LCOE does and does not include), that absolute and relative costs can vary significantly depending on circumstances, and that cost estimates for nuclear and coal with carbon capture and storage include a significant degree of uncertainty that is not reflected in Figure 2. Nonetheless, Figure 2 does illustrate that a price on carbon makes wind power more cost competitive with other power sources but that even a significant price on carbon is not expected to make current solar power technologies cost competitive in most cases.

Figure 2: How carbon prices influence electricity costs



Notes: Costs will vary depending on location of plant, costs of capital, and other variables. “Solar PV” is solar photovoltaic. “Solar CSP” is concentrating solar power. “IGCC coal with CCS” is integrated gasification with combined cycle coal with carbon capture and storage. Eighty percent carbon capture assumed for CCS. Costs for solar PV, solar CSP, wind, and natural gas combined cycle are from Table 1. Midpoints from the ranges in Table 1 are shown here. Costs for nuclear, conventional coal, and IGCC coal with CCS are author’s estimates, based in part on E3, 2007.⁴³ Assumed carbon intensities are one tonne CO₂/MWh for coal, and 0.5 tonne CO₂/MWh for natural gas.

4. Regulatory Approaches

A third approach is to require the use of renewables. The predominant such policy approach in the United States is the renewable portfolio standard (RPS). An RPS requires that a minimum percentage of electricity come from renewables by a set date, and typically that percentage increases over time. For example, California’s RPS requires that 20 percent of electricity come from renewables by 2010.⁴⁴ More than half the states now have RPSs, and federal legislation to set a national RPS is currently under consideration.

RPSs vary considerably by state. RPS attributes that vary include the percentage and date specifications, penalties for noncompliance, definition of qualifying renewables, and breadth of coverage (for example, whether the RPS covers municipal utilities). Some RPSs use “set-asides” (also called “carve-outs”), which require that some subset of the required renewables come from specific technologies. For example, New Jersey’s RPS requires that 22.5 percent of electricity come from renewables by 2021, with about one tenth of the

requirement “carved out” for solar. In states with solar set-asides, solar is being built as required; however, it is not yet clear if these set-asides are building an enduring solar industry or driving significant cost reduction.

Germany’s Feed-in Tariff: Solar, But at What Price?

An alternative to the RPS is the “feed-in tariff:” a requirement that electricity providers purchase electricity from renewable electricity generators at a mandated price. Feed-in tariffs are a popular policy approach in Western Europe, with Germany’s feed-in tariff (called the Renewable Energy Law, REL) being the most well known.

Germany’s REL requires utilities to purchase electricity from certain types of renewable generators, and sets the price that utilities must pay. In 2006 utilities paid 52 to 72 US ¢/kWh for electricity from solar PV systems, for wind the set price was 11 ¢/kWh.⁴⁵ These prices generally decline over time.

Given these generous prices, it’s not a surprise that the REL has triggered a renewables boom in Germany. Germany has more wind power (~22 GW)⁴⁶ and more installed PV (~4 GW)⁴⁷ than any other country in Europe.

Clearly, if policy success is defined as the amount of new renewables built as a result of that policy, then Germany’s REL is an astounding success. Renewable generators have clear profit margins and little risk, as they are guaranteed a high and enduring price for their product. These generators can also access relatively low-price capital, as lenders see little risk due to the high price and the fact that the customer is a large, regulated, and stable entity. So renewable generators have flocked to the German market.

What’s less clear, however, is the REL’s overall economic impact. The high prices paid to renewable generators mean that these generators face no direct competition (as utilities must buy from them, at the regulated price), and thus have a reduced incentive for price reduction. The price paid to renewable generators does not directly reflect market costs or market forces, but is instead set via a political process.

Overall, the REL has clearly driven large amounts of new renewables installations. What is less clear is if the price paid for these renewables was as low as it could have been.

5. Markets and Policy Goals

Although solar electricity production technologies will need to achieve significant cost reductions to become cost-competitive, the United States is well situated to accomplish this goal because:

- There is clearly a huge financial incentive/reward for industry: Retail electricity sales totaled \$340 billion in 2007 in the United States alone.⁴⁸
- Due to a number of aggressive state and federal policies, PV installations are growing rapidly.⁴⁹ More companies are entering the business, innovative financing mechanisms are being developed, and installation techniques are improving—all necessary components of an effective industry.

When thinking about options to accelerate this process, it is useful to consider policy goals and market functioning. Addressing climate change requires reducing economy-wide greenhouse gas emissions. Such reductions will have to include large reductions in GHG emissions from the electric power sector. If the goal, then, is low-carbon electricity at a reasonable cost, there are alternative approaches that can already provide low- or zero-carbon electricity at costs competitive with fossil fuels (such as wind and efficiency).

More generally, it is not clear that aggressive policies to promote deployment of *current* PV technologies are warranted. These technologies are still quite expensive relative to other options for reducing GHG emissions. If deployment policies simply subsidize installations of current technologies without providing strong incentives for cost reduction, then these policies are not building an enduring role for PV in the electricity market.

B. Overcome Transmission Constraints

New transmission lines are needed in order to extend the transmission system to remote locations that have wind and/or solar resources and to allow for interstate flow of renewable-fueled electricity from wind- and solar-rich regions to other regions.

1. *Develop Innovative Financing*

Building new transmission lines typically costs \$2 million to \$4 million per mile; however, there is revenue associated with transmission. Once transmission is built, fees can be charged to those using it. Since there is a long time gap between the start of construction and when revenue starts flowing, it is usually unclear at the beginning who will pay these fees and how much they will pay, and these fees are influenced not just by market forces but by regulatory decisions (such as public utility commission rulings). Therefore, attracting private sector investment in new transmission projects will likely require significant public/government support, and will certainly require better clarification of who pays and how much.

One way to clarify who pays and reduce perceived financial risk is to promote agreements among states, and particularly among state utility regulators, that commit multiple states to ensure cost recovery for these projects through, for example, an electricity bill surcharge. This surcharge could begin when construction starts, rather than when electricity starts flowing through the line—reducing the time between investment and return (such an approach has been used to fund power plants, although not without controversy). This approach should stick closely to a user-pays philosophy—that is, those who expect to benefit (through, for example, receiving low-priced wind electricity) should contribute financially.

Greater use of tax-advantaged financing, such as allowing for the use of tax-exempt bonds, is a promising policy option for promoting new transmission, given the high cost of new transmission construction.⁵⁰ More generally, innovative ways to merge the strengths and abilities of the public and private sectors in large infrastructure projects will be critical.

States—and state regulators—have little incentive to contribute to a transmission line if it means low-priced electricity flows out of their state. However, if regulators were able to consider the larger economic impacts of in-state renewables development, rather than only electricity price impacts, they might be more supportive. State regulators could be encouraged to take a broader view of impacts when assessing multi-state transmission projects.

