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

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ABSTRACT

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

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

One of the major concerns with the use of energy supplies, such as wind, solar, and wave power, which produce variable output is whether such supplies can provide reliable sources of electric power second-by-second, daily, seasonally, and yearly. A new WWS energy infrastructure must be able to provide energy on demand at least as reliably as does the current infrastructure (e.g., De Carolis and Keith, 2005). In general, any electricity system must be able to respond to changes in demand over seconds, minutes, hours, seasons, and years, and must be able to accommodate unanticipated changes in the availability of generation. With the current system, electricity-system operators use "automatic generation control" (AGC) (or frequency regulation) to respond to variation on the order of seconds to a few minutes; spinning reserves to respond to variation on the order of minutes to an hour; and peak-power generation to respond to hourly variation (De Carolis and Keith, 2005; Kempton and Tomic, 2005a; Electric Power Research Institute, 1997). AGC and spinning reserves have very low cost, typically less than 10% of the total cost of electricity (Kempton and Tomic, 2005a), and are likely to remain this inexpensive even with large amounts of wind power (EnerNex, 2010; DeCesaro et al., 2009), but peak-power generation can be very expensive.

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

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

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

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

1.1. 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; De Carolis and Keith, 2006; Archer and Jacobson, 2003, 2007; US DOE, 2008; North American Electric Reliability Corporation, 2009b; Kempton et al., 2010; EnerNex, 2010; GE Energy, 2010; Katzenstein et al., 2010). Similarly, the combined energy from co-located wind and wave farms reduces variability of wind and wave power individually (Stoutenburg et al., 2010).

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

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

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

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

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

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

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

Fig. 1 presents an example of the combined use of wind (variable), solar rooftop PV (variable), concentrated solar power (CSP, or solar thermal) with storage (variable), geothermal (baseload), and hydroelectric (dispatchable) to match hourly power demand plus transmission and distribution losses on two days in California in 2005. The geothermal power installed was increased over 2005 levels but was limited by California's geothermal resources. The daily hydroelectric generation was determined by estimating the historical generation on those days from reservoir discharge data. Wind and solar capacities were increased substantially over current levels, but did not exceed maximum levels determined by prior land and resource availability studies. The figure illustrates the potential for matching power demand hour by hour based on a Monte Carlo simulation that accounts for the stochastic nature of each resource (20 potential realizations each hour). Although results for only two days are shown, results for all hours of all days of both 2005 and 2006 (730 days total) suggest that 99.8% of delivered energy during these days could be produced from WWS technology. For these scenarios, natural gas was held as reserve backup and supplied energy for the few remaining hours. However, it is expected that natural gas reserves can be eliminated with the use of demand-response measures, storage beyond CSP, electric vehicle charging and management, and increases in wind and solar capacities beyond the inflexible power demand, which would also allow the excess energy to produce hydrogen for commercial processes, thereby reducing emissions from another sector.

