Evaluating the Feasibility of Meeting all Global Energy Needs with Wind, Water, and Solar Power

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Climate change, air pollution, water pollution, and increasingly insecure and unreliable energy supplies are among the greatest environmental and economic challenges of our time. Addressing these challenges will require major changes to the ways we generate and use energy. With this in mind, scientists, policy analysts, entrepreneurs, and others have proposed large-scale projects to transform the global energy system from one that relies primarily on fossil fuels to one that uses clean, abundant, widespread renewable energy resources. Here, we analyze the feasibility associated with providing all our energy for all purposes from wind, water, and the sun (WWS), which are the most promising renewable resources. We first describe the more prominent renewable energy plans that have been proposed, and then discuss the characteristics of 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. We conclude that barriers to a 100% conversion to WWS power are primarily social and political, not technological or even economic. We suggest a goal to produce all new energy with WWS by 2030 and replace all pre-existing energy by 2050. The cost of energy due to a conversion is expected to be similar to that today.

1. Renewable Energy Plans

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 increases in energy efficiency. Over the past decade, a number of scientists have proposed large-scale renewable energy plans.[1] In 2001, a Stanford University study (Jacobson

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[1] 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

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). In 2001, Czisch (2006, 2007) 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 costs of the current system. A 2002 paper published in *Science* (Hoffert et al., 2002) suggested a portfolio of solutions for stabilizing atmospheric CO_2, including increasing the use of renewable energy and nuclear energy, decarbonizing fossil fuels and sequestering carbon, and improving energy efficiency. A 2004 Princeton University study (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.

A considerable amount of research has been done since 2009. An analysis of the technical, geographical, and economic feasibility for solar energy to supply the energy needs of the U.S. concluded 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_2 emissions to a level commensurate with the most aggressive climate-change goals" (Fthenakis et al., 2009, p. 397). 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_2-equivalent GHG emissions in the U.S. by 56% compared with 2005 levels. That study featured an economy-wide CO_2 cap-and-trade program and policies to increase energy efficiency and the use of renewable energy in industry, buildings, electricity, and transportation.

In 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) (Jacobson and Delucchi, 2009). 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 2030. However, that study 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

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 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 (www.pickensplan.com/theplan/).

WWS by 2050. The analysis presented here is an extension of the work begun in Jacobson and Delucchi (2009).

Since our 2009 work, several more large-scale plans have emerged. These are summarized in Table 1 and compared with our present plan.[2] 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.

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	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	80% WWS+NCBmBf	2050	UK
Price-Waterhouse-Coopers (2010)	Electricity	100% WWS+Bm	2050	Europe & North Africa
Beyond Zero Emissions (2010)	Electricity	100% WWS+NCBm	2020	Australia
ECF (2010)	Electricity Transport Heat	80% WWS+NCBm	2050	Europe
EREC (2010)	Electricity Transport Heat	100% WWS+BmBf	2050	Europe

WWS = wind, water, solar power; FF = fossil fuels; Bm = biomass; Bf=liquid biofuels; N=nuclear; C=coal-CCS

There is little doubt that the large-scale use of renewable energy envisaged in these plans and studies would greatly mitigate or even 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).[3] But is a large-scale transformation of the

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[2] We have not included the Cleetus et al. (2009) study in Table 1 because its focus is mainly on efficiency and demand management rather than on renewable energy. For example, their plan calls for only 20% electric vehicles in 2030, and only 25% more renewable energy in 2030 than in a modified version of the U.S. Energy Information Administration's "reference case." In their plan, renewable energy including hydropower supplies 25% of total energy demand.

[3] Although we focus here on mitigating the impacts of the energy-use sector, we recognize that a comprehensive plan to address global environmental problems must address other sectors, including agriculture, forestry, and non-energy-related industrial processes. There is a large

world's energy systems feasible? In this paper 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.

2. Clean, Low-risk, Sustainable Energy Systems

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

Because climate change, air pollution, and energy insecurity are current and growing problems, but it takes several decades for new technologies to become fully adopted, we consider only those technologies and policies that work or are close to working today, on a global scale, rather than those that may exist 20 or 30 years from now. This means, for example, that we do not discuss the prospects for nuclear fusion. Also, 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.

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 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). Jacobson (2009) 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, and that nuclear power, coal with carbon capture, corn ethanol, and cellulosic ethanol were all moderately or significantly worse than the WWS options with respect to environmental and land use impacts. Importantly, all WWS technologies can be deployed today, and indeed most already have been deployed on at least small scales worldwide.

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

literature on sustainable agriculture and sustainable forestry; see Harnley (2004) for a review. Horrigan et al. (2002) discuss the impacts of sustainable agriculture on human health and the environment. Wall and Smit (2005) discuss sustainable agriculture in a changing climate. Niles et al. (2002) discuss the potential for mitigating carbon emissions by reforesting degraded lands, implementing sustainable agriculture, and slowing tropical deforestation in developing countries.

availability (See Delucchi [2009] 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), because the method of producing ethanol has no impact on the tailpipe-emissions from ethanol combustion or the resulting urban air pollution. The use of carbon capture and sequestration (CCS) can reduce CO_2 emissions from the stacks of coal power plants by 85-90% or more, but it will *increase* emissions 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 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. 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 (Macfarland and Miller, 2007; Adamantiades and Kessides, 2009).[4] 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., 2010; Adamantiades and Kessides, 2009; Mourogov et al., 2002; Mourogov, 2000), there is no guarantee that the reactors will be designed, built and operated correctly,[5] and 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. Historically, the growth of nuclear energy has increased the ability of nations to obtain or enrich uranium for nuclear weapons (Ullom [1994]), as evidenced by the development or attempted development of weapons capabilities secretly in nuclear energy facilities by Pakistan, India (www.fas.org/nuke/guide/india/nuke/), Iraq (prior to 1981), Iran (e.g., Adamantiades and Kessides, 2009. p. 16), and to some extent North Korea. A large-scale expansion of nuclear

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[4] Macfarlane and Miller (2007) show that an expansion of nuclear energy in which 1500 GWe of capacity using a once-through fuel cycle was installed by 2051 would consume all identified and estimated undiscovered conventional resources, at any price, by 2100. Adamantiades and Kessides (2009) conclude that "setting aside the unconventional resources, the number of years that known and recoverable uranium resources would last is not impressive—indicating that, under most assumptions, nuclear power (without fuel recycling and breeding) is not a long-term sustainable technology, based on available resources" (p. 8).

[5] 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 (www.energy-net.org/01NUKE/DIABLO2.HTM), and nuclear regulators in France recently told the French firm Areva, one of the largest designers and builders of nuclear power plants in the world, to correct a safety design flaw in its latest-generation reactor (http://www.nuclearpowerdaily.com/reports/Nuclear_safety_bodies_call_for_redesign_of_EPR_reactor_999.html).

energy worldwide would exacerbate this risk (Kessides, 2010; Feiveson, 2009; Miller and Sagan, 2009; Macfarlane and Miller, 2007; Harding, 2007).[6] In addition, conventional nuclear power produces radioactive wastes, which must be stored for thousands of years, raising technical questions (Barré, 1999; von Hippel, 2008; Adamantiades and Kessides, 2009).[7] Finally, nuclear energy results in 9-25 times more carbon emissions than wind energy, in part due to the emissions from uranium refining and transport and reactor construction, in part due to the longer time required to permit and construct a nuclear plant compared with a wind farm (resulting in greater emissions from the fossil-fuel electricity sector during this period),[8] 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 (e.g., Koomey and Hultman, 2007; Lenzen, 2008; Sovacool, 2008; Jacobson, 2009).

So-called "breeder" reactors 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., 2010; Purushotham et al., 2000; Till et al., 1997).[9] However, they produce nuclear

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[6] Feiveson (2009) writes that "it is well understood that one of the factors leading several countries now with-out 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 that "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, in their nuanced review of proliferation risks, Miller and Sagan (2009) write that "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).