2. Include the Non-Wires Option

Improved energy efficiency and growth in distributed generation will dampen the demand for new transmission capacity. Looking further ahead, new technologies—notably plug-in hybrid electric vehicles (PHEVs) and smart grids—may change the way electricity is priced and managed.

For example, PHEVs may provide short-term energy storage to smooth the output of wind power plants, and smart grids may allow for demand response that reduces the need for new transmission. These “non-wires” solutions (meaning they reduce or postpone the need for new transmission) should be considered in any comprehensive analysis of new transmission needs.

The current U.S. electricity grid consists of a number of regional grids that operate largely independently, and within these grids smaller “balancing areas” operate somewhat independently as well. Increasing coordination both within and among regional grids, and providing incentives for sharing power when needed, would ease management of variable resources like wind and solar.

3. Clarify Federal and State Roles

The Energy Policy Act of 2005 established a process whereby federal eminent domain authority could be used to override state or local opposition to new transmission lines. In addition, that Act required the Secretary of Energy to designate “National Interest Electric Transmission Corridors” (NIETC) in areas experiencing transmission constraints. In response, DOE designate two large areas as such corridors. Public and Congressional opposition to those designations was strong; 14 Senators signed a letter to the Chair of the Senate Energy Committee arguing that DOE’s actions were inappropriate and calling for hearings. Clearly, the appropriate balance between Federal, state, and local land use decision-making has not yet been found.

Congress could revisit the NIETC process, with extensive input from state and local governments. State and local governments are unlikely to support a project that does not benefit them, so consideration should be given to designing projects with wider benefits and compensation to affected parties who do not benefit.

Some have called for a “national power grid” as a way to overcome the state/federal conflicts and to promote integrated operation of the electricity system. Congress has considered legislation that would further increase the Federal role in transmission siting and construction.⁵¹ This is an ambitious proposal, and one deserving further study. The experience of implementing the related section of the Energy Policy Act of 2005 (discussed above) suggests that such an approach will require extensive consultation with all stakeholders.

C. Manage Variability

The variability of wind and solar electricity reduces their value to electricity system operators, who must continually match electricity supply with electricity demand. That variability also raises some concerns about impacts on electricity system reliability.

Complicating the issue is considerable uncertainty over how much of a problem variability really is. As discussed above, several electricity systems are operating with significant amounts (over 10 percent) of variable electricity (mostly wind), and few systematic problems have emerged. Estimates of the costs of managing this variable electricity suggest that the costs are low. Nevertheless, higher levels of variable electricity, such as 20 percent, will require changes in electricity system operation.

There are three fundamental approaches to this problem: supply flexibility (providing more or less electricity as needed to accommodate the variable generation), demand flexibility (changing the demand for electricity as needed), and storage.

1. Supply Flexibility

All electricity systems have some flexibility in the amount of electricity they can provide; this is how they accommodate changes in electricity demand. This flexibility can come from power plants that can change their output as needed, or from contractual relationships with neighboring electricity systems that allow for exchanges of electricity between systems as needed. This is how some European countries (see Table 2) are able to manage the large amounts of wind electricity in their systems: they can call on neighboring systems to provide—or accept—electricity as needed.

One way to facilitate this contractual approach is to build and improve transmission links, as discussed above. The more physical links between electricity systems, the more options there are for contractual relationships to handle renewables’ variability. Similarly, combining the electrical output of several geographically dispersed wind power plants yields a smoother total output that is worth more to electricity system operators. Such combining is made possible by greater transmission availability.

A second option is to encourage transparency and disaggregation of grid operation costs. Currently, traditionally regulated utilities typically manage their own generation and transmission systems, and the various costs of wind integration are usually not broken out or monetized. If the costs of wind integration were broken

out, then it might encourage new solutions (either technical or contractual) that could provide these services at a reasonable cost. Such markets are starting to develop in some parts of the United States, but they are not yet widespread.⁵²

2. Demand Flexibility

A small fraction of U.S. electricity demand is currently “controllable”—meaning that grid operators can actually reduce that demand when needed to maintain electricity grid reliability. This option, called “demand response” or “load management,” is typically used only when there are no remaining electricity supply options. For example, on a hot summer afternoon, a utility may actually be in danger of running short of electricity. In this situation, the utility may ask its large customers to reduce their electricity use, or may remotely cycle (switch on and off) residential customers’ air conditioners.

The variability of wind and solar generation is conceptually similar to the variability in demand that electricity systems already manage; and increases in demand flexibility (through, for example, real-time pricing or other incentive programs) can be a cost-effective option for managing both sources of variability. Considering demand response as an economic option—using it when it costs less than the alternatives—rather than just in emergencies, should be given greater consideration.

3. Develop Physical Storage Options

Adding storage to the grid is another option for managing the variability of wind and solar electricity. For example, when wind electricity output drops due to a reduction in wind speeds, an electricity storage system could discharge stored electricity to make up for the reduction in wind electricity.

It is possible to store electricity; however, it is neither inexpensive nor simple. The only storage technology currently in widespread use is pumped hydro, of which the United States currently has 22 GW.⁵³ However, it is unlikely that many more large pumped hydro systems will be built, due to the land requirements and environmental impacts of building large new reservoirs. There are a number of new storage technologies under development, both utility-scale and distributed (also called end-use storage). (See Box: *Storage Technologies*).

Physical storage is an area in which R&D funding is appropriate, because low-cost electricity storage could be a cost-effective means to accommodate the additional variability introduced by new wind and solar electricity. Distributed storage could also reduce or postpone the need for transmission and distribution system upgrades.

Electricity Storage Technologies

Electricity storage technologies can be divided into “utility-scale” (typically 10+ MW) and “distributed” (less than one MW).

Research into utility-scale storage has been ongoing for many years, but with modest funding and modest progress; the availability of low-cost natural gas peaking power plants reduced the need for such storage. Interest has increased recently; however, no new utility-scale storage technologies have yet emerged as commercially dominant. There are numerous utility-scale storage technologies under discussion; those currently in commercial use include compressed air energy storage (CAES), flywheels, and batteries.

CAES uses off-peak electricity to store air under pressure, typically underground in a cavern or salt mine. When on-peak electricity is needed, that air is used as input to a natural gas turbine. That turbine can operate at very high efficiency, as it uses pre-compressed air. So CAES uses some natural gas to provide peak electricity, but less than a conventional natural gas peaking power plant would require. There are currently two CAES plants in operation: one in Germany (started up 1978) and one in Alabama (started up 1991).

Flywheel storage uses off-peak electricity to spin a low-friction flywheel, converting electrical energy into rotational energy. When peak electricity is needed, that flywheel is used to turn a generator, converting the rotational energy back into electricity. In early 2009 an agreement to build a one MW flywheel storage system was announced. This system when complete will provide regulation services to the PJM interconnection.