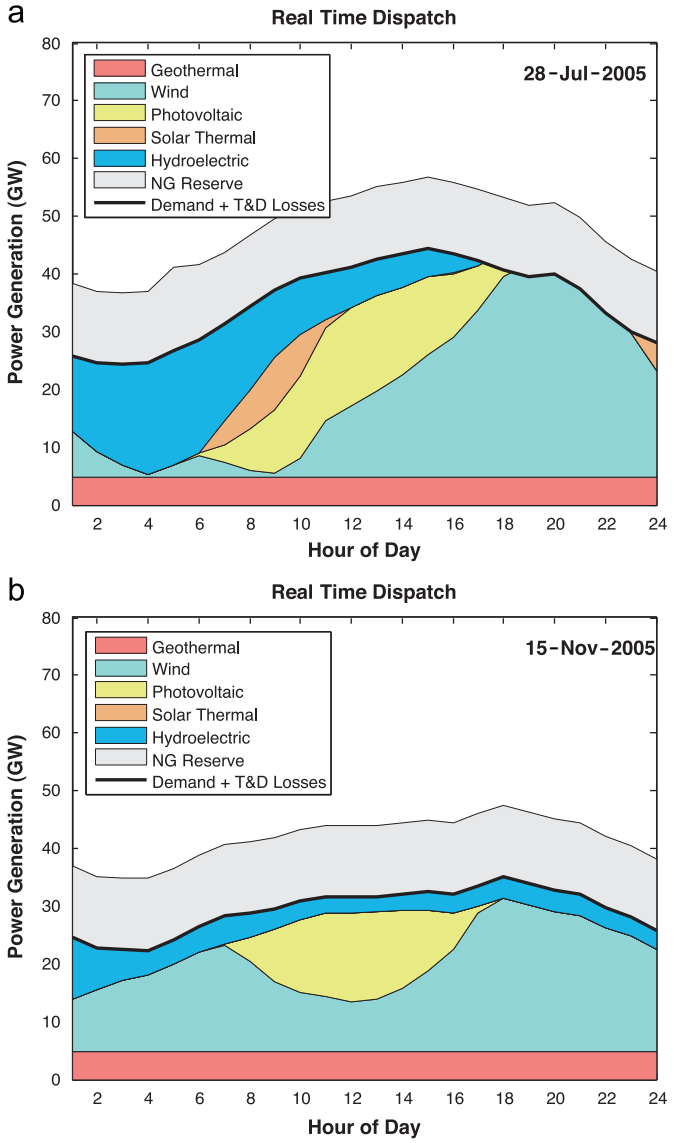

Fig. 1. Least-cost dispatch on 2 days in 2005 in which 100% of California's electricity demand plus transmission/distribution losses are met with load-matching renewables. *Notes*: System capacities: 73.5 GW of wind; 26.4 GW of CSP; 28.2 GW of photovoltaics; 4.8 GW of geothermal; 20.8 GW of hydroelectric;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

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

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

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

1.4. Store electric power at the site of generation

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

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

1.5. Oversize WWS generation capacity to match demand better and to produce H_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 would not necessarily coincide with times of hydrogen demand. The optimal (lowest-cost) system configuration depends on the balance between the demand-matching benefits of increasing WWS peak-generation capacity, the benefits of producing needed hydrogen for transportation and heat, and the costs of increasing spare WWS capacity to produce hydrogen and hydrogen storage. Some papers that have examined the cost of wind-hydrogen systems, although not directly for the application just described, include Jacobson et al. (2005) (for transportation), Martin and Grasman (2009) (for transportation), Aguado et al. (2009), Honnery and Moriarty (2009), and Clarke et al. (2009). Aguado et al. (2009) use the simulation/optimization tool "WindHyGen" to analyze the economic feasibility of a wind-hydrogen energy system with a wind turbine, inverter, electrolyzer, compressor, and hydrogen storage tank, and find that current systems are relatively expensive, but expect that improvements in technology eventually will make them cost-competitive. Honnery and Moriarty (2009) provide an estimate of the technical potential hydrogen production from wind globally, and Clarke et al. (2009) analyze the benefits of coupling an electrolyzer to a PV system.

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

The use of EV batteries to store electrical energy, known as "vehicle-to-grid," or V2G, is especially promising, albeit not necessarily easy to implement (Sovacool and Hirsch, 2010). In general, V2G systems are designed either to provide load-management services, such as peak-power supply, spinning reserves, or power regulation, or to provide a longer-term, decentralized form of electricity storage in a system (such as the one proposed here) relying primarily on variable electricity supply. Kempton and Tomic (2005a), Peterson et al. (2010a), and Andersson et al. (2010) analyze the economics of V2G for load management in a conventional electricity system, and describe the conditions under which the benefits provided (e.g., displacing expensive alternative sources of peak power or spinning reserves) exceed the costs of V2G (degradation of battery capacity, extra electronics and wiring infrastructure, and energy cycling or production losses). More pertinent here are analyses of V2G systems that provide decentralized storage to enable better matching of variable renewable electricity supply with demand (Lund and Kempton, 2008; Kempton and Tomic, 2005b). Kempton and Tomic (2005b) calculate that in order for V2G systems to regulate power output to keep frequency and voltage steady over very short time intervals (minutes) when wind power supplies 50% of current US electricity demand, 3.2% of the US light-duty vehicle (LDV) fleet would have to be battery-powered and be on V2G contract for regulation of wind power. In order for V2G systems to provide operating reserves to compensate for hourly variations in wind power (again when wind power supplies 50% of US electricity demand), 38% of the US LDV fleet would have to be battery-powered and be on V2G contract. (In both cases, Kempton and Tomic (2005b) assume that only half of the battery EVs would available for V2G at any time.) Finally, in order for V2G systems to provide longer-term storage to compensate for daily variation in wind power to ensure that wind output never drops below 20% of capacity, given the yearly wind profiles from an interconnected wind system in the Midwest (based on Archer and Jacobson, 2003), 23% of the US LDV fleet would have to be fuel-cell powered and be on V2G contract.

