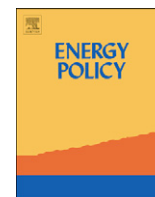




Contents lists available at ScienceDirect

## Energy Policy

journal homepage: [www.elsevier.com/locate/enpol](http://www.elsevier.com/locate/enpol)

# Providing all global energy with wind, water, and solar power, Part I: Technologies, energy resources, quantities and areas of infrastructure, and materials

Mark Z. Jacobson<sup>a,\*</sup>, Mark A. Delucchi<sup>b,1</sup>

<sup>a</sup> Department of Civil and Environmental Engineering, Stanford University, Stanford, CA 94305-4020, USA

<sup>b</sup> Institute of Transportation Studies, University of California at Davis, Davis, CA 95616, USA

## ARTICLE INFO

## Article history:

Received 3 September 2010

Accepted 22 November 2010

## Keywords:

Wind power

Solar power

Water power

## ABSTRACT

Climate change, pollution, and energy insecurity are among the greatest problems of our time. Addressing them requires major changes in our energy infrastructure. Here, we analyze the feasibility of providing worldwide energy for all purposes (electric power, transportation, heating/cooling, etc.) from wind, water, and sunlight (WWS). In Part I, we discuss WWS energy system characteristics, current and future energy demand, availability of WWS resources, numbers of WWS devices, and area and material requirements. In Part II, we address variability, economics, and policy of WWS energy. We estimate that ~3,800,000 5 MW wind turbines, ~49,000 300 MW concentrated solar plants, ~40,000 300 MW solar PV power plants, ~1.7 billion 3 kW rooftop PV systems, ~5350 100 MW geothermal power plants, ~270 new 1300 MW hydroelectric power plants, ~720,000 0.75 MW wave devices, and ~490,000 1 MW tidal turbines can power a 2030 WWS world that uses electricity and electrolytic hydrogen for all purposes. Such a WWS infrastructure reduces world power demand by 30% and requires only ~0.41% and ~0.59% more of the world's land for footprint and spacing, respectively. We suggest producing all new energy with WWS by 2030 and replacing the pre-existing energy by 2050. Barriers to the plan are primarily social and political, not technological or economic. The energy cost in a WWS world should be similar to that today.

© 2010 Elsevier Ltd. All rights reserved.

## 1. Introduction

A solution to the problems of climate change, air pollution, water pollution, and energy insecurity requires a large-scale conversion to clean, perpetual, and reliable energy at low cost together with an increase in energy efficiency. Over the past decade, a number of studies have proposed large-scale renewable energy plans. Jacobson and Masters (2001) suggested that the U.S. could satisfy its Kyoto Protocol requirement for reducing carbon dioxide emissions by replacing 60% of its coal generation with 214,000–236,000 wind turbines rated at 1.5 MW (million watts). Also in 2001, Czisch (2006) suggested that a totally renewable electricity supply system, with intercontinental transmission lines linking dispersed wind sites with hydropower backup, could supply Europe, North Africa, and East Asia at total costs per kWh comparable with the costs of the current system. Hoffert et al. (2002) suggested a portfolio of solutions for stabilizing atmospheric CO<sub>2</sub>, including increasing the use of renewable energy and nuclear energy, decarbonizing fossil fuels and sequestering carbon, and

improving energy efficiency. Pacala and Socolow (2004) suggested a similar portfolio, but expanded it to include reductions in deforestation and conservation tillage and greater use of hydrogen in vehicles.

More recently, Fthenakis et al. (2009) analyzed the technical, geographical, and economic feasibility for solar energy to supply the energy needs of the U.S. and concluded (p. 397) that “it is clearly feasible to replace the present fossil fuel energy infrastructure in the U.S. with solar power and other renewables, and reduce CO<sub>2</sub> emissions to a level commensurate with the most aggressive climate-change goals”. Jacobson (2009) evaluated several long-term energy systems according to environmental and other criteria, and found WWS systems to be superior to nuclear, fossil-fuel, and biofuel systems (see further discussion in Section 2). He proposed to address the hourly and seasonal variability of WWS power by interconnecting geographically disperse renewable energy sources to smooth out loads, using hydroelectric power to fill in gaps in supply. He also proposed using battery-electric vehicles (BEVs) together with utility controls of electricity dispatch to them through smart meters, and storing electricity in hydrogen or solar-thermal storage media. Cleetus et al. (2009) subsequently presented a “blueprint” for a clean-energy economy to reduce CO<sub>2</sub>-equivalent GHG emissions in the U.S. by 56% compared with the 2005 levels. That study featured an economy-wide CO<sub>2</sub>

\* Corresponding author. Tel.: +1 650 723 6836.

E-mail addresses: [jacobson@stanford.edu](mailto:jacobson@stanford.edu) (M.Z. Jacobson), [madelucchi@ucdavis.edu](mailto:madelucchi@ucdavis.edu) (M.A. Delucchi).

<sup>1</sup> Tel.: +1 916 989 5566.

**Table 1**

Recent studies of rapid, large-scale development of renewable energy.

Study	Energy mix by sector	Time frame	Geographic scope
This study and Jacobson and Delucchi (2009)	Electricity transport heat/cool	100% WWS All new energy: 2030. All energy: 2050	World
Alliance for Climate Protection (2009)	Electricity transport	100% WWS+Bm 2020	U.S.
Parsons-Brinckerhoff (2009)	Electricity transport heat/cool	80% WWS+NCBmBf 2050	UK
Price-Waterhouse-Coopers (2010)	Electricity	100% WWS+Bm 2050	Europe & North Africa
Beyond Zero Emissions (2010)	Electricity transport heat/cool	100% WWS+Bm 2020	Australia
European Climate Foundation (ECF) (2010)	Electricity transport heat/cool	80% WWS+NCBm 2050	Europe
European Renewable Energy Council (EREC) (April (2010)	Electricity transport heat/cool	100% WWS+BmBf 2050	Europe

WWS=wind, water, solar power; FF=fossil fuels; Bm=biomass; Bf=liquid biofuels; N=nuclear; C=coal-CCS. Cleetus et al. (2009) is not included only because its focus is mainly on efficiency and demand management, with only modest increases in renewable energy.

cap-and-trade program and policies to increase energy efficiency and the use of renewable energy in industry, buildings, electricity, and transportation. Sovacool and Watts (2009) suggested that a completely renewable electricity sector for New Zealand and the United States is feasible.

In Jacobson and Delucchi (2009), we outlined a large-scale plan to power the world for all purposes with WWS (no biofuels, nuclear power, or coal with carbon capture). The study found that it was technically feasible to power the world with WWS by 2030 but such a conversion would almost certainly take longer due to the difficulty in implementing all necessary policies by then. However, we suggested, and this study reinforces, the concept that all new energy could be supplied by WWS by 2030 and all existing energy could be converted to WWS by 2050. The analysis presented here is an extension of that work.

Table 1 compares and summarizes several other recent large-scale plans. While all plans are ambitious, forward thinking, and detailed, they differ from our plan, in that they are for limited world regions and none relies completely on WWS. However, some come close in the electric power sector, relying on only small amounts of non-WWS energy in the form of biomass for electric power production. Those studies, however, address only electricity and/or transport, but not heating/cooling.

More well known to the public than the scientific studies, perhaps, are the “Repower America” plan of former Vice-President and Nobel-Peace Prize winner Al Gore, and a similar proposal by businessman T. Boone Pickens. Mr. Gore’s proposal calls for improvements in energy efficiency, expansion of renewable energy generation, modernization of the transmission grid, and the conversion of motor vehicles to electric power. The ultimate (and ambitious) goal is to provide America “with 100% clean electricity within 10 years,” which Mr. Gore proposes to achieve by increasing the use of wind and concentrated solar and improving energy efficiency (Alliance for Climate Protection, 2009). In Gore’s plan, solar PV, geothermal, and biomass electricity would grow only modestly, and nuclear power and hydroelectricity would not grow. Mr. Pickens’ plan is to obtain up to 22% of the U.S. electricity from wind, add solar capacity to that, improve the electric grid, increase energy efficiency, and use natural gas instead of oil as a transitional fuel (Pickens, 2009).

There is little doubt that the large-scale use of renewable energy envisaged in these plans and studies would greatly mitigate or eliminate a wide range of environmental and human health impacts of energy use (e.g., Jacobson, 2009; Sovacool and Sovacool, 2009; Colby et al., 2009; Weisser, 2007; Fthenakis and Kim, 2007). But, is a large-scale transformation of the world’s energy systems feasible? In this paper and in Part II, we address this question by examining the characteristics and benefits of wind, water, and solar (WWS)-energy systems, the availability of WWS resources, supplies of critical materials, methods of addressing the variability of WWS energy to ensure that power supply reliably

matches demand, the economics of WWS generation and transmission, the economics of the use of WWS power in transportation, and policy issues. Although we recognize that a comprehensive plan to address global environmental problems must also address other sectors, including agriculture (Horrigan et al., 2002; Wall and Smit, 2005) and forestry (Niles et al., 2002), we do not address those issues here.

## 2. Clean, low-risk, sustainable energy systems

### 2.1. Evaluation of long-term energy systems: why we choose WWS power

Because climate change (particularly loss of the Arctic sea ice cap), air pollution, and energy insecurity are the current and growing problems, but it takes several decades for new technologies to become fully adopted, we consider only options that have been demonstrated in at least pilot projects and that can be scaled up as part of a global energy system without further major technology development. We avoid options that require substantial further technological development and that will not be ready to begin the scale-up process for several decades. Note that we select technologies based on the state of development of the technology only rather than whether industrial capacity is currently ramped up to produce the technologies on a massive scale or whether society is motivated to change to the technologies. In this paper and in Part II, we do consider the feasibility of implementing the chosen technologies based on estimated costs, necessary policies, and available materials as well as other factors.

In order to ensure that our energy system remains clean even with large increases in population and economic activity in the long run, we consider only those technologies that have essentially zero emissions of greenhouse gases and air pollutants per unit of output over the whole “lifecycle” of the system. Similarly, we consider only those technologies that have low impacts on wildlife, water pollution, and land, do not have significant waste-disposal or terrorism risks associated with them, and are based on primary resources that are indefinitely renewable or recyclable.

The previous work by Jacobson (2009) indicates that WWS power satisfies all of these criteria. He ranked several long-term energy systems with respect to their impacts on global warming, air pollution, water supply, land use, wildlife, thermal pollution, water-chemical pollution, and nuclear weapons proliferation. The ranking of electricity options, starting with the highest, included: wind power, concentrated solar, geothermal, tidal, solar photovoltaic, wave, and hydroelectric power, all of which are powered by wind, water, or sunlight (WWS). He also found that the use of BEVs and hydrogen fuel-cell vehicles (HFCVs) powered by the WWS options would largely eliminate pollution from the transportation sector. Here, we consider these technologies and other existing

technologies for the heating/cooling sectors, discussed in Section 2. Although other clean WWS electric power sources, such as ocean or river current power, could be deployed in the short term, these are not examined here simply because we could not cover every technology. Nevertheless, we do cover related although slightly different power sources (e.g., wave, tidal, and hydroelectric power).

Finally, Jacobson (2009) concluded that coal with carbon capture, corn ethanol, cellulosic ethanol, and nuclear power were all moderately or significantly worse than WWS options with respect to environmental and land use impacts. Similarly, here we do not consider any combustion sources, such as coal with carbon capture, corn ethanol, cellulosic ethanol, soy biodiesel, algae biodiesel, biomass for electricity, other biofuels, or natural gas, because none of these technologies can reduce GHG and air-pollutant emissions to near zero, and all can have significant problems in terms of land use, water use, or resource availability (See Delucchi (2010) for a review of land-use, climate-change, and water-use impacts of biofuels.) For example, even the most climate-friendly and ecologically acceptable sources of ethanol, such as unmanaged, mixed grasses restored to their native (non-agricultural) habitat (Tilman et al., 2006), will cause air pollution mortality on the same order as gasoline (Jacobson, 2007; Anderson, 2009; Ginnebaugh et al., 2010). The use of carbon capture and sequestration (CCS) can reduce CO<sub>2</sub> emissions from the stacks of coal power plants by 85–90% or more, but it has no effect on CO<sub>2</sub> emissions due to the mining and transport of coal; in fact it will increase such emissions and of air pollutants per unit of net delivered power and will increase all ecological, land-use, air-pollution, and water-pollution impacts from coal mining, transport, and processing, because the CCS system requires 25% more energy, thus 25% more coal combustion, than does a system without CCS (IPCC, 2005).

For several reasons we do not consider nuclear energy (conventional fission, breeder reactors, or fusion) as a long-term global energy source. First, the growth of nuclear energy has historically increased the ability of nations to obtain or enrich uranium for nuclear weapons (Ullom, 1994), and a large-scale worldwide increase in nuclear energy facilities would exacerbate this problem, putting the world at greater risk of a nuclear war or terrorism catastrophe (Kessides, 2010; Feiveson, 2009; Miller and Sagan, 2009; Macfarlane and Miller, 2007; Harding, 2007). The historic link between energy facilities and weapons is evidenced by the development or attempted development of weapons capabilities secretly in nuclear energy facilities in Pakistan, India (Federation of American Scientists, 2010), Iraq (prior to 1981), Iran (e.g., Adamantiades and Kessides, 2009, p. 16), and to some extent North Korea. Feiveson (2009) writes that “it is well understood that one of the factors leading several countries now without nuclear power programs to express interest in nuclear power is the foundation that such programs could give them to develop weapons” (p. 65). Kessides (2010) asserts, “a robust global expansion of civilian nuclear power will significantly increase proliferation risks unless the current non-proliferation regime is substantially strengthened by technical and institutional measures and its international safeguards system adequately meets the new challenges associated with a geographic spread and an increase in the number of nuclear facilities” (p. 3860). Similarly, Miller and Sagan (2009) write, “it seems almost certain that some new entrants to nuclear power will emerge in the coming decades and that the organizational and political challenges to ensure the safe and secure spread of nuclear technology into the developing world will be substantial and potentially grave” (p. 12).

If the world were converted to electricity and electrolytic hydrogen by 2030, the 11.5 TW in resulting power demand would require ~15,800 850 MW nuclear power plants, or one installed every day for the next 43 years. Even if only 5% of these were

installed, that would double the current installations of nuclear power worldwide. Many more countries would possess nuclear facilities, increasing the likelihood that these countries would use the facilities to hide the development of nuclear weapons as has occurred historically.

Second, nuclear energy results in 9–25 times more carbon emissions than wind energy, in part due to emissions from uranium refining and transport and reactor construction (e.g., Lenzen, 2008; Sovacool, 2008), in part due to the longer time required to site, permit, and construct a nuclear plant compared with a wind farm (resulting in greater emissions from the fossil-fuel electricity sector during this period; Jacobson, 2009), and in part due to the greater loss of soil carbon due to the greater loss in vegetation resulting from covering the ground with nuclear facilities relative to wind turbine towers, which cover little ground. Although recent construction times worldwide are shorter than the 9-year median construction times in the U.S. since 1970 (Kooimey and Hultman, 2007), they still averaged 6.5 years worldwide in 2007 (Ramana, 2009), and this time must be added to the site permit time (~3 years in the U.S.) and construction permit and issue time (~3 years). The overall historic and present range of nuclear planning-to-operation times for new nuclear plants has been 11–19 years, compared with an average of 2–5 years for wind and solar installations (Jacobson, 2009). Feiveson (2009) observes that “because wind turbines can be installed much faster than could nuclear, the cumulative greenhouse gas savings per capital invested appear likely to be greater for wind” (p. 67). The long time required between planning and operation of a nuclear power plant poses a significant risk to the Arctic sea ice. Sea ice records indicate a 32% loss in the August 2010 sea ice area relative to the 1979–2008 mean (Cryosphere Today, 2010). Such rapid loss indicates that solutions to global warming must be implemented quickly. Technologies with long lead times will allow the high-albedo Arctic ice to disappear, triggering more rapid positive feedbacks to warmer temperatures by uncovering the low-albedo ocean below.

Third, conventional nuclear fission relies on finite stores of uranium that a large-scale nuclear program with a “once through” fuel cycle would exhaust in roughly a century (e.g., Macfarlane and Miller, 2007; Adamantiades and Kessides, 2009). In addition, accidents at nuclear power plants have been either catastrophic (Chernobyl) or damaging (Three-Mile Island), and although the nuclear industry has improved the safety and performance of reactors, and has proposed new (but generally untested) “inherently” safe reactor designs (Piera, 2010; Penner et al., 2008; Adamantiades and Kessides, 2009; Mourougov et al., 2002; Mourougov, 2000), there is no guarantee that the reactors will be designed, built, and operated correctly. For example, Pacific Gas and Electric Company had to redo some modifications it made to its Diablo Canyon nuclear power plant after the original work was done backwards (Energy Net, 2010), and French nuclear regulators recently told the firm Areva to correct a safety design flaw in its latest-generation reactor (Nuclear Power Daily, 2009). Further, catastrophic scenarios involving terrorist attacks are still conceivable (Feiveson, 2009). Even if the risks of catastrophe are very small, they are not zero (Feiveson, 2009), whereas with wind and solar power, the risk of catastrophe is zero. Finally, conventional nuclear power produces radioactive waste, which must be stored for thousands of years, raising technical and long-term cost questions (Barré, 1999; von Hippel, 2008; Adamantiades and Kessides, 2009).

“Breeder” nuclear reactors have similar problems as conventional fission reactors, except that they produce less low-level radioactive waste than do conventional reactors and re-use the spent fuel, thereby extending uranium reserves, perhaps indefinitely (Penner et al., 2008; Purushotham et al., 2000; Till et al., 1997). However, they produce nuclear material closer to weapons

grade that can be reprocessed more readily into nuclear weapons (Kessides, 2010; Adamantiades and Kessides, 2009; Macfarlane and Miller, 2007; Glaser and Ramana, 2007), although some technologies have technical features that make diversion and reprocessing especially difficult—albeit not impossible (Hannum et al., 1997; Kessides, 2010; Penner et al., 2008). Kessides (2010) writes, “analyses of various reactor cycles have shown that all have some potential for diversion, i.e., there is no proliferation-proof nuclear power cycle” (p. 3861).

A related proposal is to use thorium as a nuclear fuel, which is less likely to lead to nuclear weapons proliferation than the use of uranium, produces less long-lived radioactive waste, and greatly extends uranium resources (Macfarlane and Miller, 2007). However, thorium reactors require the same significant time lag between planning and operation as conventional uranium reactors and most likely longer because few developers and scientists have experience with constructing or running thorium reactors. As such, this technology will result in greater emissions from the background electric grid compared with WWS technologies, which have a shorter time lag. In addition, lifecycle emissions of carbon from a thorium reactor are on the same order as those from a uranium reactor. Further, thorium still produces radioactive waste containing  $^{231}\text{Pa}$ , which has a half-life of 32,760 years. It also produces  $^{233}\text{U}$ , which can be used in fission weapons, such as in one nuclear bomb core during the Operation Teapot nuclear tests in 1955. Weaponization, though, is made more difficult by the presence of  $^{232}\text{U}$ .

Fusion of light atomic nuclei (e.g., protium, deuterium, or tritium) theoretically could supply power indefinitely without long-lived radioactive wastes as the products are isotopes of helium (Ongena and Van Oost, 2006; Tokimatsu et al., 2003); however, it would produce short-lived waste that needs to be removed from the reactor core to avoid interference with operations, and it is unlikely to be commercially available for at least another 50–100 years (Tokimatsu et al., 2003; Barré, 1999; Hammond, 1996), long after we will have needed to transition to alternative energy sources. By contrast, wind and solar power are available today, will last indefinitely, and pose no serious risks. Note that our reasons for excluding nuclear are not economic. A brief discussion of the economics of nuclear power is given in Appendix A.

For these reasons, we focus on WWS technologies. We assume that WWS will supply electric power for the transportation, heating (including high-temperature heating and cooking)/cooling sectors, which traditionally have relied mainly on the direct use of oil or gas rather than electricity, as well as for traditional electricity-consuming end uses such as lighting, cooling, manufacturing, motors, electronics, and telecommunications. Although we focus mainly on energy supply, we acknowledge and indeed emphasize the importance of demand-side energy conservation measures to reduce the requirements and impacts of energy supply. Demand-side energy-conservation measures include improving the energy-out/energy-in efficiency of end uses (e.g., with more efficient vehicles, more efficient lighting, better insulation in homes, and the use of heat-exchange and filtration systems), directing demand to low-energy-use modes (e.g., using public transit or telecommuting instead of driving), large-scale planning to reduce energy demand without compromising economic activity or comfort (e.g., designing cities to facilitate greater use of non-motorized transport and to have better matching of origins and destinations, thereby reducing the need for travel), and designing buildings to use solar energy directly (e.g., with more daylighting, solar hot water heating, and improved passive solar heating in winter and cooling in summer). For a general discussion of the potential to reduce energy use in transportation and buildings, see the American Physical Society (2008). For a classification scheme that facilitates analyses of the potential gains from energy efficiency, see Cullen and Allwood (2009).

## 2.2. Characteristics of electricity-generating WWS technologies

### 2.2.1. Wind

Wind turbines convert the energy of the wind into electricity. Generally, a gearbox turns the slow-moving turbine rotor into faster-rotating gears, which convert mechanical energy to electricity in a generator. Some modern turbines are gearless. Although less efficient, small turbines can be used in homes or buildings. Wind farms today appear on land and offshore, with individual turbines ranging in size up to 7 MW, with 10 MW planned. High-altitude wind energy capture is also being pursued today by several companies.

### 2.2.2. Wave

Winds passing over water create surface waves. The faster the wind speed, the longer the wind is sustained, the greater the distance the wind travels, the greater the wave height, and the greater the wave energy produced. Wave power devices capture energy from ocean surface waves to produce electricity. One type of device is a buoy that rises and falls with a wave. Another type is a surface-following device, whose up-and-down motion increases the pressure on oil to drive a hydraulic motor.

### 2.2.3. Geothermal

Steam and hot water from below the Earth's surface have been used historically to provide heat for buildings, industrial processes, and domestic water and to generate electricity in geothermal power plants. In power plants, two boreholes are drilled—one for steam alone or liquid water plus steam to flow up, and the second for condensed water to return after it passes through the plant. In some plants, steam drives a turbine; in others, hot water heats another fluid that evaporates and drives the turbine.

### 2.2.4. Hydroelectricity

Water generates electricity when it drops gravitationally, driving a turbine and generator. While most hydroelectricity is produced by water falling from dams, some is produced by water flowing down rivers (run-of-the-river electricity).

### 2.2.5. Tidal

A tidal turbine is similar to a wind turbine in that it consists of a rotor that turns due to its interaction with water during the ebb and flow of a tide. Tidal turbines are generally mounted on the sea floor. Since tides run about 6 h in one direction before switching directions for 6 h, tidal turbines can provide a predictable energy source. O'Rourke et al. (2010) provide an excellent overview of the technology of tidal energy.

### 2.2.6. Solar PV

Solar photovoltaics (PVs) are arrays of cells containing a material, such as silicon, that converts solar radiation into electricity. Today, solar PVs are used in a wide range of applications, from residential rooftop power generation to medium-scale utility-level power generation.

### 2.2.7. CSP

Concentrated solar power (CSP) systems use mirrors or reflective lenses to focus sunlight on a fluid to heat it to a high temperature. The heated fluid flows from the collector to a heat engine where a portion of the heat is converted to electricity. Some types of CSP allow the heat to be stored for many hours so that electricity can be produced at night.

### 2.3. Use of WWS power for transportation

Transportation technologies that must be deployed on a large scale to use WWS-power include primarily battery-electric vehicles (BEVs), hydrogen fuel-cell vehicles (HFCVs), and hybrid BEV-HFCVs. For ships, we propose the use of hybrid hydrogen fuel cell-battery systems, and for aircraft, liquefied hydrogen combustion (Appendix A).

BEVs store electricity in and draw power from batteries to run an electric motor that drives the vehicle. So long as the electricity source is clean, the BEV system will have zero emissions of air pollutants and greenhouse gases over the entire energy lifecycle—something that internal-combustion-engine vehicles (ICEVs) using liquid fuels cannot achieve. Moreover, BEVs provide up to 5 times more work in distance traveled per unit of input energy than do ICEVs (km/kWh-outlet versus km/kWh-gasoline). BEVs have existed for decades in small levels of production, but today most major automobile companies are developing BEVs. The latest generation of vehicles uses lithium-ion batteries, which do not use the toxic chemicals associated with lead-acid or the nickel-cadmium batteries.

Hydrogen fuel cell vehicles (HFCVs) use a fuel cell to convert hydrogen fuel and oxygen from the air into electricity that is used to run an electric motor. HFCVs are truly clean only if the hydrogen is produced by passing WWS-derived electricity through water (electrolysis). Thus, we propose producing hydrogen only in this way. Several companies have prototype HFCVs, and California had about 200 HFCVs on the road in 2009 (California Fuel Cell Partnership, 2009). Hydrogen fueling stations, though, are practically non-existent and most hydrogen today is produced by steam-reforming of natural gas, which is not so clean as hydrogen produced by WWS-electrolysis.

### 2.4. Use of WWS power for heating and cooling

For building water and air heating using WWS power, we propose the use of air- and ground-source heat-pump water and air heaters and electric resistance water and air heaters. Heat pump air heaters also can be used in reverse for air conditioning. These technologies exist today although in most places they satisfy less demand than do natural gas or oil-fired heaters. The use of electricity for heating and cooking, like the use of electricity for transportation, is most beneficial when the electricity comes from WWS. For high-temperature industrial processes, we propose that energy be obtained by combustion of electrolytic hydrogen (Appendix A).

## 3. Energy resources needed and available

The power required today to satisfy all end uses worldwide is about 12.5 trillion watts (TW) (EIA, 2008a; end-use energy only, excludes losses in production and transmission). In terms of primary energy, about 35% is from oil, 27% from coal, 23% from natural gas, 6% from nuclear, and the rest from biomass, sunlight, wind, and geothermal. Delivered electricity is a little over 2 TW of the end-use total.

The EIA (2008a) projects that in the year 2030, the world will require almost 17 TW in end-use power, and the U.S. almost 3 TW (Table 2). They also project that the breakdown in terms of primary energy in 2030 will be similar to that today—heavily dependent on fossil fuels, and hence almost certainly unsustainable. What would world power demand look like if instead a sustainable WWS system supplied all end-use energy needs?

**Table 2**

Projected end-use power in 2030, by sector, U.S. and the world, conventional fossil-fuel case, and replacing 100% of fossil fuel and wood combustion with WWS.

Energy sector, by EIA energy-use categories	TW power in 2030 (conventional fossil fuels)		Elect. fract.	End-use energy/work w.r.t. fossil fuel		Upstream factor	EHCM factor	TW power in 2030 replacing all fossil fuels with WWS	
	World	U.S.		Electric	e-H <sub>2</sub>			World	U.S.
<b>Residential</b>									
Liquids	0.37	0.04	0.95	0.82	1.43	1.00	0.90	0.29	0.03
Natural gas	0.84	0.18	0.95	0.82	1.43	1.00	0.90	0.61	0.13
Coal	0.11	0.00	1.00	0.82	1.43	1.00	0.90	0.08	-
Electricity	0.92	0.20	1.00	1.00	1.00	1.00	0.95	0.83	0.18
Renewables	0.02	0.01	0.50	0.82	1.43	1.00	0.90	0.02	0.01
<b>Total</b>	<b>2.26</b>	<b>0.43</b>						<b>1.83</b>	<b>0.35</b>
<b>Commercial</b>									
Liquids	0.18	0.02	0.90	0.82	1.43	1.00	0.95	0.15	0.02
Natural gas	0.32	0.13	0.90	0.82	1.43	1.00	0.95	0.26	0.10
Coal	0.03	0.00	0.90	0.82	1.43	1.00	0.95	0.03	0.00
Electricity	0.78	0.22	1.00	1.00	1.00	1.00	1.00	0.78	0.22
Renewables	0.01	0.00	0.90	0.82	1.43	1.00	0.95	0.01	0.00
<b>Total</b>	<b>1.32</b>	<b>0.38</b>						<b>1.22</b>	<b>0.35</b>
<b>Industrial</b>									
Liquids	2.41	0.31	0.60	0.82	1.43	0.72	0.95	1.76	0.22
Natural gas	2.35	0.28	0.60	0.82	1.43	0.82	0.95	1.95	0.23
Coal	2.15	0.08	0.60	0.82	1.43	0.73	0.95	1.59	0.06
Electricity	1.75	0.12	1.00	1.00	1.00	0.93	1.00	1.62	0.11
Renewables	0.15	0.14	0.90	0.82	1.43	1.00	0.95	0.13	0.12
<b>Total</b>	<b>8.80</b>	<b>0.92</b>						<b>7.05</b>	<b>0.74</b>
<b>Transportation</b>									
Liquids	4.44	1.07	0.73	0.19	0.64	1.18	0.85	1.30	0.31
Natural gas	0.05	0.03	0.90	0.82	1.43	1.00	0.85	0.04	0.02
Coal	-	0.00	0.90	0.82	1.43	1.00	0.85	-	-
Electricity	0.04	0.00	1.00	1.00	1.00	1.00	0.95	0.03	-
<b>Total</b>	<b>4.53</b>	<b>1.10</b>						<b>1.37</b>	<b>0.33</b>
<b>Total end uses</b>	<b>16.92</b>	<b>2.83</b>						<b>11.47</b>	<b>1.78</b>

Notes: see Appendix A.2.

Table 2 shows our estimates of global and U.S. end-use energy demand, by sector, in a world powered entirely by WWS, with zero fossil-fuel and biomass combustion. We have assumed that all end uses that feasibly can be electrified use WWS power directly, and that the remaining end uses use WWS power indirectly in the form of electrolytic hydrogen (hydrogen produced by splitting water with WWS power). As explained in Section 2 we assume that most uses of fossil fuels for heating/cooling can be replaced by electric heat pumps, and that most uses of liquid fuels for transportation can be replaced by BEVs. The remaining, non-electric uses can be supplied by hydrogen, which we assume would be compressed for use in fuel cells in remaining non-aviation transportation, liquefied and combusted in aviation, and combusted to provide heat directly in the industrial sector. The hydrogen would be produced using WWS power to split water; thus, directly or indirectly, WWS powers the world.

As shown in Table 2, the direct use of electricity, for example, for heating or electric motors, is considerably more efficient than is fuel combustion in the same application. The use of electrolytic hydrogen is less efficient than is the use of fossil fuels for direct heating but more efficient for transportation when fuel cells are used; the efficiency difference between direct use of electricity and electrolytic hydrogen is due to the energy losses of electrolysis, and in the case of most transportation uses, the energy requirements of compression and the greater inefficiencies of fuel cells than batteries. Assuming that some additional modest energy-conservation measures are implemented (see the list of demand-side conservation measures in Section 2) and subtracting the energy requirements of petroleum refining, we estimate that an all-WWS world would require ~30% less end-use power than the EIA projects for the conventional fossil-fuel scenario (Table 1).

How do the energy requirements of a WWS world, shown in Table 2, compare with the availability of WWS power? Table 3 gives the estimated power available worldwide from renewable energy, in terms of raw resources, resources available in high-energy locations, resources that can feasibly be extracted in the near term considering cost and location, and the current resources used. The table indicates that only solar and wind can provide more power on their own than energy demand worldwide. Wind in developable locations can power the world about 3–5 times over and solar, about 15–20 times over.

Fig. 1 shows the modeled world wind resources at 100 m, in the range of the hub height of modern wind turbines. Globally, ~1700 TW of wind energy are available over the world's land

plus ocean surfaces at 100 m if all wind at all speeds were used to power wind turbines (Table 3); however, the wind power over land in locations over land and near shore where the wind speed is 7 m/s or faster (the speed necessary for cost-competitive wind energy) is around 72–170 TW (Archer and Jacobson, 2005; Lu et al., 2009; Fig. 1). Over half of this power is in locations that could practically be developed. Large regions of fast winds worldwide include the Great Plains of the U.S. and Canada, Northern Europe, the Gobi and Sahara Deserts, much of the Australian desert areas, and parts of South Africa and Southern South America and South Africa. In the U.S., wind from the Great Plains and offshore the East Coast (Kempton et al., 2007) could supply all U.S. energy needs. Other windy offshore regions include the North Sea, the West Coast of the U.S. (Dvorak et al., 2010), and the East Coast of Asia among others.

Extraction from the wind of 100% of the power needed for the world in 2030 (11.5 TW from Table 2) would reduce the overall power in the wind at 100 m by < 1% (Santa Maria and Jacobson, 2009). Such extracted power is eventually dissipated to heat, a portion of which is cycled back to produce more potential energy, which produces kinetic energy, regenerating some of the wind. The remaining heat goes toward slightly increasing air and ground temperature, but this addition is very small. For example, the maximum additional radiative forcing due to powering the world with wind is  $\sim 11.5 \text{ TW} / 5.106 \times 10^{14} \text{ m}^2$  (area of the Earth) = 0.022 W/m<sup>2</sup>, which is only ~0.7% of the ~3 W/m<sup>2</sup> forcing due to all

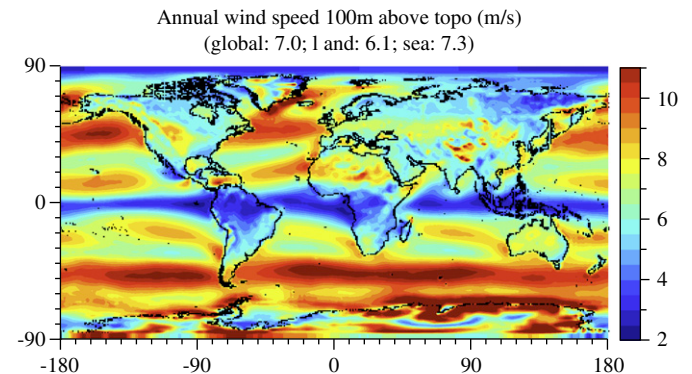


Fig. 1. Map of the yearly averaged world wind speed (m/s) at 100 m above sea level at 1.5° × 1.5° resolution, generated with the GATOR-GCMOM 3-D global model (Jacobson, 2010).