There are a number of battery technologies under consideration for utility-scale electricity storage. There are a handful of pilot and commercial systems installed, and various approaches under development. Thus far, no specific approach or technology has emerged as dominant.

An alternative approach is “distributed” storage, which includes larger systems that work on the level of substations,⁵⁴ as well as household-level systems in the tens of kilowatts. There is currently much discussion of the potential for plug-in hybrid electric vehicles (PHEVs) to act as distributed storage, marrying the electricity and transportation systems. The idea is straightforward: cars would plug in to the grid, and could be either charged with off-peak grid electricity or discharged to power the grid when demands are high. If many households had PHEVs, the total effective storage capacity would be very large. PHEVs are not yet available from major automakers. However both automobile manufacturers and some utilities see PHEVs as an intriguing way to integrate the electricity and transportation systems.

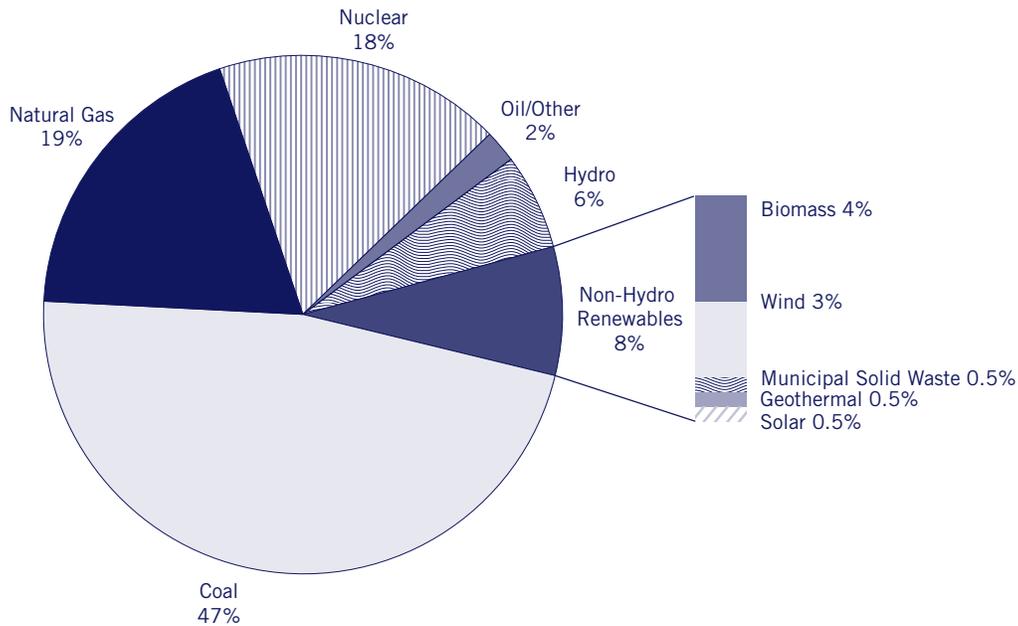
V. A High Wind and Solar Future: Scenarios and Implications

Wind and solar currently play small roles in the U.S. electricity mix. This section shows that, while our current path may lead to significant increases in wind and solar power, many alternative scenarios have been proposed that include far larger increases. The implications of these scenarios—on build rates, new transmission needs, and variability—are teased out to provide insight into the scale of the challenge of achieving a high wind and solar future.

A. Current Trends: The “Business-as-Usual” Scenario

In recent years, a number of policies have been introduced to promote greater use of renewables in electricity production. Largely because of these policies, the most recent “business-as-usual” (BAU) scenario from the U.S. Energy Information Administration (EIA)—one which assumes only “on-the-books” climate and energy policies—shows non-hydro renewable electric generation growing rapidly from 2007 to 2030. However, in this scenario renewables still only provide 14 percent of electricity in 2030 (Figure 3).⁵⁵

Figure 3: A “business-as-usual” forecast, showing the U.S. reaching 14 percent renewables by 2030



