Case No. 18-36082

IN THE UNITED STATES COURT OF APPEALS
FOR THE NINTH CIRCUIT

KELSEY CASCADIA ROSE JULIANA, *et al.*,
Plaintiffs-Appellees,
v.
UNITED STATES OF AMERICA, *et al.*,
Defendants-Appellants.

On Interlocutory Appeal Pursuant to 28 U.S.C. § 1292(b)

DECLARATION OF MARK Z. JACOBSON IN SUPPORT OF PLAINTIFFS' URGENT MOTION UNDER CIRCUIT RULE 27-3(b) FOR PRELIMINARY INJUNCTION

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I, Mark Z. Jacobson, hereby declare and if called upon would testify as follows:

1. In this Declaration, I offer my expert opinion that transitioning off of fossil fuels will prevent additional harms to the Youth Plaintiffs in this case. Doing so will also cost less than maintaining the current fossil fuel-based national energy system. To achieve an 80% renewable national energy system by 2030 and a 100% renewable national energy system by 2050, Defendants must start now.

2. I have two Bachelor's Degrees With Distinction from Stanford University, one in Civil Engineering and the other in Economics. I earned a Master's Degree in Environmental Engineering from Stanford University. I earned a second Master's Degree and then a Ph. D. in Atmospheric Sciences from UCLA.

3. Since 1989, I have been researching the impacts of human emissions of gases (among them carbon dioxide and other greenhouse gases) and particles (including black carbon) on air pollution, human health, weather, and climate. Starting in around 1999, I began examining in detail clean, renewable energy solutions to these problems.

4. In 2015, this research culminated in the development of roadmaps to transition the all-sector energy infrastructures of each of the 50 United States to 100% clean, renewable energy by 2050 (Jacobson et al., 2015a, which includes a link to the spreadsheets used to derive all numbers in the paper). The research has also resulted in the following:

a. The development of 100% clean, renewable energy roadmaps for 139 countries of the world (Jacobson et al., 2017a, which also includes a link to spreadsheets);

b. The development of electric power grid stability analyses for the 48 contiguous United States after those states have converted to 100% clean, renewable energy in all energy sectors (Jacobson et al., 2015b); and

c. The development of electric power grid stability analyses for 20 world regions containing the 139 countries examined (Jacobson et al., 2018) after those countries have converted to 100% clean, renewable energy in all energy sectors.

5. The purpose of this Declaration is to summarize the portion of this research related to Defendants, the redressability issues presented by this litigation, and the implications on the feasibility of transitioning the country swiftly off of fossil fuels to clean and renewable energy in all sectors by mid-century.

6. A true and correct copy of my Expert Report in this litigation was filed in support of Plaintiffs' Opposition to Defendants' Motion for Summary Judgment in the District Court at ECF No. 275. A true and correct copy of my expert report is attached hereto as **Exhibit 1**. My full CV, including a list of publications I authored within the last ten years, is included within my Expert Report.

Transitioning Off of Fossil Fuels and Onto 100% Wind, Water, and Solar Will Cost Less Than Maintaining The Current Fossil Fuel Based System

7. As a major component of our research, we analyzed the economic costs of the United States' current fossil fuel based energy system and compared that with the economic costs of transitioning to 100% renewable energy. The 100% renewable energy system will cost less because: (a) it requires substantially less energy overall, (b) will reduce or eliminate the costs of climate impacts, and (c) will reduce or eliminate the costs of health impacts imposed by the current fossil fuel based system.

8. **Taxpayer Savings**: Transitioning to 100% wind, water, and solar for all purposes will reduce the cost of energy borne by the federal government. Energy used by the federal government to heat buildings and transport workers will fall by 40-58% just due to electrification of many uses. The cost of constructing new onshore wind and utility-scale solar photovoltaics (PV) is already lower than is the cost of constructing new natural gas-fired and coal-fired electricity generation[1] and the cost of renewables continues to fall. By transitioning to 100% wind, water, and solar for all purposes, the federal government will save substantial taxpayer dollars.

9. **Job Creation**: Our research concludes that transitioning to 100% wind, water, and solar energy sources will be an overall job creator. Jobs in the fossil fuel industry will go away but those will be more than offset by additional jobs in the

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[1] https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf

fields of renewable energy and energy efficiency. This increase in jobs will support the full employment and economic vitality that federal agencies are seeking.

10. **Conflict Reduction**: Defendant Department of Defense ("DOD"), in particular, stands to gain from a 100% renewable national energy system because such a system will reduce or eliminate international conflicts over fossil energy supplies, saving taxpayer dollars, saving lives, and meeting DOD goals of national security. Because most energy for transportation, heating/cooling, industry, and electricity with a 100% WWS System will be produced domestically, I expect that transitioning to a 100% WWS System will reduce U.S. international conflict over scarce energy resources.

11. **Grid Stability**: There are now at least 36 peer-reviewed scientific papers among 11 independent research groups encompassing 70 scientists who find that 100% or near 100% renewable energy results in a stable grid at low cost.[2]

12. **Lower Social Cost**: The social cost (energy plus health plus climate cost) per unit energy of a 100% renewable national energy system ("WWS System") is about 1/4 that of a fossil fuel system. In addition, a WWS System needs 40%-58% less energy than does a fossil fuel system. As such, the overall energy cost to society is 11% to 15% than of a fossil fuel based system.

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[2] http://web.stanford.edu/group/efmh/jacobson/Articles/I/CombiningRenew/100PercentPaperAbstracts.pdf

13. **Lower Risk of Failure**: Due to the distributed nature of wind and solar, a WWS System has less risk of catastrophic grid failure due to natural disaster or terrorism than does a fossil fuel system, which relies on more centralized power plants.

To Achieve a Renewable Energy System, Defendants Must Start Now

14. Delay in initiating the transition to 100% renewable energy will make it much more difficult in getting to 100% renewables by 2050. During any delay in the transition, substantial new fossil infrastructure will be built, and such new infrastructure will be imbedded for decades. Because renewables have lower direct and social (health and climate) costs than fossil fuels, such a delay will result in increased costs and harms to the youth Plaintiffs and to the Nation.

15. Ceasing new fossil fuel leasing on federal public lands and preventing new fossil fuel infrastructure is necessary for meeting an 80% transition by 2030 and a 100% transition by 2050, because any new leasing will result in embedded infrastructure that can last for decades. Once this embedded fossil fuel infrastructure is in place, it will make an 80% transition by 2030 and a 100% transition by 2050 more difficult to occur because we will be less like to want to stop using fossil fuels. Also, such infrastructure projects will result in the burning of a substantial amount

of additional fossil fuels, increasing health and climate problems due to additional U.S. air pollution.

Delay In Initiating a Transition to 100% Renewable Energy Will Cost Lives

16. Delay in initiating the transition to 100% renewable energy will cost lives. Every year of powering the United States national energy system primarily with fossil fuels for all purposes (as it is now) costs about 62,000 U.S. lives annually compared with a 100% renewable system. My research report, "100% clean and renewable wind, water, and sunlight (WWS) all-sector energy roadmaps for the 50 United States[3]," provides greater detail and is included as an attachment to my Expert Report, **Exhibit 1** to this Declaration.

17. If Defendants initiate a transition to 100% renewable energy now, the changes made in just the next two years will avoid tens of thousands of U.S. air pollution deaths and millions more illnesses in that period alone.

18. If Defendants initiate a transition to 100% renewable energy now, the Youth Plaintiffs will experience a reduction in short-term climate harms, particularly in cities (due to reduction or elimination of localized carbon dioxide domes that magnify the negative effects of other air pollutants) and in locations, such as the southwest U.S., where many people are at risk of heat stress and heat stroke

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[3] http://web.stanford.edu/group/efmh/jacobson/Articles/I/USStatesWWS.pdf

19. In sum, a transition by Defendants to 100% clean, renewable energy for all energy purposes will reduce climate, air pollution, and energy insecurity problems, all of which are significant and expensive challenges for Americans under the current fossil fuel-based national energy system.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed on February 5, 2019.

Respectfully submitted,

Mark Z Jacobson

Mark Z. Jacobson

Exhibit 1

EXPERT REPORT
OF
MARK JACOBSON, Ph.D.

Professor, Dept. of Civil and Environmental Engineering
Director, Atmosphere/Energy Program
Senior Fellow, Woods Institute for the Environment
Senior Fellow, Precourt Institute for Energy
Stanford University

Kelsey Cascadia Rose Juliana; Xiuhtezcatl Tonatiuh M.,
through his Guardian Tamara Roske-Martinez; et al.,
Plaintiffs,

v.

The United States of America; Donald Trump,
in his official capacity as President of the United States; et al.,
Defendants.

IN THE UNITED STATES DISTRICT COURT
DISTRICT OF OREGON

(Case No.: 6:15-cv-01517-TC)

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TABLE OF ACRONYMS AND ABBREVIATIONS

BAU:	business as usual
CCS:	carbon capture and sequestration
coal-CCS:	coal with carbon capture and sequestration
CO_2:	carbon dioxide
CSP:	concentrated solar power
DOE:	United States Department of Energy
EIA:	United States Energy Information Administration
EPA:	United States Environmental Protection Agency
HVAC:	heating, ventilation and air conditioning
HVDC:	high-voltage direct-current
IPCC:	United Nations Intergovernmental Panel on Climate Change
kW:	kilowatt (measure of electric power)
kWh:	kilowatt hour
MW:	megawatt (measure of electric power)
OTA:	United States Congress, Office of Technology Assessment
ppm:	parts per million
ppmv:	parts per million by volume
PV:	photovoltaic
R&D:	research and development
RE:	renewable energy
UNFCCC:	United Nations Framework Convention on Climate Change
WWS:	wind, water, and sunlight

INTRODUCTION

I, Mark Jacobson, have been retained by Plaintiffs in the above-captioned matter to provide expert testimony about the feasibility of transitioning the United States of America to 100% clean and renewable energy in all energy sectors by mid-century, including whether this transition would remedy the constitutional violations alleged in the First Amended Complaint in this case. All energy sectors include electricity, transportation, heating/cooling, and industry.

QUALIFICATIONS

Since 1989, I have been researching academically and professionally, the impacts of human emissions of gases (including carbon dioxide and other greenhouse gases) and particles (including black carbon) on air pollution, human health, weather, and climate. Starting in 1999, I began examining in detail clean, renewable energy solutions to these problems. In 2015, this research culminated in the development of roadmaps to transition the all-sector energy infrastructures of each of the 50 United States to 100% clean, renewable energy by 2050 (Jacobson et al., 2015a, which includes a link to the spreadsheets used to derive all numbers in the paper). The research has also resulted in the development of 100% clean, renewable energy roadmaps for 139 countries of the world (Jacobson et al., 2017a, which also includes a link to spreadsheets) and electric power grid stability analyses for the 48 contiguous United States (Jacobson et al., 2015b) and for 20 world regions containing the 139 countries examined (Jacobson et al., 2018) after those states and countries have converted to 100% clean, renewable energy. I carried out this research, analysis, and clean, renewable energy roadmap development primarily with Dr. Mark Delucchi at U.C. Berkeley, but also along with several other experts. The purpose of this report is to summarize the portion of this research related to the United States and its major conclusions and implications on the feasibility of transitioning the country swiftly off of fossil fuels to clean and renewable energy in all sectors by mid-century.

The opinions expressed in this report are my own and are based on the data and facts available to me at the time of writing. All opinions expressed herein are to a reasonable degree of scientific certainty, unless otherwise specifically stated. Should additional relevant or pertinent information become available, I reserve the right to supplement the discussion and findings in this expert report in this action.

My full CV, including a list of publications I authored within the last ten years, is attached as **Exhibit A** to my report. My report contains a list of citations to the principal documents that I have used or considered in forming my opinions, listed in **Exhibit B**. **Exhibit C** contains a summary of my previous expert testimony. **Exhibit D** is a chart summarizing other decarbonization studies of which I am aware. I also attach, as **Exhibits E-H**, my central papers discussed herein.

In preparing my expert report and testifying at trial, I am deferring my expert witness fees to the charged plaintiffs given the financial circumstances of these young plaintiffs. If a party seeks discovery under Federal Rule 26(b), I will charge my reasonable fee of $200 per hour for the time spent in addressing that party’s discovery.

EXECUTIVE SUMMARY

In this report, I summarize research, conclusions, and implications of studies that I and my colleagues previously performed to develop 100% clean, renewable all-sector (electricity, transportation, heating/cooling, industry) roadmaps (plans) for the 50 United States (Jacobson et al., 2015a) and to analyze resulting electric grid stability for the 48 contiguous United States (Jacobson et al., 2015b). I also rely on our updated peer-reviewed research on an energy roadmap for the United States as a whole (Jacobson et al., 2017a) and a grid stability study for the United States plus Canada combined (Jacobson et al., 2018). I set forth a substantive discussion of numbers from the 50-state roadmaps in Jacobson et al. (2015a) where the numbers are set forth both on a state specific basis and for the U.S. as a whole. However, the U.S.–as-a-whole numbers were updated in Jacobson et al. (2017a) based on updated cost, efficiencies, and other data. Jacobson et al. (2017a) does not have an in-depth discussion of those data simply because the 2015a study provides state-by-state breakdowns as well. Nevertheless, both studies provide a consistent conclusion. Namely, I conclude in both studies that it is both technically and economically feasible to transition from a predominantly fossil fuel-based energy system to a 100% clean, renewable energy system for all energy sectors by 2050, with about 80% conversion by 2030, even after taking into account the U.S. Department of Energy’s (DOE’s) Energy Information Administration’s (EIA’s) energy demand forecasting and taking into account efficiencies resulting from the transition from fossil fuels to clean, renewable energy.

Presently, fossil fuels supply more than 80% of our all-purpose energy in the United States, not out of necessity, but because of political preference and historic government support that led to the development and maintenance of a widespread fossil-fuel infrastructure. Our plans provide state-by-state roadmaps to replace 80% of existing fossil fuel energy by 2030 and 100% by 2050. The main concept is to electrify all energy sectors with existing or near-existing technologies, and then to generate the electricity for all sectors with 100% wind, water, and sunlight (WWS), namely onshore wind, offshore wind, utility-scale photovoltaics (PV), rooftop PV, concentrated solar power (CSP) with storage, geothermal power, wave power, tidal power, and hydroelectric power. A 100% WWS system would also require electricity storage, heat storage, cold storage, and some hydrogen storage along with an expanded transmission and distribution system.

First, based on our 2015 study (Jacobson et al., 2015a), converting to 100% WWS would reduce the U.S.-average end-use power demand by a mean of ~39.3%. Approximately 82.4% of the reduced power demand is due to a) the higher work output to energy input of electricity compared with fossil-fuels (burning fossil fuels to move vehicles results in much more waste heat than using electricity), and b) eliminating the energy needed to mine, transport, and refine fossil fuels and uranium (because wind and solar energy, for example, come right to the wind turbine or solar panel, respectively). The rest of the reduction in power demand is due to end-use energy efficiency and conservation improvements beyond those expected in a business-as-usual (BAU) case.

Second, averaged over the United States, our roadmaps propose that all-purpose U.S. energy in 2050 could be met with ~30.9% onshore wind, ~19.1% offshore wind, ~30.7% utility-scale photovoltaics (PV), ~7.2% rooftop PV, ~7.3% concentrated solar power (CSP) with storage, ~1.25% geothermal power, ~0.37% wave power, ~0.14% tidal power, and ~3.01% hydroelectric power (where virtually all hydroelectric dams exist already). This is only one of many possible mixes. We have run our model with other mixes as well to demonstrate that a 100% WWS system by 2050 is feasible (e.g., Jacobson et al., 2017a).

Third, over all 50 states, converting from fossil fuel energy to WWS would provide an estimated 3.9 million 40-year full-time construction jobs and about 2.0 million 40-year full-time operation jobs for the energy facilities alone.

Fourth, converting from fossil fuel energy to WWS would also eliminate ~62,000 (19,000-115,000) U.S. air pollution premature mortalities per year today and ~46,000 (12,000-104,000) per year in 2050, avoiding ~$600 ($85-$2,400) billion per year (2013 dollars) in 2050, based on statistical cost of life as defined by the U.S. government, equivalent to ~3.6 (0.5-14.3) percent of the 2014 U.S. gross domestic product.

Fifth, converting from fossil fuel energy to 100% WWS would further eliminate ~$3.3 (1.9-7.1) trillion per year in 2050 global warming costs to the world due to U.S. emissions.

Sixth, these plans will result in each person in the U.S. in 2050 saving ~$260 (190-320) per year in energy costs ($2013 dollars) and U.S. health and global climate costs per person decreasing by ~$1,500 (210-6,000) per year and ~$8,300 (4,700-17,600) per year, respectively.

Seventh, the new footprint over land required to implement our plan would be ~0.42% of U.S. land. The spacing area between wind turbines, which can be used for multiple purposes, will be ~1.6% of U.S. land area. 0.42% of U.S. land is equivalent to ~14,800 square miles. For comparison, an upper bound of ~75,000 square miles of land (2.1% of U.S. land area) may have been used to date for roads, well pads, and storage facilities for the 2.5 million inactive and 1.7 million active oil and gas wells alone in the United States to date (Fracktracker Alliance, 2015). Pennsylvania alone has ~560,000 abandoned oil and gas wells (Pennsylvania Department of Environmental Protection, 2016). 20,000 new oil and gas wells are drilled in the United States every year. Allred et al. (2015) estimate that the area taken up by well pads, roads, and storage facilities for natural gas wells sum to 0.0178 square mile per well. Extrapolating this estimate to oil wells and to all abandoned plus active oil and gas wells in the U.S. gives the 75,000 mi^2 estimate. While this is an upper bound for oil and gas wells, coal and oil extraction has required additional land as have oil and gas pipelines, oil refineries, gas stations, power plants, and other oil, gas, and coal infrastructure, which will become obsolete upon the transition to 100% clean and renewable energy.

Eighth, the state-by-state roadmaps have been calculated to keep the 48 contiguous state U.S. grid stable at low cost in two separate peer-reviewed studies under multiple storage scenarios (Jacobson et al., 2015b; Jacobson et al., 2018). In the latter study, grid stability over the U.S. and Canada combined were found under three different scenarios, including two with no added hydropower turbines and one with added hydropower turbines.

In other words, the roadmaps will keep the lights on. Power supply will continue to match demand as it currently does, every minute of every day. Although the wind doesn’t always blow and the sun doesn’t always shine, it is possible to match power demand during those periods at a given location by using stored energy, shifting the time of peak demand for energy with financial incentives (demand response), and by adding some long-distance transmission to connect wind and solar in remote locations to cities. In our studies, storage is in the form of heat (in water, rocks, and thermal mass); cold (in ice and water); electricity (in concentrated solar power (CSP) with storage, batteries, pumped hydropower systems, and existing hydropower dams); and hydrogen (for use in transportation). In our studies, we have found that the grid can stay stable with no coal, natural gas, oil, biofuels, or nuclear power. The resulting 2050-2055 U.S. electricity social cost (energy cost plus health cost plus climate cost) for a full system is much less than for current energy sources, and the energy cost alone is similar or less.

In sum, conversions of the energy infrastructure of the United States to 100% wind, water, and sunlight for all purposes is technically and economically feasible at low cost and high benefit. Based upon my review of the available information and pertinent literature identified herein, as well as my many years of experience as described herein, I conclude that a transition to 100% clean, renewable energy by mid-century would stop the affirmative government infringement of the youths' constitutional rights as described in the First Amended Complaint, and even though not all of the harm caused by historic emissions would be remediated, it would put the nation on the correct path toward climate stabilization.

EXPERT OPINION

1. Technological and Economic Feasibility of Converting 100% of Our Energy From Fossil Fuels to Clean, Renewable Energy For All Sectors by 2050 and 80% by 2030.

Our research suggests that it is technologically and economically possible to electrify fully the energy infrastructures of all 50 United States and provide that electricity with 100% clean, renewable wind, water, and sunlight (WWS) at low cost, if the transition is commenced immediately (Jacobson et al., 2015a; 2017a). Whereas, a 100% transformation is technically and economically possible by 2030, we believe that, for social and political reasons, a more practical expectation to transition all sectors (electricity, transportation, heating/cooling, industry) is 80% by 2030 and 100% by 2050. These conclusions are based upon the assumption that the transition commences immediately. Our research further finds that the U.S. electric power grid with 100% WWS can stay stable at low cost (similar or less than today's direct energy cost and much less than today's social cost, which includes energy, health, and climate costs) because electrifying transportation and heating creates more flexible loads, allowing grid operators to shift times of peak demand more readily (Jacobson et al., 2015b; 2018). Further, flexible loads allow low-cost storage options for heat and cold to be used to displace electricity demand and store excess electricity rather than wasting it.

The methodology for this research, outlined in detail in Jacobson et al. (2015a,b) and updated in Jacobson et al. (2017a; 2018), is as follows:

1) For each of the 50 states, we start with contemporary business-as-usual (BAU) end-use power demand by fuel type in the residential, commercial, transportation, and industrial sectors.

2) We use U.S. Department of Energy (DOE) Energy Information Administration (EIA) data and other data to project BAU end-use power demand by fuel type to 2050.
3) We electrify end-use demand in 2050 by fuel type in each sector, for each state. For some sectors, electricity is used to produce hydrogen.
4) We specify a mix of WWS electric power generators to meet the end-use electric demand in each state. The mix is limited and optimized by the technical potentials of each WWS resource in each state.
5) We calculate the required footprint and spacing area required for the WWS technologies.
6) We calculate the cost of constructing the WWS infrastructure for each state, including necessary upgrades to national electricity transmission infrastructure.
7) We calculate the number of long-term, full-time construction and operation jobs required for the generators and the corresponding number of jobs lost in the BAU energy sectors, primarily in the fossil fuel industry.
8) We calculate the air pollution mortality and morbidity reduction and corresponding health cost reduction due to transitioning from BAU to WWS.
9) We calculate the greenhouse gas emission reduction and corresponding climate cost reduction due to transitioning from BAU to WWS.
10) We use a weather prediction model to predict the time-dependent wind and solar fields in 2050 in each of the 48 contiguous U.S. states under the 100% WWS case in each state.
11) We project time-dependent power demand to 2050 from contemporary data.
12) We simulate the time dependent matching of power demand with WWS supply over the U.S. every 30 seconds for 6 years, with zero loss of load, accounting for low-cost heat storage (in water and rocks), cold storage (in water and ice), electricity storage (in concentrated solar power with storage, pumped hydroelectric storage, batteries, and hydroelectric power), demand response, and long-distance transmission.
13) We calculate the resulting cost of energy matching supply with demand.

The research concludes that converting from fossil fuel combustion to a completely electrified system for all purposes could reduce U.S.-averaged end-use power demand (load) ~39.3%. Approximately 82.4% of the reduced electricity use results from the higher work output to energy input of electricity over fossil fuels and the elimination of energy needed to mine, transport, and refine fossil fuels and uranium. The rest of the reduced electricity use is due to end-use energy efficiency and conservation improvements beyond those expected in a business-as-usual (BAU) case. The conversion to WWS should also stabilize energy prices since fuel input costs will be zero, avoiding much of the market fluctuations in the price of oil, coal, and gas.

Remaining all-purpose annually-averaged end-use U.S. load, based on the Jacobson et al. (2015a) study, is proposed to be met (based on 2050 energy estimates) with ~328,000 new onshore 5-MW wind turbines (providing 30.9% of U.S. energy for all purposes), ~156,000 off-shore 5-MW wind turbines (19.1%), ~46,500 50-MW new utility-scale solar-PV power plants (30.7%), ~2,270 100-MW utility-scale CSP power plants (7.3%), ~75.2 million 5-kW residential rooftop PV systems (3.98%), ~2.75 million 100-kW commercial/government rooftop systems (3.2%), ~208 100-MW geothermal plants (1.23%), ~36,000 0.75-MW wave devices (0.37%),

~8,800 1-MW tidal turbines (0.14%), and no new hydroelectric plants in the 48 contiguous states but 3 new hydroelectric plants in Alaska. The output of existing hydroelectric plants would be increased slightly so that hydropower supplies 3.01% of U.S. all-purpose power.

The Jacobson et al. (2015b) grid integration study based on the 50-state plans suggests that an additional ~1,360 CSP plants (providing an additional ~4.38% of annually-averaged load) and 9,380 50-MW solar-thermal collection systems for heat storage in soil (providing an additional 7.21% of annually-averaged load) would be needed as a first estimate to ensure a reliable grid. That study also assumed an increase in the peak hydropower discharge rate while holding the annual-average hydropower output constant. It also assumed a significant amount of underground thermal energy storage. This was just one possible mix of energy generators and storage. While that study faced criticism from authors, the criticisms were not only responded to point-by-point (Jacobson et al., 2016; 2017b) but the most significant ones were also shown to be moot in a follow-up peer-reviewed published study (Jacobson et al., 2018).

The subsequent study (Jacobson et al., 2018) performed a similar calculation as in Jacobson et al. (2015b) but with more storage options, including two with zero added hydropower turbines and one with zero underground or other thermal energy storage. More specifically, the additional simulations included (1) zero increase in the hydropower discharge rate but increasing the discharge rate of concentrated solar power (CSP) and adding battery storage while keeping thermal energy storage; and (2) zero increase in the hydropower discharge rate and zero thermal energy storage but using CSP with storage, batteries, and heat pumps instead.

Simulations for Jacobson et al. (2018) were performed for 20 world regions, including the United States plus Canada, island countries, medium-sized countries, and large countries and continents, rather than just one world region in Jacobson et al. (2015b). All simulations for all world regions resulted in stable grids at low cost over a 5-year simulation period, including with no added hydropower turbines and, in one case, with no thermal energy storage at all. These results for extreme conditions suggest there are multiple intermediate solutions with a variety of combinations of WWS storage technologies and resources. All methods resulted in low-cost solutions and 100% WWS by 2050. The fact that the system works with either increased hydropower discharge or increased CSP and batteries or CSP, batteries, and heat pumps is illustrative of the feasibility of transitioning the nation's energy system to 100% WWS. There is not just one way of achieving the transition, but many pathways. In fact, even critics of our methodology do not disagree with the conclusions we reach.[1]

Practical implementation considerations will determine the actual design and operation of the U.S. energy system and may result in technology mixes different than proposed here (e.g., more rooftop PV, less power plant PV).

Other studies in the U.S. and abroad provide parallel support for the ability to swiftly move away from fossil fuels. These studies are briefly summarized in **Exhibit D**. While I do not endorse

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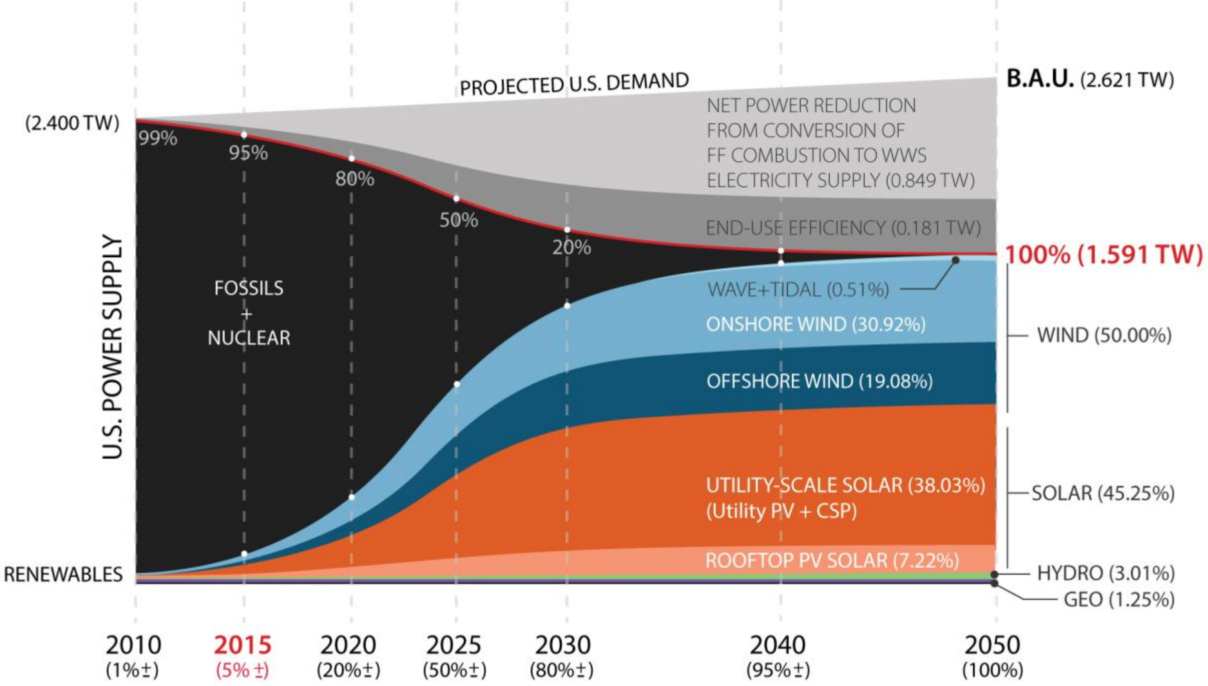
[1] June 20, 2017 Daniel Kammen Twitter: "A significant misunderstanding here: yes the 100% target is needed AND is feasible, but one must do the analytics correctly to be useful."

each of these studies and not all of the studies consider all energy sectors or 100% clean energy by 2050 as we do, collectively they illustrate the vast potential and feasibility of swift decarbonization and transition to clean, renewable energy. Specifically, several of these published studies conclude that 100% renewable energy for all sectors by 2050 for France, the European Union, and globally is feasible.

The timeline for conversion under either modeled scenario is proposed as follows: 80% of all energy to be WWS by 2030 and 100% by 2050 (**Figure 1**). If this timeline is followed, implementation of these plans and similar ones for other countries worldwide provides the pathway to eliminate energy-related global warming; air, soil, and water pollution; and energy insecurity. Transitioning at this pace should avoid global temperatures from rising more than 1.5ºC as a peak temperature increase since 1870 and reduce CO_2 back to 350 ppm by 2100 (Section 2). Transitioning to 100% WWS by 2050 also provides the best opportunity for the federal government to further reduce global surface and ocean temperatures to levels that will over the long term stabilize the planet's ice sheets.

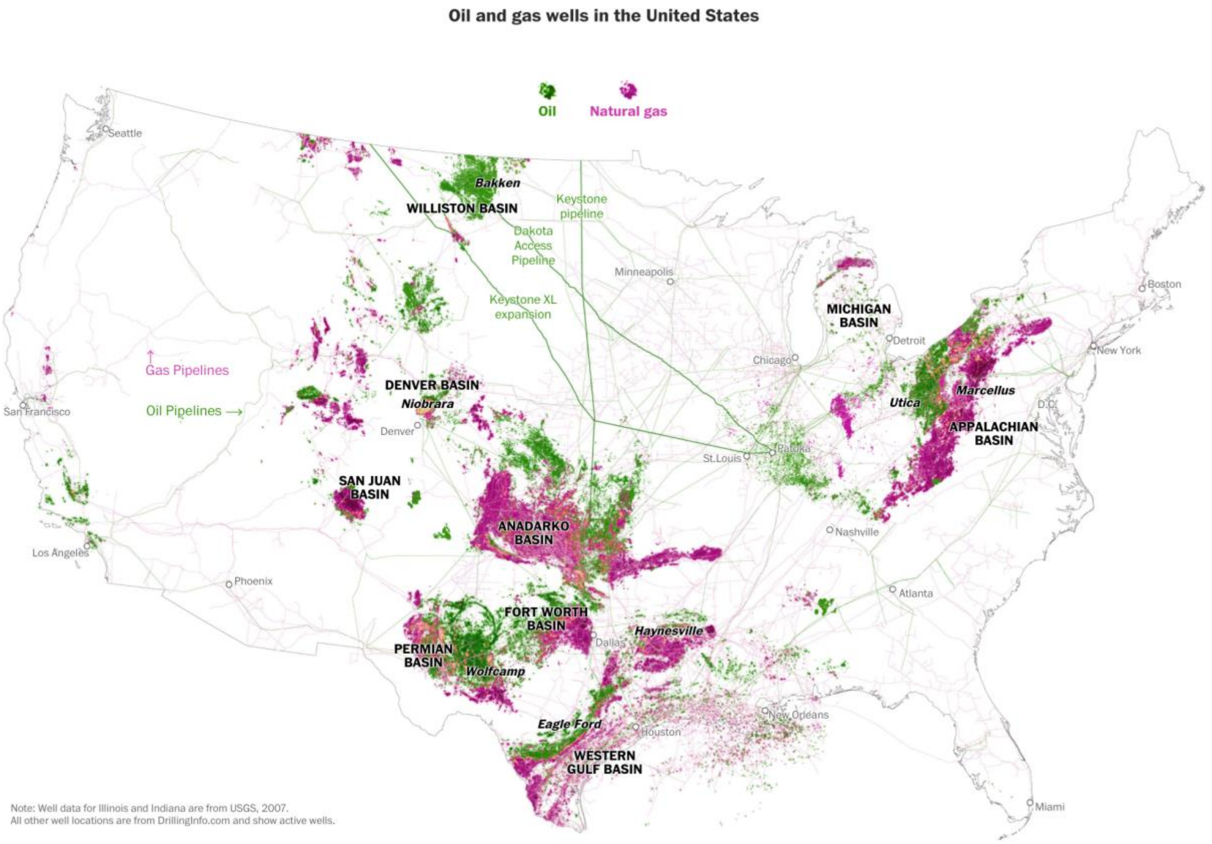
Figure 1. Time-dependent change in U.S. end-use power demand for all purposes (electricity, transportation, heating/cooling, and industry) and its supply by conventional fuels and WWS generators based on the state roadmaps proposed. Total power demand decreases upon conversion to WWS due to the higher work output per unit energy input of electricity over combustion, the elimination of energy used to mine, transport, and refine fossil fuels, and additional end-use energy efficiency measures in the WWS case. The percentages on the horizontal date axis are the percent conversion to WWS that has occurred by that year. The percentages next to each WWS source are the final estimated penetration of the source. The 100% demarcation in 2050 indicates that 100% of all-purpose power is provided by WWS technologies by 2050, and the power demand by that time has decreased. In 2010 nuclear power represented ~4% of the total end-use fossil plus nuclear power (from Jacobson et al., 2015a).



The additional footprint on land for WWS devices is equivalent to about 0.42% of the U.S. land area, mostly for utility scale PV. An additional on-land spacing area of about 1.6% is required for onshore wind, but this area can be used for multiple purposes, such as open space, agricultural land, or grazing land. The land footprint and spacing areas (open space between devices) in the proposed scenario can be reduced by shifting more land based WWS generators to the ocean, lakes, and rooftops.

As described previously, 0.42% of U.S. land is equivalent to ~14,800 square miles. For comparison, an upper bound of ~75,000 square miles of land (2.1% of U.S. land area) may have been used to date for roads, well pads, and storage facilities for the 4.2 active plus inactive oil and gas wells in the United States (Fracktracker Alliance, 2015). Additional land is required for coal and oil extraction, oil and gas pipelines, oil refineries, gas stations, power plants, and other oil, gas, and coal infrastructure (see **Figure 2**). Thus, the roadmaps here will take much less footprint than oil and gas alone in the United States.

Figure 2. Oil and Gas Wells in the United States (Meko and Karklis, Wash. Post, 2017).


Oil and gas wells in the United States

Note: Well data for Illinois and Indiana are from USGS, 2007.
All other well locations are from DrillingInfo.com and show active wells.

Offshore oil and gas infrastructure is similarly extensive for the Gulf of Mexico, as depicted in **Figure 3**.

Figure 3. Gulf Coast Oil and Gas Infrastructure (Meko and Karklis, Wash. Post, 2017).

The 2017 unsubsidized business costs of new onshore wind and utility-scale solar plants is already less than that of new natural gas power plants (Lazard, 2017). Rooftop PV, offshore wind, tidal, and wave are more expensive, but their costs are declining rapidly. By 2030 and

2050, however, the business costs of all WWS technologies are expected to drop, whereas conventional fuel costs are expected to rise (Jacobson et al., 2015a and references therein).

In 2050, the direct (business) cost of a full 100% WWS grid-integrated system (including generation, transmission, distribution, and storage) is calculated to be similar or less than that of a fossil fuel system (Jacobson et al., 2015b; 2018). The total social cost (business cost plus health and climate cost) of a 100% WWS system will be about one-third to one-fourth that of a fossil-fuel system due to the high climate and health costs of fossil fuels (Jacobson et al., 2015b; 2018).

The 50-state WWS roadmaps are anticipated to create ~3.9 million 40-year construction jobs and ~2.0 million 40-year operation jobs for the energy facilities alone, outweighing the ~3.9 million jobs lost to give a net gain of 2.0 million 40-year jobs. Earnings during the 40-year construction period for these facilities (in the form of wages, local revenue, and local supply-chain impacts) are estimated to be ~$223 billion per year in 2013 dollars and annual earnings during operation of the WWS facilities are estimated at ~$132 billion per year. Net earnings from construction plus operation minus lost earnings from lost jobs are estimated at ~$85 billion per year.

The state roadmaps will reduce U.S. air pollution mortality by ~62,000 (19,000-115,000) U.S. air pollution premature mortalities per year today and ~46,000 (12,000-104,000) per year in 2050, avoiding ~$600 (85-2,400) billion per year (2013 dollars) in 2050, equivalent to ~3.6% (0.5-14.3) of the 2014 U.S. gross domestic product.

Converting to WWS would further eliminate ~$3.3 (1.9-7.1) trillion per year in 2050 global warming costs to the world due to U.S. greenhouse gas emissions. These plans will result in the average person in the U.S. in 2050 saving ~$260 (190-320) per year in energy costs (2013 dollars), $1,500 (210-6,000) per year in health costs, and $8,300 (4,700-17,600) per year in climate costs for a total annual per capita savings of $10,060 (5,100-23,920).

Uncertainties remain in terms of the range of energy, health, and climate costs we estimate in our analysis. These ranges may miss costs impacted by unforeseen political/social events. As such, the estimates should be reviewed periodically. However, even recognizing such uncertainties, I conclude to a strong degree of scientific certainty that transitioning to 100% WWS is in the economic best interest of the United States.

Transitioning to 100% WWS will allow the United States to produce as much power as it uses in the annual average at present, thereby reducing its reliance on international competition for energy, potentially reducing international conflict and increasing energy stability within the United States. In addition, the economic benefits of transitioning to 100% WWS would flow toward the citizens of the United States, as we would not be required to purchase fossil fuels from other countries.

Transitioning to 100% WWS will increase access to distributed energy, providing easier and more access to energy for those living in remote areas.

Transitioning to 100% WWS will reduce the risk of large-scale system disruption due to large power plant outages and physical terrorism (but not necessarily due to cyberattack) because much of the world power supply will be decentralized into more, smaller power sources.

Based on the scientific results presented, current barriers to implementing the WWS roadmaps are neither technical nor economic. They are social and political. Such barriers are due partly to the fact that most people are unaware of what changes are possible, what technology is available, and how they will benefit from a transition to WWS in their own lives and partly due to the fact that many with a financial interest in the current energy industry resist change. Because the benefits of converting (reduced global warming and air pollution, new jobs and stable energy prices) far exceed the costs, converting has little downside.

2. What is Needed to Decrease Atmospheric CO_2 to 350 ppm by 2100

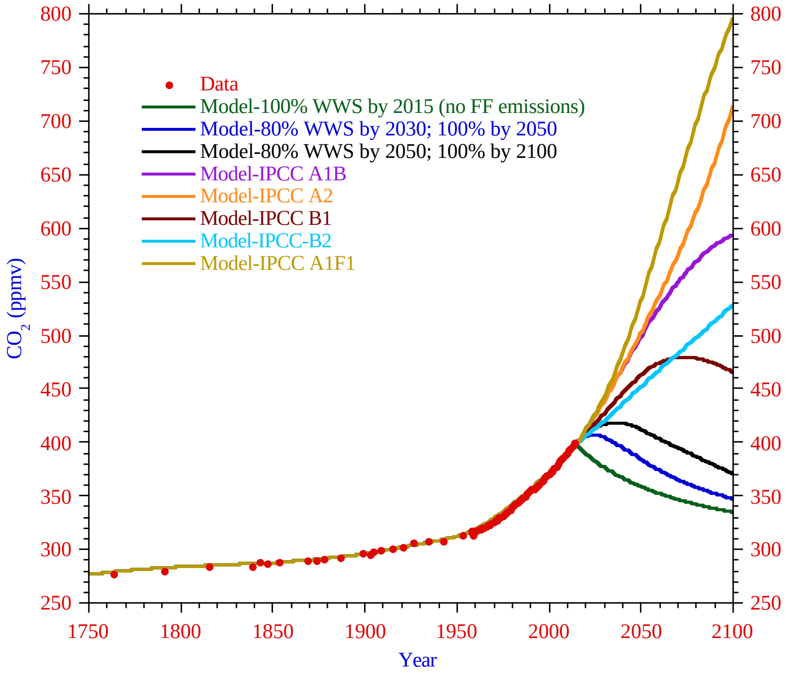
Transitioning 80% of the United States and the world's energy and land-use change emissions to WWS by 2030 and 100% by 2050 is consistent with a trajectory to allow atmospheric CO_2 levels to decrease to near 350 ppm by 2100.

Matthews (2016) estimates the global emission limits to keeping temperature increases under 1.5°C with probabilities of 67% and 50% as 2400 Gt-CO_2 and 2625 Gt-CO_2, respectively.

Between 1870 and the end of 2015, a cumulative ~2050 Gt-CO_2 was emitted globally from fossil-fuel combustion, cement manufacturing, and land use change. (Mathews, 2016). This suggests no more than 350-575 Gt-CO_2 can be emitted for a 67-50% probability of keeping post-1870 warming under 1.5°C. Given the current and projected global emission rate of CO_2, it is necessary to cut energy- and land-use change emissions yearly until emission cuts reach 80% by 2030 and 100% by 2050 to limit warming to 1.5°C with a probability of between 50% and 67%.

Figure 4 illustrates the possible impact on global atmospheric carbon dioxide levels of an 80% conversion to WWS by 2030 and 100% conversion by 2050 as well as possible impacts from less aggressive emission reductions. The 100% by 2050 scenario can reduce CO_2 to near 350 ppm by 2100, a level last measured in the atmosphere around 1988. All IPCC (2000) emission scenarios result in CO_2 levels in 2100, ranging from 460 to 800 ppm. Such scenarios are certain to drive temperatures dangerously higher. A WWS scenario for the United States is essential for stabilizing and ultimately reducing temperatures over the long-term.

Figure 4. Comparison of historic (1751-2014) observed CO_2 mixing ratios (ppmv) from the Siple ice core (Neftel et al., 1994) and the Mauna Loa Observatory (Tans and Keeling, 2015) with GATOR-GCMOM model results (Jacobson, 2005) for the same period plus model projections from 2015-2100 for five Intergovernmental Panel on Climate Change (IPCC) scenarios (IPCC, 2000) and three WWS cases: an unobtainable 100% WWS by 2015 case, an 80% WWS by 2030 and 100% by 2050 case (from Figure 1 above), and a less-aggressive 80% by 2050 and 100% by 2100 case.



The model is set up as in Jacobson (2005) with two columns (one atmospheric box over 38 ocean layers plus one atmospheric box over land). It treats full ocean chemistry in all layers, vertical ocean diffusion with canonical diffusion coefficients, ocean removal of calcium carbonate for rock formation, gas-ocean transfer, and emissions from fossil fuels. It also accounts for photosynthesis, plant and soil respiration, and removal of carbon dioxide from the air by weathering. Fossil-fuel emissions from 1751-1958 are from Boden et al. (2011), from 1959-2014 are from Le Quere et al. (2015), and for 2015 onward from the WWS scenarios scaled from 2014 emission and from the individual IPCC scenarios. Land use change emissions per year are 300 Tg-C/yr for 1751-1849, from Houghton (2012) for 1850-1958, from Le Quere et al. (2015) for 1959-2014, from the IPCC (2000) A1B scenario for the WWS cases for 2015-2100, and from the individual IPCC scenarios for the remaining cases. The net carbon sink over land from 1751-2100 is calculated from the time-dependent photosynthesis, respiration, and weathering processes mentioned.

3. List of Technology Replacements and Timelines for Their Implementation

Below is a list of electric appliances, transportation options, and WWS power generators that are needed to transition to 100% WWS. Most of these technologies are available today, and the rest (e.g., for aircraft and ships in particular) are currently being designed to transform the energy infrastructure of the United States. The list is not a complete list, but demonstrates that 95% of the technological solutions for a complete transition to WWS by 2050 already exist. Future innovations over the next 30 years and beyond will very likely provide even more technological mechanisms to facilitate the remaining transition to 100% WWS for all purposes by 2050.

A. Technology Replacements

i. Increase Energy Efficiency / Reduce Energy Demand

a. Increase efficiency in buildings through:

Lighting:

- LED lighting
- Advanced lighting controls

Appliances:

- High efficiency pumps and motors
- High efficiency commercial appliances (refrigerators, washers, dryers)
- Energy efficient residential appliances (refrigerators, water heaters, etc.)
- Variable refrigerant flow

Heating and cooling efficiency in buildings through:

- Programmable thermostats
- Improved wall, floor, ceiling, and pipe insulation
- High-efficiency double- and triple-pane windows
- Energy efficient framing practices
- Passive solar design
- Sealing doors, windows, walls, outlets, and fireplaces to reduce heat / cold loss
- Evaporative cooling systems
- Ductless heat pumps for heating and air conditioning
- Water-cooled heat exchanging
- Night ventilation cooling
- Passive ventilation design
- Combined space and water heating
- Air flow management
- Heat recovery ventilation systems
- Building energy monitors to identify opportunities to reduce wasted energy

Water efficiency:

- High efficiency residential and commercial water fixtures
- High efficiency irrigation systems
- Greywater re-use systems

b. Reduced transportation demand through:

- Telecommuting rather than commute by car
- Improved biking infrastructure
- Improved pedestrian infrastructure

- Improved public transportation
- Transportation Demand Management programs that support adoption of low-carbon transportation practices
- Improved carpooling and ride-sharing programs and technologies
- Urban land use practices to reduce transportation demand (i.e. mixed use development, increased residential densities)

c. **Improved vehicle efficiency through:**
  - Low rolling resistance tires
  - Lightweight materials (i.e. carbon fiber, aluminum, fiberglass)
  - Regenerative braking systems
  - High efficiency settings or dashboard fuel efficiency displays

ii. WWS Electric Power Generators
- Onshore/offshore wind turbines
- Solar photovoltaics (PV) for rooftops and power plants
- Concentrated Solar Power (CSP) plants
- Geothermal power plants for electricity
- Tidal turbines
- Wave devices
- Existing large hydroelectric reservoirs used more efficiently
- Small hydroelectric reservoirs
- In-stream hydroelectric turbines

iii. Low-Temperature Heat Generators
- Geothermal heat pumps
- Natural geothermal heating
- Solar thermal collection devices for heat

iv. Electricity Storage
- CSP with storage (either molten salt or phase-change material)
- Pumped hydroelectric storage
- Hydroelectric power plant reservoirs
- Batteries

v. Heat Storage Devices
- Hot water tanks
- Rocks stored underground
- Thermal walls

vi. Cold Storage Devices
- Chilled water tanks
- Ice storage

vii. **Hydrogen Storage Devices**

- Electrolyzers to produce hydrogen from electricity
- Electric compressors to compress hydrogen
- Tanks to store hydrogen for transportation primarily

viii. **Demand Response**

- Technology to enable remote start up and shut down of appliances and equipment that have flexible demand (i.e. water heaters, HVAC equipment, electric vehicles)
- Utilities provide incentives for industry, companies, and individuals to shift their electricity use for certain uses and processes to non-peak times of day or night – Time of Use electricity pricing

ix. **Electric Vehicles**

- Light-, medium-, and heavy-duty on-road automobiles
- Short-distance trucks, buses trains, ships, aircraft
- Motorcycles
- Non-road vehicles
- Construction equipment
- Agricultural equipment
- Forklifts

x. **Hydrogen Fuel Cell/Electric Hybrid Vehicles**

- Long-distance trucks
- Buses
- Long-distance trains
- Long-distance ships
- Long-distance aircraft
- Construction equipment
- Agricultural equipment

xi. **Electric Car Charging Infrastructure**

- Home car chargers
- Chargers installed in parking garages and on streets

xii. **High-Temperature Industrial Equipment**

- Electric arc furnaces
- Dielectric heaters
- Electric induction furnaces

xiii. **Electric Appliances to Replace Gas or Gasoline**

- Heat pump air and water heaters
- Electric induction cooktop stoves
- Electric dryers
- Electric leaf blowers

- Electric lawnmowers
- Electric water sprayers
- Electric fans

xiv. Long-Distance Transmission

- High-voltage direct-current (HVDC) lines

Whereas, much new WWS infrastructure can be installed upon natural retirement of BAU infrastructure, new policies are needed to force remaining existing infrastructure to retire early to allow the complete conversion to WWS by 2050. Because the air-pollution and climate-impact benefits (avoided costs) (28.5 (11.2-72) ¢/kWh-BAU-all-energy) resulting from closing BAU plants early far exceed the annualized remaining *net* asset value of such plants (the difference between the annualized capital cost and the annualized salvage or re-use value) divided by annual energy produced, and because net jobs increase upon replacing BAU plants, retiring them early results in large net health, employment, and climate benefits to society.