1.7. Forecast weather to plan energy supply needs better

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

1.8. Summary

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

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

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

2. The cost of WWS electricity generation and "supergrid" transmission and decentralized V2G storage

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

2.1. Cost of generation and conventional transmission

Table 1 presents estimates of current (2005–2010) and future (2020 and beyond) $/kWh costs of power generation and conventional (i.e., *not* extra-long-distance) transmission for WWS systems, with average US delivered electricity prices based on conventional (mostly fossil) generation (excluding electricity distribution) shown for comparison. For fossil-fuel generation, the social cost, which includes the value of air pollution and climate-change damage costs, is also shown. The estimates of Table 1 indicate that onshore wind, hydroelectric, and geothermal systems already can cost less than typical fossil and nuclear generation, and that in the future onshore wind power is expected to cost less than any other form of large-scale power generation.[3] 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 1 are based partly on our own cost estimates, detailed in Tables A.1c and A.1d of Appendix A.1. Appendix A.1 presents two sets of calculations: one with the reference-case parameter values used by the by the Energy Information Administration (EIA) in its Annual Energy Outlook (our Tables A.1a and A.1b), and one with what we think are more realistic values for some key parameters (Tables A.1c and A.1d). The estimates based on the EIA reference-case are higher than the estimates shown in Table 1 because of the relatively high discount rate, relatively short amortization period, and (in some cases) relatively high capital costs used by the EIA. However, when we use what we believe are more realistic values for the discount rate and the amortization period, and also use the EIA's lower "falling cost" case estimates of $/kW capital costs, the resultant estimates of the total $/kWh generating costs for wind, geothermal, hydro, and solar thermal are lower, and comparable with the other estimates in Table 1. This exercise gives us confidence in the estimates of Table 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

[f] 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.

[g] 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.

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

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

2.2. Cost of extra-long-distance transmission

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

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

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

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

2.3. V2G decentralized storage

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

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

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

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

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

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

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

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

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

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

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

	Air pollution 2005			Air pollution 2030	Climate change (2005/2030)		
	5th%	Mean	95th%	Mean	Low	Mid	High
Coal[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	0.13	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, and 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. For natural gas and coal, the NRC (2010) estimates damages from the cleanest plants (5th percentile) and the dirtiest plants (95th percentile), and the generation-weighted mean damages from all plants in 2005. For coal only, the NRC (2010) estimates the generation-weighted mean damages from all plants in 2030. We assume that the generation-weighed mean damages from all natural gas plants in 2030 are 80% of the NRC-estimated mean in 2005, because current natural gas plants are relatively clean. (By comparison the NRC estimates that the generation-weighted mean damages from coal plants in 2030 are about 50% of the 2005 damages. Because coal plants are dirtier than NG plants, it is appropriate for us to assume a greater emissions reduction for coal plants.) To estimate climate-change costs, the NRC (2010) reviews results from Integrated Assessment Models and then assumes that marginal climate-change damage costs are $10/$CO_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 50–80% higher; we assume 60%. Note that in the case of air pollution, the variation in damage costs per kWh is due primarily to variation in emission rates rather than to uncertainty regarding the other parameters in the multi-step analysis, whereas in the case of climate change the wide range in damage costs per kWh is due primarily to uncertainty in estimates of marginal damages per ton of CO_2-equivalent emission rather than to uncertainty in estimates of emissions (NRC, 2010) 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, because the energy will be provided by zero-emission WWS. There will be some minor emissions related to construction dust and non-energy processes such as in the making concrete, but these are tiny compared with direct and indirect energy-related emissions.