2030 (Forecasted)
5,124 billion TWh/yr

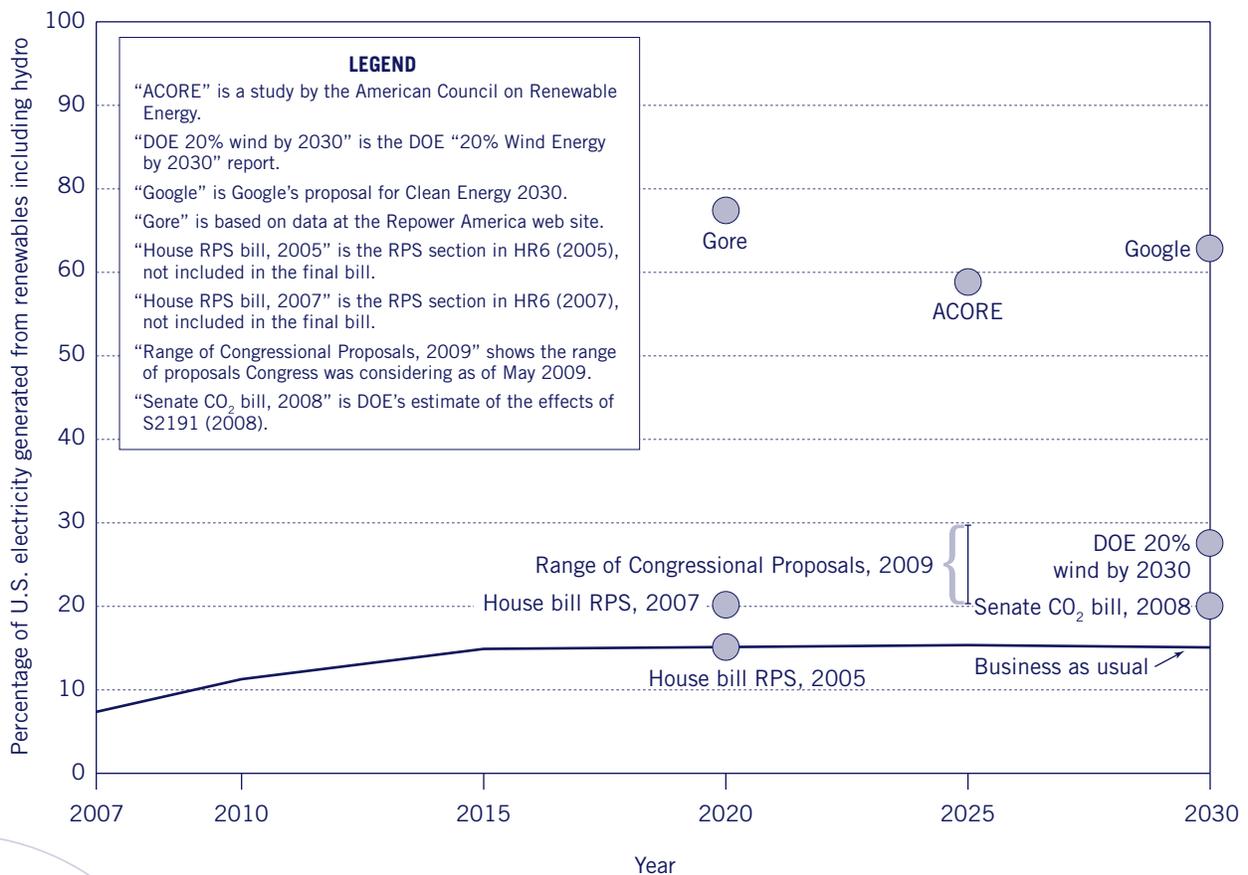
Source: DOE, March 2009⁵⁶

There are significant uncertainties in this type of forecasting. Unknowns include future fossil fuel prices, legislative changes (notably, the introduction of a national greenhouse gas cap-and-trade system, further extension of tax incentives for renewable energy, new state renewable portfolio standards, and a possible federal renewable energy standard), costs of new generation, and future electricity demand. However, this forecast does suggest that without changes to existing policies, shifts in market conditions, or technology developments renewables are likely to play a larger role in the U.S. electricity market by 2030 but one that is less substantial than the role envisioned by some policymakers, experts, and advocates.

B. Alternative High-Renewables Scenarios

A number of policymakers, organizations, and researchers have offered alternative scenarios, in which the growth of renewables in the U.S. electricity system is accelerated (see Figure 4). These studies vary widely in their assumptions, the depth of the analyses underlying the results, and their findings.

Figure 4: Business-as-usual (BAU) scenario and some alternatives



Notes: Since analyses differ as to their definitions of qualifying renewables, data are adjusted to show the percentage of total U.S. electricity coming from renewables, including hydropower, in the relevant year for that study. For full references, assumptions, and calculations; see Appendix 2. Some of the Congressional proposals provide mechanisms that in effect reduce the renewables requirement, so actual renewables levels achieved under these proposals could be lower than shown above.

Figure 4 clearly shows the sizable gap between the current trajectory (the BAU scenario) and many of the alternative proposals. These alternative proposals typically require modest or no technological improvements—that is, achieving the results they propose does not require new or radically different technologies. Rather, these results come largely from much greater use of technologies that exist today.

Whether these projections are realistic, economically preferable, or politically viable is arguable. The critical observation is that, although renewable electricity generation is growing, the United States is not currently on a path to reach the aggressive renewable electricity goals proposed or advocated by many in Congress and other organizations.

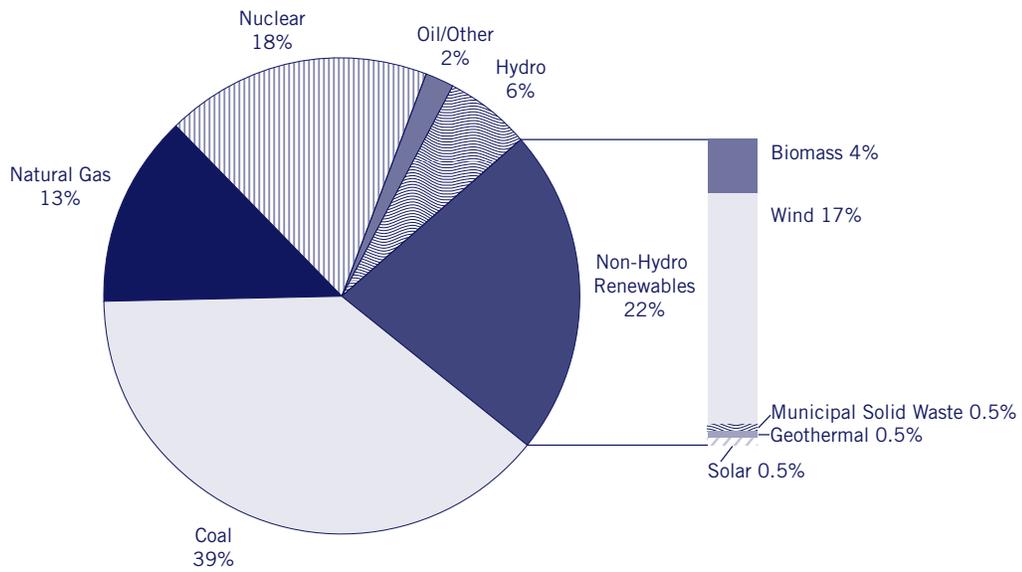
C. Implications of a High Wind and Solar Scenario

What would it take to make a high-renewable scenario, such as recent Congressional proposals or the DOE 20 percent wind by 2030 scenario, a reality? How much transmission would be needed, and by when? And could the electricity grid manage that much renewables? There are many uncertainties—technical, economic, and political—that make answering these questions difficult. Nevertheless, it is possible to bracket, or roughly quantify, the implications of a high-renewables scenario.

To do so, this analysis defines a “High Wind” Scenario using the DOE analysis of “20 percent wind energy by 2030” as a starting point.⁵⁷ This is not to endorse this as a policy goal, but rather because this scenario is extensively documented and is roughly comparable in scope and ambition to the RPS proposals in the 111th Congress.

The DOE scenario would require building 280 GW of new wind by 2030.⁵⁸ Assuming that renewables other than wind were built at rates corresponding to that in EIA’s “business as usual” scenario, this 280 GW of new wind would put the U.S at 29 percent renewables by 2030 (see Figure 5).⁵⁹ Assuming linear build rates (that is, the same amount of wind is built every year, starting in 2010 and ending in 2030), 280 GW corresponds to 14 GW per year. Alternatively, one could consider a “ramp-up,” in which build rates grow from the actual 8.3 GW installed in 2008 to, for example, 18 GW per year by 2020, and continue at that level to 2030.

Figure 5: A “High Wind” scenario with all other renewables achieving the same levels of generation as in “business as usual.”



2030 (Forecasted)
5,124 billion TWh/yr

The actual 2008 installations of 8.3 GW was a record year for the wind industry, and one that is unlikely to be surpassed in 2009. A build rate of 18 GW by 2020 would represent over a doubling of the installation rate of 2008; however, it is certainly conceivable that the wind industry could accomplish that by ramping up to 18 GW per year by 2020. DOE’s analysis concluded that, “achieving the 20 percent wind scenario by 2030 would not overwhelm U.S. industry.”⁶⁰ Furthermore, DOE found no fundamental materials, manufacturing, or labor barriers to such a ramp-up. Clearly, the wind industry would need to see clear and profitable demand for wind electricity in order to build at that rate. However there is no reason why that would not be physically achievable.