B. Timelines for Transitioning Individual Sectors

The overall timeline proposed for transitioning to 100% WWS is 80% by 2030 and 100% by 2050. To meet this timeline, rapid transitions are needed in each technology sector. Below is a list of proposed transformation timelines for individual sectors.

> ***Development of super grids and smart grids:*** as soon as possible, the United States should develop long-term power-transmission-and-distribution systems to provide "smart" management of energy demand and supply at all scales, from local to international, with a 100% WWS system. This allows supply and demand to be optimized.
>
> ***Power plants*****:** by 2020 at the latest, no more construction of new coal, nuclear, natural gas, or biomass fired power plants; all new power plants built should be WWS.
>
> ***Storage:*** starting immediately, heat, cold, and electric storage technologies should be deployed. Heat storage technologies include underground storage in rocks, storage in hot water tanks, and storage in thermal mass (e.g., wax, cement blocks). Cold storage includes primarily storage in ice and water. Electric storage includes storage in concentrated solar power, pumped hydroelectric power, batteries, and in existing hydroelectric reservoirs. Other types of storage are also possible.
>
> ***Heating, drying, and cooking in the residential and commercial sectors*****:** by 2020, all new devices, appliances, and machines should be electric.
>
> ***Industrial heat*****:** by 2023, all new high-temperature heating equipment for industrial applications should be electric.

***Large-scale waterborne freight transport*:** by 2020-2025, all new ships should be electrified and/or use electrolytic hydrogen, all new port operations should be electrified, and port retro-electrification should be well underway.

***Rail and bus transport*:** by 2025, all new trains and buses should be electrified. This requires changing the supporting energy-delivery infrastructure and the manufacture method of transportation equipment.

***Off-road transport, small-scale marine*:** by 2025 to 2030, all new production should be electrified.

***Long-distance heavy-duty truck transport*:** by 2025 to 2030, all new heavy-duty trucks and buses should be electric or hydrogen fuel cell-electric hybrids.

Light-duty on-road transport: by 2025-2030, all new light-duty on-road vehicles should be electric.

***Short-haul aircraft*:** by 2035, all new small, short-range aircraft should be electric.

***Long-haul aircraft*:** by 2040, all remaining new aircraft should be hydrogen fuel cell-electric hybrids.

During the transition, conventional fuels and existing WWS technologies are needed to produce the remaining WWS infrastructure. However, much of the conventional energy would be used in any case to produce conventional power plants and automobiles if the plans proposed here were not implemented. Further, as the fraction of WWS energy increases, conventional energy generation will decrease, ultimately to zero, at which point all new WWS devices will be produced with existing WWS. In sum, the creation of WWS infrastructure may result in a temporary increase in emissions before they are ultimately reduced to zero.

4. Recommended First Steps and Potential Policies

Whereas, much new WWS infrastructure can be installed upon natural retirement of BAU infrastructure, new policies are needed to encourage remaining existing infrastructure to retire early to allow the complete conversion to WWS. Because the annual air-pollution and climate-impact benefits (avoided costs), as quantified here, resulting from closing BAU plants early far exceed the annualized remaining *net* asset value of such plants (the difference between the annualized capital cost and the annualized salvage or re-use value), and because net jobs increase upon replacing BAU plants, retiring them early results in large net benefits to society.

5. Why Nuclear, Biofuels, and Coal with Carbon Capture are Not Included

While some people have suggested that energy options aside from WWS, such as nuclear power, coal with carbon capture and sequestration (coal-CCS), and biofuels, can play a role in solving these problems, all four technologies, while better in several respects than fossil fuel technologies, have some disadvantages relative to fossil fuel technologies and significant disadvantages relative to WWS technologies. These advantages/disadvantages are listed below and then explained in more detail below that.

With respect to some of the disadvantages, it is important to note that because we must reduce emissions 80% by 2030 (thus only 12 years from 2018), we do not recommend power plant technologies that cannot be installed within the next few years.

Nuclear power

Advantages

- Low carbon and air pollution relative to fossil fuels.
- Requires only modest land use.

Disadvantages

- Requires 10-19 years between planning and operation versus 2-5 years for wind/solar.
- Expensive; cannot be built without significant financial support and insurance guarantee from government.
- Carries weapons proliferation risk.
- Carries meltdown risk (1.5% of all reactors built to date have melted down).
- Nuclear waste disposal issue (where to put the waste).
- Significant water is required for cooling with current and future technology.
- Nuclear material mining risks.
- Nuclear material transportation risks.
- 6-23 times the carbon emissions of wind power per unit energy generated.
- Not a renewable resource.
- Potential terrorism target.

Coal with carbon capture

Advantages

- Less carbon dioxide emissions than coal without carbon capture.
- Keeps coal miners employed in mining.

Disadvantages

- Requires 25% more energy than regular coal → 25% more air pollution emissions than regular coal because carbon capture equipment reduces only carbon dioxide.
- Still produces 50-60 times more CO_2 per unit energy than wind because it doesn't reduce CO_2 from mining or transporting coal, which is one-third of the emissions associated with coal power generation.
- Still results in land/habitat destruction due to coal mining.
- Still results in black lung disease to coal miners.
- Much more expensive than wind or solar power.
- Requires a minimum of 6-9 years between planning and operation versus 2-5 years for wind/solar.
- Coal-CCS can only be placed near specific geological formations.
- Long-term geologic storage of CO_2 is unproven.

- CO_2 stored underground has potential to leak.
- Not a renewable resource.

Biofuels

Advantages

- Carbon produced from burning a biofuel can be recaptured during regrowth of the biofuel.
- Biofuel combustion emits less of some chemicals than gasoline or diesel combustion.
- Biofuels can sometimes be substituted directly for fossil fuels in some automobiles, for example.

Disadvantages

- Biofuels require a significant amount of energy to produce, and a lot of that energy can be from fossil fuel combustion.
- Biofuel combustion emits more of some chemicals than gasoline or diesel combustion.
- Overall ozone production and mortality from burning ethanol as a fuel exceeds that from burning gasoline in the United States.
- The land required for growing biocrops is enormous.
- Solar PV produces 20 times more electricity than a biocrop produces energy over the same amount of land.
- Using land for food instead of fuel raises the price of food and spurs deforestation in parts of the world to create more land for biocrops.

With respect to the cost of nuclear and coal-CCS, the Intergovernmental Panel on Climate Change (IPCC) (2014) states (Section 7.8.2), "*Without support from governments, investments in new nuclear power plants are currently generally not economically attractive within liberalized markets,…"*

Similarly, Freed et al. (2017), who are strong nuclear advocates, state, "*…there is virtually no history of nuclear construction under the economic and institutional circumstances that prevail throughout much of Europe and the United States*."

Further, Cooper (2016), who compared WWS with nuclear and CCS scenarios, concluded, "*Neither fossil fuels with CCS or nuclear power enters the least-cost, low-carbon portfolio*."

IPCC (2014) further states that, with high penetrations of renewable energy (RE), nuclear and CCS are not efficient (Section 7.6.1.1), "*…high shares of variable RE power…may not be ideally complemented by nuclear, CCS,…"*

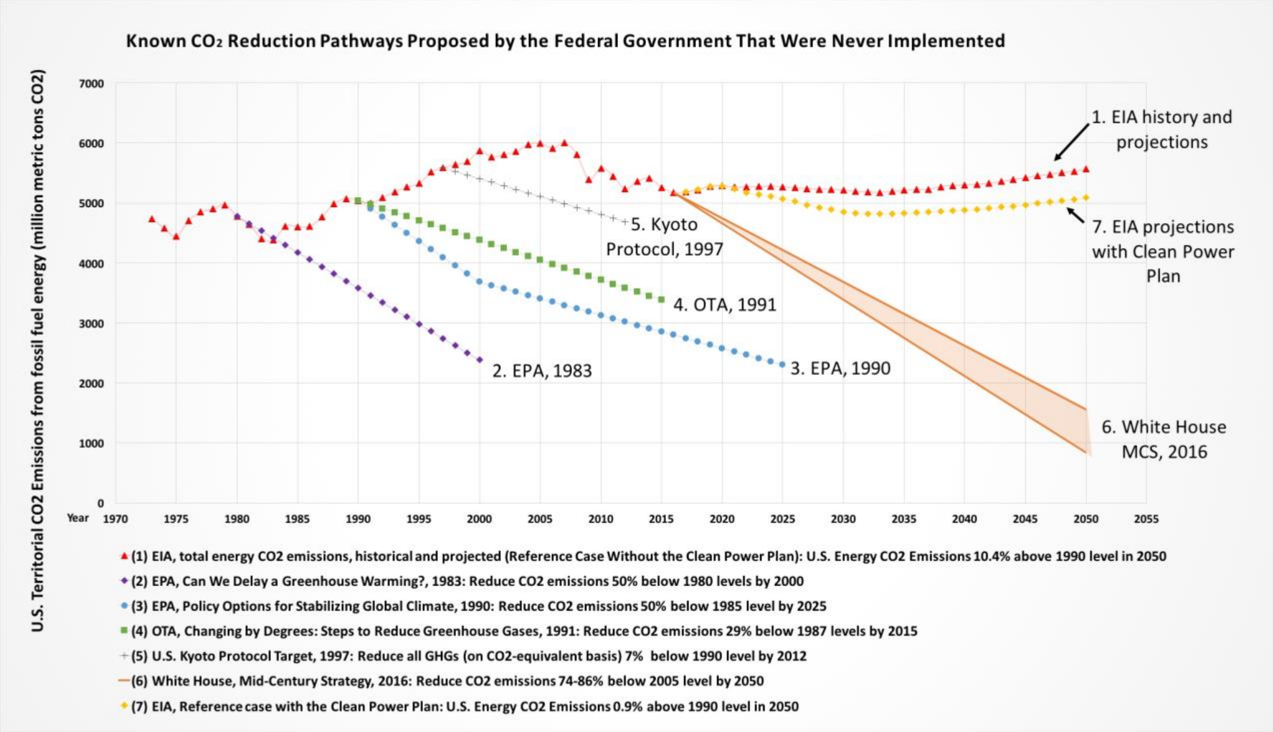
With respect to the other disadvantages of nuclear, IPCC (2014, p. 517) concludes that there is "*robust evidence"* and *"high agreement*" that "*Barriers to and risks associated with an increasing use of nuclear energy include operational risks and the associated safety concerns, uranium mining risks, financial and regulatory risks, unresolved waste management issues, nuclear weapons proliferation concerns, and adverse public opinion."* As such, expanding the use of nuclear to countries where it doesn't exist may increase weapons proliferation and meltdown risks. Wind, water, and solar power have none of these risks. More advanced nuclear cannot be evaluated until it is commercialized, but it does not exist today.

With respect to the time lag between planning and operation of nuclear versus wind/solar, the air pollution emissions of nuclear versus coal-CCS versus biofuels versus wind/solar, please see Jacobson (2007, 2009).

6. Historical WWS Technological Feasibility

The United States could have begun the WWS transition by at least the late 1970s and early 1980s. In my expert opinion, had government promoted a climate-safe national energy policy at that time, the proportion of our nation's energy system powered by WWS would today be much greater than it is currently in my estimation. For example, the graph in **Figure 5** below shows several historical examples of the U.S. government making recommendations, roadmaps, or plans since the early 1980s to decarbonize the national energy system, none of which was implemented. Notwithstanding their knowledge of climate change, and the alternative energy systems available to the country, the Federal Defendants chose to continue a fossil fuel energy system, which still supplies the majority of our energy today across all sectors. The red line shows actual and projected business as usual US emissions by the EIA under the Trump administration, which diverge substantially from the other recommended energy emission pathways.

Figure 5. Known CO_2 reduction pathways proposed by the Federal Government that were never implemented. ((1) EIA Reference Case, 2017 (2) EPA, 1983, (3) EPA, 1990, (4) OTA 1991, (5) Kyoto Protocol, 1997, (6) U.S. White House, 2016, (7) EIA Reference Case: with Clean Power Plan, 2017)



Other Examples:

- California developed the first three major wind farms worldwide in the late 1970s and early 1980s. These were Altamont Pass, Tehachapi, and San Gorgonio Pass. However, U.S. national policy shifted, and further growth of wind was slowed substantially for 1-2 decades. During that period, the center of wind farm development and manufacturing moved to Europe.

- Similarly, burgeoning U.S. policy in the 1970s encouraged solar energy expansion, but dominant U.S. policies that favored traditional fossil fuels squeezed out solar growth in the 1980s and 1990s. Only in the last decade has solar begun to grow substantially. In a December 5, 1978 Department of Energy Domestic Policy Review of Solar Energy Report to the White House, Defendant DOE projected that technical capacity for solar penetration by the year 2000 was 26-31% of national energy supply (Schlesinger 1978). The same report also confirmed the inefficiency of the energy system where 56% of annual energy use was consumed in conversion, transmission and end-use losses, not in actual energy use. The report confirms that widespread use of solar energy, which was technically available even in the 1970s was “hindered by Federal and state policies and market imperfections that effectively subsidize competing energy sources.” The lack of federal R&D and other support, which was largely given to fossil fuels, limited the “long-term contribution of solar energy to the nation’s energy supply.” (Schlesinger 1978).

- Electric cars have been around for over 180 years (since 1837). The first U.S. electric car was built in 1890. By 1900, 34,000 cars, or 38% of the U.S. fleet was electric. However, their popularity declined in the 1910s due to greater range of fossil fuel cars. Electric cars only began to re-emerge in the U.S. in the 1990s following a push by the California Air Resources Board to reduce emissions. But, pressure by the oil industry combined with U.S. policy that supported the internal combustion engine and fossil fuels, not electric vehicles, caused manufacturers to stop producing and even destroying electric cars. After the development of the Toyota Prius, Tesla began working on an electric car in 2004, successfully producing a long-distance Roadster in 2008. In my expert opinion, if government had given support to electric cars during any decade prior to the mid- to- late 2000s, I believe, the percent of the U.S. automobile market that is electric would be significantly higher than today.

- It is my expert opinion that if the policies of the United States had encouraged more subsidies and R&D for renewable energy, efficiency, electric appliances, and electric cars rather than subsidies and other support for fossil fuels, our country would be a lot further toward a renewable-powered energy system today than it is, the amount of carbon dioxide pollution emitted would be substantially less, and the harms from climate change would not be as severe as they are today and are projected to be in the near and long-term.

CONCLUSION AND RECOMMENDATION

In sum, I conclude that electrification and use of direct heat in all energy sectors in the United States, and providing the electricity and direct heat with 100% wind, water, and sunlight (WWS) by 2050, with 80% by 2030, is technologically and economically feasible. Use of WWS technologies may be the only way to solve the climate, air pollution, and energy security problems in a timely manner. They also involve the least risk of collateral damage and serve multiple public interests, including creating more full-time, long-term jobs than lost, reducing reliance on the international search for energy, providing energy security, and reducing substantial air pollution health and climate problems. Given that 4-7 million people currently die premature each year worldwide due to fossil fuel pollution, including 62,000 (19,000-115,000) in the United States, and climate is changing rapidly due to the increase in human-emitted gases and particles into the atmosphere, the rapid deployment of a 100% WWS solution is important and practical for solving these problems simultaneously. The bottom line is that it is technically and economically feasible to transition off of fossil fuels by 2050 and supply our energy needs with 100% WWS. The primary barrier is the lack of government direction to move energy policy in the WWS direction and government policies and actions that continue to favor a fossil-fuel based energy system.

In my expert opinion, if the U.S. defendants in this case are ordered to plan for, and implement, a 100% WWS transition by 2050, it is feasible to develop such a plan and almost all the technology is available to carry out the plan quickly in a cost-effective manner.

Signed this 6th day of April, 2018 in Palo Alto, California.

Mark Z Jacobson

Mark Jacobson, Ph.D.

EXHIBIT A: CV

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Stanford University, Stanford, CA; Economics B.A., with distinction, 1988
Stanford University, Stanford, CA; Environmental Engineering M.S., 1988
UCLA, Los Angeles, CA; Atmospheric Sciences M.S., 1991
UCLA, Los Angeles, CA; Atmospheric Sciences Ph.D., 1994

Professional Appointments

Stanford University Atmosphere/Energy Program Director/co-founder, 2004-present
Stanford University Energy Resources Engineering Professor by Courtesy, 2007-2010
Stanford University Civil & Environmental Engineering Professor, 2007-present
Stanford University Civil & Environmental Engineering Associate Professor, 2001-2007
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Mark Z. Jacobson's career has focused on better understanding air pollution and global warming problems and developing large-scale clean, renewable energy solutions to them. Toward that end, he has developed and applied three-dimensional atmosphere-biosphere-ocean computer models and solvers to simulate air pollution, weather, climate, and renewable energy. He has also developed roadmaps to transition states and countries to 100% clean, renewable energy for all purposes and computer models to examine grid stability in the presence of high penetrations of renewable energy.

To date, he has published two textbooks of two editions each and 152 peer-reviewed journal articles. He has testified four times for the U.S. Congress. Nearly a thousand researchers have used computer models he has developed. In 2005, he received the American Meteorological Society Henry G. Houghton Award for "significant contributions to modeling aerosol chemistry and to understanding the role of soot and other carbon particles on climate." In 2013, he received an American Geophysical Union Ascent Award for "his dominating role in the development of models to identify the role of black carbon in climate change" and the Global Green Policy Design Award for the "design of analysis and policy framework to envision a future powered by renewable energy." In 2016, he received a Cozzarelli Prize from the *Proceedings of the National Academy of Sciences* for "outstanding scientific excellence and originality" in his paper on a solution to the U.S. grid reliability problem with 100% penetration of wind, water, and solar power for all purposes. He has also served on the Energy Efficiency and Renewables advisory committee to the U.S. Secretary of Energy and was invited to talk about his world and U.S. clean-energy plans on the Late Show with David Letterman.

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Mason, I.G., SC Page, and AG. Williamson, 2010. A 100% renewable electricity generation system for New Zealand utilizing hydro, wind, geothermal and biomass, *Energy Policy* 38 (8): 3973-3984, doi.org/10.1016/j.enpol.2010.03.022.	Electricity	100% renewable electricity in New Zealand
Connolly, D. and BV. Mathiesen, 2014. A technical and economic analysis of one potential pathway to a 100% renewable energy system, *International Journal of Sustainable Energy Planning and Management* 1, doi.org/10.5278/ijsepm.2014.1.2.	Electricity, heating/cooling, transportation	100% renewable Ireland by 2050
Connolly, D., H. Lund, and BV. Mathiesen, 2016. Smart energy Europe: The technical and economic impact of one potential 100% renewable energy scenario for the European Union, *Renewable and Sustainable Energy Reviews* 60: 1634–1653, doi.org/10.1016/j.rser.2016.02.025.	Electricity, heating/cooling, transportation	100% renewable for all uses in Europe by 2050
Mathiesen, BV., H. Lund, and K. Karlsson, 2011. 100% Renewable energy systems, climate mitigation and economic growth, *Applied Energy* 88 (2): 488-501, doi.org/10.1016/j.apenergy.2010.03.001.	Electricity, heating/cooling, transportation	100% renewable for all uses by 2050
Mathiesen, BV., et al., 2015. Energy systems for coherent 100% renewable energy and transport solutions, *Applied Energy* 145: 139-154, doi.org/10.1016/j.apenergy.2015.01.075.	Electricity, heating/cooling, transportation	100% renewable for all uses
Elliston, B., I. MacGill, and M. Diesendorf, 2013. Least cost 100% renewable electricity scenarios in the Australian National Electricity Market, *Energy Policy* 59: 270-282, doi.org/10.1016/j.enpol.2013.03.038.	Electricity	100% renewable electricity
Elliston, B., I. MacGill, and M. Diesendorf, 2014. Comparing least cost scenarios for 100% renewable electricity with low emission fossil fuel scenarios in the Australian National Electricity Market, *Renewable Energy* 66: 196-204, doi.org/10.1016/j.renene.2013.12.010.	Electricity	100% renewable energy for electricity
Budischak, C., et al., 2013. Cost-minimized combinations of wind power, solar power and electrochemical storage, powering the grid up to 99.9% of the time. *Journal of Power Sources* 225: 60-74, doi.org/10.1016/j.jpowsour.2012.09.054.	Electricity	90-99.9% renewable electricity in US territory covered by PJM
MacDonald, A.E., C.T. Clack, et.al., 2016. Future cost-competitive electricity systems and their impact on US CO_2 emissions, *Nature Climate Change* 6: 526–531, doi:10.1038/nclimate2921.	Electricity	GHGs 78% below 1990 levels by 2030

Williams, J.H., B. Haley, F. Kahrl, J. Moore, A.D. Jones, M.S. Torn, and H. McJeon, 2014. Pathways to deep decarbonization in the United States, *SDSN – IDDRI*, http://unsdsn.org/wp-content/uploads/2014/09/US-Deep-Decarbonization- Report.pdf.	All sectors	GHGs 80% below 1990 levels by 2050
United States White House, 2016. *U.S. Mid Century Strategy for Deep Decarbonization*, https://unfccc.int/files/focus/long-term_strategies/application/pdf/mid_century_strategy_report-final_red.pdf	All sectors	All greenhouse gas emissions 80%+ below 2005 by 2050.
Hand, M.M., S. Baldwin, E. DeMeo, J.M. Reilly, T. Mai, D. Arent, G. Porro, M. Meshek, and D. Sandor, eds. 4 vols., 2012. Renewable Electricity Futures Study (Entire Report) *National Renewable Energy Laboratory NREL*/TP-6A20-52409. Golden, CO: National Renewable Energy Laboratory, http://www.nrel.gov/analysis/re_futures/.	Electricity	Renewables could supply 80% of total U.S. electric generation by 2050
Mai, T., D. Mulcahy, MM Hand; and SF Baldwin, 2014. Envisioning a renewable electricity future for the United States, Energy 65: 374-386, doi.org/10.1016/j.energy.2013.11.029.	Electricity	80% renewable electricity by 2050
Arent, D., J. Pless, et.al., 2014. Implications of high renewable electricity penetration in the U.S. for water use, greenhouse gas emissions, land-use, and materials supply, Applied Energy 123: 368-377, doi.org/10.1016/j.apenergy.2015.01.075.	Electricity	80% renewable electricity by 2050
Mathiesen, B.V., H. Lund, et.al., 2015. Smart energy systems for coherent 100% renewable energy and transport solutions, *Applied Energy* 145: 139-154, doi.org/10.1016/j.apenergy.2015.01.075.	Electricity, heating, transportation	100% renewable Denmark by 2050
Connolly, D., BV Mathiesen, 2014. A technical and economic analysis of one potential pathway to a 100% renewable energy system, *International Journal of Sustainable Energy Planning and Management* 1, https://journals.aau.dk/index.php/sepm/article/view/497.	Electricity, heating/cooling, transportation	100% renewable Ireland by 2050
Bogdanov, D. and C. Breyer, 2016. North-East Asian Super Grid for 100% renewable energy supply: Optimal mix of energy technologies for electricity, gas and heat supply options, *Energy Conversion and Management* 112: 176-190, doi.org/10.1016/j.enconman.2016.01.019.	Electricity	100% renewable electricity in NE Asia by 2030
Parsons Brinkerhoff, 2009. Powering the Future: Mapping our Low-Carbon Path to 2050, http://hub.globalccsinstitute.com/sites/default/files/publications/138013/powering-future-mapping-low-carbon-path-2050.pdf.	All sectors of the UK economy	80% reduction in CO2 in the UK by 2050

Schellekens, G., A. Battaglini, J. Lilliestam, J. McDonnell, and A. Patt, 2010. 100% renewable electricity: A roadmap to 2050 for Europe and North Africa, *PricewaterhouseCoopers*, London, UK.	Electricity	100% renewable electricity in Europe and N. Africa by 2050
Wright, M. and P. Hearps, 2010. Zero Carbon Australia Stationary Energy Plan, *University of Melbourne Energy Research Institute*, http://media.bze.org.au/ZCA2020_Stationary_Energy_Report_v1.pdf.	Electricity, transportation, heating	100% renewable stationary power for Australia in 10 years.
Denis, A., Jotzo, F., et.al., 2014. Pathways to Deep Decarbonization in 2050: How Australia Can Prosper in a Low Carbon World, *SDSN – IDDRI*, http://deepdecarbonization.org/wp-content/uploads/2015/09/AU_DDPP_Report_Final.pdf.	Greenhouse gas emissions from all sources	Net zero emissions in Australia by 2050
McKinsey & Company, KEMA, The Energy Futures Lab at Imperial College London, Oxford Economics, and European Climate Foundation, 2010. Roadmap 2050: A Practical Guide to a Prosperous, Low Carbon Europe, Vol 1.: Technical Analysis, http://www.roadmap2050.eu/attachments/files/Volume1_fullreport_PressPack.pdf. E3G, The Energy Research Centre of the Netherlands, and European Climate Foundation, 2010. Roadmap 2050: A Practical Guide to a Prosperous, Low Carbon Europe, Vol 2.: Policy Recommendations, http://www.roadmap2050.eu/attachments/files/Volume2_Policy.pdf.	Greenhouse gas emissions from all sources	Reduce GHGs 80% below 1990 levels by 2050
Zervos, A., C. Lins, and J. Muth, 2010. Re-thinking 2050: A 100% Renewable Energy Vision for the European Union, *European Renewable Energy Council*, http://fft.szie.hu/mnt/Re-thinking%202050.pdf.	All sectors	100% renewable energy for the EU by 2050
Blake, L., P. Allen, et al., 2013. Zero Carbon Britain: Rethinking the future. *Center for Alternative Energy*, http://zerocarbonbritain.com/images/pdfs/ZCBrtflo-res.pdf.	All sectors	Net Zero GHG emissions in the UK by 2030
Bataille, C., et al., 2015. Pathways to deep decarbonization in Canada, *SDSN – IDDRI*, http://deepdecarbonization.org/wp-content/uploads/2015/09/DDPP_CAN.pdf.	All greenhouse gases, all sectors	90% below baseline scenario in 2050.
The négaWatt Association, 2017. The 2017-2050 négaWatt Scenario, *The négaWatt Association*, https://negawatt.org/IMG/pdf/negawatt-scenario-2017-2050_english-summary.pdf.	All sectors	100% renewable France by 2050

Aghahosseini, A., et al., 2018. Analysis of 100% renewable energy for Iran in 2030: Integrating solar PV, wind energy and storage, *International Journal of Environmental Science and Technology*,	Electricity	100% renewable Iran by 2030
Garcia-Olivares, A., et al., 2018. Transportation in a 100% renewable energy system, *Energy Conversion and Management*	Transportation	100% renewable global transportation.

EXHIBIT E

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100% clean and renewable wind, water, and sunlight (WWS) all-sector energy roadmaps for the 50 United States†

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This study presents roadmaps for each of the 50 United States to convert their all-purpose energy systems (for electricity, transportation, heating/cooling, and industry) to ones powered entirely by wind, water, and sunlight (WWS). The plans contemplate 80–85% of existing energy replaced by 2030 and 100% replaced by 2050. Conversion would reduce each state's end-use power demand by a mean of ∼39.3% with ∼82.4% of this due to the efficiency of electrification and the rest due to end-use energy efficiency improvements. Year 2050 end-use U.S. all-purpose load would be met with ∼30.9% onshore wind, ∼19.1% offshore wind, ∼30.7% utility-scale photovoltaics (PV), ∼7.2% rooftop PV, ∼7.3% concentrated solar power (CSP) with storage, ∼1.25% geothermal power, ∼0.37% wave power, ∼0.14% tidal power, and ∼3.01% hydroelectric power. Based on a parallel grid integration study, an additional 4.4% and 7.2% of power beyond that needed for annual loads would be supplied by CSP with storage and solar thermal for heat, respectively, for peaking and grid stability. Over all 50 states, converting would provide ∼3.9 million 40-year construction jobs and ∼2.0 million 40-year operation jobs for the energy facilities alone, the sum of which would outweigh the ∼3.9 million jobs lost in the conventional energy sector. Converting would also eliminate ∼62 000 (19 000–115 000) U.S. air pollution premature mortalities per year today and ∼46 000 (12 000–104 000) in 2050, avoiding ∼$600 ($85–$2400) bil. per year (2013 dollars) in 2050, equivalent to ∼3.6 (0.5–14.3) percent of the 2014 U.S. gross domestic product. Converting would further eliminate ∼$3.3 (1.9–7.1) tril. per year in 2050 global warming costs to the world due to U.S. emissions. These plans will result in each person in the U.S. in 2050 saving ∼$260 (190–320) per year in energy costs ($2013 dollars) and U.S. health and global climate costs per person decreasing by ∼$1500 (210–6000) per year and ∼$8300 (4700–17 600) per year, respectively. The new footprint over land required will be ∼0.42% of U.S. land. The spacing area between wind turbines, which can be used for multiple purposes, will be ∼1.6% of U.S. land. Thus, 100% conversions are technically and economically feasible with little downside. These roadmaps may therefore reduce social and political barriers to implementing clean-energy policies.

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Broader context

This paper presents a consistent set of roadmaps for converting the energy infrastructures of each of the 50 United States to 100% wind, water, and sunlight (WWS) for all purposes (electricity, transportation, heating/cooling, and industry) by 2050. Such conversions are obtained by first projecting conventional power demand to 2050 in each sector then electrifying the sector, assuming the use of some electrolytic hydrogen in transportation and industry and applying modest end-use energy efficiency improvements. Such state conversions may reduce conventional 2050 U.S.-averaged power demand by ∼39%, with most reductions due to the efficiency of electricity over combustion and the rest due to modest end-use energy efficiency improvements. The conversions are found to be technically and economically feasible with little downside. They nearly eliminate energy-related U.S. air pollution and climate-relevant emissions and their resulting health and environmental costs while creating jobs, stabilizing energy prices, and minimizing land requirements. These benefits have not previously been quantified for the 50 states. Their elucidation may reduce the social and political barriers to implementing clean-energy policies for replacing conventional combustible and nuclear fuels. Several such policies are proposed herein for each energy sector.

1. Introduction

This paper presents a consistent set of roadmaps to convert each of the 50 U.S. states' all-purpose (electricity, transportation,

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heating/cooling, and industry) energy infrastructures to ones powered 100% by wind, water, and sunlight (WWS). Existing energy plans in many states address the need to reduce greenhouse gas emissions and air pollution, keep energy prices low, and foster job creation. However, in most if not all states these goals are limited to partial emission reductions by 2050 (see, for example,[1] for a review of California roadmaps), and no set of consistently-developed roadmaps exist for every U.S. state. By contrast, the roadmaps here provide a consistent set of pathways to eliminate 100% of present-day greenhouse gas and air pollutant emissions from energy by 2050 in all 50 sates while growing the number of jobs and stabilizing energy prices. A separate study[2] provides a grid integration analysis to examine the ability of the intermittent energy produced from the state plans here, in combination, to match time-varying electric and thermal loads when combined with storage and demand response.

The methods used here to create each state roadmap are broadly similar to those recently developed for New York,[3] California,[4] and the world as a whole.[5–7] Such methods are applied here to make detailed, original, state-by-state estimates of

(1) Future energy demand (load) in the electricity, transportation, heating/cooling, and industrial sectors in both a business-as-usual (BAU) case and a WWS case;

(2) The numbers of WWS generators needed to meet the estimated load in each sector in the WWS case;

(3) Footprint and spacing areas needed for WWS generators;

(4) Rooftop areas and solar photovoltaic (PV) installation potentials over residential and commercial/government buildings and associated carports, garages, parking lots, and parking structures;

(5) The levelized cost of energy today and in 2050 in the BAU and WWS cases;

(6) Reductions in air-pollution mortality and associated health costs today based on pollution data from all monitoring stations in each state and in 2050, accounting for future reductions in emissions in the BAU *versus* WWS cases;

(7) Avoided global-warming costs today and in 2050 in the BAU *versus* WWS cases; and

(8) Numbers of jobs produced and lost and the resulting revenue changes between the BAU and WWS cases.

This paper further provides a transition timeline, energy efficiency measures, and potential policy measures to implement the plans. In sum, whereas, many studies focus on changing energy sources in one energy sector, such as electricity, this study integrates changes among all energy sectors: electricity, transportation, heating/cooling, and industry. It further provides rigorous and detailed and consistent estimates of 2050 state-by-state air pollution damage, climate damage, energy cost, solar rooftop potential, and job production and loss not previously available.

2. WWS technologies

This study assumes all energy sectors are electrified by 2050. The WWS energy technologies chosen to provide electricity include wind, concentrated solar power (CSP), geothermal, solar PV, tidal, wave, and hydroelectric power. These generators are existing technologies that were found to reduce health and climate impacts the most among multiple technologies while minimizing land and water use and other impacts.[8]

The technologies selected for ground transportation, which will be entirely electrified, include battery electric vehicles (BEVs) and hydrogen fuel cell (HFC) vehicles, where the hydrogen is produced by electrolysis. BEVs with fast charging or battery swapping will dominate long-distance, light-duty transportation; Battery electric-HFC hybrids will dominate heavy-duty transportation and long-distance shipping; batteries will power short-distance shipping (*e.g.*, ferries); and electrolytic cryogenic hydrogen, with batteries for idling, taxiing, and internal power, will power aircraft.

Air heating and cooling will be electrified and powered by electric heat pumps (ground-, air-, or water-source) and some electric-resistance heating. Water will be heated by heat pumps with electric resistance elements and/or solar hot water preheating. Cook stoves will have either an electric induction or resistance-heating element.

High-temperature industrial processes will be powered by electric arc furnaces, induction furnaces, dielectric heaters, and resistance heaters and some combusted electrolytic hydrogen.

HFCs will be used only for transportation, not for electric power generation due to the inefficiency of that application for HFCs. Although electrolytic hydrogen for transportation is less efficient and more costly than is electricity for BEVs, some segments of transportation (*e.g.*, long-distance ships and freight) may benefit from HFCs.

The roadmaps presented here include energy efficiency measures but not nuclear power, coal with carbon capture, liquid or solid biofuels, or natural gas, as previously discussed.[3,6] Biofuels, for example, are not included because their combustion produces air pollution at rates on the same order as fossil fuels and their lifecycle carbon emissions are highly uncertain but definitely larger than those of WWS technologies. Several biofuels also have water and land requirements much larger than those of WWS technologies. Since photosynthesis is 1% efficient whereas solar PV, for example, is ~20% efficient, the same land used for PV produces ~20 times more energy than does using the land for biofuels.

This study first calculates the installed capacity and number of generators of each type needed in each state to potentially meet the state's *annual* power demand (assuming state-specific average-annual capacity factors) in 2050 after all sectors have been electrified, without considering sub-annual (*e.g.*, daily or hourly) load balancing. The calculations assume only that existing hydroelectric from outside of a state continues to come from outside. The study then provides the additional number of generators needed by state to ensure that hourly power demand across all states does not suffer loss of load, based on results from ref. 2. As such, while the study bases each state's installed capacity on the state's annual demand, it allows interstate transmission of power as needed to ensure that supply and demand balance every hour in every state. We also roughly estimate the additional cost of transmission lines needed for

Exhibit E 2

this hourly balancing. Note that if we relax our assumption that each state's capacity match its annual demand, and instead allow states with especially good solar or wind resources to have enough capacity to supply larger regions, then the average levelized cost of electricity will be lower than we estimate because of the higher average capacity factors in states with the best WWS resources.

3. Changes in U.S. power load upon conversion to WWS

Table 1 summarizes the state-by-state end-use load calculated by sector in 2050 if conventional fuel use continues along BAU or ''conventional energy'' trajectory. It also shows the estimated new load upon a conversion to a 100% WWS infrastructure (with zero fossil fuels, biofuels, or nuclear fuels). The table is derived from a spreadsheet analysis of annually averaged end-use load data.[9] All end uses that feasibly can be electrified are assumed to use WWS power directly, and remaining end uses (some heating, high-temperature industrial processes, and some transportation) are assumed to use WWS power indirectly in the form of electrolytic hydrogen (hydrogen produced by splitting water with WWS electricity). End-use power excludes losses incurred during production and transmission of the power.

With these roadmaps, electricity generation increases, but the use of oil and gas for transportation and heating/cooling decreases to zero. Further, the increase in electricity use due to electrifying all sectors is much less than the decrease in energy in the gas, liquid, and solid fuels that the electricity replaces, because of the high energy-to-work conversion efficiency of electricity used for heating and electric motors. As a result, end use load decreases significantly with WWS energy systems in all 50 states (Table 1).

In 2010, U.S. all-purpose, end-use load was ~2.37 TW (terawatts, or trillion watts). Of this, 0.43 TW (18.1%) was electric power load. If the U.S. follows the business-as-usual (BAU) trajectory of the current energy infrastructure, which involves growing load and modest shifts in the power sector away from coal to renewables and natural gas, all-purpose end-use load is expected to grow to 2.62 TW in 2050 (Table 1).

A conversion to WWS by 2050 is calculated here to reduce U.S. end-use load and the power required to meet that load by ~39.3% (Table 1). About 6.9 percentage points of this reduction is due to modest additional energy-conservation measures (Table 1, last column) and another relatively small portion is due to the fact that conversion to WWS reduces the need for energy use in petroleum refining. The remaining and major reason for the reduction is that the use of electricity for heating and electric motors is more efficient than is fuel combustion for the same applications.[6] Also, the use of WWS electricity to produce hydrogen for fuel cell vehicles, while less efficient than the use of WWS electricity to run BEVs, is more efficient and cleaner than is burning liquid fossil fuels for vehicles.[6,10] Combusting electrolytic hydrogen is slightly less efficient but cleaner than is combusting fossil fuels for direct heating, and this is accounted for in Table 1. In Table 1, ~11.48% of all 2050 WWS electricity (47.8% of transportation load, and 5.72% of industrial load) will be used to produce, store, and use hydrogen, for long distance and heavy transportation and some high-temperature industrial processes.

The percent decrease in load upon conversion to WWS in Table 1 is greater in some states (*e.g.*, Hawaii, California, Florida, New Jersey, New Hampshire, and Vermont) than in others (*e.g.* Minnesota, Iowa, and Nebraska). The reason is that the transportation-energy share of the total in the states with the large reductions is greater than in those with the small reductions, and efficiency gains from electrifying transportation are much greater than are efficiency gains from electrifying other sectors.

4. Numbers of electric power generators needed and land-use implications

Table 2 summarizes the number of WWS power plants or devices needed to power each U.S. state in 2050 for all purposes assuming end use power requirements in Table 1, the percent mix of end-use power generation in Table 3, and electrical transmission, distribution, and array losses. The specific mix of generators presented for each state in Table 3 is just one set of options.

Rooftop PV in Table 2 is divided into residential (5 kW systems on average) and commercial/government (100 kW systems on average). Rooftop PV can be placed on existing rooftops or on elevated canopies above parking lots, highways, and structures without taking up additional undeveloped land. Table 4 summarizes projected 2050 rooftop areas by state usable for solar PV on residential and commercial/government buildings, carports, garages, parking structures, and parking lot canopies. The rooftop areas in Table 4 are used to calculate potential rooftop generation, which in turn limits the penetration of residential and commercial/government PV in Table 3. Utility-scale PV power plants are sized, on average, relatively small (50 MW) to allow them to be placed optimally in available locations. While utility-scale PV can operate in any state because it can take advantage of both direct and diffuse solar radiation, CSP is assumed to be viable only in states with sufficient direct solar radiation. While some states listed in Table 3, such as states in the upper Midwest, are assumed to install CSP although they have marginal average solar insolation, such states have regions with greater than average insolation, and the value of CSP storage is sufficiently high to suggest a small penetration of CSP in those states.

Onshore wind is assumed to be viable primarily in states with good wind resources (Section 5.1). Offshore wind is assumed to be viable offshore of any state with either ocean or Great Lakes coastline (Section 5.1). Wind and solar are the only two sources of electric power with sufficient resource to power the whole U.S. independently on their own. Averaged over the U.S., wind (~50.0%) and solar (45.2%) are the largest generators of

Exhibit E 3

Table 1 1st row of each state: estimated 2050 total end-use load (GW) and percent of total load by sector if conventional fossil-fuel, nuclear, and biofuel use continue from today to 2050 under a business-as-usual (BAU) trajectory. 2nd row of each state: estimated 2050 total end-use load (GW) and percent of total load by sector if 100% of BAU end-use all-purpose delivered load in 2050 is instead provided by WWS. The estimate in the "% change" column for each state is the percent reduction in total 2050 BAU load due to switching to WWS, including (second-to-last column) the effects of assumed policy-based improvements in end-use efficiency, inherent reductions in energy use due to electrification, and the elimination of energy use for the upstream production of fuels (*e.g.*, petroleum refining). The number in the last column is the reduction due only to assumed, policy-driven end-use energy efficiency measures[a]

State	Scenario	2050 total end-use load (GW)	Residential % of total	Commercial % of total	Industrial % of total	Transport % of total	% change in end-use power with WWS	
							Overall	Effic. only
Alabama	BAU	53.9	11.3	9.3	51.2	28.2		
	WWS	35.3	13.5	11.2	60.4	14.9	−34.4	−4.5
Alaska	BAU	24.0	4.9	7.8	56.4	30.9		
	WWS	14.5	5.6	10.9	66.2	17.2	−39.8	−3.0
Arizona	BAU	38.0	20.7	18.9	15.5	44.9		
	WWS	21.9	28.7	25.4	19.0	27.0	−42.2	−10.5
Arkansas	BAU	31.6	14.8	13.0	38.8	33.4		
	WWS	20.3	18.2	16.5	47.4	17.8	−35.5	−4.5
California	BAU	229.3	13.2	14.6	26.9	45.3		
	WWS	127.8	16.9	22.2	34.3	26.6	−44.3	−7.1
Colorado	BAU	46.5	18.2	14.2	34.6	33.0		
	WWS	27.9	23.0	18.5	39.2	19.3	−40.1	−9.1
Connecticut	BAU	19.2	24.1	22.6	14.7	38.6		
	WWS	11.4	29.0	30.6	17.5	22.8	−40.7	−9.6
Delaware	BAU	5.9	19.5	23.2	23.4	33.9		
	WWS	3.5	24.2	30.6	27.2	18.0	−41.1	−10.5
Florida	BAU	107.2	19.5	18.2	16.9	45.4		
	WWS	61.2	26.9	24.7	22.4	25.9	−42.9	−9.8
Georgia	BAU	79.4	16.7	14.3	30.7	38.2		
	WWS	47.2	20.6	18.7	39.9	20.8	−40.6	−8.3
Hawaii	BAU	7.4	7.1	13.6	22.1	57.2		
	WWS	3.8	10.3	22.1	32.6	35.0	−49.5	−6.6
Idaho	BAU	15.0	17.5	12.9	36.0	33.6		
	WWS	9.5	21.8	15.9	42.9	19.5	−37.0	−7.8
Illinois	BAU	93.5	16.9	17.2	36.7	29.1		
	WWS	57.9	20.2	21.4	42.3	16.2	−38.1	−8.1
Indiana	BAU	64.4	12.4	11.5	50.6	25.6		
	WWS	40.4	15.0	14.1	57.5	13.5	−37.2	−6.6
Iowa	BAU	42.7	10.0	10.4	57.7	21.9		
	WWS	30.6	10.9	11.5	67.3	10.3	−28.3	2.0
Kansas	BAU	30.1	14.0	12.1	44.8	29.1		
	WWS	18.8	17.5	15.5	49.9	17.1	−37.5	−7.0
Kentucky	BAU	46.5	11.9	10.0	47.2	31.0		
	WWS	28.5	14.6	12.8	55.6	17.0	−38.8	−7.6
Louisiana	BAU	147.7	4.9	3.8	73.4	18.0		
	WWS	92.7	6.2	4.8	78.3	10.7	−37.2	−3.4
Maine	BAU	13.5	12.1	11.4	49.6	27.0		
	WWS	9.1	13.3	13.4	60.1	13.2	−32.7	−2.1
Maryland	BAU	34.9	20.9	25.9	14.1	39.1		
	WWS	20.1	25.9	34.8	16.6	22.7	−42.3	−11.4
Massachusetts	BAU	35.8	24.9	20.4	17.8	36.9		
	WWS	21.4	29.1	27.9	22.4	20.6	−40.3	−8.8
Michigan	BAU	64.8	19.3	19.5	28.2	33.0		
	WWS	39.9	22.9	24.5	33.8	18.7	−38.4	−9.4
Minnesota	BAU	48.8	14.8	14.5	41.1	29.6		
	WWS	31.5	17.7	17.9	48.9	15.5	−35.4	−4.0
Mississippi	BAU	33.9	10.5	9.5	44.1	35.8		
	WWS	21.0	13.1	12.1	53.7	21.0	−38.0	−6.3
Missouri	BAU	42.8	20.9	16.9	23.6	38.6		
	WWS	25.5	27.8	22.6	28.7	21.0	−40.4	−7.3
Montana	BAU	12.3	15.5	15.4	34.8	34.3		
	WWS	7.4	19.8	19.8	39.3	21.1	−39.5	−8.2
Nebraska	BAU	21.9	12.2	12.3	50.4	25.1		
	WWS	15.5	13.6	13.9	60.5	12.1	−29.3	0.4
Nevada	BAU	18.5	20.3	17.0	23.4	39.3		
	WWS	11.0	26.7	22.2	29.2	21.8	−40.6	−9.2
New Hampshire	BAU	7.1	20.9	19.0	17.9	42.3		
	WWS	3.9	27.4	26.9	21.7	24.0	−44.2	−8.7
New Jersey	BAU	57.5	17.7	23.3	17.0	42.0		
	WWS	32.9	22.7	33.9	19.6	23.7	−42.8	−7.1
New Mexico	BAU	21.6	12.9	13.6	40.3	33.2		
	WWS	12.8	16.9	17.9	45.3	19.9	−41.0	−8.8

Exhibit E 4

Table 1 (*continued*)

State	Scenario	2050 total end-use load (GW)	Residential % of total	Commercial % of total	Industrial % of total	Transport % of total	% change in end-use power with WWS	
							Overall	Effic. only
New York	BAU	86.3	23.0	30.1	15.0	31.8		
	WWS	54.9	26.5	39.0	16.6	17.9	−36.4	−7.8
North Carolina	BAU	62.7	19.8	18.9	25.8	35.5		
	WWS	37.9	24.8	24.2	32.1	18.9	−39.5	−9.8
North Dakota	BAU	14.3	7.3	8.7	59.0	24.9		
	WWS	9.0	9.1	11.0	64.4	15.5	−36.9	−4.6
Ohio	BAU	87.0	16.2	16.4	37.6	29.8		
	WWS	53.5	19.8	20.5	43.6	16.1	−38.5	−8.2
Oklahoma	BAU	47.3	13.1	11.4	41.1	34.4		
	WWS	29.1	16.7	15.0	47.0	21.3	−38.5	−6.9
Oregon	BAU	27.3	15.4	15.6	26.5	42.6		
	WWS	16.3	18.9	21.9	34.6	24.6	−40.4	−8.5
Pennsylvania	BAU	94.0	15.4	14.1	39.5	31.0		
	WWS	59.1	18.5	18.3	44.1	19.2	−37.2	−7.3
Rhode Island	BAU	5.5	24.2	21.1	19.9	34.9		
	WWS	3.2	28.9	28.9	21.7	20.5	−41.5	−10.7
South Carolina	BAU	39.7	15.1	13.0	36.3	35.6		
	WWS	24.2	19.0	16.6	45.8	18.6	−39.1	−7.8
South Dakota	BAU	10.6	10.6	11.1	50.4	28.0		
	WWS	7.5	11.8	12.5	61.9	13.9	−29.1	1.8
Tennessee	BAU	52.8	15.6	13.5	36.5	34.3		
	WWS	32.2	19.6	17.4	44.5	18.4	−39.1	−7.3
Texas	BAU	376.6	8.4	8.0	56.9	26.7		
	WWS	225.3	11.2	10.8	62.7	15.3	−40.2	−4.8
Utah	BAU	23.2	17.8	16.6	28.7	36.8		
	WWS	13.8	22.8	21.8	33.0	22.4	−40.6	−9.1
Vermont	BAU	3.7	25.1	16.3	19.2	39.4		
	WWS	2.1	31.8	22.4	24.3	21.5	−42.7	−8.6
Virginia	BAU	60.3	18.0	20.3	23.1	38.6		
	WWS	35.1	22.7	27.1	28.5	21.7	−41.8	−10.2
Washington	BAU	52.8	14.3	15.2	30.2	40.4		
	WWS	31.7	17.7	21.3	38.7	22.4	−39.9	−7.4
West Virginia	BAU	21.7	14.3	12.3	40.6	32.7		
	WWS	13.0	17.0	15.9	45.3	21.7	−39.9	−12.3
Wisconsin	BAU	41.9	15.7	17.2	39.6	27.4		
	WWS	26.8	18.3	20.7	47.3	13.8	−36.0	−6.4
Wyoming	BAU	18.1	6.0	8.3	56.2	29.5		
	WWS	11.2	7.4	10.4	61.2	20.9	−38.3	−8.5
United States	BAU	2621.4	14.3	14.1	38.5	33.1		
	WWS	1591.0	17.8	18.6	45.0	18.6	−39.3	−6.9

[a] BAU values are extrapolations from the U.S. Energy Information Administration (EIA) projections for the year 2040. WWS values are estimated with respect to BAU values accounting for the effect of electrification of end-uses on energy requirements and the effects of additional energy-efficiency measures. See the ESI and ref. 9 for details.

annually averaged end-use electric power under these plans. The ratio of wind to solar end-use power is 1.1 : 1.