[7] Adamantiades and Kessides (2009) note that "Nuclear waste disposal has been one of the more recalcitrant problems facing the nuclear industry—a decisive impediment to its expansion. It could be a significant consideration in decisions to expand nuclear plants" (p. 13).

[8] 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).

[9] A related alternative is the use of thorium as a nuclear fuel, which, compared with conventional uranium reactor, is less likely to lead to nuclear weapons proliferation, 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, thus result in emissions from the background electric grid during this period. In addition, lifecycle emissions of carbon from a thorium reactor are on the same order as those from a uranium reactor. Thorium still produces radioactive waste containing ^{231}Pa, which has a half life of 32,760 years. It also produces ^{233}U, which can be used in fission

material closer to weapons grade that can be reprocessed into nuclear weapons (Kessides, 2010; Adamantiades and Kessdes, 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[10] (Kessides, 2010; Penner et al, 2010; Hannum et al., 2010). Fusion of light atomic nuclei (e.g., protium, deuterium, or tritium) theoretically could supply power cleanly, safely, indefinitely, and without long-lived radioactive wastes as the products are isotopes of helium (Ongena and Van Oost, 2006; Tokimatsu et al., 2003), but it is unlikely to be commercially available for at least another 50 to 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.[11]

For these reasons, we focus on WWS technologies. We assume that WWS will supply electric power to the transportation, heating (including high-temperature heating) and cooking sectors – which traditionally have relied mainly on direct use of oil or gas rather than electricity – as well as to 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).

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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}U.

[10] Kessides (2010) writes that "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).

[11] Note that our reasons for excluding nuclear power from our plan do *not* include economics. Readers interested in a brief discussion of the economics of nuclear power should see Appendix A.1.

Characteristics of electricity-generating WWS technologies

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.

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.

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.

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).

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 six hours in one direction before switching directions for six hours, tidal turbines can provide a predictable energy source. O'Rourke et al. (2010) provide an excellent overview of the technology of tidal energy.

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.

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.

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.2)

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 get about 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 production of hydrogen only in this way. Several companies have prototype HFCVs, and California has about 200 HFCVs on the road (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.

<u>Use of WWS power for heating and cooling</u>
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.2).

3. Energy Resources Needed and Available

The power required today to satisfy all end uses worldwide is about 12.5 trillion watts (TW) (Energy Information Administration, 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 U.S. Energy Information Administration (EIA) projects that in the year 2030, the world will require almost 17 TW of end-use power, and the U.S. almost 3 TW (Table 2). The EIA (2008a) also projects that the breakdown in terms of primary energy in 2030 will be similar to today's – 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 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-electrified uses can be supplied by hydrogen, which we assume would be compressed or liquefied for use in the transportation sector (and used mainly with fuel cells, except in aviation and high-temperature processes), and combusted to provide heat directly in the industrial sector. The hydrogen would be produced by 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).

Table 2. Projected end-use power in 2030, by sector, U.S. and world, conventional fossil-fuel case and replacing 100% of fossil fuels 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$_2$*			*World*	*U.S.*
Residential									
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
Total	**2.26**	**0.43**						**1.83**	**0.35**
Commercial									
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
Total	**1.32**	**0.38**						**1.22**	**0.35**
Industrial									
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
Total	**8.80**	**0.92**						**7.05**	**0.74**
Transportation									
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	-
Total	**4.53**	**1.10**						**1.37**	**0.33**
Total end uses	**16.92**	**2.83**						**11.47**	**1.78**

Notes: see Appendix A.2

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

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 three times over and solar, about 15-20 times over.

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, 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[a]	72-170[b]	40-85[c]	0.02[d]
Wave	>2.7[d]	2.7[e]	0.5[d]	0.000002[d]
Geothermal	45[f]	2[g]	0.07-0.14[d]	0.0065[d]
Hydroelectric	1.9[d]	<1.9[d]	1.6[d]	0.32[d]
Tidal	3.7[d]	0.8[d]	0.02[d]	0.00006[d]
Solar PV	6500[h]	1300[i]	340[d]	0.0013[d]
CSP	4600[j]	920[j]	240[j]	000046[d]

[a] Fig. 1 here; accounts for all wind speeds at 100 m over land and ocean.
[b] Locations over land or near the coast where the mean wind speed ≥ 7 m/s at 80 m (Archer and Jacobson, 2005) and 100 m (Fig. 1).
[c] Eliminating remote locations.
[d] Jacobson (2009) and references therein.
[e] Wave power in coastal areas.
[f] Fridleifsson et al. (2008).
[g] Includes estimates of undiscovered reservoirs over land.
[h] Fig. 2 here, assuming use of 160 W solar panels and areas determined in Jacobson (2009), over all latitudes, land and ocean.
[i] Same as (h) but locations over land between 50 S and 50 N.
[j] Scaling solar PV resource with relative land area requirements from Jacobson (2009).

Figure 1 shows the 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 worlds land plus ocean surfaces 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. About 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 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., 2009), and the East Coast of Asia among others.

Figure 1. Modeled map of the yearly-averaged world wind speed (m/s) at 100 m above sea level.
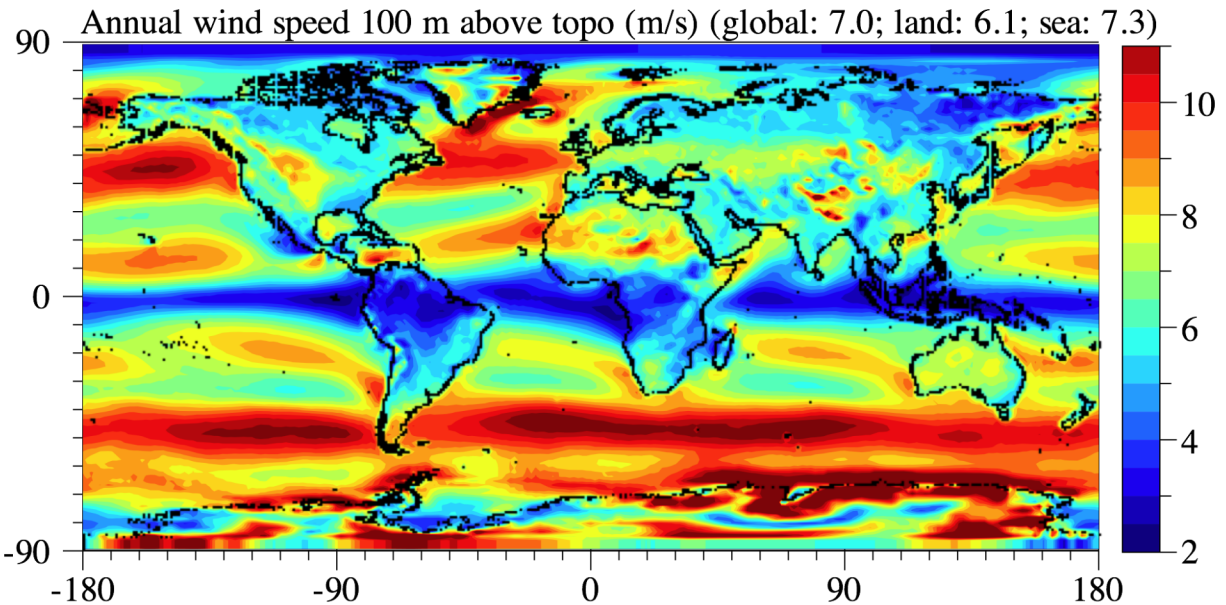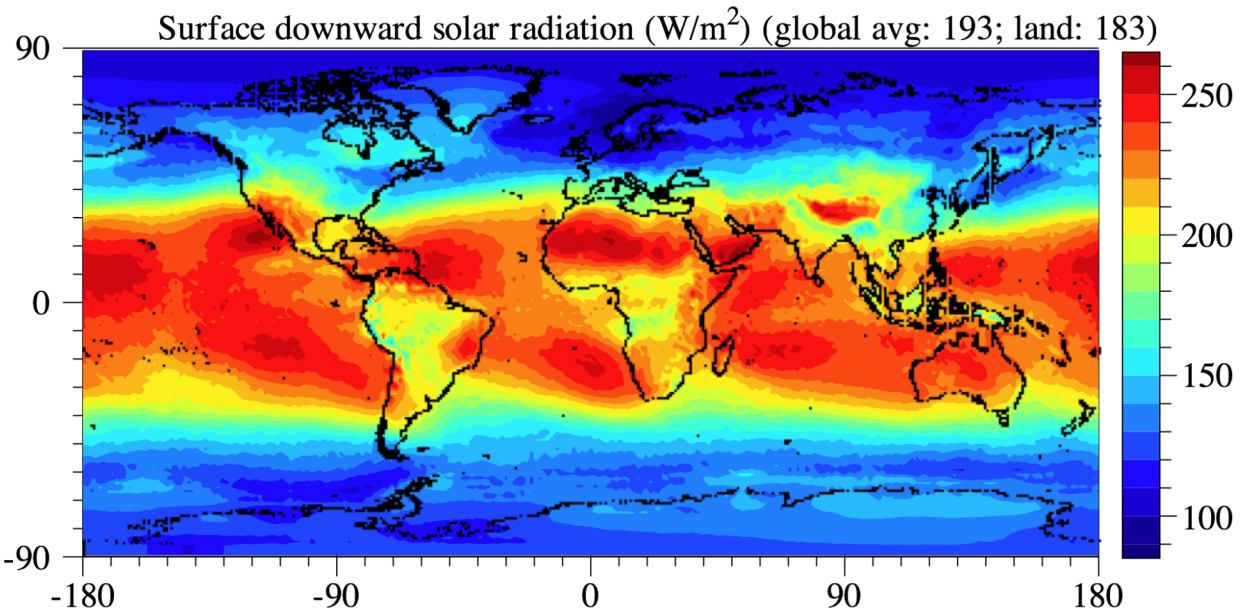