How much new transmission would be needed to accommodate 280 GW of new wind, and what would that cost? DOE estimates that 280 GW of new wind generation would require 12,650 miles of new high-voltage transmission, at an undiscounted cost of approximately \$60 billion.⁶¹ A separate study estimated that 19,000 miles of new high-voltage (765 kilovolt) transmission lines would be needed, at an estimated cost of \$60 billion (2007\$).⁶² This equates to approximately \$3 billion per year, for the period 2010 to 2030. To put this in perspective, U.S. investor-owned utilities currently spend about \$6 billion per year on transmission,⁶³ and DOE estimates total current transmission spending at about \$8 billion per year.⁶⁴

An alternative method to estimate transmission costs is to apply the per-kWh costs of transmission needed to accommodate wind, as estimated in specific wind and transmission planning studies, to this scenario. A comprehensive review of U.S. transmission studies found that the transmission needed for new wind had a median cost of 1.5 ¢/kWh.⁶⁵ This implies a 13-17 percent increase in wind power's levelized cost.

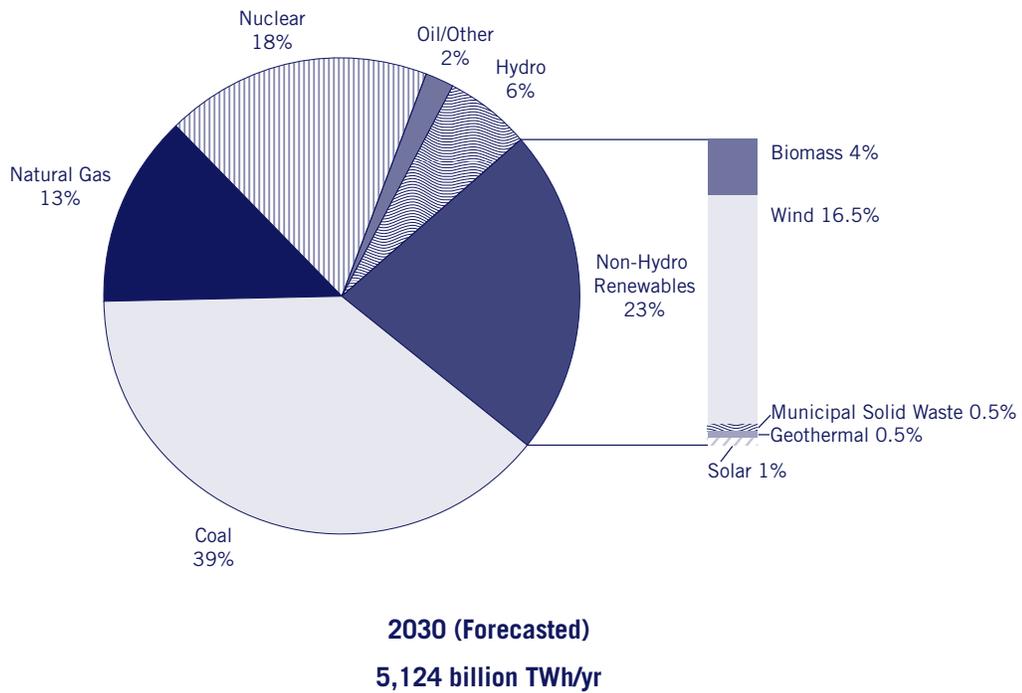
To summarize, the new transmission needed to accommodate the “High Wind” scenario would probably cost about \$3 to \$4 billion per year—a 40 to 50 percent increase in annual transmission spending. If this cost were charged to the new wind capacity, it would increase the cost of wind by about 15 percent.

In the “High Wind” scenario at least 17 percent of U.S. electricity (MWh) comes from a non-dispatchable resource in 2030. Can the electricity system manage this level of wind penetration, and if so at what cost? It is important to recognize that utilities and electricity grid operators have been successfully managing *demand* variability since the first electricity systems began operating. The issue therefore is the *increased* variability due to wind and solar. As noted above (see Table 2), some countries have already exceeded 10 percent wind, but 17 percent is certainly beyond U.S. experience. Several studies have examined the impacts of higher wind penetration rates, and DOE's review of these studies concluded that 20 percent wind energy “can be reliably accommodated.”⁶⁶ The available evidence does suggest that the “High Wind” scenario involves a manageable level of wind penetration.

As discussed above, non-dispatchable resources impose costs estimated at 0.1¢ to 0.5¢/kWh. It is likely that higher penetration rates of wind will correspond to the higher end of this range. Assuming 0.5¢/kWh, therefore, yields an increase in wind costs of four to six percent.⁶⁷ That is, prices for electricity from wind would need to increase four to six percent to include the costs of wind integration.

The discussion above focuses exclusively on wind. What might a “High Wind and Solar” scenario look like, and what might be the implications for build rate, transmission, and variability? Given the high per-kWh costs of solar, it is likely that even a “High Wind and Solar” scenario would mean a relatively small fraction of solar in the total electricity mix. To illustrate the implications, this analysis uses as a starting point the “High Wind” scenario, except that in the “High Wind and Solar” scenario solar generation in 2030 is roughly double its “business as usual” projection, with wind generation reduced by a corresponding amount (see Figure 6). This “High Wind and Solar” scenario corresponds to about 18 GW of new solar compared to today.

Figure 6: A “High Wind and Solar” scenario with nearly a doubling of solar generation compared to “business as usual”



Achieving 18 GW of new solar by 2030 would mean about 900 MW of new solar installations per year, from 2010 through 2030. For comparison, in 2008 340 MW of new solar was installed in the United States.⁶⁸ So ramping up to 900 MW/year would be challenging if it was predominantly in the form of PV; however, a number of CSP plants have been proposed that are in the hundreds of MW, so it is conceivable to reach 900 MW per year of new solar if CSP plays a role.

The transmission implications of this “High Wind and Solar” scenario are not dissimilar to those for the “High Wind” scenario. Transmission requirements would be lower if some of the solar was distributed (that is, building-scale rather than utility-scale).⁶⁹ Similarly, the variability implications and costs would be qualitatively similar to the “High Wind” scenario, as solar presents comparable challenges and costs to grid operation. If the solar was primarily in the form of CSP, then the variability costs could be somewhat lower if the CSP was built with storage capability.

The key difference between the two scenarios is in first costs for the technologies themselves. As discussed above, wind’s costs are close to those of new gas-fired generation, while solar costs significantly more.

VI. Conclusions

Renewables currently play a small but growing role in the U.S. electricity system. However, legislation now under consideration, such as a national renewable portfolio standard (RPS) and GHG cap-and-trade program, could lead to a significantly larger role for renewable electricity. Wind and solar could play a larger role, as wind and solar resources are plentiful and wind and solar technologies are commercially available. The principal barriers to greater use are the costs of the technologies (notably for solar), the need for new transmission lines, and the challenge of integrating variable power sources (that is, power plants whose generation is dependent on fluctuating resources) into the electricity system.