Under the roadmaps, the 2050 installed capacity of hydroelectric, averaged over the U.S., is assumed to be virtually the same as in 2010, except for a small growth in Alaska. However, existing dams in most states are assumed to run more efficiently for producing peaking power, thus the capacity factor of dams is assumed to increase (Section 5.4). Geothermal, wave, and tidal energy expansions are limited in each state by their potentials (Sections 5.3, 5.5 and 5.6, respectively).

Table 2 lists installed capacities beyond those needed to match annually averaged power demand for CSP with storage and for solar thermal. These additional capacities are derived in the separate grid integration study[2] and are needed to produce peaking power, to account for additional loads due to losses in and out of storage, and to ensure reliability of the grid, as described and quantified in that paper.

Fig. 1 shows the additional footprint and spacing areas required from Table 2 to replace the entire U.S. all-purpose energy infrastructure with WWS by 2050. Footprint area is the physical area on the ground needed for each energy device. Spacing area is the area between some devices, such as wind, tidal, and wave turbines, needed to minimize interference of the wake of one turbine with downwind turbines.

Table 2 indicates that the total new land footprint required for the plans, averaged over the U.S. is ∼0.42% of U.S. land area, mostly for solar PV power plants (rooftop solar does not take up new land). This does not account for the decrease in footprint from eliminating the current energy infrastructure, which includes the footprint for mining, transporting, and refining fossil fuels and uranium and for growing, transporting, and refining biofuels.

The only spacing over land needed for the WWS system is between onshore wind turbines and this requires ∼1.6% of U.S. land. The footprint associated with this spacing is trivial,

Table 2 Number, capacity, footprint area, and spacing area of WWS power plants or devices needed to provide total annually-averaged end-use all-purpose load over all 50 states plus additional power needed to provide peaking and storage services, as derived in ref. 2. The numbers account for short- and moderate-distance transmission, distribution, forced and unforced maintenance, and array losses. Ref. 9 derives individual tables for each state

Energy technology	Rated power one plant or device (MW)	Percent of 2050 all-purpose load met by plant/device[a]	Name-plate capacity of existing plus new plants or devices (MW)	Percent name-plate capacity already installed 2013	Number of new plants or devices needed for U.S.	Percent of U.S. land area for footprint of new plants/devices[b]	Percent of U.S. land area for spacing of new plants/devices
Annual power							
Onshore wind	5	30.92	1 701 000	3.59	328 000	0.00004	1.5912
Offshore wind	5	19.08	780 900	0.00	156 200	0.00002	0.7578
Wave device	0.75	0.37	27 040	0.00	36 050	0.00021	0.0098
Geothermal plant	100	1.25	23 250	10.35	208	0.00078	0.0000
Hydroelectric plant[c]	1300	3.01	91 650	95.87	3	0.02077	0.0000
Tidal turbine	1	0.14	8823	0.00	8823	0.00003	0.0004
Res. roof PV	0.005	3.98	379 500	0.94	75 190 000	0.03070	0.0000
Com/gov roof PV[d]	0.1	3.24	276 500	0.64	2 747 000	0.02243	0.0000
Solar PV plant[d]	50	30.73	2 326 000	0.08	46 480	0.18973	0.0000
Utility CSP plant	100	7.30	227 300	0.00	2273	0.12313	0.0000
Total		100.00	5 841 000	2.71		0.388	2.359
Peaking/storage							
Additional CSP[e]	100	4.38	136 400	0.00	1364	0.07388	0.0000
Solar thermal[e]	50	7.21	469 000	0.00	9380	0.00731	0.0000
Total all			6 447 000	2.46		0.469	2.359
Total new land[f]						0.416	1.591

The national total number of each device is the sum among all states. The number of devices in each state is the end use load in 2050 in each state (Table 1) multiplied by the fraction of load satisfied by each source in each state (Table 3) and divided by the annual power output from each device. The annual output equals the rated power (this table; same for all states) multiplied by the state-specific annual capacity factor of the device and accounting for transmission, distribution, maintenance-time, and array losses. The capacity factor is determined for each device in each state in ref. 9. The state-by-state capacity factors for onshore wind turbines in 2050, accounting for transmission, distribution, maintenance-time, and array losses, are calculated from actual 2013 state installed capacity[11] and power output[12] with an assumed increase in capacity factor between 2013 and 2050 due to turbine efficiency improvements and a decrease due to diminishing quality of sites after the best are taken. The 2050 U.S. mean onshore wind capacity factor calculated in this manner (after transmission, distribution, maintenance-time, and array losses) is 29.0%. The highest state onshore wind capacity factor in 2050 is estimated to be 40.0%, for Oklahoma; the lowest, 17.0%, for Alabama, Kentucky, Mississippi, and Tennessee. Offshore wind turbines are assumed to be placed in locations with hub-height wind speeds of 8.5 m s^{-1} or higher,[13] which corresponds to a capacity factor before transmission, distribution, maintenance, and array losses of $\sim$42.5% for the same turbine and 39.0%, in the U.S. average after losses. Short- and moderate distance transmission, distribution, and maintenance-time losses for offshore wind and all other energy sources treated here, except rooftop PV, are assumed to be 5–10%. Rooftop PV losses are assumed to be 1–2%. Wind array losses due to competition among turbines for the same energy are an additional 8.5%.[2] The plans assume 38 (30–45)% of onshore wind and solar and 20 (15–25)% of offshore wind is subject to long-distance transmission with line lengths of 875 (750–1000) km and 75 (50–100) km, respectively. Line losses are 4 (3–5)% per 1000 km plus 1.5 (1.3–1.8)% of power in the station equipment. Footprint and spacing areas are calculated from the spreadsheets in ref. 9. Footprint is the area on the top surface of soil covered by an energy technology, thus does not include underground structures. [a] Total end-use power demand in 2050 with 100% WWS is estimated from Table 1. [b] Total land area for each state is given in ref. 9. U.S. land area is 9 161 924 km^2. [c] The average capacity factor for hydro is assumed to increase from its current value to 52.5% (see text). For hydro already installed capacity is based on data for 2010. [d] The solar PV panels used for this calculation are Sun Power E20 panels. The capacity factors used for residential and commercial/government rooftop solar production estimates are given in ref. 9 for each state. For utility solar PV plants, nominal spacing between panels is included in the plant footprint area. The capacity factors assumed for utility PV are given in ref. 9. [e] The installed capacities for peaking power/storage are derived in the separate grid integration study.[2] Additional CSP is CSP plus storage beyond that needed for annual power generation to firm the grid across all states. Additional solar thermal is used for soil heat storage. Other types of storage are also used in ref. 2. [f] The footprint area requiring new land is equal to the footprint area for new onshore wind, geothermal, hydroelectric, and utility solar PV. Offshore wind, wave, and tidal are in water, and so do not require new land. The footprint area for rooftop solar PV does not entail new land because the rooftops already exist and are not used for other purposes (that might be displaced by rooftop PV). Only onshore wind entails new land for spacing area. The other energy sources either are in water or on rooftops, or do not use additional land for spacing. Note that the spacing area for onshore wind can be used for multiple purposes, such as open space, agriculture, grazing, *etc.*

and the spacing area can be used for multiple purposes, such as agricultural land, grazing land, and open space. Landowners can thus derive income, not only from the wind turbines on the land, but also from farming around the turbines.

5. Resource availability

This section evaluates whether the United States has sufficient wind, solar, geothermal, and hydroelectric resources to supply the country's all-purpose energy in 2050.

5.1. Wind

Fig. 2 shows three-dimensional computer model estimates, derived for this study, of the U.S. annually averaged capacity factor of wind turbines if they are installed onshore and offshore. The calculations are performed assuming a REpower 5 MW turbine with a 126 m diameter rotor (the same turbine assumed for the roadmaps). Results are obtained for a hub height of 100 m above the topographical surface. Spacing areas of 4 × 7 rotor diameters are used for onshore turbines and 5 × 10 diameters for offshore turbines.

Table 3 Percent of annually-averaged 2050 U.S. state all-purpose end-use load in a WWS world from Table 1 proposed here to be met by the given electric power generator. Power generation by each resource in each state is limited by resource availability, as discussed in Section 5. All rows add up to 100%

State	Onshore wind	Offshore wind	Wave	Geothermal	Hydro-electric	Tidal	Res PV	Comm/gov PV	Utility PV	CSP
Alabama	5.00	10.00	0.08	0.00	4.84	0.01	3.50	2.20	64.38	10.00
Alaska	50.00	20.00	1.00	7.00	14.96	1.00	0.23	0.15	5.66	0.00
Arizona	18.91	0.00	0.00	2.00	6.49	0.00	1.30	9.30	32.00	30.00
Arkansas	43.00	0.00	0.00	0.00	3.44	0.00	4.40	3.50	35.66	10.00
California	25.00	10.00	0.50	5.00	4.48	0.50	7.50	5.50	26.52	15.00
Colorado	55.00	0.00	0.00	3.00	1.24	0.00	4.20	4.00	17.56	15.00
Connecticut	5.00	45.00	1.00	0.00	0.56	0.00	4.00	3.35	41.09	0.00
Delaware	5.00	65.00	1.00	0.00	0.00	0.50	5.00	3.85	19.65	0.00
Florida	5.00	14.93	1.00	0.00	0.05	0.04	11.2	7.80	49.98	10.00
Georgia	5.00	35.00	0.30	0.00	2.27	0.08	5.50	4.30	42.55	5.00
Hawaii	12.00	16.00	1.00	30.00	0.33	1.00	14.0	9.00	9.67	7.00
Idaho	35.00	0.00	0.00	15.00	14.96	0.00	4.00	3.20	17.84	10.00
Illinois	60.00	5.00	0.00	0.00	0.03	0.00	2.85	2.90	26.22	3.00
Indiana	50.00	0.00	0.00	0.00	0.08	0.00	2.45	2.20	42.77	2.50
Iowa	68.00	0.00	0.00	0.00	0.25	0.00	1.50	1.50	25.75	3.00
Kansas	70.00	0.00	0.00	0.00	0.01	0.00	3.20	3.00	13.79	10.00
Kentucky	8.45	0.00	0.00	0.00	1.51	0.00	3.20	2.10	79.74	5.00
Louisiana	0.65	60.00	0.40	0.00	0.11	0.00	1.30	1.20	31.34	5.00
Maine	35.00	35.00	1.00	0.00	5.79	1.00	5.40	1.80	15.01	0.00
Maryland	5.00	60.00	1.00	0.00	1.53	0.03	5.40	4.80	22.24	0.00
Massachusetts	13.00	55.00	1.00	0.00	1.42	0.06	3.90	3.30	22.32	0.00
Michigan	40.00	31.00	1.00	0.00	0.69	0.00	3.50	3.20	18.61	2.00
Minnesota	60.00	19.00	0.00	0.00	3.61	0.00	2.50	3.00	9.89	2.00
Mississippi	5.00	10.00	1.00	0.00	0.00	1.00	2.40	1.60	74.00	5.00
Missouri	60.00	0.00	0.00	0.00	1.15	0.00	5.10	4.40	24.35	5.00
Montana	35.00	0.00	0.00	9.00	19.15	0.00	2.80	2.10	21.95	10.00
Nebraska	65.00	0.00	0.00	0.00	0.94	0.00	2.20	2.00	19.86	10.00
Nevada	10.00	0.00	0.00	30.00	5.02	0.00	12.0	8.00	19.23	15.75
New Hampshire	40.00	20.00	1.00	0.00	6.48	0.50	4.50	3.30	24.22	0.00
New Jersey	10.00	55.50	0.80	0.00	0.01	0.10	3.54	2.80	27.25	0.00
New Mexico	50.00	0.00	0.00	10.00	0.35	0.00	5.50	3.80	14.35	16.00
New York	10.00	40.00	0.80	0.00	6.54	0.10	3.60	3.20	35.76	0.00
North Carolina	5.00	50.00	0.75	0.00	2.69	0.03	6.00	4.00	26.53	5.00
North Dakota	55.00	0.00	0.00	0.00	2.95	0.00	1.00	1.00	35.05	5.00
Ohio	45.00	10.00	0.00	0.00	0.10	0.00	3.20	3.00	35.70	3.00
Oklahoma	65.00	0.00	0.00	0.00	1.54	0.00	3.20	2.80	17.46	10.00
Oregon	32.50	15.00	1.00	5.00	27.25	0.05	4.00	2.20	8.00	5.00
Pennsylvania	20.00	3.00	1.00	0.00	0.74	0.85	3.30	2.35	68.76	0.00
Rhode Island	10.00	63.00	1.00	0.00	0.05	0.08	4.40	3.70	17.78	0.00
South Carolina	5.00	50.00	1.00	0.00	2.90	0.30	4.00	2.80	27.70	6.30
South Dakota	61.00	0.00	0.00	0.00	11.10	0.00	1.70	1.80	14.40	10.00
Tennessee	8.00	0.00	0.00	0.00	4.26	0.00	3.50	2.20	75.04	7.00
Texas	50.00	13.90	0.10	0.50	0.16	0.00	3.00	2.50	15.84	14.00
Utah	40.00	0.00	0.00	8.00	1.03	0.00	4.00	4.00	27.97	15.00
Vermont	25.00	0.00	0.00	0.00	64.35	0.00	4.20	2.80	3.65	0.00
Virginia	10.00	50.00	0.50	0.00	1.29	0.05	4.20	3.50	25.46	5.00
Washington	35.00	13.00	0.50	0.65	35.42	0.30	2.90	1.50	10.73	0.00
West Virginia	30.00	0.00	0.00	0.00	1.14	1.00	2.50	1.70	61.66	2.00
Wisconsin	45.00	30.00	0.00	0.00	0.96	0.00	3.30	2.90	15.84	2.00
Wyoming	65.00	0.00	0.00	1.00	1.43	0.00	1.10	0.70	20.77	10.00
United States	30.92	19.08	0.37	1.25	3.01	0.14	3.98	3.24	30.73	7.30

Results suggest a U.S. mean onshore capacity factor of ∼30.5% and offshore of ∼37.3% before transmission, distribution, maintenance-time, and array losses (Fig. 2). Locations of strong onshore wind resources include the Great Plains, northern parts of the northeast, and many areas in the west. Weak wind regimes include the southeast and the westernmost part of the west coast continent. Strong offshore wind resources occur off the east coast north of South Carolina and the Great Lakes. Very good offshore wind resources also occur offshore the west coast and offshore the southeast and gulf coasts. Table 2 indicates that the 2050 clean-energy plans require ∼1.6% of U.S. onshore land and 0.76% of U.S. onshore-equivalent land area sited offshore for wind-turbine spacing to power 50.0% of all-purpose annually-averaged 2050 U.S. energy. The mean capacity factor before transmission, distribution, maintenance-time, and array losses used to derive the number of onshore wind turbines needed in Table 2 is ∼35% and for offshore turbines is 42.5% (Table 2, footnote). Fig. 2 suggests that much more land and ocean areas with these respective capacity factors or higher are available than are needed for the roadmaps.

5.2. Solar

World solar power resources are known to be large.[16] Here, such resources are estimated (Fig. 3) for the U.S. using a 3-D climate

Exhibit E 7

Table 4 Rooftop areas suitable for PV panels, potential capacity of suitable rooftop areas, and proposed installed capacity for both residential and commercial/government buildings, by state. See ref. 9 for detailed calculations

	Residential rooftop PV				Commercial/government rooftop PV			
State	Rooftop area suitable for PVs in 2012 (km^2)	Potential capacity of suitable area in 2050 (MW$_{\text{dc-peak}}$)	Proposed installed capacity in 2050 (MW$_{\text{dc-peak}}$)	Percent of potential capacity installed	Rooftop area suitable for PVs in 2012 (km^2)	Potential capacity of suitable area in 2050 (MW$_{\text{dc-peak}}$)	Proposed installed capacity in 2050 (MW$_{\text{dc-peak}}$)	Percent of potential capacity installed
Alabama	59.7	10 130	7409	73	35.4	6150	4175	68
Alaska	7.0	760	414	54	4.2	460	242	53
Arizona	7.1	3520	1379	39	46.9	23 210	8841	38
Arkansas	36.7	7090	5217	74	27.0	5330	3720	70
California	336.1	83 150	48 412	58	220.6	55 330	31 826	58
Colorado	48.8	11 190	6684	60	40.6	9440	5706	60
Connecticut	32.2	4640	3301	71	25.1	3690	2478	67
Delaware	10.9	1940	1182	61	7.3	1320	816	62
Florida	229.1	85 950	33 873	39	148.4	55 750	21 147	38
Georgia	108.9	25 760	15 431	60	76.9	18 450	10 815	59
Hawaii	12.7	3260	2291	70	7.5	1950	1320	68
Idaho	16.2	4030	2318	58	12.2	3070	1663	54
Illinois	116.3	17 220	11 537	67	110.6	16 770	10 524	63
Indiana	65.6	10 500	6652	63	54.8	8960	5354	60
Iowa	31.2	4430	3165	71	29.4	4260	2837	67
Kansas	32.1	5220	3804	73	28.1	4680	3197	68
Kentucky	52.7	8270	6076	73	32.3	5200	3575	69
Louisiana	54.2	9910	6582	66	44.6	8350	5447	65
Maine	32.2	4740	3340	70	9.4	1410	998	71
Maryland	60.5	11 550	7102	61	49.0	9530	5659	59
Massachusetts	58.6	8560	6053	71	46.4	6930	4591	66
Michigan	105.0	14 970	10 142	68	89.0	12 980	8312	64
Minnesota	52.9	9280	5564	60	54.6	9740	5985	61
Mississippi	35.5	4950	3653	74	22.6	3230	2183	68
Missouri	72.9	12 260	8270	67	58.0	9980	6396	64
Montana	11.6	1880	1391	74	8.2	1350	936	69
Nebraska	20.5	3140	2228	71	18.0	2830	1816	64
Nevada	29.4	15 120	6451	43	18.8	9600	3855	40
New Hampshire	13.9	2480	1287	52	9.3	1680	846	50
New Jersey	83.1	12 730	8345	66	60.7	9520	5917	62
New Mexico	24.7	5070	3674	72	15.7	3300	2276	69
New York	165.2	20 140	14 545	72	135.0	16 940	11 590	68
North Carolina	119.2	28 340	14 084	50	74.6	17 950	8417	47
North Dakota	7.2	940	639	68	6.8	920	573	62
Ohio	117.0	16 960	11 623	69	101.0	15 000	9768	65
Oklahoma	46.2	8150	5544	68	34.8	6270	4349	69
Oregon	43.5	8590	4431	52	21.6	4330	2185	50
Pennsylvania	136.4	18 870	13 757	73	87.9	12 410	8782	71
Rhode Island	9.9	1460	1015	70	7.8	1180	765	65
South Carolina	58.4	9220	6057	66	36.8	5950	3801	64
South Dakota	8.5	1290	857	66	8.3	1280	813	64
Tennessee	76.6	12 020	7246	60	45.9	7370	4083	55
Texas	268.9	78 190	36 792	47	216.9	63 550	27 485	43
Utah	23.1	6360	3160	50	20.9	5810	2833	49
Vermont	7.5	1110	672	61	4.5	680	402	59
Virginia	88.1	17 400	9825	56	65.8	13 190	7339	56
Washington	73.6	14 050	6774	48	37.2	7180	3141	44
West Virginia	24.3	3140	2273	72	16.1	2140	1386	65
Wisconsin	59.5	9310	6236	67	48.3	7710	4912	64
Wyoming	6.3	1050	754	72	4.5	760	430	57
United States	3197.6	660 290	379 513	57	2386	505 070	276 508	55

model that treats radiative transfer accounting for sun angles, day/night, and clouds. The best solar resources in the U.S. are broadly in the Southwest, followed by the Southeast, the Northwest, then the Northeast. The land area in 2050 required for non-rooftop solar under the plan here is equivalent to ~0.394% of U.S. land area, which is a small percentage of the area of strong solar resources available (Fig. 3).

The estimates of potential generation by solar rooftop PV shown in Tables 2 and 3 are based on state-by-state calculations of available roof areas and PV power potentials on residential, commercial, and governmental buildings, garages, carports, parking lots, and parking structures. Commercial and governmental buildings include all non-residential buildings except manufacturing, industrial, and military buildings. (Commercial buildings do include schools.)

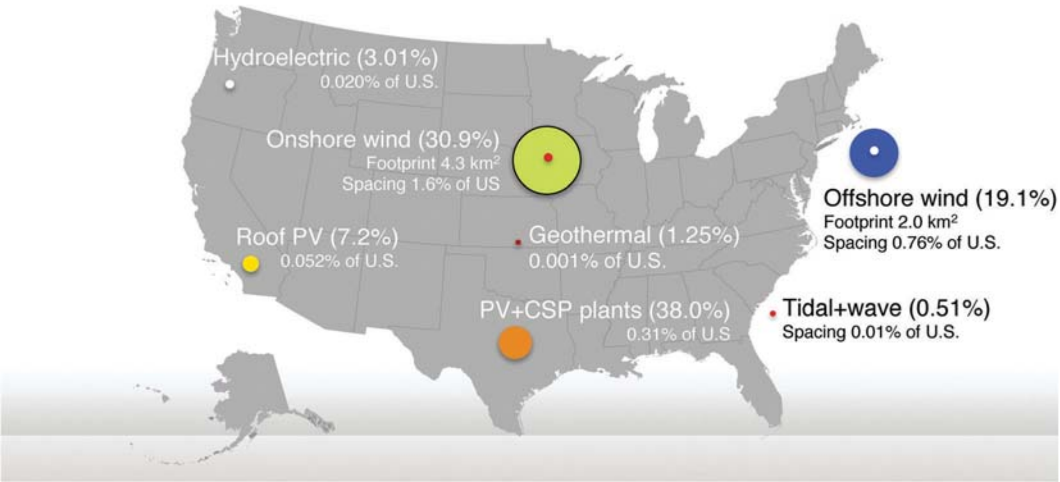

Fig. 1 Spacing and footprint areas required from Table 2 for annual power load, beyond existing 2013 resources, to repower the U.S. state-by-state for all purposes in 2050. The dots do not indicate the actual location of energy farms. For wind, the small dot in the middle is footprint on the ground or water (not to scale) and the green or blue is space between turbines that can be used for multiple purposes. For others, footprint and spacing areas are mostly the same (except tidal and wave, where only spacing is shown). For rooftop PV, the dot represents the rooftop area needed.

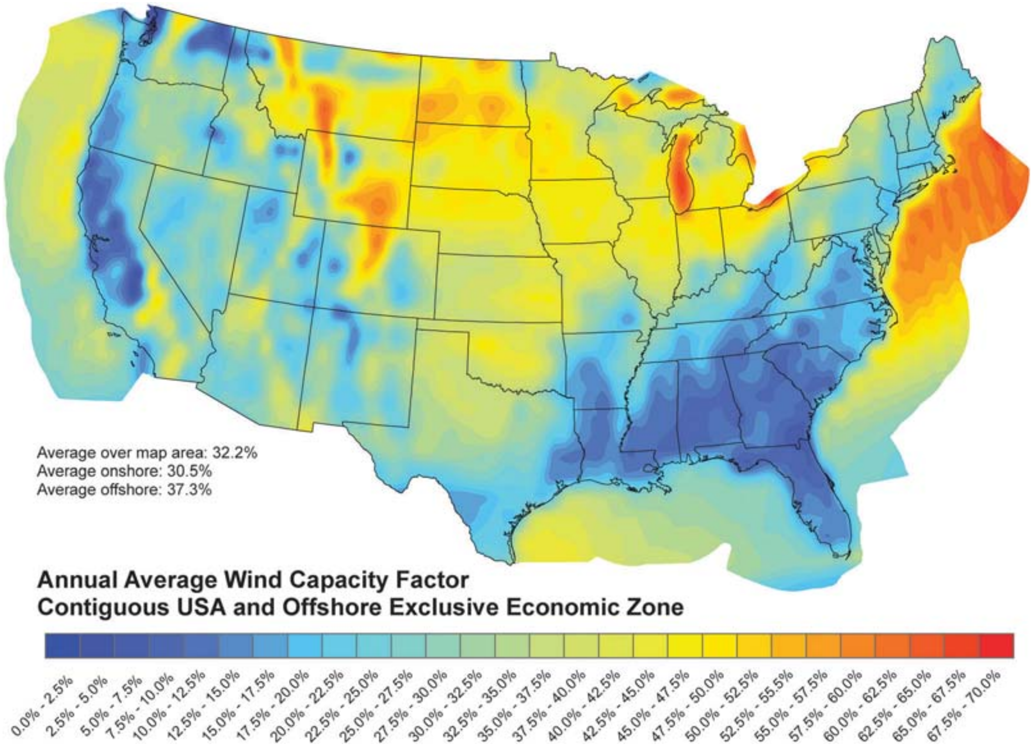

Fig. 2 Modeled 2006 annually averaged capacity factor for 5 MW REpower wind turbines (126 m diameter rotor) at 100 m hub height above the topographical surface in the contiguous United States ignoring competition among wind turbines for the same kinetic energy and before transmission, distribution, and maintenance-time losses. The model used is GATOR-GCMOM,[14,15] which is nested for one year from the global to regional scale with resolution on the regional scale of 0.6° W–E × 0.5° S–N.

Ref. 4 (Supplemental Information) and ref. 9 document how rooftop areas and generation potential are calculated for California for four situations: residential-warm, residential-cool, commercial/government-warm, and commercial/government-cool. This method is applied here to calculate potential rooftop PV generation in each state, accounting for housing units and building areas, available solar insolation, degradation of solar panels over time, technology improvements over time, and DC to AC power conversion losses.

Each state's potential installed capacity of rooftop PV in 2050 equals the potential alternating-current (AC) generation from rooftop PV in 2050 in the state divided by the PV capacity

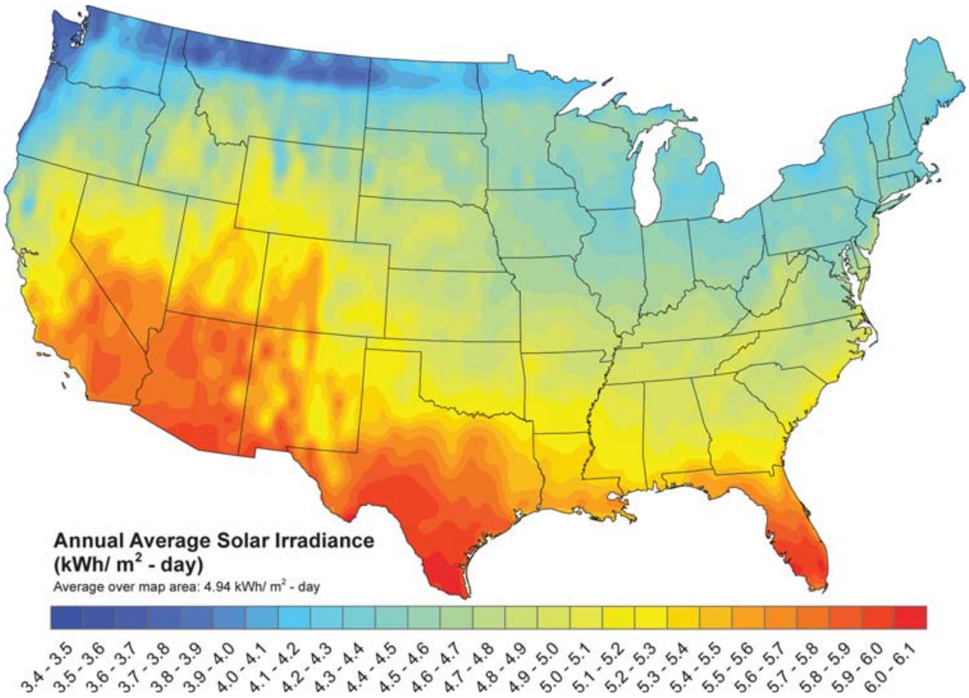

Fig. 3 Modeled 2013 annual downward direct plus diffuse solar radiation at the surface (kW h per m^2 per day) available to photovoltaics in the contiguous United States. The model used is GATOR-GCMOM,[14,15] which simulates clouds, aerosols gases, weather, radiation fields, and variations in surface albedo over time. The model is nested from the global to regional scale with resolution on the regional scale 0.6° W–E × 0.5° S–N.

factor in 2050. This calculation is performed here for each state under the four situations mentioned above: residential and commercial/government rooftop PV systems, in warm and cool climate zones.

Based on the analysis, we estimate that, in 2050, residential rooftop areas (including garages and carports) could support 660 GW$_{\text{dc-peak}}$ of installed power. The plans here propose to install ~57% of this potential. In 2050, commercial/government rooftop areas (including parking lots and parking structures) could support 505 GW$_{\text{dc-peak}}$ of installed power. The state plans here propose to cover ~55% of installable power.

5.3. Geothermal

The U.S. has significant traditional geothermal resources (volcanos, geysers, and hot springs) as well as heat stored in the ground due to heat conduction from the interior of the Earth and solar radiation absorbed by the ground. In terms of traditional geothermal, the U.S. has an identified resource of 9.057 GW deliverable power distributed over 13 states, undiscovered resources of 30.033 GW deliverable power, and enhanced recovery resources of 517.8 GW deliverable power.[17] As of April 2013, 3.386 GW of geothermal capacity had been installed in the U.S. and another 5.15–5.523 GW was under development.[18]

States with identified geothermal resources (and the percent of resource available in each state) include Colorado (0.33%), Hawaii (2.0%), Idaho (3.68%), Montana (0.65%), Nevada (15.36%), New Mexico (1.88%), Oregon (5.96%), Utah (2.03%), Washington State (0.25%), Wyoming (0.43%), Alaska (7.47%), Arizona (0.29%), and California (59.67%).[17] All states have the ability to extract heat from the ground for heat pumps. This extracted energy would not be used to generate electricity, but rather would be used directly for heating, thereby reducing electric power demand for heating, although electricity would still be needed to run heat pumps. This electricity use for heat pumps is accounted for in the numbers for Table 1.

The roadmaps here propose 19.8 GW of delivered existing plus new electric power from geothermal in 2050, which is less than the sum of identified and undiscovered resources and much less than the enhanced recovery resources. The proposed electric power from geothermal is limited to the 13 states with known resources plus Texas, where recent studies show several potential sites for geothermal. If resources in other states prove to be cost-effective, these roadmaps can be updated to include geothermal in those states.

5.4. Hydroelectric

In 2010, conventional (small and large) hydroelectric power provided 29.7 GW (260 203 GW h per year) of U.S. electric power, or 6.3% of the U.S. electric power supply.[19] The installed conventional hydroelectric capacity was 78.825 GW,[19] giving the capacity factor of conventional hydro as 37.7% in 2010. Fig. 4 shows the installed conventional hydroelectric by state in 2010.

In addition, 23 U.S. states receive an estimated 5.103 GW of delivered hydroelectric power from Canada. Assuming a capacity factor of 56.47%, Canadian hydro currently provides ~9.036 GW worth of installed capacity to the U.S. This is included as part of existing hydro capacity in this study to give a total existing (year-2010) capacity in the U.S. in Table 2 of 87.86 GW.

Exhibit E 10

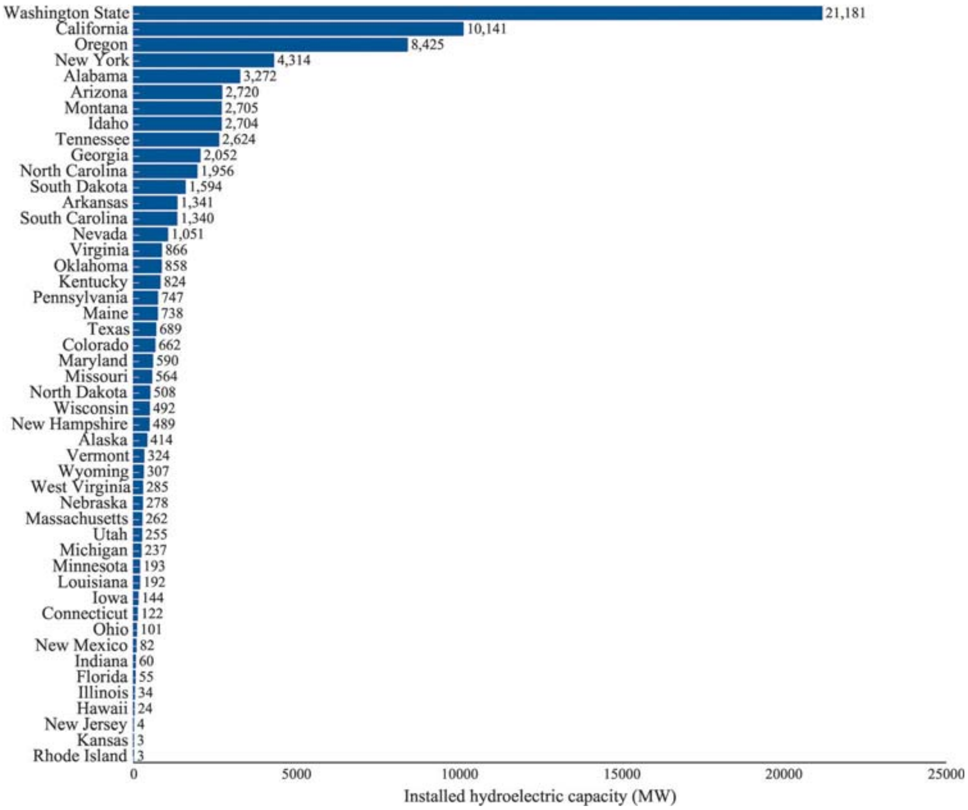

Fig. 4 Installed conventional hydroelectric by U.S. state in 2010.[19]

Under the plan proposed here, conventional hydro would supply 3.01% of U.S. total end-use all-purpose power demand (Table 2), or 47.84 GW of delivered power in 2050. In 2010, U.S. plus Canadian delivered 34.8 GW of hydropower, only 13.0 GW less than that needed in 2050. This additional power will be supplied by adding three new dams in Alaska with a total capacity of 3.8 GW (Table 2) and increasing the capacity factor on existing dams from a Canada-plus-US average of ∼39% to 52.5%. Increasing the capacity factor is feasible because existing dams currently provide much less than their maximum capacity, primarily due to an oversupply of energy available from fossil fuel sources, resulting in less demand for hydroelectricity. In some cases, hydroelectricity is not used to its full extent in deference to other priorities affecting water use.

Whereas, we believe modestly increasing hydroelectric capacity factors is possible, if it is not, additional hydroelectric capacity can be obtained by powering presently non-powered dams. In addition to the 2500-plus dams that provide the 78.8 GW of installed conventional power and 22.2 GW of installed pumped-storage hydroelectric power, the U.S. has over 80 000 dams that are not powered at present. Although only a small fraction of these dams can feasibly be powered, ref. 20 estimates that the potential amounts to 12 GW of capacity in the contiguous 48 states. Two-thirds of this comes from just 100 dams, but potential exists in every state. Over 80% of the top 100 dams with the most new-powering capacity are navigation locks on the Ohio, Mississippi, Alabama, and Arkansas Rivers and their tributaries. Illinois, Kentucky, and Arkansas each have over 1 GW of potential. Alabama, Louisiana, Pennsylvania, and Texas each have 0.5–1 GW of potential. Because the costs and environmental impacts of such dams have already been incurred, adding electricity generation to these dams is less expensive and faster than building a new dam with hydroelectric capacity.

In addition, ref. 21 estimates that the U.S. has an additional low-power and small-hydroelectric potential of 30–100 GW of delivered power – far more than the 11.3 GW of additional generation proposed here. The states with the most additional low- and small-hydroelectric potential are Alaska, Washington State, California, Idaho, Oregon, and Montana. However, 33 states can more than double their small hydroelectric potential and 41 can increase it by more than 50%.

5.5. Tidal

Tidal (or ocean current) is proposed to contribute about 0.14% of U.S. total power in 2050 (Table 2). The U.S. currently has the potential to generate 50.8 GW (445 TW h per year) of delivered power from tidal streams.[22] States with the greatest potential offshore tidal power include Alaska (47.4 GW), Washington State (683 MW), Maine (675 MW), South Carolina (388 MW), New York (280 MW), Georgia (219 MW), California (204 MW), New Jersey (192 MW), Florida (166 MW), Delaware (165 MW), Virginia (133 MW), Massachusetts (66 MW), North Carolina (66 MW), Oregon (48 MW), Maryland (35 MW), Rhode Island (16 MW), Alabama (7 MW), Texas (6 MW), Louisiana (2 MW). The available power in Maine, for example, is distributed over 15 tidal streams. The present state plans call for extracting

~2.2 GW of delivered power, which would require an installed capacity of ~8.82 GW of tidal turbines.

5.6. Wave

Wave power is proposed to contribute 0.37%, or about 5.85 GW, of the U.S. total end-use power demand in 2050 (Table 2). The U.S. has a recoverable delivered power potential (after accounting for array losses) of 135.8 GW (1190 TW h) along its continental shelf edge.[23] This includes 28.5 GW of recoverable power along the West Coast, 18.3 GW along the East Coast, 6.8 GW along the Gulf of Mexico, 70.8 GW along Alaska's coast, 9.1 GW along Hawaii's coast, and 2.3 GW along Puerto Rico's coast. Thus, all states border the oceans have wave power potential. The available supply is ~23 times the delivered power proposed under this plan.

6. Matching electric power supply with demand

Ref. 2 develops and applies a grid integration model to determine the quantities and costs of additional storage devices and generators needed to ensure that the 100% WWS system developed here for the U.S. can match load without loss every 30 s for six years (2050–2055) while accounting for the variability and uncertainty in WWS resources. Wind and solar time-series are derived from 3-D global model simulations that account for extreme events, competition among wind turbines for kinetic energy, and the feedback of extracted solar radiation to roof and surface temperatures.

Solutions to the grid integration problem are obtained by prioritizing storage for excess heat (in soil and water) and electricity (in ice, water, phase-change material tied to CSP, pumped hydro, and hydrogen); using hydroelectric only as a last resort; and using demand response to shave periods of excess demand over supply. No batteries (except in electric vehicles), biomass, nuclear power, or natural gas are needed. Frequency regulation of the grid can be provided by ramping up/down hydroelectric, stored CSP or pumped hydro; ramping down other WWS generators and storing the electricity in heat, cold, or hydrogen instead of curtailing; and using demand response.

The study is able to derive multiple low-cost stable solutions with the number of generators across the U.S. listed in Table 2 here, except that that study applies to the continental U.S., so excludes data for Alaska and Hawaii. Numerous low-cost solutions are found, suggesting that maintaining grid reliability upon 100% conversion to WWS is economically feasible and not a barrier to the conversion.

7. Costs of electric power generation

In this section, current and future full social costs (including capital, land, operating, maintenance, storage, fuel, transmission, and externality costs) of WWS electric power generators *versus* non-WWS conventional fuel generators are estimated. These costs do not include the costs of storage necessary to keep the grid stable, which are quantified in ref. 2. The estimates here are based on current cost data and trend projections for individual generator types and do not account for interactions among energy generators and major end uses (*e.g.*, wind and solar power in combination with heat pumps and electric vehicles[24]). The estimates are only a rough approximation of costs in a future optimized renewable energy system.

Table 5 presents 2013 and 2050 U.S. averaged estimates of fully annualized levelized business costs of electric power generation for conventional fuels and WWS technologies. Whereas, several studies have calculated levelized costs of present-day renewable energy,[25,26] few have estimated such costs in the future. The methodology used here for determining 2050 levelized costs is described in the ESI.† Table 5 indicates that the 2013 business costs of hydroelectric, onshore wind, utility-scale solar, and solar thermal for heat are already similar to or less than the costs of natural gas combined cycle. Residential and commercial rooftop PV, offshore wind, tidal, and wave are more expensive. However, residential rooftop PV costs are given as if PV is purchased for an individual household. A common business model today is where multiple households contract together with a solar provider, thereby decreasing the average cost.

By 2050, however, the costs of all WWS technologies are expected to drop, most significantly for offshore wind, tidal, wave, rooftop PV, CSP, and utility PV, whereas conventional fuel costs are expected to rise. Because WWS technologies have zero fuel costs, the drop in their costs over time is due primarily to technology improvements. In addition, WWS costs are expected to decline due to less expensive manufacturing and streamlined project deployment from increased economies of scale. Conventional fuels, on the other hand, face rising costs over time due to higher labor and transport costs for mining, transporting, and processing fuels continuously over the lifetime of fossil-fuel plants.

The 2050 U.S. air pollution cost (Table 7) plus global climate cost (Table 8) per unit total U.S. energy produced by the conventional fuel sector in 2050 (Table 1) corresponds to a mean 2050 externality cost (in 2013 dollars) due to conventional fuels of ~\$0.17 (0.085–0.41) per kWh. Such costs arise due to air pollution morbidity and mortality and global warming damage (*e.g.* coastline losses, fishery losses, heat stress mortality, increased drought and wildfires, and increased severe weather) caused by conventional fuels. When externality costs are added to the business costs of conventional fuels, all WWS technologies cost less than conventional technologies in 2050.

Table 6 provides the mean value of the 2013 and 2050 levelized costs of energy (LCOEs) for conventional fuels and the mean value of the LCOE of WWS fuels in 2050 by state. The table also gives the 2050 energy, health, and global climate cost savings per person. The electric power cost of WWS in 2050 is not directly comparable with the BAU electric power cost, because the latter does not integrate transportation, heating/cooling, or industry energy costs. Conventional vehicle fuel costs, for example, are a factor of 4–5 higher than those of electric vehicles, yet the cost of BAU electricity cost in 2050 does not include the transportation cost, whereas the WWS electricity cost does. Nevertheless, based on the comparison, WWS energy in

Exhibit E 12

Table 5 Approximate fully annualized, unsubsidized 2013 and 2050 U.S.-averaged costs of delivered electricity, including generation, short- and long-distance transmission, distribution, and storage, but not including external costs, for conventional fuels and WWS power (2013 U.S. $ per kWh-delivered)[a]

	Technology year 2013			Technology year 2050		
Technology	LCHB	HCLB	Average	LCHB	HCLB	Average
Advanced pulverized coal	0.083	0.113	0.098	0.079	0.107	0.093
Advanced pulverized coal w/CC	0.116	0.179	0.148	0.101	0.151	0.126
IGCC coal	0.094	0.132	0.113	0.084	0.115	0.100
IGCC coal w/CC	0.144	0.249	0.197	0.098	0.146	0.122
Diesel generator (for steam turb.)	0.187	0.255	0.221	0.250	0.389	0.319
Gas combustion turbine	0.191	0.429	0.310	0.193	0.404	0.299
Combined cycle conventional	0.082	0.097	0.090	0.105	0.137	0.121
Combined cycle advanced	n.a.	n.a.	n.a.	0.096	0.119	0.108
Combined cycle advanced w/CC	n.a.	n.a.	n.a.	0.112	0.143	0.128
Fuel cell (using natural gas)	0.122	0.200	0.161	0.133	0.206	0.170
Microturbine (using natural gas)	0.123	0.149	0.136	0.152	0.194	0.173
Nuclear, APWR	0.082	0.143	0.112	0.073	0.121	0.097
Nuclear, SMR	0.095	0.141	0.118	0.080	0.114	0.097
Distributed gen. (using natural gas)	n.a.	n.a.	n.a.	0.254	0.424	0.339
Municipal solid waste	0.204	0.280	0.242	0.180	0.228	0.204
Biomass direct	0.132	0.181	0.156	0.105	0.133	0.119
Geothermal	0.087	0.139	0.113	0.081	0.131	0.106
Hydropower	0.063	0.096	0.080	0.055	0.093	0.074
On-shore wind	0.076	0.108	0.092	0.064	0.101	0.082
Off-shore wind	0.111	0.216	0.164	0.093	0.185	0.139
CSP no storage	0.131	0.225	0.178	0.091	0.174	0.132
CSP with storage	0.081	0.131	0.106	0.061	0.111	0.086
PV utility crystalline tracking	0.073	0.107	0.090	0.061	0.091	0.076
PV utility crystalline fixed	0.078	0.118	0.098	0.063	0.098	0.080
PV utility thin-film tracking	0.073	0.104	0.089	0.061	0.090	0.075
PV utility thin-film fixed	0.077	0.118	0.098	0.062	0.098	0.080
PV commercial rooftop	0.098	0.164	0.131	0.072	0.122	0.097
PV residential rooftop	0.130	0.225	0.177	0.080	0.146	0.113
Wave power	0.276	0.661	0.468	0.156	0.407	0.282
Tidal power	0.147	0.335	0.241	0.084	0.200	0.142
Solar thermal for heat ($ per kWh-th)	0.057	0.070	0.064	0.051	0.074	0.063

[a] LCHB = low cost, high benefits case; HCLB = high cost, low benefits case. The methodology for determining costs is given in the ESI. For the year 2050 100% WWS scenario, costs are shown for WWS technologies; for the year 2050 BAU case, costs of WWS are slightly different. The costs assume $0.0115 (0.11–0.12) per kWh for standard (but not extra-long-distance) transmission for all technologies except rooftop solar PV (to which no transmission cost is assigned) and $0.0257 (0.025–0.0264) per kWh for distribution for all technologies. Transmission and distribution losses are accounted for. CC = carbon capture; IGCC = integrated gasification combined cycle; AWPR = advanced pressurized-water reactor; SMR = small modular reactor; PV = photovoltaics. CSP w/storage assumes a maximum charge to discharge rate (storage size to generator size ratio) of 2.62 : 1. Solar thermal for heat assumes $3600–$4000 per 3.716 m^2 collector and 0.7 kW-th per m^2 maximum power.[2]

2050 will save the average U.S. consumer $260 (190–320) per year in energy costs ($2013 dollars). In addition, WWS will save $1500 (210–6000) per year in health costs, and $8300 (4700–17 600) per year in global climate costs. The total up-front capital cost of the 2050 WWS system is ~$13.4 trillion (~$2.08 mil. per MW).

8. Air pollution and global warming damage costs eliminated by WWS

Conversion to a 100% WWS energy infrastructure in the U.S. will eliminate energy-related air pollution mortality and morbidity and the associated health costs, and it will eliminate energy-related climate change costs to the world while causing variable climate impacts on individual states. This section discusses these topics.

8.A. Air pollution cost reductions due to WWS

The benefits of reducing air pollution mortality and its costs in each U.S. state can be quantified with a top-down approach and a bottom-up approach.

The top-down approach. The premature human mortality rate in the U.S. due to cardiovascular disease, respiratory disease, and complications from asthma due to air pollution has been estimated conservatively by several sources to be at least 50 000–100 000 per year. In ref. 27, the U.S. air pollution mortality rate is estimated at about 3% of all deaths. The all-cause death rate in the U.S. is about 833 deaths per 100 000 people and the U.S. population in 2012 was 313.9 million. This suggests a present-day air pollution mortality rate in the U.S. of ~78 000 per year. Similarly, from ref. 15, the U.S. premature mortality rate due to ozone and particulate matter is calculated with a three-dimensional air pollution-weather model to be 50 000–100 000 per year. These results are consistent with those of ref. 28, who estimated 80 000 to 137 000 premature mortalities per year due to all anthropogenic air pollution in the U.S. in 1990, when air pollution levels were higher than today.

