Options for Near-Term Phaseout of Coal Emissions in the United States

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Pushker A. Kharecha[1,#], Charles F. Kutscher[2], James E. Hansen[1], Edward Mazria[3]

[1] NASA Goddard Institute for Space Studies & Columbia University Earth Institute

[2] National Renewable Energy Laboratory

[3] 2030 Inc. / Architecture 2030

[#]Corresponding author: pushker@giss.nasa.gov

Summary

The global climate problem becomes tractable if coal emissions are phased out rapidly and unconventional fossil fuels (such as oil shale and tar sands) are prohibited. This paper outlines technology and policy options for phasing out coal emissions in the United States by ~2030. We focus on the U.S. because it is most responsible for accumulated fossil fuel CO_2 in the atmosphere today, specifically targeting electricity production, which is the primary use of coal.

A major challenge for mitigation efforts in the U.S. is that coal provides the single largest proportion of base load power, i.e., power that satisfies minimum electricity demand. Because this demand is relatively constant, coal is responsible for the vast majority of utility carbon emissions. The current U.S. electric power grid incorporates renewable power on a very limited basis, and most of that is not base load power. However, this can be changed within the next 2 to 3 decades – even intermittent renewables can be deployed in a manner that displaces coal power. Replacing coal usage will also require improved efficiency, a "smart grid", additional energy storage, and, possibly, advanced nuclear power. Any further coal usage must be accompanied by carbon capture and storage (CCS).

We conclude that U.S. coal emissions could be phased out by 2030 using technologies that are available now or could be commercially competitive with coal within about a decade. Elimination of fossil fuel subsidies and a substantial rising price on carbon emissions are the root requirements for a clean, carbon-free future.

Tax policy, energy efficiency regulations, and utility profit motives must be altered to achieve rapid phaseout of coal emissions. Large-scale efficiency improvements and conservation measures are deployable the soonest. The building sector – by far the dominant user of coal – could be carbon neutral by 2030, with appropriate policies. A rising fee for carbon emissions is needed, along with rigorous, enforceable building design standards, increased government investment in efficiency measures, and restructuring of utility profit motives. We emphasize that a rising carbon fee does not imply increased cost for those consumers who reduce their carbon footprint – indeed, their costs may decline.

Two renewable energy sources – geothermal and biomass – could displace much of the base load electric power now provided by coal. Federal investment in research, development, and demonstration of enhanced geothermal systems should be given high priority. Biomass power has special attraction, because, combined with CCS, it has the potential to draw down atmospheric CO_2. Biomass power should employ non-food or waste-derived feedstocks.

Two intermittent renewable energies – wind and solar – could be deployed to a much larger degree via addition of new transmission lines and improvements to the national electric grid. Concentrating solar power generated in the arid Southwest combined with at least 12 hours of thermal storage (typically using molten salt storage tanks) could become a large, commercially viable source of base load power. Although this power would serve Southwest cities in the near term, construction of long-distance, high-voltage DC transmission lines could allow it to be transported across the country. Solar photovoltaic (PV) cells are well suited for rooftop deployment in which transmission issues are avoided and they compete against the retail cost of electricity. PV power does not lend

itself to low-cost storage and typically displaces electricity from natural gas plants that provide power in the peak and intermediate load markets. Wind power also tends to displace natural gas. Both of these technologies will be enabled to an even greater extent by the use of batteries in plug-in hybrid-electric vehicles (PHEVs) or all-electric vehicles (EVs), as well as by a smart grid. They could then displace gasoline and some base load coal plants.

Energy efficiency, renewable energy technologies and a smart grid deserve first priority, but we cannot assume that these will meet all electric needs. High-priority development and demonstration of fourth generation nuclear technology is needed to determine its merits, and current generation nuclear power is ready to contribute to base load power if needed to complete phaseout of coal use, albeit with the several well-known and continuing major non-climate-related problems of nuclear power. Fourth generation nuclear technology, such as the Integral Fast Reactor (IFR) and the Liquid Fluoride Thorium Reactor (LFTR), have the potential to largely solve the nuclear waste problem and eliminate the need to mine more uranium for many centuries. The time required for these technologies to be proven is debatable, but they warrant rapid development given the need to dispose of existing nuclear waste and the growing global need for electric power.

CCS technology development also deserves support up to the point of large-scale demonstration. It can then be one of the elements in the competition among different energy technologies, and it can be used with both coal and biomass power.

With public health and environmental safeguards in place, and with barriers to efficiency removed, competition among alternative energy sources and energy efficiency measures should be determined by market forces. Elimination of fossil fuel subsidies and a substantial and rising carbon price are needed to achieve the most economically efficient path to a clean energy future.

It should not escape attention that the policies needed to eliminate coal emissions are also the policies needed to achieve national energy independence. Specifically, a rising carbon price (and elimination of fossil fuel subsidies) is the core requirement for moving our society to a clean energy future beyond fossil fuels. We suggest that public acceptance of a sufficiently high carbon price requires full return of the revenues to the public in a transparent way that rewards consumers for reducing their carbon emissions.

1. Introduction: The requirement to eliminate coal emissions

A startling requirement emerged from climate science research in the past few years: The "safe" long-term level of atmospheric greenhouse gases is much lower than has been supposed. Indeed, the present amount of atmospheric CO_2 is already into the dangerous zone. We must reduce atmospheric CO_2, already at 385 ppm in 2008, to no more than 350 ppm (Hansen et al. 2008). This requirement derives from improved understanding of Earth's climate history and observations of ongoing changes, such as world-wide recession of mountain glaciers, loss of Arctic sea ice, Greenland and Antarctic ice mass loss, expansion of the sub-tropics, rising sea level, and deterioration of coral reefs.

Implication of the low CO_2 ceiling for coal follows immediately from examination of the fossil fuel reserves of oil, gas and coal (Fig. 1), as pointed out by Hansen et al. (2008) and Kharecha and Hansen (2008). Readily available reserves of oil and gas are sufficient to take atmospheric CO_2 to at least 400 ppm. Oil and gas are such convenient fuels, and the world has developed such a strong dependence on them, that it is certain that the large readily available pools of these fuels will be exploited. The only practical way to preserve a planet resembling that of the Holocene, with reasonably stable shorelines and preservation of species, is to rapidly phase out coal emissions and prohibit emissions from unconventional fossil fuels such as oil shale and tar sands.

Requirements of (1) phasing out coal emissions, (2) averting use of unconventional fossil fuels, and (3) avoiding the need to extract final drops of oil from the most extreme places on the planet, together have strong policy implications. The core requirement is for governments to make fossil fuels more expensive than clean energy alternatives. A first step is to remove fossil fuel subsidies. In addition, there needs to be a substantial rising fee on carbon emissions, so as to generate innovations in renewable energies and energy efficiency.

A further logical inference is that the carbon fee must be returned fully to the public, so they have the wherewithal to invest in new carbon-free technologies and energy efficiency. If the fee is returned uniformly on a per capita basis, people doing better than average in reducing their carbon footprints will make money. With such a rational approach, amplifying socioeconomic feedbacks can take hold and help move the world rapidly beyond the fossil fuel era into a clean energy future.

2. Building sector energy reductions and energy conservation

2.1 Building sector energy reductions

Building energy reduction strategies and material, equipment and efficiency improvements are widely believed to hold great potential for offsetting GHG emissions in the near and long term, both in the US (e.g., ASES 2007) and globally (e.g., IPCC 2007). Numerous studies (e.g., McKinsey 2008) have shown that these measures provide net economic gains per ton of carbon emissions reduced. Improved efficiency is generally defined by the ability to do more with less, i.e., to reduce energy consumption while maintaining or improving services provided by the energy. Given our focus on near-term reduction of emissions from coal burning, we are primarily concerned with available, off-the-shelf building energy reduction and efficiency improvements related to electricity use, as that is the primary use of coal. However we will also briefly discuss potential improvements in other uses of fossil energy (e.g., transportation).

According to the Energy Information Administration (EIA) 2007 Annual Energy Report (EIA 2008), in the US, approximately 93% of coal usage is for electric power generation, with virtually all the remainder used in industrial processes. Conversely, as of 2007, coal burning provided almost half (49%) of all US electric power generation (which totaled 480 GW of capacity or approximately 4200 TWh, or 15 EJ, of energy), with natural gas contributing another 20%. (Most of the remainder is provided by low-carbon sources, primarily nuclear and hydroelectric plants – see Table 2). Overall, electricity consumption therefore accounts for about 40% of US CO_2 emissions.

Over 75% of electricity generation is used for building operations (Mazria 2008[*]). The latest EIA energy "reference case" projects that coal-fired electric power will increase by about 20% or 400 TWh (1.4 EJ) between 2007 and 2030 (Fig. 55 in EIA 2009), and that residential and commercial buildings will account for most of this increase. Regardless of whether or not the EIA reference case is realistic, reducing electrical energy consumption and increasing the efficiency of electricity use via improvements in the building sector must be given high priority.

Numerous technologies, materials and strategies that are currently deployable would allow significant improvements in building energy consumption (e.g., see Table SPM.3 of IPCC 2007). In the commercial and residential sectors, these measures include appropriate planning and design strategies, improved material and building envelope design and insulation; more efficient lighting, equipment and appliances; site and community-scale renewable energy technologies; and recovery and recycling of fluorinated gases used in refrigeration. In the industrial sector, currently available efficiency improvement measures include more efficient end-use electrical equipment and heat/power recovery.

Large-scale implementation of these strategies and numerous existing efficiency, equipment and systems improvements and applications are hindered largely by a lack of appropriate education, policies and market incentives (Levine 2008*; Mazria 2008*). In broad terms, suitable policy measures would include adoption of more rigorous energy codes and standards for buildings and electrical appliances, improved professional design education and government investment in building energy reduction measures and

[*] Asterisks denote workshop presentations – see References.

incentives. Such measures have already been proven to be very effective in reducing electricity consumption on a statewide scale in California (Levine 2008*), as well as many other areas. Development and implementation of new building codes between 2010 and 2030 that satisfy the "2030 Challenge"[1] would greatly reduce building sector GHG emissions. A key market incentive should be the decoupling of utility profits from the sale of electricity (thereby decreasing GHG emissions) and providing a financial incentive for energy reduction and efficiency improvements. Additional suggestions are outlined by Mazria & Kershner (2008), who assert that aggressive policies and sufficient incentives could allow the building sector to become largely or entirely carbon-neutral by 2030, thereby potentially leading to very large reductions in coal emissions (Fig. 2). Design and planning strategies and material and equipment applications that would allow significant energy reduction and efficiency improvements, and are available today, include (but are not limited to) the items listed in Table 1.

2.2. Energy Conservation

Policies related to carbon emissions pricing are especially important and necessary. Global bottom-up analyses across all emissions-generating sectors of human activity reveal that appropriate carbon pricing would lead to substantial GHG emissions reductions in all sectors, and the building sector represents by far the greatest potential source of emissions reductions (see Fig. SPM.6 of IPCC 2007). Furthermore, such analyses show that in the same amount of time, a higher carbon price would lead to correspondingly higher GHG emissions reductions. If carbon pricing schemes are supplemented by concomitant cuts in fossil fuel subsidies, the true costs of coal and other fossil fuel use would become clear, as subsidies have the effect of masking these costs (i.e., from environmental damage such as climate impacts) by simply externalizing them.