The technology cost issues are quite different for wind than for solar. Electricity from wind can be cost competitive with electricity from new coal and natural gas power plants, depending on fuel prices, the carbon price, and various subsidies. For example, as shown in Table 1, the levelized cost of wind electricity is typically 9 to 12¢/kWh without the production tax credit, compared to, for example, 5 to 10¢/kWh for electricity from natural gas combined cycle power plants. Solar is considerably more expensive, with utility-scale solar photovoltaic at 28 to 42¢/kWh without the investment tax credit, and concentrating solar at 24 to 29¢/kWh without the ITC. A carbon price is unlikely to make current solar technology cost-competitive.

Achieving high levels of wind and solar in the U.S. electricity system—nearly 20 percent by 2030—would require new transmission spending of \$3 to \$4 billion per year, about a 40 percent to 50 percent increase over current transmission spending. If these costs were included in the costs of electricity from wind, then wind costs would increase by about 15 percent. Studies suggest that 20 percent wind penetration in the electricity grid is manageable, although there would be costs for integrating this variable power source. These costs would add four to six percent to the price of wind electricity.

There appears to be no fundamental technical, resource, or manufacturing barrier to achieving roughly 20 percent wind by 2030. While uncertain, the available evidence suggests the costs for doing so are not enormous; adding variability and new transmission costs would likely increase the cost of wind power by *roughly* 20 percent. This would make wind electricity more expensive than that from natural gas without a carbon price, but in many cases still less expensive than that from new nuclear or coal with carbon capture and storage. Solar, in contrast, has quite high first costs, and adding variability and new transmission costs makes solar not economically competitive at current prices. Significant cost reductions in solar, however, could bring costs down to where solar could play a role in meeting future electricity needs.

Appendix 1: Cost Assumptions and Calculations

To calculate the LCOEs shown in Table 1, the following are assumed: no decommissioning costs or scrap value, 15 year plant lifetime, and a 9 percent per year capital cost. Costs and LCOEs do not include the production tax credit or the investment tax credit. Costs and LCOEs do not include land, transmission, permitting, or other non-hardware costs. See Box: *Measuring and Comparing Costs of Electricity Production for discussion.*

Table A1: Cost assumptions for LCOE calculation

Technology	First Cost (\$/kW)	Operation and Maintenance Cost (¢/kWh)	Fuel Cost (¢/kWh)	Capacity Factor	Resulting LCOE (¢/kWh)
Wind (> 1 MW)	1900-2400	1	0	0.32	9-12
Concentrating Solar Power (CSP)	3800-4800	3	0	0.26	24-29
Utility-scale photovoltaic (> 10 MW)	5000-7500	1	0	0.26	28-42
Distributed photovoltaic (< 10 kW)	7000-9000	1	0	0.22	46-59
Natural Gas	800	0.5	2.8–8.3	0.70	5-10

Technology-specific major assumptions: CSP assumes no built-in storage. Tracking capability assumed for utility-scale PV, but not for distributed PV. Natural gas fuel costs of 2.8¢/kWh to 8.3¢/kWh correspond to assumed fuel prices of \$4/MBTU to \$12/MBTU, at a heat rate of 6900 BTU/kWh.

Sources: Author's estimates, based in part on Black & Veatch 2008⁷⁰ and Wiser et al. 2009.⁷¹

Appendix 2: Assumptions and Calculations for Figure 4

The business-as-usual (BAU) scenario is based on U.S. DOE, March 2009.

The “ACORE” data point—58 percent by 2025—is based on data in ACORE, March 2007.⁷² Table 1 in that source provides new renewable capacity for 2025. Assumed capacity factors are shown in Table A2 below. This new generation was added to 2007 renewable generation (from U.S. DOE, March 2009) to yield total (new plus existing) renewable generation in 2025. This was then divided by BAU forecasted 2025 generation (from U.S. DOE, March 2009) to yield the percentage of total generation in 2025 that would come from renewables, under the Table 1 scenario in ACORE, March 2007.

Table A2: Assumed capacity factors for scenarios

Technology	Capacity Factor
Wind	0.32
Solar	0.26
Geothermal	0.70
Biomass/other	0.70
Hydro	0.70

The “DOE 20 percent wind by 2030” data point—29 percent by 2030—is based on data in U.S. DOE, July 2008.⁷³ That report proposes 305 GW of wind in 2030, including currently existing wind (see Figure 1-3, page 7). The generation of that 305 GW was calculated, based on the capacity factor shown above in Table A2. From the BAU scenario (U.S. DOE, April 2009), BAU renewable generation in 2030, excluding BAU wind, was calculated. To that number the “new” wind 2030 generation was added. That total renewable generation number was then divided by 2030 total generation. By 2030, coal and natural gas generation were assumed to be displaced in equal amounts by the new wind generation.

The “Google” data point—65 percent by 2030—is based on data in Google, February 2009.⁷⁴ That plan keeps electricity consumption “flat” at 2008 levels. 2008 electricity consumption is based on U.S. DOE, March 2009 data for 2007; a one percent increase was assumed to calculate 2008 total electricity consumption.

Renewables are based on capacities shown in Figure 1 in Google, February 2009. Capacity factors are as shown in Table A2 on the previous page.

The “Gore” data point—76 percent by 2020—is based on data in Repower America, February 2009.⁷⁵ The 76 percent is the percentage of all electricity generated in 2020 that comes from renewable sources, in scenario A.

The “House RPS bill 2005” data point—10 percent by 2020—refers to sec. 609 in a version of HR6, The Energy Policy Act of 2005 (engrossed amendment as agreed to by Senate). Although HR6 was passed into law, that section was not included in the final bill. That section’s definition of renewables excluded existing hydropower, so an estimate for current-day hydropower as a percentage of 2020 electricity consumption (5 percent) was added to the 10 percent.

The “House RPS bill 2007” data point—15 percent by 2020—refers to sec. 610 in a version of HR6, the Energy Independence and Security Act of 2007 (engrossed amendment as agreed to by House). Although HR6 was passed into law, that section was not included in the final bill. That section’s definition of renewables excluded existing hydropower, so an estimate for current-day hydropower as a percentage of 2020 electricity consumption (5 percent) was added to the 15 percent.

The “Congressional proposals 2009” range of 20 to 30 percent includes the RPS discussion draft from Senator Bingaman, the discussion draft of the “American Clean Energy and Security Act of 2009” introduced by Representatives Markey and Waxman, and HR 890 and S433 in the 111th Congress (2009). These proposals exclude existing hydropower, so an estimate for current-day hydropower as a percentage of 2020 electricity consumption (5 percent) was added to their stated 2025 goals.