Table 3

Power available in energy resource worldwide if the energy is used in conversion devices, in locations where the energy resource is high, in likely-developable locations, and in delivered electricity in 2005 or 2007 (for wind and solar PV).

Energy technology	Power worldwide (TW)	Power in high-energy locations (TW)	Power in likely-developable locations (TW)	Current power delivered as electricity (TW)
Wind	1700 <sup>a</sup>	72–170 <sup>b</sup>	40–85 <sup>c</sup>	0.02 <sup>d</sup>
Wave	> 2.7 <sup>d</sup>	2.7 <sup>e</sup>	0.5 <sup>d</sup>	0.000002 <sup>d</sup>
Geothermal	45 <sup>f</sup>	2 <sup>g</sup>	0.07–0.14 <sup>d</sup>	0.0065 <sup>d</sup>
Hydroelectric	1.9 <sup>d</sup>	< 1.9 <sup>d</sup>	1.6 <sup>d</sup>	0.32 <sup>d</sup>
Tidal	3.7 <sup>d</sup>	0.8 <sup>d</sup>	0.02 <sup>d</sup>	0.00006 <sup>d</sup>
Solar PV	6500 <sup>h</sup>	1300 <sup>i</sup>	340 <sup>d</sup>	0.0013 <sup>d</sup>
CSP	4600 <sup>j</sup>	920 <sup>j</sup>	240 <sup>j</sup>	000046 <sup>d</sup>

<sup>a</sup> Fig. 1 here; accounts for all wind speeds at 100 m over land and ocean.

<sup>b</sup> Locations over land or near the coast where the mean wind speed  $\geq 7$  m/s at 80 m (Archer and Jacobson, 2005) and at 100 m (Lu et al., 2009; Fig. 1 here).

<sup>c</sup> Eliminating remote locations.

<sup>d</sup> Jacobson (2009) and references therein.

<sup>e</sup> Wave power in coastal areas.

<sup>f</sup> Fridleifsson et al. (2008).

<sup>g</sup> Includes estimates of undiscovered reservoirs over land.

<sup>h</sup> Fig. 2 here, assuming use of 160 W solar panels and areas determined in Jacobson (2009), over all latitudes, land, and ocean.

<sup>i</sup> Same as (h) but locations over land between 50S and 50N.

<sup>j</sup> Scaling solar PV resource with relative land area requirements from Jacobson (2009).

greenhouse gases. Since wind turbines replace other electricity sources that also produce heat in this manner (Santa Maria and Jacobson, 2009), wind turbines (and other renewable electricity sources) replacing current infrastructure cause no net heat addition to the atmosphere. They serve only to reduce global-warming pollutants and health-affecting air pollutants that current electricity and energy sources produce.

Fig. 2 shows the distribution of solar energy at the Earth's surface. Globally, 6500 TW of solar energy are available over the world's land plus ocean surfaces if all sunlight is used to power photovoltaics (Table 3); however, the deliverable solar power over land in locations where solar PV could practically be developed is about 340 TW. Alternatively CSP could provide about 240 TW of the world's power output, less than PV since the land area required for CSP without storage is about one-third greater than is that for PV. With thermal storage, the land area for CSP increases since more solar collectors are needed to provide energy for storage, but energy output does not change and the energy can be used at night. However, water-cooled CSP plants can require water for cooling during operation (about 8 gal/kWh—much more than PVs and wind (~0 gal/kWh), but less than nuclear and coal (~40 gal/kWh) (Sovacool and Sovacool, 2009)), and this might be a constraint in some areas. This constraint is not accounted for in the estimates of Table 3. However, air-cooled CSP plants require over 90% less water than water-cooled plants at the cost of only about 5% less electric power and 2–9% higher electricity rates (USDOE, 2008b),

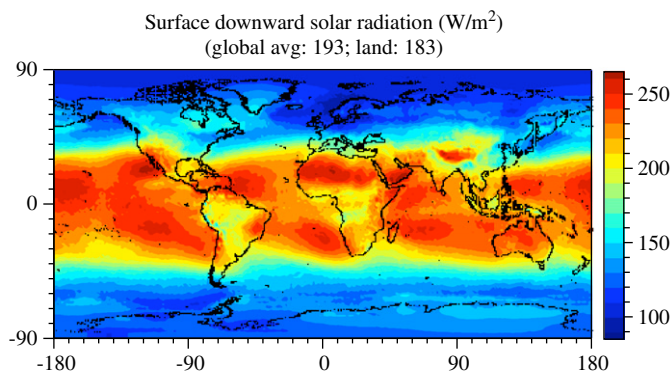


Fig. 2. Map of the yearly averaged downward surface solar radiation reaching the surface ( $\text{W/m}^2$ ) at  $1.5 \times 1.5^\circ$  resolution, generated with the GATOR-GCMOM 3-D global model (Jacobson, 2010).

Table 4

Number of WWS power plants or devices needed to power the world and U.S. total energy demand in 2030 (11.5 and 1.8 TW, respectively, from Table 2), assuming a given partitioning of the demand among plants or devices. Also shown are the footprint and spacing areas required to power the world, as a percentage of the global land area,  $1.446 \times 10^8 \text{ km}^2$ . Derived from appendix A of Jacobson (2009).

Energy technology	Rated power of one plant or device (MW)	Percent of 2030 power demand met by plant/device	Number of plants or devices needed World	Footprint area (% of global land area)	Spacing area (% of global land area)	Number of plants or devices needed U.S.
Wind turbine	5	50	3.8 million	0.000033	1.17	590,000
Wave device	0.75	1	720,000	0.00026	0.013	110,000
Geothermal plant	100	4	5350	0.0013	0	830
Hydroelectric plant	1300	4	900 <sup>a</sup>	0.407 <sup>a</sup>	0	140 <sup>a</sup>
Tidal turbine	1	1	490,000	0.000098	0.0013	7600
Roof PV system	0.003	6	1.7 billion	0.042 <sup>b</sup>	0	265 million
Solar PV plant	300	14	40,000	0.097	0	6200
CSP plant	300	20	49,000	0.192	0	7600
Total		100		0.74	1.18	
Total new land				0.41 <sup>c</sup>	0.59 <sup>c</sup>	

<sup>a</sup> About 70% of the hydroelectric plants are already in place. See Jacobson (2009) for a discussion of apportioning the hydroelectric footprint area by use of the reservoir.

<sup>b</sup> The footprint area for rooftop solar PV does not represent an increase in land since the rooftops already exist and are not used for other purposes.

<sup>c</sup> Assumes 50% of the wind is over water, wave and tidal are in water, 70% of hydroelectric is already in place, and rooftop solar does not require new land.

suggesting air-cooled plants may be a viable alternative in water-limited locations.

The other WWS technologies have much less resource availability than do wind, CSP, and PV (Table 3), yet can still contribute beneficially to the WWS solution. Wave power can be extracted practically only near coastal areas, which limits its worldwide potential. Although the Earth has a very large reservoir of geothermal energy below the surface, most of it is too deep to extract practically. Even though hydroelectric power today exceeds all other sources of WWS power, its future potential is limited because most of the large reservoirs suitable for generating hydropower are already in use.

Further, although there is enough feasibly developable wind and solar power to supply the world, other WWS resources will be more abundant and more economical than wind and solar in many locations. Finally, wind and solar power are variable, so geothermal and tidal power, which provide relatively constant power, and hydroelectric, which fills in gaps, will be important for providing a stable electric power supply.

See a detailed discussion of this in Part II of this work, Delucchi and Jacobson (this issue).

#### 4. Quantities and areas of plants and devices required

How many WWS power plants or devices are required to power the world and U.S.? Table 4 provides an estimate for 2030, assuming a given fractionation of the demand (from Table 2) among technologies. Wind and solar together are assumed to comprise 90% of the future supply based on their relative abundances (Table 3). Although 4% of the proposed future supply is hydro, most of this amount (70%) is already in place. Solar PV is divided into 30% rooftop, based on an analysis of likely available rooftop area (Jacobson, 2009) and 70% power plant. Rooftop PV has three major advantages over power-plant PV: rooftop PV does not require an electricity transmission and distribution network, it can be integrated into a hybrid solar system that produces heat, light, and electricity for use on site (Chow, 2010), and it does not require new land area. Table 4 suggests that almost 4 million 5 MW wind turbines (over land or water) and about 90,000 300 MW PV plus CSP power plants are needed to help power the world. Already, about 0.8% of the wind is installed.

The total footprint on the ground (for the turbine tubular tower and base) for the 4 million wind turbines required to power 50% of the world's energy is only  $\sim 48 \text{ km}^2$ , smaller than Manhattan ( $59.5 \text{ km}^2$ ) whereas the spacing needed between turbines to

minimize the effects of one turbine reducing energy to other turbines is  $\sim 1.17\%$  of the global land area. The spacing can be used for agriculture, rangeland, open space, or can be open water. Whereas, wind turbines have foundations under the ground larger than their base on the ground, such underground foundation areas are not footprint, which is defined as the area of a device or plant touching the top surface of the soil, since such foundations are covered with dirt, allowing vegetation to grow and wildlife to flourish on top of them. The footprint area for wind also does not need to include temporary or unpaved dirt access roads, as most large-scale wind will go over areas such as the Great Plains and some desert regions, where photographs of several farms indicate unpaved access roads blend into the natural environment and are often overgrown by vegetation. Offshore wind does not require roads at all. In farmland locations, most access roads have dual purposes, serving agricultural fields as well as turbines. In cases where paved access roads are needed,  $1 \text{ km}^2$  of land provides  $\sim 200 \text{ km}$  (124 miles) of linear roadway 5 m wide, so access roads would not increase the footprint requirements of wind farms more than a small amount. The footprint area also does not include transmission, since the actual footprint area of a transmission tower is smaller than the footprint area of a wind turbine. This is because a transmission tower consists of four narrow metal support rods separated by distance, penetrating the soil to an underground foundation. Many photographs of transmission towers indicate more vegetation growing under the towers than around the towers since areas around that towers are often agricultural or otherwise used land whereas the area under the tower is vegetated soil. Since the land under transmission towers supports vegetation and wildlife, it is not considered footprint beyond the small area of the support access roads.

For non-rooftop solar PV plus CSP, the areas required are considered here to be entirely footprint although technically a walking space, included here as footprint, is required between solar panels (Jacobson, 2009). Powering 34% of the world with non-rooftop solar PV plus CSP requires about one-quarter of the land area for footprint plus spacing as does powering 50% of the world with wind but a much larger footprint area alone than does wind (Table 4). The footprint area required for rooftop solar PV has already been developed, as rooftops already exist. As such, these areas do not require further increases in land requirements. Geothermal power requires a smaller footprint than does solar but a larger footprint than does wind per unit energy generated. The footprint area required for hydroelectric is large due to the large area required to store water in a reservoir, but 70% of the needed hydroelectric power for a WWS system is already in place.

Together, the entire WWS solution would require the equivalent of  $\sim 0.74\%$  of the global land surface area for footprint and  $1.18\%$  for spacing (or  $1.9\%$  for footprint plus spacing). Up to 61% of the footprint plus spacing area could be over the ocean if all wind were placed over the ocean although a more likely scenario is that 30–60% of wind may ultimately be placed over the ocean given the strong wind speeds there (Fig. 1). If 50% of wind energy were over the ocean, and since wave and tidal are over the ocean, and if we consider that 70% of hydroelectric power is already in place and that rooftop solar does not require new land, the additional footprint and spacing areas required for all WWS power for all purposes worldwide would be only  $\sim 0.41\%$  and  $\sim 0.59\%$ , respectively, of all land worldwide (or  $1.0\%$  of all land for footprint plus spacing).

## 5. Material resources

In a global all-WWS-power system, the new technologies produced in the greatest abundance will be wind turbines, solar

PVs, CSP systems, BEVs, and electrolytic-HFCVs. In this section, we examine whether any of these technologies use materials that either are scarce or else concentrated in a few countries and hence subject to price and supply manipulation.

### 5.1. Wind power

The primary materials needed for wind turbines include steel (for towers, nacelles, rotors, etc.), pre-stressed concrete (for towers), magnetic materials (for gearboxes), aluminum (nacelles), copper (nacelles), wood epoxy (rotor blades), glassfiber reinforced plastic (GRP) (for rotor blades), and carbon-filament reinforced plastic (CFRP) (for rotor blades). In the future, use of composites of GFRP, CFRP, and steel will likely increase.

The manufacture of four million 5 MW or larger wind turbines will require large amounts of bulk materials such as steel and concrete (USDOE, 2008a). However, there do not appear to be significant environmental or economic constraints on expanded production of these bulk materials. The major components of concrete – gravel, sand, and limestone – are widely abundant, and concrete can be recycled and re-used. The Earth does have a somewhat limited reserves of economically recoverable iron ore (on the order of 100–200 years at current production rates (USGS, 2009, p. 81)), but the steel used to make towers, nacelles, and rotors for wind turbines should be virtually 100% recyclable (for example, in the U.S. in 2007, 98% of steel construction beams and plates were recycled (USGS, 2009, p. 84)). The USDOE (2008a) concludes that the development of 20% wind energy by 2030 is not likely to be constrained by the availability of bulk materials for wind turbines.

For wind power, the most problematic materials may be rare earth elements (REEs) like neodymium (Nd) used in permanent magnets (PMs) in generators (Margonelli, 2009; Gorman, 2009; Lifton, 2009). In some wind-power development scenarios, demand for REEs might strain supplies or lead to dependence on potentially insecure supplies. (e.g., Margonelli, 2009; Hurst, 2010). One estimate suggests that current PM generators in large wind turbines use  $0.2 \text{ kg Nd/kWh}$ , or one-third the  $0.6 \text{ kg/kWh}$  of an Nd-based permanent magnet (Hatch, 2009). Building the 19 million installed MW of wind power needed to power 50% of world energy in 2030 (Table 4) would require 3.8 million metric tonnes of Nd, or about 4.4 million metric tonnes of Nd oxide (based on  $\text{Nd}_2\text{O}_3$ ), which would amount to approximately 100,000 metric tons of Nd oxide per year over a 40–50 year period. In 2008, the world produced 124,000 metric tonnes of rare-earth oxide equivalent, which included about 22,000 metric tonnes of Nd oxide (Table 5). Annual world production of Nd therefore would have to increase by a factor of more than five to accommodate the demand for Nd for production of PMs for wind-turbine generators for our global WWS scenario.

The global Nd reserve or resource base could support 122,000 metric tonnes of Nd oxide production per year (the amount needed for wind generators in our scenario, plus the amount needed to supply other demand in 2008) for at least 100 years, and perhaps for several hundred years, depending on whether one considers the known global economically available reserves or the more speculative potential global resource (Table 5). Thus, if Nd is to be used beyond a few hundred years, it will have to be recycled from magnet scrap, a possibility that has been demonstrated (Takeda et al., 2006; Horikawa et al., 2006), albeit at unknown cost.

However, even if the resource base and recycling could sustain high levels of Nd use indefinitely, it is not likely that actual global production will be able to increase by a factor of five for many years, because of political or environmental limitations on expanding supply (Lifton, 2009; Reisman, 2009). Therefore, it seems likely that a rapid global expansion of wind power will require many



**Table 5**

Rare earth oxide and neodymium oxide (in parentheses)<sup>a</sup> production, reserves, and resources worldwide (million metric tonnes of rare earth oxide).

Source: USGS (2009, p. 131).

Country	Mine production 2008	Reserves	Reserve Base	Resources
United States	0 (0.000)	13 (2.0)	14 (2.1)	n.r.
Australia	0 (0.000)	5.2 (0.9)	5.8 (1.0)	n.r.
China	0.120 (0.022)	27 (4.9)	89 (16.0)	n.r.
CIS	n.a.	19 (3.4)	21 (3.8)	n.r.
India	0.003 (0.001)	1.1 (0.2)	1.3 (0.2)	n.r.
Others	0.001 (0.000)	22 (4.0)	23 (4.1)	
World total	0.124 (0.022)	88 (15.3)	150 (27.3)	"very large" <sup>b</sup>

CIS=Commonwealth of Independent States. n.a.=not available. "Reserves" are "that part of the reserve base which could be economically extracted or produced at the time of determination. The term reserves need not signify that extraction facilities are in place and operative" (USGS, 2009, p. 192). The "Reserve Base" comprises reserves (as defined above), plus marginally economic resources, plus currently sub-economic resources. "Resources" comprise the reserve base (as defined above) plus commodities that may be economically extractable in the future (USGS, 2009, p. 191).

<sup>a</sup> Assumes that the Nd oxide content of total rare earth oxides is 15% in the U.S. and 18% in China, Australia, and all other countries (based on Table 2 of Hedrick, 2009).

<sup>b</sup> The USGS (2009) writes that "undiscovered resources are thought to be very large relative to expected demand" (p. 131).

generators that do not use Nd (or other REE) PMs or a rapid transition into recycling. There are at least two kinds of alternatives:

- (i) generators that perform at least as well as PM generators but don't have scarce REEs (e.g., switched-reluctance motors (Lovins and Howe, 1992)), new high-torque motors with inexpensive ferrite magnets, and possibly high-temperature super-conducting generators (Hatch, 2009);
- (ii) generators that don't use REEs but have higher mass per unit of power than do PM generators (the greater mass will require greater structural support if the generator is in the tower).

Morcos (2009) presents the most cogent summary of the implications of any limitation in the supply of Nd for permanent magnets:

A possible dwindling of the permanent magnet supply caused by the wind turbine market will be self-limiting for the following reasons: large electric generators can employ a wide variety of magnetic circuit topologies, such as surface permanent magnet, interior permanent magnet, wound field, switched reluctance, induction and combinations of any of the above. All of these designs employ large amounts of iron (typically in the form of silicon steel) and copper wire, but not all require permanent magnets. Electric generator manufacturers will pursue parallel design and development paths to hedge against raw material pricing, with certain designs making the best economic sense depending upon the pricing of copper, steel and permanent magnets. Considering the recent volatility of sintered NdFeB pricing, there will be a strong economic motivation to develop generator designs either avoiding permanent magnets or using ferrite magnets with much lower and more stable pricing than NdFeB.

## 5.2. Solar power

Solar PVs use amorphous silicon, polycrystalline silicon, microcrystalline silicon, cadmium telluride, copper indium selenide/sulfide, and other materials. According to a recent review of materials issues for

terawatt-level development of photovoltaics, the power production of silicon PV technologies is limited not by crystalline silicon (because silicon is widely abundant) but by reserves of silver, which is used as an electrode (Feltrin and Freundlich, 2008). That review notes that "if the use of silver as top electrode can be reduced in the future, there are no other significant limitations for c-Si solar cells" with respect to reaching multi-terawatt production levels (Feltrin and Freundlich, 2008, p. 182).

For thin-film PVs, substituting ZnO electrodes for indium thin oxide allows multi-terawatt production, but thin-film technologies require much more surface area. The limited availability of tellurium (Te) and indium (In) reduces the prospects of cadmium telluride (CdTe) and copper indium gallium selenide (CIGS) thin cells.

For multi-junction concentrator cells, the limiting material is germanium (Ge), but substitution of more abundant gallium (Ga) would allow terawatt expansion.

Wadia et al. (2009) estimate the annual electricity production that would be provided by each of 23 different PV technologies if either one year of total current global production or alternatively the total economic reserves (as estimated by the USGS) of the limiting material for each technology were used to make PVs. They also estimate the minimum \$/W cost of the materials for each of the 23 PV technologies. They conclude that there is a "major opportunity for fruitful new research and development based on low cost and commonly available materials" (Wadia et al., 2009, p. 2076), such as FeS<sub>2</sub>, CuO, Cu<sub>2</sub>S, and Zn<sub>3</sub>P<sub>2</sub>.

On the basis of this limited review, we conclude that the development of a large global PV system is not likely to be limited by the scarcity or cost of raw materials.

## 5.3. Electric vehicles

For electric vehicles there are three materials that are of most concern: rare-earth elements (REEs) for electric motors, lithium for lithium-ion batteries, and platinum for fuel cells. Some permanent-magnet ac motors, such as in the Toyota Prius hybrid electric vehicle (Toyota, 2010), can use significant amounts of REEs. For example, the motor in the Prius uses 0.2–1 kg of Nd or 3.6–16.7 kg/MW (Maximum EV, 2009; Gorman, 2009). The low estimate is based on the assumption that the Prius' permanent magnet motors are 55 kW, with NdFeB magnet containing 31% Nd by mass (Maximum EV, 2009). The high kg/MW estimate assumes 60 kW motors (Toyota, 2010). Although this is an order of magnitude less than is used in some wind-turbine generators (see discussion above), the total potential demand for Nd in a worldwide fleet of BEVs with permanent-magnet motors would still be large enough to be of concern. However, there are a number of electric motors that do not use REEs, and at least one of these, the switched reluctance motor, currently under development for electric vehicles (e.g., Goto et al., 2005), is economical, efficient, robust, and high-performing (Lovins and Howe, 1992). Given this, we do not expect that the scarcity of REEs will appreciably affect the development of electric vehicles.

Next we consider lithium and platinum supply issues. To see how lithium supply might affect the production and price of battery-electric vehicles, we examine global lithium supplies, lithium prices, and lithium use in batteries for electric vehicles. Table 6 shows the most recent estimates of lithium production, reserves, and resources from USGS (2009).

Note that Table 6 does not include the recently discovered, potentially large lithium reserves in Afghanistan (Risen, 2010). Roughly half of the global lithium reserve base known in 2009 is in one country, Bolivia, which has been called "the Saudi Arabia of lithium" (Friedman-Rudovsky, 2009). However, Bolivia does not yet have any economically recoverable reserves or lithium production infrastructure (Ritter, 2009; Wright, 2010), and to date has not produced any lithium (Table 6). About 75% of the world's known

**Table 6**

Lithium production, reserves and resources worldwide as of 2009 (metric tonnes).  
Source: USGS 2009.

Country	Mine production 2008	Reserves	Reserve Base	Resources
United States	n.r.	38,000	410,000	n.r.
Argentina	3200	n.r.	n.r.	n.r.
Australia	6900	170,000	220,000	n.r.
Bolivia	0	0	5,400,000 <sup>a</sup>	n.r.
Chile	12,000	3,000,000	3,000,000	n.r.
China	3500	540,000	1,100,000	n.r.
World total	27,400	4,100,000	11,000,000	> 13,000,000

n.r.=not reported. For explanation of terms, see notes to Table 5.

<sup>a</sup> Wright (2010, p. 58) reports that the head of the Bolivian scientific committee charged with developing Bolivia's lithium resources estimates that there are about 100,000,000 metric tonnes of metallic lithium in Bolivia.

economically recoverable reserves are in Chile, which is also the world's leading producer (Table 6). Both Bolivia and Chile recognize the importance of lithium to battery and car makers, and are hoping to extract as much value from it as possible (Wright, 2010). This concentration of lithium in a few countries, combined with rapidly growing demand, could increase the price of lithium upon expanded BEV production. Currently, lithium carbonate ( $\text{Li}_2\text{CO}_3$ ) costs ~\$6–7/kg, and lithium hydroxide (LiOH), ~\$10/kg (Jaskula, 2008), which correspond to about \$35/kg Li. Lithium is ~1–2% of the mass of a lithium-ion battery (Gaines and Nelson, 2009; Wilburn, 2009, Table A-9); in a pure BEV with a relatively long range (about 100 miles), the battery might contain on the order of 10 kg of lithium (Gaines and Nelson, 2009). At current prices this adds ~\$350 to the manufacturing cost of a vehicle battery, but if lithium prices were to double or triple, the lithium raw material cost could approach \$1000, which would increase vehicle costs further.

At 10 kg per vehicle, the production of 26 million EVs per year – more than half of the 48 million passenger cars produced in the world in 2009 (OICA, 2010) – would require 260,000 metric tonnes-Li per year, which in the absence of recycling lithium batteries (which currently is negligible) would exhaust the current reserve base (Table 6) in less than 50 years. If one considers an even larger EV share of a growing, future world car market, and includes other demands for lithium, it is likely that the current reserve base would be exhausted in less than 20 years, in the absence of recycling. This is the conclusion of the recent analysis by Meridian International Research (2008).

However, the world will not consume lithium reserves in an uncontrolled manner until, one day, the supply of lithium is exhausted. As demand grows the price will rise and this will spur the hunt for new sources of lithium, most likely from recycling. Another potential source of lithium is the oceans, which contain 240 million tonnes, far more than all the known land reserves. However, currently the cost of extracting such lithium is high and energy intensive, so alternatives are strongly preferred. According to an expert, recycling lithium currently is more expensive than is mining virgin material (Ritter, 2009), but as the price of lithium rises, at some point recycling will become economical. The economics of recycling depend in part on the extent to which batteries are made with recyclability in mind, an issue that the major industries already are aware of: according to a recent report, “lithium mining companies, battery producers, and automakers have been working together to thoroughly analyze lithium availability and future recyclability before adopting new lithium-ion chemistries” (Ritter, 2009, p. 5). Gaines and Nelson (2010) discuss recycling processes for lithium-ion batteries, and write that “recovery of battery-grade material has been demonstrated” (p. 7).

Ultimately, then, the issue of how the supply of lithium affects the viability of lithium-ion-battery EVs in an all-WWS world boils down to the price of lithium with sustainable recycling. As noted above, it does make some difference to EV economics if that price is \$35/kg-Li or \$100/kg-Li.

Finally we consider the use of platinum in fuel cells. The production of millions of hydrogen fuel cell vehicles (HFCVs) would increase demand for Pt substantially. Indeed, the production of 20 million 50 kW HFCVs annually might require on the order of 250,000 kg of Pt—more than the total current world annual production of Pt (Yang, 2009; USGS, 2009, p. 123). How long this output can be sustained, and at what platinum prices, depends on several factors: (1) the technological, economic, and institutional ability of the major supply countries to respond to changes in demand; (2) the ratio of recoverable reserves to total production; (3) improvements in technology that reduce the cost of recovery; and (4) the cost of recycling as a function of quantity recycled.

Regarding the first factor, it does not seem likely that the current production problems in South Africa, mentioned by Yang (2009), will be permanent. Rather, it seems reasonable to assume that in the long run, output can be increased in response to large changes in demand and price. In support of this, the U.K. Department of Transport (UKDOT, 2006) cites a study that concludes that “production in South Africa could be expanded at a rate of 5% per year for at least another 50 years”. TIAX (2030) finds that “the platinum industry has the potential to meet a scenario where FCVs achieve 50% market penetration by 2050, while an 80% scenario could exceed the expansion capabilities of the industry” (p. 7).

Regarding the second factor, Spiegel (2004) writes that the International Platinum Association concludes that “there are sufficient available reserves to increase supplies by up to 5–6% per year for the next 50 years,” (p. 364), but does not indicate what the impact on prices might be. Gordon et al. (2006) estimate that 29 million kg of platinum-group metals are available for future use, and state that “geologists consider it unlikely that significant new platinum resources will be found” (p. 1213). This will sustain annual production of at least 20 million HFCVs, plus production of conventional catalyst-equipped vehicles, plus all other current non-automotive uses, for less than 100 years, without any recycling.

Regarding the third factor, TIAX (2003) argues that in the long run the price of platinum is stable because the extra cost of recovering deeper and more diffuse reserves is balanced by technological improvements that reduce recovery costs. It is not clear, however, that this improvement can be expected to continue indefinitely. Thus, the prospects for very long term use of platinum, and the long-term price behavior of platinum, depend in large part on the prospects for recycling (TIAX, 2003).

According to an expert in the precious-metal recycling industry, the full cost of recycled platinum in a large-scale, international recycling system is likely to be much less than the cost of producing virgin platinum metal (Hagelüken, 2009). Consistent with this, UKDOT (2006) cites an analysis that indicates that platinum recycling will be economical even if platinum loadings on fuel-cell catalysts are greatly reduced from current levels. Thus, the more the recycling, the less the production of high-cost virgin material, and hence the lower the price of platinum, since the price will be equal to the long-run marginal cost of producing virgin metal. The effect of recycling on platinum price, therefore, depends on the extent of recycling.

The prospects for recycling are difficult to quantify, because they depend more on institutional and logistical factors than on technical factors. The current rate of recycling autocatalysts is between 10% and 25%, if expressed as the ratio {Pt recovered from catalysts in year X}:{Pt used in new catalysts in year X} (Carlson and

Thijssen, 2002; Hagelüken et al., 2009; Hagelüken, 2009), but is around 50% if expressed as the ratio {Pt recovered from catalysts in year X}:{Pt used in new catalysts in the year in which the currently recycled products were made} (Hagelüken, 2009 (also quoted in Ritter, 2009, p. 4)). This second ratio, representing the “dynamic recycling rate,” is more meaningful because it is based on the lifecycle of a particular product (e.g., Schaik and Reuter, 2004). Technically, there appears to be ample room to increase dynamic recycling rates. Hagelüken et al. (2009) believe that “a progressive conversion of existing open loop recycling systems to more efficient closed loops... would more than double the recovery of PGMs from used autocatalysts by 2020” (p. 342). (Hagelüken et al. (2009) and UKDOT (2006) also note that emissions from recycling PGMs are significantly lower than emissions from mine production of PGMs.) Spiegel (2004) states that “technology exists to profitably recover 90% of the platinum from catalytic converters” (p. 360), and in his own analysis of the impact of HFCV platinum on world platinum production, he assumes that 98% of the Pt in HFCVs will be recoverable. Similarly, Hagelüken, 2009 asserts that the technology is available to recover more than 90% of the platinum from fuel cells, although he believes that 98% recovery will be difficult to achieve. Finally, in their separate analyses of the impact of the introduction of hydrogen HFCVs on platinum supply and prices, UKDOT (2006) and TIAX (2003) assume that 95% of the platinum in fuel cells will be recovered and recycled. (UKDOT (2006) cites two sources, one of them a catalyst manufacturer, in support of its assumption.)

It seems likely that a 90%+ recycling rate will keep platinum prices lower than will a 50% recycling rate. The main barriers to achieving a 90%+ recycling rate are institutional rather than technical or economic: a global recycling system requires international agreement on standards, protocols, infrastructure, management, and enforcement (Hagelüken, 2009). We cannot predict when and to what extent a successful system will be developed.

Nevertheless, it seems reasonable to assume that enough platinum will be recycled to supply a large and continuous fuel-cell vehicle market with only moderate increases in the price of platinum, until new, less costly, more abundant catalysts or fuel cell technologies are found. Indeed, catalysts based on inexpensive, abundant non-platinum materials may be available soon (e.g., Lefèvre et al., 2009). Preliminary work by Sun et al. (2010) supports this conclusion. They developed an integrated model of HFCV production, platinum loading per HFCV (a function of HFCV production), platinum demand (a function of HFCV production, platinum loading, and other factors), and platinum prices (a function of platinum demand and recycling), and found that in a scenario in which HFCV production was increased to 40% of new LDV output globally in the year 2050, the average platinum cost per HFCV was \$400, or about 10% of the cost of the fuel-cell system.

## 6. Summary of technical findings and conclusions

This is Part I of a study to examine the feasibility of providing all energy for all purposes (electric power, transportation, heating/cooling, etc.) worldwide from wind, water, and the sun (WWS). The main technical findings of this analysis are as follows:

Converting to a WWS energy infrastructure will reduce 2030 world power demand by 30%, primarily due to the efficiency of electricity compared with internal combustion. The amount of wind power plus solar power available in likely developable locations over land outside of Antarctica worldwide to power the world for all purposes exceeds projected world power demand by more than an order of magnitude.

One scenario for powering the world with a WWS system includes 3.8 million 5 MW wind turbines (supplying 50% of projected total global power demand in 2030), 49,000 300 MW CSP power plants (supplying 20% of demand), 40,000 solar PV power plants (14%), 1.7 3 kW rooftop PV systems (6%), 5350 100 MW geothermal power plants (4%), 900 1300 MW hydroelectric power plants, of which 70% are already in place (4%), 720,000 0.75 MW wave devices (1%), and 490,000 1 MW tidal turbines (1%).

The equivalent footprint area on the ground for the sum of WWS devices needed to power the world is ~0.74% of global land area; the spacing area is ~1.16% of global land area. Spacing area can be used for multiple purposes, including agriculture, ranching, and open space. However, if one-half of the wind devices are placed over water, if we consider wave and tidal devices are in water, and if we consider that 70% of hydroelectric is already developed and rooftop solar areas are already developed, the additional footprint and spacing of devices on land required are only ~0.41% and ~0.59% of the world land area, respectively.

The development of WWS power systems is not likely to be constrained by the availability of bulk materials, such as steel and concrete. In a global WWS system, some of the rarer materials, such as neodymium (in electric motors and generators), platinum (in fuel cells), and lithium (in batteries), will have to be recycled or eventually replaced with less-scarce materials unless additional resources are located. The cost of recycling or replacing neodymium or platinum is not likely to affect noticeably the economics of WWS systems, but the cost of large-scale recycling of lithium batteries is unknown.

In Part II of this study (Delucchi and Jacobson, *this issue*), we examine reliability, system and transmission costs, and policies needed for a worldwide WWS infrastructure.

## Acknowledgements

We would like to thank Elaine Hart and Dave Elliott for helpful comments. This paper was not funded by any interest group, company, or government agency.