It is self-evident that in addition to improvements in energy efficiency, energy conservation – defined simply as lowered absolute consumption of energy – can also contribute substantially to the broader goal of reduction in energy intensity (defined as the energy consumed per unit GDP), thereby providing substantial savings in GHG emissions from coal as well as the other fossil fuels. It is somewhat difficult to quantify the potential savings from conservation measures, as they relate largely to lifestyle choices. However, effective incentives for individuals and households can be enacted to encourage increased conservation, such as a carbon tax accompanied by a 100% dividend. The latter can be computed based on comparing individual/household emissions with national per capita emissions (e.g., see Hansen 2009).

[1] See http://www.architecture2030.org/2030_challenge/targets.html for detailed targets.

3. Renewable energy sources

3.1 Geothermal power

Geothermal power is derived from naturally occurring heat energy in the Earth's crust. As with essentially all renewable energy sources, it produces >95% fewer life-cycle GHG emissions than coal power (Fig. 3). One of its greatest benefits is provision of base load power, thus potentially displacing coal-fired power and its associate carbon emissions. In addition, it causes relatively few other environmental problems; the resource base lasts the entire life of the plant; and the most common types of plants can generate electricity at competitive costs (on the order of 5-8 cents/kWh; ASES 2007).

Currently the US has about 3 GW of installed geothermal power capacity (providing 26 TWh/yr or 0.09 EJ/yr), with an additional 3.5–5.5 GW under development (Fig. 4; GEA 2009). In 2007 this accounted for approximately 4% of total renewable electricity production, and thus less than 0.4% of total electricity consumption, or 0.7% of electricity production from coal (Table 2).

However, the national geothermal resource base is very large. There are currently three main types of conventional geothermal power plants in use in the world: dry steam plants, flash steam plants, and binary-cycle plants (which use a power cycle working fluid other than water)[1]. All current plants use hydrothermal resources, i.e., naturally occurring hot fluids (liquid water or steam) contained in rocks with relatively high permeability. These plants operate at a capacity factor (ratio of average power output to rated power output) of greater than 90%, whereas coal-fired plants typically operate at about a 67% capacity factor (ASES 2007). Geographically, geothermal resources of the US are concentrated in the west (Fig. 5a). A recent analysis by the US Geological Survey (USGS) estimates a mean national hydrothermal electric power potential of about 9 GW (providing 88 TWh/yr or 0.3 EJ/yr) in identified resources and an additional 30 GW in unexplored resources (Williams et al. 2008). However, there is a large uncertainty in these resource estimates. The 95% and 5% confidence values for these resources are, respectively, 4 to 16 GW for identified sources and 8 to 73 GW for undiscovered resources.

An additional type of geothermal power, known as enhanced geothermal systems (EGS[1]), has the potential to vastly expand the geothermal resource base (Fig 5b). This involves the use of hydrofracturing to add water and permeability to underground regions that lack either water or permeability (or both) but have high temperatures. Major technological barriers include site selection and engineering of sustainably large fluid reservoirs that avoid water loss and short-circuiting between injection and production wells. A reasonable goal of an EGS project is to obtain a continuous water flow rate at a production well of 80 kg/s at 200°C (Kutscher 2008a*). Thus far the highest achieved flow rate at an experimental EGS site has been 25 kg/s (DOE 2008a). Economically, there are substantial costs and risks associated with exploration, drilling, and plant development. Because depths of 3 to 10 km are required to reach sufficient temperatures, drilling costs are especially important. Until recently, there was limited federal funding for EGS projects, providing little incentive to conduct the high-risk experiments in a wide

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[1] For plant designs see http://www1.eere.energy.gov/geothermal/powerplants.html and http://www1.eere.energy.gov/geothermal/enhanced_systems.html

range of geologic settings that are required in order to validate this technology on a commercially competitive scale (Kutscher 2008a*). Recently, however, the Obama administration announced that $80 million from the American Reinvestment and Recovery Act would support the research and development of Enhanced Geothermal Systems.[1]

EGS is attractive despite the high risks and technical challenges, for two reasons: the resource potential is enormous and EGS plants would provide base load power that could directly displace coal-fired plants. As with hydrothermal resources, the USGS estimates of the EGS resource span a wide range. The 95% and 5% confidence level estimates are 345 to 728 GW with a mean of 518 GW, the latter equivalent to 4000 TWh/yr or 14 EJ/yr (Williams et al. 2008), which is equivalent to all current US generation and 50% more than projected coal-fired generation in the EIA 2030 reference case. A 2007 Department of Energy (DOE)-sponsored study estimated that the potential EGS power supply by mid-century could be 100 GW (DOE 2008a), at an electricity cost of 7 cents/kWh (MIT 2006). A subsequent DOE review did not dispute the 100 GW goal but indicated that significant advancements must be made in drilling and reservoir production/maintenance to achieve the 7 cents per kWh cost number (DOE 2008a)

A study by the American Solar Energy Society (ASES 2007) concluded that there is potential for 50 GW (about 400 TWh/yr or 1.4 EJ/yr) of geothermal power by 2030 without relying on deep EGS resources. It assumed that 25% of the 50 GW would be from hydrothermal resources, 50% from waste hot water at existing oil and gas wells along the U.S. Gulf Coast, and 25% from expansion of existing hydrothermal fields through water injection and fracturing.

In summary, geothermal power has the potential to offset some US demand for coal-fired power in the near term and a very large long-term potential, albeit with considerable technological risk. Because of its potential to provide base load power, near term development of known geothermal resources can make an important contribution to carbon emissions reductions. And because of the extremely large resource potential of EGS, an aggressive research and development (R&D) effort to develop EGS resources is warranted despite the technological risks and challenges. Similar conclusions apply to the global scale as well. For example, by some estimates (IPCC 2007) the world's geothermal resource base is 5000 EJ/yr (~175,000 GW), which is about 10 times greater than current total annual energy use worldwide.

[1] See http://www.energy.gov/news2009/7427.htm

3.2 Biomass power

Electricity is produced in biomass-fired power plants in three basic ways: by direct combustion, by co-firing with a fossil fuel (usually coal), or by integrated gasification combined cycle (IGCC), which involves gasification via pyrolysis followed by combustion of the gas. Typical biomass sources are plant matter (including wood and leaves/stems), agricultural crop residues (e.g., corn stover), and urban or industrial wastes (e.g., pulp from paper mills, municipal solid waste, and landfill gas). Along with geothermal energy, bioenergy is the only non-hydro renewable energy source that can generate reliable base load power and thereby potentially allow direct displacement of coal. If done properly, biomass power (as well as liquid biofuels) can be a low-carbon or even carbon-negative source of energy (e.g., see Tilman et al. 2006; Hansen et al. 2008). Furthermore, besides reducing CO_2 emissions from fossil fuels, bioenergy sourced from agricultural and forest residues and landfills can also reduce non-CO_2 emissions (e.g., CH_4).

Biomass power capacity in the US is currently about 10 GW (78 TWh/yr or 0.3 EJ/yr) (Fig. 4). In 2007 it provided approximately 1% of total electric power generation, 16% of renewable power generation, and about 3% of coal-fired power generation (Table 2). Wood and wood-derived fuels comprise about 2/3 of the supply and urban waste and agricultural byproducts comprise about 1/3 of the supply (EIA 2008). Unlike other renewable resources, a major cost of biomass power are associated with the resource itself (Kutscher 2008b*). These include vegetation planting and management; harvesting and collection; and transportation of biomass products to power plants. In dollar terms, these costs amount to $20–60/ton dry biomass, with resulting electricity costs of 5–12 cents/kWh (IPCC 2007). Typical operating efficiency for biomass power plants ranges from 20% for direct combustion plants to 40% for IGCC plants, and biomass power plants can operate with capacity factors of 90% (ASES 2007).

A comprehensive interagency analysis led by DOE's Oak Ridge National Laboratory suggests that the US potential resource base for bioenergy is large – about 1.3 billion tons of biomass by 2025 (Perlack et al. 2005). Of the various sources of biomass in that study, approximately 70% are from agriculture and 30% from forestry. Substantial resources are available in most states, although supplies are largest on the West Coast and the upper Midwest states (Fig. 6). This resource base could be capable of generating over 230 GW (1800 TWh/yr or 6 EJ/yr) of power, of which slightly less than half, or 1000 TWh/yr, might be economically viable (ASES 2007). This amounts to approximately half of current US coal-fired power generation and could offset far more than the projected 400 TWh increase in coal power by 2030 in the EIA reference case (EIA 2009). Carbon prices in the range of $25–35/t$CO_2$ would likely be needed to make large-scale biomass power economically competitive with coal power (Rhodes and Keith 2005).

Biomass power is generally considered to be roughly carbon-neutral. That is, carbon dioxide is released to the atmosphere during power production but is extracted from the atmosphere by plant growth. Some studies have indicated, however, that biomass power can be carbon-negative in some cases, as when forest residues are harvested rather than allowed to decay in the forest. Biomass power also offers an important option that other renewables do not: the potential to incorporate carbon capture and storage (CCS), thereby making biomass power strongly carbon-negative. Whether or not CCS is employed, however, it is important to consider the full spectrum of carbon impacts in evaluating the use of biomass. Specifically, crops that are specially grown for bioenergy should not indirectly lead to carbon-positive land use changes elsewhere or result in conversion of pristine ecosystems to cropland. For instance, the current approach involving food crop-based bioenergy seems untenable from both a climate and sustainability standpoint (UN-Energy 2007; Searchinger et al. 2008). A more sound approach utilizes biomass waste products or low-input/high-diversity perennial plants grown on degraded or marginal lands (Tilman et al. 2006; Fargione et al. 2008).

Although this paper focuses largely on alternative electricity sources, liquid biofuels warrants some brief discussion here, as it is highly contentious. As mentioned above, current-generation liquid biofuels – primarily corn starch-derived ethanol and biodiesel from soy or palm – appear undesirable climatically, ecologically, and socioeconomically (e.g. see UN-Energy 2007; Fargione et al. 2008; Searchinger et al. 2008). However, substantial carbon savings could be provided by next-generation liquid biofuels, e.g., lignocellulosic ethanol derived from biomass residues, perennial prairie grasses or algae-based fuels. These fuels could offset significant demand for liquid fossil fuels, which could become a particularly critical issue socioeconomically as well as climatically, in light of concerns about likely near-term supply constraints on conventional liquid fossil fuels (Hirsch et al. 2005; Kharecha and Hansen 2008). Although liquid biofuels seem desirable from various standpoints, biomass used in electricity production can provide greater carbon emissions reductions, due in large part to its significant potential to displace coal power (ASES 2007).

3.3 Wind power

Wind power has been the fastest growing renewable energy source in the U.S. in recent years, primarily because of its low overall costs. Consequently, wind power accounts for the vast majority of added renewable electricity capacity in the US (Fig. 4). The current nationwide capacity is over 28 GW[1] (90 TWh/yr or 0.35 EJ/yr, based on an average 40% capacity factor). In 2007 wind accounted for about 0.8% of total electric power generation, 9% of renewable power generation, and 1.6% of coal-fired power generation (Table 2). Principal costs associated with wind power generation relate to turbine construction and deployment, land costs, and grid integration costs. Despite these costs, because of the sophistication of modern wind turbines, wind power is still economically competitive with fossil fuel power – even without a production tax credit, its overall cost is about 4–7 cents/kWh, with precise cost being inversely proportional to wind speed (ASES 2007). Life-cycle CO_2 emissions of wind power generation are trivial compared to any of the three fossil fuels and are among the lowest of all the renewables (Fig. 3).