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

4. Policy issues and needs

Current energy markets, institutions, and policies have been developed to support the production and use of fossil fuels. Because fossil-fuel energy systems have different production, transmission, and end-use costs and characteristics than do WWS energy systems, new policies are needed to ensure that WWS systems develop as quickly and broadly as is socially desirable. Schmalensee (2009) lists four kinds of economic policies that have been adopted in the US and abroad to stimulate production of renewable energy: feed-in tariffs, output subsidies, investment subsidies, and output quotas (sometimes called "renewables portfolio standards"—see e.g., Wiser et al., 2010). Dusonchet and Telaretti (2010) analyze the economics of policies that support the development of photovoltaic energy in Europe. Most studies find that feed-in tariffs (FITs), which are subsidies to cover the difference between generation cost (ideally including grid connection costs (Swider et al., 2008)) and wholesale electricity prices, are especially effective at stimulating generation from renewable fuels (Fthenakis et al., 2009; Sovacool and Watts, 2009; Couture and Cory, 2009; Wei and Kammen, 2010). A recent survey of venture capitalists investing in renewable energy technologies found that the investors ranked FITs as the most effective policy for stimulating the market for renewable energy (Bürer and Wüstenhagen, 2009). To encourage innovation and economies of scale that can lower costs, FITs should be reduced gradually (Couture and Cory, 2009 call this an "annual tariff degression"). 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 degression" is that as the cost of producing power from WWS technologies (particularly photovoltaics) declines, FITs can be reduced and eventually phased out.

Other economic policies include eliminating subsidies for fossil-fuel energy systems (for estimates of subsidies, see Koplow, 2004, 2009; Koplow and Dernbach, 2001; The Environmental Law Institute, 2009; The Global Studies Initiative, 2010; and http://subsidyscope.org/energy/) or taxing fossil-fuel production and use to reflect its environmental damages, for example with "carbon" taxes that represent the expected cost of climate change due to CO_2 emissions (for estimates of environmental damages, see National Research Council (2010) (Table 2 here) and Krewitt, 2002). However, it appears that eliminating fossil-fuel subsidies and charging environmental-damage taxes would compensate for the extra cost of the currently most expensive WWS systems only if climate-change damage was valued at the upper end of the range of estimates in the literature. For example. The Environmental Law Institute (2009) estimates that US government subsidies to fossil fuel energy amount to about $10 billion per year, which is less than 5% of the roughly $300 billion value of fossil-fuel production (EIA, 2010d)).[4] Regarding environmental damages, the US National Research Council (2010) estimates that the external costs of air pollution and climate change from coal and natural-gas electricity generation in the US total $0.03–$0.11/kWh for 2005 emissions, and $0.03–$0.15/kWh for 2030 emissions (using the mean air-pollution damages and the low and high climate change damages from Table 2). Only the upper end of the 2005 range, which is driven by assumed high climate-change damages, can begin to compensate for the more than $0.10/kWh higher current private cost of solar PVs and tidal power (Table 1). Assuming that it is politically infeasible to add to fossil-fuel generation carbon taxes that would more than double the price of electricity, eliminating subsidies and charging environmental damage taxes cannot by themselves make the currently most expensive WWS options economical.

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

[4] However, subsidies to the biofuels industry may be much 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.

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

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

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

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

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

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

5. Technical findings and conclusions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table A.1a
Estimates of generation costs using EIA (2009a, 2009b, 2009c, 2009d) parameter values, for 2008 (year 2007 $/kWh).

Technology	Input parameters							Calculated results		
	Capital cost ($/kW)	Cap. factor (%)	Life (years)	Variable O&M ($/kWh)	Fixed O&M ($/kW/year)	Fuel ($/10^6-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	11.70	8.87	51	$0.031	$0.065	$0.096
NG adv. CC/CCS	1890	42	20	0.0029	19.90	8.87	40	$0.062	$0.085	$0.146
Geothermal	1711	90	20	0.0000	164.64	0.00	100	$0.026	$0.021	$0.047
Hydropower	2242	65	20	0.0024	13.63	0.00	100	$0.047	$0.005	$0.052
Wind onshore	1923	38	20	0.0000	30.30	0.00	100	$0.069	$0.009	$0.078
Wind offshore	3851	40	20	0.0000	89.48	0.00	100	$0.132	$0.026	$0.157
Solar thermal	5021	31	20	0.0000	56.78	0.00	100	$0.222	$0.021	$0.243
Solar PV	6038	21	20	0.0000	11.68	0.00	100	$0.393	$0.006	$0.400

Table A.1b
Estimates of generation costs using EIA (2009a, 2009b, 2009c, 2009d) parameter values, for 2030 (year 2007 $/kWh).