## Appendix A

### A.1. The economics of nuclear power

The economics of nuclear power are discussed in Kessides (2010), Grubler (2010), Joskow and Parsons (2009), Feiveson (2009), Koomey and Hultman (2007), Hultman et al. (2007), Hultman and Koomey (2007), Harding (2007), and Deutch et al. (2003, 2009). Kessides (2010) and Joskow and Parsons (2009) discuss at length the issues that affect the economics of nuclear power. Feiveson (2009) reviews recent escalation in capital costs. Grubler (2010) argues that the real costs of nuclear power can increase with an expansion of capacity (and in fact did increase in France) because of ever-increasing complexity in the design, construction, operation, management, and regulatory oversight of nuclear systems. Koomey and Hultman (2007) estimate that the total levelized busbar costs of 99 US reactors, including capital costs amortized at 6%/year, range from \$0.03/kWh to \$0.14/kWh (2004 USD), with the 50% percentile falling between \$0.05/kWh and \$0.06/kWh. Hultman et al. (2007) argue that costs at the upper end of the \$0.03–0.14/kWh range are driven in part by unanticipated factors, and Hultman and Koomey (2007) argue that the possibility of such “cost surprises” should be incorporated formally into cost estimates for nuclear power. Koomey and Hultman (2007) argue that standardization of design, improvements in construction

management, computer-assisted design, and other factors might tend to drive costs down, but that the special conditions that attend each nuclear job site, and the possibility of cost “surprises,” tend to drive costs up. Deutch et al. (2003) estimate that the real levelized cost of nuclear power using an “open” or “once-through” fuel cycle (in which spent fuel is treated as waste, rather than recycled back to the reactor) ranges from \$0.04 to \$0.08/kWh (2002 USD) (with an effective interest rate of 11.5%), depending on assumptions regarding the capacity factor, the plant lifetime, construction costs, and construction time. Deutch et al. (2009) and Du and Parsons (2009) estimate that since the Deutch et al. (2003) report, construction costs have escalated substantially, resulting in a doubling of capital costs and an increase in the estimated median levelized cost from \$0.067/kWh in the 2003 study (2002 USD) to \$0.084/kWh in the 2009 update (2007 USD) (see also Joskow and Parsons, 2009). Harding (2007) estimates even higher levelized costs of \$0.09–0.12/kWh (2007 USD).

In summary, the costs of nuclear power are estimated to cover a very wide range, depending on a number of variables that are difficult to project: the costs of new, untested designs; construction times; interest rates; the impact of unforeseen events; regulatory requirements; the potential for economies of scale; site- and job-specific design and construction requirements; the availability of specialty labor and materials; bottlenecks in the supply chains; the potential for standardization; and so on.

## A.2. Notes to Table 2

### A.2.1. TW power in 2030 (fossil-fuel case)

This is the projected total world and total U.S. power for all energy end uses in the year 2030, in the conventional or business-as-usual scenario relying primarily on fossil fuels. The projections are from EIA (2008a); we converted from BTUs per year to Watts. The breakdown here is by type of energy in end use; thus, “renewables” here refers, for example, to end-use combustion of biomass, such as wood used for heating.

### A.2.2. Electrified fraction

This is the fraction of energy service demand in each sector that can be satisfied feasibly by direct electric power. For example, gas water heating and space heating can readily be converted to air- and ground-source heat-pump water heaters and air heaters and electric resistance heaters. Liquid-fuel internal-combustion-engine vehicles can be replaced by battery electric vehicles. Indeed, direct electricity can, technically, provide almost any energy service that fuel combustion can, with the likely exception of transportation by air. However, in other cases, even if it is technically feasible, it may be relatively expensive or difficult for electricity to provide exactly the same service that fuel combustion does: for example, some cooking and heating applications where a flame is preferred, some large-scale direct uses of process heat, some applications of combined heat and power production, and some forms of heavy freight transportation. As explained below, we assume that energy services that are *not* electrified are provided by combustion of electrolytic hydrogen. Our assumptions regarding the directly electrified fraction in each sector are as follows:

### A.2.3. Residential sector

We assume that 5% of fuel use for space heating and 20% of fuel use for “appliances” (mainly cooking) are *not* electrified, and then use the data from Table 2.5 of EIA (2008b) to calculate a weighted-average electrifiable fraction by type of fuel. We assume that renewables are mainly fuelwood, which will not be replaced with electricity. We assume that the estimates calculated on the basis of U.S. data apply to the world.

### A.2.4. Commercial sector

We assume that the fraction of energy-end use that can be electrified is slightly less than we estimated for the residential sector, except in the case of renewables.

### A.2.5. Industrial sector

We assume that 50% of direct-process heat end use, 50% of cogeneration and combined heat-and-power end use, and 25% of conventional boiler fuel use are *not* electrified, and then use data on manufacturing consumption of energy in the U.S. (Table 2.3 of EIA (2008b)) to calculate a weighted-average electrified fraction by type of fuel. We assume that the estimates calculated on the basis of U.S. data apply to the world.

### A.2.6. Transport sector

We assume that 5% of motor-gasoline use, 30% of highway diesel-fuel use, 50% of off-road diesel fuel use, 100% of military fuel use, 20% of train fuel use, and 100% of airplane and ship fuel use are *not* electrified. We use data on transport energy consumption from the IEA (2008, p. 464, 508), data on transport fuel use in the U.S. (EIA, 2008b, Table 5.14c), and data on diesel fuel use in the U.S. (EIA, 2008b, Table 5.15) to estimate a weighted-average electrified fraction by type of fuel. We assume that estimates calculated on the basis of U.S. data apply to the world.

### A.2.7. Non-electrified energy services

We assume that the remaining (non-electrified) energy service demands are met by hydrogen derived from electrolysis of water using WWS power. For analytical simplicity we assume that WWS power is delivered to the site of hydrogen use or refueling and used there to produce hydrogen electrolytically. (This is a useful simplification because it obviates the need to analyze a hydrogen transmission system.) We assume that in all sectors *except* transportation (e.g., in many industrial processes) the electrolytically produced hydrogen is burned directly to provide heat. In the transportation sector except aviation, we assume that hydrogen is compressed and then used in a fuel cell.

For aviation, we assume that hydrogen is liquefied and burned in jet engines. Coenen (2009), Nojoui et al. (2009), Janic (2008), Maniaci (2006), Mital et al. (2006), Corchero and Montañes (2005), Koroneos et al. (2005), and Westenberg (2003) discuss various aspects of liquid-hydrogen-powered aircraft. Westenberg (2003), reporting on a European analysis of liquid-hydrogen aircraft systems (the CRYOPLANE project), concludes that hydrogen is a “suitable alternative fuel for future aviation” (p. 2), and could be implemented within 15–20 years (of 2003) with continued research and development of engines, materials, storage, and other components. Corchero and Montañes (2005) also discuss the CRYOPLANE project and conclude that “evolving a conventional engine from burning kerosene to burning hydrogen, without implementing large-scale hardware changes, does not seem to be an insurmountable task” (p. 42). Whereas, liquefied hydrogen aircraft would require about four times more volume to store their fuel, they would require three times less mass, since hydrogen is one-twelfth the density of jet fuel. Coenen (2009) asserts that “LH2 fueled aircraft are lighter, cleaner, quieter, safer, more efficient and have greater payload and range for equivalent weight of Jet A fuel,” and that “there are no critical technical barriers to LH2 air transport” (p. 8452). Koroneos et al. (2005) perform a lifecycle assessment of the environmental impacts of jet fuel and hydrogen made from various feedstocks, and find that hydrogen made from water and wind power has the lowest impacts across all dimensions. For a discussion of liquid jet fuels made from biomass, see Hileman et al. (2009).

Thus, in transportation, all vehicles, ships, trains, and planes are either battery-powered or hydrogen powered. In this way, WWS

power meets all energy needs, either directly as electricity or indirectly via electrolytic hydrogen.

#### A.2.8. End-use energy/work w.r.t. to fossil fuel

This is the ratio of BTUs-electric/unit-work to BTUs-fossil-fuel/unit-work. For example, it is the ratio of BTUs of electricity (at 3412 BTUs/kWh) input to an electric vehicle from the outlet, per mile of travel provided, to BTUs of gasoline input to a conventional vehicle from the pump, per mile of travel provided. In the case of electrified end uses, BTUs-electric are measured at the point of end use, and do not include any upstream or “indirect” electricity uses. In the case of electrolytic hydrogen (eH<sub>2</sub>), BTUs-electric are measured at the input to the electrolyzer, which for simplicity is assumed to be at the site of end use, and again do not include any upstream or indirect electricity uses such as for hydrogen compression. (We treat compression and liquefaction separately, in the “upstream factor” column.) Thus, the figures shown for eH<sub>2</sub> include losses during electrolysis. Our estimates are based on results or assumptions from the *Advanced Vehicle Cost and Energy Use Model* (AVCEM) (Delucchi, 2005), the *Lifecycle Emissions Model* (LEM) (Delucchi, 2003), and other sources, as listed in Table A1.

#### A.2.9. Upstream factor

The upstream factor accounts for changes, in a WWS world compared with the base-case fossil-fuel world, in sectoral energy use in activities that are “upstream” of final end use by consumers. We first discuss these changes qualitatively, and then provide quantitative estimates of the changes in upstream fuel processing activities, which we believe are the largest of the upstream changes.

In a WWS world some of the energy-generation technologies (such as wind turbines), forms of energy (such as compressed hydrogen), and energy-use technologies (such as electric vehicles) will be different from those in a conventional fossil-fuel world. These differences will give rise to differences in energy use in the sectors that manufacture energy technologies and process energy. Qualitatively these differences are described in Table A2.

Table 2 has upstream adjustment factors for fuel use in the industrial sector and liquid fuel use in the transportation sector. The factors shown in Table 2 for the industrial sector account for the elimination of energy use in petroleum refining. The factor shown for liquid fuel in transportation accounts for electricity use for

hydrogen compression or liquefaction. Our estimation of these factors is based on the data in Table A1.

Although 5–10% of the volumetric output of refineries is non-fuel product such as lubricants, petrochemical feedstocks, road asphalt, and petroleum coke (EIA, 2010), these products require much less than 5–10% of refinery energy, because refinery energy is used disproportionately to produce highly refined transportation fuels (Delucchi, 2003). Moreover, some of these non-fuel products would be eliminated in a WWS world (e.g., some kinds of lubricants), and some could be replaced at very low energy cost, for example, by recycling. For these reasons, we do not attempt to estimate the very small amount of refinery energy (probably on the order of 2%) that still would be required in a WWS world.

#### A.2.10. EHCM factor

EHCM stands for “electricity and hydrogen conservation measure.” This is the ratio of demand for end-use energy after EHCMS have been instituted to the demand for end-use energy before the EHCMS. Demand-side energy-conservation measures include improving the energy-out/energy-in efficiency of end uses (e.g., with more efficient vehicles, more efficient lighting, better insulation in homes, and the use of heat-exchange and filtration systems), directing demand to low-energy-use modes (e.g., using public transit or telecommuting in place of driving), large-scale planning to reduce overall energy demand without compromising economic activity or comfort (e.g., designing cities to facilitate greater use of non-motorized transport and to have better matching of origins and destinations (thereby reducing the need for travel)), and designing buildings to use solar energy directly (e.g., with more daylighting, solar hot water heating, and improved passive solar heating in winter and cooling in summer). We assume that EHCMS can achieve modest reductions in energy demand, on the order of 5–15% in most cases.

#### A.2.11. TW power in 2030 (WWS case)

These are the world and the U.S. power in the year 2030 when wind, water, and solar power provide all energy services, and thus replace 100% of fossil-fuel use and biomass combustion. It is calculated from the other values in the table.

**Table A1**

Parameters values used to derive results in Table 2.

Value	Parameter	Data source
0.80	Efficiency of fossil-fuel heating (BTUs-work/BTUs-input-energy)	LEM (Delucchi, 2003)
0.97	Efficiency of electric resistance heating (BTUs-work/BTUs-power)	LEM (Delucchi, 2003)
0.80	Efficiency of hydrogen heating (BTUs-work/BTUs-input-energy)	Assume same as fossil fuel
0.70	Efficiency of electrolytic hydrogen production on site (BTUs-H <sub>2</sub> /BTUs-electricity, higher heating value)	AVCEM, LEM (Delucchi, 2003, 2005; Aguado et al., 2009, assume 75%)
1.10	Work/energy ratio of hydrogen combustion in engines (mainly jet engines) relative to ratio for petroleum fuel	LH2 in vehicles is more efficient than gasoline
0.15	Of total liquid fuel use in transportation, the fraction that is replaced with liquefied H <sub>2</sub> rather than compressed H <sub>2</sub> , on an energy basis	Assume LH2 used by airplanes and some ships (EIA, 2008b, Table 5.14c)
5.30	Ratio of mi/BTU for EVs to mi/BTU ICEVs	AVCEM (Delucchi, 2005)
2.70	Ratio of mi/BTU for HFCVs to mi/BTU ICEVs	AVCEM (Delucchi, 2005)
1.12	Multiplier for electricity requirements of H <sub>2</sub> compression for transportation (10,000 psi) (BTUs-electricity plus BTUs-H <sub>2</sub> /BTU-H <sub>2</sub> )	AVCEM (Delucchi, 2005)
1.32	Multiplier for electricity requirements of H <sub>2</sub> liquefaction for transportation, mainly air transport (includes boil-off losses) (BTUs-electricity plus BTUs-H <sub>2</sub> /BTU-H <sub>2</sub> )	AVCEM (Delucchi, 2005)
0.28	Petroleum energy in oil refining as a fraction of total petroleum use in industrial sector	Projections for the U.S. for the year 2030 (EIA, 2009, Table 6)
0.18	NG energy in oil refining as a fraction of total NG use in industrial sector	Projections for the U.S. for the year 2030 (EIA, 2009, Table 6)
0.27	Coal energy in oil refining as a fraction of total coal use in industrial sector	Projections for the U.S. for the year 2030 (EIA, 2009, Table 6)
0.07	Electricity in oil refining as a fraction of total electricity use in industrial sector	Projections for the U.S. for the year 2030 (EIA, 2009, Table 6)

**Table A2**  
Qualitative differences between a fossil-fuel and a WWS world.

Sector	Fossil-fuel world	WWS world	Difference	Our treatment
Mining—oil, gas, and coal	Energy use in this sector typically is 1–4% of final fuel energy (Delucchi, 2003).	Energy use for mining for non-fuel products only.	Small reduction in energy use in a WWS world.	Not estimated.
Mining—other metals and minerals	Energy use in mining of metals and minerals for the production of power plants, motors, engines, vehicles, equipment, etc.; probably very small fraction of total energy use.	Energy use in mining of metals and minerals for the production of power plants, motors, engines, vehicles, equipment, etc. Because the types of equipment (etc.) produced will be different than in the fossil-fuel world, mining energy use will be different.	A WWS world will require more bulk materials (e.g., steel, concrete, etc.) per unit of power output than does a fossil-fuel world, and hence probably will require more energy in mining raw materials. This increase in energy use likely is small.	Not estimated.
Manufacturing—materials production and assembly for energy generation and use-technologies	Energy use to make and assemble finished materials for power plants, motors, engines, vehicles, equipment, etc. For reference, direct and indirect energy in the manufacture of motor vehicles is 5–15% of the lifetime fuel energy (Delucchi, 2003).	Energy use to make and assemble finished materials for power plants, motors, engines, vehicles, equipment, etc. Because the types of equipment (etc.) produced will be different than in the fossil-fuel world, manufacturing energy use will be different.	To the extent that WWS technologies have greater mass per unit of power output (e.g., battery-electric vehicles versus gasoline vehicles), the manufacturing energy use will be greater.	Not estimated.
Manufacturing—materials production and assembly for energy delivery infrastructure	Energy use to make pipelines, tankers, trucks, trains, and power lines that carry energy, energy feedstocks, vehicles, and materials for the energy system.	Energy use to make pipelines, tankers, trucks, trains, and power lines that carry energy, energy feedstocks, vehicles, and materials for the energy system.	A WWS world will not have pipelines, tankers, trucks, or trains delivering fuel or fuel feedstocks, but will have more power lines, on balance, small reduction in energy use in WWS world?	Not estimated.
Manufacturing—fuel process	Petroleum refining and natural-gas processing.	Compression and liquefaction of hydrogen.	Significant net energy reduction in WWS world.	Estimated; see Table 2 and Section A.2.9.

## References

- Adamantides, A., Kessides, I., 2009. Nuclear power for sustainable development: current status and future prospects. *Energy Policy* 37, 5149–5166.
- Aguado, M., Ayerbe, E., Azcárate, C., Blanco, R., Garde, R., Mallor, F., Rivas, D.M., 2009. Economical Assessment of a wind–hydrogen energy system using WindHyGen software. *International Journal of Hydrogen Energy* 34, 2845–2854.
- Alliance for Climate Protection, Repower America, 2009. <<http://www.repoweramerica.org/>>.
- Anderson, L.G., 2009. Ethanol fuel use in Brazil: air quality impacts. *Energy and Environmental Science* 2, 1015–1037.
- American Physical Society, 2008. Energy future: think efficiency, how America can look within to achieve energy security and reduce global warming. <<http://www.aps.org/energyefficiencyreport/report/aps-energyreport.pdf>>.
- Archer, C.L., Jacobson, M.Z., 2005. Evaluation of global windpower. *Journal of Geophysics Research*.
- Barré, B., 1999. “Nuclear energy” From here to where? *Nuclear Physics A654*, 409c–416c.
- Beyond Zero Emissions, 2010. Zero carbon Australia stationary energy plan. Melbourne Energy Institute, University of Melbourne. <<http://beyondzeroemissions.org/>>.
- California Fuel Cell Partnership, 2009. Hydrogen fuel-cell vehicle and station deployment plan: a strategy for meeting the challenge ahead. West Sacramento, California. <[http://www.cafcp.org/sites/files/Action\\_Plan\\_Final.pdf](http://www.cafcp.org/sites/files/Action_Plan_Final.pdf)>.
- Carlson, E.J., Thijssen, J.H.J., 2002. Precious metal availability and cost analysis for PEMFC commercialization, part IV.F.1. (pp. 513–516) of hydrogen, fuel cells and infrastructure technologies. FY 2002 Progress Report, U.S. Department of Energy, Energy Efficiency and Renewable Energy, Office of Hydrogen, Fuel Cells, and Infrastructure Technologies, Washington, D.C.
- Chow, T.T., 2010. A review of photovoltaic/thermal hybrid solar technology. *Applied Energy* 87, 365–379.
- Cleetus, R., Clemmer, S., Friedman, D., 2009. Climate 2030: a national blueprint for a clean energy economy, Union of Concerned Scientists, Cambridge, Massachusetts. <[http://www.ucsusa.org/global\\_warming/solutions/big\\_picture\\_solutions/climate-2030-blueprint.html#Download\\_the\\_Climate\\_2030\\_Blueprint\\_repo](http://www.ucsusa.org/global_warming/solutions/big_picture_solutions/climate-2030-blueprint.html#Download_the_Climate_2030_Blueprint_repo)>.
- Coenen, R.M., 2009. A proposal to convert air transport to clean hydrogen (CATCH). *International Journal of Hydrogen Energy* 34, 8451–8453.
- Colby, D.W., et al., 2009. Wind turbine sound and health effects, an expert review panel, American Wind Energy Association. <[http://awea.org/newsroom/releases/AWEA\\_CanWEA\\_SoundWhitePaper\\_12-11-09.pdf](http://awea.org/newsroom/releases/AWEA_CanWEA_SoundWhitePaper_12-11-09.pdf)>.
- Corchero, G., Montañes, J.L., 2005. An Approach to the use of hydrogen for commercial aircraft engines. Proceedings of the Institution of Mechanical Engineers, Part G: Journal of Aerospace Engineering 219, 35–44.
- Cullen, J.M., Allwood, J.M., 2009. The efficient use of energy: Tracing the global flow of energy from fuel to service. *Energy Policy* doi:10.1016/j.enpol.2009.08.054.
- Cryosphere Today, Current Northern Hemisphere Sea Ice Area accessed August 30, 2010. <<http://arctic.atmos.uiuc.edu/cryosphere/IMAGES/seaice.recent.arctic.png>>.
- Czisch, G., 2006. Low cost but totally renewable electricity supply for a huge supply area—a European/Trans-European example. Unpublished manuscript. <[http://www.iset.uni-kassel.de/abt/w3-w/projekte/LowCostEuropEISup\\_revised\\_for\\_AKE\\_2006.pdf](http://www.iset.uni-kassel.de/abt/w3-w/projekte/LowCostEuropEISup_revised_for_AKE_2006.pdf)>.
- Delucchi, M.A., 2010. Impacts of Biofuels on Climate, Land, and Water. *Annals of the New York Academy of Sciences* 1195, 28–45 (Issue The Year in Ecology and Conservation Biology, Ostfeld, R.S. and W. H. (Eds.). Schlesinger.).
- Delucchi, M.A., 2003. A lifecycle emissions model (LEM): lifecycle emissions from transportation fuels, motor vehicles, transportation modes, electricity use, heating and cooking fuels, and materials. Main Report, UCD-ITS-03-17. Institute of Transportation Studies, University of California, Davis. <<http://www.its.ucdavis.edu/people/faculty/delucchi/>>.
- Delucchi, M.A., 2005. Overview of AVCEM. UCD-ITS-RR-05-17 (1). Institute of Transportation Studies, University of California, Davis. <<http://www.its.ucdavis.edu/people/faculty/delucchi/>>.
- Delucchi, M.Z., Jacobson, M.Z., (this issue). Providing all global energy with wind, water, and solar power, part II: reliability, system and transmission costs, and policies. *Energy Policy*, doi:10.1016/j.enpol.2010.11.045.
- Deutch, J., et al., 2009. Update of the MIT 2003 Future of Nuclear Power. Massachusetts Institute of Technology, Cambridge, Massachusetts. <<http://web.mit.edu/nuclearpower/>>.
- Deutch, J., et al., 2003. The Future of Nuclear Power. Massachusetts Institute of Technology, Cambridge, Massachusetts. <<http://web.mit.edu/nuclearpower/>>.
- Du, Y., J.E. Parsons, 2009. Update on the Cost of Nuclear Power, 09-004. Center for Energy and Environmental Policy Research, Massachusetts Institute of Technology, Cambridge, Massachusetts. <<http://web.mit.edu/ceepr/www/publications/workingpapers/2009-004.pdf>>.
- Dvorak, M., Archer, C.L., Jacobson, M.Z., 2010. California offshore wind energy potential. *Renewable Energy* 35, 1244–1254 doi:10.1016/j.renene.2009.11.022.
- Energy Information Administration (EIA), 2008a. International Energy Outlook 2008, DOE/EIA-0484(2008). U.S. Department of Energy, Washington, D.C. <<http://www.eia.doe.gov/oiaf/ieo/index.html>>.

- Energy Information Administration (EIA), 2008b. Annual Energy Review 2007, DOE/EIA-0384(2007). U.S. Department of Energy, Washington, D.C., June 23, 2008. <<http://www.eia.doe.gov/emeu/aer/consump.html>>.
- Energy Information Administration (EIA), 2009. Annual Energy Outlook 2009, DOE/EIA-0383(2009). U.S. Department of Energy, Washington, D.C. <<http://www.eia.doe.gov/oaia/aeo/index.html>>.
- Energy Information Administration (EIA), Petroleum Navigator, July 29, 2010 <[http://tonto.eia.doe.gov/dnav/pet/PET\\_PNP\\_PCT\\_DC\\_NUS\\_PCT\\_A.htm](http://tonto.eia.doe.gov/dnav/pet/PET_PNP_PCT_DC_NUS_PCT_A.htm)> (last accessed August 30, 2010).
- Energy Net Nuclear: Diablo Canyon History II. <http://www.energy-net.org/01NUKE/DIABLO2.HTM> (last accessed August 28, 2010).
- European Climate Foundation (ECF), 2010. Roadmap 2050: a practical guide to a prosperous, low-carbon Europe. <<http://www.europeanclimate.org/>>.
- European Renewable Energy Council (EREC), 2010. Re-thinking 2050: a 100% renewable energy vision for the European Union. <<http://www.erec.org/>>.
- Federation of American Scientists, 2010. Nuclear weapons. <http://www.fas.org/nuke/guide/india/nuke/> (last accessed August 28, 2010).
- Feiveson, H.A., 2009. A skeptic's view of nuclear energy. *Daedalus*, Fall, 60–70.
- Feltrin, A., Freundlich, A., 2008. Material considerations for terawatt level development of photovoltaics. *Renewable Energy* 33, 180–185.
- Friedman-Rudovsky, J., 2009. For lithium car batteries, Bolivia is in the driver's seat. *Time Magazine*, January 22 <<http://www.time.com/time/world/article/0,8599,1872561,00.html>>.
- Fridleifsson, I.B., Bertani, R., Huenges, E., Lund, J.W., Ragnarsson, A., Rybach, L., 2008. The possible role and contribution of geothermal energy to the mitigation of climate change. In: O. Hohmeyer and T. Trittin (Eds.), *IPCC Scoping Meeting on Renewable Energy Sources*, Proceedings, Luebeck, Germany, 20–25 January 2010, pp. 59–80.
- Fthenakis, V., Mason, J.E., Zweibel, K., 2009. The technical, geographical, and economic feasibility of solar energy to supply the energy needs of the US. *Energy Policy* 37, 387–399.
- Fthenakis, V.M., Kim, H.C., 2007. Greenhouse-gas emissions from solar electric- and nuclear power: a lifecycle study. *Energy Policy* 35, 2549–2557.
- Gaines, L., Nelson, P., 2009. Lithium-ion batteries: possible materials issues. In: Paper Presented at The 13th International Battery Materials Recycling Seminar and Exhibit, Broward County Convention Center, Fort Lauderdale, Florida, March 16–18, 2009.
- Gaines, L., Nelson, P., 2010. Lithium-ion batteries: examining material demand and recycling issues. Argonne National Laboratory, presented at 2010 TMS Annual Meeting and Exhibition, Seattle Washington, February 14–18, 2010. <<http://www.transportation.anl.gov/pdfs/B/626.PDF>>.
- Ginnebaugh, D.L., Liang, J., Jacobson, M.Z., 2010. Examining the temperature dependence of ethanol (E85) versus gasoline emissions on air pollution with a largely-explicit chemical mechanism. *Atmospheric Environment* 44, 1192–1199. doi:10.1016/j.atmosenv.2009.12.024.
- Glaser, A., Ramana, M.V., 2007. Weapon-grade plutonium production potential in the India prototype fast breeder reactor. *Science and Global Security* 15, 85–105.
- Gorman, S., 2009. As hybrid cars gobble rare metals, shortage looms. *Reuters*, August 31, 2009. <<http://www.reuters.com/article/newsOne/idUSTRE57U02B20090831>> (last accessed August 28, 2010).
- Gordon, R.B., Bertram, M., Graedel, T.E., 2006. Metal stocks and sustainability. *Proceedings of the National Academy of Science* 103 (5), 1209–1214.
- Goto, H., Suzuki, Y., Nakamura, K., Watanabe, T., Guo, H.J., Ichinokura, O., 2005. A multipolar SR motor and its application in EV. *Journal of Magnetism and Magnetic Materials* 290–291, 1338–1342.
- Grubler, A., 2010. The costs of the French nuclear scale-up: a case of negative learning by doing. *Energy Policy* 38, 5174–5188.
- Hagelüken, C., 2009. Umicore precious metals refining, Hanau, Germany, personal communications via e-mail, October–November 2009).
- Hagelüken, C., Buchert, M., Ryan, P., 2009b. Materials flow of platinum group metals in Germany. *International Journal of Sustainable Manufacturing* 1, 330–346. See also Hagelüken, C., Buchert, M., Ryan, P., 2006. Materials flow of platinum group metals in Germany, *Proceedings of LCE 2006*, pp. 477–482. <<http://www.mech.kuleuven.be/lce2006/052.pdf>>.
- Hammond, G.P., 1996. Nuclear energy in the twenty-first century. *Applied Energy* 54, 327–344.
- Hannum, W.H., Wade, D.C., McFarlane, H.F., Hill, R.N., 1997. Nonproliferation and safeguards aspects of the IFR. *Progress in Nuclear Energy* 31, 203–217.
- Harding, J., 2007. Economics of Nuclear Power and Proliferation Risks in a Carbon-Constrained World. White paper, Nonproliferation Policy Education Center. <<http://www.npolicy.org/files/20070600-Harding-EconomicsNewNuclearPower.pdf>>.
- Hatch, G. <<http://nucleargreen.blogspot.com/2009/01/jack-liftons-research-on-mineral.html>>; <<http://www.terramagnetica.com/2009/08/03/how-does-using-permanent-magnets-make-wind-turbines-more-reliable/>>; <<http://www.terramagnetica.com/2009/08/07/10-mw-and-beyond-are-superconductors-the-future-of-wind-energy/>> (2009).
- Horikawa, T., Miura, K., Itoh, M., Machida, K., 2006. Effective recycling for Nd–Fe–B sintered magnet scraps. *Journal of Alloys and Compounds* 408–412, 1386–1390.
- Horrihan, L., Lawrence, R.S., Walker, P., 2002. How sustainable agriculture can address the environmental and human health harms of industrial agriculture. *Environmental Health Perspectives* 110, 445–456.
- Hedrick, J.B., 2009. Rare Earths, chapter 60 in 2007 Minerals Yearbook. U.S. Geological Survey, U.S. Department of Interior. <[http://minerals.usgs.gov/minerals/pubs/commodity/rare\\_earth/myb1-2007-rare.pdf](http://minerals.usgs.gov/minerals/pubs/commodity/rare_earth/myb1-2007-rare.pdf)>.
- Hileman, J.I., Ortiz, D.S., Bartis, J.T., Wong, H.M., Donohoo, P.E., Weiss, M.A., Waitz, I.A., 2009. Near-term feasibility of alternative jet fuels. RAND TR554, Rand Corporation and Massachusetts Institute of Technology. <[http://www.rand.org/pubs/technical\\_reports/2009/RAND\\_TR554.pdf](http://www.rand.org/pubs/technical_reports/2009/RAND_TR554.pdf)>.
- Hoffert, M.I., et al., 2002. Advanced technology paths to global climate stability: energy for a greenhouse planet. *Science* 298, 981–987.
- Hultman, N.E., Koomey, J.G., Kammen, D.M., 2007. What history can teach us about the future costs of U.S. nuclear power. *Environmental Science and Technology* 1, 288–293.
- Hultman, N.E., Koomey, J.G., 2007. The risk of surprise in energy technology costs. *Environmental Research Letters* 2, 034002 doi:10.1088/1748-9326/2/3/034002.
- Hurst, C., 2010. China's rare earth elements industry: what can the west learn? Institute for the Analysis of Global Security, Washington, D.C. <<http://fmso.leavenworth.army.mil/documents/rareearth.pdf>>.
- Intergovernmental Panel on Climate Change (IPCC), 2005. IPCC special report on carbon dioxide capture and storage. Prepared by working group III. In: Metz, B., Davidson, O., de Coninck, H.C., Loos, M. and Meyer, L.A. (Eds.). Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp. <<http://arch.rivm.nl/env/int/ipcc/>>.
- International Energy Agency (IEA), 2008. World Energy Outlook 2008, Organization for Economic Cooperation and Development, Paris, France.
- Jacobson, M.Z., 2007. Effects of ethanol (E85) versus gasoline vehicles on cancer and mortality in the United States. *Environmental Science and Technology* 41, 4150–4157. doi: 10.1021/es062085v.
- Jacobson, M.Z., 2009. Review of solutions to global warming, air pollution, and energy security. *Energy and Environmental Science* 2, 148–173. doi:10.1039/b809990c.
- Jacobson, M.Z., Masters, G.M., 2001. Exploiting wind versus coal. *Science* 293, 1438.
- Jacobson, M.Z., M.A. Delucchi, 2009. A path to sustainable energy by 2030, *Scientific American*, November.
- Jacobson, M.Z., 2010. Short-term effects of controlling fossil-fuel soot, biofuel soot and gases, and methane on climate, Arctic ice, and air pollution health. *Journal of Geophysical Research* 115, D14209. doi:10.1029/2009JD013795.
- Janic, M., 2008. The potential of liquid hydrogen for the future 'carbon-neutral' air transport system. *Transportation Research D* 13, 428–435.
- Jaskula, B.W., 2008. Lithium. 2007 Minerals Yearbook. U.S. Geological Survey, U.S. Department of the Interior, August 2008. <<http://minerals.usgs.gov/minerals/pubs/commodity/lithium/myb1-2007-lithi.pdf>>.
- Joskow, P.L., Parsons, J.E., 2009. The economic future of nuclear power. *Daedalus*, Fall, 45–59.
- Kempton, W., Archer, C.L., Dhanju, A., Garvine, R.W., Jacobson, M.Z., 2007. Large CO<sub>2</sub> reductions via offshore wind power matched to inherent storage in energy end-uses. *Geophysical Research Letters* 34, L02817. doi:10.1029/2006GL028016.
- Kessides, I.N., 2010. Nuclear power: understanding the economic risks and uncertainties. *Energy Policy* 38, 3849–3864.
- Koomey, J., Hultman, N.E., 2007. A reactor-level analysis of busbar costs for U.S. nuclear plants, 1970–2005. *Energy Policy* 35, 5630–5642.
- Koroneos, C., Dompros, A., Roubas, G., Moussiopoulos, N., 2005. Advantages of the use of hydrogen fuel as compared to kerosene. *Resources, Conservation, and Recycling* 44, 99–113.
- Lefèvre, M., Proietti, E., Jaouen, F., Dodelet, J.-P., 2009. Iron-based catalysts with improved oxygen reduction activity in polymer electrolyte fuel cells. *Science* 324, 71–74.
- Lenzen, M., 2008. Life cycle energy and greenhouse gas emissions of nuclear energy: a review. *Energy Conversion & Management* 49, 2178–2199.
- Lifton, J., 2009. Braking wind: where's the neodymium going to come from? <<http://www.glgroup.com/News/Braking-Wind-Wheres-the-Neodymium-Going-To-Come-from-35041.html>>.
- Lovins, A.B., Howe, B., 1992. Switched reluctance motors poised for rapid growth. Tech Update, TU-92-4, E-Source, a subsidiary of Rocky Mountain Institute, Boulder, Colorado, November 1992.
- Lu, X., McElroy, M.B., Kiviluoma, J., 2009. Global potential for wind-generated electricity. *Proceedings of the National Academy of Sciences* 106, 10933. doi:10.1073/pnas.0904101106.
- Macfarlane, A.M., Miller, M., 2007. Nuclear energy and uranium resources. *Elements* 3, 185–192.
- Maniaci, D.C., 2006. Operational performance prediction of a hydrogen-fueled commercial transport. College of Engineering Research Symposium 2006, Pennsylvania State University, University Park, Pennsylvania, March 2006. <<http://www.engr.psu.edu/symposium2006/papers/Session%20E%20-%20E-nergy/Maniaci.doc>>.
- Margonelli, Lisa, 2009. Clean energy's dirty little secret The Atlantic, May 2009. <<http://www.theatlantic.com/doc/200905/hybrid-cars-minerals>>.
- Maximum EV, 2009. Rare earths and neodymium, June 21, 2009. <<http://maximumev.blogspot.com/>> (last accessed August 28, 2010).
- Meridian International Research, 2008. The Trouble with Lithium 2, Under the Microscope, Martiansville, France, May 29, 2008. <[http://www.meridian-int-res.com/Projects/Lithium\\_Microscope.pdf](http://www.meridian-int-res.com/Projects/Lithium_Microscope.pdf)>.
- Miller, S.E., Sagan, S.D., 2009. Nuclear Power without Proliferation? *Daedalus*, Fall, 7–18.
- Mital, S.K., Gyekenyessi, J.Z., Arnold, S.M., Sullivan, R.M., Manderscheid, J.M., Murthy, P.L.N., 2006. Review of current state of the art and key design issues with potential solutions for liquid hydrogen cryogenic storage tank structures for aircraft applications. NASA/TM-2006-214346, National Aeronautics and Space