Figure 2 shows the distribution of solar energy at the Earth's surface. Globally, 6500 TW of solar energy are available over the world's land plus ocean surfaces if all sunlight were used to power photovoltaics (Table 3); however, the deliverable solar power over land in locations where solar PV could 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 (U.S. Department of Energy, 2008b) suggesting air-cooled plants may be a viable alternative in water-limited locations.

Figure 2. Modeled map of the yearly-averaged downward surface solar radiation reaching the surface (W/m²).

The other WWS technologies have much less potential than do wind, CSP, and PV (Table 3) yet can still contribute in important ways 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. And 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. However, existing and some new hydro will be valuable for filling in gaps in supply due to wind and solar power, in particular.

Even though 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. Further, 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.

4. Number 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 assumed to be divided 30%

rooftop[12] and 70% power plant. The table 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 power the world. Already, about 0.8% of the wind is installed. The worldwide footprint on the ground (for the turbine tubular tower and base) for the 4 million wind turbines is only 48 km^2, smaller than Manhattan (59.5 km^2) whereas the spacing needed (which can be used for agriculture, rangeland, open space, or other purposes) is ~1% of the global land area. For non-rooftop solar PV plus CSP, whose spacing areas are similar to its footprint areas, powering 34% of the world requires about 25% of the land area for spacing as does powering 50% of the world with wind but a much larger footprint area than does wind. Together, the entire WWS solution would require ~0.74% of the global land surface area for footprint and 1.9% for spacing. In theory, 61% of the 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 (Figure 1).

Table 4. Number of WWS power plants or devices needed to power the world's and the U.S.'s total energy demand in 2030 (11.5 TW 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, 1.446x10^8 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	0.0013	830
Hydroelectric plant	1300	4	900	0.407	0.407	140
Tidal turbine	1	1	490,000	0.000098	0.0013	7600
Roof PV system	0.003	6	1.7 billion	0.042	0.042	265 million
Solar PV plant	300	14	40,000	0.097	0.097	6200
CSP plant	300	20	49,000	0.192	0.192	000046

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[12] Rooftop PV systems have two major advantages over power-plant PV systems: they do not require an electricity transmission and distribution network, and they can be integrated into a hybrid solar system that produces heat, light, and electricity for use on site (Chow, 2010).

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.

Wind power. The primary materials needed for wind turbines include steel (for towers, nacelles, rotors), 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 hundreds of thousands 5-MW or more wind turbines will require large amounts of bulk materials such as steel and concrete (U.S. Department of Energy [DOE}, 2008a). However, there do not appear to be any 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 somewhat limited reserves of economically recoverable iron ore (on the order of 100 to 200 years at current production rates [U.S. Geological Survey, 2009, p. 81]), but the steel used to make towers, nacelles, and rotors for wind turbines should be 100% recyclable (for example, in the U.S. in 2007, 98% of steel construction beams and plates were recycled [U.S. Geological Survey (USGS), 2009, p. 84]). The U.S. DOE (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. (In this respect, one analyst has raised the prospect of "trading a troubling dependence on Middle East oil for a risky dependence on Chinese neodymium" (Irving Mintzer, quoted in Margonelli, 2009). One estimate suggests that current PM generators in large wind turbines use 0.2 kg-Nd/kWh, or one-third the 0.6 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 Nd_2O_3; http://en.wikipedia.org/wiki/Neodymium), which would amount to approximately 100,000 metric tons of Nd oxide per year over a 40 to 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.

Table 5. Rare earth oxide and neodymium oxide (in parentheses)[a] production, reserves and resources worldwide (million metric tones of rare earth oxide)

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"*[b]

Source: USGS (2009, p. 131). 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).

[a] 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).

[b] The USGS (2009) writes that "undiscovered resources are thought to be very large relative to expected demand" (p. 131).

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; Evans-Prichard, 2009). Therefore, it seems likely that a rapid global expansion of wind power will require many 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); and

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.

Solar power. Solar PVs use amorphous silicon, polycrystalline silicon, micro-crystalline 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 was 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_2, CuO, Cu_2S, and Zn_3P_2.

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.

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 (www.hybridsynergydrive.com/en/electric_motor.html), can use significant amounts of REEs: according to Gorman (2009), the motor in the Prius uses 1 kg of Nd, or 16-kg/MW (assuming that the Prius has a 60-kW motor [www.hybridsynergydrive.com/en/electric_motor.html]).[13] 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 still would 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 the U.S. Geological Survey (USGS) *Minerals Commodity Summaries* (USGS, 2009).

Table 6. Lithium production, reserves and resources worldwide as of 2009 (metric tonnes)

Country	Mine production 2008	Reserves	Reserve Base	Resources
United States	n.r.	38,000	410,000	n.r.
Argentina	3,200	n.r.	n.r.	n.r.
Australia	6,900	170,000	220,000	n.r.
Bolivia	0	0	5,400,000[a]	n.r.
Chile	12,000	3,000,000	3,000,000	n.r.
China	3,500	540,000	1,100,000	n.r.
World total	*27,400*	*4,100,000*	*11,000,000*	*> 13,000,000*

Source: USGS (2009). n.r. = not reported. For explanation of terms, see notes to Table 5.

[a] 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.

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[13] Another expert estimates that the Prius' permanent magnet motors have 0.45 kg Nd per motor (www.magnetweb.com/Col04.htm).

[14] See van Schaik and Reuter (2004) for a general discussion of the factors that influence the recycling rate of products.

Note that Table 6 does not include the recently discovered, potentially large lithium reserves in Afghanistan (http://www.nytimes.com/2010/06/14/world/asia/14minerals.html). Roughly half of the global lithium reserve base known in 2009 is in one country, Bolivia, which *Time* magazine has called "the Saudi Arabia of lithium" (www.time.com/time/world/article/0,8599,1872561,00.html). 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 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 (Li_2CO_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 $1,000, which would increase vehicle costs further.