The potential onshore wind resource base in the US is substantial, particularly west of the Mississippi; however the Southeast is largely lacking in onshore wind resources (Fig. 7). A recent major study led by DOE examined the feasibility of wind energy providing 20% of electricity production by 2030 (DOE 2008b; Gramlich 2008*). Key assumptions of that analysis include the following: electricity demand would follow the EIA's 2007 Annual Energy Outlook projections, i.e., demand would increase by about 1600 TWh/yr; over 300 GW of additional wind capacity would be needed to supply 20% of the 2030 electricity supply; 10% of existing grid capacity is available for wind; and wind turbine costs would be 10% lower by 2030 while turbine capacity factors would increase by about 15% by 2030 without major breakthroughs in wind technology. Major findings of that study relevant to this report are that integration of wind energy into the electric grid can be done at very low cost (<0.5 cent/kWh) and without limitations by supplies of raw materials; and excluding grid integration costs, over 600 GW of onshore wind power could be economically viable (<10 cents/kWh), even without a production tax credit. In addition, the scenario leads to a decrease of about 18% of coal consumption and 50% of natural gas consumption by electric utilities, thereby offsetting construction of >80 GW of new coal-fired power plants (from a baseline projection of 140 GW of added coal power).

It is important to bear in mind that the above DOE study was based on consideration of additional wind capacity only, i.e., it excluded integration of other renewables and effects of efficiency/conservation measures. It is much more likely – and advisable – that the country would deploy a combination of efficiency and various renewable energy technologies (plus possibly nuclear). For example the ASES study (ASES 2007), which found wind energy to be the largest renewable energy contributor by 2030, estimated that 20% grid penetration by wind would require only 245 GW when reduced electric demand from efficiency improvements is taken into account. Both the ASES and DOE studies demonstrate that wind power holds great potential to significantly reduce U.S. electric energy requirements from fossil fuel plants.

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[1] As of April 30, 2009 – see http://www.windpoweringamerica.gov/wind_installed_capacity.asp.

That being said, the most fundamental drawbacks of wind power (as with solar power, discussed below) are its variable nature and the distances between resource locations and population centers. Wind power is variable both on a diurnal basis (wind speeds are generally higher at night) and a seasonal basis (winter is windier than the summer). Solar energy experiences the opposite effects. Thus, deploying wind and solar together is complementary. The variable nature of the wind hinders its ability to provide base load power, which is a fundamental advantage of coal from a supply perspective. It is not very surprising, then, that utilities currently don't give much capacity credit to wind.

Wind energy (and solar energy) might therefore ostensibly seem to have limited potential to reduce emissions from coal power. However, analysis has shown that the shortcomings of wind power in this respect might be compensated to a significant degree by deploying a large fleet of plug-in hybrid electric vehicles (PHEVs) or all-electric vehicles (EVs) (Fig. 8). The batteries from such a vehicle fleet would provide distributed electrical storage, which, when coupled with a smart grid, could enable higher integration of variable renewables into the electric grid (ASES 2007). Wind power could charge batteries mostly at night, when most electricity is provided by coal. Furthermore, aside from reductions in coal emissions, this type of fleet could also lead to significant reductions in emissions from oil use, which has now been the largest single source of CO_2 emissions in the US for a number of years (Marland et al. 2008).

3.4 Solar photovoltaic power

Like wind turbines, solar photovoltaics (PVs) have been in use around the world for several decades. There are two basic types of PVs: thin film and wafered crystalline silicon. The latter type accounts for the vast majority of PVs in current use. Various figures of merit for both types of PVs are given in Hall (2008*). Wafered silicon PVs have a solar conversion efficiency of 15 to 23%; module manufacturing costs of about \$300/m^2; unit power cost of about \$2/W$_p$ (peak watt); and solar utilization (capacity factor) of 17-19% (for non-tracking installations). By contrast, thin film PVs have a solar conversion efficiency of about10%; module manufacturing costs of about \$117/m^2; unit power cost near \$1/W$_p$; and the same solar utilization factor. Typical resulting electricity costs are about 35 cents/kWh and 28 cents/kWh for wafered silicon and thin film PVs, respectively. Life-cycle energy payback times are around 1 year for thin film PVs and 2-3 years for wafered silicon PVs. Life-cycle CO_2 emissions of PVs, especially crystalline silicon, are significantly higher than those of other renewable energies, although they are substantially lower than all fossil fuels (Fig. 3).

Solar PVs currently account for about 2 GW (3 TWh/yr or 0.01 EJ/yr) of electricity in the U.S. and have exhibited significant growth this decade (Fig. 4). Electricity generated by solar PVs and solar thermal plants (see next section) accounted for about 0.01% of total generation, 0.17% of renewable electricity generation, and 0.03% of coal-fired generation in 2007 (Table 2). The highest use in the US is in the residential sector (i.e., rooftop installations), as PVs can provide electricity on that scale on a competitive basis with local utility providers if the cost is folded into a 30-year mortgage. The development of single-axis tracking PV modules and innovative business models have helped PV also enter the central electric generating market.

Country-level assessment of PV potential by 2030 (ASES 2007) suggests that suitable rooftop area for PV installation amounts to 6 to 9 billion m^2, and that the industry has the capability to produce 200 GW$_p$ by 2030, i.e., two orders of magnitude higher than current capacity. Furthermore, PV deployment on rooftops, along highways, and atop shading structures in parking lots would reduce the large amount of land that would otherwise be needed to achieve this level of penetration, and it also reduces the need for extra transmission capacity and grid usage, since the electricity produced would be consumed in the immediate vicinity. One concern about both large-scale PV and wind production is that there will be times during the day when the remaining power that needs to be provided by the utility dips below that being produced by base load plants. Because base load plants cannot be economically scaled back in power output, wind and PV would have to be curtailed instead. This overlap between variable renewable power supply and steady fossil fuel base load power supply already results in curtailment of wind power in some areas such as in Texas.

Although PVs have enormous theoretical potential as a power source both nationally and globally, they are hindered by the fact that solar energy is intermittent and electrical storage (e.g., batteries) is currently expensive. Thus, they would not likely be viable substitutes for coal plants without additional storage (such as pumped hydro or compressed air energy storage). However, they could provide substantial displacement of demand for peak load power from natural gas plants. High cost is still a major barrier for PV, although cost reductions are likely to continue in the future as automated manufacturing facilities for thin film PV are developed. Further efficiency improvements are also anticipated (IPCC 2007).

3.5 Concentrating solar power (CSP)

CSP, a.k.a. solar thermal power, has been attracting increasing attention in recent years as a potentially large source of peak load as well as intermediate and even base load power when combined with relatively low-cost thermal energy storage. Five different types of CSP plant designs have been designed and deployed, distinguished by their method of concentrating solar flux (Morse 2008*). Most of these designs consist primarily of concrete, steel, and glass materials. Unlike solar PVs, all CSP plants work with direct radiation only, as diffuse radiation cannot be optically concentrated to achieve the high temperatures needed to run a heat engine. CSP plants also require dedicated land area, although sparsely inhabited areas such as deserts can become viable options if appropriate transmission infrastructure is in place (see Section 4). The most common existing plant designs, employing parabolic troughs, are able to achieve solar flux to annual grid electricity conversion efficiencies of about 15%, and within the next few decades, CSP capacity factors can reach levels of 50–70% (IPCC 2007) given a sufficiently large thermal storage, possibly including up to 15% back-up with natural gas.

For many years, CSP represented the largest amount of deployed solar energy in the United States, as a result of the 354 MW (0.7 TWh/yr or 0.003 EJ/yr, based on a no-storage capacity factor of 25%) of parabolic trough plants that were installed in the Mojave Desert during the 1980s. Construction of trough plants ceased in 1992 as a result of low natural gas prices, loss of power purchase incentives and utility deregulation. Recently, however, there has been a strong resurgence in this technology. (Fig. 4). A 1 MW plant was built in 2006 near Tucson, Arizona and a 64 MW plant was built outside of Las Vegas, Nevada in 2007.

An additional 4800 MW of plant capacity is currently under contract in California, Arizona, Nevada, New Mexico, and Florida (Morse 2008*). A new 250 MW trough plant with 6 hours of thermal storage that will be built outside of Phoenix for Arizona Public Service (APS) is projected to have an electricity cost of 14-15 cents per kWh after the 30% investment tax credit (M. Mehos [NREL], personal communication). This compares to about 12 cents per kWh for a new combined-cycle natural gas plant. But a CSP plant has effectively no fuel costs and the 2-3 cent premium is viewed by APS as a hedge against future increases in natural gas prices. Continuing reductions in the costs of CSP technology are expected as a result of R&D, economies of scale, and learning curve effects. As an R&D example, one new collector being developed uses a polymer reflective film in place of a glass mirror, resulting in a significant reduction in reflector weight with an accompanying reduction in support structure costs. Deployment of 4 GW of cumulative capacity by 2015 could drop the electricity cost to about 8 cents/kWh (Morse 2008*). Life-cycle CO_2 emissions from CSP power are trivial compared to all fossil fuels and substantially smaller than PV power (Fig. 3).

Solar energy has by far the largest potential of all renewable energy sources. A 2005 study for the Western Governors' Association (WGA 2006) started with the direct normal solar radiation potential in the Southwestern states. It then excluded the following locations: areas with solar direct normal radiation less than 6.75 kWh/m^2/day; environmentally sensitive land, major urban areas, and water bodies; and terrain having slope >1 to 3% or contiguous area <1 km^2. The resulting potential electric capacity for

CSP was 7000 GW (ASES 2007), i.e., about 7 times the total current U.S. electricity capacity.

After also factoring in distance to available transmission lines, a National Renewable Energy Laboratory (NREL) market deployment model identified 200 GW of optimal sites (ASES 2007), distributed as shown in Fig. 9. The same analysis suggests that, assuming a carbon price of at least 35$/t$CO_2$, 80 GW could be competitively deployed by 2030. These plants would have 6 hours of thermal energy storage, resulting in an average capacity factor of 43%. They would generate about 300 TWh/yr, which is about 75% of the EIA's projected increase in coal demand between 2007 and 2030 (EIA 2009). The US DOE aims to make CSP an intermediate-load, economically viable power source by 2015, and a viable source of base load power by 2020[1]. On a global scale there are ambitious plans to further develop over 3400 GW of CSP capacity (including in developing countries). CSP-supplied electricity could account for 5% of world electricity demand by 2040 (IPCC 2007).

Several key research and technology needs will need to be addressed in order to allow CSP to become a large-scale energy source. Specifically, in order for CSP to become a viable substitute for coal-fired base load power, larger thermal storage size will be needed. For instance, to achieve the DOE's 2015 goal of competitive intermediate-load CSP power would require up to 6 hours of storage (and plant operating temperature of 500°C), while meeting the 2020 goal of commercially viable CSP base load power would need up to 12–16 hours of storage (and, preferably, operating temperature up to 650°C) (Morse 2008*), thereby raising costs significantly, absent any major technology improvements, subsidies, etc. In addition to the critical R&D needs related to energy storage, the cooling water need for CSP plants is also an important consideration, especially since CSP plants are best suited for arid regions. Air cooling increases the cost of electricity by about 8% compared to water cooling; however, parallel wet-dry cooling systems show promise for greatly reducing water consumption with better economics than an air-cooled plant.[2]

[1] See http://www1.eere.energy.gov/solar/csp_program.html (accessed Feb. 2009)
[2] See DOE Report to Congress, http://www1.eere.energy.gov/solar/pdfs/csp_water_study.pdf (accessed Jun. 2009)

4. Electricity transmission and grid integration of renewables

As discussed in Section 3, with the exception of geothermal and biomass power (and CSP combined with substantial thermal storage), renewable energy sources are inherently limited in their ability to substitute for coal-fired base load power due to their variability. This currently poses a major barrier to the large-scale deployment of renewables, although this problem is not insurmountable.