- Administration, Glenn Research Center, Cleveland, Ohio, October 2006. <<http://gltrs.nasa.gov/reports/2006/TM-2006-214346.pdf>>.
- Morcus, T., 2009. Harvesting wind power with (or without) permanent magnets. *Magnetics and Business Technology*, Summer, p. 26. <[http://www.magneticsmagazine.com/images/PDFs/Online%20Issues/2009/Magnetics\\_Summer09.pdf](http://www.magneticsmagazine.com/images/PDFs/Online%20Issues/2009/Magnetics_Summer09.pdf)>.
- Mourovov, V., 2000. Role of nuclear energy for sustainable development. *Progress in Nuclear Energy* 37, 19–24.
- Mourovov, V., Fukuda, K., Kagramanian, V., 2002. The need for innovative nuclear reactor and fuel cycle systems: strategy for development and future prospects. *Progress in Nuclear Energy* 40, 285–299.
- Niles, J.O., Brown, S., Pretty, J., Ball, A.S., Fay, J., 2002. Potential carbon mitigation and income in developing countries from changes in land use and management of agricultural and forest lands. *Philosophical Transactions of the Royal Society of London* 360, 1621–1639.
- Nojoumi, H., Dincer, I., Naterer, G.F., 2009. greenhouse gas emissions assessment of hydrogen and kerosene-fueled aircraft propulsion. *International Journal of Hydrogen Energy* 34, 1363–1369.
- Nuclear Power Daily, 2009. Nuclear Safety Bodies Call for Redesign of EPR Reactor, November 2. <[http://www.nuclearpowerdaily.com/reports/Nuclear\\_safety\\_bodies\\_call\\_for\\_redesign\\_of\\_EPR\\_reactor\\_999.html](http://www.nuclearpowerdaily.com/reports/Nuclear_safety_bodies_call_for_redesign_of_EPR_reactor_999.html)> (last accessed August 28, 2010).
- OICA, International Organization of Motor Vehicle Manufacturers, "2009 Production Statistics". <<http://oica.net/category/production-statistics/>> (accessed August 28, 2010).
- Ongena, J., Van Oost, G., 2006. Energy for Future centuries: prospects for fusion power as a future energy source. *Transactions of Fusion Science and Technology* 49, 3–15.
- O'Rourke, F., Boyle, F., Reynolds, A., 2010. Tidal energy update 2009. *Applied Energy* 87, 398–409.
- Pacala, S., Socolow, R., 2004. Stabilization wedges: solving the climate problem for the next 50 years with current technologies. *Science* 305, 968–971.
- Parsons-Brinckerhoff, Powering the Future: Mapping our Low-Carbon Path to 2050, December (2009). <<http://www.pbpoweringthefuture.com>>.
- Penner, S.S., Seiser, R., Schultz, K.R., 2008. Steps toward passively safe, proliferation-resistant nuclear power. *Progress in Energy and Combustion Science* 34, 275–287.
- Pickens, T.B., 2009. Pickens Plan. <<http://www.pickensplan.com/theplan/%20Accessed%20Nov.%208.%202010>>.
- Piera, M., 2010. Sustainability issues in the development of nuclear fission energy. *Energy Conversion and Management* 51, 938–946.
- Price-Waterhouse-Coopers, 2010. 100% renewable electricity: a roadmap to 2050 for Europe and North Africa. <[http://www.pwcwebcast.co.uk/dpliv\\_mu/100\\_percent\\_renewable\\_electricity.pdf](http://www.pwcwebcast.co.uk/dpliv_mu/100_percent_renewable_electricity.pdf)>.
- Purushotham, D.S.C., Venugopal, V., Ramanujam, A., 2000. Nuclear fuel cycle: recent developments and future directions. *Journal of Radioanalytica and Nuclear Chemistry* 243, 199–203.
- Ramana, M.V., 2009. Nuclear power: economic, safety, health, and environmental issues of near-term technologies. *Annual Review of Environment and Resources* 34, 127–152.
- Reisman, L., 2009. China and rare earth metals: two sides to every story (Part one). <<http://agmetminer.com/2009/09/03/china-and-rare-earth-metals---two-sides-to-every-story-part-one/>>, September 2009.
- Risen, J., 2010. U.S. identifies vast mineral riches in Afghanistan. *New York Times*, June 13, 2010. <<http://www.nytimes.com/2010/06/14/world/asia/14minerals.html>>.
- Ritter, S.K., 2009. Future of metals. *Chemical and Engineering News* 87 (23), 53–57 <<http://pubs.acs.org/cen/science/87/8723sci.html>>.
- Sovacool, B.K., 2008. Valuing the greenhouse gas emissions from nuclear power: a critical survey. *Energy Policy* 36, 2940–2953.
- Sovacool, B.K., Watts, C., 2009. Going completely renewable: is it possible (let alone desirable)? *The Electricity Journal* 22 (4), 95–111.
- Sovacool, B.K., Sovacool, K.E., 2009. Identifying future electricity–water tradeoffs in the United States. *Energy Policy* 37, 2763–2773.
- Spiegel, R.J., 2004. Platinum and fuel cells. *Transportation Research D* 9, 357–371.
- Santa Maria, M.R.V., Jacobson, M.Z., 2009. Investigating the effect of large wind farms on energy in the atmosphere. *Energies* 2, 816–838.
- Sun, Y., Delucchi, M., Ogdan, J., July 2010. Platinum Price and Fuel-cell System Cost, manuscript. Institute of Transportation Studies, University of California, Davis.
- Takeda, O.T.H., Okabe, Umetsu, Y., 2006. Recovery of neodymium from a mixture of magnet scrap and other scrap. *Journal of Alloys and Compounds* 408–412, 387–390.
- TIAX L.L.C., 2003. Platinum Availability and Economics for PEMFC Commercialization. Report to the U.S. Department of Energy, DE-FC04-01AL67601, TIAX LLC, Cambridge, Massachusetts, December 2003. <[http://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/tiax\\_platinum.pdf](http://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/tiax_platinum.pdf)>.
- Tokimatsu, K., Fujino, J., Konishi, S., Ogawa, Y., Yamaji, K., 2003. Role of nuclear fusion in future energy systems and the environment under future uncertainties. *Energy Policy* 31, 775–797.
- Toyota, Hybrid synergy drive information terminal. <[http://www.hybridsynergydrive.com/en/electric\\_motor.html](http://www.hybridsynergydrive.com/en/electric_motor.html)> (last accessed August 28, 2010).
- Till, C.E., Chang, Y.I., Hannum, W.H., 1997. The integral fast reactor—an overview. *Progress in Nuclear Energy* 31, 3–11.
- Tilman, D., Hill, J., Lehman, C., 2006. Carbon-negative biofuels from low-input high-diversity grassland biomass. *Science* 314, 1598–1600.
- Ullom, J., 1994. Enriched uranium versus plutonium: proliferant preferences in the choice of fissile material. *The Nonproliferation Review* 1 (2), 1–15.
- United Kingdom Department of Transport (UKDOT), 2006. Platinum and hydrogen for fuel cell vehicles, January 26, 2006. <<http://www.dft.gov.uk/pgr/roads/environment/research/cqvcf/platinumandhydrogenforfuelce3838>>.
- U.S. Department of Energy (USDOE), 2008a. Energy Efficiency and Renewable Energy, 20% Wind Energy by 2030, Increasing Wind Energy's Contribution to U.S. Electricity Supply. DOE/GO-102008-256, Washington, D.C. <[http://20percentwind.org/20percent\\_wind\\_energy\\_report\\_revOct08.pdf](http://20percentwind.org/20percent_wind_energy_report_revOct08.pdf)>.
- U.S. Department of Energy (USDOE), 2008b. Concentrating Solar Power Commercial Application Study: Reducing Water Consumption of Concentrating Solar Power Electricity Generation, Report to Congress. <[http://www1.eere.energy.gov/solar/pdfs/csp\\_water\\_study.pdf](http://www1.eere.energy.gov/solar/pdfs/csp_water_study.pdf)> (last accessed Jan. 24, 2010).
- U.S. Geological Survey (USGS), 2009. Mineral Commodities Summaries 2009, U.S. Government Printing Office, Washington, D.C. <<http://minerals.usgs.gov/minerals/pubs/mcs/>>.
- Von Hippel, F.N., 2008. Nuclear fuel recycling: more trouble than its worth. *Scientific American* 2008. <[http://old.armscontrolcenter.org/policy/nonproliferation/articles/nuclear\\_fuel\\_recycling/](http://old.armscontrolcenter.org/policy/nonproliferation/articles/nuclear_fuel_recycling/)>.
- Van Schaik, A., Reuter, M.A., 2004. The time-varying factors influencing the recycling rate of products. *Resources, Conservation, and Recycling* 40, 301–328.
- Wadia, C., Alivisatos, A.P., Kammen, D.M., 2009. Materials availability expands the opportunity for large-scale photovoltaics deployment. *Environmental Science and Technology* 43, 2072–2077.
- Wall, E., Smit, B., 2005. Climate change adaption in light of sustainable agriculture. *Journal of Sustainable Agriculture* 27, 113–123.
- Weisser, D., 2007. A guide to life-cycle greenhouse gas (GHG) emissions from electric supply technologies. *Energy* 32, 1543–1559.
- Westenberger, A., 2003. Hydrogen fuelled aircraft. In: Presented at the AIAA/ICAS International Air and Space Symposium and Exposition: The Next 100 Years, Dayton, Ohio, AIAA 2003-2880. <<http://www.aiaa.org/content.cfm?pageid=406&gTable=Paper&gID=3274>>.
- Wilburn, D.R., 2009. Material use in the United States—selected case studies for cadmium, cobalt, lithium, and nickel in rechargeable batteries. *Scientific Investigations Report* 2008-5141, U.S. Geological Survey, U.S. Department of the Interior. <<http://pubs.usgs.gov/sir/2008/5141/>>.
- Wright, L., 2010. Lithium dreams: can Bolivia become the Saudi Arabia of the electric-car era? *The New Yorker*, March 22, 48–59.
- Yang, C.-J., 2009. An impending platinum crisis and its implications for the future of the automobile. *Energy Policy* 37, 1805–1808.

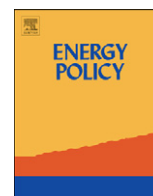




ELSEVIER

Contents lists available at ScienceDirect

## Energy Policy

journal homepage: [www.elsevier.com/locate/enpol](http://www.elsevier.com/locate/enpol)

## Providing all global energy with wind, water, and solar power, Part II: Reliability, system and transmission costs, and policies

Mark A. Delucchi<sup>a,\*</sup>, Mark Z. Jacobson<sup>1,b</sup>

<sup>a</sup> Institute of Transportation Studies, University of California at Davis, Davis, CA 95616, USA

<sup>b</sup> Department of Civil and Environmental Engineering, Stanford University, Stanford, CA 94305-4020, USA

## ARTICLE INFO

## Article history:

Received 3 September 2010

Accepted 22 November 2010

Available online 31 December 2010

## Keywords:

Wind power

Solar power

Water power

## ABSTRACT

This is Part II of two papers evaluating the feasibility of providing all energy for all purposes (electric power, transportation, and heating/cooling), everywhere in the world, from wind, water, and the sun (WWS). In Part I, we described the prominent renewable energy plans that have been proposed and discussed the characteristics of WWS energy systems, the global demand for and availability of WWS energy, quantities and areas required for WWS infrastructure, and supplies of critical materials. Here, we discuss methods of addressing the variability of WWS energy to ensure that power supply reliably matches demand (including interconnecting geographically dispersed resources, using hydroelectricity, using demand-response management, storing electric power on site, over-sizing peak generation capacity and producing hydrogen with the excess, storing electric power in vehicle batteries, and forecasting weather to project energy supplies), the economics of WWS generation and transmission, the economics of WWS use in transportation, and policy measures needed to enhance the viability of a WWS system. We find that the cost of energy in a 100% WWS will be similar to the cost today. We conclude that barriers to a 100% conversion to WWS power worldwide are primarily social and political, not technological or even economic.

© 2010 Elsevier Ltd. All rights reserved.

### 1. Variability and reliability in a 100% WWS energy system in all regions of the world

One of the major concerns with the use of energy supplies, such as wind, solar, and wave power, which produce variable output is whether such supplies can provide reliable sources of electric power second-by-second, daily, seasonally, and yearly. A new WWS energy infrastructure must be able to provide energy on demand at least as reliably as does the current infrastructure (e.g., De Carolis and Keith, 2005). In general, any electricity system must be able to respond to changes in demand over seconds, minutes, hours, seasons, and years, and must be able to accommodate unanticipated changes in the availability of generation. With the current system, electricity-system operators use “automatic generation control” (AGC) (or frequency regulation) to respond to variation on the order of seconds to a few minutes; spinning reserves to respond to variation on the order of minutes to an hour; and peak-power generation to respond to hourly variation (De Carolis and Keith, 2005; Kempton and Tomic, 2005a; Electric Power Research Institute, 1997). AGC and spinning reserves have very low

cost, typically less than 10% of the total cost of electricity (Kempton and Tomic, 2005a), and are likely to remain this inexpensive even with large amounts of wind power (EnerNex, 2010; DeCesaro et al., 2009), but peak-power generation can be very expensive.

The main challenge for the current electricity system is that electric power demand varies during the day and during the year, while most supply (coal, nuclear, and geothermal) is constant during the day, which means that there is a difference to be made up by peak- and gap-filling resources such as natural gas and hydropower. Another challenge to the current system is that extreme events and unplanned maintenance can shut down plants unexpectedly. For example, unplanned maintenance can shut down coal plants, extreme heat waves can cause cooling water to warm sufficiently to shut down nuclear plants, supply disruptions can curtail the availability of natural gas, and droughts can reduce the availability of hydroelectricity.

A WWS electricity system offers new challenges but also new opportunities with respect to reliably meeting energy demands. On the positive side, WWS technologies generally suffer less downtime than do current electric power technologies. For example, the average coal plant in the US from 2000 to 2004 was down 6.5% of the year for unscheduled maintenance and 6.0% of the year for scheduled maintenance (North American Electric Reliability Corporation, 2009a), but modern wind turbines have a down time of only 0–2% over land and 0–5% over the ocean (Dong Energy et al.,

\* Corresponding author. Tel.: +1 916 989 5566.

E-mail addresses: [madelucchi@ucdavis.edu](mailto:madelucchi@ucdavis.edu) (M.A. Delucchi), [jacobson@stanford.edu](mailto:jacobson@stanford.edu) (M.Z. Jacobson).

<sup>1</sup> Tel.: +1 650 723 6836.

2006, p. 133). Similarly, commercial solar projects are expected to have downtimes of ~1% on average, although some have experienced zero downtime during a year and some have experienced downtimes of up to 10% (Banke, 2010). Moreover, there is an important difference between outages of centralized power plants (coal, nuclear, and natural gas) and outages of distributed plants (wind, solar, and wave): when individual solar panels or wind turbines are down, only a small fraction of electrical production is affected, whereas when a centralized plant is down, a large fraction of the grid is affected. And when more than one large, centralized plant is offline at the same time, due to a common problem, the entire national grid can be affected. For example, the *Nuclear Power Daily* reported that on November 2, 2009, one-third of France's nuclear power plants were shut down "due to a maintenance and refueling backlog," and that as a consequence France's power distribution firm stated "that it could be forced to import energy from neighboring markets for two months from mid-November" (Nuclear Power Daily, 2009).

The main new challenge is the maximum solar or wind power available at a single location varies over minutes, hours, and days, and this variation generally does not match the demand pattern over the same time scales (North American Electric Reliability Corporation, 2009b). (Of course, other WWS technologies are not so variable over these time scales: tidal power is relatively reliable because of the predictability of the tides; geothermal energy supply is generally constant; and hydroelectric power can be turned on and off quickly and currently is used to provide peaking and gap-filling power [although available hydropower varies seasonally and annually].) As a result, there will be times when a single installation cannot supply enough power to meet demand and when the installation can produce more power than is needed, which can be an economic waste of generating capacity (but see item E in the list below). However, there are at least seven ways to design and operate a WWS energy system so that it will reliably satisfy demand and not have a large amount of capacity that is rarely used: (A) interconnect geographically dispersed naturally variable energy sources (e.g., wind, solar, wave, and tidal), (B) use a non-variable energy source, such as hydroelectric power, to fill temporary gaps between demand and wind or solar generation, (C) use "smart" demand-response management to shift flexible loads to better match the availability of WWS power, (D) store electric power, at the site of generation, for later use, (E) over-size WWS peak generation capacity to minimize the times when available WWS power is less than demand and to provide spare power to produce hydrogen for flexible transportation and heat uses, (F) store electric power in electric-vehicle batteries, and (G) forecast the weather to plan for energy supply needs better. (See Holttinen et al. (2005), for a related list, and Denholm et al. (2010), for a similar discussion.)<sup>2</sup>

### 1.1. Interconnect dispersed generators

Interconnecting geographically dispersed wind, solar, or wave farms to a common transmission grid smoothes out electricity supply – and demand – significantly (Kahn, 1979; Palutikof et al., 1990; Milligan and Factor, 2000; De Carolis and Keith, 2006; Archer and Jacobson, 2003, 2007; US DOE, 2008; North American Electric Reliability Corporation, 2009b; Kempton et al., 2010; EnerNex,

2010; GE Energy, 2010; Katzenstein et al., 2010). Similarly, the combined energy from co-located wind and wave farms reduces variability of wind and wave power individually (Stoutenburg et al., 2010).

For wind, interconnection over regions as small as a few hundred kilometers apart can eliminate hours of zero power, accumulated over all wind farms. Palutikof et al. (1990) simulated the effects of geographical dispersion on wind turbine performance in England, using hourly wind data on four widely dispersed sites in England. When the sites were considered individually, output changed by 100% of rated capacity in zero to 4.2 h per 1000 h, and by at least 50% of rated capacity in 5.7–39 h per 1000 h. However, when three dispersed sites were considered together, there were no hours when the output changed by 100%, and only zero to 1.9 h per 1000 h when the output changed by at least 50%. In another study, when 19 geographically dispersed wind sites in the Midwest, over a region 850 km × 850 km, were hypothetically interconnected, about 33% of yearly averaged wind power was calculated to be usable at the same reliability as a coal-fired power plant (Archer and Jacobson, 2007). The amount of power guaranteed by having the wind farms dispersed over 19 sites was 4 times greater than the amount of power guaranteed by having the wind farms at one site. Having more sites would guarantee even more power, but with diminishing marginal benefits (each additional site provides less benefit than the last). Archer and Jacobson (2007) also note that portion of the generation that remains variable can be used to charge batteries or make hydrogen.

It is interesting to note that the longer term (monthly or annual) variability in output potential of interconnected wind sites can be much less than the long-term variability of output potential of hydropower. Katzenstein et al. (2010) estimated annual production from 16 modeled (not actual) 1.5 MW turbines located throughout the Central and Southern Great Plains of the US, for 1973–2008, and compared this with observed hydropower in the US over the same period. The standard deviation for the estimated wind production was 6% of the annual mean wind energy production over the period; for hydropower, the standard deviation was 12% of the annual mean production. The greatest single-year deviations from the mean were +14% and –10% for modeled wind power, and +26% and –23% for hydropower. Thus, the predicted long-term variations in output from interconnected wind sites in the US were about half of the national variations in hydropower output.

Finally, we note that interconnection of dispersed photovoltaic sites also reduces variability (Mills and Wiser, 2010; Mills et al., 2009a). Mills et al. (2009a) report that the spatial separation between PV plants required for changes in output to be uncorrelated over time scales of 15, 30, or 60 min is on the order of 20, 50, and 150 km. Mills and Wiser (2010) review several studies of the effect of dispersion on the variability of PV generation and state that "the clear conclusion from this body of previous research is that with "enough" geographic diversity the sub-hourly variability due to passing clouds can be reduced to the point that it is negligible relative to the more deterministic variability due to the changing position of the sun in the sky" (p. 11).

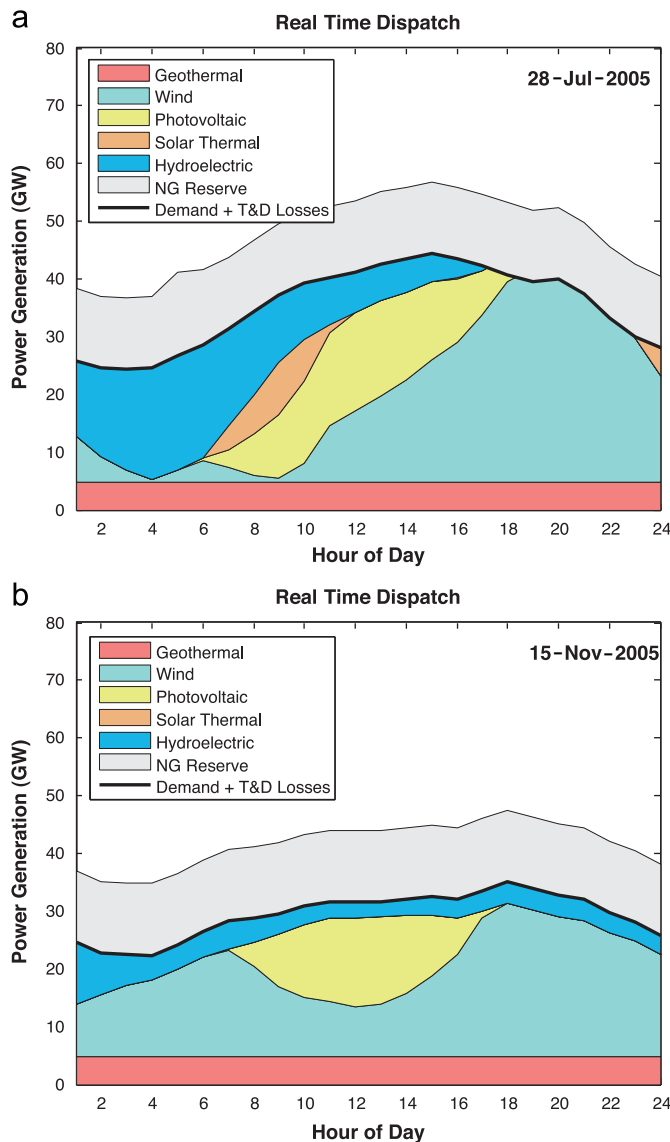
### 1.2. Use complementary and non-variable sources to help supply match demand

The complementary nature of different renewable energy resources can also be taken advantage of to match minute-by-minute and hourly power demand. For example, when the wind is not blowing, the sun is often shining and vice versa (North American Electric Reliability Corporation, 2009b). Some studies that have examined combining WWS renewables to match demand over time include those that have examined combining wind, solar,

<sup>2</sup> Note that the issue we discuss here – variability in a 100% WWS power system – differs in some ways from the more commonly discussed issue of integrating wind power into conventional electricity systems that retain a very large fraction of thermal generation. Regarding the latter, see the special section on integration of large-scale wind power in electricity markets, in *Energy Policy* volume 38, issue 7, 2010, the North American Electric Reliability Corporation (2009b), DeCesaro et al. (2009), and Denholm et al. (2010).

and geothermal (CWECC, 2003)); wind, solar, and wave (Lund, 2006), wind, solar, and hydroelectric (Czisch, 2006; Czisch and Giebel, 2007); wind, solar, geothermal, and hydroelectric (Hoste et al., 2009; Jacobson, 2009; Jacobson and Delucchi, 2009; Hart and Jacobson, under review), and wind, solar, and battery storage (Ekren and Ekren, 2010; Zhou et al., 2010).

Fig. 1 presents an example of the combined use of wind (variable), solar rooftop PV (variable), concentrated solar power (CSP, or solar thermal) with storage (variable), geothermal (base-load), and hydroelectric (dispatchable) to match hourly power demand plus transmission and distribution losses on two days in



**Fig. 1.** Least-cost dispatch on 2 days in 2005 in which 100% of California's electricity demand plus transmission/distribution losses are met with load-matching renewables. *Notes:* System capacities: 73.5 GW of wind; 26.4 GW of CSP; 28.2 GW of photovoltaics; 4.8 GW of geothermal; 20.8 GW of hydroelectric; and 24.8 GW of natural Gas. Transmission and distribution losses are 7% of the demand. The least-cost optimization accounts for the day-ahead forecast of hourly resources, carbon emissions, wind curtailment, and thermal storage at CSP facilities. The hydroelectric supply is based on historical reservoir discharge data and currently imported generation from the Pacific Northwest. The wind and solar supplies were obtained by aggregating hourly wind and solar power at several sites in California estimated from wind speed and solar irradiance data for those hours applied to a specific turbine power curve, a specific concentrated solar plant configuration (parabolic trough collectors on single-axis trackers), and specific rooftop PV characteristics. The geothermal supply was limited by California's developable resources. From Hart and Jacobson (under review).

California in 2005. The geothermal power installed was increased over 2005 levels but was limited by California's geothermal resources. The daily hydroelectric generation was determined by estimating the historical generation on those days from reservoir discharge data. Wind and solar capacities were increased substantially over current levels, but did not exceed maximum levels determined by prior land and resource availability studies. The figure illustrates the potential for matching power demand hour by hour based on a Monte Carlo simulation that accounts for the stochastic nature of each resource (20 potential realizations each hour). Although results for only two days are shown, results for all hours of all days of both 2005 and 2006 (730 days total) suggest that 99.8% of delivered energy during these days could be produced from WWS technology. For these scenarios, natural gas was held as reserve backup and supplied energy for the few remaining hours. However, it is expected that natural gas reserves can be eliminated with the use of demand-response measures, storage beyond CSP, electric vehicle charging and management, and increases in wind and solar capacities beyond the inflexible power demand, which would also allow the excess energy to produce hydrogen for commercial processes, thereby reducing emissions from another sector.

Czisch (2006; 2007) similarly calculated that electricity demand for 1.1 billion people in Europe, North Africa, and near Asia could be satisfied reliably and at low cost by interconnecting wind sites dispersed over North Africa, Europe, Russia, and near Asia, and using hydropower from Scandinavia as back up.

### 1.3. Use "smart" demand-response management to shift flexible loads to better match available WWS generation

A third method of addressing the short-term variability of WWS power is to manage demand so that flexible loads are shifted to times when more WWS is available (Stadler, 2008; Everett, 2006; GE Energy, 2010). Flexible loads are those that do not require power in an immutable minute-by-minute pattern, but rather can be supplied in adjustable patterns over several hours. Electricity demand for computers and lighting might be an inflexible load; electricity demand for electric vehicle charging, and for some kinds of heating and cooling, are flexible loads. In our plan, electric vehicles (EVs) create an additional demand for electric power (compared with current systems, which use liquid fuels for transportation), so it is especially important to manage this demand intelligently. With EVs, the basic idea is to use smart meters to provide electricity for EVs when wind power supply is high and to reduce the power supplied to vehicles when wind power is low. (See Pratt et al. (2010) for a detailed discussion of "smart" grids.) Utility customers would sign up their EVs under a plan by which the utility controlled the nighttime (primarily) or daytime supply of power to the vehicles. Since most electric vehicles would be charged at night, this would provide a nighttime method of smoothing out demand to meet supply. Similarly, flexible heating and cooling demand can be shifted to better match WWS supply (Stadler, 2008).

### 1.4. Store electric power at the site of generation

A fourth method of dealing with variability is to store excess energy at the site of generation (Wilson et al., 2010; Denholm et al., 2010), in batteries (e.g., Lee and Gushee, 2009), hydrogen gas (e.g., for use in HFCVs—see item E, next), pumped hydroelectric power, compressed air (e.g., in underground caverns or turbine nacelles) (e.g., Pickard et al., 2009), flywheels, or a thermal storage medium (as is done with CSP). Benitez et al. (2008) use a nonlinear mathematical optimization program to investigate the integration

of wind and hydropower in Alberta, Canada, and find that with pumped hydro storage or sufficiently large water reservoirs, the combination of wind and hydropower could virtually eliminate back-up generation from gas-fired plants. Ekren and Ekren (2010) develop a method for optimizing the size of a hybrid PV/wind energy system with battery storage.

#### 1.5. Oversize WWS generation capacity to match demand better and to produce H<sub>2</sub>

Sizing the peak capacity of wind and solar installations to significantly exceed peak inflexible power demand can reduce the time that available WWS power is below demand, thereby reducing the need for other measures to meet demand. The spare capacity available when WWS generation exceeds demand can be used to produce H<sub>2</sub> for heating processes and transportation, which must be produced anyway as part of the WWS solution. The greater the “spare” WWS generation capacity (the difference between peak generation and peak inflexible demand), the greater the benefit of reducing times when generation is less than demand, but also the greater the cost of hydrogen storage, because the hydrogen will be produced when spare WWS power is available, which would not necessarily coincide with times of hydrogen demand. The optimal (lowest-cost) system configuration depends on the balance between the demand-matching benefits of increasing WWS peak-generation capacity, the benefits of producing needed hydrogen for transportation and heat, and the costs of increasing spare WWS capacity to produce hydrogen and hydrogen storage. Some papers that have examined the cost of wind-hydrogen systems, although not directly for the application just described, include Jacobson et al. (2005) (for transportation), Martin and Grasman (2009) (for transportation), Aguado et al. (2009), Honnery and Moriarty (2009), and Clarke et al. (2009). Aguado et al. (2009) use the simulation/optimization tool “WindHyGen” to analyze the economic feasibility of a wind-hydrogen energy system with a wind turbine, inverter, electrolyzer, compressor, and hydrogen storage tank, and find that current systems are relatively expensive, but expect that improvements in technology eventually will make them cost-competitive. Honnery and Moriarty (2009) provide an estimate of the technical potential hydrogen production from wind globally, and Clarke et al. (2009) analyze the benefits of coupling an electrolyzer to a PV system.

#### 1.6. Store electric power at points of end use, in EV batteries

The use of EV batteries to store electrical energy, known as “vehicle-to-grid,” or V2G, is especially promising, albeit not necessarily easy to implement (Sovacool and Hirsch, 2010). In general, V2G systems are designed either to provide load-management services, such as peak-power supply, spinning reserves, or power regulation, or to provide a longer-term, decentralized form of electricity storage in a system (such as the one proposed here) relying primarily on variable electricity supply. Kempton and Tomic (2005a), Peterson et al. (2010a), and Andersson et al. (2010) analyze the economics of V2G for load management in a conventional electricity system, and describe the conditions under which the benefits provided (e.g., displacing expensive alternative sources of peak power or spinning reserves) exceed the costs of V2G (degradation of battery capacity, extra electronics and wiring infrastructure, and energy cycling or production losses). More pertinent here are analyses of V2G systems that provide decentralized storage to enable better matching of variable renewable electricity supply with demand (Lund and Kempton, 2008; Kempton and Tomic, 2005b). Kempton and Tomic (2005b) calculate that in order for V2G systems to regulate power output to keep

frequency and voltage steady over very short time intervals (minutes) when wind power supplies 50% of current US electricity demand, 3.2% of the US light-duty vehicle (LDV) fleet would have to be battery-powered and be on V2G contract for regulation of wind power. In order for V2G systems to provide operating reserves to compensate for hourly variations in wind power (again when wind power supplies 50% of US electricity demand), 38% of the US LDV fleet would have to be battery-powered and be on V2G contract. (In both cases, Kempton and Tomic (2005b) assume that only half of the battery EVs would be available for V2G at any time.) Finally, in order for V2G systems to provide longer-term storage to compensate for daily variation in wind power to ensure that wind output never drops below 20% of capacity, given the yearly wind profiles from an interconnected wind system in the Midwest (based on Archer and Jacobson, 2003), 23% of the US LDV fleet would have to be fuel-cell powered and be on V2G contract.

#### 1.7. Forecast weather to plan energy supply needs better

Forecasting the weather (winds, sunlight, waves, tides, and precipitation) gives grid operators more time to plan ahead for a backup energy supply when a variable energy source might produce less than anticipated (e.g., Goodall, 2009; US DOE, 2008; Lange et al., 2006; North American Electric Reliability Corporation, 2009b; GE Energy, 2010). Forecasting is done with either a numerical weather prediction model, the best of which can produce minute-by-minute predictions 1–4 days in advance with good accuracy, or with statistical analyses of local measurements (Lange et al., 2006). The use of forecasting reduces uncertainty and makes planning more dependable, thus reducing the impacts of variability. The impact of forecasting can be significant: a detailed study of the integration of 30% wind and solar power into grids in the western US found that state-of-the-art wind and solar forecasting reduces operating costs by \$0.01–\$0.02/kWh, compared to no forecasting (GE Energy, 2010).