At 10 kg per vehicle, the production of 26 million EVs per year – half of the total passenger-car production in the world in 2008 (http://oica.net/category/production-statistics/) – 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 which 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 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, 2002b; 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.[14] 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.[15]

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[15] Indeed, catalysts based on inexpensive, abundant materials may be available relatively soon: Lefèvre et al. (2009) report that a microporous carbon-supported iron-based catalyst was able to produce a current density equal to that of a platinum-based catalyst with 0.4 mg-pt/cm^2 at the cathode. Although the authors note that further work is needed to improve the stability and other aspects of iron-based catalysts, this research suggests a world-wide fuel-cell vehicle market will not have to rely on precious-metal catalysts indefinitely.

[16] 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. 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 neighbouring markets for two months from

Preliminary work by Sun et al. (2010a) 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. Variability and Reliability

A new WWS energy infrastructure must be able to provide energy on demand at least as reliably as does the current infrastructure (e.g., DeCarolis and Keith, 2005). In general, any electricity system must be able to respond to changes in demand over seconds, minutes, and hours, 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 (DeCarolis 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), 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 U.S. from 2000-2004 was down 6.5% of the year for unscheduled maintenance and 6.0% of the year for scheduled maintenance (North American Reliability Corporation, 2009), but modern wind turbines have a down time of only 0-2% over land and 0-5% over the ocean (Dong Energy et al., 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, natural gas) and outages of distributed plants (wind, solar, 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.[16]

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. (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 does vary 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, 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.)[17]

A) Interconnect dispersed generators. Interconnecting geographically-disperse 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; DeCarolis and Keith, 2007; Archer and Jacobson, 2003, 2007; U.S. DOE, 2008a; 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 hours per 1000 hours, and by at least 50% of rated capacity in 5.7 to 39 hours per 1000 hours. However, when three dispersed sites were considered together, there were no hours when the output changed by 100%, and only zero to 1.9 hours per 1000 hours when the output changed by at least 50%. In another study, when 19 geographically disperse wind sites in the Midwest, over a region 850 km

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[17] Note that the issue we discuss here – variability in a 100% WWS power system – is not the same as 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.

x 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 U.S., for 1973 to 2008, and compared this with observed hydropower in the U.S. 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 U.S. were about half of the national variations in hydropower output.

Finally, we note that interconnection of dispersed photovoltaic sites also reduces variability. 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 minutes is on the order of 20, 50, and 150 km.
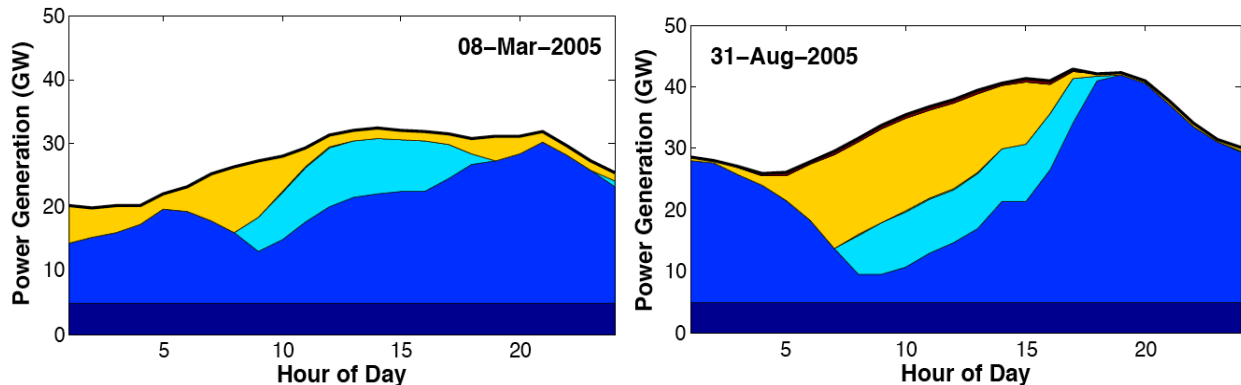
B) Use complementary and non-variable sources to help supply match demand.
The complementary nature of different renewable energy resources can also be taken advantage of to match minutely and hourly power demand. For example, when the wind is not blowing, the sun is often shining and vice versa. Some studies that have examined combining WWS renewables to match demand over time include those that have examined combining wind, solar, and geothermal (CWEC, 2003); wind, solar, and wave (Lund, 2006), wind, solar, and hydroelectric (Czisch, 2006; Czisch and Geibel, 2007); wind, solar, geothermal, and hydroelectric (Hoste et al., 2009; Jacobson, 2009; Jacobson and DeLucchi, 2010; Hart and Jacobson, 2010), and wind, solar, and battery storage (Ekren and Ekren, 2010; Zhou et al, 2010).

Figure 3 presents an example of the use of wind (variable), solar (variable), geothermal (baseload), and hydroelectric (gap-filling) together to match hourly power demand plus transmission and distribution losses on two days in California in 2005 from Hart and Jacobson, (2010). The geothermal power delivered was increased slightly over 2005 levels but was limited by California's geothermal resources, and the hydroelectric power delivered was the actual amount delivered on those days. Only wind and solar were increased substantially. The figure illustrates the potential for matching power demand hour by hour. A match could be obtained on more than 95% of the hours of the year. The remaining hours are expected to be matched with demand-response, with storage beyond CSP, by adding electric vehicle charging and management, and by increasing wind and solar supplies further, 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.

Figure 3. Least-cost (in terms of levelized cost of electricity) optimal solution to matching 100% of California's electricity demand plus transmission/distribution losses with load-matching renewables on two days in 2005.

Notes: Dark blue = geothermal; medium blue=wind; light blue=concentrated solar with storage; yellow=hydroelectric; black=power demand plus transmission and distribution losses of 7%. The least-cost optimization accounts for the day-ahead forecast of hourly resources, carbon emissions, wind curtailment, and storage. The hydroelectric supply is the actual supply used on each day. 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 and a specific concentrated solar plant configuration (parabolic trough collectors on single-axis trackers). The geothermal supply was limited by California's developable resources. From Hart and Jacobson (2010).

To improve the efficiency and reliability of variable electric power sources, an organized and interconnected transmission system 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.

C) 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).

D) 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), in batteries (e.g., Lee and Gushee, 2009), hydrogen gas (e.g., for use in HFCVs), 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. 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.

E) Oversize WWS generation capacity to match demand better and to produce H_2. 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_2 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 won't 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), Aguado et al. (2009) (for storage, sales, and electricity production), and Martin and Grasman (2009) (for transportation). 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.

F) 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. 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).[18] 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 U.S. electricity demand, 3.2% of the U.S. 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 U.S. electricity demand), 38% of the U.S. 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 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 U.S. LDV fleet would have to be fuel-cell powered and be on V2G contract.

G) 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; U.S. DOE, 2008a; Lange et al., 2006; 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 U.S. found that state-of-the-art wind and solar forecasting reduces operating costs by $0.01/kWh to $0.02/kWh, compared to no forecasting (GE Energy, 2010).

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

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[18] For discussions of issues involved in implementing V2G, see Andersson et al. (2010), Kempton and Tomic (2005b), and especially Sovacool and Hirsch (2009).

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. 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-demand balancing method of last resort.) These cost estimates are included in the following section on the cost of WWS electricity generation, transmission, and decentralized storage.

7. 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.[19] 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.

Cost of generation and conventional transmission. Table 7 presents estimates of current (2005 to 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 U.S. 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 7 indicate that wind, hydroelectric, and geothermal systems already can cost less than typical fossil and nuclear generation, and that in the future wind power is expected to cost less than any other form of

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[19] Electricity generation technologies sometimes are compared on the basis of the capital cost per kW of power capacity, but because this is neither a complete measure of the relevant costs nor a measure of the energy provided, it is not a useful basis for comparison. In Appendix A.3 we show EIA (2009a, b) estimates of capital costs for various generating technologies, and then derive total amortized+operating costs per kWh from the capital costs and other parameters.

large-scale power generation.[20] If alternatives are compared on the basis of social cost, all WWS options, including solar PVs, are projected to cost less than conventional fossil-fuel generation in 2030.