Bottom-up approach. This approach involves combining measured countywide or regional concentrations of particulate matter ($PM_{2.5}$) and ozone (O_3) with a relative risk as a function of concentration and with population by county. From these

Table 6 Mean values of the levelized cost of energy (LCOE) for conventional fuels in 2013 and 2050 and for WWS fuels in 2050. The LCOEs do not include externality costs. The 2013 and 2050 values are used to calculate energy cost savings per person per year in each state (see footnotes). Health and climate cost savings per person per year are derived from data in Section 8. All costs are in 2013 dollars. Low-cost and high-cost results can be found in the "Expanded cost results by state" tab in ref. 9[a]

State	(a) 2013 average LCOE conventional fuels (¢ per kWh)	(b) 2050 average LCOE conventional fuels (¢ per kWh)	(c) 2050 average LCOE of WWS (¢ per kWh)	(d) 2050 average electricity cost savings per person per year ($ per person per year)	(e) 2050 average air quality damage savings per person per year due to WWS ($ per person per year)	(f) 2050 average climate cost savings to state per person per year due to WWS ($ per person per year)	(g) 2050 average climate cost savings to world per person per year due to WWS ($ per person per year)	(h) 2050 average energy + air quality damage + world climate cost savings due to WWS ($ per person per year)
Alabama	11.4	10.7	8.7	693	1464	1808	15 046	17 203
Alaska	15.1	15.5	11.1	483	886	−1042	25 692	27 060
Arizona	11.2	10.3	8.7	250	1852	958	4266	6368
Arkansas	11.2	10.8	8.2	731	1132	1585	12 855	14 717
California	12.5	10.7	9.7	161	2503	494	4731	7395
Colorado	9.9	9.9	8.5	312	1033	−165	7957	9303
Connecticut	12.5	11.0	11.9	114	1475	−215	5359	6948
Delaware	12.0	11.1	12.8	65	2361	1218	10 045	12 470
Florida	12.7	11.6	9.1	319	1099	1905	3789	5207
Georgia	11.4	10.7	10.1	293	1568	1045	7198	9059
Hawaii	22.7	30.3	11.9	1785	1028	2176	8762	11 575
Idaho	9.4	9.0	9.0	188	1051	−349	4228	5468
Illinois	10.1	9.8	9.4	231	1790	18	9736	11 757
Indiana	10.6	10.4	9.3	436	1922	129	16 770	19 128
Iowa	9.4	9.3	8.4	392	1270	−903	17 063	18 726
Kansas	9.6	9.4	8.3	349	962	1130	13 972	15 283
Kentucky	10.1	9.6	8.7	516	1492	919	19 346	21 354
Louisiana	11.2	10.8	11.5	242	1250	3019	30 706	32 197
Maine	12.5	11.0	11.4	143	739	−1713	8029	8912
Maryland	12.0	11.1	12.5	72	1725	556	5390	7187
Massachusetts	12.5	11.0	12.7	26	1148	−460	5192	6365
Michigan	10.6	10.8	11.4	157	1280	−468	9495	10 932
Minnesota	9.4	9.3	9.8	98	963	−299	8074	9134
Mississippi	11.2	10.8	9.5	531	1357	1975	12 125	14 013
Missouri	10.1	9.8	8.5	368	1377	1190	11 418	13 162
Montana	9.4	9.0	9.0	260	1021	−564	19 245	20 526
Nebraska	9.4	9.3	8.3	382	973	−1366	15 420	16 775
Nevada	9.4	9.0	9.4	98	1628	589	4110	5836
New Hampshire	12.5	11.0	10.8	144	967	−880	5621	6732
New Jersey	12.0	11.1	12.4	57	1272	675	6174	7504
New Mexico	11.2	10.3	9.2	437	1230	523	18 095	19 762
New York	14.5	12.6	13.4	112	1168	112	4508	5789
North Carolina	11.1	10.5	11.1	131	1322	741	5170	6623
North Dakota	9.4	9.3	8.4	483	598	482	47 504	48 584
Ohio	10.6	10.4	9.6	369	1834	55	12 065	14 268
Oklahoma	10.5	10.5	8.1	655	1189	1778	15 855	17 699
Oregon	9.4	9.0	10.0	33	894	−719	4305	5232
Pennsylvania	12.0	11.1	9.8	341	1746	28	10 799	12 886
Rhode Island	12.5	11.0	12.8	48	1144	−766	6094	7286
South Carolina	11.1	10.5	11.1	193	1511	1560	8396	10 100
South Dakota	9.4	9.3	8.1	372	719	−653	9972	11 063
Tennessee	10.1	9.6	8.6	338	1620	1119	7576	9534
Texas	10.7	10.7	8.7	384	1267	1456	10 273	11 923
Utah	9.4	9.0	8.9	127	1640	93	8405	10 173
Vermont	12.5	11.0	8.7	336	726	−1392	4933	5995

Exhibit E 14

Table 6 (continued)

State	(a) 2013 average LCOE conventional fuels (¢ per kWh)	(b) 2050 average LCOE conventional fuels (¢ per kWh)	(c) 2050 average LCOE of WWS (¢ per kWh)	(d) 2050 average electricity cost savings per person per year ($ per person per year)	(e) 2050 average air quality damage savings per person per year due to WWS ($ per person per year)	(f) 2050 average climate cost savings to state per person per year due to WWS ($ per person per year)	(g) 2050 average climate cost savings to world per person per year due to WWS ($ per person per year)	(h) 2050 average energy + air quality damage + world climate cost savings due to WWS ($ per person per year)
Virginia	11.1	10.5	11.2	142	1255	676	5501	6898
Washington	9.4	9.0	9.4	85	949	−635	4195	5229
West Virginia	10.6	10.4	9.2	703	1259	172	38911	40 873
Wisconsin	10.1	11.3	10.6	318	1197	−548	9264	10 779
Wyoming	9.9	9.9	8.3	1382	787	−612	75 614	77 783
United States	11.11	10.55	9.78	263	1491	661	8265	10 019

[a] (a) The 2013 LCOE cost for conventional fuels in each state combines the estimated distribution of conventional and WWS generators in 2013 with 2013 mean LCOEs for each generator from Table 5. Costs include all-distance transmission, pipelines, and distribution, but they exclude externalities. (b) Same as (a), but for a 2050 BAU case (ESI) and 2050 LCOEs for each generator from Table 5. (c) The 2050 LCOE of WWS in the state combines the 2050 distribution of WWS generators from Table 3 with the 2050 mean LCOEs for each WWS generator from Table 5. The LCOE accounts for all-distance transmission and distribution and storage (footnotes to Tables 2 and 5). (d) The total cost of electricity use in the electricity sector in the BAU (the product of electricity use and the LCOE) less the total cost in the electricity sector in the WWS scenario and less the annualized cost of the assumed efficiency improvements in the electricity sector in the WWS scenario. See ESI and ref. 9, for details. (e) Total cost of air pollution per year in the state from Table 7 divided by the 2050 population of the state. (f) Total climate cost per year in the state due to U.S. emissions (Table 8) divided by the 2050 population of the state. (g) Total climate cost per year to the world due to state's emissions (Table 8) divided by the 2050 population of the state. (h) The sum of columns (d), (e), and (g).

three pieces of information, low, medium, and high estimates of mortality due to $PM_{2.5}$ and O_3 pollution are calculated with a health-effects equation.[15]

Table 7 shows the resulting estimates of premature mortality for each state in the U.S. due to the sum of $PM_{2.5}$ and O_3, as calculated with 2010–2012 air quality data. The mean values for the U.S. for $PM_{2.5}$ are ∼48 000 premature mortalities per year, with a range of 12 000–95 000 per year and for O_3 are ∼14 000 premature mortalities per year, with a range of 7000–21 000 per year. Thus, overall, the bottom-up approach gives ∼62 000 (19 000–115 000) premature mortalities per year for $PM_{2.5}$ plus O_3. The top-down estimate (50 000–100 000), from ref. 15, is within the bottom-up range.

Mortality and non-mortality costs of air pollution. The total damage cost of air pollution from fossil fuel and biofuel combustion and evaporative emissions is the sum of mortality costs, morbidity costs, and non-health costs such as lost visibility and agricultural output. We estimate this total damage cost of air pollution in each state S in a target year Y as the product of an estimate of the number of premature deaths due to air pollution and the total cost of air pollution per death. The total cost of air pollution premature death is equal to the value of a statistical life multiplied by the ratio of the value of total mortality-plus-non-mortality impacts to mortality impacts. The number of premature deaths in the base year is as described in the footnote to Table 7. The number of deaths in 2050 is estimated by scaling the base-year number by factors that account for changes in population, exposure, and air pollution. The method is fully documented in the ESI† and ref. 9.

Given this information, the total social cost due to air pollution mortality, morbidity, lost productivity, and visibility degradation in the U.S. in 2050 is conservatively estimated from the ∼45 800 (11 600–104 000) premature mortalities per year to be $600 (85–2400) bil. per year using $13.1 (7.3–23.0) million per mortality in 2050. Eliminating these costs in 2050 represents a savings equivalent to ∼3.6 (0.5–14.3)% of the 2014 U.S. gross domestic product of $16.8 trillion. The U.S.-averaged payback time of the cost of installing all WWS generators in Table 2 due to the avoided air pollution costs alone is 20 (5–140) years.

8.B. Global-warming damage costs eliminated by 100% WWS in each state

This section provides estimates of two kinds of climate change costs due to greenhouse gas (GHG) emissions from energy use (Table 8). GHG emissions are defined here to include emissions of carbon dioxide, other greenhouse gases, and air pollution particles that cause global warming, converted to equivalent carbon dioxide. A 100% WWS system in each state would eliminate such damages. The two kinds of costs calculated are

(1) The cost of climate change impacts to the world and U.S. *attributable to* emissions of GHGs from each of the 50 states, and

(2) The cost of climate-change impacts *borne* by each state due to U.S. GHG emissions.

Costs due to climate change include coastal flood and real estate damage costs, energy-sector costs, health costs due to heat stress and heat stroke, influenza and malaria costs, famine costs, ocean acidification costs, increased drought and wildfire costs,

Exhibit E 15

Table 7 Avoided air pollution $PM_{2.5}$ plus O_3 premature mortalities by state in 2010–2012 and 2050 and mean avoided costs (in 2013 dollars) from mortalities and morbidities in 2050[a]

State	2012 population	2010–2012 low avoided mortalities per year	2010–2012 mean avoided mortalities per year	2010–2012 high avoided mortalities per year	2050 mean avoided mortalities per year	2050 mean avoided cost ($mil. per year)
Alabama	4 822 023	291	954	1784	596	7799
Alaska	731 449	23	84	155	71	922
Arizona	6 553 255	517	1518	2729	1911	24 988
Arkansas	2 949 131	126	448	859	301	3937
California	38 041 430	3825	12 528	23 194	9778	127 868
Colorado	5 187 582	262	699	1215	568	7428
Connecticut	3 590 347	235	729	1338	393	5142
Delaware	917 092	61	198	367	132	1723
Florida	19 317 568	818	2681	5018	3118	40 770
Georgia	9 919 945	632	2043	3799	1585	20 733
Hawaii	1 392 313	51	192	374	121	1584
Idaho	1 595 728	73	219	395	185	2420
Illinois	12 875 255	942	3150	5909	1811	23 678
Indiana	6 537 334	523	1704	3170	1037	13 562
Iowa	3 074 186	164	540	1010	272	3552
Kansas	2 885 905	121	377	695	220	2878
Kentucky	4 380 415	280	887	1638	542	7089
Louisiana	4 601 893	236	780	1462	465	6075
Maine	1 329 192	43	136	250	71	927
Maryland	5 884 563	436	1350	2475	966	12 630
Massachusetts	6 646 144	328	1033	1906	628	8206
Michigan	9 883 360	565	1744	3192	927	12 129
Minnesota	5 379 139	205	692	1305	475	6213
Mississippi	2 984 926	167	553	1036	320	4186
Missouri	6 021 988	361	1123	2065	700	9156
Montana	1 005 141	37	139	266	81	1054
Nebraska	1 855 525	74	245	460	142	1863
Nevada	2 758 931	212	567	986	632	8261
New Hampshire	1 320 718	54	171	317	119	1557
New Jersey	8 864 590	467	1528	2854	946	12 373
New Mexico	2 085 538	117	353	640	184	2409
New York	19 570 261	901	3137	5963	1708	22 342
North Carolina	9 752 073	543	1672	3065	1485	19 417
North Dakota	699 628	18	57	105	29	385
Ohio	11 544 225	911	2920	5403	1551	20 279
Oklahoma	3 814 820	186	606	1131	412	5383
Oregon	3 899 353	132	453	849	403	5265
Pennsylvania	12 763 536	921	3065	5730	1649	21 563
Rhode Island	1 050 292	53	166	307	87	1131
South Carolina	4 723 723	288	948	1774	663	8667
South Dakota	833 354	26	81	150	45	595
Tennessee	6 456 243	432	1380	2558	1047	13 688
Texas	26 059 203	1294	4217	7869	4142	54 161
Utah	2 855 287	209	598	1060	598	7821
Vermont	626 011	20	62	115	36	473
Virginia	8 185 867	436	1352	2483	1051	13 740
Washington	6 897 012	242	839	1592	832	10 887
West Virginia	1 855 413	101	327	610	147	1920
Wisconsin	5 726 398	294	934	1727	544	7109
Wyoming	576 412	23	62	108	32	417
United States	313 281 717	19 273	62 241	115 461	45 754	598 356

[a] Premature mortality due to ozone exposure is estimated on the basis of the 8 h maximum ozone each day over the period 2010–2012.[29] Relative risks and the ozone-health-risk equation are as in ref. 15. The low ambient concentration threshold for ozone premature mortality is assumed to be 35 ppbv (ref. 15, and reference therein). Mortality due to $PM_{2.5}$ exposure is estimated on the basis of daily-averaged $PM_{2.5}$ over the period 2010–2012[29] and the relative risks[30] for long-term health impacts of $PM_{2.5}$ are applied to all ages as in ref. 31 rather than to those over 30 years old as in ref. 30. The threshold for $PM_{2.5}$ is zero but concentrations below 8 $\mu g\ m^{-3}$ are down-weighted as in ref. 15. For each county in each state, mortality rates are averaged over the three-year period for each station to determine the station with the maximum average mortality rate. Daily air quality data from that station are then used with the 2012 county population and the relative risk in the health effects equation to determine the premature mortality in the county. For the $PM_{2.5}$ calculations, data are not available for 25% of the population and for the ozone calculations data are not available for 26% of the population. For these populations, mortality rates are set equal to the minimum county value for a given state, as determined per the method specified above. In cases where 2012 data are unavailable, data from 2013 are used instead. $PM_{2.5}$ and ozone concentrations shown in the table above reflect the three-year average concentrations at the representative station(s) within each county. Since mortality rates are first calculated for each monitoring site in a county and then averaged over each station in the county, these average concentrations cannot directly be used to reproduce each county's mortality rate. In cases where n/a is shown, data within that county are not available (and the minimum county mortality rate within the state is used in these cases, as specified above). 2050 estimates of avoided mortality are derived from 2010–2012 estimates as detailed in the ESI. The cost of avoided mortalities plus associated morbidities is determined as described in the text.

Exhibit E 16

severe weather costs, and increased air pollution health costs. These costs are partly offset by fewer extreme cold events and associated reductions in illnesses and mortalities and gains in agriculture in some regions. Net costs due to global-warming-relevant emissions are embodied in the social cost of carbon dioxide. The range of the 2050 social cost of carbon from recent papers is \$500 (282–1063) per metric tonne-CO_2e in 2013 dollars (ESI†). This range is used to derive the costs in Table 8. State costs due to their own air pollution also take into account a study of the state-by-state damage *versus* benefits of climate change (ESI†).

Table 8 indicates that, in some, primarily northern cold states, climate change due to total U.S. emissions may contribute to fewer extreme cold events and improved agriculture; however, the sum of all states' emissions cause a net positive damage to the U.S. as a whole (with total damage caused by all states' emissions in 2050 of \$265 bil. per year in 2013 dollars) and to the world (with total damage to the world caused by all states' emissions of \$3.3 (1.9–7.1) tril. per year). Thus, the global climate cost savings per person in the U.S. due to reducing all U.S. climate-relevant emissions through a 100% WWS system is ~\$8300 (4700–17 600) per person per year (in 2013 dollars) (Table 6).

Table 8 Percent of 2010 world CO_2 emissions by state,[32] mean estimate of avoided (+) or increased (−1) 2050 climate change cost in each state due to converting the U.S. as a whole to 100% WWS for all purposes, and low, medium, and high estimates of avoided 2050 global climate-change costs due to converting to 100% WWS for all purposes in each state individually. All costs are in 2013 dollars

	2010	2050	2050 avoided global climate cost (\$2013 bil. per year)		
State	Percent of world CO_2 emissions	Medium avoided state climate costs (\$2013 bil. per year)	Low	Medium	High
Alabama	0.39	9.63	170.6	80.1	45.2
Alaska	0.12	−1.09	57.0	26.8	15.1
Arizona	0.28	12.92	122.5	57.6	32.4
Arkansas	0.20	5.51	95.2	44.7	25.2
California	1.04	25.24	514.4	241.7	136.2
Colorado	0.28	−1.19	121.8	57.2	32.3
Connecticut	0.10	−0.75	39.8	18.7	10.5
Delaware	0.04	0.89	15.6	7.3	4.1
Florida	0.68	70.63	299.0	140.5	79.2
Georgia	0.46	13.82	202.6	95.2	53.7
Hawaii	0.06	3.35	28.7	13.5	7.6
Idaho	0.05	−0.80	20.7	9.7	5.5
Illinois	0.68	0.24	274.1	128.8	72.6
Indiana	0.62	0.91	251.9	118.3	66.7
Iowa	0.25	−2.53	101.6	47.7	26.9
Kansas	0.22	3.38	89.0	41.8	23.6
Kentucky	0.45	4.37	195.7	91.9	51.8
Louisiana	0.67	14.68	317.8	149.3	84.2
Maine	0.05	−2.15	21.4	10.1	5.7
Maryland	0.19	4.07	84.0	39.5	22.2
Massachusetts	0.20	−3.29	79.0	37.1	20.9
Michigan	0.47	−4.44	191.5	89.9	50.7
Minnesota	0.28	−1.93	110.9	52.1	29.4
Mississippi	0.18	6.09	79.6	37.4	21.1
Missouri	0.40	7.91	161.6	75.9	42.8
Montana	0.10	−0.58	42.3	19.9	11.2
Nebraska	0.16	−2.62	62.9	29.5	16.7
Nevada	0.10	2.99	44.4	20.9	11.8
New Hampshire	0.05	−1.42	19.3	9.0	5.1
New Jersey	0.33	6.57	127.8	60.0	33.8
New Mexico	0.17	1.02	75.5	35.4	20.0
New York	0.48	2.15	183.5	86.2	48.6
North Carolina	0.37	10.89	161.7	76.0	42.8
North Dakota	0.16	0.31	65.2	30.6	17.3
Ohio	0.70	0.61	284.0	133.4	75.2
Oklahoma	0.32	8.06	152.9	71.8	40.5
Oregon	0.11	−4.24	53.9	25.3	14.3
Pennsylvania	0.74	0.35	283.8	133.3	75.2
Rhode Island	0.03	−0.76	12.8	6.0	3.4
South Carolina	0.23	8.95	102.5	48.1	27.1
South Dakota	0.04	−0.54	17.6	8.2	4.6
Tennessee	0.31	9.46	136.3	64.0	36.1
Texas	1.98	62.26	935.0	439.3	247.6
Utah	0.19	0.45	85.3	40.1	22.6
Vermont	0.02	−0.91	6.8	3.2	1.8
Virginia	0.29	7.40	128.2	60.2	34.0
Washington	0.21	−7.28	102.4	48.1	27.1
West Virginia	0.29	0.26	126.4	59.4	33.5
Wisconsin	0.29	−3.26	117.1	55.0	31.0
Wyoming	0.19	−0.32	85.1	40.0	22.5
United States	16.2	265.3	7058.7	3316.1	1869.4

9. Impacts of WWS on jobs and earnings in the electric power sector

This section provides estimates of the jobs and total earnings created by implementing WWS-based electricity and the jobs and earnings lost in the displaced fossil-fuel electricity and petroleum industries. The analysis does not include the potential job and revenue gains in other affected industries such as the manufacturing of electric vehicles, fuel cells or electricity storage because of the additional complexity required and greater uncertainty as to where those jobs will be located.

9.A. JEDI job creation analysis

Changes in jobs and total earnings are estimated here first with the Jobs and Economic Development Impact (JEDI) models.[33] These are economic input–output models programmed by default for local and state levels. They incorporate three levels of impacts: (1) project development and onsite labor impacts; (2) local revenue and supply chain impacts; and (3) induced impacts. Jobs and revenue are reported for two phases of development: (1) the construction period and (2) operating years.

Scenarios for wind and solar powered electricity generation are run assuming that the WWS electricity sector is fully developed by 2050. Existing capacities are excluded from the calculations. As construction period jobs are temporary in nature, JEDI models report job creation in this stage as full-time equivalents (FTE, equal to 2080 hours of work per year). This analysis assumes that each year from 2010 to 2050 1/40th of the WWS infrastructure is built.

The JEDI models are economic input–output models that have several uncertainties.[34] To evaluate the robustness of the models, we compared results with calculations derived from a compilation of 15 different renewable energy job creation models.[35] These included input/output models such as JEDI and bottom-up analytical models. Table 9 suggests that the JEDI models estimate the number of 40-year operation jobs as 2.0 million across the U.S. due to WWS. This estimate falls within the range of 0.9–4.8 million jobs derived from the aggregation of models shown in Table 10.

9.B. Job loss analysis

Table 11 provides estimates of the number of U.S. jobs that may be lost in the oil, gas, and uranium extraction and production industries; petroleum refining industry; coal, gas, and nuclear power plant operation industries; fuel transportation industry, and other fuel-related industries upon a shift to WWS.

Although the petroleum industry will lose jobs upon the elimination of extraction of crude oil in the U.S., jobs in the production of non-fuel petroleum commodities such as lubricants, asphalt, petrochemical feedstocks, and petroleum coke will remain. The number of these jobs is estimated as follows: currently, 195 000 people work in oil and gas production alone across the U.S.[48] Assuming 50% of these workers are in oil production, 97 500 jobs exist in the U.S. oil production industry. Petroleum refineries employ another 73 900 workers (Table 11). Nationally, the non-fuel output from oil refineries is ~10% of refinery output.[49] We thus assume that only 10% (~17 000) of petroleum production and refining jobs will remain upon conversion to WWS. We assume another 33 000 jobs will remain for transporting this petroleum for a total of 50 000 jobs remaining. These jobs are assigned to states with current oil refining based on the current capacity of refining. This study does not address the economics of the remaining petroleum industry.

In sum, the shift to WWS may result in the displacement of ~3.86 million jobs in current fossil- and nuclear-related industries in the U.S. At $69 930 per year per job – close to the average for the WWS jobs – the corresponding loss in revenues is ~$270 billion.

9.C. Jobs analysis summary

The JEDI models predict the creation of ~3.9 million 40-year construction jobs and ~2.0 million 40-year operation and maintenance jobs for the WWS generators proposed. The shift to WWS will simultaneously result in the loss of ~3.9 million in the current fossil-based electricity generation, petroleum refining, and uranium production industries in the U.S. Thus, a net of ~2.0 million 40-year jobs will be created in the U.S. The direct and indirect earnings from WWS amount to $223 bil. per year during the construction stage and $132 bil. per year for operation. The annual earnings lost from fossil-fuel industries total ~$270 bil. per year giving a net gain in annual earnings of ~$85 bil. per year.

10. Energy efficiency

The proposed state plans will continue and enhance existing efforts to improve energy efficiency in residential, commercial, institutional, and government buildings, thereby reducing energy demand in each state. Current state energy policies promote building efficiency through appliance standards, regulations, tax incentives, education, and renewable energy portfolios. A number of studies have estimated that efficiency measures can reduce energy use in non-transportation sectors by up to 30%.[50–54]

11. Timeline for implementing the roadmaps

Fig. 5 shows a proposed timeline for the implementation of the roadmaps presented here. The plans call for 80–85% conversion to WWS by 2030 and 100% by 2050. For such a transition to occur, conversions need to occur rapidly for technologies as follows:

Power plants: by 2020, no more construction of new coal, nuclear, natural gas, or biomass fired power plants; all new power plants built are WWS. This is feasible because few power plants are built every year, and most relevant WWS electric power generator technologies are already cost competitive. We do not believe a technical or economic barrier exists to ramping up production of WWS technologies, as history suggests that rapid ramp-ups of production can occur given strong enough political will. For example during World War II, aircraft production increased from nearly zero to 330 000 over five years.

Heating, drying, and cooking in the residential and commercial sectors: by 2020, all new devices and machines are powered by electricity. This is feasible because the electric versions of all of these products are already available, and all sectors can use electricity without any adaptation (the devices can just be plugged in).

Large-scale waterborne freight transport: by 2020–2025, all new ships are electrified and/or use electrolytic hydrogen, all new port operations are electrified, and port retro-electrification is well underway. This should be feasible for relatively large ships and ports because large ports are centralized and few ships are built each year. Policies may be needed to incentivize the early retirement of ships that do not naturally retire before 2050.

Rail and bus transport: by 2025, all new trains and buses are electrified. This sector will take a bit longer to convert to WWS because we also need to make changes to the supporting energy-delivery infrastructure, and this is somewhat decentralized across the U.S. However, relatively few producers of buses and trains exist, and the supporting energy infrastructure is concentrated in major cities.

Off-road transport, small-scale marine: by 2025 to 2030, all new production is electrified. If these vehicles can all be battery powered, conversion will be simplified because electricity is everywhere. The potential slowdown in converting these sectors may be social.

Heavy-duty truck transport: by 2025 to 2030, all new vehicles are electrified or use electrolytic hydrogen. It may take 10–15 years for manufacturers to completely retool and for enough of the supporting energy-delivery infrastructure to be in place.

Light-duty on-road transport: by 2025–2030, all new vehicles are electrified. It takes time for manufacturers to retool, but more importantly, it will take several years to get the energy-delivery infrastructure in place, because it will need to be everywhere by 2030 when no more ICEV are made.

Exhibit E 18

Table 9 Estimated 40-year construction jobs, 40-year operation jobs, construction plus operation jobs minus jobs lost, annual earnings corresponding to construction and operation jobs produced, and net earnings from construction plus operation jobs produced minus jobs lost, by state, due to converting to WWS. Earnings are in 2013 dollars per year

State	40-year construction jobs	40-year operation jobs	Job losses in current energy industry	40-year net construction plus operation jobs created minus jobs lost	Earnings from new 40-year construction jobs ($bil 2013 per year)	Earnings from new 40-year operation jobs ($bil 2013 per year)	Net earnings from new construct-ion plus operation jobs minus jobs lost ($bil 2013 per year)
Alabama	130 925	49 650	57 095	123 480	7.28	3.11	6.40
Alaska	14 662	15 099	24 423	5339	0.87	1.10	0.26
Arizona	49 200	18 536	63 825	3911	2.92	1.23	−0.31
Arkansas	53 887	20 481	38 570	35 798	3.04	1.36	1.70
California	315 982	142 153	413 097	45 039	18.12	9.51	−1.26
Colorado	49 417	21 119	76 576	−6040	2.89	1.48	−0.98
Connecticut	40 487	21 662	34 194	27 955	2.25	1.40	1.27
Delaware	8286	6458	8922	5822	0.48	0.43	0.28
Florida	222 082	90 727	173 635	139 175	12.41	5.76	6.03
Georgia	146 597	73 419	95 086	124 929	8.24	4.74	6.33
Hawaii	8239	4239	13 599	−1120	0.47	0.29	−0.19
Idaho	16 877	6707	14 746	8837	0.97	0.47	0.40
Illinois	132 687	59 709	138 722	53 675	7.46	4.16	1.93
Indiana	119 791	47 951	71 464	96 277	6.64	3.26	4.90
Iowa	57 914	25 106	29 899	53 121	3.25	1.76	2.92
Kansas	29 065	13 346	42 836	−425	1.70	0.96	−0.34
Kentucky	142 163	47 719	62 687	127 195	7.78	2.95	6.35
Louisiana	174 500	143 400	134 860	183 040	10.18	9.51	10.26
Maine	17 771	13 381	12 446	18 706	1.02	0.92	1.07
Maryland	51 557	35 893	54 286	33 164	2.94	2.38	1.52
Massachusetts	53 490	37 950	64 380	27 060	3.05	2.55	1.10
Michigan	89 250	58 810	99 191	48 869	5.12	4.10	2.28
Minnesota	46 025	29 767	56 345	19 447	2.67	2.14	0.87
Mississippi	100 778	40 659	39 126	102 310	5.54	2.56	5.37
Missouri	60 791	23 469	59 914	24 345	3.41	1.60	0.82
Montana	13 833	5642	16 202	3273	0.79	0.39	0.05
Nebraska	26 533	12 006	23 343	15 196	1.54	0.85	0.75
Nevada	27 457	9140	27 589	9008	1.56	0.60	0.24
New Hampshire	10 402	5697	13 662	2437	0.58	0.39	0.02
New Jersey	86 049	58 606	90 836	53 819	4.88	3.90	2.43
New Mexico	20 885	9663	41 674	−11 126	1.23	0.70	−0.98
New York	174 775	94 644	187 203	82 216	9.75	6.19	2.85
North Carolina	99 676	63 199	94 223	68 652	5.70	4.16	3.28
North Dakota	21 744	8574	26 690	3628	1.21	0.57	−0.08
Ohio	151 668	66 117	123 109	94 677	8.47	4.46	4.32
Oklahoma	46 516	20 350	95 445	−28 579	2.69	1.43	−2.55
Oregon	21 564	14 235	36 020	−221	1.26	1.00	−0.26
Pennsylvania	279 540	107 584	158 788	228 337	15.24	6.83	10.97
Rhode Island	7473	5775	9892	3356	0.43	0.39	0.12
South Carolina	58 473	40 345	48 132	50 687	3.37	2.67	2.68
South Dakota	10 244	4714	8028	6930	0.60	0.33	0.37
Tennessee	148 143	49 950	63 345	134 748	8.14	3.09	6.80
Texas	312 979	191 331	571 429	−67 119	18.73	13.52	−7.71
Utah	29 857	11 987	37 942	3902	1.72	0.82	−0.11
Vermont	2496	1005	6455	−2953	0.14	0.07	−0.24
Virginia	89 362	57 779	83 707	63 434	5.14	3.83	3.11

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Table 9 (*continued*)

State	40-year construction jobs	40-year operation jobs	Job losses in current energy industry	40-year net construction plus operation jobs created minus jobs lost	Earnings from new 40-year construction jobs ($bil 2013 per year)	Earnings from new 40-year operation jobs ($bil 2013 per year)	Net earnings from new construction plus operation jobs minus jobs lost ($bil 2013 per year)
Washington	38 226	24 927	67 603	−4449	2.17	1.75	−0.81
West Virginia	53 944	20 295	53 862	20 377	2.95	1.30	0.49
Wisconsin	51 458	33 200	54 168	30 490	2.96	2.32	1.50
Wyoming	15 806	7731	40 009	−16 472	0.92	0.56	−1.32
United States	3 931 527	1 971 907	3 859 275	2 044 158	222.9	131.9	85

40-year jobs are number of full-time equivalent (FTE) 1-year (2080 hours of work per year) jobs for 40 years.Earnings are in the form of wages, services, and supply-chain impacts. During the construction period, they are the earnings during all construction. For the operation period, they are the annual earnings.

Table 10 Estimated number of permanent operations, maintenance, and fuel processing jobs per installed MW of proposed new energy technology plants (Table 2)

		Jobs per installed MW		Number of permanent jobs	
Energy technology	Installed MW	Low	High	Low	High
Onshore wind	1 639 819	0.14	0.40	229 575	655 927
Offshore wind	780 921	0.14	0.40	109 329	312 368
Wave device	27 036	0.14	0.40	3785	10 814
Geothermal plant	20 845	1.67	1.78	34 811	37 103
Hydroelectric plant	3789	1.14	1.14	4319	4319
Tidal turbine	8823	0.14	0.40	1235	3529
Residential roof PV	375 963	0.12	1.00	45 116	375 963
Com/gov roof PV	274 733	0.12	1.00	32 968	274 733
Solar PV plant	2 323 800	0.12	1.00	278 856	2 323 800
CSP plant	363 640	0.22	1.00	80 001	363 640
Solar thermal	469 008	0.12	1.00	56 281	469 008
Total	6 288 375			876 275	4 831 206

Table 11 U.S. job loss upon eliminating energy generation and use from the fossil fuel and nuclear sectors

Energy sector	Number of jobs lost
Oil and gas extraction/production	806 300[a]
Petroleum refining	73 900[b]
Coal/gas power plant operation	259 400[c]
Coal mining	89 700[d]
Uranium extraction/production	1160[e]
Nuclear power plant operation	58 870[f]
Coal and oil transportation	2 448 300[g]
Other	171 500[h]
Less petroleum jobs retained	−50 000[i]
Total	3 859 000

[a] Ref. 36. [b] Workers employed in U.S. refineries from ref. 37. State values are estimated by multiplying the U.S. total by the fraction of U.S. barrels of crude oil distilled in each state from ref. 38. [c] Includes coal plant operators, gas plant operators, compressor and gas pumping station operators, pump system operators, refinery operators, stationary engineers and boiler operators, and service unit operators for oil, gas, and mining. Coal data from ref. 39. All other data from ref. 40. [d] Ref. 41. [e] Sum U.S. uranium mining employment across 12 U.S. states that mine uranium from ref. 42. State values are estimated by multiplying the total by the state population divided by the total population of the 12 states. [f] Ref. 43. [g] Multiply the total number of direct U.S. jobs in transportation (11 000 000) from ref. 44 by the ratio (0.287 in 2007) of weight of oil and coal shipped in the U.S. relative to the total weight of commodities shipped from ref. 45 and by the fraction of transportation jobs that are relevant to oil and coal transportation (0.78) from ref. 46 and by the fraction of the U.S. population in each state. [h] Other includes accountants, auditors, administrative assistants, chemical engineers, geoscientists, industrial engineers, mechanical engineers, petroleum attorneys, petroleum engineers, and service station attendants associated with oil and gas.[47] [i] See text for discussion of jobs retained.

Short-haul aircraft: by 2035, all new small, short-range planes are battery- or electrolytic-hydrogen powered. Changing the design and manufacture of airplanes and the design and operation of airports are the main limiting factors to a more rapid transition.

Long-haul aircraft: by 2040, all remaining new aircraft are electrolytic cryogenic hydrogen (ref. 6, Section A.2.7) with electric power for idling, taxiing, and internal power. The limiting factors to a faster transition are the time and social changes required for the redesign of aircraft and the design and operation of airports.

Exhibit E 20

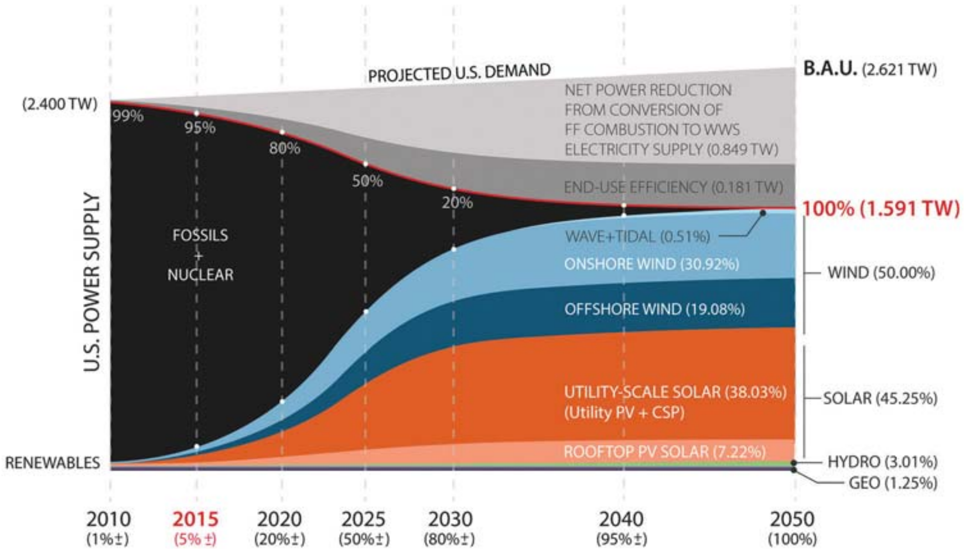

Fig. 5 Time-dependent change in U.S. end-use power demand for all purposes (electricity, transportation, heating/cooling, and industry) and its supply by conventional fuels and WWS generators based on the state roadmaps proposed here. Total power demand decreases upon conversion to WWS due to the efficiency of electricity over combustion and end-use energy efficiency measures. The percentages on the horizontal date axis are the percent conversion to WWS that has occurred by that year. The percentages next to each WWS source are the final estimated penetration of the source. The 100% demarcation in 2050 indicates that 100% of all-purpose power is provided by WWS technologies by 2050, and the power demand by that time has decreased. Karl Burkart, personal communication.

During the transition, conventional fuels will be needed along with existing WWS technologies to produce the remaining WWS infrastructure. The use of such fuels results in lifecycle carbon emissions that vary, depending on where the technologies are manufactured.[55] However, at least some of that conventional energy would be used in any case to produce conventional power plants and automobiles, for example, if the plans proposed here were not implemented. In fact, it is not known whether the total lifecycle energy required to manufacture the main components of the WWS energy system, mainly solar panels and wind turbines, will be much different from the total lifecycle energy required to manufacture *all* of the components of the conventional BAU energy system, which includes power plants, refineries, mining equipment, oil and gas wells, pipelines, tanker ships, trucks, rail cars, and more. In any event, as the fraction of WWS energy increases, conventional energy generation decreases, ultimately to zero, at which point all new WWS devices are produced by existing WWS devices with zero emissions. In sum, the creation of WWS infrastructure *might* result in a temporary, minor increase in emissions before emissions are ultimately reduced to zero, and might have minor impacts on energy use in the industrial sector.

12. Recommended first steps

This section discusses short-term policy options to aid conversion to WWS at the state level. Within each section, the policy options listed are listed roughly in order of proposed priority.

12.1. Energy efficiency measures

- Expand Renewable Energy Standards and Energy Efficiency Resource Standards.
- Incentivize conversion from natural gas water and air heaters to heat pumps (air and ground-source) and rooftop solar thermal hot water pre-heaters. Incentivize more use of efficient lighting in buildings and on city streets.
- Promote, though municipal financing, incentives, and rebates, energy efficiency measures in buildings. Efficiency measures include, but are not limited to, using LED lighting; optimized air conditioning systems; evaporative cooling; ductless air conditioning; water-cooled heat exchangers; night ventilation cooling; heat-pump water heaters; improved data center design; improved air flow management; advanced lighting controls; combined space and water heaters; variable refrigerant flow; improved wall, floor, ceiling, and pipe insulation; sealing leaks in windows, doors, and fireplaces; converting to double-paned windows; using more passive solar heating; monitoring building energy use to determine wasteful processes; and performing an energy audit to discover energy waste.
- Revise building codes as new technologies become available.
- Incentivize landlords' investment in efficiency. Allow owners of multi-family buildings to take a property tax exemption for energy efficiency improvements made in their buildings that provide benefits to their tenants.
- Introduce a Public Benefit Funds (PBF) program for energy efficiency. Fund the program with a non-bypassable charge on consumers' electricity bills for distribution services. These funds generate capital that sponsor energy efficiency programs, and research and development related to clean energy technologies and training.

12.2. Energy supply measures

- Increase Renewable Portfolio Standards (RPS).
- Extend or create state WWS production tax credits.

Exhibit E 21

- Implement taxes on emissions by current utilities to encourage their phaseout.
- Streamline the small-scale solar and wind installation permitting process. Create common codes, fee structures, and filing procedures across the state.
- Incentivize clean-energy backup emergency power systems rather than diesel/gasoline generators at both the household and community levels.
- Incentivize home or community energy storage (through battery systems) accompanying rooftop solar to mitigate problems associated with grid power losses.

12.3. Utility planning and incentive structures

- Incentive the development of utility-scale grid storage.
- Require utilities to use demand response grid management to reduce the need for short-term energy backup on the grid.
- Implement virtual net metering (VNM) for small-scale energy systems. VNM allows a utility customer to assign the net production from an electrical generator (*e.g.*, solar PV) on his or her property to another metered account not physically connected to that generator. This allows credits from a single solar PV system to be distributed among multiple electric service accounts, such as in low-income residential housing complexes, apartment complexes, school districts, multi-store shopping centers, or a residential neighborhood with multiple residents and one PV system. To that end, useful policies would be to (1) remove the necessity for subscribers to have proprietorship in the energy-generating site, (2) expand or eliminate the capacity limit of net metering for each utility, and (3) remove the barrier to inter-load zone transmission of net-metered renewable power.

12.4. Transportation

- Promote more public transit by increasing its availability and providing compensation to commuters for not purchasing parking passes.
- Increase safe biking and walking infrastructure, such as dedicated bike lanes, sidewalks, crosswalks, timed walk signals, *etc.*
- Adopt legislation mandating BEVs for short- and medium distance government transportation and using incentives and rebates to encourage the transition of commercial and personal vehicles to BEVS.
- Use incentives or mandates to stimulate the growth of fleets of electric and/or hydrogen fuel cell/electric hybrid buses starting with a few and gradually growing the fleets. Electric or hydrogen fuel cell ferries, riverboats, and other local shipping should be incentivized as well.
- Ease the permitting process for the installation of electric charging stations in public parking lots, hotels, suburban metro stations, on streets, and in residential and commercial garages.
- Set up time-of-use electricity rates to encourage charging at night.
- Incentivize the electrification of freight rail and shift freight from trucks to rail.

12.5. Industrial processes

- Provide financial incentives for industry to convert to electricity and electrolytic hydrogen for high temperature and manufacturing processes.
- Provide financial incentives to encourage industries to use WWS electric power generation for on-site electric power (private) generation.

12.6. State planning and incentive structures

- Lock in in-state fossil fuel and nuclear power plants to retire under enforceable commitments. At the same time, streamline the permit approval process for WWS power generators and high-capacity transmission lines.
- Work with local and regional governments to manage zoning and permitting issues within existing regional planning efforts or pre-approve sites to reduce the cost and uncertainty of projects and expedite their physical build-out. In the case of offshore wind, include the federal government in planning and management efforts.
- Create a green building tax credit program for the corporate sector.
- Create energy performance rating systems with minimum performance requirements to assess energy efficiency levels across the state and pinpoint areas for improvement.

13. Summary

This study develops consistent roadmaps for each of the 50 United States to convert their energy infrastructures for all purposes into clean and sustainable ones powered by wind, water, and sunlight (WWS) producing electricity and electrolytic hydrogen for all purposes (electricity, transportation, heating/cooling, and industry).

The study evaluates U.S. WWS resources and proposes a mix of WWS generators that can match projected 2050 demand. A separate grid integration study[2] quantifies the additional generators and storage needed to ensure grid reliability. The numbers of generators from that study are included here. This study also evaluates the state-by-state land and water areas required, energy, air pollution, and climate cost changes, and net jobs created from such a conversion.

The conversion from combustion to a completely electrified system for all purposes is calculated to reduce U.S.-averaged end-use load ~39.3% with ~82.4% of this due to electrification and the rest due to end-use energy efficiency improvements. Additional end-use energy efficiency measures may reduce load further. The conversion to WWS should stabilize energy prices since fuel costs will be zero.

Remaining all-purpose annually-averaged end-use U.S. load is proposed to be met (based on 2050 energy estimates) with 328 000 new onshore 5 MW wind turbines (providing 30.9% of U.S. energy for all purposes), 156 200 off-shore 5 MW wind turbines (19.1%), 46 480 50 MW new utility-scale solar-PV power plants (30.7%), 2273 100 MW utility-scale CSP power plants (7.3%), 75.2 million 5 kW residential rooftop PV systems (3.98%),

Exhibit E 22

2.75 million 100 kW commercial/government rooftop systems (3.2%), 208 100 MW geothermal plants (1.23%), 36 050 0.75 MW wave devices (0.37%), 8800 1 MW tidal turbines (0.14%), and 3 new hydroelectric power plants (all in Alaska). The capacity of existing plants would be increased slightly so that hydro supplies 3.01% of all-purpose power. The parallel grid integration study suggests that an additional 1364 CSP plants (providing an additional ∼4.38% of annually-averaged load) and 9380 50 MW solar-thermal collection systems for heat storage in soil (providing an additional 7.21% of annually-averaged load) are needed to ensure a reliable grid. This is just one possible mix of generators. Practical implementation considerations will determine the actual design and operation of the energy system and may result in technology mixes different than proposed here (*e.g.*, more power plant PV, less rooftop PV).

The additional footprint on land for WWS devices is equivalent to about 0.42% of the U.S. land area, mostly for utility scale PV. This does not account for land gained from eliminating the current energy infrastructure. An additional on-land spacing area of about 1.6% is required for onshore wind, but this area can be used for multiple purposes, such as open space, agricultural land, or grazing land. The land footprint and spacing areas (open space between devices) in the proposed scenario can be reduced by shifting more land based WWS generators to the ocean, lakes, and rooftops.

The 2013 business costs of hydroelectric, onshore wind, utility-scale solar, and solar thermal collectors for heat are already similar to or less than the costs of natural gas combined cycle. Rooftop PV, offshore wind, tidal, and wave are more expensive. By 2050, though, the business costs of all WWS technologies are expected to drop, most significantly for offshore wind, tidal, wave, rooftop PV, CSP, and utility PV, whereas conventional fuel costs are expected to rise.

The 50-state roadmaps are anticipated to create ∼3.9 million 40-year construction jobs and ∼2.0 million 40-year operation jobs for the energy facilities alone, outweighing the ∼3.9 million jobs lost to give a net gain of 2.0 million 40-year jobs. Earnings during the 40-year construction period for these facilities (in the form of wages, local revenue, and local supply-chain impacts) are estimated to be ∼$223 bil. per year in 2013 dollars and annual earnings during operation of the WWS facilities are estimated at ∼$132 bil. per year. Net earnings from construction plus operation minus lost earnings from lost jobs are estimated at ∼$85 bil. per year.

The state roadmaps will reduce U.S. air pollution mortality by ∼62 000 (19 000–115 000) U.S. air pollution premature mortalities per year today and ∼46 000 (12 000–104 000) in 2050, avoiding ∼$600 ($85–$2400) bil. per year (2013 dollars) in 2050, equivalent to ∼3.6 (0.5–14.3) percent of the 2014 U.S. gross domestic product.

Converting would further eliminate ∼$3.3 (1.9–7.1) tril. per year in 2050 global warming costs to the world due to U.S. emissions. These plans will result in the average person in the U.S. in 2050 saving $260 (190–320) per year in energy costs ($2013 dollars), $1500 (210–6000) per year in health costs, and $8300 (4700–17 600) per year in climate costs.

Many uncertainties in the analysis here are captured in broad ranges of energy, health, and climate costs given. However, these ranges may miss costs due to limits on supplies caused by wars or political/social opposition to the roadmaps. As such, the estimates should be reviewed periodically.

The timeline for conversion is proposed as follows: 80–85% of all energy to be WWS by 2030 and 100% by 2050. If this timeline is followed, implementation of these plans and similar ones for other countries worldwide will eliminate energy-related global warming; air, soil, and water pollution; and energy insecurity.

Based on the scientific results presented, current barriers to implementing the roadmaps are neither technical nor economic. As such, they must be social and political. Such barriers are due partly to the fact that most people are unaware of what changes are possible and how they will benefit from them and partly to the fact that many with a financial interest in the current energy industry resist change. However, because the benefits of converting (reduced global warming and air pollution; new jobs and stable energy prices) far exceed the costs, converting has little downside. This study elucidates the net benefits and quantifies what is possible thus should reduce social and political barriers to implementing the roadmaps.

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Supplemental Information

for

100% Clean and Renewable Wind, Water, and Sunlight (WWS) All-Sector Energy Roadmaps for the 50 United States

by

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OVERVIEW OF THE SUPPLEMENTAL INFORMATION

Our objective and general method

This document contains detailed methodologies for calculating most of the end-result numbers in the main paper. The calculations provided here and all additional calculations for the main paper are detailed further in accompanying spreadsheets (Delucchi et al., 2015).

Our general objective in this document is to estimate the costs and benefits of meeting all end-use energy demand in all 50 U.S. states with wind, water, and solar (WWS) power, compared with a "business-as-usual" (BAU) scenario. We base our BAU scenario on highly detailed projections by the U. S. Energy Information Administration (EIA), because these are the most comprehensive, detailed, well-documented, and well-known energy-use projections for the U.S.

In the following sections we describe how we obtain our estimates of

1) Energy use in a 100%-WWS world versus a BAU world

2) The difference in the cost of electricity use in the 100% WWS scenario versus the BAU scenario.

3) The total damage cost of air pollution from conventional fuels.

4) The cost of climate change from fossil-fuel use: damages attributable to and borne by each state.

5) Earnings from new construction and operation jobs in a 100% WWS world.

6) Projection of state population and GDP.

7) The national-average levelized cost of electricity by type of generator.

8) Calculation of the cost of electricity by state, year, and scenario.

Construction of "low" and "high" cost scenarios

In order to unify our presentation, we report costs and other results for two general cases: one based on low costs and high benefits (i.e., low net costs or high net benefits) for the 100% WWS scenario, and one based on the reverse, high costs and low benefits (i.e., high net costs or low net benefits) for the 100% WWS scenario. For ease of exposition we use the following abbreviations:

LCHB = low-cost, high benefits for 100% WWS
HCLB = high cost, low benefits for 100% WWS

For each case, all of the component costs and benefits summed to make the total have the same underlying explicit or implicit assumptions regarding the discount rate and other parameters. This means, for example, that in either case we do not add a cost estimate based on a low discount rate to a benefit estimate based on a high-discount rate. This results in the following for the LCHB case (with the opposite for the HCLB case):

Cost or benefit	Discount rate, Low (LCHB) case	Other parameters, Low (LCHB) case
WWS delivered electricity cost	Low value. Results in low annualized capital costs.	Low capital cost of construction. Low operating costs. High capacity factor. High (long) lifetime.
Conventional delivered electricity cost	Low value.	Low capital cost of construction. Low operating costs. High capacity factor. High (long) lifetime. (It is possible that WWS could have low values while conventional has high values, and vice

		versa, but we do not examine this here.)
Storage costs	Low value. Results in low annualized capital costs.	Low capital cost. Low operating costs. High (long) lifetime.
Long distance transmission costs	Low value. Results in low annualized capital costs.	Shorter transmission distance and other assumptions that result in lower annualized costs.
Cost of energy efficiency improvements	Low value. Results in low annualized cost.	Low initial cost. High (long) life of efficiency improvement.
Change in electricity costs, WWS vs. BAU	Low value, in order to ensure consistency when added with other costs (e.g., climate-change costs).	Low value of parameters affecting cost of delivered electricity and efficiency improvements.
Foregone air-pollution costs (benefit of WWS)	Not specified. (A component of the discount rate, productivity growth per capita, can affect the value of a statistical life [VOSL], such that a low discount rate results in a lower VOSL and hence a lower benefit for WWS, but this effect is small, and we ignore it.)	High air pollution levels. High value of life. High exposure to pollution. High value of non-mortality impacts.
Foregone climate-change costs (benefit of WWS)	Not specified, but implicitly a low value, because low values of the discount rate result in higher present worth of climate-change damages which gives high net benefits (or low net costs) of WWS. Note that whereas the discount rate does not have a major effect on the cost of air pollution, it *does* have a major effect on the social cost of carbon.	High social cost of carbon, leading to high net benefits (or low net costs) for WWs.