#### 1.8. Summary

A 100% WWS world will employ most of the methods described above for dealing with short-term variability in WWS generation potential, to ensure that supply reliably matches demand. Three of these methods – use of complementary and gap-filling WWS resources, smart demand-response management, and better forecasting – require little additional cost (forecasting, demand management) or virtually no additional cost (hydropower), compared with a conventional energy system, and hence will be employed as much as is technically and socially feasible. However, it is likely that even with the best forecasting, the full use of available gap-filling resources such as hydropower, and the use of as much demand-response management as is socially and technically feasible (and even with as much end-use energy efficiency improvement as is economically feasible), available WWS power will still not match demand in some regions of the world at some times. To ensure a reliable energy supply everywhere in the world at all times, even with efficient and intelligently managed demand and hydropower gap-filling, a WWS system will also need to interconnect resources over wide regions and use spare WWS capacity to make electrolytic hydrogen, and might need to have decentralized (V2G) or perhaps centralized energy storage. The optimal 100% WWS system will have the lowest-cost combination of long-distance interconnection/transmission, hydrogen production, and energy storage that reliably satisfies intelligently managed (and economically efficient) demand (Denholm et al., 2010). Of course, the optimal system design and operation will vary spatially and temporally.

No such optimization analysis has been done for a 100% WWS system in a major region of the world (let alone for all regions of the

world), so this clearly is a critical area for new research. Although we do not know exactly what the lowest-cost 100% WWS system will look like in any particular region, we can provide a general sense of the likely magnitude of costs of extra-long-distance transmission and decentralized V2G storage. (We do not provide our own estimates of centralized storage because generally it is relatively costly, and will be the supply and demand balancing method of last resort.) These cost estimates are included in Section 2, which discusses the cost of WWS electricity generation, transmission, and decentralized storage.

## 2. The cost of WWS electricity generation and “supergrid” transmission and decentralized V2G storage

An important criterion in the evaluation of WWS systems is the full cost of delivered power, including annualized total capital and land costs, operating and maintenance costs, storage costs, and transmission costs, per unit of energy delivered with overall reliability comparable with that of current systems. In this section, we present estimates of the cost of WWS generation and of the likely additional cost of ensuring that WWS generation reliably matches demand by the use of V2G storage and a “supergrid” that interconnects dispersed generators and load centers.

### 2.1. Cost of generation and conventional transmission

Table 1 presents estimates of current (2005–2010) and future (2020 and beyond) \$/kWh costs of power generation and conventional (i.e., *not* extra-long-distance) transmission for WWS systems, with average US delivered electricity prices based on conventional (mostly fossil) generation (excluding electricity distribution) shown for comparison. For fossil-fuel generation, the social cost, which includes the value of air pollution and climate-change damage costs, is also shown. The estimates of Table 1 indicate that onshore wind, hydroelectric, and geothermal systems already can cost less than typical fossil and nuclear generation, and that in the future onshore wind power is expected to cost less than any other form of large-scale power generation.<sup>3</sup> If alternatives are compared on the basis of social cost, all WWS options, including

<sup>3</sup> An important and uncertain variable in the estimation of the cost of wind is the capacity factor—the ratio of actual energy generated over a period of time to the amount of energy that would have been generated if the turbine operated continuously at 100% of its rated power output. Capacity factor depends both on wind speed and turbine characteristics: higher hub heights, greater rotor diameters, more reliable technology, and better wind resources increase the capacity factor. Capacity factors of newer-generation turbines have generally increased relative to those of older turbines, primarily because of increasing hub height and rotor diameter (Wiser and Bolinger, 2010). For example, Wiser and Bolinger (2009) found that the 2008 average capacity factor increased from 22% for projects installed before 1998 to 30–33% for projects installed from 1998–2003 to 35–37% for projects installed from 2004 to 2007. (Wiser and Bolinger, 2010 report a drop in the sample-wide capacity factor in 2009, but this was due to considerable voluntary curtailment of wind power output, due mainly to inadequate transmission capacity, and to poor wind resources in 2009 due to El Niño.) Boccard (2009) reported that the capacity factor from 2003 to 2007 averaged only 21% in Europe and 26% in the US. By contrast, Berry (2009) estimates that the capacity factor for 34 large wind farms in the US averaged 35%, more consistent with Wiser and Bolinger (2009). The uncertainty in the estimates of capacity factors is due to poor information regarding actual generation, because the installed capacity is well known. Boccard's (2009) estimates are based mainly on reports from transmission system operators; Berry's (2009) estimate is based on utility reports of MWh of wind energy purchases filed with the US Federal Energy Regulatory Commission.

The cost-per-kWh of wind energy is inversely proportional to the capacity factor; hence, if actual capacity factors are 33% less than commonly assumed, generating costs are 50% higher than commonly estimated. However, even if the long-term cost of wind power is as high as \$0.06/kWh, it still will be less than the projected cost of fossil-fuel generation (Table 1), without including the value of any externalities.

solar PVs, are projected to cost less than conventional fossil-fuel generation in 2030.

The cost ranges shown in Table 1 are based partly on our own cost estimates, detailed in Tables A.1c and A.1d of Appendix A.1. Appendix A.1 presents two sets of calculations: one with the reference-case parameter values used by the Energy Information Administration (EIA) in its Annual Energy Outlook (our Tables A.1a and A.1b), and one with what we think are more realistic values for some key parameters (Tables A.1c and A.1d). The estimates based on the EIA reference-case are higher than the estimates shown in Table 1 because of the relatively high discount rate, relatively short amortization period, and (in some cases) relatively high capital costs used by the EIA. However, when we use what we believe are more realistic values for the discount rate and the amortization period, and also use the EIA's lower “falling cost” case estimates of \$/kW capital costs, the resultant estimates of the total \$/kWh generating costs for wind, geothermal, hydro, and solar thermal are lower, and comparable with the other estimates in Table 1. This exercise gives us confidence in the estimates of Table 1.

It is worth emphasizing that onshore wind power already can cost less than fossil-fuel generation. This is exemplified by the fact that in the United States, wind power was the second-largest source of new electric power behind natural gas from 2006 to 2009. In general, for the unsubsidized costs of land-based wind energy to be similar to the costs of a new coal-fired power plant, the annual-average wind speed at 80 m must be at least 6.9 m/s (15.4 mph) (Jacobson and Masters, 2001). Data analyses indicate that 15% of the data stations (and thus, statistically, land area) in the United States (and 17% of land plus coastal offshore data stations) have wind speeds above this threshold. Globally, 13% of stations are above the threshold (Archer and Jacobson, 2005).

For tidal power, current speeds need to be at least 6.8 knots (3.5 m/s) for tidal energy to be economical. Installed tidal power to date is relatively expensive (Table 1) and one analysis suggests that tidal power is not likely to be so economic as other WWS energy technologies in the near future (Denny, 2009). However, another analysis suggests relatively inexpensive tidal power in the future so long as turbines are located in currents 3.5 m/s or faster (Table 1).

As shown in Table 1, solar power is relatively expensive today, but is projected to be cost-competitive by as early as 2020. Because solar PV systems can supply an enormous amount of power (Jacobson and Delucchi, *this issue*), but presently are relatively expensive (Table 1), it is important to understand the potential for reducing costs. The fully annualized \$/kWh cost of a PV system depends on the manufacturing cost of the PV module, the efficiency of the module, the intensity of solar radiation, the design of the system, the balance-of-system costs, and other factors. The manufacturing cost, in turn, depends on the scale of production, technological learning, profit structures, and other factors. A recent careful analysis of the potential for reducing the cost of PV systems concludes that within 10 years costs could drop to about \$0.10/kWh, including the cost of compressed-air storage and long-distance high-voltage dc transmission (Table 1, Fthenakis et al., 2009). The same analysis estimated that CSP systems with sufficient thermal storage to enable them to generate electricity at full capacity 24 h a day in spring, summer, and fall in sunny locations could deliver electricity at \$0.10/kWh or less.

Although this review and analysis suggests that WWS technologies will be economical by 2030, in the near term, some key WWS technologies (especially PVs) will remain relatively expensive on a private-cost basis (albeit not necessarily on a social-cost basis). To the extent that WWS power is more costly than fossil power, some combination of subsidies for WWS power and environmental taxes on fossil power will be needed to make WWS power economically feasible today. We turn to this issue in Section 4.

**Table 1**  
Approximate fully annualized generation and conventional transmission costs for WWS power.

Energy technology	Annualized cost (~2007 \$/kWh-delivered)	
	Present (2005–2010)	Future (2020+)
Wind onshore <sup>a</sup>	\$0.04–0.07	≤ \$0.04
Wind offshore <sup>b</sup>	\$0.10–0.17	\$0.08–0.13
Wave <sup>c</sup>	≥ \$0.11	\$0.04
Geothermal <sup>d</sup>	\$0.04–0.07	\$0.04–0.07
Hydroelectric <sup>e</sup>	\$0.04	\$0.04
CSP <sup>f</sup>	\$0.11–0.15	\$0.08
Solar PV <sup>g</sup>	> \$0.20	\$0.10
Tidal <sup>h</sup>	> \$0.11	0.05–0.07
Conventional (mainly fossil) generation in US <sup>i</sup>	\$0.07 (social cost: \$0.12)	\$0.08 (social cost: \$0.14)

<sup>a</sup> Present costs are from Sovacool and Watts (2009), Schilling and Esmundo (2009), Berry (2009), Benitez et al. (2008), Cavallo (2007), Greenblatt et al. (2007), De Carolis and Keith (2006), Boccard (2010), and Table A.1c; wherever necessary we have added \$0.01/kWh for typical (not extra-long-distance) electricity transmission (EIA, 2009a, Table A8). Future costs are projections from Schilling and Esmundo (2009) and Table A.1d. Cavallo's (2007) estimate of \$0.05–0.06/kWh and Greenblatt et al.'s (2007) estimate of \$0.06/kWh include transmission cost and the cost of compressed air storage; De Carolis and Keith's (2006) estimate of \$0.05/kWh includes the cost of long-distance transmission, and back-up. Berry's (2009) estimate of \$0.04/kWh for the generation cost of wind charged under long-term contracts in the US includes system integration costs, which he defines as costs "incurred by the utility to maintain electric grid stability over periods as short as a few seconds, to deal with uncertainty in wind output over the next few minutes to follow variations in load, and to schedule adequate resources for the next day given uncertainty about future wind production" (p. 4494).

<sup>b</sup> Our estimates based on generation cost estimates in Tables A.1a–A.1d and capital cost estimates in Musial and Ram (2010) (discussed in notes of Tables A.1a and A.1b), with \$0.01/kWh added for conventional transmission.

<sup>c</sup> Bedard et al. (2005) estimate a levelized production cost of about \$0.10/kWh for "the first commercial scale wave plant" (we have added \$0.01/kWh for transmission). They then project cost as a function of installed generating capacity using a learning-curve model and estimate levelized production cost comparable to that for wind power. Allan et al. (2011) report estimates of the capital cost, maintenance cost, and capacity factor for the first production models of wave-power plants; with these, using the methods of Tables A.1a–A.1d, we calculate a levelized production cost of at least \$0.16/kWh. The Allan et al. (2011) estimates include undersea cables and minor onshore transmission and grid upgrade.

<sup>d</sup> Present costs are from Sovacool and Watts (2009), Schilling and Esmundo (2009), and Table A.1c; we have added \$0.01 for electricity transmission. For the future, we assume that some trends increase costs (e.g., drilling deeper wells), but that other trends decrease costs (e.g., developing more cost-effective technology), with the overall result that future costs are the same as present costs. See also Table A.1d.

<sup>e</sup> Present costs are from Sovacool and Watts (2009); we have added \$0.01 for electricity transmission. We assume that future costs are the same as present costs. In Tables A.1c and A.1d we estimate slightly higher costs.

<sup>f</sup> Present costs are from Sovacool and Watts (2009) and Schilling and Esmundo (2009); we have added \$0.01 for electricity transmission. Future costs are from Fthenakis et al. (2009), for a baseload plant, and include long-distance high-voltage dc transmission.

<sup>g</sup> Present costs are from Fthenakis et al. (2009), Mondol et al. (2009), Sovacool and Watts (2009), and Schilling and Esmundo (2009). Future costs are from Fthenakis et al. (2009) and include compressed air energy storage, which costs about \$0.04/kWh, and long-distance high-voltage dc transmission, which in their work costs \$0.007/kWh.

<sup>h</sup> Current tidal costs are based on 240 MW La Rance station, France (<http://www.global-greenhouse-warming.com/tidal.html>), which indicates greater than \$0.20/kWh, and on the analysis of Allan et al. (2011), who report estimates of the capital cost, maintenance cost, and capacity factor for the first production models of tidal-power plants. With the Allan et al. (2011) estimates, and using the methods of Tables A.1a–A.1d, we calculate a levelized production cost for near-term tidal-power projects of \$0.10–0.26/kWh. Future costs assume currents > 3.5 m/s (Pure Energy Systems Wiki, 2010).

<sup>i</sup> Average price (in 2007 dollars) of conventional (mainly fossil-fuel) electricity generation and transmission in all end-use sectors in the US in 2007, and projected for the year 2030 (EIA, 2009a, Table A8). Excludes cost of electricity distribution (\$0.024/kWh (EIA, 2009a, Table A8)), which is not included in the cost estimates for WWS and is the same for all centralized power systems. (Note that rooftop PV systems would have no distribution-system costs.) The social cost of conventional generation is equal to the generation and transmission cost plus the estimated mean or mid values of damages from air pollution and climate change due to emissions from coal and gas-fired plants (Table 2). Air-pollution and climate-change damages from WWS power plants are zero.

## 2.2. Cost of extra-long-distance transmission

The estimates of Table 1 include the cost of electricity transmission in a conventionally configured system, over distances common today. However, as discussed in Section 1, the more that dispersed wind and solar generating sites are interconnected, the less the variability in output of the whole interconnected system. A system of interconnections between widely dispersed generators and load centers has been called a "supergrid." The configuration and length of transmission lines in a supergrid will depend on the balance between the cost of adding more transmission lines and the benefit of reducing system output variability as a result of connecting more dispersed generation sites. As mentioned above, no such cost-optimization study has been performed for the type of WWS system we propose, and as a result, the optimal transmission length in a supergrid is unknown. It is almost certain, however, that the average transmission distances from generators to load centers in a supergrid will be longer – and perhaps much longer – than the average transmission distance in the current system. The cost of this extra transmission distance is an additional cost (compared with the cost of the current conventional system) of ensuring that WWS generation reliably matches demand.

Appendix A.2 presents our calculation of the additional \$/kWh cost of extra-long-distance transmission on land with high-voltage

direct-current (HVDC) lines. The \$/kWh cost is a function of the cost of the towers and lines per unit of wind capacity and per km of transmission, the cost of equipment such as converters, transformers, filters, and switchgear, the distance of transmission, the capacity factor for the wind farm, electricity losses in lines and equipment, the life of the transmission line, maintenance costs, and the discount rate. Table A.2a presents our low-cost, mid-cost, and high-cost assumptions for these parameters. The most important and uncertain cost component is the cost of lines and towers per km and per MW. In Appendix A.2 we discuss several estimates of this cost. The unit cost of lines and towers is uncertain because it depends on factors that vary from project to project: the capacity of the wind farm, the capacity of the transmission line relative to the capacity of the wind farm, system design, right-of-way acquisition costs, construction costs, and other factors. Construction costs and right-of-way acquisition costs are especially variable because they are related to highly variable site-specific characteristics of the land, such as slope, accessibility, and the potential for alternative uses.

With the assumptions documented in Appendix A.2, we estimate that the additional cost of extra-long-distance transmission on land, beyond the transmission costs of a conventional system, range from \$0.003/kWh to \$0.03/kWh, with a best estimate of about \$0.01/kWh. A rough calculation in Appendix A.2 suggests that a system with up to 25% undersea transmission, which is

relatively expensive, would increase our best-estimate of the additional long-distance transmission cost by less than 20%.

### 2.3. V2G decentralized storage

As discussed in Section 1, the use of EV batteries to store electrical energy, known as “vehicle-to-grid,” or V2G, is an especially promising method for matching WWS generation with demand. V2G systems have three kinds of costs: they might accelerate the battery’s loss of capacity, they require extra electronics for managing V2G operations, and they lose energy during charge/discharge cycling. In Appendix A.3, we estimate all three costs of a V2G scheme, and draw three conclusions:

- (1) If Li-ion batteries have a cycle life  $> 5000$  and a calendar life about equal to the life of a vehicle, then V2G cycling will not change battery replacement frequency and will have a battery replacement cost of zero and a total cost of only \$0.01–\$0.02 per kWh diverted to V2G. (We think that this case, or something close to it, is the most likely.)
- (2) Otherwise, if the calendar life is very long (30 years), but if V2G cycling can be managed so as to cause minimal degradation of battery capacity, then the total cost of V2G cycling will be in the range of \$0.03/kWh to \$0.11/kWh, depending on the type of vehicle and the value of the other variables considered in Appendix A.3.
- (3) Otherwise, if the calendar life is long and V2G cycling causes the same degradation of capacity as does charging and discharging during driving, then the cost of V2G cycling will be in the range of \$0.05–\$0.26/kWh. (This case is unlikely, because there is evidence that V2G cycling does not cause the same battery degradation as does driving.)

Note that these cost estimates are per kWh diverted to V2G. To get an estimate of the cost per kWh of all WWS generation, we multiply the cost per kWh diverted by the ratio of kWhs diverted to total kWhs of WWS generation. This ratio will depend on the design and operation of an optimized system, which are not yet known, but we speculate that the ratio is not likely to exceed 25%. If so, then the cost of V2G storage is likely to be on the order of \$0.01/kWh-generated or less.

We conclude that in an intelligently designed and operated WWS system, the system-wide average additional cost (relative to the cost of a conventional system) of using a supergrid and V2G storage (along with demand management, hydropower, and weather forecasting) to ensure that WWS generation reliably satisfies demand is not likely to exceed \$0.02/kWh-generated. Even with this additional cost, future wind power is likely to have a lower private cost than future conventional fossil generation, and all WWS alternatives are likely to have a lower *social* cost than fossil-fuel generation (Table 1).

## 3. The economics of the use of WWS power in transportation

So far, we have compared alternatives in terms of the cost per unit of energy delivered (i.e., \$/kWh), but ideally we want to compare alternatives on the basis of the cost per unit of service provided, the difference between the two being in the cost of the end-use technologies that use energy to provide services such as heating and transportation. In the residential, commercial, and industrial sectors the end-use technologies in a WWS world for the most part will be the same as those in our current fossil-fuel world (motors, heating and cooling devices, lights, appliances, and so on), and hence in these sectors the economics of end-use will not be different in a WWS world. However, the transportation sector in a WWS world will be powered by batteries or fuel cells driving

electric motors rather than by liquid fuels burned in heat engines, and so in the transportation sector we should compare the economics of electric vehicles with the economics of combustion-engine vehicles. We address this in this section.

As detailed in Part I of this work (Jacobson and Delucchi, this issue), our plan assumes that all of the liquid fuels and engines used in transportation today are replaced by batteries, fuel cells, and electric drives. In order to realize this transformation, electric transportation technologies must be commercializable in the next 20 years.

Several studies show that mass-produced, advanced, battery- and fuel-cell electric light-duty vehicles using WWS power can deliver transportation services economically. Early detailed analyses indicated that mass-produced BEVs with advanced lithium-ion or nickel metal-hydride batteries could have a full lifetime cost per mile (including annualized initial costs and battery replacement costs) comparable with that of a gasoline vehicle when gasoline sells for between \$2.5 and \$5 per gallon in the US (the “break-even” gasoline price) (Delucchi and Lipman, 2001). More recent unpublished analyses using an updated and expanded version of the same model indicate break-even prices at the lower end of this range, around \$3/gal (based on private cost). This is the price of gasoline in the US in summer 2009, and less than the \$4/gal price projected by the EIA for 2030 (EIA, 2009a), Table A12). Similarly, Offer et al. (2010) find that BEVs powered by wind energy will have a lower private lifecycle cost than gasoline vehicles in 2030, when gasoline is \$3/gallon, and Hellgren (2007) estimates that in Europe in 2020, Li-ion BEVs will have a much lower private lifecycle cost than a conventional gasoline vehicle in 2020. Finally, recent analyses also show that with expected technological development, mass-produced HFCVs can be economically competitive with gasoline vehicles before 2030, on a private-cost (Hellgren, 2007) or social-cost basis (Sun et al., 2010; Delucchi and Lipman, 2010; Offer et al., 2010), even when hydrogen is made from renewable resources (Offer et al., 2010).

There has been less work on the economics of battery or fuel-cell power for trucks, buses, ships and trains. (For general overviews of the use of hydrogen fuel cells for bus, rail and marine transport, see Whitehouse et al. (2009), Miller, 2009, Winkler (2009) and the “Hydrail” organization and associated conferences [www.hydrail.org].) Hellgren (2007) uses a computer model to estimate that in Europe in 2020, a hydrogen-fuel cell bus will have a lower private lifecycle cost than a diesel bus in intra-city use, and the same lifecycle cost in inter-city use. Cockroft and Owen (2007) estimate that a wind-hydrogen fuel-cell bus has a significantly lower social lifetime cost than does a diesel bus when oil costs \$72/bbl (USD) and air pollution costs are estimated for European conditions. Scott et al. (1993) compare a diesel locomotive with hydrogen fuel-cell locomotive, and estimate that the hydrogen fuel-cell system will have a lower private lifetime cost when diesel fuel costs about \$0.45/liter (1990 Canadian dollars—about \$2/gallon in 2008 US dollars). Similarly, Wancura (2010) expects that a hydrogen fuel-cell/battery locomotive eventually will be “an economical choice,” even with hydrogen produced from renewable resources. Finally, Glykas et al. (2010) analyze a photovoltaic electrolytic hydrogen system for merchant marine vessels, and find that the payback period for the investment is in the range of 10–20 years for areas with the most intense solar radiation, assuming that the price of fuel oil rises by at least 15%.

Note that the Hellgren (2007), Scott et al. (1993), and Glykas et al. (2010) studies compare on the basis of private cost, not social cost, which includes external costs as well as private costs. A comparison on the basis of social cost would be more favorable to hydrogen fuel-cell systems. To give a sense of the magnitude of the external costs, we note that analyses in Sun et al. (2010) and Chernyavs'ka and Gullí (in press) indicate that present value of the stream of the external costs of a renewable-hydrogen fuel-cell car is about \$500–\$10,000 less than the present value of the stream of the

**Table 2**  
Environmental external costs of electricity generation in the US (year 2007 US cents/kWh).

	Air pollution 2005			Air pollution 2030	Climate change (2005/2030)		
	5th%	Mean	95th%	Mean	Low	Mid	High
Coal <sup>a</sup>	0.19	3.2	12.0	1.7	1.0/1.6	3.0/4.8	10/16
Natural gas <sup>a</sup>	0.0	0.16	0.55	0.13	0.5/0.8	1.5/2.4	5.0/8.0
Coal/NG mix <sup>b</sup>	n.a.	2.4	n.a.	1.3	0.9/1.4	2.6/4.2	8.8/14
Wind, water, and solar power <sup>c</sup>	0.0	0.0	0.0	0.0	0	0	~0

<sup>a</sup> Estimates from the National Research Council (NRC, 2010). To estimate air-pollution costs, the NRC (2010) uses a standard three-step damage-function model (emissions to air quality, air quality to physical impacts, physical impacts to monetary value) to quantify the value of the impacts of air pollution on human health, visibility, agriculture, and other sectors. For natural gas and coal, the NRC (2010) estimates damages from the cleanest plants (5th percentile) and the dirtiest plants (95th percentile), and the generation-weighted mean damages from all plants in 2005. For coal only, the NRC (2010) estimates the generation-weighted mean damages from all plants in 2030. We assume that the generation-weighted mean damages from all natural gas plants in 2030 are 80% of the NRC-estimated mean in 2005, because current natural gas plants are relatively clean. (By comparison the NRC estimates that the generation-weighted mean damages from coal plants in 2030 are about 50% of the 2005 damages. Because coal plants are dirtier than NG plants, it is appropriate for us to assume a greater emissions reduction for coal plants.) To estimate climate-change costs, the NRC (2010) reviews results from Integrated Assessment Models and then assumes that marginal climate-change damage costs are \$10/CO<sub>2</sub>-equivalent (low), \$30/CO<sub>2</sub>-equivalent (mid) or \$100/CO<sub>2</sub>-equivalent (high), for emissions in 2005. The NRC (2010) says that the marginal damage cost of emissions in 2030 could be 50–80% higher; we assume 60%. Note that in the case of air pollution, the variation in damage costs per kWh is due primarily to variation in emission rates rather than to uncertainty regarding the other parameters in the multi-step analysis, whereas in the case of climate change the wide range in damage costs per kWh is due primarily to uncertainty in estimates of marginal damages per ton of CO<sub>2</sub>-equivalent emission rather than to uncertainty in estimates of emissions (NRC, 2010) n.a. = not applicable.

<sup>b</sup> Our estimate of damages for the actual 73%/27% coal/NG proportions in 2005 (EIA, 2009e) and for the projected 75%/25% coal/NG proportions in 2030 (EIA, 2009a).

<sup>c</sup> In an all-WWS world, there will be no emissions of air pollutants or greenhouse-gases related to energy use in any phase of the lifecycle, including construction and the manufacture of materials, because the energy will be provided by zero-emission WWS. There will be some minor emissions related to construction dust and non-energy processes such as in the making concrete, but these are tiny compared with direct and indirect energy-related emissions.

external costs of a gasoline ICEV. Thus, on the basis of these studies, we conclude that by 2030, hydrogen fuel-cell buses, trains, and ships could have a lifetime social cost comparable to that of petroleum-fueled modes.

#### 4. Policy issues and needs

Current energy markets, institutions, and policies have been developed to support the production and use of fossil fuels. Because fossil-fuel energy systems have different production, transmission, and end-use costs and characteristics than do WWS energy systems, new policies are needed to ensure that WWS systems develop as quickly and broadly as is socially desirable. Schmalensee (2009) lists four kinds of economic policies that have been adopted in the US and abroad to stimulate production of renewable energy: feed-in tariffs, output subsidies, investment subsidies, and output quotas (sometimes called “renewables portfolio standards”—see e.g., Wiser et al., 2010). Dusonchet and Telaretti (2010) analyze the economics of policies that support the development of photovoltaic energy in Europe. Most studies find that feed-in tariffs (FITs), which are subsidies to cover the difference between generation cost (ideally including grid connection costs (Swider et al., 2008)) and wholesale electricity prices, are especially effective at stimulating generation from renewable fuels (Fthenakis et al., 2009; Sovacool and Watts, 2009; Couture and Cory, 2009; Wei and Kammen, 2010). A recent survey of venture capitalists investing in renewable energy technologies found that the investors ranked FITs as the most effective policy for stimulating the market for renewable energy (Bürer and Wüstenhagen, 2009). To encourage innovation and economies of scale that can lower costs, FITs should be reduced gradually (Couture and Cory, 2009 call this an “annual tariff degeneration”). An example of this is a “declining clock auction,” in which the right to sell power to the grid goes to the bidders willing to do it at the lowest price, providing continuing incentive for developers and generators to lower costs (New York State Energy Research and Development Authority, 2004). A risk of any auction, however, is that the developer will underbid and be left unable to profitably develop the proposed project (Macauley, 2008; KEMA, 2006; Wiser et al., 2005). Regardless of the actual mechanism, the goal of “tariff degeneration” is that as the cost of producing power from WWS technologies (particularly photovoltaics) declines, FITs can be reduced and eventually phased out.

Other economic policies include eliminating subsidies for fossil-fuel energy systems (for estimates of subsidies, see Koplów, 2004, 2009; Koplów and Dernbach, 2001; The Environmental Law Institute, 2009; The Global Studies Initiative, 2010; and <http://subsidyscope.org/energy/>) or taxing fossil-fuel production and use to reflect its environmental damages, for example with “carbon” taxes that represent the expected cost of climate change due to CO<sub>2</sub> emissions (for estimates of environmental damages, see National Research Council (2010) (Table 2 here) and Krewitt, 2002). However, it appears that eliminating fossil-fuel subsidies and charging environmental-damage taxes would compensate for the extra cost of the currently most expensive WWS systems only if climate-change damage was valued at the upper end of the range of estimates in the literature. For example, The Environmental Law Institute (2009) estimates that US government subsidies to fossil fuel energy amount to about \$10 billion per year, which is less than 5% of the roughly \$300 billion value of fossil-fuel production (EIA, 2010d).<sup>4</sup> Regarding environmental damages, the US National Research Council (2010) estimates that the external costs of air pollution and climate change from coal and natural-gas electricity generation in the US total \$0.03–\$0.11/kWh for 2005 emissions, and \$0.03–\$0.15/kWh for 2030 emissions (using the mean air-pollution damages and the low and high climate change damages from Table 2). Only the upper end of the 2005 range, which is driven by assumed high climate-change damages, can begin to compensate for the more than \$0.10/kWh higher current private cost of solar PVs and tidal power (Table 1). Assuming that it is politically infeasible to add to fossil-fuel generation carbon taxes that would more than double the price of electricity, eliminating subsidies and charging environmental damage taxes cannot by themselves make the currently most expensive WWS options economical.

Two important non-economic programs that will help in the development of WWS are reducing demand, and planning and managing the development of the appropriate energy-system infrastructure (Sovacool and Watts, 2009). Reducing demand by

<sup>4</sup> However, subsidies to the biofuels industry may be much larger: Koplów (2009) estimates that, absent changes in current policies, taxpayers will pay over \$400 billion in subsidies to the biofuels industry between 2008 and 2022. Koplów also asserts that this subsidy “accelerates land conversion and exacerbates a wide range of environmental problems” (p. 4), and we agree.



improving the efficiency of end use or substituting low-energy activities and technologies for high-energy ones, directly reduces the pressure on energy supply, which means less need for higher cost, less environmentally suitable resources.

Because a massive deployment of WWS technologies requires an upgraded and expanded transmission grid and the smart integration of the grid with BEVs and HFCVs as decentralized electricity storage and generation components, governments need to carefully fund, plan and manage the long-term, large scale restructuring of the electricity transmission and distribution system. In much of the world, international cooperation in planning and building “supergrids” that span across multiple countries, is needed. Some supergrids will span large countries alone. A supergrid has been proposed to link Europe and North Africa (e.g., [Czisch, 2006](#); [www.desertec.org](#)), and ten northern European countries are beginning to plan a North Sea supergrid for offshore wind power ([Macilwain, 2010](#); [www.offshoregrid.eu](#)). Supergrids are needed for Australia/Tasmania (e.g., [Beyond Zero Emissions, 2010](#)); North America, South America, Africa, Russia ([The Union for the Co-ordination of Transmission of Electricity \(2008\)](#) has studied the feasibility of a supergrid linking Russia, the Baltic States, and all of Europe), China, Southeastern and Eastern Asia, and the Middle East. Thus, a high priority for national and international governing bodies will be to cooperate and help to organize extra-long-distance transmission and interconnections, particularly across international boundaries.

Another policy issue is how to encourage end users to adopt WWS systems or end-use technologies (e.g., residential solar panels, and electric vehicles) different from conventional (fossil-fuel) systems. Municipal financing for residential energy-efficiency retrofits or solar installations can help end users overcome the financial barrier of the high upfront cost of these systems ([Fuller et al., 2009](#)). Purchase incentives and rebates and public support of infrastructure development can help stimulate the market for electric vehicles ([Åhman, 2006](#)). Recent comprehensive analyses have indicated that government support of a large-scale transition to hydrogen fuel-cell vehicles is likely to cost just a few tens of billions of dollars—a tiny fraction of the total cost of transportation ([National Research Council, 2008](#); [Greene et al., 2007, 2008](#)).

Finally, we note that a successful rapid transition to a WWS world may require more than targeted economic policies: it may require a broad-based action on a number of fronts to overcome what [Sovacool \(2009\)](#) refers to as the “socio-technical impediments to renewable energy:”

Extensive interviews of public utility commissioners, utility managers, system operators, manufacturers, researchers, business owners, and ordinary consumers reveal that it is these socio-technical barriers that often explain why wind, solar, biomass, geothermal, and hydroelectric power sources are not embraced. Utility operators reject renewable resources because they are trained to think only in terms of big, conventional power plants. Consumers practically ignore renewable power systems because they are not given accurate price signals about electricity consumption. Intentional market distortions (such as subsidies), and unintentional market distortions (such as split incentives) prevent consumers from becoming fully invested in their electricity choices. As a result, newer and cleaner technologies that may offer social and environmental benefits but are not consistent with the dominant paradigm of the electricity industry continue to face comparative rejection (p. 4500).

Changing this “dominant paradigm” may require concerted social and political efforts beyond the traditional sorts of economic incentives outlined here.

## 5. Technical findings and conclusions

A large-scale wind, water, and solar energy system can reliably supply all of the world’s energy needs, with significant benefit to climate, air quality, water quality, ecological systems, and energy security, at reasonable cost. To accomplish this, we need about 4 million 5-MW wind turbines, 90,000 300-MW solar PV plus CSP power plants, 1.9 billion 3 kW solar PV rooftop systems, and lesser amounts of geothermal, tidal, wave, and hydroelectric plants and devices (see Part I of this work, [Jacobson and Delucchi, this issue](#)). In addition, we need to expand greatly the transmission infrastructure to accommodate the new power systems and expand production of battery-electric and hydrogen fuel cell vehicles, ships that run on hydrogen fuel-cell and battery combinations, liquefied hydrogen aircraft, air- and ground-source heat pumps, electric resistance heating, and hydrogen production for high-temperature processes.

A 100% WWS world can employ several methods of dealing with short-term variability in WWS generation potential, to ensure that supply reliably matches demand. Complementary and gap-filling WWS resources (such as hydropower), smart demand-response management, and better forecasting have little or no additional cost and hence will be employed as much as is technically and socially feasible. A WWS system also will need to interconnect resources over wide regions, and might need to have decentralized (V2G) or perhaps centralized energy storage. Finally, it will be advantageous for WWS generation capacity to significantly exceed peak inflexible power demand in order to minimize the times when available WWS power is less than demand and, when generation capacity does exceed inflexible supply, to provide power to produce hydrogen for flexible transportation and heating/cooling uses. The optimal system design and operation will vary spatially and temporally, but in general will have the lowest-cost combination of long-distance interconnection/transmission, energy storage, and hydrogen production that reliably satisfies intelligently managed (and economically efficient) demand.