Electrification, enabled by the current US power grid, has been deemed by the National Academy of Engineering to be the most important engineering achievement of the 20th century (see www.greatachievements.org). However, the current grid has a number of fundamental limitations that will need to be addressed in order to become a truly "smart" grid that provides value to the customer, the local utility and economy, and the environment – most notably, grid efficiency, reliability, and security, and environmental and economic concerns (Hauser 2008*). The US DOE recently commissioned a comprehensive report that provides a useful introduction to the "Smart Grid" notion.[1] Among other things, the report asserts that increasing the efficiency of existing (centralized) grid structure by just 5% would provide GHG emissions reductions equivalent to removal of over 50 million cars. The DOE outlines five broad smart grid-enabling technologies: (1) an integrated network for two-way communication among the various grid components; (2) advanced sensing and monitoring technologies; (3) advanced physical components; (4) advanced transmission control methods; and (5) improved interfaces and decision support. Public and private utilities in a number of US states are already implementing smart grid demonstration projects, which will provide valuable insights into the feasibility of various aspects of a smart grid.

Improvements in power transmission and distribution methods hold great potential to help enable much larger scale deployment of renewable power. Major factors affecting implementation of grid improvements include economic costs as well as energy policies. Current costs for up to 15% grid integration for solar and wind power are of the order of 0.4 cents/kWh (Table 3), but these costs are projected to decrease with improvements in forecasting (APS 2007). In a recent study on the deployment of 20% wind by 2030 (DOE 2008b), new transmission was estimated to cost about 10% of the wind capital cost. Costs of required additional high-voltage DC transmission lines can be of the order of \$1600/MW-mile (\$1000/MW-km) (Gramlich 2008*), but estimates of transmission costs vary widely by region. "Smart" redistributing of wind power would also require substantial new transmission capacity (Fig. 7), as wind source regions are often far-removed from power demand regions.

Several key policy measures will need to be enacted to allow large-scale, near-term construction of next-generation grids (Gramlich 2008*). Federal legislation calling for implementation of "green power superhighways" and decentralized (regional) grid operations is especially important. Federal agencies such as the Federal Energy Regulatory Commission (FERC) and the DOE can determine cost allocation and transmission line planning, including right-of-way considerations. State governments (governors) can then help to shape regional transmission plans and grid operations.

In addition to economic and policy measures, Earth science research can also play an important role in enabling large-scale renewable grid integration, via improved

[1] Available at **http://www.oe.energy.gov/1165.htm** (accessed Feb. 2009)

forecasting of solar and wind fluxes. (NREL and the National Oceanic and Atmospheric Administration are currently engaged in such a collaborative effort.)

5. Nuclear power

The vast majority of the world's existing (second and third generation) nuclear power plants, all of which are fission-based, employ once-through fuel cycles, i.e., they do not recycle/reprocess the spent fuel products. There are a number of different nuclear reactor designs in use around the world, but of the 104 fully licensed U.S. nuclear plants, all are light water reactors. Of these, 69 are pressurized water reactors (PWRs) and 35 are boiling water reactors (BWRs).[1] PWRs use nuclear fission to heat water at high pressure in the reactor, which is then circulated through heat exchangers to generate steam that drives electric turbines. BWRs use the heat from fission to boil the reactor coolant water into the electric generator-driving steam.

A major advantage of nuclear power over most alternative (low-carbon) energy sources is its ability to supply reliable base load power. France, for instance, depends on nuclear power for about 80% of its electricity production. However, current generation nuclear reactors pose numerous environmental and other issues that might limit their future viability – notably, relatively high costs, large-scale radioactive waste generation (and the consequent need for long-term storage), safety concerns, and risk of increased nuclear weapons proliferation (e.g., see MIT 2003). As with renewable energy sources, life cycle emissions from nuclear power are generally very low compared to fossil fuels (>90% lower) and have a magnitude roughly between that of crystalline silicon PV and wind power (Fig. 3).

All existing and currently planned US nuclear power plants employ a once-through fuel cycle. Nationally, nuclear power presently has a capacity of about 100 GW and operates at a capacity factor of over 90% (EIA 2008). In 2007 it provided about 800 TWh/yr (3 EJ/yr), or about 19% of total US electricity generation and 40% as much as coal-fired power (Table 2). There are 21 pending license applications for new nuclear reactors under review by the Nuclear Regulatory Commission (NRC), located mostly in the Atlantic states (Davis 2008*)[2]. Spent nuclear fuel rods are currently stored on site in specially designed water pools at the power plants, although if maximum storage capacity is reached, the NRC allows plants to store the waste in above-ground dry containers. As spent fuel waste exceeds on-site storage capacity at a growing number of plants, the longstanding debate over future long-term storage of this waste will intensify.

The future potential of current-generation nuclear power could be limited by waste disposal and the other significant barriers mentioned above, along with costs and timeliness of plant construction. For instance, in the EIA reference case, nuclear power capacity and generation both grow by about 12% by 2030, while proportional contribution to total electricity generation decreases by almost 2%, a result similar to other near-term projections (see Table 18 in EIA 2009). However, such analyses do not fully incorporate policies enacting major constraints on GHG emissions. Thus with respect to climate they can be regarded as very conservative projections. By contrast, more optimistic scenarios (e.g., MIT 2003) yield several-fold increases in US and global nuclear power capacity by mid-century, assuming cost mitigation measures and other policies designed to make nuclear and other alternative power sources more economically competitive with fossil fuels. Given growing awareness and concern about anthropogenic

[1] See **http://www.eia.doe.gov/cneaf/nuclear/page/analysis/nucenviss2.html** (accessed Feb. 2009)
[2] Also see **http://www.nrc.gov/reactors/new-reactors/col/new-reactor-map.html** (accessed Feb. 2009)

climate change among both the public and politicians, it seems likely that GHG emissions constraints will indeed be adopted in the US and elsewhere in the near term, and thus the share of nuclear power might increase significantly beyond what the EIA reference case and similar studies project. Nonetheless, even under such favorable circumstances, nuclear power might be limited by the time frame in which it can be deployed. Licensing and construction of a planned new plant might take the better part of a decade.

5.2 Next-generation reactors

There are various possible designs for nuclear breeder reactors that employ closed fuel cycles that create (breed) new fuel during their operation. Two such designs are thorium-based reactors (specifically liquid fluoride thorium reactors, or LFTRs) and integral fast reactors (IFRs). As discussed further below, both of these designs, and breeder reactors in general, potentially have numerous major advantages over current-generation (once-through fuel cycle) reactors. Most notably, if designed properly they would generate little or no long-lived waste, nothing suitable for weapons, and would require neither mining nor enrichment of uranium, thereby potentially reducing life-cycle GHG emissions much more than even conventional nuclear power.

A key disadvantage of these and other advanced (closed) fuel cycle technologies is that they have not yet been demonstrated at commercially viable (~GW) scales. And while there have been projects in which fundamental prototype concepts have been successfully demonstrated (see Section 5.2.2), it is not clear that large-scale deployment could be accomplished in a shorter or even similar time frame as current-generation reactors require. Because uranium supplies appear adequate in the near term, reprocessing is expensive, and current reprocessing systems produce plutonium, a study by MIT (2003) concluded that near-term expansion of the nuclear industry should use conventional nuclear power plants employing the once-through fuel cycle. The assumptions and conclusions of this study are challenged in detail by Blees (2008).

In any case, we believe that it is vital to pursue commercial-scale feasibility assessment of IFRs and LFTRs and other next-generation reactor technologies because of the many potential benefits they could provide. This could be easily accomplished with appropriate government policies. Indeed, some major energy-consuming countries have plans to deploy advanced fuel cycles including LFTRs (see Section 5.2.1), given the major problems inherent in current-generation technology (see Section 5.1).

<u>5.2.1 Thorium-based nuclear fuel cycles</u>

Use of thorium, which exists in nature entirely as weakly radioactive ^{232}Th, as a fertile fuel for nuclear power has been demonstrated since the mid-1960s in five different reactor designs in numerous countries, with reactor power output ranging from 2 to 300 MW (e.g., see IAEA 2005 and references therein). Numerous benefits are afforded by Th-based fuel cycles, including some advantages over fertile ^{238}U-based cycles (IAEA 2005). For instance, thorium is 3 times more abundant than uranium in the Earth's crust and is present in high concentrations in populous, major energy-consuming countries such as India where relatively little uranium is available. Thorium-based fuel cycles are inherently proliferation-resistant due to the production of strongly radioactive ^{232}U (half-life ~74 yr) and its relatively short-lived daughter products. In addition, waste and other byproducts are generally easily managed, as over 80% of them would become stable within a decade, and the remainder would pose a radiation hazard for a much shorter time than byproducts of current-generation reactors. And unlike ^{238}U-based breeding, which can only occur in fast neutron reactors, Th-based breeding can also occur with thermal neutrons. Thorium-based fuel cycles also possess several disadvantages relative to U-based cycles, a key practical one being the relatively limited experience and empirical data on which to base future larger-scale investment (see IAEA 2005 for further details on advantages and disadvantages of Th-based power).

The USGS estimates that domestic reserves of Th amount to about 300,000 tonnes, or 20% of the world's supply (USGS 2008). In the context of LFTRs in the US, Oak Ridge National Laboratory (ORNL) successfully conducted the Molten Salt Reactor Experiment in the mid-late 1960s, which provided a modest amount of power (~7 MW) and operated for 4 years (Haubenreich & Engel 1970). That experiment and others highlighted some substantial advantages of LFTRs over current-generation reactors (Sorensen 2008*). For instance, they can be designed to be passively safe: if the power shuts down completely, a frozen salt plug holding the core salt in place can melt and drain the core salt into a passively cooled reservoir, rendering fission impossible. LFTRs can also make highly efficient use of fuel – to generate the same amount of energy in a given year in a current-generation reactor, several thousand times more uranium ore would have to be mined. Additionally, far fewer problems arise with the spent nuclear fuel. Properly designed and constructed LFTRs could ultimately provide electric power at lower costs than current-generation reactors. Large-scale feasibility assessment projects are currently being planned by some thorium-rich energy-intensive countries (e.g., India), and other countries also have substantial R&D programs (e.g., Russia, Norway, and Canada).

5.2.2 U-based integral fast reactors (IFRs, a.k.a. liquid metal fast reactors)

The world's first, and to date only, IFR prototype was conceived and developed at Argonne National Laboratory (ANL) from 1984 to 1994. A complete overview of the IFR technology is provided by Till et al. (1997), in a special issue of the journal *Progress in Nuclear Energy* devoted to all the key aspects of the technology. A full accounting of the development and fate of the IFR, as told by the ANL scientists involved, is given by Blees (2008). As discussed below, almost all of the elements of the IFR were demonstrated successfully, although the program was canceled by Congress at the behest of the Clinton Administration.