1. ENERGY USE IN A 100% WWS WORLD VS. A BAU WORLD

We estimate energy end-use in a 100% WWS world relative to the EIA's (2014c) *Annual Energy Outlook* (AEO) projections of energy use in its so-called "reference" scenario, which we also refer to as a BAU (Business –As-Usual) scenario. We start with the EIA-based estimates for the BAU and then adjust them for differences between the BAU and the WWS scenario due to extensive electrification in the WWS scenario, the absence of energy use in the industrial sector for petroleum refining to produce energy products in the WWS scenario, and extra end-use energy efficiency measures in the WWS scenario beyond those assumed in the BAU scenario.

Projections of end-use energy by state, sector, and fuel source, BAU

We start with estimates of the use of liquid fuels, natural gas, coal, renewable fuels, and electricity in the residential, commercial, industrial, and transportation sectors of each state in 2010. The EIA's *AEO* does not project energy use by state, but it does project energy use by sector and fuel source in each of nine Census Divisions covering all 50 states. We therefore project each state's energy use based on the changes projected for the Census Division covering that state. Formally,

$$E_{i,X,S,Y} = E_{i,X,S,2010} \cdot \frac{E_{i,X,R:S\in R,Y}}{E_{i,X,R:S\in R,2010}}$$

where

$E_{i,X,S,Y}$ = end-use of fuel i in sector X in state S in year Y (BTU)
$E_{i,X,S,2010}$ = end-use of fuel i in sector X in state S in year 2010 (BTU) (EIA State Energy Data System, www.eia.gov/state/seds/)
$E_{i,X,R:S\in R,Y}$ = end-use of fuel i in sector X in Census Division R (containing S) in year Y (BTU) (EIA, 2014c; the EIA projects out to 2040, and we extend to 2075 by using a moving 10-year trend extrapolation starting with the estimate for 2031)
$E_{i,X,R:S\in R,2010}$ = end-use of fuel i in sector X in Census Division R (containing S) in year 2010 (BTU) (EIA, 2013b)

Subscripts
i = fuels for which the EIA estimates energy use (liquid fuels, natural gas, coal, renewable energy, electricity)
X = end-use energy sectors (residential, commercial, industrial, transportation)
S = state in the U.S.
Y = target year of the analysis
R = Census region of the U.S. in the EIA's estimates of energy-related CO2 emissions (New England, Middle Atlantic, East North Central, West North Central, South Atlantic, East South Central, West South Central, Mountain, and Pacific)

We also re-aggregate the resultant state-level projections to Census-Division-level projections.

Electrification of end uses in the WWS scenario

Partly on the basis of our examination of end-use energy consumption projected in the EIA's *AEO,* we assume that end-uses are electrified as follows (with the non-electrified fractions producing electrolytic hydrogen as described below):

Sector	**Fraction electrified**
Residential	
Liquids	1.00
Natural Gas	1.00
Coal	1.00
Electricity (retail)	1.00
Renewables	1.00
Commercial	
Liquids	1.00
Natural Gas	1.00
Coal	1.00
Electricity (retail)	1.00
Renewables	1.00
Industrial	
Liquids	0.95
Natural Gas	0.95
Coal	0.95
Electricity (retail)	1.00
Renewables (incl. biofuels for heat)	1.0
Transportation	
Liquids	0.76
Natural Gas	0.95
Electricity (retail)	1.00

The value for liquids in Transportation is calculated from more disaggregated assumptions, as follows:

Transport mode	*% of energy*	*Fraction electrified*
On road gasoline, LPG	61%	95%
On-road diesel	19%	70%
Off-road diesel	1%	65%
Military	0%	20%
Trains	2%	85%
Aircraft	12%	10%
Ships	4%	25%
Lubricants	1%	0%
All liquid in Transport	*100%*	*76%*

End uses that are not electrified (e.g., cooking with a flame in the residential and commercial sectors) generally are assumed to use electrolytic hydrogen produced from WWS power, or in the case of aircraft, cryogenic hydrogen produced from WWS power.

Energy use in the industrial sector to refine petroleum into energy products

To estimate energy use in the WWS scenario we deduct from the industrial sector an estimate of the proportion of energy used to refine petroleum (Jacobson and Delucchi, 2011).

Extra end-use energy saving measures in the WWS scenario

As explained in the main text, we assume additional energy-efficiency measures beyond the EIA's reference case scenario. Our method is to start with one of the EIA's own higher efficiency scenarios and then make further adjustments that we believe are appropriate.

The EIA (2014c) examines three scenarios in which end-use energy efficiency is higher, and delivered energy use lower, than in the reference-case scenario: "Integrated High Demand Technology," "Integrated Best Available Demand Technology," and "Low Electricity Demand." These three, along with a scenario in which efficiency remains at year-2013 levels ("Integrated 2013 Demand Technology") are described below and in Table E-1 and Appendix E of EIA (2014c) (with our shortened descriptors shown in parentheses).

Integrated 2013 Demand Technology	Assumes that future equipment purchases in the residential and commercial sectors are based only on the range of equipment available in 2013. Commercial and existing residential building shell efficiency is held constant at 2013 levels. Energy efficiency of new

(2013Tech)	industrial plant and equipment is held constant at the 2014 level over the projection period.
Integrated High Demand Technology (High Efficiency All Sectors – HEAS)	Assumes earlier availability, lower costs, and higher efficiencies for more advanced residential and commercial equipment. For new residential construction, building code compliance is assumed to improve after 2013, and building shell efficiencies are assumed to meet ENERGY STAR requirements by 2023. Existing residential building shells exhibit 50% more improvement than in the Reference case after 2013. New and existing commercial building shells are assumed to improve 25% more than in the Reference case by 2040. Industrial sector assumes earlier availability, lower costs, and higher efficiency for more advanced equipment and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes. In the transportation sector, the characteristics of conventional and alternative-fuel LDVs reflect more optimistic assumptions about incremental improvements in fuel economy and costs, as well as battery electric vehicle costs. Freight trucks are assumed to see more rapid improvement in fuel efficiency. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors.
Integrated Best Available Demand Technology (Best Efficiency Residential and Commercial – BERC)	Assumes that all future equipment purchases in the residential and commercial sectors are made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. All residential building shells for new construction are assumed to be code compliant and built to the most efficient specifications after 2013, and existing residential shells have twice the improvement of the Reference case. New and existing commercial building shell efficiencies improve 50% more than in the Reference case by 2040. Industrial and transportation sector assumptions are the same as in the Reference case.
Low Electricity Demand (High Efficiency Electricity Use -- HEEE)	This case was developed to explore the effects on the electric power sector if growth in sales to the grid remained relatively low. It uses the assumptions in the Best Available Demand Technology case for the residential and commercial sectors. In addition, input values for the industrial sector motor model are adjusted to increase system savings values for pumps, fans, and air compressors relative to the Reference case. This adjustment lowers total motor electricity consumption by slightly less than 20%. Although technically plausible, this decrease in motor adjustment is not intended to be a likely representation of motor development. As a result of these changes across the end-use sectors, retail sales in 2040 in this case are roughly the same as in 2012.

Here we start with the EIA's HEAS (High Efficiency All Scenarios) scenario, and estimate the ratio of HEAS to Reference energy use by sector (residential, commercial, industrial, and transportation), fuel (petroleum, natural gas, coal, renewable fuel, electricity), Census Division (nine for the U.S.), and year (2011-2075; recall that we use 10-year moving linear trend extrapolation to extend the EIA's projections from 2040 to 2075). We then multiply the resultant HEAS/Reference ratios by *additional* adjustment factors to make the final energy-saving estimates closer to the BERC or HEEU scenario estimates for the residential, commercial and industrial sectors and closer to our own sense of what is reasonable for the transportation sector.

Table S1. Energy Use by Sector and Source for various energy-use scenarios, United States, year 2040

	% change versus EIA Reference						Ref. (quad. BTU)
Sector and Source	*2013Tech*	*HEEU*	*HEAS*	*BERC*	*JD11*	*This paper*	
Residential							
Petroleum, Other Liquids	8.5%	-16.5%	-9.2%	-16.6%	-10%	-12.9%	0.66
Natural Gas	7.9%	-28.2%	-10.8%	-28.3%	-15%	-17.0%	4.21
Renewable Energy	20.5%	-21.7%	-13.2%	-21.6%	-10%	-14.5%	0.42
Electricity	8.8%	-22.2%	-12.9%	-22.8%	-10%	-17.2%	5.65
Delivered Energy	**8.9%**	**-24.1%**	**-11.9%**	**-24.5%**			**10.94**
Electricity Related Losses	8.3%	-19.2%	-10.4%	-20.2%			10.55
Total	8.6%	-21.7%	-11.2%	-22.4%			21.48
Commercial							
Petroleum, Other Liquids	0.2%	-4.4%	-4.0%	-4.5%	-5%	-4.0%	0.68
Natural Gas	-3.1%	-0.8%	1.3%	-0.5%	-10%	-0.7%	3.65
Coal	-0.1%	0.3%	0.2%	0.2%	-5%	0.2%	0.04
Renewable Energy	0.0%	0.0%	0.0%	0.0%	-5%	0.0%	0.13
Electricity	9.7%	-21.2%	-17.5%	-21.7%	0%	-19.2%	5.72
Delivered Energy	**4.3%**	**-12.4%**	**-9.6%**	**-12.6%**			**10.22**
Electricity Related Losses	9.2%	-18.2%	-15.2%	-19.1%			10.66
Total	6.8%	-15.4%	-12.5%	-15.9%			20.88
Industrial							
Petroleum, Other Liquids	6.3%	0.1%	-2.1%	0.0%	-5%	-2.1%	10.10
Natural Gas and related	10.6%	-0.4%	-0.3%	-0.1%	-5%	-1.3%	11.28
Coal	12.6%	5.5%	-4.0%	4.9%	-5%	-3.9%	1.44
Biofuels Heat Coproducts	-0.2%	0.0%	-0.1%	-0.1%	-5%	-3.9%	0.79
Renewable Energy		1.0%	11.0%	1.0%	-5%	11.0%	2.28

Electricity	10.0%	-16.6%	-2.5%	3.8%	0%	-7.3%	4.34
Delivered Energy	**7.6%**	**-2.1%**	**-0.5%**	**0.8%**			**30.22**
Electricity Related Losses	9.5%	-13.4%	0.3%	7.2%			8.10
Total	8.0%	-4.5%	-0.4%	2.2%			38.33
Transportation							
Petroleum, Other Liquids	-0.3%	0.9%	-0.5%	0.8%	-15%	-5.5%	23.73
Natural gas and hydrogen	-1.7%	0.0%	-23.2%	1.1%	-15%	-23.3%	1.71
Electricity	-0.1%	0.5%	8.4%	0.4%	-5%	7.9%	0.06
Delivered Energy	**-0.4%**	**0.8%**	**-2.0%**	**0.8%**			**25.50**
Electricity Related Losses	-0.6%	4.3%	11.5%	3.7%			0.12
Total	-0.4%	0.8%	-2.0%	0.8%			25.62
All sectors							
Petroleum, Other Liquids	1.8%	0.2%	-1.2%	0.1%			35.17
Natural gas and related	6.6%	-6.0%	-4.0%	-5.8%			20.85
Coal	12.2%	5.3%	-3.9%	4.8%			1.48
Renewable energy	-1.7%	-1.9%	5.4%	-1.9%			3.62
Electricity	9.4%	-20.2%	-11.6%	-15.0%			15.77
Delivered Energy	**4.7%**	**-5.7%**	**-3.8%**	**-4.6%**			**76.88**
Electricity Related Losses	8.9%	-17.1%	-9.1%	-12.2%			29.43
Total	5.9%	-8.8%	-5.3%	-6.7%			106.31
Electric Power generation							
Petroleum, Other Liquids	7.2%	-17.8%	-8.6%	-12.9%			0.19
Natural Gas	7.9%	-25.1%	-20.9%	-19.5%			11.48
Steam Coal	2.8%	-21.2%	-5.3%	-12.9%			17.27
Nuclear / Uranium	9.7%	-4.0%	-2.8%	-4.0%			8.49
Renewable Energy	25.1%	-17.5%	-12.4%	-14.9%			7.44
Non-biogenic Waste	0.0%	0.0%	0.0%	0.0%			0.23
Electricity Imports	21.8%	-20.9%	-12.6%	-16.6%			0.12
Total	9.1%	-18.2%	-10.0%	-13.1%			**45.20**

Source: our tabulation of results from the EIA's *Annual Energy Outlook 2014 online data tables:* *http://www.eia.gov/oiaf/aeo/tablebrowser/*. 2013Tech = 2013 Technology; HEEU = High Efficiency Electricity Use; HEAS = High Efficiency All Sectors; BERC = Best Efficiency Residential Commercial; JD11 = Jacobson and Delucchi (2011).; Quad. BTU = quadrillion British Thermal Units. Note that JD11 changes are with respect to the EIA AEO 2008 projections for the year 2030. All changes reflect fuel shifting as well as efficiency improvements.

Table S1 shows the EIA's projections of energy use in the U.S. in 2040 by source and sector, for the 2013Tech, HEEU, HEAS, and BERC scenarios versus the EIA Reference case. It also shows Jacobson and Delucchi's (2011) (JD11) assumed energy-use savings for the U.S. in 2030 and the results of our current calculations (described above) for the year 2040. Note that the EIA scenarios in Table S1 reflect the results of fuel shifting as well as the results of efficiency improvements.

As shown in Table S1, the two highest efficiency scenarios, HEEU and BERC, reduce electricity use in the residential and commercial sectors by more than 20%, and reduce NG use in the residential sector by almost 30%, with respect to the Reference case. Overall, the HEEU and BERC scenarios reduce total delivered energy by over 24% in the residential sector and by about 12.5% in the commercial sector. The HEAS scenario, which generally is less aggressive but also presumably more realistic, reduces total delivered energy by 12% in the residential sector and almost 10% in the commercial sector. The assumptions of JD11 are broadly consistent with the results of the HEAS scenario, except that JD11 assumed no reductions in electricity use in the commercial sector.

As mentioned above, we start with the HEAS scenario and make additional adjustments. Overall this results in residential-sector and commercial-sector efficiency improvements greater than in the HEAS scenario but less than in the BERC and HEEU scenarios ("This paper" column of Table S1.)

None of the three EIA high-efficiency scenarios result in significant reductions in delivered energy in the industrial or transportation sectors. The HEEU does result in nearly a 17% reduction in industrial electricity use, but electricity use is a minor fraction of total industrial energy use, and in any event, as indicated above, the EIA implies that the HEEU assumptions for the industrial sector probably are not realistic. In general, it appears that the EIA believes that there is relatively little room to reduce energy use in the industrial sector. JD11 assumed somewhat higher but still modest reductions in energy use in the industrial sector. Our current results are less aggressive than in JD11, and generally follow the EIA's HEAS scenario, except that we do assume modest additional improvements in electricity-use efficiency in the industrial sector.

Only one of the scenarios, HEAS, examines efficiency improvements in the transportation sector. These improvements turn out to be quite modest, resulting in only a 2% reduction in energy use over the Reference case. By contrast, JD11 assumed much greater potential to reduce energy use in transportation. We believe that JD11 overestimated but the EIA underestimated the potential for reductions in energy use in the transportation sector.

Because energy use in the residential and commercial sectors is much less than in the industrial and transportation sectors, and the EIA assumptions result in very little efficiency improvement in the industrial and transportation sectors, the EIA's three high-efficiency scenarios reduce total, all-sectors delivered energy in the U.S. in 2040 by only 4-6% compared with the reference case. Our assumptions, which assume modest efficiency improvements beyond the EIA's HEAS scenario, especially in the transportation sector, result in a 6.7% reduction in overall energy use in 2040.

2) THE DIFFERENCE IN THE COST OF ELECTRICITY USE IN THE 100% WWS SCENARIO VERSUS THE BAU SCENARIO

Method of analysis

The total cost of all energy use in a 100% WWS scenario is different from the total cost in a predominantly fossil-fueled BAU scenario, on account of differences in the types of energy and energy-using equipment. For example, referring to the EIA's fuel end-use categories listed above – liquids, natural gas, coal, renewables, and electricity – in the BAU scenario oil and natural gas are used by combustion devices, such as space heaters or gasoline-engine vehicles, whereas in the WWS scenario these same end uses are powered by electric heat pumps, battery-electric vehicles, and so on. To estimate the BAU-vs.-WWS difference in the cost of energy in the oil, natural gas, and coal end-use categories, one must estimate differences in the in the per-unit cost of delivered energy, the efficiency of energy end-use, and the cost of energy-using equipment in both the BAU and WWS cases. While we do this for the WWS case and for the BAU electricity end-use category, we consider this effort – for the oil, natural gas, and coal end-use categories in non-electricity end-use categories – outside the scope of this paper.

By contrast, it is simpler to estimate the WWS-vs.- BAU cost differences in the electricity end-use category, because the type of energy (electricity) and the end-use equipment are the same in the BAU and the WWS scenarios.

The WWS-vs.-BAU difference in the cost of electricity use is equal to the difference between total electricity end-use expenditures in the BAU scenario and total expenditures for the same end uses in the WWS scenario. Total expenditures are a function of the unit cost of electricity, the quantity of electricity used in the BAU and the WWS scenarios, and the cost of any efficiency improvements that reduce electricity consumption in the WWS compared with the BAU scenario. Formally,

$$\Delta TC_{el,S,Y,BAU-WWS} = TC_{el,S,Y,BAU} - TC_{el,S,Y,WWS}$$

$$TC_{el,S,Y,BAU} = E_{el,S,Y,BAU} \cdot AC_{el,S,Y,BAU}$$

$$TC_{el,S,Y,WWS} = E_{el,S,Y,WWS} \cdot AC_{el,S,Y,WWS} + \Delta E_{el,eff,S,Y,BAU-WWS} \cdot AC_{el,eff(an),S,Y}$$

$$\Delta E_{el,eff,S,Y,BAU-WWS} = E_{el,S,Y,BAU} - E_{el,S,Y,WWS}$$

where

$\Delta TC_{el,S,Y,BAU-WWS}$ = difference in the total cost of electricity use in the *BAU* vs. the *WWS* scenario in state *S* in year *Y* ($)

$TC_{el,S,Y,W}$ = the cost of electricity use in state *S* in year *Y* in scenario *W* ($)

$E_{el,S,Y,W}$ = the use of electricity in state *S* in year *Y* in scenario *W* (kWh) (discussed above)
$AC_{el,S,Y,W}$ = the average cost of electricity in state *S* in year *Y* in scenario *W* ($/kWh) (discussed below)
$\Delta E_{el,eff,S,Y,BAU-WWS}$ = the difference in electricity use in the *BAU* vs. the *WWS* scenario, due to efficiency improvements, in state *S* in year *Y* (kWh)
$AC_{el,eff(an),S,Y}$ = the average annualized cost of the efficiency improvements that provide the electricity savings *ΔE* in state *S* in year *Y* in the *WWS* scenario ($/kWh)

The average annualized cost of efficiency improvements is estimated by first estimating the initial cost of an efficiency improvement, as a function of the payback period of the initial investment with respect to the U.S.-average *BAU* electricity cost, and then annualizing this cost over the life of the improvement. The payback period and the lifetime depend on the end-use sector (residential, commercial, industrial, or transportation). Formally,

$$AC_{el,eff(an),S,Y} = \sum_X C_{el,eff(an),X,S,Y,WWS} \cdot \frac{\Delta E_{el,eff,X,S,Y,BAU-WWS}}{\Delta E_{el,eff,S,Y,BAU-WWS}}$$

$$C_{el,eff(an),X,S,Y,WWS} = \frac{r \cdot IC_{el,eff,X}}{1-e^{-r \cdot L_{el,eff,X}}}$$

$$IC_{el,eff,X} = AC_{el,US,Y,BAU} \cdot PB_{el,eff,X}$$

$$PB_{el,eff,X} \equiv fr_{PB,X} \cdot L_{el,eff,X}$$

where

$C_{el,eff(an),X,S,Y,WWS}$ = the annualized cost of electricity-use efficiency improvements in sector *X* in state *S* in year *Y* in the *WWS* scenario ($/kWh)
$\Delta E_{el,eff,X,S,Y,BAU-WWS}$ = the difference in electricity use in the *BAU* vs. the *WWS* scenario, due to efficiency improvements, in sector *X* in state *S* in year *Y* (kWh) (calculated using the data described above)
$IC_{el,eff,X}$ = the initial cost of electricity-use efficiency improvements in sector *X* ($) (constant for all years and states)
$L_{el,eff,X}$ = the lifetime of electricity-use efficiency improvements in sector *X* ($) (constant for all years and states) (discussed below)
r = the annual discount rate (discussed below)
$AC_{el,US,Y,BAU}$ = the average cost of delivered electricity in the US in year *Y* in the *BAU* scenario ($/kWh) (calculated as documented below)

$PB_{el,eff,X}$ = the simple (zero-discount-rate) payback period for electricity-use efficiency improvements in sector X (constant for all years and states) (years) (discussed below)

$fr_{PB,X}$ = the simple payback period expressed as a fraction of the lifetime $L_{el,eff,X}$

Combining the foregoing equations and re-arranging into the most useful forms gives

$$\Delta TC_{el,S,Y,BAU-WWS} = E_{el,S,Y,BAU} \cdot AC_{el,S,Y,BAU} - E_{el,S,Y,WWS} \cdot AC_{el,S,Y,WWS}$$

$$-\Delta E_{el,eff,S,Y,BAU-WWS} \cdot \sum_X C_{el,eff(am),X,S,Y,WWS} \cdot \frac{\Delta E_{el,eff,X,S,Y,BAU-WWS}}{\Delta E_{el,eff,S,Y,BAU-WWS}}$$

$$= E_{el,S,Y,BAU} \cdot AC_{el,S,Y,BAU} - E_{el,S,Y,WWS} \cdot AC_{el,S,Y,WWS} - \sum_X C_{el,eff(am),X,S,Y,WWS} \cdot \Delta E_{el,eff,X,S,Y,BAU-WWS}$$

$$= E_{el,S,Y,BAU} \cdot AC_{el,S,Y,BAU} - E_{el,S,Y,WWS} \cdot AC_{el,S,Y,WWS} - \sum_X \frac{r \cdot IC_{el,eff,X}}{1-e^{-r \cdot L_{el,eff,X}}} \cdot \Delta E_{el,eff,X,S,Y,BAU-WWS}$$

Data

$$= E_{el,S,Y,BAU} \cdot AC_{el,S,Y,BAU} - E_{el,S,Y,WWS} \cdot AC_{el,S,Y,WWS} - AC_{el,US,Y,BAU} \cdot \sum_X \frac{r \cdot \left(fr_{PB,X} \cdot L_{el,eff,X} \right)}{1-e^{-r \cdot L_{el,eff,X}}} \cdot \Delta E_{el,eff,X,S,Y,BAU-WWS}$$

Here we need to specify two parameters, the lifetime $L_{el,eff,X}$ and the simple payback period as fraction $fr_{PB,X}$ of the lifetime. On the basis of our review of a detailed analysis of energy efficiency measures for the residential, commercial, and industrial sectors of the U.S. economy (Granade et al., 2009), we assume the values shown in Table S2.

Note again that we have estimated here differences in energy expenditures only in the EIA's electricity end-use category, and have not estimated differences in all energy-related expenditures in the WWS vs. the BAU scenario.

Table S2. Assumed payback-time fractions (payback period as fraction of lifetime) and lifetimes (years) of efficiency measures, in the retail electricity sector

	Payback time fraction (a)		Lifetime (years) (b)	
Energy-use sector	*Low*	*High*	*Low*	*High*
Residential electricity	0.10	0.30	20.0	14.0
Commercial electricity	0.10	0.25	18.0	12.0
Industrial electricity	0.15	0.25	25.0	18.0
Transportation electricity	0.20	0.40	25.0	20.0

Notes.

Our assumptions based on Granade et al. (2009), who analyze a comprehensive range of efficiency measures, including improvements to building shells, heating and cooling systems, refrigeration, lighting, small and large appliances, office equipment, motors, pumps, compressors, industrial processes, and more.

"Low" and "high" mean low and high annualized initial costs.

(a) Time for energy savings to pay back initial investment, based on the US-average BAU electricity cost with no discounting, expressed as a fraction of the investment lifetime.

(b) Lifetime of energy efficiency improvements (until failure).

3) THE TOTAL DAMAGE COST OF AIR POLLUTION FROM CONVENTIONAL FUELS

The total damage cost of air pollution from fossil-fuel and biofuel combustion and evaporative emissions comprises mortality costs, morbidity costs, and non-health costs such as lost visibility and agricultural output. We estimate this total damage cost of air pollution in each state *S* in a target year *Y* as the product of an estimate of the number of premature deaths due to air pollution, which is determined from pollution exposure levels, relative risks, and population, and the total cost of air pollution per death as follows:

$$APcost_{S,Y} = N_{D,S,Y} \cdot V_{P/D,Y}$$

where

$APcost_{S,Y}$ = the damage cost of air pollution in state *S* year *Y*

$N_{D,S,Y}$ = the number of deaths D due to air pollution in state *S* in year *Y*

$V_{P/D,Y}$ = the total cost of pollution per death in year *Y* (includes mortality, morbidity, and non-health costs; assumed to be the same for all states)

The number of deaths due to air pollution

To estimate the number of premature deaths *D* due to air pollution in state *S* in year *Y*, we start with a detailed estimate of the average number of premature deaths per year in each state from 2010 to 2012. We then scale this to account for changes in population, exposure, and air pollution between ca. 2011 and the target year *Y* as follows:

$$N_{D,S,Y} = N_{D,S,2010-12} \cdot \frac{A_Y}{A_{2011}} \cdot \frac{E_{S,Y}}{E_{S,2010}}$$

$$\frac{A_Y}{A_{2011}} = \exp^{\Delta A \cdot (Y-2011)}$$

$$\frac{E_{S,Y}}{E_{S,2010}} = \exp^{g_S \cdot x_S \cdot (Y-2011)} = \left(\exp^{g_S \cdot (Y-2011)}\right)^{x_S} = \left(\frac{P_{S,Y}}{P_{S,2011}}\right)^{x_S}$$

where

$N_{D,S,Y}$ = the number of premature deaths D due to air pollution in state *S* in year *Y*

$N_{D,S,2010-12}$ = the number of premature deaths in state *S* over the period 2010-2012 (see discussion in the main text)

A_Y = the ambient pollution level, as determined from all air quality monitoring stations in each county of each state, in target year *Y*.

$E_{S,Y}$ = the exposed population in state *S* in target year *Y*.

ΔA = the annual rate of change in the damage-weighted ambient pollution levels, in the future (see discussion below in this section)

g_S = the rate of population growth in state *S* (see section "Projection of State Population and GDP")

x_S = the change in exposed population per change in population in state *S*

$P_{S,Y}$ = the population in state *S* in year *Y* (see section "Projection of State Population and GDP")

The number of premature deaths in each state for the period 2010-2012 is determined by considering data from all air quality monitoring stations in each county of each state. For each county in each state, mortality rates are averaged over the three-year period for each station to determine the station with the maximum average mortality rate in the county. Daily air-quality data from that station are then used with the 2012 county population and the relative risk in the health effects equation described in the footnote to Table 7 of the main text to determine the premature mortality in the county. County numbers are then summed over all counties in a state to obtain state numbers.

Annual rate of change in damage-weighted ambient pollution. We estimate the annual rate of change in damage-weighted ambient pollution levels in the future by first examining historical trends and then considering how the future might be different from the past. The EPA provides historical time series data for ambient levels of fine particulate matter (PM2.5), ozone (O3), sulfur dioxide (SO2), and carbon monoxide (CO) (http://www.epa.gov/airtrends/aqtrends.html). We use these data to estimate rates of change in the concentration of each pollutant over several past time periods. We then estimate the rate of change of a damage-weighted combination of the pollutants, where the weights are our judgment based on estimates of damages by pollutant in Delucchi (2000). The resulting rate-of-change values are

Period	*PM2.5*	*O3*	*SO2*	*CO*	*Damage weighted*
2012-2013	-2.0%	-11.0%	-17.3%	-5.1%	-3.1%
2009-2013	-2.1%	-0.8%	-12.2%	-3.6%	-2.5%
2004-2013	-3.2%	-1.2%	-9.8%	-5.8%	-3.4%
2000-2013	-3.1%	-1.5%	-7.5%	-6.5%	-3.2%
Damage weights	90%	5%	4%	1%	

Next we consider that for several reasons, in the future the *rate* of decline in damage-weighted ambient pollution is likely to be less, and perhaps much less, than the historic rates shown above. First, while emission levels will decline as stock turnover results in new, low-emission equipment (e.g., vehicles, power plants) replacing old, high-emission equipment, activity levels (e.g., driving, electricity use) will also increase, and the net effect of these opposing factors on emissions is unclear. Second, although government will continue to implement new emission-control regulations, the marginal costs of abating pollution tend to increase while the marginal emission reductions tend to decrease, which means that future policies will likely result in lower emission reductions than have past policies. Third, a warming climate in a non-WWS world will exacerbate the levels and impacts of air pollution (Madaniyazi et al., 2015).

With these considerations, we assume that in the future the effective damage-weighted ambient pollution levels decline at annual rates lower than the historical rate of approximately -3%/year estimated above. Specifically, we assume declines of -1.0%, -1.5%, and -2.0% in the LCHB, medium, and HCLB cases, respectively. (A lower rate leads to higher benefits of pollution reduction in the 100% WWS scenario.) We assume that the same rates apply in all states.

<u>Change in exposed population</u>. As discussed in the "Projection of state population and GDP" section below, we use U.S. Census projections of state population and other assumptions to estimate $\frac{P_{S,Y}}{P_{S,2011}}$. In order to calculate the rate of change of exposure with population change (x_S), we assume that the exposed population is predominantly in urban areas, and use Census data to calculate the ratio of the change in urban population to the change in total population. Presently we do not have data to distinguish this ratio for each state, so for now we use a single set of low-medium-high values for all states. According to the U.S. Census Bureau (2012), from 2000 to 2010 the population of the U. S. changed by 9.7%, and the population of Metropolitan Statistical Areas changed by 10.8%, a ratio of 1.11. Given this, we assume values for x_S of 1.14, 1.11, and 1.08 in the LCHB, medium, and HCLB cases. (A high value of exposed population leads to higher benefits of pollution reduction in the 100% WWS scenario.)

The total cost of pollution per premature death

We estimate the total pollution cost per premature death as the product of (i) the mortality value per premature death *per se* and (ii) two adjustment factors, one that accounts for non-mortality (i.e., morbidity) health impacts and a second that accounts for health impacts. The calculation is as follows:

$$V_{P/D,Y} = V_{D,Y} \cdot F_1 \cdot F_2$$

where

$V_{D,Y}$ = the value per death *per se* (known as the value of a statistical life, VOSL) year *Y*
F_1 = adjustment factor that accounts for morbidity effects of air pollution, relative to the mortality effect
F_2 = adjustment factor that accounts for the non-health effects of air pollution, relative to the mortality effect

The VOSL is calculated by scaling an estimate for a base year to a value for the target year *Y*, accounting for the effects on the VOSL of increases in real per-capita income over time with

$$V_{D,Y} = V_{D,Y*} \cdot \exp^{(r \cdot e) \cdot (Y - Y*)}$$

where

$V_{D,Y*}$ = the VOSL in base year *Y**
r = the annual rate of change in income per capita
e = the income elasticity of the VOSL

<u>VOSL in base year</u>. Viscusi and Aldy (2003) and The National Center for Environmental Economics (NCEE) (2014) provide comprehensive reviews of estimates of the VOSL. Viscusi and Aldy's (2003) meta-analysis of US studies indicates a mean VOSL of $6.1 million, with a 95% confidence interval of $4.6 to $8.2 million, in year-2000 dollars, for the robust regression with an income elasticity of 0.48. The NCEE (2014) gives a mean estimate of $7.4 million with a standard deviation of $4.7 million, in year-2006 dollars (mean of $6.4 million in year-2000 dollars, for comparison with Viscusi and Aldy). We start with values of $9, $7, and $5 million (LCHB, medium, and HCLB cases) in year-2006 dollars, and at year-2006 levels of wealth, and then update to year-2013 dollars using GDP implicit price deflators.

<u>Income growth and the income elasticity of VOSL.</u> At this point we have the VOSL in year-2013 dollars and, by assumption, at year-2006 levels of wealth or income. To estimate the VOSL in future years, we need projections of changes in income and a relationship between changes in income and changes in the VOSL. Projections of changes in income are discussed in the section "State GDP". The income elasticity of the VOSL typically is assumed to be 0.4 to 0.6 (Hammitt and Robinson, 2011), and the NCEE (2014) recommends values of 0.08, 0.40, and 1.0.

Given this, our assumptions are

	LCHB	*Medium*	*HCLB*
Input VOSL (million year-2006 dollars)	5.00	7.00	9.00
Annual change in real GDP per capita		See "State GDP"	
Income elasticity of VOSL	0.75	0.50	0.50

A higher VOSL results in higher benefits for the 100% WWS scenario.

Adjustment factors for morbidity and non-health impacts. Rather than perform detailed, original estimates of morbidity and non-health costs, we take a simpler approach and use other studies to scale up our VOSL to account for morbidity and non-health costs. Our method for this scaling is as follows.

First we define total air-pollution costs as the sum of premature mortality, morbidity, and non-health costs, where each is the product of a quantity and a value per unit quantity (here omitting the subscripts for states S and year Y):

$$APcost = N_D \cdot V_D + N_M \cdot V_M + N_O \cdot V_O$$

where

APcost = the total damage cost of air pollution
N_j = the quantity of impact j
V_j = the value per unit of j
j = premature mortality (D), morbidity (M), and other non-health impacts (O)

Next we expand the APcost term into a form that will allow us to scale-up our detailed estimates of deaths from air pollution. Specifically, we want to develop scaling factors related to mortality costs V_D.

$$APcost = N_D \cdot V_D \cdot \left(\frac{N_D \cdot V_D + N_M \cdot V_M}{N_D \cdot V_D} \right) \cdot \left(\frac{N_D \cdot V_D + N_M \cdot V_M + N_O \cdot V_O}{N_D \cdot V_D + N_M \cdot V_M} \right)$$

$$= N_D \cdot V_D \cdot \left(\frac{N_D \cdot V_D}{N_D \cdot V_D} + \frac{N_M \cdot V_M}{N_D \cdot V_D} \right) \cdot \left(\frac{N_D \cdot V_D + N_M \cdot V_M}{N_D \cdot V_D + N_M \cdot V_M} + \frac{N_O \cdot V_O}{N_D \cdot V_D + N_M \cdot V_M} \right)$$

$$= N_D \cdot V_D \cdot \left(1 + \frac{N_M \cdot V_M}{N_D \cdot V_D}\right) \cdot \left(1 + \frac{N_O \cdot V_O}{N_D \cdot V_D + N_M \cdot V_M}\right)$$

$$= N_D \cdot V_D \cdot \left(1 + \frac{N_M \cdot V_M}{N_D \cdot V_D}\right) \cdot \left(1 + \frac{\frac{N_O \cdot V_O}{N_D \cdot V_D}}{1 + \frac{N_M \cdot V_M}{N_D \cdot V_D}}\right)$$

For simplicity, we designate

$$B_1 \equiv \frac{N_M \cdot V_M}{N_D \cdot V_D} \quad \text{and} \quad B_2 \equiv \frac{N_O \cdot V_O}{N_D \cdot V_D}$$

giving $APcost = N_D \cdot V_D \cdot (1 + B_1) \cdot \left(1 + \frac{B_2}{1 + B_1}\right)$

At this point we can create our adjustment factors, $F_1 \equiv 1 + B_1$ and $F_2 \equiv 1 + \frac{B_2}{F_1}$. Now we have

$$APcost = N_D \cdot (V_D \cdot F_1 \cdot F_2)$$

The next task is to find the adjustment factors F_1 and F_2 by referring to other studies of morbidity and non-health costs. Designating these other studies with an asterisk, we have

$$B_1 = B_1^* \cdot \frac{B_1}{B_1^*} = B_1^* \cdot \frac{\frac{N_M \cdot V_M}{N_D \cdot V_D}}{\frac{N_M^* \cdot V_M^*}{N_D^* \cdot V_D^*}} = B_1^* \cdot \left(\frac{\frac{N_M}{N_M^*}}{\frac{N_D}{N_D^*}}\right) \cdot \left(\frac{\frac{V_M}{V_M^*}}{\frac{V_D}{V_D^*}}\right)$$

Given that the impact functions that generate the values of N in B_1 are the same as the functions in B_1^*, and knowing that generally health effects N are linear functions of population and air pollution, then to a first approximation the ratio of premature deaths to morbidity impacts is constant; i.e., $\frac{N_M}{N_M^*} \approx \frac{N_D}{N_D^*}$. However, this relationship does not hold in the case of valuation, so instead we establish a more generation relationship,

$$\frac{V_M}{V_M^*} = \left(\frac{V_D}{V_D^*}\right)^K.$$

Defining $\frac{V_D}{V_D^*} \equiv V_D^\wedge$ (where the values are expressed in the same year dollars), we now have

$$B_1 = B_1^* \cdot \left(\frac{\frac{V_M}{V_M^*}}{V_D^\wedge} \right) = B_1^* \cdot \frac{\left(V_D^\wedge\right)^K}{V_D^\wedge} = B_1^* \cdot \left(V_D^\wedge\right)^{K-1}$$

With similar reasoning and algebra for B_2 we have $\frac{V_O}{V_O^*} = \left(V_D^\wedge\right)^L$ and $B_2 = B_2^* \cdot \left(V_D^\wedge\right)^{L-1}$. The final adjustment factors thus are

$$F_1 = 1 + B_1^* \cdot \left(V_D^\wedge\right)^{K-1} \quad \text{and} \quad F_2 = 1 + \frac{B_2^* \cdot \left(V_D^\wedge\right)^{L-1}}{F_1}$$

Morbidity and non-health impacts in other studies. Using results in McCubbin and Delucchi (1999), we calculate LCHB and HCLB values for B_1^* (the reference ratio of morbidity to mortality costs) and V_D^* (the reference value of a statistical life). Using results in Delucchi (2000), we calculate LCHB and HCLB values for B_2^* (the reference ratio of non-health to health costs). (The EPA [2011] estimates much lower values for B_1^* and B_2^*, but the analyses summarized in Delucchi and McCubbin (2011) are much more comprehensive.) McCubbin and Delucchi (1999) and Delucchi (2000) do not report middle or mid-point estimates, so we calculate a "medium" case here based on the geometric mean of the LCHB and HCLB estimates. (This gives more reasonable results than does using the arithmetic average.)

The calculation of the morbidity multiplier (B_1^*) is as follows:

All anthropogenic pollution, 1990 (McCubbin and Delucchi, 1999)	*LCHB*	*Medium (geo. mean)*	*HCLB*
Number of premature deaths (thousands)	138.5	105.59	80.5
Mortality costs (billion 1991 $)	475.5	138.9	40.6
Other health costs	196.8	52.7	14.1
Value of life (V_D^*) (million 1991 $)	3.43	1.32	0.50
Ratio of morbidity to mortality costs (B_1^*)	0.41	0.38	0.35

The calculation of the non-health damage multiplier (B_2^*) is as follows:

Motor-vehicle air-pollution costs, excluding upstream emissions and road dust, 1990-91 (Delucchi, 2000)	*LCHB*	*Medium (geo. mean)*	*HCLB*
Health costs (billion 1991 $)	283.5	73.4	19.0
Non-health costs (billion 1991 $)	43.1	18.7	8.1
Ratio of non-health to health costs (B_2^*)	0.15	0.25	0.43

Exponents *K* and *L*. The exponents *K* and *L* relate changes in morbidity valuation or non-health-impact valuation to changes in the VOSL. If the exponent is 0.0, then changes in the VOSL do not affect the other values; if the exponent is 1.0, then changes in the VSL affect the other valuations proportionately. We believe that intermediate values are more reasonable, and use 0.7, 0.5, and 0.3 in our LCHB, medium, and HCLB cases. (High values of the exponent result in high benefits of air pollution reduction in the 100% WWS scenario.)

Results

The main text shows the calculated values of $N_{D,S,Y}$, the number of deaths due to air pollution in state *S* in year *Y*, adjusting for changes in exposure and ambient air quality to year *Y*. These are multiplied by the calculated values of $V_{P/D,Y}$, the total cost of pollution per death in year *Y* (230, 13.1, 7.3 million $; LCHB, medium, and HCLB), to produce $APcost_{S,Y}$, the damage cost of air pollution in state *S* year *Y*.

4) THE COST OF CLIMATE CHANGE FROM FOSSIL-FUEL USE: DAMAGES ATTRIBUTABLE TO AND BORNE BY EACH STATE

Overview

We estimate two kinds of climate-change costs of fossil-fuel use:

1) The cost of climate-change impacts in the U.S. and in the world *attributable to* emissions of greenhouse gases (GHGs) from the use of fossil fuels in each of the 50 states, and

2) The cost of climate-change impacts in the U.S., due to fossil-fuel use in the U.S., *borne* by each state.

We estimate damages borne by each state because this represents the monetary value of the benefits of converting to WWS in each state and hence is an appropriate alternative metric to add to the other state-specific monetary benefits of converting to WWS (electricity-cost savings and reduced air-pollution damages). The portion of damages borne by each state is equal to total climate-change damages in the U.S. from total U.S. emissions multiplied by each state's share of total damages.

The cost of climate-change impacts attributable to each state's GHG emissions is the product of three factors, 1) estimated CO2 combustion emissions from energy use; 2) the ratio of total CO2-equivalent (CO2e) lifecycle GHG emissions to lifecycle CO2 combustion emissions; and 3) the damage cost per unit of CO2e emission. All three factors can vary over time.

The main work here is in calculating climate-change damage costs attributable to each state's GHG emissions. Formally,

$$CC_{A,GHG,S,Y} = E_{GHG,S,Y} \cdot D_{GHG,A,Y}$$

$$E_{GHG,S,Y} = E_{CO2,S,Y^*} \cdot \frac{E_{GHG,R:S\in R,Y^*}}{E_{CO2,R:S\in R,Y^*}} \cdot \exp^{w_{GHG,R:S\in R} \cdot (Y-Y^*)}$$

$$E_{CO2,R:S\in R,Y^*} = \sum_{S\in R} E_{CO2,S,Y^*}$$

$$w_{GHG,R:S\in R} = \frac{\ln\left(\frac{E_{GHG,R:S\in R,Ye}}{E_{GHG,R:S\in R,Ys}}\right)}{Ye - Ys}$$

$$E_{GHG,R:S\in R,Y^*} = \sum_{i} E_{i,CO2,R:S\in R,Y^*} \cdot \frac{E_{i,LC-CO2e,Y^*}}{E_{i,LC-CO2-EN,Y^*}}$$

$$D_{GHG,A,Y} = D\,\hat{}_{GHG,A,Y\hat{}} \cdot \exp^{d\cdot(Y-Y\hat{})} \cdot \frac{p_{GDP-IPD,Y'}}{p_{GDP-IPD,Y\#}}$$

where

$CC_{A,GHG,S,Y}$ = climate-change damages in area A (U.S. or world) attributable to energy-related, lifecycle, CO2-equivalent GHG emissions from state S in year Y ($)

$E_{GHG,S,Y}$ = emissions of GHGs from state S in year Y (metric-tons)

$D_{GHG,A,Y}$ = the present worth of climate change damages in area A in year Y per unit of GHG emission in year Y ($/metric-ton)

E_{CO2,S,Y^*} = emissions of CO2 from energy use (fuel combustion) in state S in base year Y^* (metric tons) (EIA estimates for 2011; http://www.eia.gov/environment/emissions/state/state_emissions.cfm)

$E_{GHG,R:S\in R,Y^*}$ = lifecycle CO2e GHG emissions from U.S. region R (containing state S) in base year Y^* (metric-tons)
$E_{CO2,R:S\in R,Y^*}$ = emissions of CO2 from energy use (fuel combustion) in region R in base year Y^* (metric-tons)
$w_{GHG,R:S\in R}$ = the rate of growth over time of GHG emissions in region R (see discussion below)
Y = technology or impact target year of the analysis (2050 here, but can be any year from 2015 to about 2075)
Y^* = the base year of EIA CO2 emissions data (2011)
Ys and Ye = the start year and the end year of the time range over which the rate of growth in emissions is calculated (2011 and 2040)
$E_{i,CO2,R:S\in R,Y^*}$ = emissions of CO2 from combustion of fuel i in region R in base year Y^* (metric-tons) (EIA, 2014c)
$\frac{E_{i,LC-CO2e,Y^*}}{E_{i,LC-CO2-EN,Y^*}}$ = the ratio of lifecycle, CO2-equivalent GHG emissions from fuel i to lifecycle combustion emissions of CO2 from fuel i, in base year Y^* (see discussion below)
$D\wedge_{GHG,A,Y\wedge}$ = reference climate-change damages in area A in year $Y\wedge$ per unit of GHG emission in year $Y\wedge$ ($/metric-ton) (see discussion below)
d = the rate of growth over time of damages per unit of GHG emissions (see discussion below)
Y^ = the reference year of estimates of damages per unit of CO2e emission (see discussion below)
Y′ = designated price year (2013 here, but can be any date for which the GDP implicit price deflator is known)
$\frac{p_{GDP-IPD,Y'}}{p_{GDP-IPD,Y\#}}$ = the ratio of prices in our designated price year Y' to prices in the price-year $Y\#$ of the reference CO2 damage-cost analysis (calculated using GDP implicit price deflators)

For $E_{GHG,R:S\in R,Ye}$ and $E_{GHG,R:S\in R,Ys}$, substitute Ye or Ys for Y^* in the equation for $E_{GHG,R:S\in R,Y^*}$.

Subscripts:

A = relevant area for which damages are estimated (U.S. or world)
S = state in the U.S.
GHG = lifecycle CO2-equivalent emissions of all greenhouse gases
$CO2$ = carbon dioxide per se (as distinguished from other GHGs, or the CO2-equivalent of GHGs)
R = region of the U.S. in the EIA's estimates of energy-related CO2 emissions (New England, Middle Atlantic, East North Central, West North Central, South Atlantic, East South Central, West South Central, Mountain, and Pacific)
LC = lifecycle of a fuel from feedstock production through end use
i = fuels for which the EIA estimates CO2 emissions (oil, natural gas, coal, other) natural gas, other)

GDP-IPD = GDP implicit price deflator

Important reminder: when we say "climate change damages in year Y," we mean "the year-Y present worth of the future stream of damages from emissions in year Y."

Lifecycle CO2e emissions of all GHGs from all sources relative to lifecycle CO2 emissions from energy use

As mentioned above, the EIA projects CO2 emissions from the combustion of coal, oil, natural gas, and other fuels in 9 regions of the U.S. from 2011 to 2040. However, the use of fossil-fuels also produces a range of GHGs other than CO2 and also a small amount of CO2 from non-combustion processes. To fully account for the climate impact of all GHG emissions associated with fossil-fuel energy use, we use the Lifecycle Emissions Model (LEM) (Delucchi et al., 2003, unpublished updates; Delucchi, 2005) to estimate the ratio of lifecycle CO2e GHG emissions to lifecycle combustion-CO2 emissions for coal, oil, and natural gas. The LEM estimates emissions of greenhouse gases and urban air pollutants over the complete lifecycle of fuels, materials, vehicles, and infrastructure for the use of transportation fuels and electricity, as follows:

Lifecycle stages: electricity end use; electricity transmission and distribution; electricity generation; transportation of electricity-generation feedstocks (e.g., coal); and production of electricity generation feedstocks.

Sources of emissions: combustion of fuels; evaporation or leakage of energy feedstocks or finished fuels; venting, leaking or flaring of gas mixtures (e.g., venting of coal bed gas from coal mines); fugitive dust emissions; and chemical transformations that are not associated with burning process fuels (for example, the scrubbing of sulfur oxides from the flue gas of coal-fired power plants).

Pollutants/GHGs

carbon dioxide (CO_2)
carbon in (in NMOC, CO, CH4, soil)
nonmethane organic compounds (NMOCs) (weighted by O3 potential)
methane (CH4)
carbon monoxide (CO)
nitrous oxide (N2O)
nitrogen oxides (NO2)
sulfur oxides (SO2)
ammonia (NH3)
particulate-matter (PM) combustion, black carbon (BC)
PM combustion, organic matter (OM)
PM combustion, dust-like
PM all else
PM non-combustion, dust
hydrogen (H2)
sodium hexafluoride (SF6)
chlorofluorocarbons (CFC-12)
hydrofluorocarbons (HFC-134a)

The LEM estimates emissions of each pollutant individually, and also converts all of the pollutants into CO_2-equivalent greenhouse-gas emissions. To calculate total CO_2-

equivalent emissions, the model uses internally developed CO_2-equivalency factors (CEFs) that convert mass emissions of all of the non- CO_2 gases into the mass amount of CO_2 with the equivalent present worth of damages from climate change.

The LEM projects energy use, emissions, and other factors out to the year 2050.