The private cost of generating electricity from onshore wind power is less than the private cost of conventional, fossil-fuel generation, and is likely to be even lower in the future. By 2030, the social cost of generating electricity from any WWS power source, including solar photovoltaics, is likely to be less than the social cost of conventional fossil-fuel generation, even when the additional cost of a supergrid and V2G storage (probably on the order of \$0.02/kWh, for both) is included. The social cost of electric transportation, based either on batteries or hydrogen fuel cells, is likely to be comparable to or less than the social cost of transportation based on liquid fossil fuels.

Of course, the complete transformation of the energy sector would not be the first large-scale project undertaken in US or world history. During World War II, the US transformed motor vehicle production facilities to produce over 300,000 aircraft, and the rest of the world was able to produce an additional 486,000 aircraft (<http://www.taphilo.com/history/WWII/Production-Figures-WWII.shtml>). In the US, production increased from about 2000 units in 1939 to almost 100,000 units in 1944. In 1956, the US began work on the Interstate Highway System, which now extends for 47,000 miles and is considered one of the largest public works project in history ([http://en.wikipedia.org/wiki/Interstate\\_Highway\\_System](http://en.wikipedia.org/wiki/Interstate_Highway_System)). The iconic Apollo Program, widely considered one of the greatest engineering and technological accomplishments ever, put a man on the moon in less than 10 years. Although these projects obviously differ in important economic, political, and technical ways from the project we discuss, they do suggest that the large scale of a complete transformation of the energy system is not, in itself, an insurmountable barrier.

We recognize that historically, changes to the energy system, driven at least partly by market forces, have occurred more slowly than we are envisioning here (e.g., Kramer and Haigh, 2009). However, our plan is for governments to implement policies to mobilize infrastructure changes more rapidly than would occur if development were left mainly to the private market. We believe that manpower, materials, and energy resources do not constrain the development of WWS power to historical rates of growth for the energy sector, and that government subsidies and support can be redirected to accelerate the growth of WWS industries. A concerted international effort can lead to scale-up and conversion of manufacturing capabilities such that by around 2030, the world no longer will be building new fossil-fuel or nuclear electricity-generation power plants or new transportation equipment using internal-combustion engines, but rather will be manufacturing new wind turbines and solar power plants and new electric and fuel-cell vehicles (excepting aviation, which will use liquid hydrogen in jet engines). Once this WWS power-plant and electric-vehicle manufacturing and distribution infrastructure is in place, the remaining stock of fossil-fuel and nuclear power plants and internal-combustion-engine vehicles can be retired and replaced with WWS-power-based systems gradually, so that by 2050, the world is powered by WWS.

To improve the efficiency and reliability of a WWS infrastructure, advance planning is needed. Ideally, good wind, solar, wave, and geothermal sites would be identified in advance and sites would be developed simultaneously with an updated interconnected transmission system. Interconnecting geographically dispersed variable energy resources is important both for smoothing out supplies and reducing transmission requirements.

The obstacles to realizing this transformation of the energy sector are primarily social and political, not technological. As discussed herein, a combination of feed-in tariffs, other incentives, and an intelligently expanded and re-organized transmission system may be necessary but not sufficient to enough ensure rapid deployment of WWS technologies. With sensible broad-based policies and social changes, it may be possible to convert 25% of the current energy system to WWS in 10–15 years and 85% in 20–30 years, and 100% by 2050. Absent that clear direction, the conversion will take longer.

## Acknowledgment

This paper was not funded by any interest group, company, or government agency.

**Table A.1a**

Estimates of generation costs using EIA (2009a, 2009b, 2009c, 2009d) parameter values, for 2008 (year 2007 \$/kWh).

Technology	Input parameters							Calculated results		
	Capital cost (\$/kW)	Cap. factor (%)	Life (years)	Variable O&M (\$/kWh)	Fixed O&M (\$/kW/year)	Fuel (\$/10 <sup>6</sup> -BTU)	Fuel effic. (%)	Levelized initial cost (\$/kWh)	Periodic costs (\$/kWh)	Total cost (\$/kWh)
New coal scrubbed	2058	74	20	0.0046	27.53	1.93	37	\$0.038	\$0.027	\$0.065
IGCC coal	2378	74	20	0.0029	38.67	1.93	39	\$0.044	\$0.026	\$0.070
IGCC coal/CCS	3496	74	20	0.0044	46.12	1.93	32	\$0.065	\$0.032	\$0.097
NG advanced CC	948	42	20	0.0020	11.70	8.87	51	\$0.031	\$0.065	\$0.096
NG adv. CC/CCS	1890	42	20	0.0029	19.90	8.87	40	\$0.062	\$0.085	\$0.146
Geothermal	1711	90	20	0.0000	164.64	0.00	100	\$0.026	\$0.021	\$0.047
Hydropower	2242	65	20	0.0024	13.63	0.00	100	\$0.047	\$0.005	\$0.052
Wind onshore	1923	38	20	0.0000	30.30	0.00	100	\$0.069	\$0.009	\$0.078
Wind offshore	3851	40	20	0.0000	89.48	0.00	100	\$0.132	\$0.026	\$0.157
Solar thermal	5021	31	20	0.0000	56.78	0.00	100	\$0.222	\$0.021	\$0.243
Solar PV	6038	21	20	0.0000	11.68	0.00	100	\$0.393	\$0.006	\$0.400

## Appendix A.1. Estimates of \$/kw capital costs and total amortized + operating \$/kwh costs for various generating technologies

### A.1.a. Discussion of estimates based on the EIA reference-case parameters

To validate our cost-calculation method, we can compare our estimates of generation costs based on the EIA's parameter values, in Tables A.1a and A.1b, with what the EIA actually calculates in the National Energy Modeling System (NEMS) (Table A.1e).

The estimates in Table A.1e are based on the EIA's NEMS full internal calculation of the average generation costs for all plants in the given year, whereas the estimates Table A.1a are based on our calculations using EIA's reported parameters for new power plants in the given year. For three reasons, we cannot (easily) calculate average generation costs to check against EIA's results: we do not have data for all of the generation types in NEMS; we do not have data on plants that are not new; and we do not know the EIA's complete calculation methodology. Nevertheless, we can show that our estimates of generation costs based on EIA parameters are consistent with the EIA's calculated average generation costs for 2008, but not with the average generation costs in 2030 (Tables A.1a and A.1b versus Table A.1e).

In Table A.1a, we estimate that according to EIA's cost parameters, new coal-fired generation in the year 2008 costs 6.5 cents/kWh, new hydro costs 5.2 cents/kWh, and new advanced gas costs 9.6 cents/kWh. Allowing that older gas and coal plants have slightly higher fuel costs than do new plants because they are less efficient, but also have lower capital costs, and assuming 5.0 cents/kWh for nuclear, we estimate an approximate average generation cost in 2008 of 6.7 cents/kWh, based on the actual generation by fuel type reported by the EIA (2009a). This is close to the estimate calculated by NEMS (Table A.1e).

However, we cannot reproduce the EIA results for 2030. On the one hand, the EIA parameter values shown in Table A.1b indicate that capital costs decline from 2008 to 2030, and that fuel prices remain roughly constant but efficiency increases, which means that the fuel cost component also decreases. Thus, the EIA parameter values indicate declining total generation costs, which is what we have calculated in of Table A.1b (compare Table A.1b results with Table A.1a results). Yet the EIA's actual cost calculations in NEMS, shown in Table A.1e, indicate that average costs rise from 2008 to 2030. We cannot explain this discrepancy.

## Appendix A.2. The cost of long-distance electricity transmission

In this appendix we estimate the cost of electricity transmission on land, in dollars per kWh of electricity into the local electricity

**Table A.1b**

Estimates of generation costs using EIA (2009a, 2009b, 2009c, 2009d) parameter values, for 2030 (year 2007 \$/kWh).

Technology	Input parameters							Calculated results		
	Capital cost (\$/kW)	Cap. factor (%)	Life (years)	Variable O&M (\$/kWh)	Fixed O&M (\$/kW/year)	Fuel (\$/10 <sup>6</sup> -BTU)	Fuel eff. (%)	Levelized initial cost (\$/kWh)	Periodic costs (\$/kWh)	Total cost (\$/kWh)
New coal scrubbed	1654	78	20	0.0046	27.53	2.04	39	\$0.029	\$0.026	\$0.056
IGCC coal	1804	78	20	0.0029	38.67	2.04	46	\$0.032	\$0.024	\$0.056
IGCC coal/CCS	2533	78	20	0.0044	46.12	2.04	41	\$0.045	\$0.028	\$0.073
NG advanced CC	717	46	20	0.0020	11.70	8.34	54	\$0.021	\$0.058	\$0.079
NG adv. CC/CCS	1340	46	20	0.0029	19.90	8.34	46	\$0.040	\$0.070	\$0.110
Geothermal	3942	90	20	0.0000	164.64	0.00	100	\$0.061	\$0.021	\$0.081
Hydropower	1920	55	20	0.0024	13.63	0.00	100	\$0.048	\$0.005	\$0.053
Wind onshore	1615	46	20	0.0000	30.30	0.00	100	\$0.048	\$0.008	\$0.056
Wind offshore	2859	40	20	0.0000	89.48	0.00	100	\$0.098	\$0.026	\$0.123
Solar thermal	3082	31	20	0.0000	56.78	0.00	100	\$0.136	\$0.021	\$0.157
Solar PV	3823	21	20	0.0000	11.68	0.00	100	\$0.249	\$0.006	\$0.255

Notes for Tables A.1a and A.1b: Cap. factor = capacity factor; Fuel eff. = fuel efficiency; IGCC = integrated gasification combined cycle; CCS = carbon capture and sequestration; CC = combined cycle; PV = photovoltaic.

Capital costs in 2008 and 2030 are from Table 8.13 of the EIA's *Assumptions to the Annual Energy Outlook 2009* (EIA, 2009b). The capital costs are "total overnight costs," and include project contingency, technological optimism factors, and learning factors. Costs pertain to projects online in the given year. In year-2007 dollars. (The 2010 edition of the EIA's *Assumptions to the Annual Energy Outlook* (EIA, 2010c) – which came out after we completed our analysis – does not have a Table 8.13, and also reports values for different time periods than is done in the 2009 edition, so a direct comparison with the 2009-edition values shown here is not possible. However, the overnight costs for WWS technologies shown in Table 8.2 of the 2010 edition of the EIA's *Assumptions to the Annual Energy Outlook* (EIA, 2010c) are approximately the same, in real dollars, as the overnight costs shown in Table 8.2 of the 2009 edition.)

For comparison, Johnson and Solomon (2010) report that it costs \$3.4 million to purchase, transport, and install a 1.65 MW Vestas wind turbine at a small college in the US. This is \$2060/kW, very close to the EIA estimate for wind in 2008 shown in Table A.1a.

Wiser and Bollinger (2008, 2009, 2010) show that capacity-weighted average installed wind-power project costs, including turbine purchase and installation, balance of plant, and any expenses for interconnections and collecting substations, have increased from about \$1550/kW in 2002 to \$1950/kW in 2008 and \$2120/kW in 2009, due mainly to a near doubling of turbine prices over the period. Wiser and Bollinger (2008, 2010) state that turbine prices have increased because of increased material and energy prices, the declining value of the dollar relative to the Euro, more sophisticated designs, shortages in certain components, and greater manufacturer profit. Of these, only higher energy prices are likely to continue to put significant upward pressure on turbine costs in the long run. As Wiser and Bolinger (2010) note: "Some of the cost pressures facing the industry in recent years (e.g., rising materials costs, the weak dollar, and turbine and component shortages) have eased since late 2008. As a result, there are expectations that average installed costs will decline over time" (p. 45).

The US DOE (2008a) study of 20% wind power in the US uses a consultant report that estimates that estimates that wind costs \$1650/kW in 2010 and \$1480/kW in 2030 (2006 USD).

Musial and Ram (2010) report that total capital costs of offshore wind plants commissioned between 1991 and 2006 ranged from \$1300 to \$2800/kW, with a capacity-weighted average of \$2273/kW. (The capital cost includes the turbine, the electrical infrastructure including cables to onshore substations, support structures, logistics and installation, project development and permitting, regularly scheduled maintenance, and other costs.) Between 2007 and 2009 capital costs rose to average of \$3544/kW, and projects proposed for 2010–2015 have an estimated capacity-weighted average cost of \$4259/kW (US 2008\$). Most of the reasons for the increase in the capital costs of offshore wind plants are the same as the reasons, discussed above, for the increase in the capital costs of onshore wind plants: fluctuations in exchange rates, supply-chain bottlenecks, higher profit margins, and higher raw material prices, but also increased awareness of technical risks, and increasing complexity of projects. However, Musial and Ram (2010) write that "significant cost declines are plausible based on the historical behavior of other new industries, including land-based wind" (p. 122). We thus expect that with progress in technological development and under normal market conditions, capital costs for offshore wind will decline in the future.

Boccard (2010) estimates investment costs of \$3080/kW for nuclear, \$2100/kW for coal (similar to the EIA value in Table A.1a), \$840/kW for gas (comparable to EIA's estimate in Table A.1a), and \$1540/kW for onshore wind (somewhat lower than EIA's estimate for onshore wind in Table A.1a) (converting his Euros to US dollars at 1.4 dollars/Euro). Wiser et al. (2009) report that the installed cost of large (500–750 kW) PV systems in the US in 2008 was \$6500/kW, just slightly higher than the EIA's estimate. The average cost in Germany for all systems (including small systems) was \$6100/kW, the same as the EIA's estimate.

Capacity factors for renewables are from Table 13.2 of the EIA's *Assumptions to the Annual Energy Outlook 2009* (EIA, 2009b). The EIA shows values for the year 2012 (which we use for 2008) and the year 2030. Here, capacity factor for coal and natural gas for 2008 are assumed to be equal to actual average capacity factors for coal and NG in 2007, as reported in Table A6 of the EIA's *Electric Power Annual 2007* (2009d). Capacity factors for coal and natural gas for 2030 assumed to be 5% (coal) or 10% (NG) higher than in 2007, because the EIA (2009d) data indicate that the capacity factor is increasing over time. (In the 2010 edition of the EIA's *Assumptions to the Annual Energy Outlook* (EIA, 2010c), the capacity factors for geothermal, photovoltaic, and solar thermal are the same as in the 2009 edition; the capacity factors for hydropower are lower in the out years than in the 2009 edition; and the capacity factors for onshore and offshore wind are slightly higher than in the 2009 edition.)

Lifetime based on this statement in EIA's NEMS documentation: "Technologies are compared on the basis of total capital and operating costs incurred over a 20-year period" (EIA, 2009c, p. 5).

Variable O&M and fixed O&M are from Table 8.2 of the EIA (2009b). The EIA shows only one set of values; we assume these are the same in 2030 and 2008. In year-2007 dollars. Note that Table 8.2 reports "fixed O&M," in units of \$/kW, but according to private communications from EIA staff, the correct units are \$/kW/year. (The O&M values in the 2010 edition of the EIA's *Assumptions to the Annual Energy Outlook* (EIA, 2010c) are approximately the same, in real dollars, as the 2009-edition values, except that the fixed O&M cost for offshore wind is about 5% lower than the 2009 value shown here.)

For comparison, Johnson and Solomon (2010) report that a typical price for a new maintenance contract for their 1.65 MW Vestas turbine is \$50,000 per year, or \$30.3/kW/year, which is exactly the figure used by the EIA in Tables A.1a and A.1b, suggesting that the EIA used the same source of information. Wiser and Bollinger (2008, 2009) report that large wind projects installed after 2000 have an O&M cost of \$0.009/kWh, the same as the EIA estimate. The US DOE (2008a) study of 20% wind power in the US uses a consultant report that estimates that estimates that wind has a fixed O&M cost of \$11.5/kW-year, and a variable cost of \$0.0055/kWh in 2010 and \$0.0044/kWh in 2030; together, these amount to about \$0.008/kWh, close to the EIA estimate. Boccard (2010) assumes that O&M costs are 2% of investment costs for coal, gas, oil, and onshore wind; the EIA estimates of "fixed" O&M costs in Table A.1a are slightly lower, around 1.5% of investment costs.

Musial and Ram (2010) state that O&M costs for offshore wind are two to three times higher than those of land-based systems (p. 116); the EIA estimates here are that the O&M costs for offshore wind are three times higher than those of land-based systems.

Fuel costs for coal and natural gas used in the electricity sector are from Table 3 of EIA's *Annual Energy Outlook* (EIA, 2009a).

Combustion efficiency is calculated from heat rates shown in Table 8.2 of the EIA (2009b). (The heat rates in the 2010 edition of the EIA's *Assumptions to the Annual Energy Outlook* (EIA, 2010c) are the same.) That Table shows the rate in 2008 and the rate for the "nth-of-a-kind plant," which we assume applies to the year 2030. (Elsewhere in that report, the EIA states that "heat rates for fossil-fueled technologies are assumed to decline linearly through 2025" (EIA 2009b, p. 88).) We assume that BTUs are based on higher heating values, which is the EIA's usual convention.

Discount rate estimate is based on the EIA's estimate of the weighted average cost of capital (WACC). In Fig. 9 of the documentation for the electricity module of the National Energy Modeling System (NEMS), the estimated WACC is shown to be about 10.4% in 2008 and 10.2% in 2030 (EIA, 2009c). We assume a value of 10.3%.

Periodic costs comprise variable O&M, fixed O&M, and fuel cost.

**Table A.1c**

Estimates of generation costs using alternative values for lifetime and discount rate, for 2008 (year 2007 US\$/kWh).

Technology	Input parameters							Calculated results		
	Capital cost (\$/kW)	Cap. factor (%)	Life (years)	Variable O&M (\$/kWh)	Fixed O&M (\$/kW)	Fuel (\$/10 <sup>6</sup> -BTU)	Fuel effic. (%)	Levelized initial cost (\$/kWh)	Periodic costs (\$/kWh)	Total cost (\$/kWh)
New coal scrubbed	2058	74	30	0.0046	27.53	1.93	37	\$0.026	\$0.027	\$0.052
IGCC coal	2378	74	30	0.0029	38.67	1.93	39	\$0.030	\$0.026	\$0.055
IGCC coal/CCS	3496	74	30	0.0044	46.12	1.93	32	\$0.044	\$0.032	\$0.076
NG advanced CC	948	42	30	0.0020	11.70	8.87	51	\$0.021	\$0.065	\$0.086
NG adv. CC/CCS	1890	42	30	0.0029	19.90	8.87	40	\$0.042	\$0.085	\$0.126
Geothermal	1711	90	30	0.0000	164.64	0.00	100	\$0.018	\$0.021	\$0.038
Hydropower	2242	65	30	0.0024	13.63	0.00	100	\$0.032	\$0.005	\$0.037
Wind onshore	1923	38	30	0.0000	30.30	0.00	100	\$0.047	\$0.009	\$0.056
Wind offshore	3851	40	30	0.0000	89.48	0.00	100	\$0.089	\$0.026	\$0.114
Solar thermal	5021	31	30	0.0000	56.78	0.00	100	\$0.149	\$0.021	\$0.170
Solar PV	6038	21	30	0.0000	11.68	0.00	100	\$0.265	\$0.006	\$0.271

**Table A.1d**

Estimates of generation costs using alternative values for lifetime, discount rate, and WWS capital cost, for 2030 (year 2007 US\$/kWh).

Technology	Input parameters							Calculated results		
	Capital cost (\$/kW)	Cap. factor (%)	Life (years)	Variable O&M (\$/kWh)	Fixed O&M (\$/kW)	Fuel (\$/10 <sup>6</sup> -BTU)	Fuel effic. (%)	Levelized initial cost (\$/kWh)	Periodic costs (\$/kWh)	Total cost (\$/kWh)
New coal scrubbed	1654	78	30	0.0046	27.53	2.04	39	\$0.020	\$0.026	\$0.046
IGCC coal	1804	78	30	0.0029	38.67	2.04	46%	\$0.022	\$0.024	\$0.045
IGCC coal/CCS	2533	78	30	0.0044	46.12	2.04	41	\$0.030	\$0.028	\$0.058
NG advanced CC	717	46	30	0.0020	11.70	8.34	54	\$0.014	\$0.058	\$0.072
NG adv. CC/CCS	1340	46	30	0.0029	19.90	8.34	46	\$0.027	\$0.070	\$0.097
Geothermal	3942	90	30	0.0000	164.64	0.00	100	\$0.040	\$0.021	\$0.061
Hydropower	1920	55	30	0.0024	13.63	0.00	100	\$0.032	\$0.005	\$0.037
Wind onshore	1143	46	30	0.0000	30.30	0.00	100	\$0.023	\$0.008	\$0.030
Wind offshore	2023	40	30	0.0000	89.48	0.00	100	\$0.047	\$0.026	\$0.072
Solar thermal	2181	31	30	0.0000	56.78	0.00	100	\$0.065	\$0.021	\$0.086
Solar PV	2705	21	30	0.0000	11.68	0.00	100	\$0.118	\$0.006	\$0.125

Notes for Tables A.1c and A.1d. All parameter values the same as in Tables A.1a and A.1b, except that the discount rate is 7% (rate recommended by OMB (2003) and used here in V2G analysis (Appendix A.3); similar to the value used in Fthenakis et al. (2009), the lifetime is 30 years (as assumed in Fthenakis et al., 2009; Johnson and Solomon, 2010, and in the most recent version of the EIA's AEO (EIA, 2010b)), and, in the 2030 case, the capital costs for wind and solar are about 30% lower, following the EIA's "falling costs" case (EIA, 2009b, Table 8.13). See the US DOE (2008a) and Cohen et al. (2008) for discussions of potential technological improvements and cost reductions for wind turbines.

**Table A.1e**

EIA (2009a) NEMS breakdown of electricity prices (year-2007 cents/kWh).

	Year 2008	Year 2030
Generation	6.5	6.9
Transmission	0.7	0.9
Distribution	2.3	2.3

distribution system. Table A.2a shows the parameters in our calculation and our low-cost, mid-cost, and high-cost assumptions. Table A.2a also explains the bases of our assumptions, except in the case of the \$/MW<sub>TS</sub>-km unit transmission cost, which is the most important and uncertain parameter and which we discuss in detail next.

We estimate costs for long-distance, high voltage (~500+kV) DC transmission, for a system with 100% WWS power.

#### A.2.a. Separate estimates of the cost of the transmission lines and the cost of station equipment

In our analysis, presented in Table A.2a, the main cost parameters are the cost of the transmission lines, towers, and land, in dollars per MW of transmission-system (not wind-farm) capacity, per km of transmission distance (\$/MW<sub>TS</sub>-km), and the cost of the station equipment (transformers, power conditioners, converters,

filters, switches, etc.) per MW of transmission-system capacity (\$/MW<sub>TS</sub>). In this section, we review estimates of these costs. In the next section, we review estimates of the cost of the entire system – lines, towers, station equipment – and use these to calibrate our parameter estimates.

Table A.2b presents detailed estimates of transmission-system cost parameters from Bahrman (2006). By comparison, Cavallo (2007) reports that an HVDC line in Canada cost \$680/kV-km, or \$0.34 million/km for 500 kV, with converter stations and filter banks costing \$320 million. Hauth et al. (1997) (cited by De Carolis and Keith, 2006; Greenblatt et al., 2007) assume a value of \$0.33 million/km for 408 kV HVDC transmission, including land and construction cost but not including engineering, legal, and other costs, which they claim could double the line cost (although this seems unlikely to us), and \$452 million for a converter station for a 500 kV, 3000 MW station (costs in about 1995 USD). Weigt et al. (2010) write that overhead transmission lines – apparently they mean 500 kV HVDC lines—typically cost 0.25–0.45 million Euro per km, or about \$0.3–\$0.6 million USD per km, and that converter stations cost about \$200 million (USD). These estimates of line costs (\$0.3–\$0.6 million/km) are substantially lower than Bahrman's; the estimates of station-equipment costs (\$200–\$452 million) are somewhat lower than but overlapping with Bahrman's (2006) (Table A.2b). On the other hand, in their recent detailed assessment of the costs of integrating 20–30% wind power in the Eastern Interconnection region of the US (basically the eastern half of the country), EnerNex (2010) assumed a total cost of \$3.7 million/km

**Table A.2a**

The cost of electricity transmission (year 2007 US\$).

Component	Low	Mid	High	Source of estimate and notes
Transmission-line cost (\$/MW <sub>TS</sub> -km)	200	280	340	Table A.2b and discussion in the appendix text. This is the cost per MW of transmission system capacity. Includes land, towers, and lines, but no station equipment.
Extra transmission distance in supergrid (km)	1200	1600	2000	Our assumptions. Note that this is the distance beyond what is typical in a conventional electricity transmission system.
Reference cost for station equipment (transformers, power conditioners, converters, etc.), at reference power (\$/MW <sub>TS,REF</sub> )	100,000	125,000	150,000	Table A.2b and discussion in Appendix A.2 text.
Reference transmission-system power (for reference station-equipment cost) (MW <sub>TS,REF</sub> )	4000	4000	4000	Table A.2b and discussion in Appendix A.2 text.
Exponent <i>b</i> on power in station-equipment cost function	0.75	0.75	0.75	The station-equipment cost function is $\$/MW_{TS} = \$/MW_{TS,REF} \cdot (MW_{TS}/MW_{TS,REF})^b$ . De Alegria et al. (2009) show that the cost of transformers, switchgear, and underwater cables do increase with increasing power, but not quite linearly. For example, in their work the cost of transformers, in million Euros, is equal to the $0.003227P^{0.75}$ , where <i>P</i> is power.
Power capacity of transmission system (MW <sub>TS</sub> )	5000	5000	5000	Our assumptions.
Ratio of MW capacity of transmission system to MW capacity of served wind farms (MW <sub>TS</sub> /MW <sub>WC</sub> )	70%	80%	90%	In a study of adding up to 35% wind and solar power in the western interconnection region of the US, GE Energy (2010) assumed that only 0.7 MW of new transmission was added for each 1.0 MW of remote generation, on the grounds that "that all remote renewable generation sites would rarely be at maximum output simultaneously" (p. 32).
Wind capacity factor (%)	45%	38%	33%	See Table A.1 and endnote.
Electricity loss in transmission line (%/1000-km, at rated line capacity)	3%	4%	6%	According to Siemens (2010), the losses from a 6.4 GW, 800 kV DC line are 3.5%/1000-km, and the losses from a 3 GW, 500 kV DC line are 6.6%/1000-km. Bahrman (2006) estimates slightly lower losses (Table A.2b).
Average transmission current (fraction of current at rated capacity)	40%	40%	40%	Because the main transmission losses are proportional to the square of the load current (Nourai et al., 2008), the actual losses are calculated here by multiplying the loss at the rated-capacity current by the square of the actual current as a percent of rated (Negra et al., 2006). The actual current fraction depends on the capacity of the line relative to the capacity of the generators, the fraction of zero-current time, and other factors.
Electricity loss in station equipment (% of average power)	1.3%	1.5%	1.8%	Bahrman (2006) says that converter station losses are 0.75% per station, and assumes that total substation (transformer, reactors) losses are 0.5% of rated power. Hauth et al. (1997) assume that converter losses for HVDC are 1% of the converter rating, but this is based on older technology. Bresesti et al. (2007) assume that converter losses are 1.8% at full power. De Alegria et al. (2009) write that converter losses are 1–2%. Negra et al.'s (2006) detailed evaluation of HVDC transmission losses for wind systems finds that converter station losses are 1.4–1.6% of the annual output of the connected wind farm. (The converter station includes converters, transformers, filters, smoothers, auxiliary and protection equipment.)
Lifetime until replacement or major overhaul—transmission towers and lines (years)	70	60	50	Information from Chan (2010), the Electric Power Research Institute (EPRI) (2010), Quest Reliability (2010), and Rimmer (2010) suggest a life of at least 50 years for towers and lines.
Lifetime—station equipment (years)	30	30	30	Energy Resources International (1999) states that "the lifetime of HVDC components (rectifiers, invertors, thyristors and DC circuit breakers) is about 30 years".
Maintenance cost (percent of capital cost, per year)	1.0	1.0	1.5	Chan (2010) says that in his experience, 1% is typical, but 2% would be ideal. We assume this applies to lines and station equipment. Bresesti et al. (2009) assume that the yearly maintenance costs for substations are 0.4% of investment costs.
Discount rate (%/year)	3%	7%	10%	The OMB (2003) recommends a range of 3–7% (see Table A.3a). As discussed in notes to Table A.1, the EIA's NEMS estimates a weighted-average cost of capital power-plant construction of about 10% (EIA, 2009c).
<b>Capital cost of line, land, and tower (\$/MW<sub>TS</sub>)</b>	<b>240,000</b>	<b>448,000</b>	<b>680,000</b>	
<b>Capital cost of station equipment (\$/MW<sub>TS</sub>)</b>	<b>118,000</b>	<b>148,000</b>	<b>177,000</b>	
<b>Capital cost of transmission system (\$/MW<sub>TS</sub>-km)</b>	<b>299</b>	<b>372</b>	<b>429</b>	<b>This quantity is calculated for comparison with estimates of total transmission-system capital cost in other studies</b>
<b>Total cost of extra transmission (\$/kWh)</b>	<b>0.003</b>	<b>0.012</b>	<b>0.032</b>	

for 800 kV HVDC and \$2.4 million/km for 400 kV HVDC, including converter terminals and communications (2004 USD). If the line cost is 74% of this, it is \$2.8 and \$1.7 million/km, roughly twice the figures estimated by Bahrman (Table A.2b).

Bresesti et al. (2007) estimate that converters cost 0.11 million Euros per MW, or about \$430 million for a 3000-MW system, which is similar to Bahrman's (2006) estimate (Table A.2b). (Bahrman's

estimates of station costs include transformer, filters, and other equipment as well as converters, but converters probably account for more than 90% of the total (de Alegria et al., 2009).) In summary, estimates of transmission-line costs for ~500 kV, ~3000 MW HVDC systems span a wide range, from about \$0.3 million/km to about \$2.0 million/km, and estimates of station-equipment costs for the same size system range from about \$200 million to about \$500 million.

**Table A.2b**  
Cost of HVDC transmission (based on Bahrman, 2006).

500 kV bipole	2–500 kV bipoles	600 kV bipole	800 kV bipole	Inputs (from Bahrman, 2006)
3000	4000	3000	3000	Rated power (MW)
\$0.99	\$0.99	\$1.12	\$1.21	Transmission line cost (million \$/km)
\$420	\$680	\$465	\$510	Total station cost (million \$)
1207	2414	1207	1207	Transmission distance (km)
193	134	148	103	Losses at full load (MW)
				Calculated results (our calculations)
\$331	\$249	\$373	\$404	Transmission line cost (\$/MW-km)
\$140,000	\$170,000	\$155,000	\$170,000	Station equipment cost (\$/MW)
\$1200	\$2400	\$1350	\$1463	Transmission line cost (million \$)
\$1620	\$3080	\$1815	\$1973	Total cost including station equipment (million \$)
\$447	\$319	\$501	\$545	Total cost including station equipment(\$/MW-km)
74%	78%	74%	74%	Transmission line cost as a percentage of total <sup>a</sup>
5.3%	1.4%	4.1%	2.8%	Losses (% of power per 1000 km/at rated capacity)

<sup>a</sup> The percentage is slightly higher for AC lines. Bahrman's (206) estimates indicate 82% for 500 kV AC and 87% for 765 kV AC. American Electric Power (2010) assumes 83% for 765 kV AC lines.

### A.2.b. Estimates of the total transmission-system cost

There are several comprehensive estimates of the total \$/MW-km cost of transmission systems (including station equipment as well as lines, towers, and land). We can compare these estimates with the total cost that results from our assumed line cost and our assumed station-equipment cost. As a starting point, we note that the total transmission-system costs that result from Bahrman's assumptions (2006) are \$320/MW<sub>TS</sub>-km to \$550/MW<sub>TS</sub>-km (Table A.2b).

Denholm and Sioshansi (2009) collected historical transmission cost data from the National Renewable Energy Laboratory, and plotted the cost per MW-km (in 2008 USD) versus the MW line capacity for about 40 AC and DC transmission-line projects. For all projects the costs ranged from \$200/MW-km to \$1400/MW-km, with most below \$1000/MW-km. Cost decreased with increasing line capacity, which is expected, because higher voltage (higher capacity) lines generally have a lower cost per unit of capacity. The six projects with a line capacity of 3 GW or greater (corresponding to 500 kV DC or 765 kV AC, according to Siemens, 2010) cost between \$200 and \$400/MW-km. It is not clear whether the MW-km unit in the denominator refers to MW of wind capacity or MW of line capacity, but assuming that the two are roughly equal (following Mills et al., 2009b assumption that "new transmission is sized to exactly the size required by the incremental generation added in a particular scenario" (p. 28)), these figures correspond to \$200 and \$400/MW<sub>TS</sub>-km.

The EIA's (2009f) documentation of the renewable fuels module of the National Energy Modeling System (NEMS) assumes "an increment to capital cost to account for the cost of maintaining and expanding the transmission network" (p. 49) to connect wind turbines to the grid: about \$130/kW<sub>WC</sub> in 7 "electric power" regions of the US, \$150/kW<sub>WC</sub> in 3 regions, and \$230–\$320/kW<sub>WC</sub> in 3 regions. (The subscript WC refers to wind-farm capacity.) The costly regions are all in the Western US: the Northwest Power Pool, the Rocky Mountain Area, and California and Nevada. If one assumes that these figures correspond to 500–1000-km transmission, and that in the EIA work the transmission-system capacity is equal to the wind-farm capacity, then the cost range is \$130/MW<sub>TS</sub>-km to \$640/MW<sub>TS</sub>-km.