Technology	Input parameters							Calculated results		
	Capital cost ($/kW)	Cap. factor (%)	Life (years)	Variable O&M ($/kWh)	Fixed O&M ($/kW/year)	Fuel ($/10^6-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	11.70	8.34	54	$0.021	$0.058	$0.079
NG adv. CC/CCS	1340	46	20	0.0029	19.90	8.34	46	$0.040	$0.070	$0.110
Geothermal	3942	90	20	0.0000	164.64	0.00	100	$0.061	$0.021	$0.081
Hydropower	1920	55	20	0.0024	13.63	0.00	100	$0.048	$0.005	$0.053
Wind onshore	1615	46	20	0.0000	30.30	0.00	100	$0.048	$0.008	$0.056
Wind offshore	2859	40	20	0.0000	89.48	0.00	100	$0.098	$0.026	$0.123
Solar thermal	3082	31	20	0.0000	56.78	0.00	100	$0.136	$0.021	$0.157
Solar PV	3823	21	20	0.0000	11.68	0.00	100	$0.249	$0.006	$0.255

Notes for Tables A.1a and A.1b: Cap. factor = capacity factor; Fuel 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. (The 2010 edition of the EIA's *Assumptions to the Annual Energy Outlook* (EIA, 2010c)) – which came out after we completed our analysis – does not have a Table 8.13, and also reports values for different time periods than is done in the 2009 edition, so a direct comparison with the 2009-edition values shown here is not possible. However, the overnight costs for WWS technologies shown in Table 8.2 of the 2010 edition of the EIA's *Assumptions to the Annual Energy Outlook* (EIA, 2010c) are approximately the same, in real dollars, as the overnight costs shown in Table 8.2 of the 2009 edition.)

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

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

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

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

Boccard (2010) estimates investment costs of $3080/kW for nuclear, $2100/kW for coal (similar to the EIA value in Table A.1a), $840/kW for gas (comparable to EIA's estimate in Table A.1a), and $1540/kW for onshore wind (somewhat lower than EIA's estimate for onshore wind in Table A.1a) (converting his Euros to US dollars at 1.4 dollars/Euro).

Wiser et al. (2009) report that the installed cost of large (500–750 kW) PV systems in the US in 2008 was $6500/kW, just slightly higher than the EIA's estimate. The average cost in Germany for all systems (including small systems) was $6100/kW, the same as the EIA's estimate.

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

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

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

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

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

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

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

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

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

Table A.1c
Estimates of generation costs using alternative values for lifetime and discount rate, for 2008 (year 2007 US$/kWh).

Technology	Input parameters							Calculated results		
	Capital cost ($/kW)	Cap. factor (%)	Life (years)	Variable O&M ($/kWh)	Fixed O&M ($/kW)	Fuel ($/10^6-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	11.70	8.87	51	$0.021	$0.065	$0.086
NG adv. CC/CCS	1890	42	30	0.0029	19.90	8.87	40	$0.042	$0.085	$0.126
Geothermal	1711	90	30	0.0000	164.64	0.00	100	$0.018	$0.021	$0.038
Hydropower	2242	65	30	0.0024	13.63	0.00	100	$0.032	$0.005	$0.037
Wind onshore	1923	38	30	0.0000	30.30	0.00	100	$0.047	$0.009	$0.056
Wind offshore	3851	40	30	0.0000	89.48	0.00	100	$0.089	$0.026	$0.114
Solar thermal	5021	31	30	0.0000	56.78	0.00	100	$0.149	$0.021	$0.170
Solar PV	6038	21	30	0.0000	11.68	0.00	100	$0.265	$0.006	$0.271

Table A.1d
Estimates of generation costs using alternative values for lifetime, discount rate, and WWS capital cost, for 2030 (year 2007 US$/kWh).

Technology	Input parameters							Calculated results		
	Capital cost ($/kW)	Cap. factor (%)	Life (years)	Variable O&M ($/kWh)	Fixed O&M ($/kW)	Fuel ($/10^6-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	11.70	8.34	54	$0.014	$0.058	$0.072
NG adv. CC/CCS	1340	46	30	0.0029	19.90	8.34	46	$0.027	$0.070	$0.097
Geothermal	3942	90	30	0.0000	164.64	0.00	100	$0.040	$0.021	$0.061
Hydropower	1920	55	30	0.0024	13.63	0.00	100	$0.032	$0.005	$0.037
Wind onshore	1143	46	30	0.0000	30.30	0.00	100	$0.023	$0.008	$0.030
Wind offshore	2023	40	30	0.0000	89.48	0.00	100	$0.047	$0.026	$0.072
Solar thermal	2181	31	30	0.0000	56.78	0.00	100	$0.065	$0.021	$0.086
Solar PV	2705	21	30	0.0000	11.68	0.00	100	$0.118	$0.006	$0.125

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

Table A.1e
EIA (2009a) NEMS breakdown of electricity prices (year-2007 cents/kWh).