For this project, we used the LEM to calculate two quantities for each year from 2011 to 2050: #1) total lifecycle CO2e emissions of GHGs from generic coal, oil, natural-gas, and other-fuel use; and #2) lifecycle combustion emissions of CO2 from generic coal, oil, natural-gas, and other-fuel use. For generic coal we use the lifecycle of coal for electricity generation; for generic oil we used the average of the lifecycle of oil for gasoline and oil for distillate fuel; for generic natural gas we use the lifecycle of natural gas for commercial heating; and for generic other-fuel (a trivial fraction of the total) we y4assume the values for natural gas. The ratio of quantity #1 to quantity #2 is the parameter $\frac{E_{i,LC-CO2e,Y}}{E_{i,LC-CO2-EN,Y}}$. The resultant LEM-calculated ratios for 5-year intervals from 2011 to 2050 are

	2011	2015	2020	2025	2030	2035	2040	2045	2050
Petroleum	1.21	1.11	1.11	1.11	1.11	1.09	1.09	1.09	1.09
Natural Gas	1.43	1.44	1.44	1.43	1.43	1.42	1.41	1.40	1.39
Coal	0.81	0.88	0.94	0.97	1.00	1.01	1.02	1.02	1.02
Other	1.43	1.44	1.44	1.43	1.43	1.42	1.41	1.40	1.39

The ratio for petroleum decreases as black-carbon emissions from vehicles and fuel-cycle methane emissions decrease over time. The ratio for coal is less than one until the year 2030 because of the negative forcing caused by sulfur oxide and nitrogen oxide emissions from coal power plants. As these emissions decline with improved emission controls over time, the negative forcing decreases and the ratio increases.

The damage cost per unit of CO2e GHG emission

Several studies, including some important recent meta-analyses, estimate the damage cost of CO2e GHG emissions, often referred to as the Social Cost of Carbon (SCC) (Table S3). Most studies recognize, even if only informally or qualitatively, that there is some non-trivial possibility of severe impacts of climate change and a correspondingly very high SCC. The main point of contention is the plausible lower bound on the SCC.

As shown in Table S3, the widely referenced FUND and DICE models estimate very small lower-bound estimates under some sets of assumptions regarding discount rates, risk aversion, equity weighting, extreme impacts, uncertainty, and other factors. However, in a recent review and meta-analysis, van den Bergh and Botzen's (2014) argue against the assumptions that lead to the lowest estimates of SCC, and make a persuasive case that the *lower* bound of the SCC should not be less than $125/tonne-CO2. They conclude that "the lower bound…of US 125 per tCO2 is far below various estimates found in the literature that attribute a high weight to potentially large climate change impacts…[and} therefore can be considered a realistic and conservative value" (p. 256). (See also Pindyck, 2013, and Stern, 2013). In support of this, Moore and Diaz (2015), in another recent re-analysis of the SCC, find that incorporating the effect of climate change on the rate of economic growth – a feedback typically not included in standard low-end estimates of the SCC – can dramatically increase the SCC to hundreds of dollars per ton and higher (Table S3).

The SCC of emissions in a given year is also likely to increase over time as GDP, atmospheric GHG levels, and average temperatures increase (Ackerman and Stanton, 2012; Moore and Diaz, 2015). The Ackerman and Stanton (2012) estimates shown in Table S3 increase from 2010 to 2050 at 2.0%/year in the low-SCC case, 1.6%/year in the mid-case, and 1.4%/year in the high-SCC case.

On the basis of the estimates of Table S3 and the discussion above, we assume the following:

	LCHB	*Medium*	*HCLB*
Global SCC in 2010 (2007-$)	600	250	125
Annual change in SCC	1.2%	1.5%	1.8%
U.S. share of global damages	10%	8%	5%

A high value of the SCC results in higher benefits for the 100% WWS scenario. However, if the SCC is at its high value in 2010, then a numerically high annual rate of change results in unreasonably high values in the future. Hence the high starting value of the SCC is paired with the low rate of change.

The incidence of climate-change impacts across U.S. states

Recently Houser et al. (2014) analyzed in detail the per-capita damage costs of climate change in every state in the U.S. They calculate the annual costs of coastal damages, increased energy expenditures, crop loss, reduced labor productivity, increased crime, and increased mortality, in the periods 2020-2039, 2040-2059, and 2080-2099, for three emissions scenarios: RCP 8.5 (relatively high emissions, CO2 at 940 ppm by 2100; "business as usual,"), RCP 4.5 (moderate emissions growth, CO2 at 550 ppm by 2100), and RCP 2.6 (aggressive emission reduction; CO2 below 450 ppm by 2100). (They also present another mid-range scenario, RCP 6.0, but do not provide estimates of coastal damages – one of the larger categories – for this scenario.) For each type of damage, period, and emissions scenario, they report the 5th, 17th, 50th, 83rd, and 95th percentiles of the range of damage estimates.

Table S3. Studies of the Social Cost of Carbon (SCC)

Authors	Moore and Diaz (2015)			Ackerman and Stanton (2012)			van den Bergh and Botzen (2014)			Johnson and Hope (2012)			Howarth et al. (2014)			Antoff et al. (2011)			Tol (2010)		
Model	gro-DICE			DICE			meta-analysis			DICE			IAM using DICE			FUND			FUND		
Emission year	2015-2100			2010, 2050			near term?			2010			2010			2010-2019			2010?		
Dollar year	2005			2007			2010?			2007			2005			1995			1995		
	Low	*Mid*	*High*	*Low*	*Mid*	*High*	*Low*	*Mid*	*High*	*Low*	*Mid*	*High*	*Low*	*Mid*	*High*	*Low*	*Mid*	*High*	*Low*	*Mid*	*High*
World SCC ($/tonne-CO2)	~200		1000+	~45, ~100	~230, ~430	~890, ~1520	125	--	--	-1	145	--	10	--	>500	0.5	10	~180	~0	1.3	11
Discount rate (DR)	n.r.	n.r.	n.r.	3%	1.5% or 3%	1.5%	avg.	--	--	5%	2.5%	--	n.r.	--	n.r.	n.r.	n.r.	n.r.	n.r.	n.r.	n.r.
Pure rate of time preference	3%	1.5%	0.1%	n.r.	n.r.	n.r.	n.r.	--	--	3.2%	1.1%	--	1.5%	--	1.5%	3%	1%	0.1%	3%	1%	0%
Equity weighting?	no	no	no	n.r.	n.r.	n.r.	no?	--	--	no	yes	--	no?	--	no?	no	no	ave.*	no	no	yes
Risk aversion rate	no?	no?	no?	n.r.	n.r.	n.r.	n.r.	--	--	no	no	--	2.0	--	5.6	no	no	no	1.5	1.5	15
Extreme climate impacts?	part.			no	part.	yes	part.	--	--	no	no	--	no (thin tail)	--	yes (fat tail)	no	no	no	no	no	no
U.S. % of world SCC	n.r.			n.r.			n.r.			n.r.			n.r.			33%	13%	< 10%	n.r.	8.5%	n.r.
Remarks	Authors did not estimate explicit low, mid, and high values, but rather estimated the importance of including feedbacks between climate change and the rate of economic growth.			SCC estimated as a function of the DR, climate sensitivity (CS), and form of damage function (DF). Our mid case includes all combos of DR, CS, and DF except low-low (our low) and high-high (our high).			SCC is equal to $41/tonne – the average reported in a meta-analysis – plus the average of separate "surcharges" for uncertainty, extreme damages, and risk aversion.			Authors did not analyze what would be a "high" cost case (a low rate of time preference with equity weights).			With high risk aversion rate, SCC decreases with increasing emission control rate (ECR): when ECR > 40%, SCC <10.			SCC is higher with U.S.-based equity weights than with global equity weights. (*= global equity weights)			High estimates are based on "illustrative" parameter values.		

IAM = Integrated Assessment Model; SCC = social cost of carbon; n.r. = not reported; part. = partially. "Extreme climate impacts?" includes extreme climate sensitivity to emissions, irreversible impacts, high-cost/low-probability impacts, and potentially large but difficult to quantify damage categories. Note that here "low" and "high refer to values of the SCC itself, and *not* to the LCHB and HCLB scenarios established here.

For each state we sum the Houser et al. (2014) per-capita damages for all six impacts and then multiply the resultant per-capita total damage by the state population (as used in the Houser et al., [2014] analysis) to produce an estimate of total $ damages in the state, for each emission scenario, period, and percentile. With these total $ damages by state we then calculate each state's share of the total 50-state damages.

Figure S1 shows each state's share of the 50th percentile damages, by period and emission scenario. Because coastal damage is one of the largest categories in the Houser et al. (2014) analysis, states with high coastal damages have relatively high shares of total damages. For our purpose of estimating the incidence of damages across states in the U.S., we use the calculated state shares of total damages for the RCP 8.5 scenario for the period 2040-2059, with the calculated 17th-percentile shares as our "low" case, the 50th-percentile shares as our "middle" case, and the 83rd-percentile shares as our "high" case (Table S4).

There are two minor caveats and one major caveat to our use of the Houser et al. (2014) results. The first minor caveat is that the distribution of damage costs for each state (the basis of the 5th, 17th, 50th, 83rd, and 95th percentile results) is calculated independently for each state, such that the set of conditions that produces, say, the 17th percentile result in state *A* is not necessarily the set that produces the 17th percentile results in state *B.* This means that, technically, adding up the *X*th percentile results for each state is inconsistent. However, it appears that this inconsistency is of minor consequence. In most cases, for the 17th, 50th, and 83rd percentiles, the sum of individual state damages at each percentile is not drastically different from the Houser-et al. (2014) reported total national damages at the same percentile.

The second minor caveat is that we estimate the distribution of damages across states based on the Houser et al. (2014) estimates for the period 2040-2059, whereas the unit damage-cost parameter (to which we apply the state-distribution shares) estimates the present worth of damages over a much longer period. However, we believe that if one were to estimate a present-worth weighted distribution of damages for, say, the period 2015 to 2100, it would not different dramatically from the 2040-2059 distribution from Houser et al. (2014).

The major caveat is that we multiply the Houser et al. (2014)-based state shares of total climate-change costs in the U.S. by *other* estimates of climate-change costs for the whole U.S., and it is likely that methods and assumptions used to estimate damages in these other studies are different from those in the Houser et al. (2014) study.

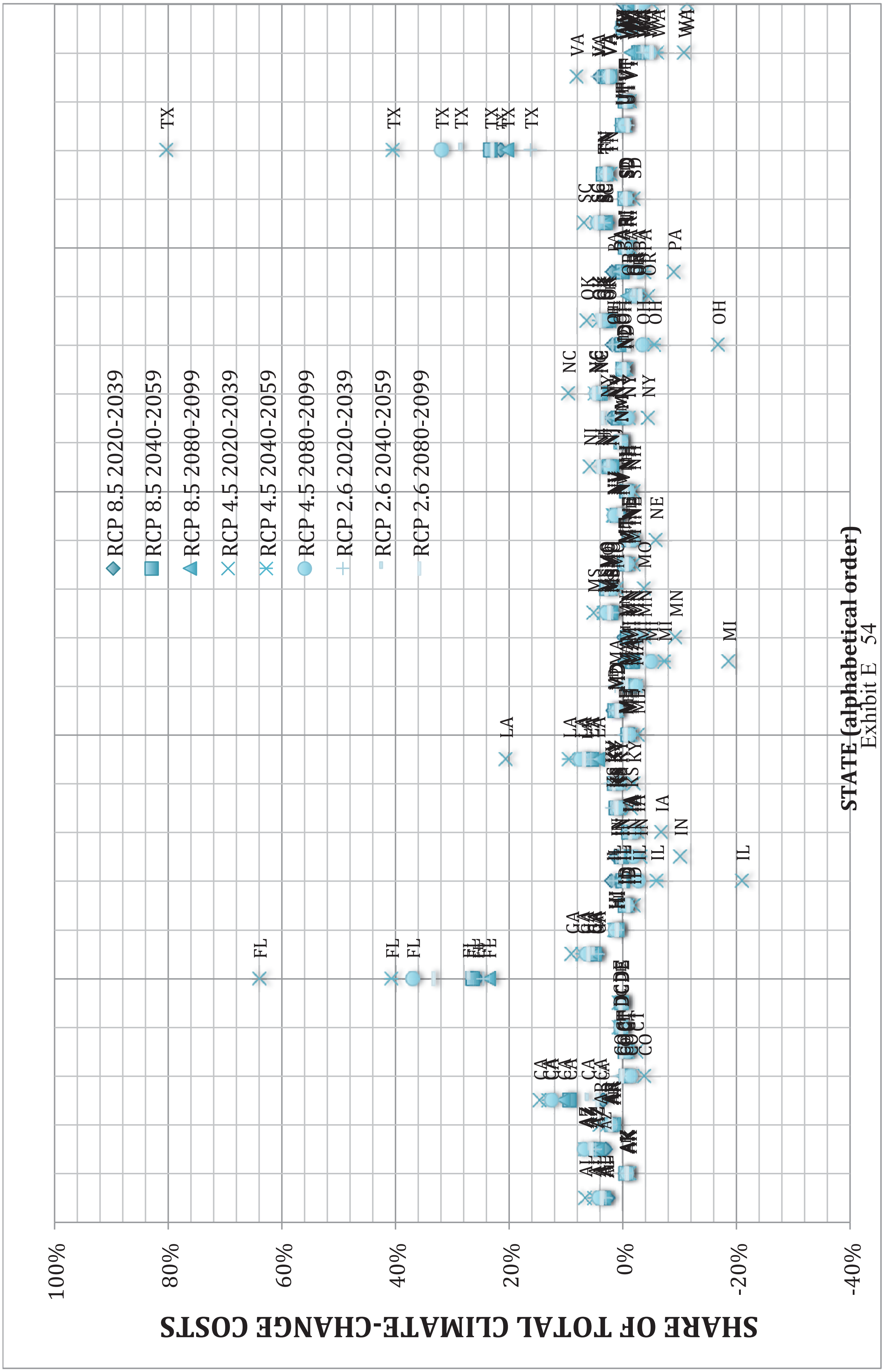

SHARE OF TOTAL CLIMATE-CHANGE COSTS
100%
80%
60%
40%
20%
0%
-20%
-40%
STATE (alphabetical order)
RCP 8.5 2020-2039
RCP 8.5 2040-2059
RCP 8.5 2080-2099
RCP 4.5 2020-2039
RCP 4.5 2040-2059
RCP 4.5 2080-2099
RCP 2.6 2020-2039
RCP 2.6 2040-2059
RCP 2.6 2080-2099
AL
AK
AZ
AR
CA
CO
CT
DC
DE
FL
GA
HI
ID
IL
IN
IA
KS
KY
LA
ME
MD
MA
MI
MN
MS
MO
MT
NE
NV
NH
NJ
NM
NY
NC
ND
OH
OK
OR
PA
RI
SC
SD
TN
TX
UT
VT
VA
WA

Exhibit E 54

Table S4. Climate-change benefits received by each state as a result of switching to WWS in the U.S., business-as-usual emissions scenario, 2040-2059 (% of total avoided damages in U.S.)

	Low damages	*Middle damages*	*High damages*		*Low damages*	*Middle damages*	*High damages*
AL	1%	1%	1%	MT	-1%	0%	0%
AK	0%	0%	0%	NE	-2%	0%	0%
AZ	1%	1%	2%	NV	0%	0%	0%
AR	0%	1%	1%	NH	-1%	0%	0%
CA	4%	7%	6%	NJ	13%	8%	6%
CO	-1%	0%	0%	NM	0%	0%	0%
CT	-1%	0%	0%	NY	13%	9%	7%
DC	0%	0%	0%	NC	2%	2%	2%
DE	1%	0%	0%	ND	0%	0%	0%
FL	60%	36%	28%	OH	-3%	0%	1%
GA	3%	3%	3%	OK	0%	1%	1%
HI	0%	0%	0%	OR	-2%	0%	0%
ID	-1%	0%	0%	PA	-3%	0%	1%
IL	-4%	0%	2%	RI	0%	0%	0%
IN	-2%	0%	1%	SC	0%	1%	2%
IA	-3%	0%	0%	SD	-1%	0%	0%
KS	0%	0%	1%	TN	0%	1%	1%
KY	0%	0%	1%	TX	15%	11%	11%
LA	18%	11%	9%	UT	-1%	0%	0%
ME	-1%	0%	0%	VT	0%	0%	0%
MD	0%	1%	1%	VA	7%	4%	4%
MA	3%	2%	2%	WA	-3%	-1%	0%
MI	-4%	0%	1%	WV	0%	0%	0%
MN	-3%	0%	0%	WI	-3%	0%	0%
MS	0%	1%	1%	WY	0%	0%	0%
MO	-1%	1%	1%	ALL	100%	100%	100%

Source: Our assumptions and calculations based on Houser et al. (2014). See the discussion in the text.

5) EARNINGS FROM NEW CONSTRUCTION AND OPERATION JOBS IN A 100% WWS WORLD

Calculation of earnings

Annual earnings from new construction and operation jobs are the product of the number of jobs and the annual earnings per job. The number of jobs is the product of a jobs/installed-MW factor, from the National Renewable Energy Laboratory (NREL) Jobs and Economic Development Impact (JEDI) models (Table S5), and the total installed MW assumed here.

Table S5. Jobs per MW of installed power for WWS technologies

Technology	Jobs/MW from JEDI model					
	Construction			Operation		
	CA	*WA*	*Average*	*CA*	*WA*	*Average*
Onshore wind	0.10	0.10	0.10	0.15	0.15	0.15
Offshore wind	0.18	0.16	0.17	0.66	0.60	0.63
Wave device	0.35	0.33	0.34	2.42	2.31	2.37
Geothermal plant	0.48	0.22	0.35	0.07	0.16	0.12
Hydroelectric plant	0.30	0.30	0.30	0.30	0.30	0.30
Tidal turbine	0.30	0.29	0.30	2.32	2.22	2.27
Res. roof PV system	1.61	1.37	1.49	0.48	0.44	0.46
Com. roof PV system	1.77	1.41	1.59	0.33	0.32	0.32
Solar PV plant	0.98	0.81	0.90	0.30	0.28	0.29
CSP plant	0.26	0.26	0.26	0.19	0.19	0.19

Source: JEDI models (http://www.nrel.gov/analysis/jedi/). CSP = concentrated solar power (solar thermal).

Earnings per year are calculated by scaling up JEDI earnings figures to our price (dollar) year and to account for effects of changes in wages and labor-hours/MW over time as follows:

$$E_J = E_{JEDI,J} \cdot \frac{p_{GDP-IPD,Y_B}}{p_{GDP-IPD,JEDI}} \cdot \exp^{w \cdot h \cdot Y}$$

where

E_J = Annual earnings for job type J (\$/year)
$E_{JEDI,J}$ = Annual earnings in the JEDI model (\$/year; shown below)
$\frac{p_{GDP-IPD,Y'}}{p_{GDP-IPD,JEDI}}$ = the ratio of our designated price-year basis Y' to the JEDI price-year basis (2010) (calculated using GDP Implicit Price Deflators)
w = rate of change in real wages, over time (we assume wages grow with our mid-range estimate of real GDP/capita; see discussion in section "State GDP" below)
h = rate of change in hours per MW, to account for improvements in production efficiency (we assume -1.0%/year)
Y = the period of time over which the changes in wages and hours/MW occur (we assume the midpoint of the entire 40-year phase-in period; i.e., 20 years)

The raw, unscaled earnings values ($E_{JEDI,J}$) from JEDI and the final scaled values (E_J) are shown in Table S6.

Table S6. Earnings in construction and operation jobs for WWS technologies

	Earnings (\$1000)/year							
	Construction				**Operation**			
	Unscaled, from JEDI			Scaled	Unscaled, from JEDI			Scaled
	CA	*WA*	*Average*	*Average*	*CA*	*WA*	*Average*	*Average*
Onshore wind	66.79	59.61	63.20	66.44	110.60	58.19	84.40	88.72
Offshore wind	73.68	71.73	72.71	76.44	67.28	64.10	65.69	69.06
Wave device	67.63	64.42	66.02	69.41	67.59	65.80	66.70	70.12
Geothermal plant	64.03	46.49	55.26	58.10	104.48	105.99	105.23	110.63
Hydroelectric plant	65.09	61.91	63.50	66.76	72.60	66.46	69.53	73.10
Tidal turbine	67.56	64.28	65.92	69.30	67.69	65.96	66.83	70.26
Res. roof PV system	50.86	52.23	51.54	54.19	56.74	58.42	57.58	60.53
Com. roof PV system	52.65	54.46	53.55	56.30	59.20	58.42	58.81	61.83
Solar PV plant	50.76	52.07	51.42	54.05	56.79	58.25	57.52	60.47
CSP plant	91.87	91.87	91.87	96.59	63.05	63.05	63.05	66.29

Source: JEDI models (http://www.nrel.gov/analysis/jedi/).

Check on consistency of labor costs implied by our earnings estimates with our estimated capital costs and O&M costs

Because the cost of labor is a component of estimates of capital costs and O&M costs, one ideally would use a single set of labor costs to estimate capital costs, O&M costs, and earnings from job creation. However, because our estimates of capital costs and O&M costs are not disaggregated into labor and materials components, we instead will check whether the labor-cost figures used in our earnings estimates are consistent with our overall capital cost and O&M cost estimates. We expect labor costs to be a small fraction of capital costs and a large or very large fraction of O&M costs for WWS technologies. As shown in Table S7, this indeed is what we find.

Table S7. Estimated construction costs and labor costs for WWS technologies

	Construction cost		Operating cost					
	Labor ($/kW)	Labor /total	Labor ($/kW/yr)			Labor/total		
Technology	*Average*	*Avg/avg*	*Low*	*Average*	*High*	*Low/high*	*Avg/avg*	*High/low*
Onshore wind	9.8	1%	8.9	13.1	17.4	22%	35%	50%
Offshore wind	26.0	1%	40.1	43.0	46.0	25%	32%	43%
Wave device	52.1	1%	158.3	164.0	169.9	32%	51%	121%
Geothermal plant	70.4	2%	8.0	13.0	18.0	3%	6%	8%
Hydroelectric plant	59.4	2%	20.7	21.7	22.6	57%	69%	87%
Tidal turbine	45.5	1%	152.1	157.5	162.9	76%	126%	326%
Res. roof PV system	14.0	0%	25.9	27.4	28.9	86%	100%	116%
Com. roof PV system	33.2	1%	19.1	19.6	20.1	96%	119%	155%
Solar PV plant	71.8	4%	16.6	17.5	18.3	66%	78%	92%
CSP plant	62.4	1%	12.3	12.3	12.3	10%	11%	11%

Solar PV plant uses values for crystalline tracking. CSP = concentrated solar power (solar thermal).
"Labor ($/kW)" is based on the average unscaled JEDI earnings (updated to the appropriate price year) over the average construction time for the technology.
"Labor/total" is equal the Labor $/kW divided by our estimated base-year capital cost in $/kW.
"Labor ($/kW/yr)" is based on the min,average, or max unscaled JEDI earnings (updated to the appropriate price year).
"Labor/total" is equal to Labor $/kW/yr divided by total O&M costs expressed in $/kW/yr. We have converted variable O&M, original in $/kWh, to $/kW/yr. Here, Low/high is low labor costs divided by high total O&M, and High/low is high labor costs divided by low O&M.

As indicated here, the labor costs used in the earnings analysis are less than 5% of capital costs. Labor costs typically are a much larger fraction of O&M costs, and account for the bulk of O&M costs for PV plants, which we expect.

There are a few combinations where the labor costs from our earnings analysis in this section constitute more than 100% of O&M costs as estimated in our "cost of delivered electricity section, but with one exception, this generally does not concern us. In one case for wave devices and two cases for tidal turbines, the labor cost exceeds 100% of the O&M cost, but this is not surprising given the enormous uncertainty in estimates of O&M costs for this non-commercial technology. In one case for residential rooftop PV – high labor costs and low O&M costs – labor costs exceed O&M costs, but only by a small amount, and in the other two (more likely) cases labor costs do not exceed 100%.

The only case of modest concern is for commercial rooftop PV, where even the average labor cost estimated here exceeds average O&M cost. Closer examination of the underlying data reveals that this is because our O&M cost estimates for commercial rooftop PV are low relative to the estimates for residential rooftop PV and utility-scale PV.

6) PROJECTION OF STATE POPULATION AND GDP

State population

We use state population estimates for 2000, 2005, 2010, 2011-2014, and 2015 to 2075 in 5 year increments. The sources of our estimates are

2000 and 2005: population estimates by the U. S. Bureau of the Census (http://www.census.gov/popest/data/intercensal/state/state2010.html).

2010-1014: population estimates by the U. S. Bureau of the Census (http://www.census.gov/popest/data/state/totals/2014/index.html).

2015: extrapolate from 2011-2014 trend.

2020 to 2075 in five year increments: see discussion in the next section.

Projection of state population to 2075. In 2006, the U. S. Bureau of the Census projected state populations from 2010 to 2030 (US Census, Table 6 Interim Projections: Total Population for Regions, Divisions, and States: 2000 to 2030. http://www.census.gov/population/projections/data/state/projectionsagesex.html.) With those Census projections, we calculate the annual rate of change over each five-year period from 2010 to 2030, for each state. We then fit a trend line to the series of five-year annual rates. Assuming that the annual rate of population growth actually changes nonlinearly rather than linearly with time, we multiply the slope of the trend line by an exponential decay function. We then use this decayed trend line to project each state's population from 2020 to 2075. We pick the value of the decay-exponent so that our resultant projections of U.S. total population match the population projections of the EIA (2014c). Formally,

$$P_{S,Y_t} = P_{S,Y_{t-1}} \cdot \exp^{g_{Y_t,Y_{t-1}} \cdot (Y_t - Y_{t-1})}$$

$$g_{Y_t,Y_{t-1}} = \left(b_{2010-2030} + m_{2010-2030} \cdot Y_t\right) \cdot \exp^{h \cdot (Y_t - 2015)}$$

$$m_{2010-2030} = \frac{\sum_{2010}^{2030} \left(Y_t - \bar{Y}_{2010-2030}\right) \cdot \left(g_t - \bar{g}_{2010-2030}\right)}{\sum_{2010}^{2030} \left(Y_t - \bar{Y}_{2010-2030}\right)^2}$$

$$b_{2010-2030} = \bar{Y}_{2010-2030} - m_{2010-2030} \cdot \bar{Y}_{2010-2030}$$

where

P_{S,Y_t} = the population in state *S* in year Y_t
t-1 = the period prior to *t*
$g_{Y_t,Y_{t-1}}$ = the annual rate of change in population between year Y_t and year Y_{t-1}, calculated as a linear extrapolation based on the growth rates between 2010 and 2030, multiplied by an exponential decay (non-linearizing) factor.
$\bar{Y}_{2010-2030}$ = the average years between 2010 and 2030 (the period over which the Census projected each state's population)
$\bar{g}_{2010-2030}$ = the average of the five-year projected population growth rates between 2010 and 2030.
h = exponent determining the rate of decay of the population growth rate, away from the linear trend derived from the Census projections, after 2015 (we assume a value of -0.0095 resulting in modest decay that makes the resultant projected population of the U.S. close to the values projected by the EIA [2014c]).

State GDP

State GDP is calculated as the product of GDP per capita and state population. The state population is discussed above. The International Monetary Fund (World Economic Outlook Data Base, http://www.imf.org/external/pubs/ft/weo/2014/02/weodata/index.aspx.), CitiGroup Global Markets (Buiter and Rahbari, 2011), and the EIA (2014c) project GDP/capita, and HSBC Global Research (Ward, 2012) projects income per capita. The projections range from between 0.6%/year to 2.1%/year, depending on the projection period, with an average of around 1.6%/year. We believe however that lower values are more realistic. We assume the following values for all states:

	LCHB	*Medium*	*HCLB*
Annual change in real GDP per capita	1.50%	1.25%	1.00%

A higher rate of change in GDP per capita results in a higher value of life, which results in higher benefits for the 100% WWS scenario.

7) THE NATIONAL-AVERAGE LEVELIZED COST OF ELECTRICITY BY TYPE OF GENERATOR

To estimate the national-average levelized cost of electricity by type of generator we expand and update the calculation documented in Delucchi and Jacobson (2011). Table S13 shows our complete set of assumptions and intermediate calculated values. In this section we document our assumptions and tabulate and annotate the main literature used in our analysis (Table S14).

Overview of the method

We estimate the fully annualized cost per delivered kWh from new capacity put in place in a near-term base year and a long-term target year, for the BAU scenario and the 100% WWS scenario. For the near-term base year, we estimate the costs of conventional (mainly coal, gas, and nuclear) and wind, water, and solar (WWS) technologies as part of present-day electricity systems. For the long-term target year, we estimate the costs of conventional, non-WWS technologies in the context of the U. S. Energy Information Administration's (EIA) *Annual Energy Outlook 2014* (EIA, 2014a, 2014c, 2014e) reference-case projections (our BAU), and estimate the costs of WWS technologies for both the BAU and the 100% WWS scenario. (The costs of WWS technologies in a 100% WWS system will be different from the costs of WWS technologies in a conventional, EIA-reference-case system because the 100% WWS system will require different measures for balancing supply and demand but also will have different costs due to economies of scale and learning associated with greater development and use of technology.) We assume that the benefit stream – the provision of electricity services – is the same in the EIA reference case (BAU) and the 100% WWS scenario, and hence the same for any particular plant/technology type within the electricity-generation scenarios.

We first estimate national-average costs by technology, as described in this section, and then in a subsequent section adjust these to estimate regional and state-level costs by accounting for regional differences in initial costs, fuel costs and capacity factors. We calculate regional adjustments for gas, coal, oil, wind, and solar plants. For the fossil-fuel plants, hydropower, and geothermal plants, the regional adjustment accounts for differences in initial costs and fuel costs, and for the wind and solar plants the regional adjustment accounts for differences in initial costs and capacity factors. We do not account for regional differences in the cost of nuclear power.

The annualized cost per kWh is equal to the annualized initial cost plus annualized periodic costs and transmission and distribution-system costs, divided by annual kWh output. The annualized initial cost is based on the actual physical depreciation (loss of capacity) over time, accounting for construction interest cost prior to operation, major capital expenditures to extend the life of the plant, and salvage value and decommissioning cost at end of life. Annual periodic costs are calculated as the present worth of the actual periodic cost stream, annualized over the operating life. Transmission and distribution system costs include the costs of measures needed to balance supply and demand in 100% WWS systems.

The annual kWh output is calculated by multiplying the rated kW capacity by the fraction of the 8760 hours in a year that the plant operates at capacity (the capacity factor). The capacity factor is estimated by considering the characteristics of the entire electricity generating system and, in the case of wind and solar power, the characteristics of the wind and solar resources and the performance of the technology. For the EIA reference-case (the basis of our BAU), we assume that the entire electricity generation system operates as projected in the EIA's *Annual Energy Outlook 2014* (EIA, 2014a, 2014c, 2014e). For the 100% WWS case, we assume what we believe is a plausible, reliable, electricity generation system, based partly on analyses by others and partly by our own analysis in Jacobson et. al (2015). (Note though that we have not done a least-cost optimization.)

Weighted LCOE vs. costs actually incurred in a particular year. Note that we estimate the levelized costs (going forward) of new systems put in place in the target year, and then estimate national or regional system-wide average costs by weighting each generator's LCOE by its assumed share of generation in the target year. This method, which we will call LCOE-TY (for "levelized cost of energy in the target year") facilitates comparison of the costs of different combinations of technology choices in the future. However, for two reasons, this method generally will not give the same relative overall system-average cost results as will an analysis of the *actual* system-wide costs incurred in the target year (ASC-TY) given a particular plan for phasing in various technologies over time, even when the target-year generation shares and capacity factors are the same in both cases (LCOE-TY and ASC-TY) The two reasons are

1) The in-place capacity of each technology can rise or fall over time, meaning that the actual total capital costs incurred in the ASC-TY case will be different from the total capital costs implied by the capacity factors and unit capital costs in the LCOE-TY case.

2) Capital costs, maintenance costs, and performance change over time, due to learning and scale economies, with the result that the actual costs and performance of the system in place in TY will not be the same as the going-forward costs and performance of new systems installed in TY.

Put another way, the two methods (LCOE-TY and ASC-TY) will give the same relative overall costs only in the case where the total installed capacity, performance, and costs of each technology are constant over time.

In our case, the LCOE-TY method differs from ASC-TY method on account of both reasons mentioned above. For example, the EIA (2014c) projects that over time natural-gas fired capacity increases substantially and coal-fired capacity decreases. This means that our LCOE-TY method, relative to the ASC-TY method

- overestimates the capital-cost component of coal-fired generation but underestimates the capital-cost component of gas-fired generation;
- underestimates the maintenance-cost component of coal-fired generation but over-estimates the maintenance-cost component of gas-fired generation (because maintenance costs increase with age); and
- overestimates the fuel efficiency and hence underestimates the fuel cost of gas and coal-fired generation (because efficiency improves over time, with the result that efficiency of new plants built in TY will be higher than the efficiency of the fleet in TY).

Sources of data used in our analysis

With four exceptions, our analysis of national-average costs by technology type, shown in Table S13, is based on the data summarized in Table S14 and the information discussed in the following sections here. The four exceptions are: we estimate costs for i) “combined-cycle conventional” and ii) “combined-cycle advanced with carbon capture” relative to costs for “combined-cycle advanced,” using relative costs from the EIA (2014a, Table 8.2) and our judgment; and we estimate costs for iii) “municipal solid waste” and iv) “distributed generation” based on the EIA (2014a, Table 8.2) and our judgment. However, for these four we do estimate capacity factors as described below, using EIA *AEO* projections. We also assume that municipal solid waste feedstock is 40% of the cost of biomass feedstock.

Note also that we treat the Table S14 estimates for diesel generators as proxies for diesel steam turbines.

Important parts of our method

We calculate the levelized cost of electricity as the sum of the annualized initial costs, annualized fixed operating and maintenance (FOM) costs, variable O&M costs, fuel costs, and transmission and distribution costs, using (as we derive in the next subsection) a continuous rather than a discrete-interval annualization,

$$C_{j,US,Y,W} = \frac{C_{AI,j,US,Y,W} + C_{FOM,j,US,Y,W}}{CF_{j,US,Y,W} \cdot 8760} + C_{VOM,j,US,Y} + C_{FUEL,j,US,Y} + C_{TD,j,US,Y,W}$$

$$C_{AI,j,US,Y,W} = \frac{r \cdot C_{I,j,US,Y,W}}{1 - e^{-r \cdot t}}$$

$$C_{FUEL,j,US,Y} = \frac{C_{FUEL^{*},j,US,Y}}{eff_{j,US,Y}}$$

where

$C_{j,US,Y,W}$ = the levelized cost of delivered electricity from technology j in the United States in year Y in scenario W (\$/kWh) (Table S13)
$C_{AI,j,US,Y,W}$ = the annualized initial cost of technology j in the U.S. in year Y in scenario W ($\$/\mathrm{kW_{P\text{-}NM}}/\mathrm{year}$) (Table S13)
$C_{FOM,j,US,Y,W}$ = the fixed operating and maintenance (OM) cost of technology j in the U.S. in year Y in scenario W ($\$/\mathrm{kW_{P\text{-}NM}}/\mathrm{year}$) (Table S13; discussed below)
$C_{VOM,j,US,Y,W}$ = the variable operating and maintenance (OM) cost of technology j in the U.S. in year Y in scenario W (\$/kWh) (Table S13; discussed below)
$C_{FUEL,j,US,Y}$ = the cost of fuel for technology j in the U.S. in year Y (\$/kWh) (Table S13)
$C_{TD,j,US,Y,W}$ = the transmission and distribution-system (TD) cost of technology j in the U.S. in year Y in scenario W (\$/kWh) (Table S13; discussed below)
$CF_{j,US,Y,W}$ = the capacity factor for technology j in the U.S. in year Y in scenario W $\left(\frac{\mathrm{kWh_{ac\text{-}grid}}/\mathrm{year}}{\mathrm{kW_{P\text{-}NM}}\cdot 8760}\right)$ (discussed below)
$kWh_{ac-grid}/year$ = kWh of ac electrical energy delivered to the grid per year
kW_{P-NM} = kW of rated "name-plate" peak power (see discussion immediately below)
8760 = hours per year
$C_{I,j,US,Y,W}$ = the initial cost of technology j in the U.S. in year Y in scenario W ($\$/\mathrm{kW_{P\text{-}NM}}$) (discussed below)
r = the annual discount rate (discussed below)
t = the lifetime of the technology before replacement (years) (Table S13; discussed below)
$C_{FUEL*,j,US,Y}$ = the cost of fuel for technology j in the U.S. in year Y (\$/million-BTU [HHV]) (Table S13; discussed below)
$eff_{j,US,Y}$ = the efficiency of fuel-use for technology j in the U.S. in year Y (kWh/million-BTU [HHV]) (Table S13; discussed below)
subscript j = technology types (Table S13) (note that the EIA's *AEO* reference projections, used in our BAU scenario, include only fixed-tilt PV, of unspecified technology [EIA, 2014a]; therefore, for utility PV in our BAU we use the average of thin-film and crystalline fixed-tilt)
subscript W = 100% WWS or BAU scenario
HHV = higher heating value

<u>The use of the rated or "nameplate" peak power</u>. The peak rated or "name-plate" power, kW_{P-NM}, is part of the capital-cost parameter and part of the capacity-factor parameter, so it is important, of course, that estimates of the capital cost and the capacity factor are in fact based on the same definition of kW_{P-NM}. This definitional consistency mainly is an issue for photovoltaics (PVs) and wind turbines, because the

peak power of these depends on the intensity of solar radiation or the wind speed. PV manufacturers rate panels under "Standard Test Conditions" (STC; irradiance of 1,000 W m^{-2}, solar spectrum of AM 1.5 and module temperature at 25 °C.) (http://en.wikipedia.org/wiki/Solar_panel), and generally analyses of the cost and performance of PVs use this standard convention (e.g., http://rredc.nrel.gov/solar/calculators/pvwatts/version1/change.html; U.S. DOE, 2012). It appears that wind turbines generally are rated at a wind speed of 11 m/s (http://distributedwind.org/wp-content/uploads/2012/08/Certified_Ratings.pdf), but that this standard is not as universally accepted as the STCs are for PVs. It therefore is possible that in the case of wind power cost figures from one source are not consistent with capacity figures from another source.

Derivation of the formula for a continuous annuity, for levelizing (annualizing) costs

A "levelized" cost per unit, such as the $/kWh levelized cost of electricity, is equal to annualized initial costs plus periodic annual costs (such as fuel and operating and maintenance) divided by annual output. Typically, annualized initial costs are calculated using the formula for an annuity "paid" in a lump sum at the end of a discrete time interval,

$$C_{AI} = \frac{r \cdot C_I}{1-(1+r)^{-t}}$$

where r is the annual interest rate, t is the life of the technology in years, and annuity payments are made at a discrete point in time, the end of the year. This method is exactly correct for calculating a payment that actually is made at discrete intervals, but it is *not* technically correct for annualizing (or "levelizing") energy-service costs, because the purpose of the annualization is to produce a cost stream with a time-flow characteristic that matches the time flow of the energy output (e.g., in the levelized $/kWh cost calculation, the output is the continuous flow of kWh). Because energy production and use actually is continuous, the annualization of the initial cost of energy generators also should be based on a continuous time stream of "payments" rather than discrete-interval payments.

To derive a *continuous* annuity formula from the standard discrete-interval formula, we first introduce a variable n that represents the number of payments per year, with the ultimate aim of solving for C_{AI} when n approaches infinity (and hence the time interval approaches zero),

$$C_{AI(n)} = \frac{\frac{r}{n} \cdot C_I}{1-\left(1+\frac{r}{n}\right)^{-n \cdot t}}$$

Here r remains the *annual* discount rate, and t still is denominated in years, but n is denominated in 1/years. If for example n =12 (months)/year, then r/n is effectively the monthly interest rate (%/year × years/month), $t \times n$ is the lifetime in months (months/year × years), and $C_{AI(n)}$ is the "payment" made every $1/n$th of a year; i.e., in every month for this example.

If we multiply both sides by n, then we have

$$C_{AI(n)} \cdot n = \frac{r \cdot C_I}{1 - \left(1 + \frac{r}{n}\right)^{-n \cdot t}}$$

where the quantity $C_{AI(n)} \cdot n$ is the total amount paid over the year (the *1/nth*-year payment multiplied by n payments per year). Note that $C_{AI(n)} \cdot n$ is *not* the same as C_{AI}; the latter is the single year-end payment made every year, whereas the former is the *sum*, over a year, of the n payments made every *1/nth* of a year. No matter what the value of n, the quantity $C_{AI(n)} \cdot n$ always equals the total payments over a year. And as n approaches infinity, $C_{AI(n)} \cdot n$ becomes the total over a year of a *continuous payment rate*, which is just what we want, because it corresponds with the total over a year of the continuous annual energy (electricity) generation rate. We will designate this continuous payment rate C_{AI^*}, to distinguish it from the discrete lump-sum end-of-year payment C_{AI}.

Finally, we want to find

$$\lim_{n \to \infty} \left(1 + \frac{r}{n}\right)^{-n \cdot t}$$

Let us define $n \equiv m \cdot r$. Thus we have

$$\lim_{n \to \infty} \left(1 + \frac{r}{n}\right)^{-n \cdot t} \equiv \lim_{m \to \infty} \left(1 + \frac{r}{m \cdot r}\right)^{-m \cdot r \cdot t} = \lim_{m \to \infty} \left(1 + \frac{1}{m}\right)^{-m \cdot r \cdot t} = \left(\lim_{m \to \infty} \left(1 + \frac{1}{m}\right)^{m}\right)^{-r \cdot t}$$

The quantity in the outer parentheses is defined to be the constant *e*. Thus we have

$$\lim_{n \to \infty} \left(1 + \frac{r}{n}\right)^{-n \cdot t} = e^{-r \cdot t}$$

and

$$C_{AI^*} = \frac{r \cdot C_I}{1 - e^{-r \cdot t}}$$

where r remains the annual discount rate and t is the lifetime in years.

We apply this continuous annuity formula to the annualization of all initial costs, to the annualization of the present worth of capacity-factor-years, and to the annualization of the present worth of the operations and maintenance cost stream.

The cost of WWS technologies in the BAU in year Y

For three reasons, the cost of WWS technologies in year Y in the BAU differs from the cost of WWS in year Y in the 100% WWS scenario:

1) The transmission and distribution (T&D) system in the 100% WWS scenario is different from the system in the BAU. The cost of the T&D system in the BAU is based on the EIA's *AEO* cost projections; the cost of T&D in the 100% WWS scenario starts with the EIA's *AEO* cost projections and then incorporates the costs of modifications to the T&D system due to more decentralized generation and additional supply-and-demand balancing measures in the 100% WWS scenario. See the discussion of T&D system costs below.

2) The installed capacity of WWS is much less in the BAU than in the 100% WWS scenario, and as a result the initial cost of WWS technology, which on account of learning and economy-of-scale effects is a function of installed capacity, is higher in the BAU than in the 100% WWS scenario. We assume that the initial cost of WWS in the BAU declines over time (from year Y^* to year Y) by only a (small) fraction of the decline in the 100% WWS scenario. We estimate this fraction as a nonlinear function of the difference between Y^* and Y. See the discussion of the parameter $C_{wws,Y,BAU}$.

3) Capacity factors for WWS technologies in the BAU are different from the capacity factor in the 100% WWS scenario, on account of differences in the installed capacity (which can entail differences in the average quality of the wind or solar resources used) and differences in system operation in order to ensure reliably matching of supply and demand. Capacity factors in the BAU are estimated based on the EIA's *AEO* projections; capacity factors in the 100% WWS scenario start with actual current-year factors and then account for assumed changes over time in resource quality, technological performance, and system operation. See the discussion of the capacity factor in the subsections below.

To ensure consistency between our estimates of WWS technology costs in the BAU and the 100% WWS scenario, we estimate BAU costs relative to 100% WWS costs where appropriate. Formally,

$$C_{wws,Y,BAU} = C_{AI,wws,Y,BAU} + C_{VOM,wws,Y} + C_{FOM,wws,Y,BAU} + C_{TD,Y,BAU}$$

$$C_{FOM,wws,Y,BAU} = C_{FOM,wws,Y,100\%WWS} \cdot \frac{CF_{wws,Y,100\%WWS}}{CF_{wws,Y,BAU}}$$

$$C_{AI,wws,Y,BAU} = \frac{C_{AI,wws,Y^*} \cdot CF_{wws,Y^*} - K_1 \cdot \left(C_{AI,wws,Y^*} \cdot CF_{wws,Y^*} - C_{AI,wws,Y,100\%WWS} \cdot CF_{wws,Y,100\%WWS}\right)}{CF_{wws,Y,BAU}}$$

$$K_1 = \left(1 - \frac{Y - Y^*}{100}\right)^{K_2}$$

where

$C_{wws,Y,BAU}$ = the levelized cost of WWS technologies in year Y in the BAU (\$/kWh)

$C_{AI,wws,Y,BAU}$ = the annualized initial cost of WWS technologies in the BAU in year Y (\$/kWh)

$C_{VOM,wws,Y}$ = the variable O&M costs of WWS technologies in year Y (\$/kWh) (assumed to be the same for the BAU and the 100% WWS scenario)

$C_{FOM,wws,Y,BAU}$ = the fixed O&M costs of WWS technologies in year Y in the BAU (\$/kWh)

$C_{TD,Y,BAU}$ = the cost of the transmission and distribution system in year Y in the BAU (\$/kWh) (based on the EIA's *AEO*; see discussion below)

$C_{FOM,wws,Y,100\%WWS}$ = the fixed O&M costs of WWS technologies in the 100% WWS scenario in year Y (\$/kWh) (see discussion of O&M costs in regards to Table S13)

$CF_{wws,Y,100\%WWS}$ = the capacity factor for WWS technologies in year Y in the 100% WWS scenario (see discussion below)

$CF_{wws,Y,BAU}$ = the capacity factor for WWS technologies in year Y in the BAU (see discussion below)

C_{AI,wws,Y^*} = the annualized initial (*AI*) cost of WWS technologies in the base year Y^* (\$/kWh)

$C_{AI,wws,Y,100\%WWS}$ = the annualized initial cost of WWS technologies in the target year Y in the 100% WWS scenario (\$/kWh)

K_1 = the decline in the annualized initial cost of WWS (in the BAU) as a fraction of the difference between the base-year Y^* and the target-year Y^* cost in the 100%WWS scenario

K_2 = exponent determining the rate of decline in the annualized initial cost of WWS technologies as a function of time (higher values result in smaller fractions) (see discussion below). Its values are as follows:

Geothermal	Hydropower	Wind	Solar thermal	Utility PV	Rooftop PV
0.00	0.00	2.50	0.50	3.50	3.00

Table S13 shows intermediate calculated values and results.

Annual discount rate

The U.S. Office of Management and Budget (OMB) (2003) recommends that cost-benefit analysis of public investments and regulatory impacts use two discount rates: one that reflects the opportunity cost of capital in the private sector, and one that reflects the time value of private consumption. In 2003, the OMB (2003) estimated that the former was 7% (based on the real before-tax rate of return on private investment) and that the latter was 3% (based on the real rate of return on long-term government debt, such as 10-year treasury notes). However, from 2003 to 2013 the real rate of return on 10-year treasury notes has averaged only 1.4% (http://www.federalreserve.gov/releases/h15/data.htm; “Market yield on U.S. Treasury securities at 10-year constant maturity, quoted on investment basis, inflation-indexed”). In line with this, the OMB (2013) now recommends using a real discount rate of 1.9% for cost-effectiveness analysis (which the OMB treats differently from cost-benefit and regulatory-impact analysis). Moreover, the OMB (2003) adds that “if your rule will have important intergenerational benefits or costs you might consider a further sensitivity analysis using a lower but positive discount rate,” and suggests a range of 1-3%.

Other analyses, more comprehensive than the OMB's, indicate that for two reasons, the OMB's upper-range value of 7% is too high. First, the real pre-tax rate of return on private investment likely is less than 7% -- Moore et al. (2004) estimate that it is about 4.5%. Second, the pre-tax rate of return to private investment is the appropriate discount rate only for relatively short-term public projects that dollar-for-dollar crowd out private investment; for projects that have a longer time horizon or that affect consumption as well private investment, a lower discount rate is appropriate (Moore et al., 2004; National Center for Environmental Economics, 2014). Moore et al. (2004) review the accepted methods for estimating the social discount rate (SDR), and conclude that "no matter which method one chooses, the estimates for the SDR vary between 1.5 and 4.5 percent for intragenerational projects, and between 0 and 3.5 percent for projects with intergenerational impacts" (p. 809). The National Center for Environmental Economics (2014) has a similar discussion and indicates (without explicitly recommending) that a reasonable range is 2% to 5%.

With these considerations, we use a rate of 1.5% in our “low” cost (LCHB) scenarios and a rate of 4.5% in our “high” cost (HCLB) scenarios.

Year of prices

We use GDP implicit price deflators to convert all costs except electricity-power-plant capital costs from the price-year basis in the original source to our designated price-year basis (2013). (The designated price-year basis can be any user-specified year up to the year for which the most current GDP implicit price deflator is available.)

For electricity-plant capital costs, we follow the EIA (2014a, 2014c) and develop an adjustment that accounts for trends in prices relevant specifically to the construction of power plants *relative* to trends in the general price level embodied in the GDP implicit price deflator. The EIA (2014a) applies "a cost adjustment factor, based on the producer price index for metals and metal products, [which] allows the overnight costs to fall in the future if this index drops, or rise further if it increases" (p. 96). More precisely, the EIA projects the metals and metal- product producer price index (MMP-PPI) – a proxy for electricity-plant prices – *relative* to its projection of GDP chain-type price indices (GDP-CTPI), for each year of its projection, and then multiplies power-plant capital costs by the relative adjustment factor for each projection year.