The cost ranges shown in Table 7 are based partly on our own cost estimates, detailed in Tables A.3c and A.3d of Appendix A.3. Appendix A.3 presents two sets of calculations: one with the reference-case parameter values used by the by the Energy Information Administration (EIA) in its *Annual Energy Outlook* (our Tables A.3a and A.3b), and one with what we think are more realistic values for some key parameters (Tables A.3c and A.3d). The estimates based on the EIA reference-case are higher than the estimates shown in Table 7 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 7. This exercise gives us confidence in the estimates of Table 7.

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[20] 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, so low capacity factors could mean an efficient wind turbine is located in a poor-wind location or an inefficient turbine is located in a wind-rich location. Capacity factors of newer-generation turbines have generally increased relative to those of older turbines. 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 2004-2007. Boccard (2009) reported that the capacity factor from 2003-2007 averaged only 21% in Europe and 26% in the U.S. By contrast, Berry (2009) estimates that the capacity factor for 34 large wind farms in the U.S. 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 U.S. 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 7), without including the value of any externalities.

Table 7. Approximate fully annualized generation and conventional transmission costs for WWS power

Energy Technology	Annualized cost (~2007 $/kWh-delivered)	
	Present (2005-2010)	*Future (2020+)*
Wind [a]	$0.04 to $0.07	≤ $0.04
Wave [b]	≥ $0.11	$0.04
Geothermal [c]	$0.04 to $0.07	$0.04 to $0.07
Hydroelectric [d]	$0.04	$0.04
CSP [e]	$0.11 to $0.15	$0.08
Solar PV [f]	> $0.20	$0.10
Tidal [g]	>$0.20	0.05-0.07
Conventional (mainly fossil) generation in U.S. [h]	$0.07 (social cost: $0.12)	$0.08 (social cost: $14)

[a] Present costs are from Sovacool and Watts (2009), Schilling and Esmundo (2009), Berry (2009), Benitez et al. (2008), Cavallo (2007), Greenblatt et al. (2007), DeCarolis and Keith (2006), Boccard (2010), and Table A.3c; where 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.3d. Cavallo's (2007)_estimate of $0.05/kWh to $0.06/kWh and Greenblatt et al's (2007) estimate of $0.06/kWh include transmission cost and the cost of compressed air storage; DeCarolis 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 U.S. 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).

[b] 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.

[c] Present costs are from Sovacool and Watts (2009), Schilling and Esmundo (2009), and Table A.3c; 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.3d

[d] 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.3c and Table A.3d we estimate slightly higher costs.

[e] 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.

[f] 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.

[g] Current tidal costs are based on 240 MW La Rance station, France (http://www.global-greenhouse-warming.com/tidal.html). Future costs assume currents >3.5 m/s (http://peswiki.com/index.php/PowerPedia:Tidal_Power)

It is worth emphasizing that 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 2006-2009. 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 meters 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. (In comparison, wind speeds over land need to be about 7 m/s or faster for wind energy to be economical.) Installed tidal power to date is relatively expensive (Table 7) 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, However, another analysis suggest relatively inexpensive tidal power in the future so long as turbines are located in currents 3.5 m/s or faster (Table 7).

As shown in Table 7, 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 (Table 3), but presently are relatively expensive (Table 7), 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 7; 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 hours 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 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 the last section.

Cost of extra-long-distance transmission. The estimates of Table 7 include the cost of electricity transmission in a conventionally configured system, over distances common today. However, as discussed in section 6, 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.

In Appendix A.4 we presents our calculation of the $/kWh cost of long-distance transmission 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.4a 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.4 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.4, we estimate that the additional cost of extra-long-distance transmission, beyond the transmission costs of a conventional system, range from $0.003/kWh to $0.04/kWh, with a best estimate of about $0.01/kWh.

V2G decentralized storage. As discussed in section 6, 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.5, we estimate all three costs of a V2G scheme, and draw three conclusions:

1) If Li-ion batteries have a cycle life > 5,000 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 to $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.5.

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/kWh to $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 less than $0.01/kWh-generated.

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 likely to be less than $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 7).

8. 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 the notes to Table 2, 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 U.S. (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 U.S. 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., 2010b; 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.[21] 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, Mancura (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 to 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. (2010b) and Chernyavs'ka and Gullí (2009) indicate that present value of the stream of the external costs of a renewable-hydrogen fuel-cell car is about $500 to $12,000 less than the present value of the stream of the 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.

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[21] 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).

9. Summary of Technical Findings

• The amount of wind power plus solar power available in *likely developable locations* exceeds projected world power demand by more than an order of magnitude. 3.8 million 5-kW wind turbines could supply 50% of projected total global power demand in 2030.

• 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 noticeably affect the economics of WWS systems, but the cost of large-scale recycling of lithium batteries is unknown.

• A 100% WWS world will 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 heat 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 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 less than \$0.02/kWh, for both) is included.

10. Policy Issues

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 U.S. and abroad to stimulate production of renewable energy: feed-in tariffs, output subsidies, investment subsidies, and output quotas. 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., 20089]) 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 scale-up economies of scale that can lower costs, FITs should be reduced gradually (Couture and Cory [2009] call this an "annual tariff digression"). 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 regression" 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[22] or taxing fossil fuel production and use to reflect its environmental damages (e.g., with "carbon" taxes that represent the expected cost of climate change due to CO_2 emissions). Note, though that current subsidies and expected environmental-damage taxes generally are smaller (and hence less effective) than are FITs for the costliest WWS systems versus the cleanest fossil-fuel systems, unless climate change damage is valued at the upper end of the range of estimates in the literature (National Research Council, 2010 [Table 8 here]; Krewitt, 2002; Koplow, 2004; Koplow and Dernbach, 2001). For example, the U.S. National Research Council (2010) estimates that the external costs of air pollution and climate change from fossil-fuel electricity generation in the U.S. total $0.03 to $0.11/kWh for 2005 emissions, and $0.03 to $0.15/kWh for 2030 emissions (using the mean air-pollution damages and the low and high climate change damages from Table 8). (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_2-equivalent emission rather than to uncertainty in estimates of emissions [NRC, 2010].)

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[22] The Environmental Law Institute (2009) estimates that U.S. government subsidies to fossil fuel energy amount to about $10 billion per year. Subsidies to the biofuels industry may be even larger: Koplow (2009) estimates that, absent changes in current policies, taxpayers will pay over $400 billion in subsidies to the biofuels industry between 2008 and 2022. Koplow also asserts that this subsidy "accelerates land conversion and exacerbates a wide range of environmental problems" (p. 4), and we agree. The Global Subsidies Initiative provides links to a number of reports on subsidies to fossil fuels and biofuels in various countries (www.globalsubsidies.org/en/research/biofuel-subsidies and www.globalsubsidies.org/en/research/fossil-fuel-subsidies).

Table 8. Environmental external costs of electricity generation in the U.S. (year 2007 US cents/kWh)

	Air pollution 2005			Air pollution 2030	Climate change (2005/2030)		
	5th %	Mean	95th %	Mean	Low	Mid	High
Coal [a]	0.19	3.2	12.0	1.7	1.0/1.6	3.0/4.8	10/16
Natural gas [a]	0.0	0.16	0.55	0.1?	0.5/0.8	1.5/2.4	5.0/8.0
Coal/NG mix [b]	n.a.	2.4	n.a.	1.3	0.9/1.4	2.6/4.2	8.8/14
Wind, water, solar power [c]	0.0	0.0	0.0	0.0	0	0	~0

[a] 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. 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 natural gas and coal, and the generation-weighted mean damages from all coal plants in 2030. We assume that the generation-weighed mean damages from all natural gas plants in 2030 are about half the estimated mean in 2005, because this is approximately the change estimated for coal plants from 2005 to 2030. 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_2$-equivalent (low), $30/$CO_2$-equivalent (mid) or $100/$CO_2$-equivalent (high), for emissions in 2005. The NRC (2010) says that the marginal damage cost of emissions in 2030 could be 50% to 80% higher; we assume 60%. n.a. = not applicable.

[b] 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).