In brief, the IFR program was developed largely out of proliferation concerns as well as recognition that continued deployment of nuclear power was growing politically untenable. The IFR design possessed four key features that distinguish it from conventional (once-through fuel cycle) reactors (Till et al. 1997). First, it can make highly efficient use of its input fuels: it can generate about 100 times more energy from uranium than conventional thermal reactors, and can consume virtually all of the uranium or plutonium used to operate it. The input fuel is metallic (rather than oxide), which can provide numerous advantages including greater safety and lower fuel recycling costs.

Second, the IFR design incorporates inherent passive safety features that obviate the need for the large amounts of safety equipment in conventional reactors (which can account for up to 80% of all reactor equipment). The key safety features in the ANL IFR project were a result of the use of metallic fuel (a U-Pu-Zr alloy) and liquid metal (sodium) cooling, designs which were tested in the precursor for the IFR, the Experimental Breeder Reactor (EBR) II (Sackett 1997). These features allowed for operating conditions to be well within safety limits and for passive processes to both balance power production with heat removal and passively remove decay heat – see Wade et al. (1997) for technical details regarding safety features of the IFR.

Third, through its fuel recycling processes, an IFR reactor can avoid production of virtually all of the most problematic waste of conventional reactors, i.e., plutonium and other long-lived (transuranic) actinides, which have lifetimes of millennia. It can accomplish this by fairly simple “pyroprocessing”, a method of on-site fuel recycling that involves high temperatures and molten salts and solvents. The metallic U-Pu alloy fuel used in an IFR can be produced via “electrorefining” during pyroprocessing, which requires minor actinides to be present along with plutonium, assuring that it is never separated during the fuel cycle (Ackerman et al. 1997; Laidler et al. 1997). Although the IFR fuel cycle could have major advantages, it would still produce some waste (fission products) that would be highly radioactive for decades and thus would require geological disposal, albeit to a far lesser scale than with conventional reactors. Unfortunately, demonstration of a complete commercial-scale IFR fuel cycle – which would have been the final step to assess the overall feasibility of the IFR prototype – would have required until at least 1998, and thus was never demonstrated due to the termination of the IFR program in 1994 (McFarlane & Lineberry 1997).

Fourth and lastly, IFR technology could be inherently free from the risk of proliferation. It could achieve this not only because its fuel cycle would never separate weapons-grade plutonium (see previous paragraph), but also because it could consume the plutonium contained in spent fuel from conventional reactors (Hannum et al. 1997). Aside from long-term geological disposal, the only effective way to eliminate the proliferation risk posed by separated plutonium is by subjecting it to fission. An IFR could do this while producing no transuranic actinides as waste. All of its fuel processing would involve “self-protecting” levels of radiation, i.e., levels that would make the fuel impractical to remove from the IFR facility. Moreover, the fuel processing would all be co-located within the same facility that houses the power reactors, thereby allowing strict materials monitoring.

6. Carbon capture and storage (CCS) at coal-fired power plants

CCS involves the prevention of power plant CO_2 emissions from reaching the atmosphere (capture) and the subsequent permanent burial (storage, or sequestration) of the captured CO_2. Of all the technologies discussed herein, CCS is the only one that would be specifically undertaken for mitigation of anthropogenic global warming, and aside from efficiency and conservation, it is the only approach that could reduce emissions from coal burning at the source. The current status of CCS reveals that although it is an urgently needed technology given the world's ever-increasing use of coal, it is not yet close to being accomplished on a sufficient scale, although there are plans for large-scale demonstrations in the works by the G8 countries, China, and others. In broad terms, the two greatest challenges for deploying widespread CCS will be reduction of capital costs (which are largely related to capture) and reduction of uncertainties related to long-term, large-scale storage. Detailed assessments of the numerous issues involved in CCS, including various technical details beyond the scope of this paper, are provided in IPCC (2005) and MIT (2007).

In general, there are three key steps in any CCS approach: (1) capture of the emissions; (2) transport of the captured effluent (usually in supercritical form); and (3) injection of the effluent into a geological reservoir – typically beneath land, although sub-seafloor burial has also been proposed (e.g., House et al. 2006). All of these components (except sub-seafloor storage) have been demonstrated successfully in other contexts (usually for enhanced oil recovery [EOR] projects), but like the IFR (see Section 5.2.2), a large-scale, integrated demonstration at an electric power plant has not yet occurred anywhere in the world (Herzog 2008*). However, a Swedish company, Vattenfall, is planning to conduct such a demonstration at a 30-MW pilot plant in eastern Germany[1]. Capture of CO_2, which is typically about 90% effective (Herzog 2008*; Rubin 2008*), can be done in three ways: post-combustion, pre-combustion, and oxyfuel combustion (see IPCC 2005 or MIT 2007 for details). Each of these methods has advantages and disadvantages, but they will each inevitably raise overall plant costs and thus electricity costs, and exert an energy penalty in the range of 10 to 40%, reducing plant power output (IPCC 2005). Geological storage (e.g., in saline aquifers) has been successfully conducted for commercial EOR projects on a limited basis on a scale of 1 Mt CO_2/yr, which is of similar magnitude as the annual CO_2 emissions of a 500 MW coal-fired power plant (which are typically 3–4 Mt CO_2/yr) (Rubin 2008*).

Several major barriers exist to large-scale CCS deployment in the near term. The biggest by far is the lack of a substantive national and global emissions reduction framework and the resulting lack of a price on carbon emissions. As a result, higher plant capital cost is prohibitive at the moment. For instance, total costs for construction and operation of a 400 MW coal-fired power plant with CCS and 5-year deep aquifer storage could amount to $1 billion (Rubin 2008*). Combined with the decreased plant efficiency due the energy penalty discussed above, these costs can raise the ultimate cost of electricity by over 60% (MIT 2007). Lack of experience with integrated, large-scale (several Mt CO_2/yr) CCS projects is also problematic. Furthermore, unresolved legal and regulatory issues exist regarding licensing for large-scale geological storage projects,

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[1] See http://www.vattenfall.com/www/co2_en/co2_en/index.jsp, and for others see http://sequestration.mit.edu/tools/projects/index.html and links therein (both accessed Feb. 2009)

subsurface property rights, and monitoring standards for sequestration sites, among other things.

Nonetheless, there is widespread agreement on the clear need for large-scale CCS demonstration projects in a variety of economic and environmental settings (e.g., see InterAcademy Council 2008). Although the scientific feasibility of the essential components of CCS seems reasonably certain, large-scale demonstration projects would help resolve many of the problematic economic and legal issues currently faced by CCS. A particularly important one is the magnitude of the required carbon price signal. Model estimates suggest a range of 50–70 $/tCO_2$ relative to a supercritical pulverized coal plant without CCS, with different ranges for different types of reference plants (e.g., IPCC 2005).

Assuming large-scale demonstration projects of CCS power plants can eventually succeed, the required time frame for widespread CCS implementation means that it is not likely to mitigate carbon emissions in the near term. Some assessments provide optimistic outlooks, asserting that CCS could play the dominant role in reducing CO_2 emissions by 2030 (Fig. 10), whereas others offer the more sobering view that even if CCS projects come into significant use, the majority are unlikely to be deployed until after ~2050 (IPCC 2005). Given the important uncertainties regarding this implementation time frame, it would stand to reason that while CCS is clearly a potential option for mitigation of mid- to long-term emissions from coal burning, it might not provide sufficient reduction rapidly enough.

7. Conclusions

We believe that the greatest near-term climate change mitigation emphasis should be on phase-out of coal emissions via efficiency measures and substitution of coal-fired power by renewable energy sources plus appropriately designed current-generation nuclear plants, as these technologies have been demonstrated successfully at the necessary (commercial) scales. Then, in the middle to long term (2030 and beyond), these measures can be supplemented by large-scale deployment of CCS at power plants and, as necessary, successfully demonstrated breeder reactors.

We believe a price on carbon is necessary and that a carbon tax would likely have a greater success at reducing emissions than the "cap-and-trade" approach, as concluded by the Congressional Budget Office (CBO 2008) and others (e.g., Hansen 2009). A sufficiently high carbon tax, along with other crucial policies such as elimination of fossil fuel subsidies, will ensure a level playing field for alternative energies. Such incentives will also guide the country away from other potentially disastrous choices such as large-scale usage of unconventional fossil fuels (e.g., coal-to-liquids, underground coal gasification, methane hydrates, and tar sands) without CCS.

Ultimately, it appears that the main barrier to achieving the goals outlined here is political will, as the means are already available or can become available in the near term. Once the U.S. makes it clear that it is taking serious, meaningful actions to curb CO_2 emissions, other countries will surely take similar measures if they have not already done so. In the interest of basic fairness and "climatic justice", developing countries should be allowed reasonable additional time to implement the types of measures outlined here. Interestingly, recent policies and actions outlined by China and India suggest that they might already be ahead of the West in some respects. However, where necessary, technology transfer accompanied by financial assistance could be very effective in assisting emissions reduction efforts in developing countries.

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Tables

Table 1. Currently available strategies, material, equipment, and technologies that would allow substantial building sector GHG reductions (not an exhaustive list).

Planning and design strategies	**Building envelope and material and equipment selection**	**Added technology**
Building shape, orientation and color	Adequate insulation values	Solar hot water heating
Spatial layout	Radiant barriers	Photovoltaic systems
Window shape and orientation	Low-e coatings and argon gas filled glazing	Micro-wind electric generation
Daylighting	Thermal break windows and systems and movable insulation	Community scale solar thermal, wind and biomass electric generation
Natural ventilation	Sunlight and daylight fixtures and systems	Combined heat and power systems
Exterior shading	Cool roofs	
Vegetation and microclimate control	Green roofs	
Passive solar heating systems	Occupancy and CO2 sensors	
Night-vent and night-sky radiation cooling systems	Daylighting controls and photo sensors	
Double envelope systems	Energy management systems	
Common wall design strategies	High efficiency equipment, lighting and appliances	
Building and unit density	Geothermal heat pump	
Mixed-use development	Air-to-air heat exchangers and heat recovery systems	
Pedestrian and transit oriented development (reduced vehicle miles traveled)	Building commissioning	

Table 2. 2007 US electric power generation by source (based on EIA 2008; totals might not add up precisely due to rounding).

Electricity Source		**Billion kWh**	**EJ**	**% relative to coal**	**% of renewables**	**% of total**
Fossil Fuels						
Coal		2021	7.3			48.6
Oil		66	0.2	3.3		1.6
Natural Gas		893	3.2	44.2		21.5
Total		2995	10.8			72.0
Nuclear		806	2.9	39.9		19.4
Renewable Energy						
Hydroelectric		248	0.89	12.3	70.7	6.0
Biomass	Wood	38.5	0.14	1.91	11.0	0.93
	Waste	16.9	0.06	0.84	4.81	0.41
Geothermal		14.8	0.05	0.73	4.22	0.36
Solar		0.6	0.002	0.03	0.17	0.01
Wind		32.1	0.12	1.59	9.15	0.77
Total		351	1.3	17.4		8.4
All Sources		4160	15			

Table 3. Summary of utility grid integration studies (****source? resembles Table 12 on p. 64 of the APS 2007 study ****).