We start with the EIA's projection of the GDP-CTPI and the MMP-PPI from 2012 to 2040. We use historical data to fill in the series back to 1990 (to enable the use of a designated price year as early as 1990), and extend the series to 2075 using a ten-year moving linear extrapolation. To get from the starting estimate of capital costs in the original price year of the source material to capital costs in the designated price year of our analysis, we multiply the original estimate by the appropriate MMP-PPI ratio, which converts the capital-cost estimate to what it would be were it estimated in designated-year prices specifically for capital costs. To capture the effect of changes over time in real power-plant capital costs relative to changes in general prices, we then multiply by the ratio of the MMP-PPI to the GDP-CTPI for the target year vs. the designated price year.

Formally,

$$CC_{El,Y',Y} = CC_{El,Y_0} \cdot ADJ_{El,p}$$

$$ADJ_{El,p} = \frac{p_{MMP-PPI,Y'}}{p_{MMP-PPI,Y_0}} \cdot \frac{\dfrac{p_{MMP-PPI,Y}}{p_{MMP-PPI,Y'}}}{\dfrac{p_{GDP-CTPI,Y}}{p_{GDP-CTPI,Y'}}}$$

where

CC_{El} = the capital cost of electricity power plants (\$/kW)

$ADJ_{El,p}$ = the adjustment factor for changes in the price of electric power plants

p = price index

Subscripts:

MMP-PPI = metals and metal products producer price index
GDP-CTPI = gross domestic product chain-type price index
Y = target year of the analysis (for impacts or technology status)
Y′ = the designated price-year of the analysis
Y_o = the price year of the original cost estimates in the source documents (2012 for power-plant cost data used here)

Because the EIA projects that the MMP-PPI will rise more slowly than the GDP-CTPI, the adjustment factor $ADJ_{El,p}$ is less than 1.0. Because WWS technologies are more capital intensive than conventional technologies, this has the effect of slightly reducing the levelized cost of electricity from WWS technologies relative to the levelized cost of conventional technologies.

Interest charges during construction

We assume that 1/2 to 2/3 of the total capital is required at the start of construction, and the remainder is required 1/2 or 2/3 of the way through the construction period. In comparison, Lazard (Jalan, 2014) estimates interest charges on construction capital assuming effectively that 1/2 of the capital is required at the beginning of construction and 1/2 is required at the end of construction. Lazard also ignores interest costs on projects less than 24 months.

Overnight capital cost (national average) (year-2012 dollars): technology base year 2013 (new capacity) ($/kW)

These are complete system installed costs including engineering, other owner costs, and connection to the transmission system, but excluding borrowing costs during the construction period (which we treat separately). We estimate capital cost, lifetime, efficiency, capacity factors, and O&M costs to be mutually consistent. Our estimates are based on a review of the literature (Table S14) with extra weight given in some cases to the data from Lazard (2014), because those data are the most up-to-date and transparent. For hydropower we give more weight to EIA's estimates from our literature review. We assume that nuclear power costs are 10% to 35% higher than reported in the literature because nuclear power plants have tended to have particularly high cost over-runs (as much as 100%; Sovacool et al., 2014a, b, c), and as Hultman et al. (2007, p. 2088) note, for nuclear power "past experience suggests that high-cost surprises should be included in the planning process." (The discussion in Sovacool et al. supports the notion that even though recent estimates of the capital cost of nuclear power are higher than past estimates, the recent increases do not account for the factors that lead to cost overruns in the past.) We assume that coal-plant costs are 5% to 10% higher than reported in the studies consulted here because thermal plants also tend to have cost overruns (about 10%; Sovacool et al., 2014b). For PV systems the capital cost here includes the inverter; however, In the intermediate calculated results the total capital cost is broken into an inverter component and an all other components, and the annualized cost for each of these is estimated. Solar thermal costs are based on Lazard's (2014) estimates with 18-hour storage.

As mentioned above, here we estimate national-average costs. In the next main section we estimate state or region-specific cost adjustments.

Note: see the discussion in the section "Year of prices".

Overnight capital cost (year-2012 dollars): long-run limit cost w.r.t. base cost

Our estimates of long-run costs relative to current costs are based on a review of the literature (Table S14 and other sources). We focus in particular on the long-run costs of wind and solar, because these are more uncertain.

PVs: Barbose et al. (2014a) show that PV capital costs in the US have declined rapidly in the last several years, and are expected to continue to decline. In the US there appears to be considerable opportunity to reduce system costs not related to the cost of the modules, as evidenced by the much lower system costs today in other developed countries (e.g., in Germany in 2014 residential systems cost $2100/kW and commercial systems cost $1900/kW, excluding taxes -- much lower than in the US). (See also Goodrich et al., 2012, 2013.)

For the residential and commercial PV markets, installed prices depend on the type of inverter (standard vs. micro-inverter) and the efficiency of the module (higher efficiency modules cost more) (Barbose et al., 2014), but we do not consider these differences here.

Wind: Capital costs have declined in recent years in part because of economies of scale from building larger projects and higher-capacity turbines (Barbose et al., 2014b).

Note: see the discussion in the section "Year of prices".

Overnight capital cost (year-2012 dollars): decline rate towards limit

This is the continuous annual rate of approach to the long-run lower-limit cost from the base cost. We assume this is higher (i.e., that there are faster cost reductions) for technologies such as PVs for which there is significant potential for continued learning and relatively rapid cost reduction. In general we assume slower rates of decline in costs for conventional technologies than does the EIA (2014b) in its projections of the change in the levelized capital cost of generation technologies from 2019 to 2040.

Capital expenditure to extend life (% of overnight capital)

We assume that after at least 40 years of operating life, large coal, gas, and nuclear power plants either are allowed to age and retire or are refurbished for significant life extension (see e.g. EIA, 2010, 2014c; ICF Incorporated, 2013). We assume that operators will extend life only when it is economically advantageous, which we assume pertains to our low-cost (LCHB) (longest-potential-life) but **not** our high-cost (HCLB) case. Estimates of the expenditure for coal and nuclear are based on our judgment. Byrne (2013) indicates that capital costs to extend the life of wind turbines are a very small fraction of overnight capital costs.

Note that in principle we should have in internally consistent estimation of facility life, capital expenditure to extend life, initial capital cost, capacity factor, and O&M expenditure. Here we assume that if there is no capital expenditure to extend life, then O&M costs increase in the later years of the life of the facility.

Here we use ICF Incorporated (2013) estimates of the life extension cost as a percentage of new unit cost,

Coal steam	7.0%
Combined cycle	9.3%
Combustion turbine and internal-combustion engine	4.2%
Oil/gas steam	3.4%
IGCC	7.4%
Nuclear	9.0%

Timing of capital expenditure (% of facility life)

For most technologies, we assume that in the low-cost (LCHB), long-life case, the life-extension expenditure is made after about 65% of the ultimate *extended* life. For wind, we assume the expenditure is made after 60% of the ultimate extended life (Byrne, 2013). In the high-cost (HCLB), short-life case there is no life-extension expenditure, but the timing variable is relevant nevertheless because as discussed elsewhere it determines a break point between two rates of changes in O&M expenditures. We assume that this break point occurs at 70% of the life time in the HCLB case. The timing here is defined to be the time when the funds for the life-extension work are secured, which will be months and in some cases year before the life-extension work is completed.

Decommission/salvage cost (% of overnight capital)

This is the complete cost of decommissioning (scrapping) a power plant, as a fraction of its initial cost. Ideally the cost here is the total cost to return the site to the original condition, after any salvage value of material sold or left in place. Our estimates for nuclear and coal plants are based on site-specific cost estimates and other sources (Nuclear Regulatory Commission, 2013; Electric Power Research Institute, 2004; Nuclear Energy Agency, 2003). Our estimates for nuclear are consistent with World Nuclear Association's (2014) remark that decommissioning costs are 9-15% of initial capital cost. Our estimates of nuclear power-plant decommissioning cost are meant to include long-term waste disposal, but it is not clear if the estimates in the literature include this fully. For nuclear SMR, we scale decommissioning factor for APWRs by the APWR/SMR capital cost ratio. Our estimates for on-shore wind are based on Byrne (2013). Our estimates for solar are based on our consideration of the plant complexity, mass of materials, toxicity and hazardousness, recyclability, and salvageability. Note that in some cases the percentages are higher in the "low-cost" (LCHB) case because decommissioning costs tend to be constant rather than an actual percentage of the initial cost, which means that if the initial cost is lower the decommissioning cost as a percentage is higher.

Build time (years)

Our estimates are based on a review of the literature (Table S14). For nuclear APWR we use estimates at the high end of the reported ranges because the construction time for nuclear power plants typically is substantially underestimated (Sovacool et al., 2014a). For nuclear SMR we assume significantly less time than for APWRs. We assume that future hydropower projects will be modest in size and hence not take up to a decade to build. We assume that CSP without storage takes 5% less time to build than does CSP with storage.

Facility life (years)

The facility life is the period of operation before the facility either is decommissioned or is so extensively rebuilt that it effectively is new construction. (Note that the facility life is not necessarily the same as the "cost recovery" period used in some financial analyses.) Our estimates are based partly on a review of the literature (Table S14) and partly on data on actual retirement ages, discussed below (Table S8).

Assumptions about the facility life must be consistent with assumptions regarding initial capital cost, capital expenditure to increase life, the capacity factor, and O&M expenditures. For example, the long lifetimes typically assumed for nuclear power presume major additional capital expenditures in mid-life, which we do account for here.

Similarly, Peltier (2011) analyzed a similar database of U.S. power plants and found that the capacity factor and energy efficiency of coal-fired plants decrease with the age of the units. He suggests that old, inefficient, infrequently used plants that are costly to upgrade are the most likely to be retired in the coming years. The EIA's National Energy Modeling System (NEMS), used to produce it's *Annual Energy Outlook*, has an "Electricity Capacity Planning" Submodule that will retire older fossil-fuel plants if the costs of continuing to run them (including expected capital/upgrade expenditures) is greater than the cost of building new capacity (EIA, 2014e).

The EIA's Form 860 collects generator-specific data on capacity, power plant equipment, fuels used, date of operation, and planned and actual retirement dates (http://www.eia.gov/electricity/data/eia860/). Based on these data, an online "Today in Energy" brief from the EIA (http://www.eia.gov/todayinenergy/detail.cfm?id=15031) reports the following for retired coal-fired generating units:

	2010	2011	2012
total net summer capacity (MW)	1,418	2,456	10,214
number of units	29	31	85
average net summer capacity (MW)	49	79	123
average age at retirement	58	63	51
average tested heat rate (Btu/kWh)	11,094	10,638	10,353
capacity factor	36%	33%	35%

An earlier brief (http://www.eia.gov/todayinenergy/detail.cfm?id=7290) shows that units planned for retirement from 2012 to 2015 have an average age of about 56 years.

For this project we used the complete EIA-Form 860 database to calculate the capacity-weighted average actual or planned retirement age for plants using different fuels (Table S8).

Table S8. Summer-capacity-weighted average of retirement for generators using different energy sources (years)

	Plants retired 2001 to 2013			Planned for retirement 2014-		
Fuel or plant type	*All sectors*	*Electric Utility*	*IPP Non-CHP*	*All sectors*	*Electric Utility*	*IPP Non-CHP*
Nuclear	32.5	31.3	38.9	46.0	NA	46.0
Bituminous coal	51.5	52.9	49.7	53.2	53.8	53.6
Subbituminous coal	48.7	45.9	51.9	50.4	49.0	54.3
Lignite	52.8	NA	52.8	NA	NA	NA
Anthracite	NA	NA	NA	NA	NA	NA
Natural gas	41.8	48.7	39.2	49.7	53.8	46.3
Gas turbine	32.8	37.5	32.4	43.3	42.8	43.7
Distillate fuel oil	40.5	41.1	40.4	44.3	44.1	44.7
Residual fuel oil	46.9	44.2	51.6	47.2	59.6	42.0
Hydropower	62.4	57.5	79.7	53.2	53.4	30.2
Geothermal	17.3	NA	16.6	NA	NA	NA

Source: Data from EIA Form-860 (http://www.eia.gov/electricity/data/eia860/).
IPP-Non-CHP = independent power producer, non-combined heat and power.

Our assumptions for the main BAU technologies (Table S13) are based in part on the results shown in Table S8. For nuclear SMR, we assume a slightly shorter life time than for APWRs. Our estimates for wind farms assume that longer-life wind farms have higher O&M costs and reduced availability (i.e., a lower capacity factor) (Byrne, 2013).

Capacity factors (national average): overview

The capacity factor is equal to [actual ac-electricity output to the grid over a year] divided by [potential energy output at maximum rated ("nameplate") power for all 8760 hours in a year].

Actual output is less than maximum potential continuous output because of planned and un-planned outages and downtime, degradation of mechanical performance due to wear and tear, intentional idling or curtailing to meet system loads, and, in the case of solar or wind power, fluctuations in the primary energy inputs (wind speed and solar insolation) that result in the annual average input being less than the maximum potential.

Our objective here is to estimate the discounted lifetime average capacity factor for each technology, for the near-term base year and the BAU scenario and the 100% WWS scenario for the long-term target year. For most in-use technologies in the near-term base year, and for most technologies in the BAU scenario in the long-term target year, we start with the EIA's (2014c, 2014f) *AEO* projections of fleet-average capacity factors. To estimate capacity factors in the 100% WWS scenario for the long-term target year, we start with estimates for the near-term base year, and then project future changes in four parameters that affect the capacity factor,

- degradation,
- resource availability (e.g., average wind speed or solar intensity),
- technological performance, and
- system operation to ensure balancing of supply and demand.

Note that the EIA estimates we start with are of the capacity factor of an in-use fleet, whereas we ultimately wish to estimate the discounted lifetime capacity factor for each technology. The two are not the same because the average age of the fleet is not necessarily the same as the effective average age of an individual technology over its life. Our method, therefore, is first to back out from the EIA's fleet-average estimates what we assume are the effects of age-related degradation, to get the capacity factor for a brand-new fleet of a particular technology, and then to account for the effects of degradation over the entire life of the plant, with discounting (as discussed next), to arrive at our objective, the discounted lifetime average capacity factor.

As just mentioned, we estimate a *discounted* lifetime average capacity factor, in order to account for the effect, on the present worth of lifetime electricity generation, of changes in the capacity factor over time. For all technologies except wind we assume that the capacity factor changes over time due only to performance degradation; i.e., we assume that plant *availability*, already included in our estimates of the year-zero capacity factor, is constant over time, except in the case of wind power. For wind, we correct for the difference between the present worth of the actual availability schedule (Byrne, 2013) and a constant availability schedule.

Capacity factor: fleet average capacity factors

The EIA's (2014c, 2014f) *AEO* projects national fleet-average capacity factors for all of the major generation technologies considered here. As mentioned above and shown below (Table S9), we use the EIA's estimates for our near-term, base-year case and for our target-year BAU scenario. In most cases, the EIA's *AEO* capacity factors are the same as, or very close to, the capacity factors we estimate for the year 2014 based on data reported for the first several months of 2014 (EIA, 2014d).

The EIA's *AEO* projects through the year 2040. We extend the projection to the year 2075 using a 10-year moving linear extrapolation, but with the resultant trend slope dampened by the 0.35 power . This prevents the capacity factor beyond 2040 from deviating much from the year-2040 value.

For any technologies not included in the EIA's *AEO,* our estimates are based on a review of the literature (Table S14). Capacity factors for solar vary greatly by solar or wind resource class; we have assumed national-average values typical for the year 2014.

Capacity factor: fleet average age (% of life)

This is the average age of the fleet to which the technology base year fleet-average capacity factor applies. We use this to back-out the effects of aging embedded in the fleet-average capacity factors, in order to obtain the capacity factors for new systems.

Capacity factor: annual degradation of capacity factor (base-year tech.) (+)

The degradation factor is mean to capture the effects of gradual, low-level, irreversible wear and tear as a system ages, resulting in, for example, increased mechanical friction, increased electrical resistance, and reduced combustion efficiency. This degradation factor does not incorporate loss of output due to planned or un-planned downtime for repairs and maintenance or the impacts of weather or other external conditions on output, effects that we include in the technology base-year capacity factors. The discounted lifetime degradation factor is calculated by taking the present worth of the actual series of degraded life-years and annualizing that into equal payments. The formula for a continuous annuity is discussed above. The present worth of degraded life-years is calculated as

$$DG_{PW} = -\frac{e^{-(d+r)\cdot L} - 1}{d+r}$$

where

DG_{PW} = the present worth of degraded life-years (years)
d = the annual rate of degradation of the capacity factor (discussed below)
r = the annual discount rate

L = the lifetime of the facility (years)

Staffell and Green (2014) cite studies that estimate or assume that conventional fossil-fuel technologies degrade at 0.2% to 0.7% per year. For wind assume that degradation is a minor component of the combined availabilty+degradation+turbine-death factor of 1.6%/year estimated by Staffell and Green (2014). Our assumptions for PV are based on the analysis in Jacobson et al. (2014) and Bolinger and Weaver's (2014) suggestion that 0.50%/year is a "standard" assumption.

Capacity factor: annual change in degradation rate (-)

We assume that over time the degradation factor decreases, at 0.1% per year for relatively mature technologies (all conventional generation) and 0.5% for year for relatively new technologies (e.g., wind and solar).

Capacity factor: resource availability long-run limit w.r.t. base (100% WWS scenario only) (<100%)

Resource availability refers to available energy from wind, solar, and water resources, with respect to the availability in the base year. Although one might expect that in general, at a national level, wind and solar would be developed in the best sites first, with the result that over time progressively worse sites would be developed leading to lower national-average capacity factors, this is not necessarily the case, because other forces are at work. Indeed, it appears that most high-wind and high-solar sites have yet to be developed. Bolinger and Weaver (2014) report that "the quality of the solar resource in which PV projects are being built in the United States has increased on average over time" (p. i), and Barbose et al. (2014b) state that "the United States still has an abundance of undeveloped high-quality wind resource areas" (p. 42).

These considerations suggest that effect on capacity factors of variation in solar intensity and wind speed over time is not well captured by a single national-average adjustment. Therefore, we account for the effect of variations in solar and wind resource availability at the state level (see discussion in a later subsection).

We do however assume that nationally most good hydropower sites already have been developed.

In the case of wind power, another factor affects the amount of energy available from wind resources in a target year with respect to the amount available in the base year. As the number of wind farms increases, the extraction of kinetic energy from the wind by the turbines decreases the average wind speeds, which in turn reduces the potential power output from the wind farms (Jacobson and Archer, 2012). We account for this at the state level (see discussion in a later subsection).

Table S9. Source of fleet-average capacity-factor estimates

Technology	**Source of estimate of capacity factor**
Advanced pulverized coal	EIA (2014f) Coal
Advanced pulverized coal w/CC	Assume same as "Advanced pulverized coal"
IGCC coal	EIA (2014f) IGCC without sequestration
IGCC coal w/CC	EIA (2014f) IGCC with sequestration
Gas combustion turbine	EIA (2014f) Combustion turbine/diesel
Combined cycle advanced	EIA (2014f) Combined cycle advanced without sequestration
Combined cycle conventional	EIA (2014f) Combined cycle conventional
Combined cycle advanced w/CC	EIA (2014f) Combined cycle advanced with sequestration
Diesel generator (for steam turbine)	EIA (2014f) Oil and natural gas steam
Nuclear, APWR	EIA (2014f) Nuclear power
Nuclear, SMR	Assume same "Nuclear APWR"
Fuel cell	EIA (2014f) Fuel Cells
Microturbine	Table S14
Distributed generation	EIA (2014c, 2014f) Distributed generation
Municipal solid waste	EIA (2014c) Municipal waste (electric power sector)
Biomass direct	EIA (2014c) Wood & other biomass (electric power sector) (because the EIA's projections of capacity for the "wood and other biomass" category do not include plants that co-fire biomass and coal, we do not include generation from co-firing plants; i.e., we include generation from "dedicated plants" only)
Geothermal	EIA (2014c) Geothermal (electric power sector)
Hydropower	EIA (2014c) Conventional hydropower (electric power sector; we ignore hydro power in the "end-use" sector because it accounts for less than 1% of hydro generation)
On-shore wind	EIA (2014c) Wind
Off-shore wind	Table S14
CSP no storage	EIA (2014c) Solar thermal (electric power sector)
CSP w/ storage	Table S14
PV utility crystalline tracking	Table S14; literature review
PV utility crystalline fixed	EIA (2014c) Solar photovoltaic (electric power sector)
PV utility thin-film tracking	Table S14; literature review
PV utility thin-film fixed	EIA (2014c) Solar photovoltaic (electric power sector)
PV commercial rooftop	EIA (2014c) Solar photovoltaic (end-use sector)
PV residential rooftop	EIA (2014c) Solar photovoltaic (end-use sector)
Wave power	Table S14
Tidal power	Table S14
Solar thermal (water or glycol solution)	Table S14

Capacity factor: resource availability change rate (-)

See the discussion regarding the resource availability, above. We assume that the modest long-run lower limits of WWS resource availability are approached relatively modestly (Table S13).

Capacity factor: technology performance, long-run limit w.r.t. base (100% WWS scenario only) (>100%)

Technological performance refers to technological changes to WWS technologies that affect the capacity factor, holding resource availability and all other factors constant. Black and Veatch (2012) project that the capacity factor for class 3 onshore-wind resources increases from 32% in 2010 to 35% in 2050. Barbose et al. (2014b) report that rotor diameter, hub height, and swept area of wind turbines increased from 1999 to 2013. Bolinger and Weaver (2014) show that in recent years utility-scale PV projects have increased the "inverter loading ratio" (the ratio of array capacity to inverter capacity), with a resultant increase in capacity factor, although it does not seem that this trend can continue indefinitely. Our estimates (Table S13) are based on our judgment that the potential to increase the capacity factor for on-shore wind is greater than the potential to increase it for PVs.

Capacity factor: technology performance change rate (+)

See discussion of technological performance.

Capacity factor: multiplier to account for changes in system operation in the long-run (100% WWS scenario only) (<>100%)

This is a multiplier on the capacity factor that accounts for changes in the capacity factor in the long run in the 100% WWS scenario, with respect to the factor in the base year, due to changes in the operation of the entire electricity system for the purpose of matching supply with demand, holding constant the other determinants of the capacity factor (changes in degradation, resource availability, and technology). For example, one way to address the mismatch between the pattern of demand and the pattern of wind and solar power availability is to increase the installed capacity of wind and solar to minimize the greatest difference between demand and available wind and solar power. However, this increase in capacity will result in times in which the available wind and solar power exceeds demand. If it is not possible to shift demand or store the immediate “excess” generation, then the excess generation will be unused (“spilled”), which reduces the capacity factor.

Ideally the use of over-capacity, long-distance transmission, decentralized storage, and other means of matching supply and demand would be estimated jointly as part of an overall, comprehensive analysis of the least-cost methods of balancing supply and demand. Although we have not done such a comprehensive least–cost optimization analysis here, and have not formally modeled how selectively building over-capacity can help balance WWS supply with demand, we have estimated the cost of decentralized storage in a system that formally balances supply and demand (Jacobson et al., 2015). In the section “Transmission, distribution, storage, gap filling : other long-term (2050) storage and related costs (100% WWS scenario only)," we estimate the amount of over-capacity (represented by a decrease in the capacity-factor multiplier) that increases the system-wide average delivered cost of electricity by the same amount as does the use of decentralized storage. In this section we briefly discussion considerations that affect the application of the capacity factor multiplier and the interpretation of the levels of over-capacity and excess generation that give the same cost increase as does decentralized storage.

Wind and solar power. For wind and solar systems, the capacity-factor multiplier represents the extent to which a system is built and operated to have "excess" or reserve renewable generation capacity, resulting in excess, unused ("spilled" or "curtailed") generation. Recent studies of the least-cost configuration of 100% renewable energy systems indicate that systems taking advantage of a relatively limited array of techniques to match supply and demand will spill 10% to 30% of total generation (Solomon et al., 2014; Rodriguez et al., 2014; Elliston et al., 2013). However, no study to date takes advantage of the full array of optimization techniques; for example, none consider aggressive demand management and decentralized storage. We therefore conclude that optimized systems taking advantage of the full array of balancing techniques will spill less than 30% of total generation from all sources (not just wind and solar), and perhaps substantially less.

In the case of wind and solar, it is most economical and practical to "overbuild" and curtail generation from technologies that are relatively inexpensive, relatively easy to control, relatively variable, and relatively abundant. We assume therefore that any overcapacity for the entire system is built into onshore wind and utility-scale solar PV plants. We do not assume any over-capacity for offshore wind because it is more expensive and less variable than is onshore wind, and we do not assume any over-capacity for rooftop PV because it is more expensive and more difficult to manage than is utility scale PV. We also assume that solar thermal with storage is not overbuilt on account of it having its own storage capacity.

With the cost estimates developed here (Table S13), it generally is less costly to build all of the over-capacity into onshore wind farms. Therefore, in the comparison, discussed below, of the cost of over-capacity with the cost of decentralized storage, we vary the capacity-factor multiplier for onshore wind.

Geothermal and hydropower. For geothermal and hydropower, which are less variable on short time scales than wind and solar, the capacity-factor multipliers in our analysis are slightly *greater* than 100% on account of these being used more steadily in a 100% WWS system than in the base year.

Capacity factor: long-run change rate (+)

For coal, oil, gas, nuclear, biomass, geothermal, and hydropower plants, we base our estimates on the rate of change in the capacity factor from 2014 to 2040, as estimated in the EIA's (2014f) *AEO 2014*. For wind and solar systems we use our judgment.

Capacity factor: final value

The maximum allowable capacity factor is 94%.

Variable and fixed operating and maintenance (O&M) costs (unadjusted average)

Most analyses distinguish “variable” from “fixed” O&M costs. Variable O&M costs generally are proportional to power output and hence typically are expressed in terms of cost per unit of generation ($/kWh). Fixed O&M costs include periodic capital and other expenditures that generally are related to the capacity rather than the generation of the plant, and hence are expressed in $/kW/year. We assume that fixed O&M costs do not include the cost of major refurbishment for the purpose of life extension, which we treat separately.

In this section we estimate “unadjusted average” costs, meaning that the estimates do not (yet) account for the effect on discounted present worth of the actual temporal variation in O&M costs, which we treat separately.

Our estimates of O&M costs are meant to include *all* the costs of operating and maintaining a power plant other than fuel costs and ongoing capital costs for the purpose of life extension. Thus, our estimates of O&M costs include administrative costs, insurance costs, plant overhead, and so on. However, O&M costs can be defined differently by different sources, and in some cases it is not clear what the reported estimates include.

Our estimates are based partly on a review of the literature (Table S14), and partly on actual O&M costs reported for electric utilities (Table S10). The actual reported costs are from the Federal Regulatory Energy Commission (FERC), which collects data on operating expenses of major investor-owned electric utilities in the U.S. (Table S10).

FERC Form 1 asks for operating expenses and maintenance expenses (separately) in 8 different categories (http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf),

- power production
- transmission
- regional market
- distribution
- customer accounts
- customer and service and informational
- sales
- administrative and general.

For nuclear SMR we assume the same O&M costs as for nuclear APWRs. We assume that CSP without storage has 90% of the fixed O&M cost of CSP with storage. For PVs, the fixed O&M cost here includes typical estimates of the cost of inverter replacement. However, as discussed under “capital costs,” we have estimated the annualized inverter cost separately. To avoid double counting, in the calculation of "periodic costs" we subtract from the input fixed O&M the fixed O&M charge implicit in our separately estimated inverter cost.

Table S10. Average reported power-plant operating expenses for major U.S. investor-owned electric utilities (year-2013 cents/kWh)

Year	Operation and maintenance				Fuel			
	Nuclear	*Fossil Steam*	*Hydro*	*Other*	*Nuclear*	*Fossil Steam*	*Hydro*	*Other*
2002	1.76	0.66	0.79	0.71	0.58	2.02	0.00	4.00
2003	1.77	0.67	0.71	0.71	0.57	2.13	0.00	5.40
2004	1.72	0.73	0.79	0.77	0.55	2.18	0.00	5.41
2005	1.57	0.72	0.78	0.65	0.54	2.52	0.00	6.44
2006	1.66	0.76	0.73	0.64	0.55	2.60	0.00	6.07
2007	1.68	0.77	1.02	0.62	0.55	2.62	0.00	6.44
2008	1.73	0.79	1.04	0.70	0.57	3.06	0.00	6.91
2009	1.74	0.87	0.89	0.60	0.57	3.45	0.00	5.54
2010	1.82	0.85	0.96	0.58	0.70	2.92	0.00	4.56
2011	1.83	0.83	0.92	0.59	0.72	2.80	0.00	4.01
2012	1.87	0.78	1.15	0.53	0.72	2.45	0.00	3.09
Average 2002-2012	1.74	0.77	0.89	0.65	0.60	2.61	0.00	5.26
Average 2008-2012	**1.80**	**0.82**	**0.99**	**0.60**	**0.66**	**2.94**	**0.00**	**4.82**

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities," as reported by the EIA for its *Electric Power Annual* (http://www.eia.gov/electricity/annual/html/epa_08_04.html). "Other" includes gas turbines, internal combustion engines, photovoltaics, and wind plants. FERC.

Annual rate of change in O&M costs (+/-)

We estimate two rates of change in O&M costs: one up to the L^*, which is the point at which any life-extension investment would occur, and one after L^* until the end of the facility life L. We take the present worth of the actual O&M stream, given the assumed rates of change, annualize the present worth, and divide the resultant annualized (discounted) cost by the present worth calculated with a zero discount rate. This ratio of the discounted to the undiscounted O&M stream then is multiplied by the unadjusted average O&M cost input. Note that we calculate the undiscounted present worth through a period of time between L^* and L because we assume that the average (undiscounted) cost estimates in the literature generally do not pertain to the entire life of a facility *after* life-extension measures.

We assume that the FERC Form 1 results shown in Table S10 include O&M expenses for the first category, "power production." As shown on Form 1, the "power production" category includes supervision, engineering, rents, allowances, and miscellaneous, but not insurance, taxes, and general administration, which are included in the category "administrative and general." It is not clear whether the results of Table S10 include any of these administrative and general expenses. If they do not, then they slightly underestimate O&M expenses as we define then.

In any event, the data in Table S10 are broadly similar to the estimates in the literature (Table S14), except that the Table S10 data for nuclear O&M costs are slightly higher than the estimates in Table S14. Our assumptions result in costs close to those reported in Table S10.

Data in Byrne (2013) and Barbose et al. (2014b) indicate that for wind, fixed O&M expenses are not constant but increase over the life of the project (6%/year according to Byrne et al., 2013). The EIA (1995) and the Nuclear Energy Institute (2014) show that O&M costs for nuclear power plants increase with age (2.5%/year according to the Nuclear Energy Institute, 2014). For other technologies our assumptions are based on our assessment of the technology. We assume that if the plant is refurbished and its life is extended, then O&M costs stop increasing, but that otherwise, they increase at a 10% to 40% higher rate than prior to L^*, depending on the technology.

Fuel cost: (national average): background

Throughout this cost analysis we wish to estimate the true economic cost, which is the area under the long-run supply curve. The per-unit economic cost (e.g., the cost of fuel in $ per unit of energy) is equal to the area under this supply curve over some region of quantity divided by the quantity. This can be interpreted as the average long-run economic cost per unit.

This *average* long-run economic cost per unit generally is not the same as the *price,* which in a competitive market is based on the *marginal* cost. With supply curve rising due to increasing scarcity of labor and material inputs, the marginal cost and hence the price will be higher than the average cost. The difference between the price and the average cost is producer surplus (PS), which is *not* an economic cost but rather is a transfer of wealth from consumers to producers. In sectors of the economy that are non-competitive or have sharply rising cost curves – such as the oil industry –PS can be quite large.

Given this, there are in general two ways to estimate the economic cost of fuels, exclusive of PS: 1) build up an estimate of average cost from capital costs, feedstock costs, labor costs, and so on, or 2) start with known prices and subtract the portion that represents PS, which as just explained is the non-cost (pure transfer) component of price. For new, developing systems for which there are not good data on the price of the mature technologies, we must use method #1. However, for mature fuels, such as are considered here, it is easier to use method #2, which is to start with the price and subtract an estimate of PS. This is what we do for coal, natural gas, oil, nuclear fuel, and biomass used by power plants.

As mentioned above, here we estimate national-average costs. In the next main section we estimate state or region-specific cost adjustments.

Fuel cost (year-2012 dollars): Starting estimates of fuel prices

The EIA (2014c) projects $/million-BTU prices of coal, natural gas, distillate fuel, residual fuel oil, nuclear fuel, and biomass, to the electricity-generating sector, through the year 2040. (The values for nuclear fuel and biomass are not published but are available from the EIA on request.) We adopt their reference-case projections for the U.S. through the year 2040 and extend them to 2075 using a moving 10-year linear extrapolation. For our base-year analysis we use these EIA estimates as is; i.e., we have a single value, not a different "low" and "high" estimate. However for our target-year analysis we do estimate "low" and "high" values; we assume that the low-cost value is 10% below the (extended) EIA projection and that the high-cost value is 10% above.

We assume that microturbines and fuel cells use natural gas.

Fuel cost (year-2012 dollars): deducting producer surplus

Producer surplus in the oil industry can be substantial because oil is a worldwide commodity and a handful of countries own very low-cost reserves, resulting in a non-competitive global market with much of the supply curve far below the prevailing oil price. This is not the case for other fuels because most suppliers to a given national or regional market have access to resources of similar cost. Given this, we assume the following PS fractions of the prices estimated above:

Fuel	LCHB	HCLB	References and notes
Coal	0.06	0.04	Low because of competitive access to low-cost resources
Natural gas	0.10	0.06	Slightly higher than for coal because of presumably steeper supply curve
Oil	0.60	0.50	Based on Delucchi et al. (2015) estimates of the PS for gasoline made from U.S. crude oil given a 50%-100% reduction in fuel use.
Nuclear	0.06	0.04	Low because of competitive access to low-cost resources
Biomass	0.06	0.04	Low because of competitive access to low-cost resources

Combustion efficiency: technology base year, 2013

Our estimates are based on a review of the literature (Table S14 and other sources).

Combustion efficiency: long-run limit

Our estimates are based on a review of the literature (Table S14 and other sources).

Combustion efficiency: annual change rate (+)

Our assumptions.

Transmission, distribution, storage, gap filling: cost of the T&D system in the neat-term base year and for the BAU in the target year

The EIA's (2014c) *AEO* projects the real (constant-dollar) cost of the U.S. transmission and distribution (T&D) system though the year 2040. We extend this projection to the year 2075 using a 10-year moving linear extrapolation. For our estimates of the cost of delivered electricity in (i) the near-term base year, and (ii) the long-term target year in the BAU scenario, we use the EIA's *AEO* estimates of the T&D cost, without any adjustments. For our estimates of the cost of delivered electricity in the long-term target year in the 100% WWS scenario, we start with the EIA's *AEO* cost projections and then incorporate the costs of modifications to the T&D system due to more decentralized generation and additional supply-and-demand balancing measures in the 100% WWS scenario. These modifications are discussed in the following subsections.

Transmission, distribution, storage, gap filling: % of plants distributed or on-site, long-run limit (100% WWS scenario only)

The 100% WWS scenario has more distributed and on-site generation than does the BAU scenario. Distributed and on-site generator plants do not require the use of the baseline (BAU) long-distance transmission system and may not require the same distribution system as in the BAU. Thus, as a 100% WWS system develops it will require less expansion of the transmission system, and possibly less expansion of the distribution system, than in the BAU scenario (IREC, 2014; Electricity Innovation Lab, 2013; Beach and McGuire, 2013). In addition, Repo et al. (2006) argue that distributed generation systems can reduce the energy-related and power-related variable costs of transmission and distribution systems.

To estimate the cost impacts of these potential changes in usage of the transmission or distribution system, we start with EIA (2014c) *AEO* reference-case projections of the costs of electricity transmission and distribution over time. We assume that these annualized costs are a function of the lifetime and the capacity of the transmission or distribution system. We make assumptions about how distributed and on-site systems change the throughput and capacity of transmission and distribution systems, and posit simple relationships between throughput and lifetime, and between capacity and cost, in the long-run limit. The estimated cost changes are relatively minor.

Transmission, distribution, storage, gap filling: change rate (+)

See discussion above. This refers to the rate of approach of the long-run limit of distributed-generation and on-site generation shares.

Transmission, distribution, storage, gap filling : additional long-term (2050) transmission costs (100% WWS scenario only)

These are costs for an upgraded, expanded, long-distance high-voltage DC transmission system that are i) not included in our estimates of capital costs for generation technologies, and ii) in addition to the cost of the baseline transmission system (the BAU system adjusted for increased distributed and on-site generation in the 100% WWS scenario). Given that most capital-cost estimates include all connections to the existing transmission and distribution network, the additional costs here generally comprise expansions to the transmission system for the purpose of integrating diverse sources of renewable energy. We assume that in the 100% WWS scenario, all WWS technologies are part of an integrated, balanced renewable energy system with an expanded transmission grid, and therefore we spread out the "additional (land-based) transmission" cost over *all* WWS generators in the 100% WWS scenario.

We calculate this additional transmission cost using Delucchi and Jacobson's (2011) detailed method, with new inputs as follows:

1) We distinguish between an expanded onshore land-based grid, the cost of which is assigned to all WWS generators including offshore wind, and an expanded offshore grid, the cost of which is assigned to offshore wind only. The expanded offshore grid here is sea-based transmission *in addition* to the generic windfarm-to-shore connections that already are included in our estimates of the capital cost of offshore wind farms.

We assign the cost of the additional long-distance onshore grid to all generators in the 100% WWS scenario, including on-site generators such as solar PV that do not transmit to the grid, because the long-distance grid, like system storage, in principle is part of a system-side supply-and-demand balancing that depends on the generation characteristics of all technologies.

2) Additional long-distance transmission costs apply only to the 100% WWS scenario in the long-term, target-year analysis, because there are no such additional costs in the near-term, base-year analysis.

3) The average length of additional transmission for the portion of the energy system that effectively sends all of its output through the new transmission is 750 to 1000 miles for onshore systems and 50 to 100 miles for offshore wind systems.

4) We assume that 30% to 45% of total WWS generation (all generators except offshore wind) is sent through the new onshore long-distance grid and that 15% to 25% of offshore wind generation is sent through the extended-transmission offshore grid.

Note that assumptions 3) and 4) are not the result of a comprehensive analysis of the least-cost combination of storage, long-distance transmission, and over-capacity in a 100% WWS system but rather represent our judgment of what is likely to be needed in a 100% WWS system.

5) The year-round average current capacity factor, as a fraction of the rated capacity, originally used to estimate transmission losses, now is used also as the overall energy (or power) capacity factor for calculating the transmission-system cost. (Given a constant voltage, the ratio of transmitted amp-hours to maximum amp-hours is the same as the ratio of transmitted energy to maximum energy.) The overall capacity factor for the transmission system depends on the capacity of the transmission system relative to the capacity of the connected generation centers, the extent to which individual generation centers have complementary generation profiles, and other factors, but it will be at least as great as the capacity factor for individual wind farms. We assume 35% to 45% for the onshore system, and 40% to 50% for the offshore system.

6) We estimate the cost per kWh delivered out of the transmission system into the distribution system, accounting for losses during transmission but not during distribution. (We assume that losses in distribution are accounted for in the estimates of the $/kWh figures we use for distribution-system costs.)

Transmission, distribution, storage, gap filling : other long-term (2050) storage and related costs (100% WWS scenario only)

In the 100% WWS scenario, additional options for balancing supply and demand (beyond using an expanded long-distance transmission grid) include demand response, supply prediction, use of gas-fired back-up, energy storage, and over-building generation capacity (Jacobson and Delucchi, 2011). We assume that demand response and supply prediction cost very little, and that gas-fired back up will almost never be needed (e.g., Hart and Jacobson, 2011). Therefore, at this point in our analysis, we consider the cost of decentralized energy storage and the cost of over-building generation capacity.

We estimate the cost of several energy-storage options, including vehicle-to-grid (V2G), underground thermal-energy storage (UTES), pumped-hydro storage (PHS), sensible-heat thermal-energy storage (STES), and phase-change materials (PCM). For V2G, we update the calculations of the battery-degradation cost in Delucchi and Jacobson (2011), and estimate that cycling 10% to 15% of all delivered power through V2G would cost $0.003 to $0.006 (0.3 to 0.6 cents) per all-kWh delivered.

Our estimates of the costs of the other decentralized energy-storage options are from Jacobson et al. (2015), who develop cost estimates as part of a grid-integration model of a 100% WWS energy system for the U. S. In Jacobson et al. (2015), the storage systems are sized so that the entire set of storage technologies ensures that the grid matches WWS supply with all-sector end-use demand with zero loss of load over six years of simulation. Table S11 shows the estimated $/kWh cost for each option, equal to the annualized capital cost plus O&M cost divided by total energy delivered for load.

Following Jacobson et al. (2015), we assume that energy-storage costs of Table S11 – 0.05 to 0.70 cents per all-kWh delivered – apply to the entire WWS system, and hence to every individual generating technology in the system, in the 100% WWS scenario.

How do the results of Table S11 compare with the approach of over-building generating capacity (and spilling unused generation) in order to balance supply and demand? Because we have not done a formal analysis of the amount of over-capacity needed to balance and demand, we answer this question by evaluating the level of over-capacity, represented by a reduction in the capacity factor and an increase in spillage, at which the resultant system-wide average costs equal the system-wide average costs in the case in which storage is used to balance supply and demand (Table S11). The cost of over-capacity is the increase in the annualized initial cost of generation due to the decrease in the capacity factor. We estimate this extra cost by reducing the capacity-factor multiplier for onshore wind and calculating the increased cost of wind power's share of the WWS generation mix, using the generator costs of Table S13 and the generation shares by generator discussed earlier.

Table S11. Annualized cost of electricity storage technologies

Storage technology	**Capital cost of storage beyond power generation ($/maximum-deliverable-kWh-th)**		**Assumed energy storage capacity (maximum-deliverable TWh)**	**Operations and maintenance cost (% of capital cost per year)**		**Lifetime (years)**		**Annualized capital cost plus O&M cost (cents/all-kWh-delivered)**	
Non-UTES	*Low*	*High*		*Low*	*High*	*Low*	*High*	*LCHB*	*HCLB*
PHS	12.00	16.00	0.808	1.0%	2.0%	35.0	25.0	0.003	0.008
STES	0.13	12.90	0.350	1.0%	2.0%	35.0	25.0	0.000	0.003
PCM-ice	12.90	64.50	0.525	1.0%	2.0%	35.0	25.0	0.002	0.020
PCM-CSP	10.00	20.00	11.60	1.0%	2.0%	35.0	25.0	0.037	0.136
Total/average	9.98	21.33	13.29					**0.04**	**0.17**
UTES	0.07	1.71	5.28	1.0%	2.0%	35.0	25.0	**0.01**	**0.53**
All storage	***10.05***	***23.04***	***541.6***					***0.05***	***0.70***

Source: Based on Jacobson et al. (2015).

UTES = Underground thermal energy storage. PHS = pumped hydro storage; STES = Sensible heat thermal energy storage; PCM = Phase-change materials; CSP=concentrated solar power. All storage is for 14 hours except UTES. CSP costs exclude the additional mirrors, which are included in the cost of a CSP plant with storage. UTES costs exclude the cost of the solar collectors, which are tracked separately.

Table S12 shows the wind capacity-factor multiplier and associated system-wide spillage (without any storage) that results in the same average overall system cost of delivered electricity as in the case of using the storage-cost estimates of Table S11 with zero over-capacity and storage.

Table S12. Levels of over-capacity and spillage that result in the same system costs as does using decentralized storage

LCHB		HCLB	
Wind CF multiplier	System-wide spill	Wind CF multiplier	System-wide spill
90%	3.5%	57%	23.4%

The "Wind CF multiplier" applies to onshore wind only. The "system-wide spill" is equal to the amount of unused generation (due to excess capacity) divided by total delivered electricity for load.

Because system costs increase with decreasing CF multipliers and increasing spillage, the results in Table S12 indicate that in the LCHB case, decentralized energy storage is less costly than is over-capacity for any on-shore wind CF multiplier below and 90% and spillage above 3.5%. In the HCLB case, storage is less costly than is over-capacity for any CF multiplier below 57% and spillage above 23%.

As discussed earlier, analyses that explore a limited range of options for balancing supply and demand in an all-renewables energy system indicate that up to 30% of generation would end up being spilled. This means that it almost certainly will be impossible to balance supply and demand with only 3.5% spillage, but that it might well be possible to balance supply and demand with 23% spillage. Thus, in the LCHB case, decentralized storage that balances supply and demand almost certainly will be less costly than over-capacity that balances supply and demand. In the HCLB case, -capacity might be able to balance supply and demand at a cost similar to or even slightly lower than the cost of decentralized storage.

With these considerations, we assume, somewhat conservatively, that the cost of extra measures needed to balance supply and demand is given by the range of costs of decentralized storage estimated in Table S11. This is conservative because of the possibility that judicious use of over-capacity could result in lower total system costs, and because the grid-integration analysis that produced the results in Table S11 was itself not a least-cost optimization analysis.

Table S13. Cost and performance assumptions for electricity generating technologies

See accompanying spreadsheet (Delucchi et al., 2015).

Table S14. Tabulation of main literature used in our analysis of the LCEO

	Capital cost, near-term or high-cost case (2013-$/kW)				
Source ->	**EIA**	**Lazard**	**Black & Veatch**	**Parsons; DECC**	**LBNL, others**
Year of dollars in source ->	2012	2014	2009	2012	2013
GDP price deflator multiplier ->	1.015	0.984	1.067	1.015	1.000
Advanced pulv. coal	2969		3085		
Advanced pulv. coal w/CC		6687	7002		
IGCC coal	3827		4280		
IGCC coal w/CC	6665	6286	7044		
Gas peaking (turbine)	683	984	695		
Gas combined cycle	1036	1155	1313		
Diesel generator		787			
Nuclear, APWR	5583	6640	6511		
Nuclear, SMR					9000
Geothermal	2531	6529	6340		
Microturbine		3738			
Biomass direct	3977	3440	4088		
Hydropower	2471		3736		
On-shore wind	2238	1771	2113		1750
Off-shore wind	6284	5410	3533		
Fuel cell	7149	7378			
Solar thermal (CSP) without storage	5120				4000-4500
Solar thermal (CSP) with storage		6148	7535		6000-8500
PV utility crystalline tracking	3617	1722	2796		3200
PV utility crystalline fixed		1476	2708		L:1690 H:3000
PV utility thin film tracking	3617	1722			2700
PV utility thin film fixed		1476			2700
PV commercial rooftop		2951	5113		L:2390 H:3500
PV residential rooftop		4427	6351		L:3740 H:4500
Wave power			9965		
Tidal power			6340		

	Capital cost, long-term or low-cost case (2013-$/kW)				
Source ->	**EIA**	**Lazard**	**Black & Veatch**	**Parsons; DECC**	**LBNL, others**
Technology					
Advanced pulv. coal	2573	2472	3085		
Advanced pulv. coal w/CC			6020		
IGCC coal	3158	3204	4280		
IGCC coal w/CC	5261		7044		
Gas peaking (turbine)	545	787	695		
Gas combined cycle	858	884	1313		
Diesel generator		492			
Nuclear, APWR	4434	4279	6511		L:3800 H:6500
Nuclear, SMR					6000
Geothermal	3227	3956	6340		
Microturbine		2263			
Biomass direct	3340	2579	4088		
Hydropower	2444		3736		
On-shore wind	1976	1377	2113		
Off-shore wind	5077	3050	3191		
Fuel cell		3738			
Solar thermal (CSP) without storage	4101				
Solar thermal (CSP) with storage		8608	5016		3500-6000
PV utility crystalline tracking	3011		2167		1950
PV utility crystalline fixed			1814		1750
PV utility thin film tracking	3011				
PV utility thin film fixed					
PV commercial rooftop		2459	2796		1900
PV residential rooftop		3443	3127		2100
Wave power			2738		
Tidal power			1595		

	Fixed O&M, near-term or high-cost case (2013-$/kW/yr)				
Source ->	**EIA**	**Lazard**	**Black & Veatch**	**Parsons; DECC**	**LBNL, others**
Technology					
Advanced pulv. coal	31.6		24.5		
Advanced pulv. coal w/CC		78.7	37.6		
IGCC coal	52.2		33.2		
IGCC coal w/CC	73.9	71.8	47.4		
Gas peaking (turbine)	7.1	24.6	5.6		
Gas combined cycle	15.6	5.4	6.7		
Diesel generator		14.8			
Nuclear, APWR	94.7	113.1	135.6		
Nuclear, SMR					
Geothermal	114.6	0.0	0.0		
Microturbine		0.0			
Biomass direct	107.2	93.5	101.4		
Hydropower	15.1		16.0		
On-shore wind	40.1	39.3	64.0		28.0
Off-shore wind	75.1	98.4	106.7		
Fuel cell	0.0	0.0			
Solar thermal (CSP) without storage	68.3				60
Solar thermal (CSP) with storage		78.7	53.4		60-70
PV utility crystalline tracking	25.1	19.7	51.2		30.0
PV utility crystalline fixed		12.8	51.2		25.0
PV utility thin film tracking	25.1	19.7			30.0
PV utility thin film fixed		12.8			25.0
PV commercial rooftop		19.7	53.4		
PV residential rooftop		29.5	53.4		
Wave power			505.9		
Tidal power			211.3		

	Fixed O&M, long-term or low-cost case (2013-$/kW/yr)				
Source ->	**EIA**	**Lazard**	**Black & Veatch**	**Parsons; DECC**	**LBNL, others**
Technology					
Advanced pulv. coal	31.6	39.3	24.5		
Advanced pulv. coal w/CC			37.6		
IGCC coal	52.2	61.2	33.2		
IGCC coal w/CC	73.2		47.4		
Gas peaking (turbine)	7.1	4.9	5.6		
Gas combined cycle	15.6	6.1	6.7		
Diesel generator		15.0			
Nuclear, APWR	94.7	93.5	135.6		
Nuclear, SMR					
Geothermal	215.1	0.0	0.0		
Microturbine		0.0			
Biomass direct	107.2	93.5	101.4		
Hydropower	16.5		16.0		
On-shore wind	41.1	34.4	64.0		
Off-shore wind	75.1	59.0	106.7		
Fuel cell		0.0			
Solar thermal (CSP) without storage	68.3				
Solar thermal (CSP) with storage		113.1	53.4		40-50
PV utility crystalline tracking		19.7	35.2		
PV utility crystalline fixed			35.2		
PV utility thin film tracking		19.7			
PV utility thin film fixed					
PV commercial rooftop		12.8	35.2		
PV residential rooftop		24.6	35.2		
Wave power			138.8		
Tidal power			54.4		

	Variable O&M, near-term or high-cost case (2013-$/MWh)				
Source ->	**EIA**	**Lazard**	**Black & Veatch**	**Parsons; DECC**	**LBNL, others**
Technology					
Advanced pulv. coal	4.5		4.0		
Advanced pulv. coal w/CC		4.9	6.4		
IGCC coal	7.3		7.0		
IGCC coal w/CC	8.6	8.4	11.3		
Gas peaking (turbine)	10.5	7.4	31.9		
Gas combined cycle	3.3	2.0	3.9		
Diesel generator		0.0			
Nuclear, APWR	2.2	0.8	n.r.		
Nuclear, SMR					
Geothermal	0.0	39.3	33.1		
Microturbine		21.6			
Biomass direct	5.3	14.8	16.0		
Hydropower	2.7		6.4		
On-shore wind	0.0	0.0	0.0		
Off-shore wind	0.0	17.7	0.0		
Fuel cell	43.6	49.2			
Solar thermal (CSP) without storage	0.0				
Solar thermal (CSP) with storage		0.0	0.0		
PV utility crystalline tracking	0.0	0.0	0.0		
PV utility crystalline fixed		0.0	0.0		
PV utility thin film tracking	0.0	0.0			
PV utility thin film fixed		0.0			
PV commercial rooftop	0.0	0.0	0.0		
PV residential rooftop		0.0	0.0		
Wave power		0.0	n.r.		
Tidal power		0.0	n.r.		