[c] 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. 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.

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 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). 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, 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.

11. Conclusion

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. In addition, we need to greatly expand 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.

Of course, the complete transformation of the energy sector would not be the first large-scale project undertaken in U.S. or world history. During World War II, the U.S. 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 U.S., production increased from about 2,000 units in 1939 to almost 100,000 units in 1944. In 1956, the U.S. 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). And 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 mainly 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.

The obstacles to realizing this transformation of the energy sector are primarily social and political, not technological. As discussed above, 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.

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APPENDIX 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 Hultuman (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 to $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/kWh 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/kWh to $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.

APPENDIX A.2. **NOTES TO TABLE 2.**

TW power in 2030 (fossil-fuel case)
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 the EIA *International Energy Outlook 2008* (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.

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 will 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:

Residential sector. We assume that 5% of fuel use for space heating and 20% of fuel use for "appliances" (mainly cooking) is *not* electrified, and then use data from Table 2.5 of the EIA's *Annual Energy Review 2007* (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.

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.

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, is *not* electrified, and then use data on manufacturing consumption of energy in the U.S. (Table 2.3 of the EIA's *Annual Energy Review 2007* [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.

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 is *not* electrified. We use data on transport energy consumption from the International Energy Agency (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.

<u>Non-electrified energy services</u>. 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 assumed that hydrogen is liquefied and burned in jet engines. Coenen (2009), Nojoumi et al. (2009), Janic (2008), Maniaci (2006), Mital et al. (2006), Corchero and Montañes (2005), Koroneos et al. (2005), and Westenberger (2003) discuss various aspects of liquid-hydrogen-powered aircraft. Westenberger (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 to 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.

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_2), 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_2 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 follows:

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_2/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_2 rather than compressed H_2, 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)*

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 windmills), 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 can be described as follows:

Sector	Fossil-fuel world	WWS world	Difference	Our treatment
Mining – oil, gas, coal	Energy use in this sector typically is 1% to 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) 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% to 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 vs. 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, natural-gas processing.	Compression and liquefaction of hydrogen.	Significant net energy reduction in WWS world.	Estimated; see below.

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 following:

Value	Parameter	Data source
1.12	Multiplier for electricity requirements of H_2 compression for transportation (10,000 psi) (BTUs-electricity plus BTUs-H_2/BTU-H_2)	*AVCEM (Delucchi, 2005)*
1.32	Multiplier for electricity requirements of H_2 liquefaction for transportation, mainly air transport (includes boil-off losses) (BTUs-electricity plus BTUs-H_2/BTU-H_2)	*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, 2009a, 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, 2009a, 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, 2009a, 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, 2009a, Table 6).*

Although 5% to 10% of the volumetric output of refineries is non-fuel product such as lubricants, petrochemical feedstocks, road asphalt, and petroleum coke (http://tonto.eia.doe.gov/dnav/pet/PET_PNP_PCT_DC_NUS_PCT_A.htm), these products require much less than 5% to 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.

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 includes 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). (For a general discussion of the potential to reduce energy use in transportation and buildings, see the American Physical Society [2008]).We assume that EHCMs can achieve modest reductions in energy demand, on the order of 5% to 15% in most cases.

TW power in 2030 (WWS case)

World and 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. Calculated from the other values in the table.

APPENDIX A.3. ESTIMATES OF $/KW CAPITAL COSTS AND TOTAL AMORTIZED + OPERATING $/KWH COSTS FOR VARIOUS GENERATING TECHNOLOGIES.

Table A.3a. Estimates of generation costs using EIA (2009a, b, c, d) 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 ($/kW/yr)	Fuel ($/$10^6$-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	11.7	8.87	51%	$0.031	$0.065	$0.096
NG adv. CC/CCS	1890	42%	20	0.0029	19.9	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	30.3	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

Table A.3b. Estimates of generation costs using EIA (2009a, b, c, d) 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 ($/kW/yr)	Fuel ($/10^6-BTU)	Fuel effic.	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	11.7	8.34	54%	$0.021	$0.058	$0.079
NG adv. CC/CCS	1340	46%	20	0.0029	19.9	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	30.3	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.3a and A.3b.
Cap. factor = capacity factor; Fuel effic. = 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.

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 U.S. This is $2060/kW, very close to the EIA estimate for wind in 2008 shown in Table A.3a. Wiser and Bollinger (2008, 2009) show that 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 $1350/kW in 2002 to $1900/kW in 2008, due mainly to a near doubling of turbine prices over the period.[23] The U.S. DOE (2008a) study of 20% wind power in the U.S. uses a consultant report that estimates that estimates that wind costs $1650/kW in 2010 and $1480/kW in 2030 (2006 USD). Boccard (2010) estimates investment costs of $3,080/kW for nuclear, $2,100/kW for coal (similar to the EIA value in Table A.3a), $840/kW for gas (comparable to EIA's estimate in Table A.3a), and $1,540/kW for onshore wind (somewhat lower than EIA's estimate for onshore wind in Table A.3a) (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 U.S. 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. Capacity factor for coal and natural gas for 2008 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.

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).

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[23] Wiser and Bollinger (2008) 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 material and energy prices are likely to continue to put upward pressure on turbine costs in the long run.

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.

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.3a and A.3b, 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 U.S. DOE (2008a) study of 20% wind power in the U.S. 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 on-shore wind; the EIA estimates of "fixed" O&M costs in Table A.3a are slightly lower, around 1.5% of investment costs.

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). 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 Figure 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.3c. Estimates of generation costs using alternative values for lifetime and discount rate, for 2008 (year 2007 $/kWh)

Technology	INPUT PARAMETERS							CALCULATED RESULTS		
	Capital cost ($/kW)	Cap. factor	Life (years)	Variable O&M ($/kWh)	Fixed O&M ($/kW)	Fuel ($/10^6-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	11.7	8.87	51%	$0.021	$0.065	$0.086
NG adv. CC/CCS	1890	42%	30	0.0029	19.9	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	30.3	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.3d. Estimates of generation costs using alternative values for lifetime, discount rate, and WWS capital cost, for 2030 (year 2007 $/kWh)

Technology	INPUT PARAMETERS							CALCULATED RESULTS		
	Capital cost ($/kW)	Cap. factor	Life (years)	Variable O&M ($/kWh)	Fixed O&M ($/kW)	Fuel ($/10^6-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	11.7	8.34	54%	$0.014	$0.058	$0.072
NG adv. CC/CCS	1340	46%	30	0.0029	19.9	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	30.3	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.3c and A.3d. All parameter values the same as in Tables A.3a and A.3b, except that the discount rate is 7.0% (rate recommended by OMB [2003] and used here in V2G analysis [Appendix A.5]; 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, 2010]), 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.

<u>Discussion of estimates based on the EIA reference-case parameters</u>. To validate our calculation method, we can compare our estimates of generation costs based on the EIA's parameter values, in Tables A.3a and A.3b, with what the EIA actually calculates in the National Energy Modeling System (NEMS) (Table A.3e).

Table A.3e. EIA (2009a) NEMS breakdown of electricity prices (year-2007 cents per kWh):

	year 2008	year 2030
generation	6.5	6.9
transmission	0.7	0.9
distribution	2.3	2.3

The estimates in Table A.3e 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.3a 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.3a and A.3b vs. Table A.3e).

In Table A.3a, we estimate that according to EIA's cost parameters, *new* coal-fired generation in the year 2008 costs 6.5 cents per kWh, new hydro costs 5.2 cents per kWh, and *new* advanced gas costs 9.6 cents per 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 per 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.3e).

However, we cannot reproduce the EIA results for 2030. On the one hand, the EIA parameter values shown in Table A.3b 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.3b (compare Table A.3b results with Table A.3a results). Yet the EIA's actual cost calculations in NEMS, shown in Table A.3e, indicate that average costs *rise* from 2008 to 2030. We cannot explain this discrepancy.

APPENDIX A.4. THE COST OF LONG-DISTANCE ELECTRICITY TRANSMISSION.