Comparison of Cost-Based U.S. Operational Impact Studies

Date	Study	Wind Capacity Penetration (%)	Regulation Cost ($/MWh)	Load Following Cost ($/MWh)	Unit Commitment Cost ($/MWh)	Gas Supply Cost ($/MWh)	Tot Oper. Cost Impact ($/MWh)
May '03	Xcel-UWIG	3.5	0	0.41	1.44	na	1.85
Sep '04	Xcel-MNDOC	15	0.23	na	4.37	na	4.60
June '06	CA RPS	4	0.45*	trace	na	na	0.45
Feb '07	GE/Pier/CAIAP	20	0-0.69	trace	na***	na	0-0.69***
June '03	We Energies	4	1.12	0.09	0.69	na	1.90
June '03	We Energies	29	1.02	0.15	1.75	na	2.92
2005	PacifiCorp	20	0	1.6	3.0	na	4.60
April '06	Xcel-PSCo	10	0.20	na	2.26	1.26	3.72
April '06	Xcel-PSCo	15	0.20	na	3.32	1.45	4.97
Dec '06	MN 20%	31**					4.41**
Jul '07	APS	14.8	0.37	2.65	1.06	na	4.08

* 3-year average; total is non-market cost
** highest integration cost of 3 years; 30.7% capacity penetration corresponding to 25% energy penetration; 24.7% capacity penetration at 20% energy penetration
*** found $4.37/MWh reduction in UC cost when wind forecasting is used in UC decision

Figures

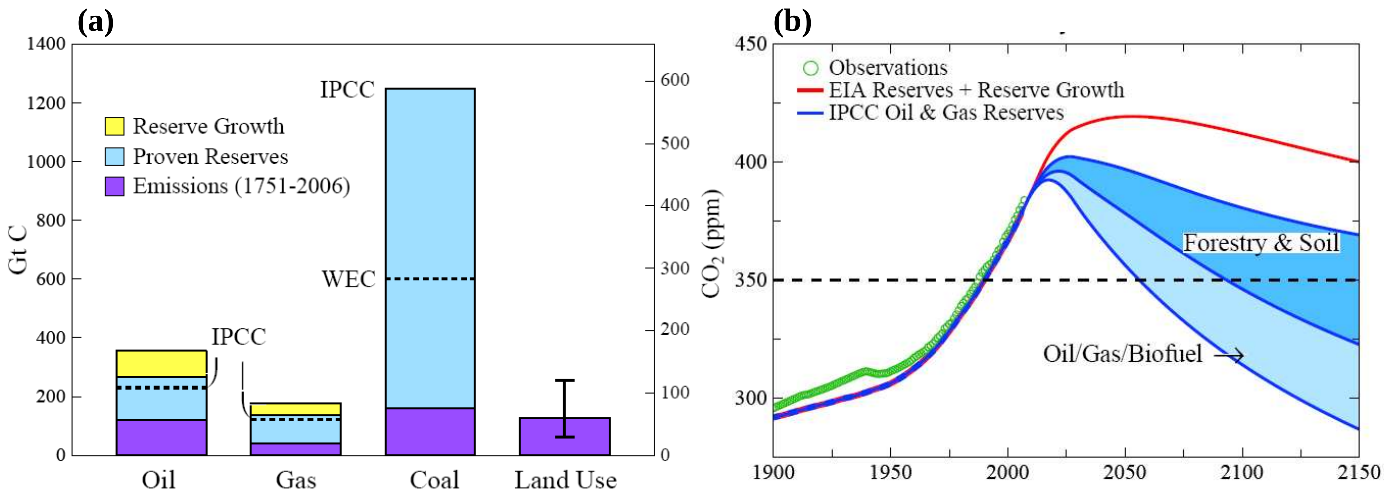


Figure 1. (a) Historical global CO_2 emissions from fossil fuel use and land use, and estimated remaining global fuel supplies (WEC = World Energy Council). (b) Simulated time evolution of atmospheric CO_2 concentrations, showing the magnitude and time frame of required mitigation measures to reduce CO_2 to levels <350 ppm; top two curves show trajectories assuming high-end vs. low-end conventional oil and gas reserves. (Both plots from Hansen et al. 2008)

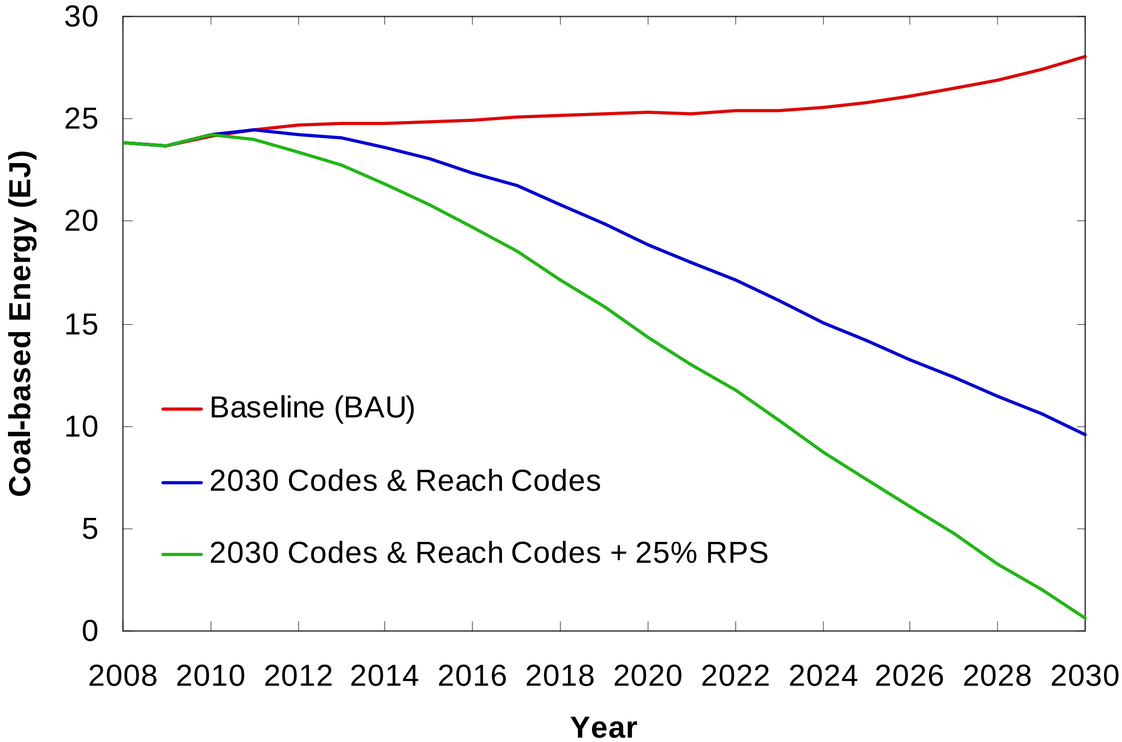


Figure 2. Potential coal energy reductions by 2030 from building energy reduction and efficiency measures over the baseline business-as-usual (BAU) case (based on EIA 2009). 25% RPS = renewable portfolio standard in which 25% of national power is generated by renewable sources by 2030. Assumptions are as follows: (1) new codes become effective in years 2010, 2016, 2022, and 2028, with corresponding improvements over code of 30%, 50%, 75%, and 100% (carbon-neutrality), respectively; (2) 25% of all new buildings meet or exceed the new code the first year it becomes effective, 50% of all new buildings meet or exceed the new code the year after, and 100% of all new buildings meet or exceed the new code every following year until a new base code is adopted; (3) the amount of existing building square footage renovated annually is equal to the square footage built anew, and this renovated square footage meets the same requirements as for new buildings in assumption 2 above; (4) aggressive reach code implementation and government incentives. For a complete description of 2030 building codes and 'reach' codes see Congressional testimony by co-author E. Mazria at http://energy.senate.gov/public/index.cfm?Fuseaction=Hearings.LiveStream&Hearing_id=672e1daf-bcc8-6e90-6e55-f95a8889b65e (oral) and http://www.architecture2030.org/downloads/Mazria_testimony.pdf (written).

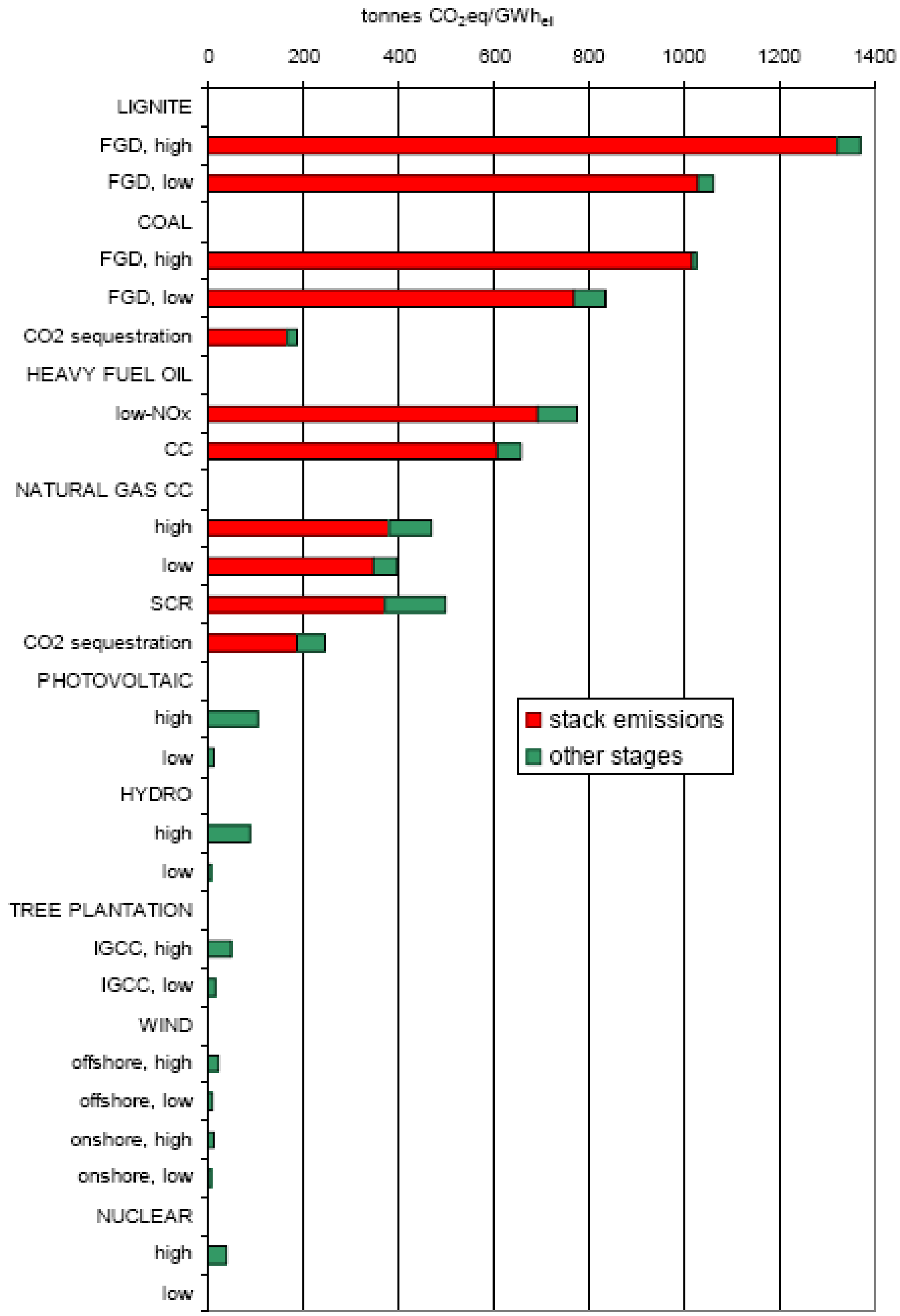


Figure 3. Life-cycle GHG emissions from fossil and alternative sources of electricity (from WEC 2004). Reported values for geothermal and CSP systems are 15 t CO_2/GWh (Hondo 2005) and 30 t CO_2/GWh, respectively (IEA 1998).