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

distribution system. Table A.2a shows the parameters in our calculation and our low-cost, mid-cost, and high-cost assumptions. Table A.2a also explains the bases of our assumptions, except in the case of the $/MW$_{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.

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

In our analysis, presented in Table A.2a, the main cost parameters are the cost of the transmission lines, towers, and land, in dollars per MW of transmission-system (not wind-farm) capacity, per km of transmission distance ($/MW$_{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 section, we review estimates of the cost of the entire system – lines, towers, station equipment – and use these to calibrate our parameter estimates.

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

Table A.2a
The cost of electricity transmission (year 2007 US$).

Component	Low	Mid	High	Source of estimate and notes
Transmission-line cost ($/$MW_{TS}$-km)	200	280	340	Table A.2b and discussion in the appendix text. This is the cost per MW of transmission system capacity. Includes land, towers, and lines, but no station equipment.
Extra transmission distance in supergrid (km)	1200	1600	2000	Our assumptions. Note that this is the distance beyond what is typical in a conventional electricity transmission system.
Reference cost for station equipment (transformers, power conditioners, converters, etc.), at reference power ($/$MW_{TS,REF}$)	100,000	125,000	150,000	Table A.2b and discussion in Appendix A.2 text.
Reference transmission-system power (for reference station-equipment cost) ($MW_{TS,REF}$)	4000	4000	4000	Table A.2b and discussion in Appendix A.2 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})	5000	5000	5000	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 US, GE Energy (2010) assumed that only 0.7 MW of new transmission was added for each 1.0 MW of remote generation, on the grounds that "that all remote renewable generation sites would rarely be at maximum output simultaneously" (p. 32).
Wind capacity factor (%)	45%	38%	33%	See Table A.1 and endnote.
Electricity loss in transmission line (%/1000-km, at rated line capacity)	3%	4%	6%	According to Siemens (2010), the losses from a 6.4 GW, 800 kV DC line are 3.5%/1000-km, and the losses from a 3 GW, 500 kV DC line are 6.6%/1000-km. Bahrman (2006) estimates slightly lower losses (Table A.2b).
Average transmission current (fraction of current at rated capacity)	40%	40%	40%	Because the main transmission losses are proportional to the square of the load current (Nourai et al., 2008), the actual losses are calculated here by multiplying the loss at the rated-capacity current by the square of the actual current as a percent of rated (Negra et al., 2006). The actual current fraction depends on the capacity of the line relative to the capacity of the generators, the fraction of zero-current time, and other factors.
Electricity loss in station equipment (% of average power)	1.3%	1.5%	1.8%	Bahrman (2006) says that converter station losses are 0.75% per station, and assumes that total substation (transformer, reactors) losses are 0.5% of rated power. Hauth et al. (1997) assume that converter losses for HVDC are 1% of the converter rating, but this is based on older technology. Bresesti et al. (2007) assume that converter losses are 1.8% at full power. De Alegría et al. (2009) write that converter losses are 1–2%. Negra et al.'s (2006) detailed evaluation of HVDC transmission losses for wind systems finds that converter station losses are 1.4–1.6% of the annual output of the connected wind farm. (The converter station includes converters, transformers, filters, smoothers, auxiliary and protection equipment.)
Lifetime until replacement or major overhaul—transmission towers and lines (years)	70	60	50	Information from Chan (2010), the Electric Power Research Institute (EPRI) (2010), Quest Reliability (2010), and Rimmer (2010) suggest a life of at least 50 years for towers and lines.
Lifetime—station equipment (years)	30	30	30	Energy Resources International (1999) states that "the lifetime of HVDC components (rectifiers, invertors, thyristors and DC circuit breakers) is about 30 years".
Maintenance cost (percent of capital cost, per year)	1.0	1.0	1.5	Chan (2010) says that in his experience, 1% is typical, but 2% would be ideal. We assume this applies to lines and station equipment. Bresesti et al. (2009) assume that the yearly maintenance costs for substations are 0.4% of investment costs.
Discount rate (%/year)	3%	7%	10%	The OMB (2003) recommends a range of 3–7% (see Table A.3a). As discussed in notes to Table A.1, the EIA's NEMS estimates a weighted-average cost of capital power-plant construction of about 10% (EIA, 2009c)).
Capital cost of line, land, and 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**	

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 and $1.7 million/km, roughly twice the figures estimated by Bahrman (Table A.2b).