In this appendix we estimate the cost of electricity transmission, in dollars per kWh of electricity into the local electricity distribution system. Table A.4a shows the parameters in our calculation and our low-cost, mid-cost, and high-cost assumptions. Table A.4a also explains the bases of our assumptions, except in the case of the $/MW$_{TS}$-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.

<u>Separate estimates of the cost of the transmission lines and the cost of station equipment</u>. In our analysis, presented in Table A.4a, 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 ($/MW$_{TS}$-km), and the cost of the station equipment (transformers, power conditioners, converters, filters, switches, etc.) per MW of transmission-system capacity ($/MW$_{TS}$). In this section, we review estimates of these costs. In the next subsection, we review estimates of the cost of the entire system – lines, towers, station equipment – and use these to calibrate our parameter estimates.

Table A.4b 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 DeCarolis and Keith [2006] and 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 to 0.45 million Euro per km, or about $0.3 to $0.6 million USD per km, and that converter stations cost about $200 million (USD). These estimates of line costs ($0.3 to $0.6 million/km) are substantially lower than Bahrman's; the estimates of station-equipment costs ($200 million to $452 million) are somewhat lower than but overlapping with Bahrman's (2006) (Table A.4b). On the other hand, in their recent detailed assessment of the costs of integrating 20% to 30% wind power in the Eastern Interconnection region of the U.S. (basically the eastern half of the country), EnerNex (2010) assumed a total cost of $3.7 million/km for 800 kv HDVC 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 million/km and $1.7 million/km, roughly twice the figures estimated by Bahrman (Table A.4b).

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.4b).[24]

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[24] 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 Alegría 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.

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_{TS}$-km to $550/ MW_{TS}-km (Table A.4b).

Denholm and Sioshani (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 [www.energy.siemens.com/hq/en/power-transmission/hvdc/hvdc-ultra/]) 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,[25] these figures correspond to $200 and $400/$MW_{TS}$-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_{WC}$ in 7 "electric power" regions of the U.S., $150/$kW_{WC}$ in 3 regions, and $230 to $320/ kW_{WC} in 3 regions. (The subscript WS refers to wind-farm capacity.) The costly regions are all in the Western U.S.: the Northwest Power Pool, the Rocky Mountain Area, and California and Nevada. If one assumes that these figures correspond to 500-km to 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_{TS}-km to $640/ MW_{TS}-km.

The U.S. DOE (2008a) study of 20% wind power in the U.S. 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 U.S. DOE assumed that new transmission line capacity cost $1,600/MW-mile in most areas of the U.S., and $1920 to $2240/MW-mile (20% to 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

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[25] In their detailed analysis of the cost of transmission for wind power additions, Mills et al. (2009) assumed that "new transmission is sized to exactly the size required by the incremental generation added in a particular scenario" (p. 28).

transmission-system capacity.) The U.S. DOE (2008a) also assumed that the "typical line is a 200-mile, 230-kV line rated at 170 megavolt amperes" (p. 188), or 170 MW (ignoring here the difference between real power and apparent power for AC transmission). This assumption -- $1000/MW$_{WC}$-km for 170 MW$_{TS}$ transmission-system capacity – is roughly consistent with the trends in Denholm and Sioshani (2009), which indicate $300/MW-km for 3000 MW$_{TS}$, about $600/MW-km for 1500 MW$_{TS}$, and about $800/MW-km for 500 MW$_{TS}$.

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

The U.S. DOE's (2008a) WindDS simulation estimated that 33 million MW$_{WC}$-miles (p. 161) (53 million MW$_{WC}$-km) of wind transmission on 12,650 miles of new transmission lines costing $60 billion (p. 98)[26] would be needed for the 233 GW of new wind power not using existing transmission lines. This amounts to $258/kW$_{WC}$ and $1132/MW$_{WC}$-km. The result of $1132/MW$_{WC}$-km is consistent with their stated assumption of a cost of $1000/MW$_{WC}$-km in most regions and a cost 20% to 40% higher in a few regions (see previous paragraph).

In a "derivative effort associated with the" U.S. DOE (2008a) study of 205 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 U.S. would cost $60 billion (2007 USD), including station integration, DC connections, and other related costs. This amounts to $150/ kW$_{WC}$ to $300/ kW$_{WC}$, which is consistent with estimates in Mills et al. (2009) 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 to 7200 MW, which indicates a cost of $260/MW$_{TS}$-km (at 7200 MW capacity) to $530/MW$_{TS}$-km (at 3600 MW capacity). This is only slightly higher than the figures from Denholm and Sioshani (2009), which indicate that three 3800-to-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 (www.nrel.gov/analysis/winds/transmission_cost.html), 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€/kW to 160€/kW (in 2008 Euros), or about $50/kW to $250/kW. (Presumably, the kW in the denominator refer to kW of wind.) If transmission distances in Europe are half of those in the U.S. – say, 250 km to 500 km – then these figures correspond to $100/MW$_{WC}$-km to $1000/MW$_{WC}$-km.

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[26] Elsewhere [p. 188], the U.S. DOE (2008a) notes that it allocated half of the actual total transmission cost to wind, and half to ratepayers. It appears that the reported $60 billion is the total actual cost, but it is possible (albeit unlikely) that it is only the half allocated to wind. It is unlikely because as noted above the figure of $60 billion results in $1132/MW$_{wc}$-km which is consistent with their assumptions regarding the cost per MW$_{wc}$-km.

Mills et al. (2009) provide the most comprehensive analysis of the cost of transmission for wind power. Mills et al. (2009) 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., 2009, p. ix). (The economies-of-scale effect is the decrease in unit cost as the transmission voltage increases.)

Table 2 of Mills et al. (2009) 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/MW-km to $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_{TS} or more costs in the range of $200/MW-km to $500/MW-km. Note that this includes the cost of station equipment.

Discussion of results. The results of our analysis are shown in Table A.4a. For comparison, the EIA (2009a, Table A8) estimates $0.009/kWh average transmission cost for all generation in the U.S. 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 (http://webblade-a3dev.nrel.gov/winds/transmission_cost.asp). 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 (www.nrel.gov/analysis/winds/transmission_cost.html):

> "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.4 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.3, 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. (2009), 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.

Table A.4a. The cost of electricity transmission

Component	Low	Mid	High	Source of estimate and notes
Transmission-line cost ($/MW$_{TS}$-km)	200	280	340	Table A.4b and discussion in Appendix text. This is the cost per MW of transmission system capacity. Includes land, towers, and lines, but no station equipment.
Extra transmission distance in supergrid (km)	1200	1600	2000	Our assumptions. Note that this is the distance beyond what is typical in a conventional electricity transmission system.
Reference cost for station equipment (transformers, power conditioners, converters, etc.), at reference power ($/MW$_{TS,REF}$)	100,000	125,000	150,000	Table A.4b and discussion in Appendix text.
Reference transmission-system power (for reference station-equipment cost) (MW$_{TS,REF}$)	4,000	4,000	4,000	Table A.4b and discussion in Appendix text.
Exponent b on power in station-equipment cost function	0.75	0.75	0.75	The station-equipment cost function is $/MW$_{TS}$ = $/MW$_{TS,REF}$·(MW$_{TS}$/MW$_{TS,REF}$)^b. De Alegría 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 P is power.
Power capacity of transmission system (MW$_{TS}$)	5,000	5,000	5,000	Our assumptions.
Ratio of MW capacity of transmission system to MW capacity of served wind farms (MW$_{TS}$/MW$_{WC}$)	70%	80%	90%	In a study of adding up to 35% wind and solar power in the western interconnection region of the U.S., 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.3 and footnote 20.
Electricity loss in transmission line (%/1000-km, at rated line capacity)	3%	4%	6%	According to Siemens, the losses from a 6.4 GW, 800kV DC line are 3.5%/1000-km, and the losses from a 3 GW, 500 kV DC line are 6.6%/1000-km (www.energy.siemens.com/hq/en/power-transmission/hvdc/hvdc-ultra/) Bahrman (2006) estimates slightly lower losses (Table A.4b).
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 Alegría et al. (2009) write that converter losses are 1% to 2%. Negra et al.'s (2006) detailed evaluation of HVDC transmission losses for wind systems finds that converter station losses are 1.4% to 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), Electric Power Research Institute (2010), Quest Reliability (www.questreliability.com/Default.aspx?tabid=177), and Electric Energy Online (www.electricenergyonline.com/?page=show_article&mag=26&article=200) suggest a life of at least 50 years for towers and lines.
Lifetime – station equipment (yrs)	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 (%/yr.)	3%	7%	10%	The OMB (2003) recommends a range of 3% to 7% (see Table A.5a). As discussed in notes to Table A.3, the EIA's NEMS estimates a weighted-average cost of capital power-plant construction of about 10% (EIA, 2009c).
Capital cost of line, land, tower ($/MW$_{TS}$)	**240,000**	**448,000**	**680,000**	
Capital cost of station equipment ($/MW$_{TS}$)	**118,000**	**148,000**	**177,000**	
Capital cost of transmission system ($/MW$_{TS}$-km)	**299**	**372**	**429**	*This quantity is calculated for comparison with estimates of total transmission-system capital cost in other studies*
Total cost of extra transmission ($/kWh)	**0.003**	**0.012**	**0.032**	