The “Senate CO₂ bill 2008” data point—19 percent by 2030—refers to S2191, America’s Climate Security of Act of 2007, in the 110th Congress. That bill was not passed into law. The 19 percent data point is an estimate by DOE of the renewables that would result if the bill were passed.⁷⁶

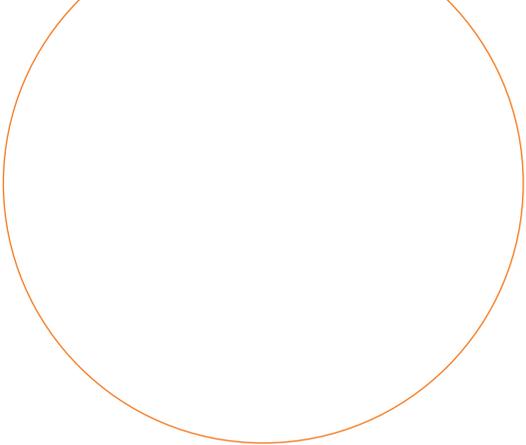
Endnotes

1. U.S. Department of Energy (DOE), Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2007*, DOE/EIA-0573(2007), December 2008, p. 4. Available at www.eia.doe.gov.
2. EIA, *Annual Energy Outlook 2009*, DOE/EIA-0383(2009), March 2009. Available at www.eia.doe.gov.
3. Natural gas imports as a percentage of total natural gas consumption increased from 8 percent in 1990 to 20 percent in 2007. EIA, *Annual Energy Review*, DOE/EIA-0384 (2007), June 2008, p. 183. Available at www.eia.doe.gov.
4. See e.g. Morgan, G., J. Apt, and L. Lave, *The U.S. Electric Power Sector and Climate Change Mitigation*, prepared for the Pew Center on Global Climate Change, June 2005, table 7. Available at www.pewclimate.org.
5. There are CO₂ emissions associated with material manufacturing and renewable plant construction, and in some cases plant operation (for example, gasoline used by plant maintenance vehicles). These emissions, however, are quite small relative to those resulting from burning of fossil fuels for electricity production.
6. Wind and solar photovoltaic (PV) technologies do not use any water, however concentrating solar power (CSP) technologies do require water.
7. See, for example, Kelly, M. and S. Tegen, "Economic Development Impacts of 20% Wind," Poster, National Renewable Energy Laboratory, June 2007, available at www.nrel.gov.
8. DOE, *20% Wind Energy by 2030*, DOE/GO-102008-2567, July 2008. Available at www.20percentwind.org. Wind capacity (GW) is not directly comparable to total capacity (GW), due to wind's lower capacity factor.
9. Assuming average insolation of 6.0 kWh/m²/day, PV conversion efficiency of 10 percent, U.S. electricity consumption of 4,000 TWh/year. Such a system would be absurdly impractical for many reasons, notably it would require huge amounts of storage to account for the variability of electricity output. Nonetheless, this is illustrative of the vast amount of solar energy that could theoretically be tapped.
10. EIA, *Annual Energy Review*, June 2008, pp.228, 260.
11. American Wind Energy Association (AWEA), *AWEA Annual Wind Industry Report—Year Ending 2008*. Available at www.awea.org.
12. As shown in Table 1, wind's current cost (LCOE) range has some overlap with that of electricity from natural gas. This means that, *in some cases*, wind can produce electricity at or below the LCOE of electricity from natural gas.
13. American Wind Energy Association (AWEA), U.S. Wind Energy Projects as of 12/31/08, database available at <http://www.awea.org>. (Data viewed April 2009).
14. DOE, *20% Wind Energy by 2030*, July 2008, p. 8.
15. "Technical potential" excludes those areas not suitable for wind turbines (such as steep slopes, national parks, and urban areas), but does not consider cost or economic viability. For details on these technical potential estimates, see Black & Veatch, *20 Percent Wind Energy Penetration in the United States*, Final report, October 2007, available at www.20percentwind.org.
16. Assuming a wind capacity factor of 0.32. U.S. total electricity consumption from U.S. Department of Energy, *Annual Energy Outlook 2009*, March 2009.

17. The production tax credit (PTC) provides a tax credit, currently valued at 2.1¢/kWh, for electricity produced from wind. For more information on the PTC, see <http://dsireusa.org/>.
18. Cost analyses of wind projects from 1998 to 2007 show year-to-year oscillations but no overall decrease, suggesting that the cost curve has bottomed out. See U.S. Department of Energy, *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007*, DOE/GO-102008-2590, May 2008, figure 14. Available at www.eere.energy.gov.
19. There are carbon emissions associated with the manufacturing and construction of wind turbines. In addition, if natural gas is used to “firm” wind power, there are carbon emissions associated with that natural gas use. See Katzenstein, W. and J. Apt, “Air Emissions Associated with Wind and Solar Power,” *Environmental Science and Technology*, 2009, 43 (2), pp. 253-258.
20. This discussion focuses on utility-scale wind farms, which consist of multiple large (1 MW or larger) wind turbines. Smaller wind turbines are commercially available for distributed applications, but are not discussed in this report.
21. Solar Energy Industries Association (SEIA), *US Solar Industry Year in Review 2008*, March 31, 2009, p. 4. Available at www.seia.org.
22. For a helpful explanation of PV systems, see the DOE’s “Photovoltaic Basics” at www1.eere.energy.gov/solar/pv_basics.html.
23. National Renewable Energy Laboratory (NREL), Annual PV Solar Radiation Map. Available at www.nrel.gov. The higher PV electricity output due to increased sunlight can be partially offset by higher ambient temperatures, which decrease PV output.
24. The investment tax credit (ITC) provides a 30 percent federal tax credit for qualifying PV systems. For more information on the ITC, see <http://dsireusa.org>.
25. Wisser, R., G. Barbose, and C. Peterman, *Tracking the Sun*, LBNL-1516E, February 2009, p. 1. Available at <http://eetd.lbl.gov/ea/EMS/re-pubs.html>. There were, and will continue to be, significant year-to-year price fluctuations due to policy changes, economic conditions, and demand/supply imbalances.
26. It should be noted that the module cost data could be reflecting actual cost decreases offset by increased profits.
27. Press release entitled, “First Solar Passes \$1 Per Watt Industry Milestone,” dated 24 February 2009, available at firstsolar.com.
28. Wisser, R., et al., *Tracking the Sun*, February 2009, p. 10.
29. Solar Energy Industries Association, *US Solar Industry Year in Review 2008*, March 2009, p. 7.
30. For more information on state-by-state electricity market regulation, see EIA, “Status of Electricity Restructuring by State,” available at www.eia.doe.gov.
31. The Brattle Group, *Transforming America’s Power Industry*, November 2008. p. 35. Available at www.eei.org.
32. North American Electric Reliability Corporation (NERC), *Accommodating High Levels of Variable Generation*, April 2009, available at www.nerc.com.
33. An example of such a firm is the American Transmission Company—see www.atc.com.
34. National Council on Electricity Policy, *Electricity Transmission: A Primer*, June 2004, p. 76, footnote 1 in appendix. Available at www.raonline.org.
35. See, for example, Milligan, M. and K. Porter, “Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation,” presented at Windpower 2008, June 2008, Houston TX. Available at www.nrel.gov.
36. Smith, J., et al., “Utility Wind Integration and Operating Impact State of the Art,” *IEEE Transactions on Power Systems*, August 2007.
37. DOE, *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007*, May 2008, pp. 6,7.