Bresesti et al. (2007) estimate that converters cost 0.11 million Euros per MW, or about $430 million for a 3000-MW system, which is similar to Bahrman's (2006) estimate (Table A.2b). (Bahrman's estimates of station costs include transformer, filters, and other equipment as well as converters, but converters probably account for more than 90% of the total (de 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.

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

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

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

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

Denholm and Sioshansi (2009) collected historical transmission cost data from the National Renewable Energy Laboratory, and plotted the cost per MW-km (in 2008 USD) versus the MW line capacity for about 40 AC and DC transmission-line projects. For all projects the costs ranged from $200/MW-km to $1400/MW-km, with most below $1000/MW-km. Cost decreased with increasing line capacity, which is expected, because higher voltage (higher capacity) lines generally have a lower cost per unit of capacity. The six projects with a line capacity of 3 GW or greater (corresponding to 500 KV DC or 765 kV AC, according to Siemens, 2010) cost between $200 and $400/MW-km. It is not clear whether the MW-km unit in the denominator refers to MW of wind capacity or MW of line capacity, but assuming that the two are roughly equal (following Mills et al., 2009b assumption that "new transmission is sized to exactly the size required by the incremental generation added in a particular scenario" (p. 28)), these figures correspond to $200 and $400/$MW_{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 US, $150/$kW_{WC}$ in 3 regions, and $230–$320/kW_{WC} in 3 regions. (The subscript WC refers to wind-farm capacity.) The costly regions are all in the Western US: the Northwest Power Pool, the Rocky Mountain Area, and California and Nevada. If one assumes that these figures correspond to 500–1000-km transmission, and that in the EIA work the transmission-system capacity is equal to the wind-farm capacity, then the cost range is $130/$MW_{TS}$-km to $640/ MW_{TS}-km.

The US DOE (2008) study of 20% wind power in the US in 2030 used the National Renewable Energy Laboratory's WinDS model to estimate the extent and cost of new transmission lines needed to support 233 GW of new wind power (another 60 GW of new wind power was assigned to existing transmission lines) (p. 161). For the WinDS analysis the US DOE assumed that new transmission line capacity cost $1600/MW-mile in most areas of the US, and $1920–$2240/MW-mile (20–40% higher) in a few high-cost regions (p. 147). (It appears that this cost estimate refers to MW of wind capacity, as opposed to MW of transmission-system capacity.) The US DOE (2008) also assumed that the "typical line is a 200-mile, 230-kV line rated at 170 MV A" (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 Sioshansi (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 US also assumed a total transmission-system cost of $1600/MW-mile.

The US DOE's (2008) 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) 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 20–40% higher in a few regions (see the previous paragraph).

In a "derivative effort associated with the" US DOE (2008) 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 US 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. (2009b) and the EIA (2009f). AEP (2010) assumed a total cost of $3.1 million/mile ($1.9 million/km) (including station cost, etc.) for 765 kV AC lines with a load of at 3600–7200 MW, which indicates a cost of $260/$MW_{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 Sioshansi (2009), which indicate that three 3800–4000-MW-capacity AC lines have a cost of $400/MW-km, and one has a cost of $200/MW-km.

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

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

the US – say, 250–500 km – then these figures correspond to \$100/MW_{WC}-km to \$1000/MW_{WC}-km.

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

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

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

A.2.c. Discussion of results

The results of our analysis are shown in Table A.2a. For comparison, the EIA (2009a), Table A8) estimates \$0.009/kWh average transmission cost for all generation in the US. NREL's WinDS model interactive database estimates that the full levelized cost of new transmission segments dedicated to connecting wind sites to the existing grid (at the point where the grid has adequate capacity) ranges from \$0.001/kWh to about \$0.03/kWh, depending mainly on the wind-output capacity factor and the distance from the wind farm to the grid (National Renewable Energy Laboratory, 2010b). The rough average appears to be on the order of \$0.01/kWh. The levelized costs in WinDS are calculated from a detailed GIS database, as follows (National Renewable Energy Laboratory, 2010a).

> "The GIS analysis begins with more than 400,000 wind resource sites and more than 15,000 transmission lines of 69 kV or larger. The size and length of the existing transmission lines are used to estimate their full capacity in MW considering thermal and stability limits. The GIS optimization then minimizes the total cost (including both generation and the construction of transmission line segments connecting the wind site to the grid) of filling the remaining capacity (after conventional generation use of the lines is considered) of the existing lines with wind generation.
>
> The results of the GIS-based optimization are used to construct the supply curves shown in our interactive database. In these curves, the cost is only the levelized cost of building the transmission segment from the wind site to the grid (i.e., the cost of generation has been subtracted from the total levelized cost used in the optimization)".