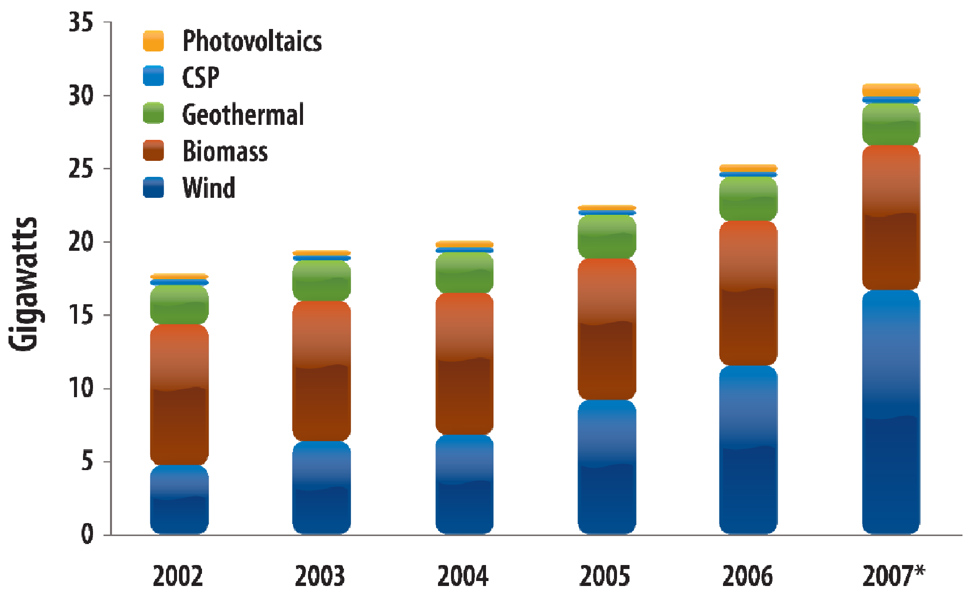


Figure 4. Recent growth in electric power production capacity of renewable energy sources in the US from 2002–2007 (GEA 2009; Kutscher 2008*)

(a) (b)

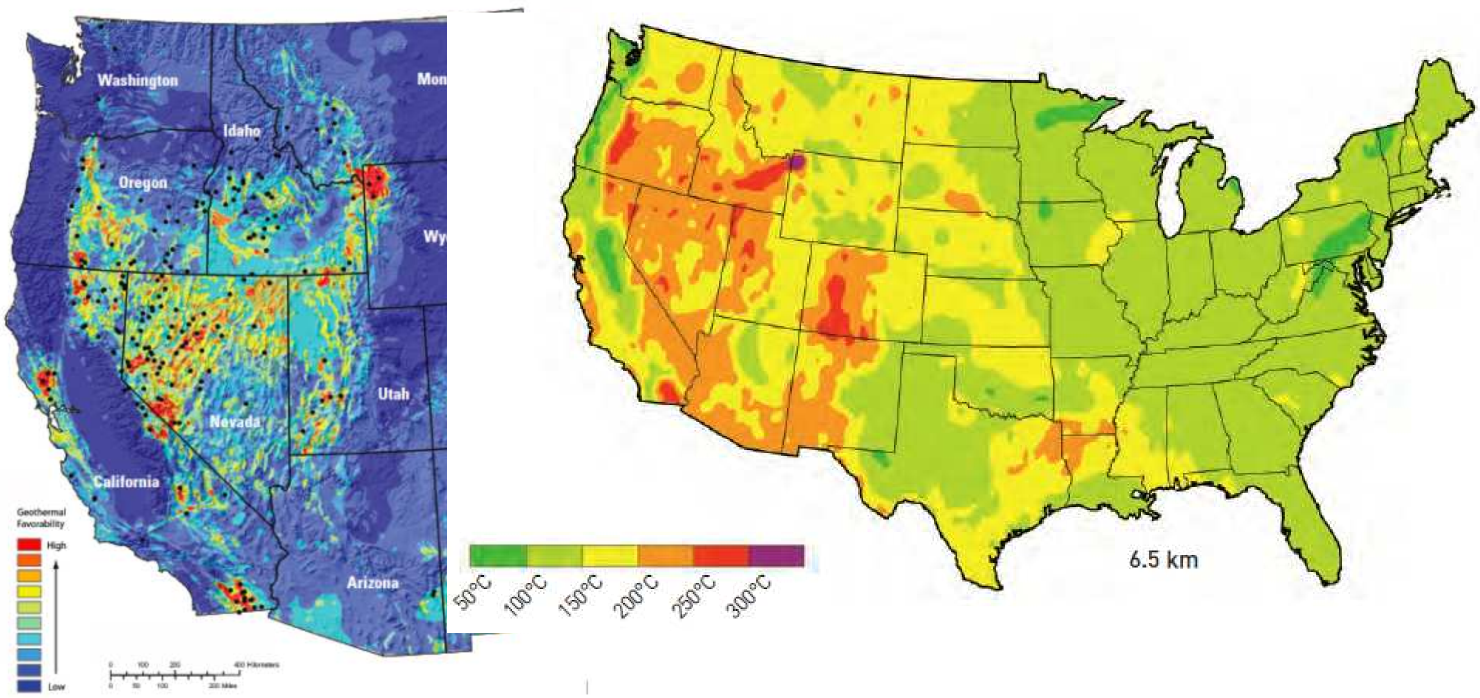


Figure 5. Geographic distribution of (a) known geothermal systems and favorable geothermal areas (from Williams et al. 2008) and (b) potential enhanced geothermal (EGS) resources in the US based on average temperatures at 6.5 km depth (from MIT 2006).

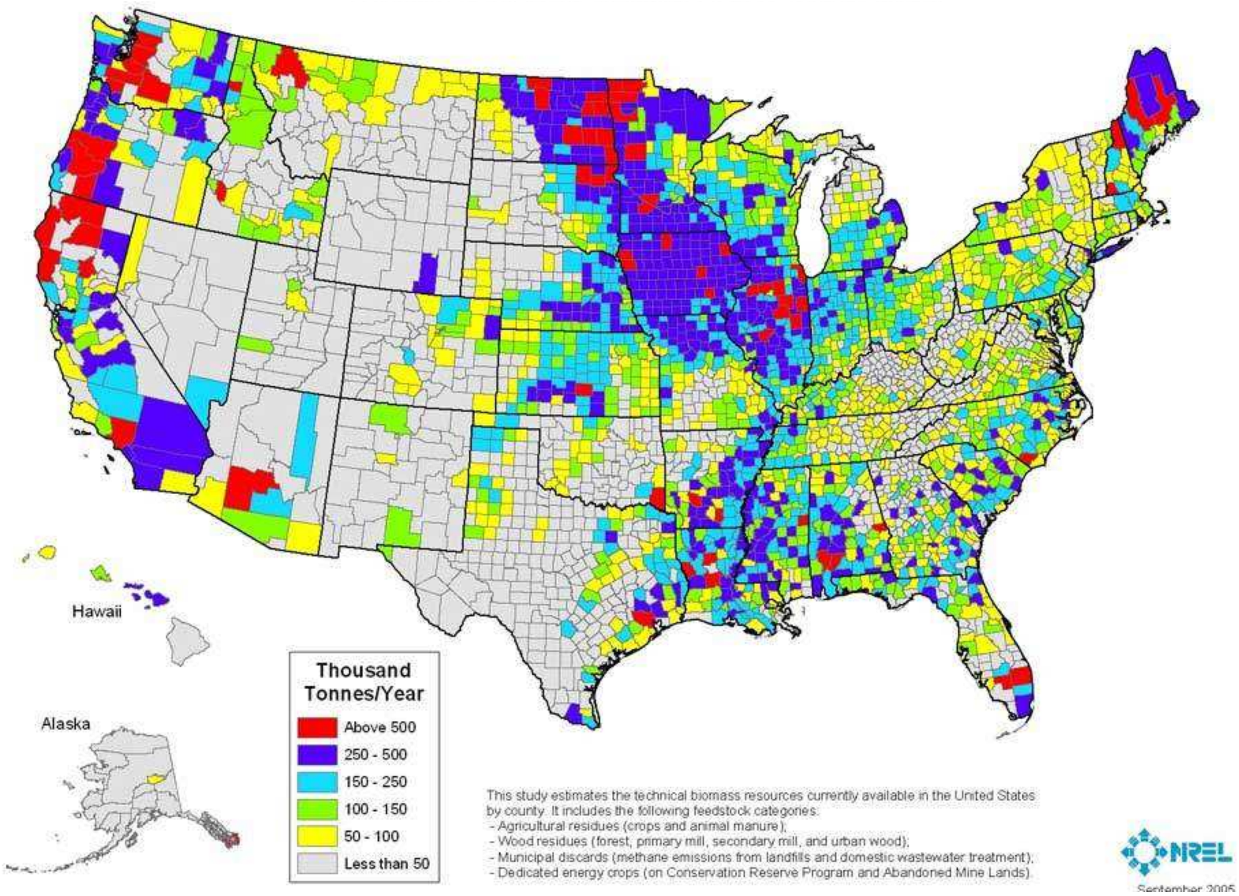


Figure 6. Geographic distribution of biomass resources in the US (from ASES 2007).

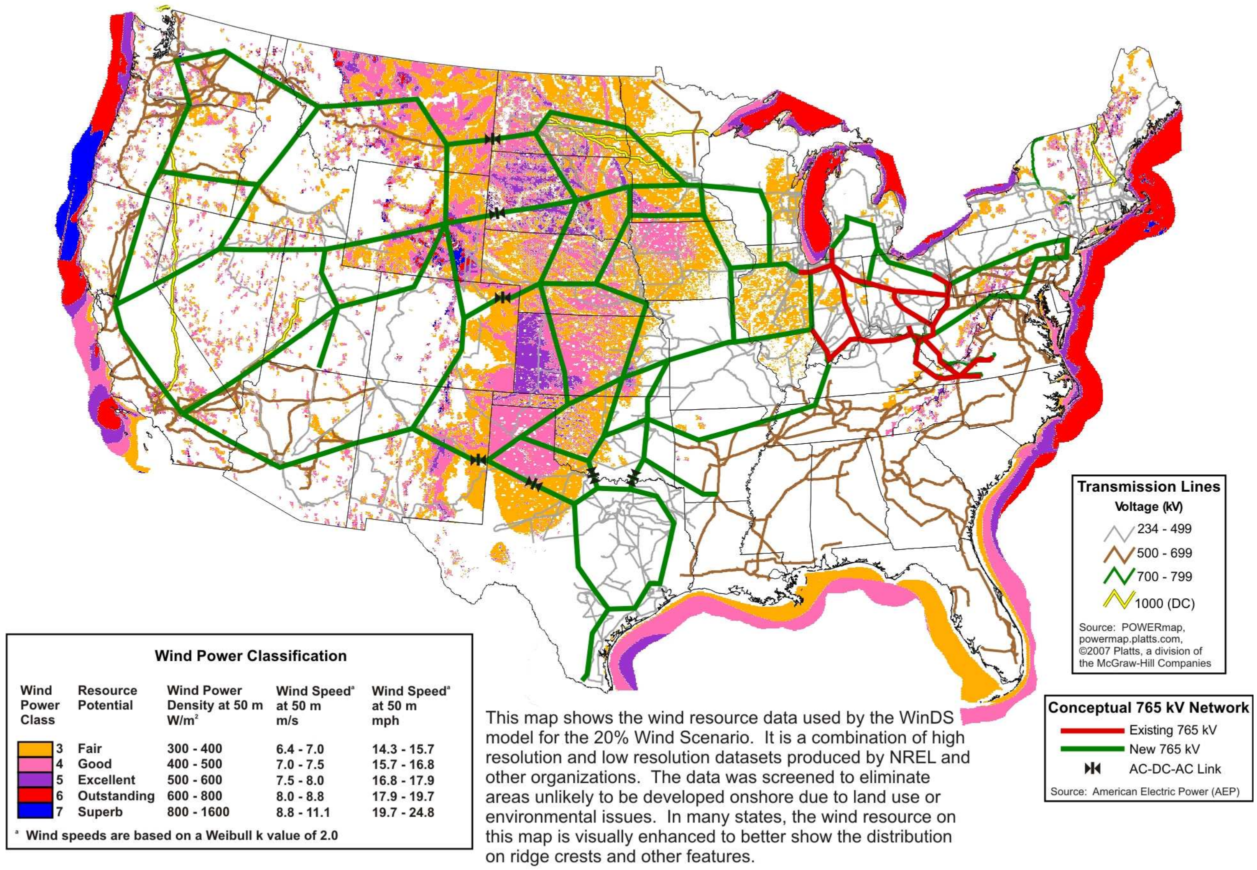


Figure 7. Geographic distribution of wind resources in the US and additional transmission requirements to enable large-scale wind power (from DOE 2008b).