38. Kirby, B. and M. Milligan, *Facilitating Wind Development: The Importance of Electric Industry Structure*, NREL/TP-500-43251, May 2008, pp.15-16. Available at www.nrel.gov.
39. Wiser, R., et al., *Tracking the Sun*, February 2009, p. 9.
40. Wiser, R., et al., *Tracking the Sun*, February 2009, p. 9.
41. For an explanation of cap and trade, see Pew Center on Global Climate Change, *Climate Change 101: Cap and Trade*, January 2009. Available at www.pewclimate.org.
42. One prominent proposal for the design of a cap-and-trade program is the United States Climate Action Partnership (USCAP), *A Blueprint for Legislative Action*, January 2009. Available at www.us-cap.org.
43. E3 (Energy and Environmental Economics), model prepared for the California Public Utility Commission, “New generation resources and costs,” available at www.ethree.com.
44. More information on state RPSs can be found at www.pewclimate.org and at www.dsireusa.org.
45. Prices are as of 2006. Source is Fraunhofer Institute Systems and Innovation Research, *Evaluation of different feed-in tariff design operations*, Karlsruhe Germany, December 2006, table 3.3. A conversion rate of 1.26 US\$/Euro is assumed.
46. As of the end of 2007. U.S. Department of Energy, *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007*, May 2008, p. 5, table 1.
47. Wiser, R. et al., *Tracking the Sun*, February 2009, p. 14.
48. EIA, *Annual Energy Review*, June 2008, pp. 255, 257.
49. U.S. PV installations in 2008 were 58 percent higher than in 2007. Solar Energy Industries Association, *US Solar Industry Year in Review 2008*, March 2009, p. 2.
50. The 2009 stimulus bill provides some support for this approach, by providing loan guarantees for transmission under the “innovative technology loan guarantee program.”
51. For example, S. 2076, the Clean Renewable Energy and Economic Development Act (introduced September 2007), would have established “national renewable energy zones.” For a discussion of this and related legislation, see Congressional Research Service (CRS), *Wind Power in the United States*, RL34546, June 20, 2008.
52. For example, PJM (the regional transmission organization that coordinates wholesale electricity movements in many Eastern states) has ancillary service markets that allow participants to offer these services for a fee. See www.pjm.com.
53. EIA, *Annual Energy Review*, June 2008, p. 260. Available at www.eia.doe.gov.
54. An electrical substation is a facility where voltage is reduced. Electric power may flow through several substations between generating plant and consumer. A distribution substation transfers electricity from high-voltage transmission lines to the distribution system, such as the power lines that bring electricity to residences and small businesses.
55. Source for this estimate is EIA, *Annual Energy Outlook 2009*, March 2009. Note that this forecast includes the effects of the American Recovery and Reinvestment Act of 2009 (commonly known as the stimulus bill).
56. EIA, *Annual Energy Outlook 2009*, April 2009. This projection reflects the provisions of the American Recovery and Reinvestment Act (ARRA).
57. See DOE, *20% Wind Energy by 2030*, July 2008. Additional documentation can be found at www.20percentwind.org.
58. The DOE proposal calls for 305 GW of wind by 2030—see U.S. Department of Energy (DOE), *20% Wind Energy by 2030*, July 2008, figure 1-3, p. 7. As of the end of 2008, the U.S. had approximately 25 GW of wind installed. American Wind Energy Association (AWEA), *AWEA Annual Wind Industry Report—Year Ending 2008*. Available at www.awea.org.
59. See Appendix 2 for supporting calculations.

60. DOE, *20% Wind Energy by 2030*, July 2008, p. 65.
61. DOE, *20% Wind Energy by 2030*, July 2008, pp. 96-98.
62. American Electric Power (AEP), "Interstate Transmission Vision for Wind Integration," undated report, available at www.20percentwind.org.
63. EIA, "Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities," available at www.eia.doe.gov.
64. DOE, *20% Wind Energy by 2030*, July 2008, p. 98.
65. Mills, A., R. Wiser, and K. Porter, *The Cost of Transmission for Wind Energy*, LBNL-1471E, February 2009. Available at <http://eetd.lbl.gov/ea/EMS/re-pubs.html>
66. DOE, *20% Wind Energy by 2030*, July 2008, p. 77.
67. This assumes a wind cost, excluding the production tax credit, of 9 to 12 ¢/kWh. See Table 1 and Appendix 1 for sources and assumptions.
68. Solar Energy Industries Association, *US Solar Industry Year in Review 2008*, March 2009, p. 2.
69. Utility-scale PV systems typically have lower per-kWh costs, however some state renewable portfolio standards (RPSs) promote or require smaller distributed PV systems.
70. Black & Veatch, *Renewable Energy Transmission Initiative Phase IA—Final Report*, prepared for the California Institute for Energy and the Environment, May 2008. Available at www.energy.ca.gov.
71. Wiser et al., *Tracking the Sun*, February 2009.
72. ACORE (American Council on Renewable Energy), "Joint Outlook on Renewable Energy in America Volume II Joint Summary Report," March 2007. Available at www.acore.org.
73. DOE, *20 Percent Wind Energy by 2030*, July 2008.
74. Google, Inc., "Clean Energy 2030—Google's Proposal for reducing U.S. dependence on fossil fuels," at <http://knol.google.com>. (Search for 'clean energy 2030'). Downloaded April 2009.
75. Repower America, "100 percent clean electricity in 10 years," at www.repoweramerica.org/plan/analysis (downloaded April 2009).
76. EIA, *Energy Market and Economic Impacts of S. 2191, The Lieberman-Warner Climate Security Act of 2007*, SR/OIAF/2008-01, April 2008, p. 26, figure 15.



This paper provides an overview of wind and solar power. The paper examines the potential for these technologies in a low carbon future, barriers to deploying them, and options for overcoming these barriers. The Pew Center on Global Climate Change was established in 1998 in order to bring a cooperative approach to the debate on global climate change. The Pew Center continues to inform the debate by publishing reports in the areas of policy (domestic and international), economics, environment, and solutions.

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