Our results in Table A.2a are consistent with the WinDS results.

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

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

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

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

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

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

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

With these considerations, we assume that sea cables cost 2 times (low-cost case), 4 times (mid-cost case), or 6 times (high-cost case) as much per MW-km as land lines. Based on Weigt et al (2010), we assume that undersea transmission distances are half those of land-transmission. The calculated undersea transmission-system costs are $0.003/kWh (low-cost case), $0.021/kWh (mid-cost case), and $0.082/kWh (high-cost case). If up to 25% of long-distance transmission in a supergrid is undersea, the mid-range total extra transmission cost in a supergrid increases from 1.2 to 1.4 cents/kWh. This does not materially affect our conclusions.

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

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

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

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

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

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

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

BEV				PHEV				
No V2G		V2G		No V2G		V2G		
Low	High	Low	High	Low	High	Low	High	
Part 2: calculated values								
9600	18,900	9600	18,900	4,800	8400	4800	8400	Cost of replacement battery ($)
15.0	30.0	15.0	9.3	15.0	25.2	15.0	8.1	Lifetime of battery in vehicle use (based on calendar life or cycling to 80% DoD) (years)
7980	17,310	7980	17,310	4140	7860	4140	7860	Cost of battery replacement, including new battery cost with installation, removal of old battery, net of value of old battery in NAAs
176%	143%	176%	32%	56%	111%	56%	27%	Discount rate for the period of time equal to the battery life (%/period)
0	0	2062	8249	0	0	687	2750	Electricity diverted to V2G cycling, measured at input to battery charger, per year (based on cycling normalized to 80% DoD) (kWh-sent-to-battery-charger/year)
								Components of the cost of V2G cycling, per kWh diverted to V2G cycling ($/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 in Appendix A.3.

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

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

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

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

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

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

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

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

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

Part 1: estimates from Burke and Miller (2009)	kWh	OEM cost ($/kWh)[a]	Cycle life (deep)[b]
Graphite/$LiNiCoAlO_2$ (NCA)	10.1	279	2000–3000
	20.2	205	2000–3000
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	210–330	350–860	350–860	290–420	470–960

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

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

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

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

[b] By comparison, in the Peterson et al. (2010b) tests described above the cycle life of lithium iron phosphate at 80% DoD exceeded 5000. Amjad et al. (2010) also cite a 2003 study that shows that a Li-ion battery has a cycle life of ~2500 at 80% DoD, and that a nickel metal-hydride (NiMH) battery has a cycle life of ~3500 at 80% DoD, but these data are much older than the Burke and Miller (2009) and Peterson et al. (2010b) data. Zhang and Wang (2009) report that an automotive Li-ion battery with a $LiNiO_2$ 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 5–15% 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/year. Cost range depends mainly on energy storage capacity of battery; the bigger the battery, the lower the $/kWh cost.

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

$$PV_{BR} = PMT_{BR}(1-(1+r_{BR})^{-(nP_{BR}^{-1})})r_{BR}^{-1}$$

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

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

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

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

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

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

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

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

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

In the high-cost case, the calendar life is no longer binding, so V2G cycling does increase the frequency of battery replacement. The frequency of replacement and hence the associated replacement cost is sensitive to assumptions regarding the impact of V2G cycling on battery life. In Table A.3a, we implicitly assume that V2G cycling (to a given DoD) causes the same degradation of battery capacity as does charge/discharge cycling during driving (to the same DoD). However, in reality the cycle life depends on the voltage and current of the charge/discharge cycle, and these will be different in V2G cycling than in charging and discharging during driving. Hence, it is likely that in reality, V2G cycling to a given DoD will *not* cause the same degradation of battery capacity as will charge/discharge cycling during driving. We therefore present here an alternative, more realistic calculation of the battery-replacement cost of V2G when V2G and driving have different effects on degradation of battery capacity.

Peterson et al. (2010b) investigated this issue in detail, cycling the A123 systems ANR26650M1 $LiFePO_4$ 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.3a, but with all else the same), along with the standard assumption that the battery has reached the end of its life when it has lost 20% of its capacity, to perform an alternative calculation of the cost of V2G cycling.

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

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