The US DOE (2008) study of 20% wind power in the US in 2030 used the National Renewable Energy Laboratory's WinDS model to estimate the extent and cost of new transmission lines needed to support 233 GW of new wind power (another 60 GW of new wind power was assigned to existing transmission lines) (p. 161). For the WinDS analysis the US DOE assumed that new transmission line capacity cost \$1600/MW-mile in most areas of the US, and \$1920–\$2240/MW-mile (20–40% higher) in a few high-cost regions

(p. 147). (It appears that this cost estimate refers to MW of wind capacity, as opposed to MW of transmission-system capacity.) The US DOE (2008) also assumed that the "typical line is a 200-mile, 230-kV line rated at 170 MW A" (p. 188), or 170 MW (ignoring here the difference between real power and apparent power for AC transmission). This assumption – \$1000/MW<sub>WC</sub>-km for 170 MW<sub>TS</sub> transmission-system capacity – is roughly consistent with the trends in Denholm and Sioshansi (2009), which indicate \$300/MW-km for 3000 MW<sub>TS</sub>, about \$600/MW-km for 1500 MW<sub>TS</sub>, and about \$800/MW-km for 500 MW<sub>TS</sub>.

The GE Energy (2010) study of up to 35% wind and solar power in the western interconnection region of the US also assumed a total transmission-system cost of \$1600/MW-mile.

The US DOE's (2008) WindDS simulation estimated that 33 million MW<sub>WC</sub>-miles (p. 161) (53 million MW<sub>WC</sub>-km) of wind transmission on 12,650 miles of new transmission lines costing \$60 billion (p. 98) would be needed for the 233 GW of new wind power not using existing transmission lines. This amounts to \$258/kW<sub>WC</sub> and \$1132/MW<sub>WC</sub>-km. The result of \$1132/MW<sub>WC</sub>-km is consistent with their stated assumption of a cost of \$1000/MW<sub>WC</sub>-km in most regions and a cost 20–40% higher in a few regions (see the previous paragraph).

In a "derivative effort associated with the" US DOE (2008) study of 20% wind power in 2030, American Electric Power (AEP, 2010; Smith and Parsons, 2007) estimates that 19,000 miles (30,600 km) of 765 kV AC lines supporting 200–400 GW of new wind capacity in the US would cost \$60 billion (2007 USD), including station integration, DC connections, and other related costs. This amounts to \$150/kW<sub>WC</sub> to \$300/kW<sub>WC</sub>, which is consistent with estimates in Mills et al. (2009b) and the EIA (2009f). AEP (2010) assumed a total cost of \$3.1 million/mile (\$1.9 million/km) (including station cost, etc.) for 765 kV AC lines with a load of at 3600–7200 MW, which indicates a cost of \$260/MW<sub>TS</sub>-km (at 7200 MW capacity) to \$530/MW<sub>TS</sub>-km (at 3600 MW capacity). This is only slightly higher than the figures from Denholm and Sioshansi (2009), which indicate that three 3800–4000-MW-capacity AC lines have a cost of \$400/MW-km, and one has a cost of \$200/MW-km.

In the WinDS model, the "base case" assumption is that new transmission lines cost \$1000/MW-mile (National Renewable Energy Laboratory, 2010a), or about \$600/MW-km. It appears that the MW in the MW-km term in the denominator refers to the capacity of the transmission line itself.

Parsons et al. (2008) review wind integration studies in Europe, and find that the cost of "reinforcing" the grid to accommodate new wind power ranged from 35–160€/kW (in 2008 Euros), or about \$50–\$250/kW. (Presumably, the kW in the denominator refer to kW of wind.) If transmission distances in Europe are half of those in

the US – say, 250–500 km – then these figures correspond to \$100/MW<sub>WC</sub>-km to \$1000/MW<sub>WC</sub>-km.

Mills et al. (2009b) provide the most comprehensive analysis of the cost of transmission for wind power. Mills et al. (2009b) reviewed 40 detailed transmission studies, and divided the total transmission cost estimated in the study by the total amount of incremental generation capacity served by the transmission. The estimated cost ranges from 0 to \$1500/MW, but most of the studies have a cost below \$500/kW, and the median cost is \$300/kW. They also found that “the studies with the largest additions of wind energy tend to have relatively low unit costs of transmission, indicating that the economies of scale effect may contribute to lower costs among our study sample” (Mills et al., 2009b, p. ix). (The economies-of-scale effect is the decrease in unit cost as the transmission voltage increases.)

Table 2 of Mills et al. (2009b) shows the length of new transmission in each study, along with the total cost of the transmission, the voltage, and the total incremental GW added. Dividing the total cost by the total incremental generation and the length of new transmission yields a range of \$8–\$1800/MW-km. However, as noted above, it is likely that in most cases the actual average transmission length per MW is less than the total length of new transmission, in which case the calculated \$/MW-km figure is less than what would be calculated on the basis of the average transmission length.

These studies indicate that HVDC transmission at 500 kV and at least 3500 MW<sub>TS</sub> or more costs in the range of \$200/MW-km to \$500/MW-km. Note that this includes the cost of station equipment.

#### A.2.c. Discussion of results

The results of our analysis are shown in Table A.2a. For comparison, the EIA (2009a), Table A8) estimates \$0.009/kWh average

transmission cost for all generation in the US. NREL's WinDS model interactive database estimates that the full levelized cost of new transmission segments dedicated to connecting wind sites to the existing grid (at the point where the grid has adequate capacity) ranges from \$0.001/kWh to about \$0.03/kWh, depending mainly on the wind-output capacity factor and the distance from the wind farm to the grid (National Renewable Energy Laboratory, 2010b). The rough average appears to be on the order of \$0.01/kWh. The levelized costs in WinDS are calculated from a detailed GIS database, as follows (National Renewable Energy Laboratory, 2010a).

“The GIS analysis begins with more than 400,000 wind resource sites and more than 15,000 transmission lines of 69 kV or larger. The size and length of the existing transmission lines are used to estimate their full capacity in MW considering thermal and stability limits. The GIS optimization then minimizes the total cost (including both generation and the construction of transmission line segments connecting the wind site to the grid) of filling the remaining capacity (after conventional generation use of the lines is considered) of the existing lines with wind generation.

The results of the GIS-based optimization are used to construct the supply curves shown in our interactive database. In these curves, the cost is only the levelized cost of building the transmission segment from the wind site to the grid (i.e., the cost of generation has been subtracted from the total levelized cost used in the optimization)”.

Our results in Table A.2a are consistent with the WinDS results. Finally, note that when we add our estimate of transmission cost to our estimate of wind-farm-installation cost, we have a complete estimate of the cost of electricity into the distribution system, with no double counting or omission. As mentioned in Appendix A.1,

**Table A.3a**  
Calculation of the \$/kWh Cost of V2G cycling of EV Batteries (Year 2007 US\$).

BEV	PHEV	Parameter	Basis
<b>Part 1: inputs</b>			
30	10	Discharge capacity of the battery to 100% DoD (kWh discharged)	Lund and Kempton (2008) assume a 30-kWh battery in their analysis of V2G for Denmark. 10 kWh is a typical size for a PHEV battery
200/300	300/400	Low/high estimate of OEM cost of replacement battery (\$/kWh)	Estimates in and discussion of Table A.3b
5.0	4.5	Efficiency of vehicle on battery (mi/kWh-battery-discharge)	Based on AVCEM, Kromer and Heywood (2007), for a mid-size BEV
10,000	5000	Annual distance on battery (miles/year)	Our assumptions
	1.6/2.1	Low-cost/high-cost ratio of retail cost to manufacturing cost	Low is based on ratio of retail to OEM cost in Santini (2010); high is from AVCEM
	5500/3500	Low-cost/high-cost cycle life (to 80% DoD)	Table A.3b
	15/30	Low-cost/high-cost calendar life (years)	Table A.3b
	80%	DoD in battery cycle life tests (%)	Standard DoD for measuring cycle life
	250	Service cost of installing new battery and removing old battery and deploying it in non-automotive applications (\$)	We assume 5 h total labor at \$50/h
	20%/10%	Low-cost/high-cost estimate of value of old battery in NAAs after end of useful life as a motor-vehicle battery (% of total retail cost)	There are several potential NAAs for old Li-ion batteries (Burke, 2009), but it is not clear how long they will last in secondary uses
	50	Hedonic cost of battery replacement (\$)	Our assumption
	0.2/0.8	V2G cycling by utility: average fraction of a standard cycle to 80% DoD, per day*	Our assumption
	7.0/3.0	Low-cost/high-cost discount rate with respect to battery costs and V2G electronics and infrastructure (%/year)	Range recommended by OMB (2003). The high end is the opportunity cost of capital in the US private sector; the low end is an estimate of the “social” discount rate
	90.0%, 94.4%, 96.0%, 99.5%	Charger efficiency, battery charge/discharge efficiency, inverter (battery-to-grid) efficiency, electricity distribution efficiency	Values from AVCEM except distribution efficiency, which is our assumption
	0.04/0.11	Low/high estimate of cost of electricity delivered to residential sector to make up for electricity lost by V2G cycling (\$/kWh)	Low assumes only some generation costs are affected; high assumes the long-run marginal cost of electricity to residential sector (EIA, 2010a))
	150	Cost of extra electronics and infrastructure to manage V2G system, per vehicle (\$).	Our assumption, based on the discussion in Kempton and Tomic (2005b)
	20	Life of V2G electronics, infrastructure (years)	Our assumption

\*In the PHEV case, high-cost case also is 80%. AVCEM = Advanced Vehicle Cost and Energy-Use Model (Delucchi, 2005). OMB = Office of Management and Budget; NAA = non-automotive application. DoD = depth of discharge.

Wiser and Bolinger (2008) report that estimates of wind-farm-installation cost typically include expenses for interconnections and collecting substations at the wind farm. According to Mills et al. (2009b), estimates of transmission-system costs generally include, or are assumed to include, the cost of power conditioners, DC inverters, and substations along or at the end of the transmission line, as well as the cost of the transmission line itself. Thus, our estimates combined account for all major equipment costs up to the point where the high-voltage transmission system ties into the distribution network.

#### A.2.d. Note on cost of undersea transmission

Some plans for “supergrids,” particularly in Europe, involve high-voltage transmission undersea (Jah, 2010). To make a rough estimate of the cost of undersea transmission, we assume that only the transmission line cost (\$/MW<sub>TS</sub>-km) and the transmission distance (km) are different for undersea transmission compared with land-based transmission, and that all of the other parameters in the analysis of Table A.2a are the same as for land-based transmission. Hauth et al. (1997) estimate that a 500-MW, 400-kV HVDC submarine cable costs \$0.63 million/km, including installation, or \$1260/MW-km, and that a 408 kV dc cable on land costs \$0.538 million/mi, or \$334/MW-km assuming 1000 MW. Thus, in Hauth et al., undersea cables cost about 4 times as much as land cables. Consistent with this, Weigt et al. (2010) report that land transmission lines typically cost 250–450 million Euros per 1000 km – but they assume 600 million because of “NIMBY problems – and state that sea cables cost “up to” 2500 million Euros per 1000 km. If the lower end of the cost range of sea cables is half of this, then sea cables can cost 2 times to 10 times as much as land lines.

With these considerations, we assume that sea cables cost 2 times (low-cost case), 4 times (mid-cost case), or 6 times (high-cost case) as much per MW-km as land lines. Based on Weigt et al (2010), we assume that undersea transmission distances are half those of land-transmission. The calculated undersea transmission-system costs are \$0.003/kWh (low-cost case), \$0.021/kWh (mid-cost case), and \$0.082/kWh (high-cost case). If up to 25% of long-distance transmission in a supergrid is undersea, the mid-range total extra transmission cost in a

supergrid increases from 1.2 to 1.4 cents/kWh. This does not materially affect our conclusions.

Note that the cost of connecting offshore wind farms to onshore substations is included in estimates of the capital cost of offshore wind projects (Musial and Ram, 2010).

### Appendix A.3. The cost of using electric-vehicle batteries for distributed electricity storage (“vehicle-to-grid”)

In this appendix, we present a simple but robust calculation of the cost of allowing an electric utility to use the consumer’s electric-vehicle (EV) battery as a form of distributed electricity storage. With this system, known as “vehicle-to-grid,” or V2G, the utility charges EV batteries with low-cost WWS power generation in excess of end-use demand, and then withdraws the power from the batteries when WWS generation is less than end-use demand.

We estimate the cost of this V2G system as the difference between the total annualized-cost stream in a world in which there is V2G and the total annualized-cost stream in a world in which there is not V2G, with all else the same. We will divide this difference in annualized cost by the amount of electricity sent to the battery charger for V2G cycling rather than to actual end use, to produce an estimate of dollars of cost difference due to V2G cycling per kWh of electricity diverted to V2G.

With this method, we must identify the cost streams that are different in a V2G world compared with a no-V2G world, and choose the discount rate appropriate for annualizing costs in this context.

In general, four cost streams will be different in a V2G world compared with a no-V2G world. First, the extra V2G charge-discharge cycling of the vehicle battery may hasten the depletion of the discharge capacity of the battery and shorten the period between battery replacements, which will increase the frequency of expenditures on new batteries and on disposal or redeployment of old batteries. Second, if batteries that have lost too much discharge capacity for vehicle use can be deployed in non-automotive applications (NAAs) at lower cost than can other alternatives, then these batteries still will have value at the end of their automotive life, and the change in the frequency of vehicle battery replacement due to V2G cycling will change the frequency of

**Table A.3a**

Calculation of the \$/kWh Cost of V2G cycling of EV batteries.

BEV				PHEV				
No V2G		V2G		No V2G		V2G		
Low	High	Low	High	Low	High	Low	High	
<b>Part 2: calculated values</b>								
9600	18,900	9600	18,900	4,800	8400	4800	8400	Cost of replacement battery (\$)
15.0	30.0	15.0	9.3	15.0	25.2	15.0	8.1	Lifetime of battery in vehicle use (based on calendar life or cycling to 80% DoD) (years)
7980	17,310	7980	17,310	4140	7860	4140	7860	Cost of battery replacement, including new battery cost with installation, removal of old battery, net of value of old battery in NAAs
176%	143%	176%	32%	56%	111%	56%	27%	Discount rate for the period of time equal to the battery life (%/period)
0	0	2062	8249	0	0	687	2750	Electricity diverted to V2G cycling, measured at input to battery charger, per year (based on cycling normalized to 80% DoD) (kWh-sent-to-battery-charger/year)
n.a.	n.a.	0.000	0.154	n.a.	n.a.	0.000	0.238	Components of the cost of V2G cycling, per kWh diverted to V2G cycling (\$/kWh-sent-to-battery-charger)
n.a.	n.a.	0.007	0.001	n.a.	n.a.	0.015	0.004	Annualized cost of present value of change in battery-replacement and disposal frequency, due to V2G cycling*
n.a.	n.a.	0.008	0.021	n.a.	n.a.	0.008	0.021	Annualized cost of extra electronic and infrastructure
n.a.	n.a.	<b>0.014</b>	<b>0.176</b>	n.a.	n.a.	<b>0.022</b>	<b>0.263</b>	Cost of replacing electricity lost in charge/discharge cycling
								Total cost per kWh diverted to V2G cycling

V2G=vehicle-to-grid, OEM=original equipment manufacturer, DoD=depth of discharge, n.a.=not applicable.

\*See the discussion in Appendix A.3.



redeployment of vehicle batteries in NAAs and hence change the associated stream of benefits.

Third, a V2G world may have more electronics and infrastructure for managing V2G operations than is needed just for charging batteries in a no-V2G world. Finally, a small amount of electrical energy is lost during V2G charge-discharge cycling, which means that if final demand is the same in a V2G world as in a no-V2G world, then in the V2G world a bit more electricity must be generated to make up for the V2G losses and meet the same demand.

We estimate all four costs. We combine the first (battery replacement cost) and the second (benefit of redeployment in NAAs) because the benefit of redeploying the battery in NAAs occurs at about the same time as does the cost of buying a new battery, and so can be treated as a negative cost that reduces the *net* cost of battery replacement.

We adopt the perspective of a utility or similar entity that is responsible for installing and maintaining the V2G electronics and infrastructure, for redeploying to NAAs batteries that are too depleted for further automotive use, and for transferring to other vehicles batteries that have adequate capacity at the end of life of the original vehicle. We assume that at the end of the life of the vehicle, the battery will be removed and used either in another vehicle or in NAAs, in the V2G scenario and the no-V2G scenario, and that the cost of this will be the same in both scenarios and hence can be ignored in our analysis (which is concerned only with cost differences between the scenarios).

Table A.3a shows all of the parameters we specify to estimate the four cost streams, the bases of our assumptions regarding parameter values, and the calculated results. Because the results depend on the size of the battery, we present two cases: one for a relatively small battery, as might be used in a plug-in hybrid EV (PHEV), and one for a relatively large battery for an all-electric battery EV. For each case, we show low-cost and high-cost assumptions for battery costs, battery calendar life, battery cycle life, battery value in NAAs, V2G cycling, the discount rate, and electricity cost, where “low cost” and “high cost” refer to the effect of the parameter on the final \$/kWh figure, not to the numerical value of the parameter itself. We assume lithium-ion (Li-ion) battery technology.

The annualized cost of the present value of the change in battery-replacement and disposal frequency is calculated by first taking the present value of the series of battery replacement costs, and then annualizing this present value. This two-step procedure is necessary whenever the period of battery replacement is different from the annualization period (which is one year). Fortunately, the formulae involved reduce conveniently to a simple expression. First, the annualized cost of battery replacement  $ANN_{BR}$  is calculated over some number of years  $n$  at an annual discount rate  $r_A$ , given a calculated present value of the battery-replacement-cost stream  $PV_{BR}$ :

$$ANN_{BR} = PV_{BR} r_A (1 - (1 + r_A)^{-n})^{-1}$$

The present value of the battery-replacement-cost stream  $PV_{BR}$  is calculated on the basis of the periodic battery-replacement cost

**Table A.3b**  
Manufacturing cost and life of lithium batteries.

Part 1: estimates from Burke and Miller (2009)	kWh		OEM cost (\$/kWh) <sup>a</sup>		Cycle life (deep) <sup>b</sup>	
Graphite/LiNiCoAlO <sub>2</sub> (NCA)	10.1		279		2000–3000	
	20.2		205		2000–3000	
Graphite/LiFePO <sub>4</sub> (LFP)	9.4		302		> 3000	
	18.7		222		> 3000	
Lithium titanate/LiMnO <sub>2</sub> (LMO)	7.2		403		> 5000	
	14.4		310		> 5000	
Part 2: estimates from Kalhammer et al. (2007)						
Battery type	Li-ion	Li-ion	Li-ion	Li-ion	NiMH	NiMH
Positive electrode	NCA	NCM	NCA	NCM		
Application	EV	EV	HEV	HEV	EV	HEV
Cycle life (DoD)	> 3200 (80%)	~3000	> 400,000 (shallow)	~3000 (80%)	> 2000 (80%)	> 150,000 (shallow)
Calendar life (years) <sup>f</sup>	> 12	> 10	> 20	> 10	> 8	> 8
OEM cost (\$/kWh) <sup>d</sup>	210–330	210–330	350–860	350–860	290–420	470–960

OEM=original equipment manufacturer, NCA=LiNiCoAl, NCM=LiNiCoMn, EV application is high energy, medium power, HEV application is high power, medium energy.

<sup>a</sup> The cost estimates by Burke and Miller (2009) are based on detailed cost modeling performed by Argonne National Laboratory (ANL). Nelson et al. (2009) provide details on the ANL modeling, and report their own estimates of the manufacturing cost at high volumes of production:

	NCA	LFP	LMO
4.3 kWh	393	422	428
17.1 kWh	202	231	281

As one would hope, these are similar to the ANL-model estimates reported by Burke and Miller (2009). Barnett et al. (2009) also perform detailed modeling of the manufacturing cost of small (~6 kWh) Li-ion batteries for PHEVs, in high volume, using current technology, and estimate that costs range from \$264/kWh to \$710/kWh, with a base-case point estimate of \$360/kWh. Amjad et al. (2010) cite a recent study that shows battery cost versus production volume; that study indicates that at high volumes, Li-ion and NiMH batteries cost about \$300/kWh. Andersson et al. (2010) cite three studies in support of an assumption that Li-ion batteries cost \$200–\$500/kWh in mass production. All of these estimates are similar.

<sup>b</sup> By comparison, in the Peterson et al. (2010b) tests described above the cycle life of lithium iron phosphate at 80% DoD exceeded 5000. Amjad et al. (2010) also cite a 2003 study that shows that a Li-ion battery has a cycle life of ~2500 at 80% DoD, and that a nickel metal-hydride (NiMH) battery has a cycle life of ~3500 at 80% DoD, but these data are much older than the Burke and Miller (2009) and Peterson et al. (2010b) data. Zhang and Wang (2009) report that an automotive Li-ion battery with a LiNiO<sub>2</sub> cathode achieved 5250 deep cycles with a loss of 18% capacity.

<sup>c</sup> Kalhammer et al. (2007) conclude that Li-ion batteries should have a calendar life of at least 15 years. Sun et al. (2009) report on the development of a high-energy cathode material that “should eventually lead to advanced lithium-ion batteries that meet the PHEV requirements” (p. 323) including a 15-year calendar life. Kromer and Heywood (2007) show a graph, adapted from another study, that indicates that a LiFePO<sub>4</sub> cell loses only 5–15% of its capacity (depending on temperature) after 15 years of open-circuit-voltage storage at 50% state of charge.

<sup>d</sup> Estimate of manufacturing cost at 100,000 batteries per year or 2500 MWh/year. Cost range depends mainly on energy storage capacity of battery; the bigger the battery, the lower the \$/kWh cost.

$PMT_{BR}$ , the discount rate  $r_{BR}$  corresponding to the period  $P_{BR}$  between battery replacements, and the total number of battery replacements over the time  $n$ , which is  $n/P_{BR}$ :

$$PV_{BR} = PMT_{BR}(1 - (1 + r_{BR})^{-(n/P_{BR})})r_{BR}^{-1}$$

The discount rate  $r_{BR}$  corresponding to the period  $P_{BR}$  between battery replacements is

$$r_{BR} = (1 + r_A)^{P_{BR}} - 1$$

Substituting this expression for  $r_{BR}$  into one of the  $r_{BR}$  terms in the expression for  $PV_{BR}$  yields

$$PV_{BR} = PMT_{BR}(1 - (1 + (1 + r_A)^{P_{BR}} - 1)^{-(n/P_{BR})})r_{BR}^{-1} = PMT_{BR}(1 - (1 + r_A)^{-P})r_{BR}^{-1}$$

Finally, substituting this new expression for  $PV_{BR}$  into the annualization expression:

$$ANN_{BR} = PMT_{BR}(1 - (1 + r_A)^{-P})r_{BR}^{-1}r_A(1 - (1 + r_A)^{-P})^{-1} = PMT_{BR}r_Ar_{BR}^{-1}$$

Thus, the annualized cost is just the periodic replacement cost multiplied by the ratio of the annual discount rate to the battery-replacement-period discount rate.

The results of our analysis, shown in Table A.3a, Part 2, show that the annualized cost of V2G cycling of EV batteries can span a fairly wide range, from \$0.01/kWh to over \$0.26/kWh. As one would expect, this uncertainty is due almost entirely to uncertainty regarding the annualized cost of the present value of the change in battery replacement, which can range from zero to \$0.24/kWh. By contrast, the annualized cost of the V2G electronics and infrastructure and the cost of replacing electricity lost in charge/discharge cycling is only \$0.01/kWh to \$0.02/kWh.

The most important and uncertain determinant of the annualized battery-replacement cost is the interaction between the calendar life of the battery and the cycle (or use) life of the battery as a result of driving and V2G cycling. Generally, a battery is considered to be unsuitable for further vehicle use when it has irreversibly lost 20% of its energy-discharge capacity. A battery can lose capacity because of self-discharge – a function of temperature, state-of-charge, and time (Yazami and Reynier, 2002) – or because of degradation of the cell (in the form of a loss of active lithium, with Li-ion batteries) due to cycling (Liu et al., 2010). The time to irreversible loss of 20% capacity due to self-discharge is the “calendar life,” and the number of charge/discharge cycles to irreversible loss of 20% capacity is the “cycle life.” As discussed in the notes to Table A.3b, Li-ion batteries have a cycle life of 3500 to more than 5000 (at 80% DoD), and a calendar life of at least 15 years, which is a typical vehicle lifetime (Davis et al., 2009). It is possible – and this is the key point – that a Li-ion battery will reach the end of its calendar life, due to self-discharge, before it has been charged and discharged (cycled) the maximum number of times. If this is the case, then more frequent charging and discharging of the battery prior to the end of the calendar life will *not* cause the battery to reach the end of its life sooner, so long as the total number of cycles still remains under the maximum. If the battery does not reach the end of its life sooner, it does not need to be replaced sooner, which means that, in this scenario, there is no “cost” to cycling the battery more. And this is precisely the situation in the low-cost case analyzed here: in the V2G scenario as well as the no-V2G scenario, the battery reaches the end of its life due to irreversible self-discharge, not due to cycling. When the calendar life rather than the cycle life is binding, V2G cycling does not change the frequency of battery replacement and hence has zero battery-replacement cost.

In the high-cost case, the calendar life is no longer binding, so V2G cycling does increase the frequency of battery replacement. The frequency of replacement and hence the associated replacement cost is sensitive to assumptions regarding the impact of V2G cycling on battery life. In Table A.3a, we implicitly assume that V2G

cycling (to a given DoD) causes the same degradation of battery capacity as does charge/discharge cycling during driving (to the same DoD). However, in reality the cycle life depends on the voltage and current of the charge/discharge cycle, and these will be different in V2G cycling than in charging and discharging during driving. Hence, it is likely that in reality, V2G cycling to a given DoD will *not* cause the same degradation of battery capacity as will charge/discharge cycling during driving. We therefore present here an alternative, more realistic calculation of the battery-replacement cost of V2G when V2G and driving have different effects on degradation of battery capacity.

Peterson et al. (2010b) investigated this issue in detail, cycling the A123 systems ANR26650M1 LiFePO<sub>4</sub> cells used in the PHEV Hymotion battery pack. They found that the charge-discharge patterns of typical driving deteriorated the battery more than did V2G cycling. They developed alternative measures of this deterioration: 0.0060% of capacity lost per normalized watt-hour used for driving, and 0.0027% of capacity lost per normalized watt-hour used for V2G. (A normalized watt-hour is equal to the actual watt-hours withdrawn divided by the watt-hour capacity of the battery at 100% DoD.) We use these alternative measures (in place of the assumptions about battery cycle life in Table A.3a, but with all else the same), along with the standard assumption that the battery has reached the end of its life when it has lost 20% of its capacity, to perform an alternative calculation of the cost of V2G cycling.

In this alternative, more realistic analysis, the high-end battery-replacement cost of V2G cycling is \$0.037/kWh for the battery-EV (versus \$0.154/kWh in the Table A.3a), and \$0.088/kWh for the PHEV case (versus \$0.238/kWh in Table A.3a). (The low-end costs are the same as in Table A.3a – zero – because in the low-cost case the calendar life is binding, and the costs of electronics and infrastructure and lost electricity are the same as in Table A.3a.) Because in this alternative analysis the capacity degradation due to V2G cycling is much less than that due to driving, the battery is replaced less frequently than in Table A.3a, and as a result the cost of V2G cycling is much less than in Table A.3a.

## References

- Åhman, M., 2006. Government policy and the development of electric vehicles in Japan. *Energy Policy* 34, 433–443.
- Aguado, M., Ayerbe, E., Azcárate, C., Blanco, R., Garde, R., Mallor, F., Rivas, D.M., 2009. Economical assessment of a wind-hydrogen energy system using WindHyGen Software. *International Journal of Hydrogen Energy* 34, 2845–2854.
- Allan, G., Gilmartin, M., McGregor, P., Swales, K., 2011. Levelised costs of wave and tidal energy in the UK: cost competitiveness and the importance of ‘banded’ Renewables Obligation Certificates. *Energy Policy* 39, 23–39.
- de Alegria, I.M., Martín, J.L., Kortabarria, I., Andreu, J., Ereño, P.I., 2009. Transmission alternatives for offshore electrical power. *Renewable and Sustainable Energy Reviews* 13, 1027–1038.
- Amjad, S., Neelakrishnan, S., Rudramoorthy, R., 2010. Review of design considerations and technological challenges for successful development and deployment of plug-in hybrid electric vehicles. *Renewable and Sustainable Energy Reviews* 14, 1104–1110.
- Andersson, S.-L., Elofsson, A.K., Galus, M.D., Göransson, L., Karlsson, S., Johnsson, F., Andersson, G., 2010. Plug-in hybrid electric vehicles as regulating power providers: case studies of Sweden and Germany. *Energy Policy* 38, 2751–2762.
- American Electric Power, 2010. Interstate Transmission Vision for Wind Integration. Available from: <www.aep.com/about/1765project/docs/WindTransmissionVisionWhitePaper.pdf> (accessed July 24).
- Archer, C.L., Jacobson, M.Z., 2003. Spatial and temporal distributions of US winds and wind power at 80 m derived from measurements. *Journal of Geophysical Research* 108 (D9), 4289.
- Archer, C.L., Jacobson, M.Z., 2005. Evaluation of global windpower. *Journal of Geophysical Research* 110, D12110. doi:10.1029/2004JD005462.
- Archer, C.L., Jacobson, M.Z., 2007. Supplying baseload power and reducing transmission requirements by interconnecting wind farms. *Journal of Applied Meteorology and Climatology* 46, 1701–1717.
- Bahrman, M., 2006. HVDC Transmission, IEEE PSCE, Atlanta, November. Available from: <http://www.ieee.org/portal/cms\_docs\_pes/pes/subpages/meetings-folder/PSCE/PSCE06/panel2/Panel-02-1\_Overview\_of\_HVDC\_Transmission.pdf>.
- Banke, B., 2010. Solar electric facility O&M now comes the hart part, Part 3. *Renewable Energy World North America Magazine* 2 (1) January/February.