Table A.4b. 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 $)
1,207	2,414	1,207	1,207	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)
$1,200	$2,400	$1,350	$1,463	Transmission line cost (million $)
$1,620	$3,080	$1,815	$1,973	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[a]
5.3%	1.4%	4.1%	2.8%	Losses (% of power per 1000 km/ at rated capacity)

[a] 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.

APPENDIX A.5. 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 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.5a 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.

Table A.5a. Calculation of the $/kWh Cost of V2G cycling of EV Batteries

Part 1. Inputs.

BEV	PHEV	PARAMETER	BASIS
30	10	Discharge capacity of the battery to 100% depth of discharge (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 ($/kWh).	Estimates in and discussion of Table A.5b.
5.0	4.5	Efficiency of vehicle on battery (mi/kWh-battery-discharge).	Based on AVCEM, Kromer and Heywood (2007), for a mid-size BEV.
10,000	5,000	Annual distance on battery (miles/year).	Our assumptions.
1.6/ 2.1		Low-cost/high-cost ratio of retail cost to manufacturing cost.	Low is based on ratio of retail to OEM cost in Santini (2010); high is from AVCEM.
5500/ 3500		Low-cost/high-cost cycle life (to 80% DoD).	Table A.5b.
15/ 30		Low-cost/high-cost calendar life (years).	Table A.5b.
80%		DoD in battery cycle life tests (%).	Standard DoD for measuring cycle life.
250		Service cost of installing new battery and removing old battery and deploying it in non-automotive applications ($).	We assume 5 hours total labor at $50/hour.
20%/10%		Low-cost/high-cost estimate of value of old battery in NAAs after end of useful life as a motor-vehicle battery (% of total retail cost).	There are several potential NAAs for old Li-ion batteries (Burke, 2009), but it is not clear how long they will last in secondary uses.
50		Hedonic cost of battery replacement ($).	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 U.S. 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 ($/kWh).	Low assumes only some generation costs are affected; high assumes the long-run marginal cost of electricity to residential sector (www.eia.doe.gov/oiaf/aeo/aeoref_tab.html).
150		Cost of *extra* electronics and infrastructure to manage V2G system, per vehicle ($).	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.

Table A. 3a. Calculation of the $/kWh Cost of V2G cycling of EV Batteries

Part 2. Calculated values

BEV				PHEV				
No V2G		*V2G*		*No V2G*		*V2G*		
low	*high*	*low*	*high*	*low*	*high*	*low*	*high*	
9,600	18,900	9,600	18,900	4,800	8,400	4,800	8,400	Cost of replacement battery ($)
15.0	30.0	15.0	9.3	15.0	25.2	15.0	8.1	Lifetime of battery in vehicle use (based on calendar life or cycling to 80% DoD) (years)
7,980	17,310	7,980	17,310	4,140	7,860	4,140	7,860	Cost of battery replacement, including new battery cost with installation, removal of old battery, net of value of old battery in NAAs.
176%	143%	176%	32%	56%	111%	56%	27%	Discount rate for the period of time equal to the battery life (%/period)
0	0	2,062	8,249	0	0	687	2,750	Electricity diverted to V2G cycling, measured at input to battery charger, per year (based on cycling normalized to 80% DoD) (kWh-sent-to-battery-charger/year)
								Components of the cost of V2G cycling, per kWh diverted to V2G cycling ($/kWh-sent-to-battery-charger)
n.a.	n.a.	0.000	0.154	n.a.	n.a.	0.000	0.238	Annualized cost of present value of change in battery-replacement and disposal frequency, due to V2G cycling*
n.a.	n.a.	0.007	0.001	n.a.	n.a.	0.015	0.004	Annualized cost of extra electronic and infrastructure
n.a.	n.a.	0.008	0.021	n.a.	n.a.	0.008	0.021	Cost of replacing electricity lost in charge/discharge cycling
n.a.	n.a.	**0.014**	**0.176**	n.a.	n.a.	**0.022**	**0.263**	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 below.

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}:

$$ANN_{BR} = PV_{BR} \cdot r_A \cdot \left(1 - \left(1 + r_A\right)^{-n}\right)^{-1}$$

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

$$PV_{BR} = PMT_{BR} \cdot \left(1 - \left(1 + r_{BR}\right)^{-\left(n \cdot P_{BR}^{-1}\right)}\right) \cdot r_{BR}^{-1}$$

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

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

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

$$PV_{BR} = PMT_{BR} \cdot \left(1 - \left(1 + \left(1 + r_A\right)^{P_{BR}} - 1\right)^{-\left(P \cdot P_{BR}^{-1}\right)}\right) \cdot r_{BR}^{-1} = PMT_{BR} \cdot \left(1 - \left(1 + r_A\right)^{-P}\right) \cdot r_{BR}^{-1}$$

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

$$ANN_{BR} = PMT_{BR} \cdot \left(1 - \left(1 + r_A\right)^{-P}\right) \cdot r_{BR}^{-1} \cdot r_A \cdot \left(1 - \left(1 + r_A\right)^{-P}\right)^{-1} = PMT_{BR} \cdot r_A \cdot r_{BR}^{-1}$$

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.

Table A.5b. Manufacturing cost and life of lithium batteries

Part 1. Estimates from Burke and Miller (2009)

Chemistry anode/ cathode	kWh	OEM cost ($/kWh)[a]	Cycle life (deep)[b]
Graphite/ LiNiCoAlO$_2$ (NCA)	10.1	279	2000 to 3000
	20.2	205	2000 to 3000
Graphite/ LiFePO$_4$ (LFP)	9.4	302	> 3000
	18.7	222	> 3000
Lithium titanate/ LiMnO$_2$ (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)[c]	>12	>10	>20	>10	>8	>8
OEM cost ($/kWh)[d]	210-330		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.

[a] The cost estimates by Burke and Miller (2009) are based on detailed cost modeling done 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 vs. 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/kWh to $500/kWh in mass production. All of these estimates are similar.

[b] By comparison, in the Peterson et al. (2010b) tests described above the cycle life of lithium iron phosphate at 80% DoD exceeded 5,000. 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 $LiNiO_2$ cathode achieved 5250 deep cycles with a loss of 18% capacity.

[c] 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 $LiFePO_4$ cell loses only 5% to 15% of its capacity (depending on temperature) after 15 years of open-circuit-voltage storage at 50% state of charge.

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

The results of our analysis, shown in Table A.5a, 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.5b, 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.5a, 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$_4$ 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.5a, 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.5a), and $0.088/kWh for the PHEV case (versus $0.238/kWh in Table A.5a). (The low-end costs are the same as in Table A.5a – 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.5a.) 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.5a, and as a result the cost of V2G cycling is much less than in Table A.5a