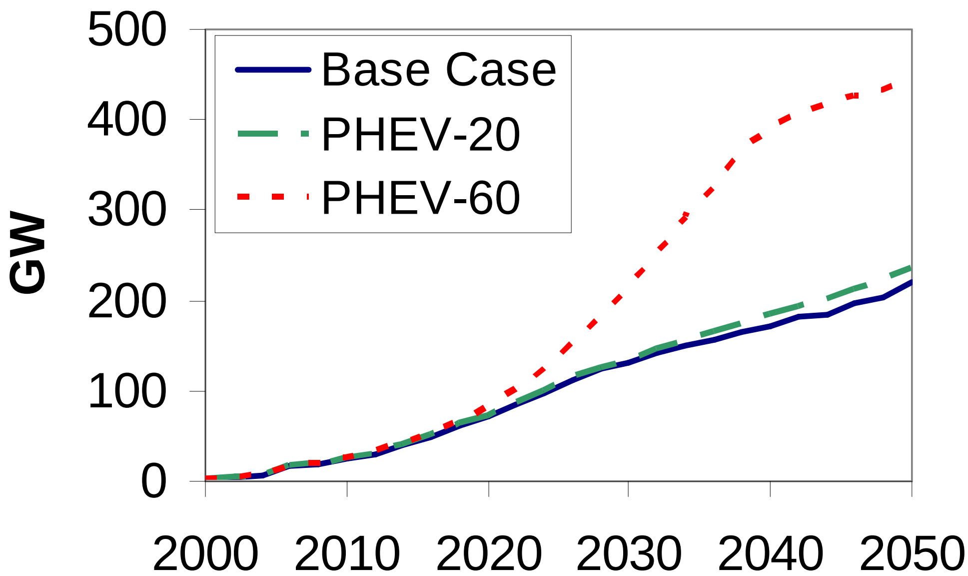


Figure 8. Potential wind electric power capacity addition assuming 50% penetration level of light-duty PHEVs by 2050 and two different sizes of PHEVs (based on Short & Denholm 2006). PHEV-20 and PHEV-60 possess battery capacities of 5.9 kWh and 17.7 kWh respectively.

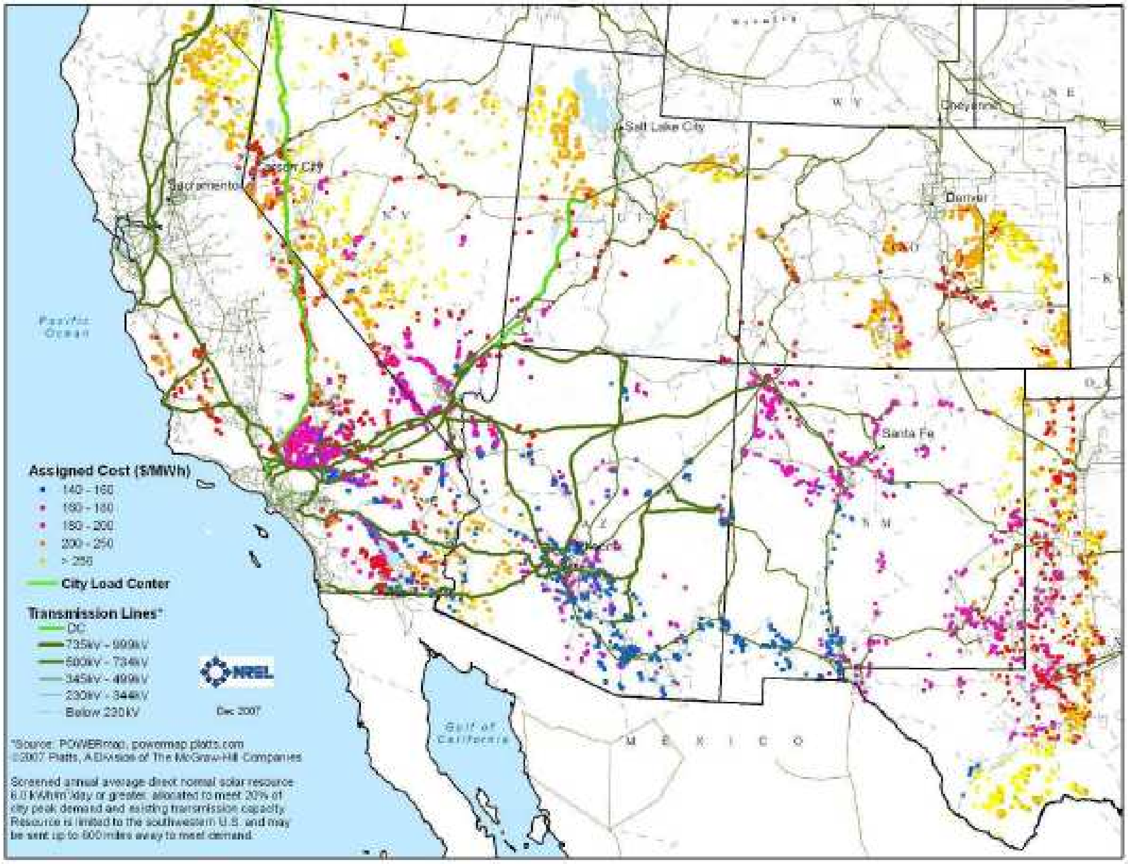
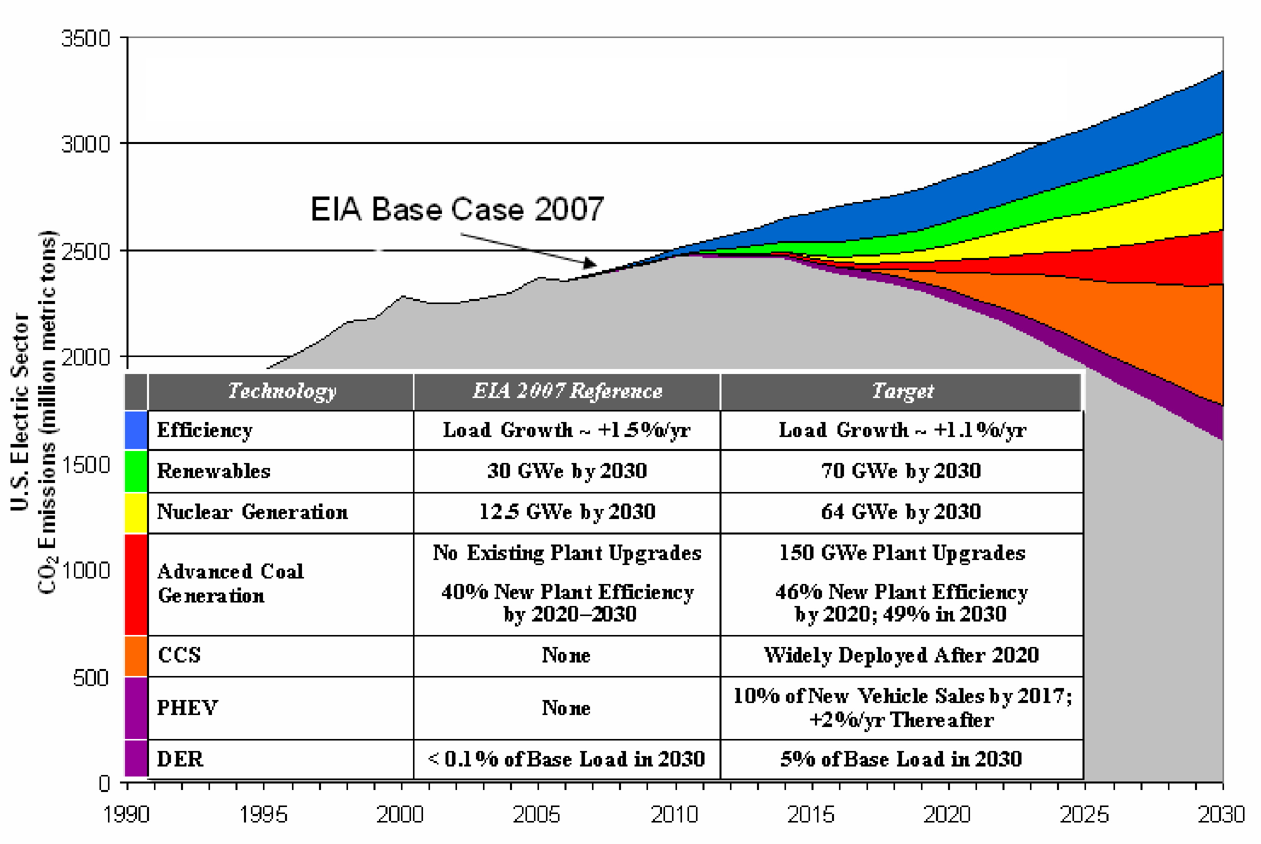


Figure 9. Geographic distribution of resources for concentrated solar power (Morse 2008*, based on unpublished 2007 NREL data)



Technology	EIA 2007 Reference	Target
Efficiency	Load Growth ~ +1.5%/yr	Load Growth ~ +1.1%/yr
Renewables	30 GWe by 2030	70 GWe by 2030
Nuclear Generation	12.5 GWe by 2030	64 GWe by 2030
Advanced Coal Generation	No Existing Plant Upgrades 40% New Plant Efficiency by 2020–2030	150 GWe Plant Upgrades 46% New Plant Efficiency by 2020; 49% in 2030
CCS	None	Widely Deployed After 2020
PHEV	None	10% of New Vehicle Sales by 2017; +2%/yr Thereafter
DER	< 0.1% of Base Load in 2030	5% of Base Load in 2030

Figure 10. Potential emissions reductions by 2030 through various actions (from EPRI 2007), highlighting the potentially substantial role of large-scale carbon capture and storage (CCS). As discussed in Section 6, there is disagreement among various groups regarding the time frame of widespread deployment of CCS – this figure reflects the more optimistic end of the spectrum.