- Barnett, B., et al., 2009. PHEV Battery Cost Assessment, 2009 DOE Merit Review, TIAX LLC, May 19. Available from: [http://www1.eere.energy.gov/vehiclesandfuels/pdfs/merit\\_review\\_2009/energy\\_storage/es\\_02\\_barnett.pdf](http://www1.eere.energy.gov/vehiclesandfuels/pdfs/merit_review_2009/energy_storage/es_02_barnett.pdf).
- Bedard, R., et al., 2005. Offshore Wave Power Feasibility Demonstration Project, Project Definition Study, Final Summary Report, E21 EPRI Global WP 0009—US Rev 2, Electric Power Research Institute, September 22. Available from: [http://oceanenergy.epri.com/attachments/wave/reports/009\\_Final\\_Report\\_R\\_B\\_Rev\\_2\\_092205.pdf](http://oceanenergy.epri.com/attachments/wave/reports/009_Final_Report_R_B_Rev_2_092205.pdf).
- Benitez, L.E., Benitez, P.C., van Kooten, G.C., 2008. The economics of wind power with energy storage. *Energy Economics* 30, 1973–1989.
- Berry, D., 2009. Innovation and the price of wind energy in the US. *Energy Policy* 37, 4493–4499.
- Beyond Zero Emissions, 2010. Zero Carbon Australia Stationary Energy Plan. Melbourne Energy Institute, University of Melbourne, July. Available from: <http://beyondzeroemissions.org/>.
- Boccard, N., 2010. Economic properties of wind power: a European assessment. *Energy Policy* 38, 3232–3244.
- Boccard, N., 2009. Capacity factor of wind power, realized values vs. estimates. *Energy Policy* 37, 2679–2688.
- Bresesti, P., Kling, W.L., Hendriks, R.L., Vailati, R., 2007. HVDC connection of offshore wind farms to the transmission system. *IEEE Transactions of Energy Conversion* 22 (1), 37–43.
- Bürer, M.J., Wüstenhagen, R., 2009. Which renewable energy policy is a venture capitalist's best friend? Empirical evidence from a survey of international cleantech investors. *Energy Policy* 37, 4997–5006.
- Burke, A., 2009. Performance, charging, and second-use considerations for lithium batteries for plug-in electric vehicles, Research Report UCD-ITS-RR-09-17. Institute of Transportation Studies, University of California, Davis, May. Available from: [http://pubs.its.ucdavis.edu/publication\\_detail.php?id=1306](http://pubs.its.ucdavis.edu/publication_detail.php?id=1306).
- Burke, A., Miller, M., 2009. The UC Davis Emerging Lithium Battery Test Project, Research Report UCD-ITS-RR-09-18, Institute of Transportation Studies, University of California, Davis. Available from: [http://pubs.its.ucdavis.edu/publication\\_detail.php?id=1307](http://pubs.its.ucdavis.edu/publication_detail.php?id=1307).
- California Wind Energy Collaborative (CWEC), 2003. California RPS integration cost analysis—Phase 1: one year analysis of existing resources, California Energy Commission 500-03-108C, December.
- Cavallo, A., 2007. Controllable and affordable utility-scale electricity from intermittent wind resources and compressed air energy storage (CAES). *Energy* 32, 120–127.
- Chan, J., 2010. Electric Power Research Institute, Transmission and Substation Group, personal communication via e-mail, July 27.
- Chernyav'ska, L., Gullí, F., in press. Measuring the environmental benefits of hydrogen transportation fuel cycles under uncertainty about external costs. *Energy Policy*. doi:10.1016/j.enpol.2009.03.036.
- Clarke, R.E., Giddey, S., Ciacchi, F.T., Badwal, S.P.S., Paul, B., Andrews, J., 2009. Direct coupling of an electrolyser to a solar PV system for generating hydrogen. *International Journal of Hydrogen Energy* 34, 2531–2542.
- Cockroft, C.J., Owen, A.D., 2007. The economics of hydrogen fuel cell buses. *Economic Record* 83, 359–370.
- Cohen, J., Schweizer, T., Laxson, A., Butterfield, S., Schrek, S., Fingersh, L., Veers, P., Ashwill, T., 2008. Technology improvement opportunities for low wind speed turbines and implications for cost of energy reduction, NREL/TP-500-41036, National Renewable Energy Laboratory, Golden, Colorado, February. Available from: <http://www1.eere.energy.gov/windandhydro/pdfs/41036.pdf>.
- Couture, T., Cory, K., 2009. State Clean Energy Policies Analysis (SCEPA) Project: an analysis of renewable energy feed-in tariffs in the United States. Technical Report NREL/TP-6A2-45551, National Renewable Energy Laboratory, Golden, Colorado, June. Available from: [www.nrel.gov/docs/fy09osti/45551.pdf](http://www.nrel.gov/docs/fy09osti/45551.pdf).
- Czisch, G., 2006. Low cost but totally renewable electricity supply for a huge supply area – a European/trans-European example. Unpublished manuscript. Available from: [www.iset.uni-kassel.de/abt/w3-w/projekte/LowCostEuropEISup\\_revised\\_for\\_AKE\\_2006.pdf](http://www.iset.uni-kassel.de/abt/w3-w/projekte/LowCostEuropEISup_revised_for_AKE_2006.pdf).
- Czisch, G., Giebel, G., 2007. Realisable scenarios for a future electricity supply based on 100% renewable energies. Unpublished manuscript. Available from: [www.risoe.dk/rispubl/reports/ris-r-1608\\_186-195.pdf](http://www.risoe.dk/rispubl/reports/ris-r-1608_186-195.pdf).
- Davis, S.C., Diegel, S.W., Boundy, R.G., 2009. Transportation Energy Data Book: Edition 28, ORNI-6984, Oak Ridge National Laboratory, Oak Ridge, Tennessee. Available from: [www.cta.ornl.gov/data](http://www.cta.ornl.gov/data).
- De Carolis, J.F., Keith, D.W., 2006. The economics of large-scale wind power in a carbon constrained world. *Energy Policy* 44, 395–410.
- De Carolis, J.F., Keith, D.W., 2005. The costs of wind's variability: is there a threshold? *Electricity Journal*, 69–77 January/February.
- DeCesaro, J., Porter, K., Milligan, M., 2009. Wind Energy and power system operations: a review of wind integration studies to date. *Electricity Journal* 22 (1), 34–43.
- Delucchi, M.A., 2005. Overview of AVCEM, UCD-ITS-RR-05-17 (1), Institute of Transportation Studies, University of California, Davis October. Available from: [www.its.ucdavis.edu/people/faculty/delucchi/](http://www.its.ucdavis.edu/people/faculty/delucchi/).
- Delucchi, M.A., Lipman, T.E., 2010. Lifetime cost of battery, fuel-cell, and plug-in hybrid electric vehicles. In: Pistoia, G. (Ed.), *Electric and Hybrid Vehicles: Power Sources, Models, Sustainability, Infrastructure and the Market*. Elsevier B. V., Amsterdam, The Netherlands, pp. 19–60.
- Delucchi, M.A., Lipman, T.E., 2001. An analysis of the retail and lifecycle cost of battery-powered electric vehicles. *Transportation Research D6*, 371–404.
- Denholm, P., Ela, E., Kirby, B., Milligan, M., 2010. The Role of energy storage with renewable electricity generation, NREL/TP-6A2-47187. National Renewable Energy Laboratory, Golden, Colorado January. Available from: [www.nrel.gov/docs/fy10osti/47187.pdf](http://www.nrel.gov/docs/fy10osti/47187.pdf).
- Denholm, P., Sioshansi, R., 2009. The value of compressed air energy storage with wind in transmission-constrained electric power systems. *Energy Policy* 37, 3149–3158.
- Denny, E., 2009. The economics of tidal energy. *Energy Policy* 37, 1914–1924.
- Dong Energy, Vattenfall, Danish Energy Authority, and Danish Forest and Nature Agency, 2006. Danish Offshore Wind, Key Environmental Issues, November. Available from: [www.ens.dk/graphics/Publikationer/Havvindmoeller/havvindmoellebog\\_nov\\_2006\\_skrm.pdf](http://www.ens.dk/graphics/Publikationer/Havvindmoeller/havvindmoellebog_nov_2006_skrm.pdf).
- Dusonchet, L., Telaretti, E., 2010. Economic analysis of different supporting policies for the production of electrical energy by solar photovoltaics in western European Union countries. *Energy Policy* 38, 3297–3308.
- Ekren, O., Ekren, B.Y., 2010. Size optimization of a PV/wind hybrid energy conversion system with battery storage using simulated annealing. *Applied Energy* 87, 592–598.
- Electric Power Research Institute (EPRI), 2010. Overhead Transmission—Program 35. Available from: [http://mydocs.epri.com/docs/Portfolio/PDF/2010\\_P035.pdf](http://mydocs.epri.com/docs/Portfolio/PDF/2010_P035.pdf).
- Electric Power Research Institute, 1997. Cost of Providing Ancillary Services from Power Plants, Volume 1: A Primer, TR-107270-V1, Palo Alto, California, March 1997. Available from: <http://mydocs.epri.com/docs/public/TR-107270-V1.pdf>.
- Energy Information Administration (EIA), 2010a. Annual Energy Outlook 2010, DOE/EIA-0383(2010), US Department of Energy, Washington, DC.
- Energy Information Administration (EIA), 2010c. Assumptions to the Annual Energy Outlook 2010, DOE/EIA-0554 (2010), US Department of Energy, Washington, DC, April. Available from: [www.eia.doe.gov/oiia/aeo/assumption/index.html](http://www.eia.doe.gov/oiia/aeo/assumption/index.html).
- Energy Information Administration (EIA), 2009a. Annual Energy Outlook 2009, DOE/EIA-0383(2009), US Department of Energy, Washington, DC, March. Available from: [www.eia.doe.gov/oiia/aeo/index.html](http://www.eia.doe.gov/oiia/aeo/index.html).
- Energy Information Administration (EIA), 2009b. Assumptions to the Annual Energy Outlook 2009, DOE/EIA-0554 (2009), US Department of Energy, Washington, DC, March. Available from: [www.eia.doe.gov/oiia/aeo/assumption/index.html](http://www.eia.doe.gov/oiia/aeo/assumption/index.html).
- Energy Information Administration (EIA), 2009c. The Electricity Market Module of the National Energy Modeling System, Model Documentation Report, DOE/EIA-M068(2009), US Department of Energy, Washington, DC, May. Available from: [http://tonto.eia.doe.gov/FTP/ROOT/modeldoc/m068\(2009\).pdf](http://tonto.eia.doe.gov/FTP/ROOT/modeldoc/m068(2009).pdf).
- Energy Information Administration (EIA), 2009d. Electric Power Annual 2007, DOE/EIA-0348(2007), US Department of Energy, Washington, DC, January. Available from: [www.eia.doe.gov/cneaf/electricity/epa/epa\\_sum.html](http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html).
- Energy Information Administration (EIA), 2010d. Annual Energy Review 2009 DOE/EIA-0384(2009), US Department of Energy, Washington, DC, July. Available from: [www.eia.gov/emeu/aer/contents.html](http://www.eia.gov/emeu/aer/contents.html).
- Energy Information Administration (EIA), 2009e. Annual Energy Review 2008 DOE/EIA-0384(2008), US Department of Energy, Washington, DC, June. Available from: [www.eia.gov/FTP/ROOT/multifuel/038408.pdf](http://www.eia.gov/FTP/ROOT/multifuel/038408.pdf).
- Energy Information Administration (EIA), 2009f. Model Documentation, Renewable Fuels Module of the National Energy Modeling System, DOE/EIA-M069(2009), US Department of Energy, Washington, DC July. Available from: [http://tonto.eia.doe.gov/FTP/ROOT/modeldoc/m069\(2009\).pdf](http://tonto.eia.doe.gov/FTP/ROOT/modeldoc/m069(2009).pdf).
- Energy Information Administration (EIA), 2010b. The Electricity Market Module of the National Energy Modeling System, Model Documentation Report, DOE/EIA-M068 (2010), US Department of Energy, Washington, DC May. Available from: [http://tonto.eia.doe.gov/FTP/ROOT/modeldoc/m068\(2010\).pdf](http://tonto.eia.doe.gov/FTP/ROOT/modeldoc/m068(2010).pdf).
- EnerNex Corporation, 2010. Eastern Wind Integration and Transmission Study, NREL/SR-550-47078, National Renewable Energy Laboratory, Golden, Colorado, January. Available from: [www.nrel.gov/wind/systemsintegration/ewits.html](http://www.nrel.gov/wind/systemsintegration/ewits.html).
- Environmental Law Institute, 2009. Estimating US Government Subsidies to Energy Sources: 2002–2008, September. Available from: [www.elistore.org/reports\\_detail.asp?ID=11358](http://www.elistore.org/reports_detail.asp?ID=11358).
- Everett, B., 2006. Demand flexibility, micro-combined heat and power and the 'informated' grid. In: Boyle, G. (Ed.), *Renewable Electricity and the Grid*. Earthscan, London, England, pp. 151–156 (Chapter 8).
- Fthenakis, V., Mason, J.E., Zweibel, K., 2009. The technical, geographical, and economic feasibility of solar energy to supply the energy needs of the US. *Energy Policy* 37, 387–399.
- Fuller, M.C., Portis, S., Kammen, D., 2009. Toward a low-carbon economy: municipal financing for energy efficiency and solar power. *Environment* 51 (1), 22–32. Available from: [www.environmentmagazine.org/Archives/Back%20Issues/January-February%202009/FullerPortisKammen-full.html](http://www.environmentmagazine.org/Archives/Back%20Issues/January-February%202009/FullerPortisKammen-full.html).
- GE Energy, 2010. Western Wind and Solar Integration Study, NREL/SR-550-47434, National Renewable Energy Laboratory, Golden, Colorado, May. Available from: [www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis\\_final\\_report.pdf](http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf).
- Global Studies Initiative, 2010. Biofuel Subsidies: available from: [www.globalsubsidies.org/en/research/biofuel-subsidies](http://www.globalsubsidies.org/en/research/biofuel-subsidies), and Fossil-Fuel Subsidies: available from: [www.globalsubsidies.org/en/research/fossil-fuel-subsidies](http://www.globalsubsidies.org/en/research/fossil-fuel-subsidies) (accessed August 29).
- Glykas, A.G., Papaioannou, Perissakis, S., 2010. Application and cost-benefit analysis of solar hybrid power installation on merchant marine vessels. *Ocean Engineering* 37, 592–602.
- Goodall, C., 2009. Spain's variable wind and stable electricity networks. *Carbon Commentary*, 15 Available from: [www.carboncommentary.com/2009/11/15/853](http://www.carboncommentary.com/2009/11/15/853).
- Greenblatt, J.B., Succar, S., Denkenberger, D.C., Williams, R.H., Socolow, R.H., 2007. Baseload wind energy: modeling the competition between gas turbines and compressed air energy storage for supplemental generation. *Energy Policy* 35, 1474–1492.
- Greene, D.L., Leiby, P.N., James, B., Perez, J., Melendez, M., Milbrandt, A., Unnasch, S., Hooks, M., 2008. Analysis of the Transition to Hydrogen Fuel Cell Vehicles and

- the Potential Hydrogen Energy Infrastructure Requirements, ORNL/TM-2008/030. Oak Ridge National Laboratory, Oak Ridge, Tennessee, March Available from: [http://cta.ornl.gov/cta/Publications/Reports/ORNL\\_TM\\_2008\\_30.pdf](http://cta.ornl.gov/cta/Publications/Reports/ORNL_TM_2008_30.pdf).
- Greene, D.L., Leiby, P.N., Bowman, D., 2007. Integrated Analysis of Market Transformation Scenarios with HyTrans, ORNL/TM-2007/094. Oak Ridge National Laboratory, Oak Ridge, Tennessee Available from: [http://cta.ornl.gov/cta/Publications/Reports/ORNL\\_TM\\_2007\\_094.pdf](http://cta.ornl.gov/cta/Publications/Reports/ORNL_TM_2007_094.pdf).
- Hart, E.K., Jacobson, M.Z. A Monte Carlo approach to generator portfolio planning and carbon emissions assessments of systems with large penetrations of intermittent renewable. *Renewable Energy*, under review. Available from: <http://www.stanford.edu/~ehart/>.
- Hauth, R.L., Tartro, P.J., Railing, B.D., Johnson, B.K., Stewart, J.R., Fink, J.L., 1997. HVDC Power Transmission Technology Assessment, ORNLSub/95-SR893/1, Oak Ridge National Laboratory, Oak Ridge, Tennessee. Available from: [www.osti.gov/bridge/product.biblio.jsp?osti\\_id=580574](http://www.osti.gov/bridge/product.biblio.jsp?osti_id=580574).
- Hellgren, J., 2007. Life cycle cost analysis of a car, a city bus, and an intercity bus powertrain for year 2005 and 2020. *Energy Policy* 35, 39–49.
- Holttinen, H., Uhlen, K., Meibom, P., Söder, L., Andersen, J.H., Weber, C., Barth, R., Nielsen, C.S., 2005. WILMAR—Wind Power Integration in Liberalised Electricity Markets, WP9 Recommendations, Contract ENK5-CT-2002-00663, January. Available from: [www.wilmar.risoe.dk/Deliverables/WP9%20Recommendations%20Final.pdf](http://www.wilmar.risoe.dk/Deliverables/WP9%20Recommendations%20Final.pdf).
- Honnery, D., Moriarty, P., 2009. Estimating global hydrogen production from wind. *International Journal of Hydrogen Energy* 34, 727–736.
- Hoste, G., Dvorak, M., Jacobson, M.Z., 2009. Matching hourly and peak demand by combining different renewable energy sources. VPU Final Report, Stanford University, Palo Alto, California. Available from: <http://www.stanford.edu/group/efmh/jacobson/Articles/!susenergy2030.html>.
- Jacobson, M.Z., 2009. Review of solutions to global warming, air pollution, and energy security. *Energy and Environmental Science* 2, 148–173. doi:10.1039/b809990c.
- Jacobson, M.Z., Masters, G.M., 2001. Exploiting wind versus coal. *Science* 293, 1438.
- Jacobson, M.Z., Delucchi, M.A., 2009. A path to sustainable energy by 2030, Scientific American, November.
- Jacobson, M.Z., Colella, W.G., Golden, D.M., 2005. Cleaning the air and improving health with hydrogen fuel cell vehicles. *Science* 308, 1901–1905.
- Jacobson, M.Z., Delucchi, M.A., 2010. A net-present value analysis for a wind turbine purchase at a small US College. *Energies* 3, 943–959.
- Kahn, E., 1979. The reliability of distributed wind generators. *Electric Power Systems* 2, 1–14.
- Kalhammer, F.R., Kopf, B.M., Swan, D.H., Roan, V.P., Walsh, M.P., 2007. Status and prospects from zero emissions vehicle technology. Report of the ARB Independent Expert Panel 2007, prepared for the California Air Resources Board, April 13. Available from: [www.arb.ca.gov/msprog/zevprog/zevreview/zev\\_panel\\_report.pdf](http://www.arb.ca.gov/msprog/zevprog/zevreview/zev_panel_report.pdf).
- Katzenstein, W., Fertig, E., Apt, J., 2010. The variability of interconnected wind plants. *Energy Policy* 38, 4400–4410.
- KEMA, Inc., 2006. Building a “Margin of Safety” into renewable energy procurements: a review of experience with contract failure. Consultant Report, prepared for the California Energy Commission, CEC-300-2006-004, Sacramento, California, January. Available from: [www.energy.ca.gov/2006publications/CEC-300-2006-004/CEC-300-2006-004.PDF](http://www.energy.ca.gov/2006publications/CEC-300-2006-004/CEC-300-2006-004.PDF).
- Kempton, W., Tomic, J., 2005a. Vehicle-to-grid power fundamentals: calculating capacity and net revenue. *Journal of Power Sources* 144, 268–279.
- Kempton, W., Tomic, J., 2005b. Vehicle-to-grid power implementation: from stabilizing the grid to supporting large-scale renewable energy. *Journal of Power Sources* 144, 280–294.
- Kempton, W., Pimenta, F.M., Veron, D.E., Colle, B.A., 2010. Electric power from offshore wind via synoptic-scale interconnection. *Proceedings of the National Academy of Sciences* 107, 7240–7245.
- Kramer, G.J., Haigh, M., 2009. No quick switch to low-carbon energy. *Nature* 462, 568–569.
- Koplow, D., 2009. A Boon to Bad Biofuels: Federal Tax Credits and Mandates Underwrite Environmental Damage at Taxpayer Expense, Earth Track, Cambridge, Massachusetts, April. Available from: [http://earthtrack.net/files/uploaded\\_files/FOE](http://earthtrack.net/files/uploaded_files/FOE), VEETC Evaluation FINAL.pdf.
- Koplow, D., 2004. Subsidies to energy industries. In: Cleveland, C.J. (Ed.), *Encyclopedia of Energy*, vol. 5. Elsevier Inc., pp. 749–764.
- Koplow, D., Dernbach, J., 2001. Federal fossil fuel subsidies and greenhouse gas emissions: a case study of increasing transparency for fiscal policy. *Annual Review of Energy and the Environment* 26, 361–389.
- Kromer, M.A., Heywood, J.B., 2007. Electric Powertrains: Opportunities and Challenges in the US Light-Duty Vehicle Fleet, Publication LFEE 2007-03 RP. Sloan Automotive Laboratory, Laboratory for Energy and the Environment, Massachusetts Institute of Technology, Cambridge, Massachusetts, May. Available from: [http://web.mit.edu/sloan-auto-lab/research/beforeh2/files/kromer\\_electric\\_powertrains.pdf](http://web.mit.edu/sloan-auto-lab/research/beforeh2/files/kromer_electric_powertrains.pdf).
- Krewitt, W., 2002. External costs of energy—do the answers match the questions? looking back at 10 years of ExternE. *Energy Policy* 30, 839–848.
- Lange, B., Rohrig, K., Schlögl, F., Cali, U., Jursa, R., 2006. Wind power forecasting. In: Boyle, G. (Ed.), *Renewable Electricity and the Grid*. Earthscan, London, England, pp. 95–120 (Chapter 5).
- Lee, B.S., Gushee, D.E., 2009. Renewable power: not yet ready for prime time. *Chemical and Engineering Progress*, 22–25 Available from: [www.aiche.org/cep/](http://www.aiche.org/cep/).
- Liu, P., Wang, J., Hicks-Garner, J., Sherman, E., Soukiazian, S., Verbrugge, M., Tataria, H., Musser, J., Finamore, P., 2010. Aging mechanisms of LiFePO<sub>4</sub> batteries deduced by electrochemical and structural analyses. *Journal of the Electrochemical Society* 157, A499–A507.
- Lund, H., 2006. Large-scale integration of optimal combinations of PV, wind and wave power into the electricity supply. *Renewable Energy* 31 (4), 503–515.
- Lund, H., Kempton, W., 2008. Integration of renewable energy into the transport and electricity sectors through V2G. *Energy Policy* 36, 3578–3587.
- Macauley, M.K., 2008. The supply of space infrastructure: issues in the theory and practice of estimating costs. *Space Policy* 24, 70–79.
- Macilwain, C., 2010. Supergrid. *Nature* 468, 624–625.
- Martin, K.B., Grasman, S.E., 2009. An assessment of wind-hydrogen systems for light duty vehicles. *International Journal of Hydrogen Energy* 34, 6581–6588.
- Miller, A.R., 2009. Rail vehicles: fuel cells. In: Garche, Juergen, Dyer, Chris, Moseley, Patrick, Ogumi, Zempachi, Rand, David, Scrosati, Bruno (Eds.), *Encyclopedia of Electrochemical Power Sources*, vol. 1. Elsevier, Amsterdam, pp. 313–322.
- Milligan, M.R., Factor, T., 2000. Optimizing the geographical distribution of wind plants in Iowa for maximum economic benefit and reliability. *Wind Engineering* 24 (4), 271–290.
- Mills, A., Wiser, R., 2010. Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power, LBNL-3884E. Lawrence Berkeley National Laboratory, Berkeley, California, September. available from: <http://eetd.lbl.gov/ea/emp/reports/lbnl-2855e.pdf>.
- Mills, A., et al., 2009a. Understanding Variability and Uncertainty of Photovoltaics for Integration with the Electric Power System, LBNL-2855E. Lawrence Berkeley National Laboratory, Berkeley, California, December. Available from: <http://eetd.lbl.gov/ea/ems/reports/lbnl-2855e.pdf>.
- Mills, A., Wiser, R., Porter, K., 2009b. The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies, LBNL-1471E. Lawrence Berkeley National Laboratory, Berkeley, California, February. Available from: <http://eetd.lbl.gov/ea/emp/reports/lbnl-1471e.pdf>.
- Mondol, J.D., Yohanis, Y.G., Norton, B., 2009. Optimising the economic viability of grid-connected photovoltaic systems. *Applied Energy* 86, 985–999.
- Musial, W., Ram, B., 2010. Large-Scale Offshore Wind Power in the United States, NREL/TP-500-40745. National Renewable Energy Laboratory, Golden, Colorado, September. Available from: [www.nrel.gov/wind/pdfs/40745.pdf](http://www.nrel.gov/wind/pdfs/40745.pdf).
- National Renewable Energy Laboratory, 2010a. Wind Deployment System (WinDS) Model, Cost of Wind Transmission Access Data. Available from: [www.nrel.gov/analysis/winds/transmission\\_cost.html](http://www.nrel.gov/analysis/winds/transmission_cost.html) (accessed August 29).
- National Renewable Energy Laboratory, 2010b. Wind Deployment System (WinDS) Model, Cost of Wind Transmission Access. Available from: [http://webblade-a3.dev.nrel.gov/winds/transmission\\_cost.asp](http://webblade-a3.dev.nrel.gov/winds/transmission_cost.asp) (accessed August 29).
- National Research Council, Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption, 2010. *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use*. The National Academies Press, Washington, DC [www.nap.edu/catalog/12794.html](http://www.nap.edu/catalog/12794.html).
- National Research Council, 2008. *Transitions to Alternative Transportation Technologies—A Focus on Hydrogen*. The National Academies Press, Washington, DC.
- Nelson, P.A., Santini, D.J., Barnes, J., 2009. Factors Determining The Manufacturing Costs Of Lithium-Ion Batteries for PHEVs. Center for Transportation Research, Argonne National Laboratory, presented at EVS24, Stavanger, Norway, May 13–16. Available from: [www.transportation.anl.gov/pdfs/B/624.PDF](http://www.transportation.anl.gov/pdfs/B/624.PDF).
- Negra, N.B., Todorovic, J., Ackerman, T., 2006. Loss evaluation of HVAC and HVDC transmission solutions for large offshore wind farms. *Electric Power Systems Research* 76, 916–927.
- New York State Energy Research and Development Authority, 2004. An Assessment of the Descending Clock Auction for the Centralized Procurement of Qualifying Renewable Attribute Certificates by the New York State Energy Research and Development Authority, September. available from: [www.nyserda.org/rps/DCA.pdf](http://www.nyserda.org/rps/DCA.pdf).
- North American Electric Reliability Corporation, 2009a. *Generating Availability Report*. Available from: [www.nerc.com/files/gar2008.zip](http://www.nerc.com/files/gar2008.zip).
- North American Electric Reliability Corporation, 2009b. *Accommodating High Levels of Variable Generation*, April. Available from: [www.nerc.com/files/IVGTF\\_Report\\_041609.pdf](http://www.nerc.com/files/IVGTF_Report_041609.pdf).
- Nourai, A., Kogan, V.I., Schafer, C.M., 2008. Load leveling reduces T&D line losses. *IEEE Transactions on Power Delivery* 23 (4), 2168–2173.
- Nuclear Power Daily, 2009. Third of French nuke plants offline, November 2. Available from: [www.nuclearpowerdaily.com/reports/Third\\_of\\_French\\_nuke\\_plants\\_off\\_line\\_999.html](http://www.nuclearpowerdaily.com/reports/Third_of_French_nuke_plants_off_line_999.html).
- Offer, G.J., Howey, D., Constestabile, M., Clague, R., Brandon, N.P., 2010. Comparative analysis of battery electric, hydrogen fuel cell and hybrid vehicles in a future sustainable road transport system. *Energy Policy* 38, 24–29.
- Office of Management and Budget (OMB), 2003. Circular A-4 (guidance to Federal agencies on the development of regulatory analysis), Washington, DC, September 17. Available from: [www.whitehouse.gov/omb/assets/omb/circulars/a004/a-4.pdf](http://www.whitehouse.gov/omb/assets/omb/circulars/a004/a-4.pdf).
- Palutikof, J.P., Cook, H.F., Davies, T.D., 1990. Effects of geographical dispersion on wind turbine performance in England: a simulation. *Atmospheric Environment* 24A, 213–227.

- Parsons, B., et al., 2008. Impacts of Large Amounts of Wind Power on Design and Operation of Power Systems: Results of IEA Collaboration, NREL/CP-500-43540. National Renewable Energy Laboratory, Golden, Colorado, June. Available from: <www.nrel.gov/wind/systemsintegration/pdfs/2008/parsons\_wind\_impacts\_large\_amounts.pdf>.
- Peterson, S.B., Whitacre, J.F., Apt, J., 2010a. The economics of using plug-in hybrid electric vehicle battery packs for grid storage. *Journal of Power Sources* 195, 2377–2384.
- Peterson, S.B., Apt, J., Whitacre, J.F., 2010b. Lithium-Ion battery cell degradation resulting from realistic vehicle and vehicle-to-grid utilization. *Journal of Power Sources* 195, 2385–2392.
- Pickard, W.F., Hansing, N.J., Shen, A.Q., 2009. Can large-scale advanced adiabatic compressed air energy storage be justified economically in an age of sustainable energy? *J. Renewable and Sustainable Energy* 1, 2009 033102-1.
- Pratt, R.G., et al., 2010. The Smart Grid: An Estimation of the Energy and CO<sub>2</sub> Benefits, PNNL-19112. Pacific Northwest National Laboratory, Richland, Washington, January. Available from: <www.pnl.gov/main/publications/external/technical\_reports/PNNL-19112.pdf>.
- Pure Energy Systems Wiki, 2010. PowerPedia: Tidal Power. Available from: <http://peswiki.com/index.php/PowerPedia:Tidal\_Power> (accessed August 29).
- Quest Reliability, 2010. Transmission Lines. Available from: <www.questreliability.com/Default.aspx?tabid=177> (accessed August 29).
- Rimmer, F., 2010. Transmission line operations and maintenance, *Electric Energy Online*. Available from: <www.electricenergyonline.com/?page=show\_article&mag=26&article=200> (accessed August 29).
- Santini, D.J., 2010. Cost effective PHEV range: battery costs versus charging infrastructure costs. In: Transportation Research Board Annual Meeting, Washington, DC, January 12. Available from: <http://cta.ornl.gov/trbenergy/trb\_documents/2010/Santini%20Session%20538.pdf>.
- Schilling, M.A., Esmundo, M., 2009. Technology S-curves in renewable energy alternatives: analysis and implications for industry and government. *Energy Policy* 37, 1767–1781.
- Schmalensee, R., 2009. Renewable Electricity Generation in the United States, 09-017. Center for Energy and Environmental Policy Research, Massachusetts Institute of Technology, Cambridge, Massachusetts, November (Chapter forthcoming in *Harnessing Renewable Energy*, edited by B. Moselle, J. Padilla, and R. Schmalensee). Available from: <http://web.mit.edu/ceep/www/publications/workingpapers/2009-017.pdf>.
- Scott, D.S., Rogner, H.-H., Scott, M.B., 1993. Fuel cell locomotives in Canada. *International Journal of Hydrogen Energy* 18, 253–263.
- Siemens, 2010. Ultra HVDC Transmission System. Available from: <www.energy.siemens.com/hq/en/power-transmission/hvdc/hvdc-ultra/> (accessed August 29).
- Smith, J.C., Parsons, B., 2007. What does 20% look like? Developments in wind technology and systems. *IEEE Power and Energy Magazine*, November/December, pp. 22–33. Available from: <www.aep.com/about/transmission/docs/WhatIs20percent.pdf>.
- Sovacool, B.K., 2009. Rejecting renewables: the socio-technical impediments to renewable electricity in the United States. *Energy Policy* 37, 4500–4513.
- Sovacool, B.K., Watts, C., 2009. Going completely renewable: is it possible (let alone desirable)? *Electricity Journal* 22 (4), 95–111.
- Sovacool, B.K., Hirsch, R.F., 2010. Beyond batteries: an examination of the benefits and barriers to plug-in hybrid electric vehicles (PHEVs) and a vehicle-to-grid (V2G) transition. *Energy Policy* 37, 1095–1103.
- Stoutenburg, E.D., Jenkins, N., Jacobson, M.Z., 2010. Power output variations of co-located offshore wind turbines and wave energy converters in California. *Renewable Energy* 35, 2781–2791.
- Stadler, I., 2008. Power grid balancing of energy systems with high renewable energy penetration by demand response. *Utilities Policy* 16, 90–98.
- Sun, Y.-K., Myung, S.-T., Park, B.-C., Prakash, J., Belharouak, I., Amine, K., 2009. High-energy cathode material for long-life and safe lithium batteries. *Nature Materials* 8, 320–324.
- Sun, Y., Ogden, J., Delucchi, M., 2010. Societal lifetime cost of hydrogen fuel cell vehicles. *International Journal of Hydrogen Energy* 35, 11932–11946.
- Swider, D.J., et al., 2008. Conditions and costs for renewables electricity grid connection: examples in Europe. *Renewable Energy* 33, 1832–1842.
- Union for the Co-ordination of Transmission of Electricity (UCTE), 2008. Feasibility Study: Synchronous Interconnection of the IPS/UPS with the UCTE, Summary of Investigations and Conclusions, UCTE, Brussels, Belgium, December.
- US Department of Energy, Energy Efficiency and Renewable Energy, 2008. 20% Wind Energy by 2030, Increasing Wind Energy's Contribution to US Electricity Supply, DOE/GO-102008-256, Washington, DC, July. Available from: <http://20percentwind.org/20percent\_wind\_energy\_report\_revOct08.pdf>.
- Wancura, H., 2010. Hydrogen and fuel cell power—an alternative to electric transport for passengers and freight? In: Sixth International Hydrail Conference, Istanbul, Turkey, July 1–2. Available from: <http://hydrail.org/summary6.php>.
- Wei, M., Kammen, D., 2010. Economic Benefits of a Comprehensive Feed-In Tariff: An Analysis of the REESA in California. Renewable and Appropriate Energy Laboratory, Energy and Resources Group, University of California, Berkeley July. Available from: <www.fitcoalition.com/economic-benefits-of-a-fit/>.
- Weigt, H., Jeske, T., Leuthold, F., von Hirschhausen, C., 2010. "Take the Long Way Down": integration of large-scale north sea wind using HVDC transmission. *Energy Policy* 38, 3164–3173.
- Whitehouse, N., Whitehouse, S., Huss, A., 2009. Buses: fuel cells. In: Garche, Juergen, Dyer, Chris, Moseley, Patrick, Ogumi, Zempachi, Rand, David, Scrosati, Bruno (Eds.), *Encyclopedia of Electrochemical Power Sources*, vol. 1. Elsevier, Amsterdam, pp. 193–202.
- Wilson, I.A.G., McGregor, P.G., Hall, P.J., 2010. Energy storage in the UK electrical network: estimation of the scale and review of technology options. *Energy Policy* 38, 4099–4106.
- Winkler, W., 2009. Ships: fuel cells. In: Garche, Juergen, Dyer, Chris, Moseley, Patrick, Ogumi, Zempachi, Rand, David, Scrosati, Bruno (Eds.), *Encyclopedia of Electrochemical Power Sources*, vol. 1. Elsevier, Amsterdam, pp. 338–358.
- Wiser, R., Barbose, G., Holt, E., 2010. Supporting Solar Power in Renewables Portfolio Standards: Experience from the United States, LBNL-3984E. Lawrence Berkeley National Laboratory, Berkeley, California, October. Available from: <http://eetd.lbl.gov/ea/ems/reports/lbnl-3984e.pdf>.
- Wiser, R., Barbose, G., Peterman, C., Darghouth, N., 2009. Tracking the Sun II, the Installed Cost of Photovoltaics in the US from 1998–2008, LBNL-2647E. Lawrence Berkeley National Laboratory, Berkeley, California, October. Available from: <http://eetd.lbl.gov/ea/ems/reports/lbnl-3984e.pdf>.
- Wiser, R., Bolinger, M., Porter, K., Raitt, H., 2005. Does It have to be this hard? Implementing the nation's most aggressive renewables portfolio standard. *Electricity Journal* 18 (8): 55–67 (see also Wiser, R., M. Bolinger, K. Porter, and H. Raitt, 2005. Does It Have to Be This Hard? Implementing the Nation's Most Aggressive Renewables Portfolio Standard in California, LBNL-58728, Ernesto Orlando Lawrence Berkeley National Laboratory, Berkeley, California, August). Available from: <http://eetd.lbl.gov/ea/EMP/reports/58728.pdf>.
- Wiser, R., Bolinger, M., 2010. 2009 Wind Technologies Market Report, LBNL-3716E. Lawrence Berkeley National Laboratory, Berkeley, California August. Available from: <http://eetd.lbl.gov/ea/emp/reports/lbnl-3716e.pdf>.
- Wiser, R., Bolinger, M., 2009. 2008 Wind Technologies Market Report. Lawrence Berkeley National Laboratory, Berkeley, California July. Available from: <http://eetd.lbl.gov/ea/EMS/reports/2008-wind-technologies.pdf> (accessed January 24).
- Wiser, R., Bolinger, M., 2008. Annual Report on US Wind Power Installation, Cost, and Performance Trends: 2007, LBNL-275E. Lawrence Berkeley National Laboratory, Berkeley, California, May. Available from: <http://eetd.lbl.gov/ea/ems/reports/lbnl-275e.pdf>.
- Yazami, R., Reynier, Y.F., 2002. Mechanism of self-discharge in graphite-lithium anode. *Electrochimica Acta* 47, 1217–1223.
- Zhang, Y., Wang, C.-Y., 2009. Cycle-life characterization of automotive lithium-ion batteries with LiNiO<sub>2</sub> cathode. *Journal of the Electrochemical Society* 156, A527–A535.
- Zhou, W., Lou, C., Li, Z., Yang, H., 2010. Current status of research on optimum sizing of stand-alone solar-wind power generation systems. *Applied Energy* 87, 380–389.