	Variable O&M, long-term or low-cost case (2013-$/MWh)				
Source ->	**EIA**	**Lazard**	**Black & Veatch**	**Parsons; DECC**	**LBNL, others**
Technology					
Advanced pulv. coal		2.0	4.0		
Advanced pulv. coal w/CC			6.4		
IGCC coal		6.9	7.0		
IGCC coal w/CC			11.3		
Gas peaking (turbine)		4.6	31.9		
Gas combined cycle		3.4	3.9		
Diesel generator		0.0			
Nuclear, APWR		0.3	n.r.		
Nuclear, SMR					
Geothermal		29.5	33.1		
Microturbine		17.7			
Biomass direct		14.8	16.0		
Hydropower			6.4		
On-shore wind		0.0	0.0		
Off-shore wind		12.8	0.0		
Fuel cell		29.5			
Solar thermal (CSP) without storage	0.0				
Solar thermal (CSP) with storage		0.0	0.0		
PV utility crystalline tracking			0.0		
PV utility crystalline fixed			0.0		
PV utility thin film tracking					
PV utility thin film fixed					
PV commercial rooftop		0.0	0.0		
PV residential rooftop		0.0	0.0		
Wave power			n.r.		
Tidal power			n.r.		

	Fuel cost, near-term or high-cost case (2013-$/MBTU)				
Source ->	**EIA**	**Lazard**	**Black & Veatch**	**Parsons; DECC**	**LBNL, others**
Technology					
Advanced pulv. coal	2.63		n.r.		
Advanced pulv. coal w/CC		1.96	n.r.		
IGCC coal	2.63		n.r.		
IGCC coal w/CC	2.63	1.96	n.r.		
Gas peaking (turbine)	5.26	4.43	n.r.		
Gas combined cycle	5.26	4.43	n.r.		
Diesel generator		28.29			
Nuclear, APWR	n.r.	0.69	n.r.		
Nuclear, SMR					
Geothermal	0.00	0.00	0.00		
Microturbine		4.43			
Biomass direct	n.r.	1.97	n.r.		
Hydropower	0.00		0.00		
On-shore wind	0.00	0.00	0.00		
Off-shore wind	0.00	0.00	0.00		
Fuel cell	n.r.	4.43			
Solar thermal (CSP) without storage	0.00				
Solar thermal (CSP) with storage		0.00	0.00		
PV utility crystalline tracking	0.00	0.00	0.00		
PV utility crystalline fixed		0.00	0.00		
PV utility thin film tracking	0.00	0.00			
PV utility thin film fixed		0.00			
PV commercial rooftop		0.00	0.00		
PV residential rooftop		0.00	0.00		
Wave power			0.00		
Tidal power			0.00		

	Fuel cost, long-term or low-cost case (2013-$/MBTU)				
Source ->	**EIA**	**Lazard**	**Black & Veatch**	**Parsons; DECC**	**LBNL, others**
Technology					
Advanced pulv. coal	3.53	1.96	n.r.		
Advanced pulv. coal w/CC			n.r.		
IGCC coal	3.53	1.96	n.r.		
IGCC coal w/CC	3.53		n.r.		
Gas peaking (turbine)	10.40	4.43	n.r.		
Gas combined cycle	10.40	4.43	n.r.		
Diesel generator		28.29			
Nuclear, APWR	n.r.	0.69	n.r.		
Nuclear, SMR					
Geothermal	0.00	0.00	0.00		
Microturbine		4.43			
Biomass direct	n.r.	0.98	n.r.		
Hydropower	0.00		0.00		
On-shore wind	0.00	0.00	106.73		
Off-shore wind	0.00	0.00	106.73		
Fuel cell	n.r.	4.43			
Solar thermal (CSP) without storage	0.00				
Solar thermal (CSP) with storage		0.00	0.00		
PV utility crystalline tracking	0.00	0.00	0.00		
PV utility crystalline fixed		0.00	0.00		
PV utility thin film tracking	0.00	0.00			
PV utility thin film fixed		0.00			
PV commercial rooftop		0.00	0.00		
PV residential rooftop		0.00	0.00		
Wave power			0.00		
Tidal power			0.00		

	Capacity factor, near-term or high-cost case (%)				
Source ->	**EIA**	**Lazard**	**Black & Veatch**	**Parsons; DECC**	**LBNL, others**
Technology					
Advanced pulv. coal	85%		84%		
Advanced pulv. coal w/CC		93%	84%	95%	
IGCC coal	85%		80%		
IGCC coal w/CC	85%	75%	80%	89%	
Gas peaking (turbine)	30%	10%	92%	94%	
Gas combined cycle	87%	40%	90%	92%	
Diesel generator		30%			
Nuclear, APWR	90%	90%	90%	89%	80%
Nuclear, SMR					
Geothermal	92%	80%	97%		
Microturbine		95%			
Biomass direct	83%	85%	83%	65%	
Hydropower	53%		93%		
On-shore wind	35%	30%	32% to 46%	28%	20% to 50%
Off-shore wind	37%	37%	36% to 50%	38%	
Fuel cell	n.r.	95%			
Solar thermal (CSP) without storage	20%				20% to 28%
Solar thermal (CSP) with storage		52%	n.r.		40% to 50%
PV utility crystalline tracking	25%	30%	n.r.	11%	20% to 32%
PV utility crystalline fixed		21%	n.r.		18% to 30%
PV utility thin film tracking	25%	30%			33%
PV utility thin film fixed		21%			16% to 31%
PV commercial rooftop		20%	n.r.		
PV residential rooftop		20%	n.r.		
Wave power			25%		
Tidal power			28%		

	Capacity factor, long-term or low-cost case (%)				
Source ->	EIA	Lazard	Black & Veatch	Parsons; DECC	LBNL, others
Technology					
Advanced pulv. coal	85%	93%	84%		
Advanced pulv. coal w/CC			84%	97%	
IGCC coal	85%	75%	80%		
IGCC coal w/CC	85%		80%	91%	
Gas peaking (turbine)	30%	10%	92%	96%	
Gas combined cycle	87%	70%	90%	94%	
Diesel generator		95%			
Nuclear, APWR	90%	90%	90%	92%	90%
Nuclear, SMR					
Geothermal	94%	90%	97%		
Microturbine		95%			
Biomass direct	83%	85%	83%		
Hydropower	51%		93%		
On-shore wind	34%	52%	35% to 46%		
Off-shore wind	37%	43%	38% to 50%		
Fuel cell	n.r.	95%			
Solar thermal (CSP) without storage	20%				
Solar thermal (CSP) with storage		80%	n.r.		66%
PV utility crystalline tracking	25%		n.r.		
PV utility crystalline fixed			n.r.		
PV utility thin film tracking	25%				
PV utility thin film fixed					
PV commercial rooftop		23%	n.r.		
PV residential rooftop		23%	n.r.		
Wave power			20%		
Tidal power			22%		

	Construction time, near-term or high-cost case (years)				
Source ->	**EIA**	**Lazard**	**Black & Veatch**	**Parsons; DECC**	**LBNL, others**
Technology					
Advanced pulv. coal	4.0		4.6		4.8, 6.0
Advanced pulv. coal w/CC		5.5	5.5	5.0	
IGCC coal	4.0		4.8		6.0
IGCC coal w/CC	4.0	5.3	4.9	6.0	6.0
Gas peaking (turbine)	2.0	2.1	2.5	2.0	3.0
Gas combined cycle	3.0	3.0	3.4	3.0	3.0
Diesel generator		0.3			
Nuclear, APWR	6.0	5.8	5.0	8.0	7.5, 6.0
Nuclear, SMR					
Geothermal	4.0	3.0	3.0		4.0
Microturbine		0.3			
Biomass direct	4.0	3.0	3.0	1.0	4.0
Hydropower	4.0		2.0		10.0, 3.0
On-shore wind	3.0	1.0	1.0	2.0	1.0, 3.0
Off-shore wind	4.0	1.0	1.0	3.0	
Fuel cell	3.0	0.3			
Solar thermal (CSP) without storage	3.0				3.0
Solar thermal (CSP) with storage		2.5	2.0		
PV utility crystalline tracking	2.0	1.0	1.1	1.0	2.2, 3.0
PV utility crystalline fixed		1.0	1.4		3.0
PV utility thin film tracking	2.0	1.0			3.0
PV utility thin film fixed		1.0			3.0
PV commercial rooftop		0.3	0.5		
PV residential rooftop		0.3	0.2		
Wave power			2.0		
Tidal power			2.0		

	Construction time, long-term or low-cost case (years)				
Source ->	**EIA**	**Lazard**	**Black & Veatch**	**Parsons; DECC**	**LBNL, others**
Technology					
Advanced pulv. coal		5.0	4.6		
Advanced pulv. coal w/CC			5.5	4.0	
IGCC coal		4.8	4.8		
IGCC coal w/CC			4.9	4.5	
Gas peaking (turbine)		2.1	2.5	1.5	
Gas combined cycle		3.0	3.4	2.0	
Diesel generator		0.3			
Nuclear, APWR		5.8	5.0	5.0	5.0
Nuclear, SMR					
Geothermal		3.0	3.0		
Microturbine		0.3			
Biomass direct		3.0	3.0		
Hydropower			2.0		
On-shore wind		1.0	1.0		
Off-shore wind		1.0	1.0		
Fuel cell		0.3			
Solar thermal (CSP) without storage					
Solar thermal (CSP) with storage		2.5	2.0		
PV utility crystalline tracking			0.8		
PV utility crystalline fixed			1.0		
PV utility thin film tracking					
PV utility thin film fixed					
PV commercial rooftop		0.3	0.3		
PV residential rooftop		0.3	0.1		
Wave power			2.0		
Tidal power			2.0		

	Plant operating life, near-term or high-cost case (years)				
Source ->	EIA	Lazard	Black & Veatch	Parsons; DECC	LBNL, others
Technology					
Advanced pulv. coal	40		n.r.		65-75
Advanced pulv. coal w/CC		40	n.r.	20	65-75
IGCC coal	40		n.r.		65-75
IGCC coal w/CC	40	40	n.r.	20	65-75
Gas peaking (turbine)	30	20	n.r.	20	
Gas combined cycle	30	20	n.r.	20	55
Diesel generator		20			
Nuclear, APWR	60+	40	n.r.	60	60-80
Nuclear, SMR					
Geothermal	40	20	n.r.		
Microturbine		20			
Biomass direct		20	n.r.	22	
Hydropower	80		60		
On-shore wind	25	20	n.r.	24	
Off-shore wind	25	20	n.r.	23	
Fuel cell		20			
Solar thermal (CSP) without storage					
Solar thermal (CSP) with storage		40	n.r.		
PV utility crystalline tracking	25	20	n.r.	25	40
PV utility crystalline fixed		20	n.r.		
PV utility thin film tracking	25	20			40
PV utility thin film fixed		20			
PV commercial rooftop		20	n.r.		38
PV residential rooftop		20	n.r.		36
Wave power	20		20		
Tidal power	20		25		

	Plant operating life, long-term or low-cost case (years)				
Source ->	**EIA**	**Lazard**	**Black & Veatch**	**Parsons; DECC**	**LBNL, others**
Technology					
Advanced pulv. coal		40	n.r.		
Advanced pulv. coal w/CC			n.r.	35	
IGCC coal		40	n.r.		
IGCC coal w/CC			n.r.	35	
Gas peaking (turbine)		20	n.r.	35	
Gas combined cycle		20	n.r.	35	
Diesel generator		20			
Nuclear, APWR		40	n.r.	60	
Nuclear, SMR					
Geothermal		20	n.r.		
Microturbine		20			
Biomass direct		20	n.r.		
Hydropower			60		
On-shore wind		20	n.r.		30 to 35
Off-shore wind		20	n.r.		
Fuel cell		20			
Solar thermal (CSP) without storage					
Solar thermal (CSP) with storage		40	n.r.		
PV utility crystalline tracking			n.r.		50
PV utility crystalline fixed			n.r.		
PV utility thin film tracking					50
PV utility thin film fixed					
PV commercial rooftop		20	n.r.		48
PV residential rooftop		20	n.r.		45
Wave power			20		
Tidal power			25		

	Fuel efficiency, near-term or high-cost case (%)				
Source ->	**EIA**	**Lazard**	**Black & Veatch**	**Parsons; DECC**	**LBNL, others**
Technology					
Advanced pulv. coal	39%		36%		
Advanced pulv. coal w/CC		28%	27%	34%	
IGCC coal	39%		38%		
IGCC coal w/CC	32%	32%	29%	35%	
Gas peaking (turbine)	35%	38%	33%	37%	
Gas combined cycle	53%	49%	51%	57%	
Diesel generator		34%			
Nuclear, APWR	33%	33%	35%	100%	
Nuclear, SMR					
Geothermal	100%	100%	100%		
Microturbine		28%			
Biomass direct	25%	24%	24%		
Hydropower	100%		100%		
On-shore wind	100%	100%	100%	100%	
Off-shore wind	100%	100%	100%	100%	
Fuel cell	36%	52%			
Solar thermal (CSP) without storage					
Solar thermal (CSP) with storage		100%	100%		
PV utility crystalline tracking	100%	100%	100%	100%	
PV utility crystalline fixed		100%	100%		
PV utility thin film tracking	100%	100%			
PV utility thin film fixed		100%			
PV commercial rooftop		100%	100%		
PV residential rooftop		100%	100%		
Wave power			100%		
Tidal power			100%		

	Fuel efficiency, long-term or low-cost case (%)				
Source ->	**EIA**	**Lazard**	**Black & Veatch**	**Parsons; DECC**	**LBNL, others**
Technology					
Advanced pulv. coal	39%	39%	36%		
Advanced pulv. coal w/CC			28%	39%	
IGCC coal	46%	39%	43%		
IGCC coal w/CC	41%		33%	40%	
Gas peaking (turbine)	40%	33%	33%	39%	
Gas combined cycle	54%	51%	51%	60%	
Diesel generator		34%			
Nuclear, APWR	33%	33%	35%	100%	
Nuclear, SMR					
Geothermal	100%	100%	100%		
Microturbine		34%			
Biomass direct	25%	24%	27%		
Hydropower	100%		100%		
On-shore wind	100%	100%	100%		
Off-shore wind	100%	100%	100%		
Fuel cell	52%	47%			
Solar thermal (CSP) without storage					
Solar thermal (CSP) with storage		100%	100%		
PV utility crystalline tracking	100%		100%		
PV utility crystalline fixed			100%		
PV utility thin film tracking	100%				
PV utility thin film fixed					
PV commercial rooftop		100%	100%		
PV residential rooftop		100%	100%		
Wave power			100%		
Tidal power			100%		

ANNOTATION OF MAIN LITERATURE SOURCES USED IN OUR ANALYSIS OF THE NATIONAL-AVERAGE LCOE (TABLE S14)

EIA = Energy Information Administration; DECC = Department of Energy and Climate Change (United Kingdom); LBNL = Lawrence Berkeley National Laboratory; pulv. coal = pulverized coal; w/CC = with carbon capture; IGCC = integrated gasification combined cycle; APWR = advanced pressurized-water reactor; SMR = small modular reactor; CSP = concentrating solar power.

EIA

Near-term estimates are from Table 8.2 of EIA (2014a), except: near term fuel prices are 2019 prices to the electric power sector (EIA, 2014c), and capacity factors are from EIA (2014b).

Capital costs are "total overnight costs," for plants initiated in 2013, and include project contingency and "technological optimism" factors but exclude investment tax credits, learning effects, regional multipliers, and interest charges. Heat rate is higher-heating-value (HHV) basis (EIA, 2013). What we call "construction time" the EPA calls "lead time," which is the time from project initiation to the plant coming on line.

In the case of geothermal and hydro the values shown in Table S14 are the EIA's estimates for "the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located" (EIA, 2014a, p. 97). (In its NEMS runs the EIA estimates site-specific marginal costs for geothermal and hydropower plants [EIA, 2014a, p. 97].)

EIA (2014a) reports estimates for "advanced" and "conventional" gas/oil combined cycle plants, and "advanced" and "conventional" combustion turbines; the estimates shown here are for the "advanced" plants. What we call "advanced coal" the EPA calls "conventional coal" or "new scrubbed coal."

PV is fixed-tilt, single-axis tracking, of unspecified cell technology.

O&M costs include administration expenses, taxes and insurance (EIA, 2013). However, the EIA estimates O&M costs for *new* plants only (Jones, 2014).

We estimate long-term capital cost and fixed O&M costs by multiplying EIA's near-term estimates by the 2040/2019 LCOE ratios from EIA (2014b). We estimate long-term (year-2050) fuel prices to the electric power sector by extrapolating EIA's 2040 price projections at the 2030-2040 rate of growth projected by EIA (2014c).

<u>Other notes</u>: The EIA notes that plant lifetimes depend in general on the economics of extending plant lifetime, which in turn depends on the cost of additional O&M, upgrades and refurbishing, regulatory requirements, competing alternatives, and so on. In the case of nuclear power, the EIA (2014c) notes that the Nuclear Regulatory Commission has approved 70% of US plants for a 20-year extension beyond the initial 40-year license, and that "the nuclear power industry currently is developing strategies to submit license applications for additional 20-year life extensions that would allow

plants to continue operating beyond 60 years" (p. IF-35). The EIA (2014c) *AEO* reference case assumes that nuclear plants operate beyond 60 years, but the "Accelerated Nuclear Retirements case assumes that O&M costs for nuclear power plants grow by 3% per year through 2040; [and] that all nuclear plants not retired for economic reasons are retired after 60 years of operation" (p. IF-35). (The EIA's [2010] *AEO 2010* assumed that O&M costs increased by $30/kW after plants reached 30 years of age.) Similarly, the EIA (2014c) assumes that in the "Accelerated Coal Retirements" case real O&M costs increase at 3% annually.

The EIA (2014c) also projects fuel use and generation in the electric power sector, from which we can calculate fleet-average generation efficiency by fuel type. For coal-fired plants, the efficiency remains just below 33% throughout the projection period (to 2040), because virtually no new coal capacity is added. However, the efficiency of natural-gas fired generation increases from about 42% in 2013 to almost 48% in 2040, as the total installed capacity of combined-cycle plants increases 1.7% per year and the total installed capacity of conventional gas steam plants decreases at -1.2%/year over the projection period (EIA, 2014f). (Note again that these are averages across a fleet of plants of a mix of different technologies.)

Lazard

From Lazard (2014). Cost estimates exclude subsidies. Our capital-cost figures include their "EPC cost" (engineering, procurement, and construction) and "Other Owner Costs," but not their "capital costs during construction" because those are interest costs on capital during construction (Jalan, 2014), which most other studies exclude and which we estimate separately. Lazard's capital costs include generic costs to connect to regular transmission grid, including such costs for off-shore wind. Their "high" case figures for a diesel generator assumes intermittent usage. Solar thermal storage "low" has 18-hours of storage; "high" has 10 hours. Their estimates of O&M cover all operating expenditures including administration, insurance, and taxes (Jalan, 2014). Fixed O&M includes periodic capital expenditures (Jalan, 2014) but not decommissioning and waste disposal costs.

Black & Veatch

From Black and Veatch (2012). Technology ca. late 2009, early 2010. Costs in 2009 USD. Costs exclude electric switchyard, transmission tap-line, interconnection, and interest during construction. For non-commercial plants, they base their estimates on engineering studies of "nth plant costs." "Near term" is their estimate for 2010 (2020 with carbon capture and sequestration); "long term" is their estimate for 2050. For thermal plants, the capacity factor we show here is equal to 100% minus their reported forced and planned outage rates. We assume that their heat rates are based on higher heating values. Geothermal is conventional hydrothermal. Wave and tidal estimates are based on their optimistic scenario, with the middle resource-availability band. For wave and tidal, "near term" is their estimates for 2015. In Black and Veatch hydropower life is "at least 50 years" (p. 106). PV utility estimates are for 100-MW systems; the technology is unspecified, so we assume crystalline-silicon. Their solar thermal has 6-hour storage. Wind capacity-factor range is for Class 3 to Class 7 resources. Offshore wind is fixed-bottom technology.

Parsons; DECC

Wind, solar, biomass estimates from U. K. Department of Energy and Climate Change (2013). Coal, gas, nuclear are low or high estimates for *n*th of a kind plant, from Parsons Binckerhoff (2013). Efficiency is based on lower heating values (LHVs). The capacity factor shown here is their "average lifetime load factor" for wind, solar, and biomass, and their "average availability" for coal, gas, and nuclear.

LBNL, others

Wind: Estimates of capacity factors, capital costs, and O&M costs are from Barbose et al. (2014b). Their capacity-factor range covers all individual project sites in 2012, and their fixed O&M estimates are for projects installed since 2000. Their estimates of O&M costs exclude administration, lease, insurance, and related costs.

Photovoltaics (PVs): Near-term, installed capital-cost estimates (except lower-end, near-term cost estimates) are based on installation prices (in $/kW-dc) are from Barbose et al. (2014a), as follows: *Utility PV:* capacity-weighted average installed price in 2013. Note that these are utility PV prices contracted several years prior to installation, and hence do not reflect recent price declines. *Residential PV:* price for systems <10 kW installed in 2014. *Commercial PV*: price for systems >100 kW installed in 2014. PV near-term lower-end prices are turnkey prices estimated for Q2 2014 from GTM Research (2014). PV commercial and residential long-term cost estimates shown here are Barbose et al. (2014a) reported prices in Germany, which Barbose et al. (2014a) state are indicative of the potential for further significant cost reductions in the U.S. Estimates for utility-PV capacity factors and utility-PV O&M costs are from Bolinger and Weaver (2014). (We use our judgment to interpret their O&M data.) Bolinger and Weaver (2014) note that utility-PV capacity factors depend primarily on the intensity of the solar resource, and secondarily on the inverter loading ratio.

Goodrich et al. (2012) estimate that "evolutionary" cost reductions for PVs will result in the following system prices in the year 2020 (year-2010 dollars per peak-watt dc): 2.29 residential rooftop, 1.99 commercial rooftop, 1.71 fixed-axis utility ground mount, 1.91 one-axis utility-scale ground mount.

PV system lifetime estimates are from Jacobson et al. (2014) and Bazilian et al. (2013). Wind lifetime estimate is based on Dvorak (2014) and Byrne (2013).

Solar thermal (or Concentrated Solar Power [CSP]): Bolinger and Weaver (2014) estimate $6000/kW capital cost for a trough with 6-hours of storage. They suggest that the storage adds $1500/kW. They also estimate $60/kW/yr for O&M for Solar thermal (CSP) without storage. US DOE (2012) estimates current costs of $4000-$8500/kW (capital) and $60-$70/kW/yr (O&M), with the low end for plants without storage and the high end for plants with storage. Current plants without storage have a capacity factor of 20%-28%; current plants with 6-7.5 hours of storage have a capacity factor of 40%-50%.

DOE (2012) estimates “evolutionary” technology cost and performance in 2020: $6070/kW (overnight capital cost), $50kW/yr (O&M cost), 66.4% capacity factor, 14 hours storage. DOE (2012) also estimates more aggressive “Sunshot"” cost and performance targets for 2020: $3560/kW, $40/kW/yr, 66.6% capacity factor, 14 hours storage (in year-2010-$.)

By comparison, Nithyanandam and Pitchumani (2014) estimate that 14-hours storage in an optimal system costs less than $300/kW, and that total capital costs could be under the DOE Sunshot target.

Nuclear: Linares and Conchado (2014) assume 5 to 9 years construction time, 6-12% weighted-average cost of capital, and a capacity factor of 80%-90% for APWRs. Anadon et al. (2013) report the range of expert estimates of the capital cost of APWR Gen III technology in year 2030; Table S14 “long-term” capital costs are based on the 10th and 90th percentiles of the expert range.

For nuclear SMRs, Table S14 capital cost estimates are “realistic” cost estimates from Cooper (2014) for 2020 (our near term) and 2030 (our long term).

Construction time and operating lifetime: Sovacool et al. (2014c) show construction times for generic categories thermal, hydro, nuclear, wind, and solar (see also Sovacool et al., 2014a, 2014b). NREL (Short et al., 2011) reports the scheduled lifetime for coal plants (65 years for units < 100 MW; 75 years for units > 100 MW), natural gas combined cycle and oil-gas-steam units (both 55 years), and nuclear plants (60-80 years). They also report construction times for a range of plant types, as shown in Table S14.

8) CALCULATION OF THE COST OF ELECTRICITY BY STATE, YEAR, AND SCENARIO

We calculate the average cost of electricity by state, year, and scenario (BAU or 100% WWS) as the sum of the product of the state’s fractional generation mix and the levelized cost of electricity (LCOE), by technology, as follows:

$$AC_{S,Y,W} = \sum_{j} S_{j,S,Y,W} \cdot C_{j,S,Y,W}$$

$$S_{j,S,Y,BAU} = S_{j,M:S\in M,Y,BAU}$$

$$C_{j,S,Y,W} = C_{j,US,Y,W} \cdot R_{ADJ,j,S,Y,W}$$

$$R_{ADJ,j,S,Y,BAU} = 1 + C\%_{AI+FOM,j,US,Y,BAU} \cdot \left(\frac{R_{IC-C,j,M:S\in M} \cdot R_{IC-A,j,M:S\in M}}{R_{CF,j,M:S\in M,BAU}} - 1 \right) + C\%_{FUEL,j,US,Y} \cdot \left(R_{FUEL,j,M:S\in M,Y} - 1 \right)$$

$$R_{ADJ,j,S,Y,100\%WWS} = 1 + C\%_{AI+FOM,j,US,Y,100\%WWS} \cdot \left(\frac{R_{IC-C,j,M:S\in M}}{R_{CF,j,S,Y,100\%WWS}} - 1 \right)$$

where

$AC_{S,Y,W}$ = the average levelized cost of electricity from all technologies in state S in year Y in scenario W ($/kWh)

$S_{j,S,Y,W}$ = the fraction of total generation provided by technology j in state S in year Y in scenario W (for 100% WWS scenario see discussion below; for BAU, see equation for parameter $S_{j,S,Y,BAU}$)

$C_{j,S,Y,W}$ = the levelized cost of electricity from technology j in state S year Y in scenario W ($/kWh)

$S_{j,M:S\in M,Y,BAU}$ = the fraction of total electricity provided by technology j in EIA Electricity Market Module Region (EMMR) M (containing state S) in year Y in the BAU scenario (see discussion below)

$C_{j,US,Y,W}$ = the average levelized cost of electricity from technology j in the United States in year Y in scenario W ($/kWh) (Table S13)

$R_{ADJ,j,S,Y,W}$ = regional adjustment factor for technology j in state S in year Y and scenario W (we calculate adjustment factors for fossil-fuel-power plants, wind power, and solar power)

$C\%_{AI+FOM,j,US,Y,W}$ = the annualized+fixed O&M cost for technology j in the U.S. in year Y in scenario W, as a fraction of the total levelized cost (calculated from the intermediate national-average results)

$C\%_{FUEL,j,US,Y}$ = the fuel cost for technology j in the U.S. in year Y, as a fraction of the total levelized cost (calculated from the intermediate national-average results)

$R_{IC-C,j,M:S\in M}$ = the ratio of initial costs for technology j in region M (containing state S) to the national-average costs assumed here, reflecting regional variability in construction costs (see the discussion below)

$R_{IC-A,j,M:S\in M}$ = the ratio of initial costs for technology j in region M (containing state S) to the national-average costs assumed here, reflecting regional variability in ambient conditions such as temperature (see discussion below)

$R_{FUEL,j,M:S\in M,Y}$ = the ratio of fuel costs for technology j in region M (containing state S) in year Y to the national-average costs assumed here (EIA's [2014c] *AEO* projections)

$R_{CF,j,M:S\in M,BAU}$ = the ratio of the capacity factor for technology j in region M (containing state S) to the national-average factors estimated here, in the BAU (assumed to be 1.0 for all technologies in the BAU scenario, for all years; see discussion below)

$R_{ADJ,j,S,Y,100\%WWS}$ = the adjustment factor for technology j in state S in year Y in the 100% WWS scenario to the national-average factors assumed here

$R_{CF,j,S,Y,100\%WWS}$ = the ratio of the capacity factor for technology j in state S in year Y to the national-average factors estimated here, in the 100% WWS scenario (see discussion below)

subscript j = technology types (Table S13)
subscript W = 100% WWS or BAU scenario
subscript M = Electricity Market Module Region (EIA 2014a, 2014e; there are no EMMs for Alaska and Hawaii, so as explained above we make separate assumptions for these two states)

Fraction of generation by technology in the 100% WWS scenario ($S_{j,S,Y,100\%WWS}$)

We constrain hydropower to existing capacity in each state except in the case of Alaska. We perform a detailed analysis of the potential generation from rooftop PV in each state (following the method of Jacobson et al., 2014) and then estimate the actual installed capacity for each state subject to a constraint that the installed capacity not exceed 93% (residential) or 95% (commercial) of the potential. (With our assumptions the installed capacity is about 60% of the potential for all 50 states.) We assume minor contributions from geothermal, wave, and tidal based on available resources in each state. For onshore wind, offshore wind, and solar thermal, we analyze the solar and wind resources available for each state and develop appropriate assumptions. Finally, we assume that utility solar PV provides the difference between demand and the supply from all other sources. We assume that 65% of utility PV is crystalline single-axis tracking technology, and 35% is thin-film single-axis tracking technology.

We also maintain an estimate of the LCOE in a 100% WWS scenario at base-year cost levels. For this base-year scenario we assume the same 100% WWS generation mix as in the target year.

Fraction of generation by technology and EMM in the BAU scenario ($S_{j,M:S\in M,Y,BAU}$)

As indicated above, in order to calculate the average LCOE for each state in the BAU we need to know $S_{j,M:S\in M,Y,BAU}$, the fraction of total electricity provided by technology j in EIA Electricity Market Module Region (EMMR) M (containing state S) in year Y in the BAU scenario. Our technology categories j are shown in Table S13. Now, the EIA does not project exactly what we want ($S_{j,M:S\in M,Y,BAU}$), but it does project something close (EIA, 2014c), which we will designate $S_{f,M:S\in M,Y[2040],BAU}$, where the subscript f is the type of generator fuel (see below) and the subscript *Y[2040]* means that their projection extends only to 2040 (we go to 2075). We therefore have to extend the EIA's projections to the year 2075, and map their fuel (*f*)-based projections to our technology-type (*j*)-based projections.

Extending the EIA's projections. We extend the EIA projections to 2075 using a ten-year moving trend line.

Mapping the EIA's fuel-based projections to our technology-type projections. The EIA (2014c) projects electricity generation by EMM and fuel type *f*, where the fuel types are Coal, Petroleum, Natural Gas, Nuclear, Pumped Storage, Conventional Hydropower, Geothermal, Biogenic Municipal Waste, Wood and Other Biomass, Solar Thermal, Solar Photovoltaic utility, Wind, Offshore Wind, Solar Photovoltaic end-use, and Distributed Generation. Our renewable technology categories are similar, but our fossil-fuel categories are more disaggregated. Fortunately, the EIA (2014f) also projects electricity generation for the whole U.S. (but not by EMM) by type of fossil-fuel technology, and we can use these national projections to break out into more specific technology types the EIA's projection of coal, natural gas, and petroleum generation by EMM.

Table S15 shows how we map the EIA's (2014c, 2014f) projections into our technology types. This mapping is straightforward except in the case of petroleum and natural gas fuels, because the EIA's (2014f) projections of generation by technology include several technology categories (e.g., steam turbine) that can use either petroleum or natural gas. Thus, in these cases, we must further disaggregate the EIA's (2014f) projections to be by fuel type as well as technology type. To do this, we extract and aggregate plant-level EIA data on generation by oil and gas, by plant type, for the lower 48 states, Alaska, Hawaii, and the whole U.S. (Table S16). We use the results of Table 16, for the lower 48 states, to distribute the EIA's (2014f) projections by technology type to our technology- and fuel-specific categories. (We use results for the lower 48 states because the EIA's [2014f] projections are for the lower 48 states only; we and the EIA treat Alaska and Hawaii separately.)

Table S15. Mapping EIA fuel-use categories to our technology types.

EIA (2014c) fuel category	2050 weight	Our technology category
Coal	99.1%	Advanced pulverized coal
Distribution based on EIA (2014f).	0.0%	Advanced pulverized coal w/CC
	0.5%	IGCC coal
	0.4%	IGCC coal w/CC
Petroleum		Diesel generator (for steam turbine)
Natural Gas	5.3%	Gas combustion turbine
Distribution based on EIA (2014f) and Table S16 analysis; see discussion below.	34.0%	Combined cycle conventional
	60.4%	Combined cycle advanced
	0.2%	Combined cycle advanced w/CC
	0.0%	Fuel cell (using natural gas)
	0.0%	Microturbine (using natural gas)
Nuclear	100.0%	Nuclear, APWR
EIA (2014g) assumes no storage	0.0%	Nuclear, SMR
Distributed generation		Distributed generation (using natural gas)
Biogenic Municipal Waste		Municipal solid waste
Wood and Other Biomass		Biomass direct
Geothermal		Geothermal
Pumped Storage, Conventional hydropower		Hydropower
Wind		On-shore wind
Offshore Wind		Off-shore wind
Solar Thermal	100.0%	CSP no storage
EIA does not consider storage.	0.0%	CSP with storage
Solar Photovoltaic utility	65.0%	PV utility crystalline tracking
EIA's AEO includes only single-axis-tracking PV of unspecified technology (EIA, 2014g, p. 66; EIA, 2014a, p. 178)	0.0%	PV utility crystalline fixed
	35.0%	PV utility thin-film tracking
	0.0%	PV utility thin-film fixed
Solar Photovoltaic end-use	35.0%	PV commercial rooftop
Our assumption.	65.0%	PV residential rooftop
No EIA projections.		Wave power
No EIA projections.		Tidal power
No EIA projections.		Solar thermal (water or glycol solution)

Note: Our category "gas combustion turbine" includes the "steam turbine" and "gas turbine" categories of Table S16.

Table S16. Generation from oil and natural gas, by plant type, all generators (electric utilities and co-generators), U. S., 2013 (MWh)

Plant type	Lower 48		Alaska		Hawaii		United states	
	Oil	*NG*	*Oil*	*NG*	*Oil*	*NG*	*Oil*	*NG*
ICE	155,853	10,450,007	403,883	60,945	347,303	0	907,039	10,510,952
Steam turbine	4,452,615	92,181,479	3,515	5,000	4,257,719	0	8,713,848	92,186,480
Combined cycle	635,860	951,534,387	364,625	2,774,980	2,474,139	0	3,474,624	954,309,367
Gas turbine	669,432	94,582,808	53,120	625,621	172,112	41,330	894,665	95,249,759
Total	*5,913,760*	*1,148,748,681*	*825,143*	*3,466,547*	*7,251,273*	*41,330*	*13,990,176*	*1,152,256,557*

ICE = internal combustion engine; NG = natural gas.

Source: Our analysis of EIA plant-level database: U.S. Department of Energy, The Energy Information Administration (EIA), EIA-923 Monthly Generation and Fuel Consumption Time Series File, 2013 Final Release, EIA-923 and EIA-860 Reports (http://www.eia.gov/electricity/data/eia923/).

Alaska and Hawaii. The EIA's EMM regions do not cover Alaska and Hawaii. For these states we assume the actual generation shares in 2013 (http://www.eia.gov/electricity/data/state/) remain constant over time. (This in essence is what the EIA does in its *AEO* projections [Jones, 2015].)

Note that our method properly and consistently accounts for the effects on CO_2 emissions *and* generation costs of the use of carbon-capture and sequestration (CCS): we use the EIA's projections of generation with CCS, the EIA's projections of the associated economy-wide CO_2 emissions from fossil-fuel use, and the EIA's assumptions on the cost of generation technology with CCS relative to the cost without.

Regional variation in initial capital costs

The EIA's *AEO* accounts for two sources of regional variation in the capital cost of electricity generation technologies: variation in construction costs (primarily labor costs), and variations in ambient conditions, such as temperatures, that affect the power output of the turbine and hence the $/kW capital cost of the technology. (For example, air temperature influences the air pressure into the turbines, which in turn determines the turbine power output.) We account for the same effects here, using the EIA's multipliers.

The EIA commissioned a consultant to estimate variability in construction costs and ambient conditions for a representative city (or cities) in all 50 states in the U. S. (EIA, 2013). With these estimates, the EIA developed its own estimates of $R_{IC-C,j,M:S\in M}$ (the capital cost in each region, relative to the national-average cost, due to the construction cost in the region relative to the national average) and $R_{IC-A,j,M:S\in M}$ (the capital cost in each region, relative to the national-average cost, due to the ambient conditions in the region relative to the national average) (EIA, 2014h; see also Table 4 of EIA, 2013, for a summary of the product of $R_{IC-C,j,M:S\in M}$ and $R_{IC-A,j,M:S\in M}$ by EMM). For the 22 EMMs in the lower 48 states, we use the EIA's (2014h) estimates. For Alaska and Hawaii we use the estimates developed in the EIA's consultant report (EIA, 2013), the average of Anchorage and Fairbanks for Alaska, and Honolulu for Hawaii.

The EIA does not apply these regional capital-cost adjustments to geothermal and hydropower. Instead, the EIA estimates geothermal and hydropower capital costs and capacity by EMM region including in this case Alaska and Hawaii (EIA, 2014i). We use these to calculate capacity-weighted average capital costs in each EMM region relative to the capacity-weighted national-average capital cost. If the EIA (2014h) did not estimate capital cost or capacity for a region, we assume a relative factor of 1.0., except in the case of geothermal for Hawaii, where we assume an adjustment factor based on the generally higher construction costs in Hawaii.

In the EIA's analysis the regional multipliers apply to "base-case" capital-cost estimates, which pertain to a "generic" facility built in an unspecified, "typical" location (EIA, 2014a, p. 96; EIA, 2013, p. 5, p.2-6). Here we apply the same regional multipliers to our own estimates of generic, nationally typical capital costs. On the reasonable assumption that our generic capital-cost estimates are conceptually similar to the EIA's generic "base-case" estimates, our use of the EIA's regional multipliers is valid.

The relative capacity factor for technology *j* in region *M* in the BAU scenario.

In this analysis we ignore regional variations in capacity factors in the BAU and instead assume that capacity factors in all regions for all technologies are equal to the national-average capacity factor for the technology as projected by the EIA. (However, as discussed below, we do adjust the EIA's projected BAU capacity factors for wind power to account for the reduction in wind speed due to increasing numbers of wind turbines.) If we were to estimate region-specific capacity factors and then weight these by regional generation, the resultant total U.S. average costs would be the same, but region-by-region costs would be slightly different from what we have estimated here.

The relative capacity factor for technology *j* in state *S* in year *Y* in the 100% WWS scenario.

We estimate capacity factors for onshore wind and all solar technologies, for each state, in target-year *Y*, relative to the estimated or assumed national-average capacity factor in Table S13. For all other technologies in the 100% WWS scenario (e.g., hydro and offshore wind), we assume that each state's capacity factor is the same as the national average factor, meaning that the adjustment term $R_{CF,j,S,Y,100\%WWS}$ is 1.0.

Onshore wind. For onshore wind, we first calculate the capacity factor for each state and for the nation as a whole in 2013 based on reported wind generation by state from the EIA's *Electric Power Monthly* (http://www.eia.gov/electricity/monthly/) and installed wind capacity by state in 2013 from the DOE (http://apps2.eere.energy.gov/wind/windexchange/wind_installed_capacity.asp). For states with either zero generation or capacity, we assume the regional-average capacity factor. We then calculate the ratio of each state's 2013 capacity factor to the national average capacity factor (calculated from the same state-level data) in the base year (2013 in the present analysis, but represented generally by the parameter Y_{CF}); we designate this ratio $R_{CF,wind,S,Y_{CF}}$. The overall target-year adjustment factor $R_{CF,wind,S,Y,100\%WWS}$ is then the product of $R_{CF,wind,S,Y_{CF}}$, a multiplier that accounts for changes in resource availability due to the use of more or less windy sites than in the base year (subscript *RA*), and a multiplier that accounts for the reduction in wind speed as the number of turbines extracting energy from the wind increases (subscript *WX*):

$$R_{CF,wind,S,Y,100\%WWS} = R_{CF,wind,S,2013} \cdot \varphi_{RA,wind,S,Y,100\%WWS} \cdot \varphi_{WX,wind,S,Y,100\%WWS}$$

$$\varphi_{RA,wind,S,Y,100\%WWS} = \varphi_{RA,wind,S,Limit} + \left(1 - \varphi_{RA,wind,S,Limit}\right) \cdot e^{\gamma_{RA} \cdot (Y - Y_{CF})}$$

$$\varphi_{WX,wind,S,Y,100\%WWS} = \varphi_{WX,wind,S,Limit} + \left(1 - \varphi_{WX,wind,S,Limit}\right) \cdot e^{\gamma_{WX} \cdot (Y - Y_{CF})}$$

where

$\varphi_{...Y}$ = the ratio of the capacity factor in year Y to the capacity factor in year Y_{CF} on account of changes in the availability in wind resources (subscript *RA*) or wind-energy extraction (subscript *WX*)

$\varphi_{RA,wind,S,Limit}$ = the ratio of the capacity factor in the long-run limit to the capacity factor in year Y_{CF} on account of changes in the availability in wind resources (discussed below)

$\varphi_{WX,wind,S,Limit}$ = the ratio of the capacity factor in the long-run limit to the capacity factor in year Y_{CF} on account of increasing wind-energy extraction (discussed below)

γ = the rate of approach of the long-run limiting reduction factor due to resource availability or competition among turbines (discussed below)

Y = the target year of the analysis

Y_{CF} = the year of the baseline capacity-factor data (2013 in the present analysis)

As discussed in the section "Capacity factor: resource availability long-run limit w.r.t. base (100% WWS scenario only) (<100%)," in the U. S. most of the high-wind sites have yet to be developed. However, in order to get a more quantitative sense of the long-run availability of wind resources by state, we examine NREL's map of wind power classes throughout the U.S., with appropriate land-use restrictions applied (Figure S3). Based on this examination, and considering that in Jacobson et al. (2015) "wind turbines are placed near each of 42,000 existing U.S. turbines..," we assume that $\varphi_{RA,wind,S,Limit}$ is 96% to 100%, with higher values for the states with the best wind resources, and that this limit is approached at a rate of 4%/year.

As mentioned above, another factor affects the amount of energy available from wind resources in a target year with respect to the amount available in the base year. As the number of wind farms increases, the extraction of kinetic energy from the wind by the turbines decreases the average wind speeds, which in turn reduces the potential power output from the wind farms (Jacobson and Archer, 2012).

The magnitude of this reduction depends on several factors, including the size, location, and spacing of wind farms; the height of the turbines; and the extent to which the increased dissipation of kinetic energy as heat eventually increases the available potential energy of the atmosphere (Jacobson and Archer, 2012). Results from Jacobson et al. (2015) indicate that the reduction in wind speeds due to large-scale deployment of wind farms, on the scale assumed here, can reduce the average capacity factor by about 7%. At higher levels of deployment – at what might constitute our long-run limit – the reduction presumably would be slightly higher. On the other hand, the base-year capacity factors we start with already reflect the actual performance of existing wind farms, and therefore account for the real-world reduction in wind speed due to use of wind power at the relatively low levels of penetration in the base year.

With these considerations, we assume that at highest levels of deployment the reduction in wind speeds due to extraction of kinetic energy by turbines would (further) reduce the capacity factor for onshore wind by 5% to 7%; i.e., that $\varphi_{WX,wind,S,Limit}$ is 93% to 95%, with higher values for the states with the best wind resources.

Offshore wind. For offshore wind we assume smaller effects because these farms generally are spaced relatively far from one-another and from onshore farms; thus, we assume a 4% reduction in the low-cost case and a 6% reduction in the high-cost case.

Note that, as discussed later, this effect applies also to wind power in the BAU scenario.

Solar power. For solar power, the adjustment factor $R_{CF,j,S,Y,100\%WWS}$ is the ratio of the average insolation in year Y for technology j in state S to the generation-weighted national average insolation for technology j in the base year Y_{CF}. The average insolation in year Y is equal to the average insolation in year Y_{CF} multiplied by an adjustment factor that accounts for changes in siting opportunities between the base year Y_{CF} and the target year Y. The average insolation in the base year Y_{CF} is the product of the three factors: i) the average insolation in a representative city in the state; ii) an adjustment for the general effect of the size of the state on the opportunity for siting in places with insolation different than in the representative city; and iii) an adjustment that accounts for the specific effect of areas in the state, such as deserts, with especially good insolation.

Formally for the case of CSP technology,

$$R_{CF,CSP,S,Y,100\%WWS} = \frac{U_{CSP,S,Y}}{U_{CSP,US,Y_{CF}}}$$

$$U_{CSP,S,Y} = U_{CSP,S,Y_{CF}} \cdot AF_{LOC-CSP,S,Y}$$

$$AF_{LOC-CSP,S,Y} = AF_{LOC-CSP,S,Y_{CF}\to Limit} + \left(1 - AF_{LOC-CSP,S,Y_{CF}\to Limit}\right) \cdot e^{\gamma_{U-CSP}\cdot(Y-Y_{CF})}$$

$$U_{CSP,S,Y_{CF}} = U_{City-S} \cdot AF_{AREA,S} \cdot AF_{LOC-CSP,S,Y_{CF}}$$

$$AF_{AREA,S} = \max\left(1, \left(\frac{A_S}{A_{GEOMEAN-US}}\right)^a\right)$$

$$U_{CSP,US,Y_{CF}} = \frac{1}{G_{CSP,US,Y_{CF}}} \cdot \sum_S U_{CSP,S,Y_{CF}} \cdot G_{CSP,S,Y_{CF}}$$

where

$R_{CF,CSP,S,Y,100\%WWS}$ = the capacity factor for technology *CSP* in state *S* in year *Y* in the 100% *WWS* scenario relative to the national-average capacity factor for CSP in year Y_{CF}

U_{CSP} = average insolation at CSP locations in (kWh/m2/d)

$U_{CSP,US,Y_{CF}}$ = generation weighed average insolation at CSP locations in the U.S. in the base year

$AF_{LOC-CSP,S,Y}$ = The ratio of average insolation at the CSP locations in state *S* in year *Y* to the average insolation at CSP locations in state *S* in year Y_{CF}

$AF_{LOC-CSP,S,Y_{CF}\to Limit}$ = the limit of $AF_{LOC-CSP,S}$ in the long run (see discussion below)

γ_{U-CSP} = the rate of approach of the long-run limit in the case of CSP (see discussion below)

U_{City-S} = average insolation in a representative city in state *S* (kWh/m2/d) (http://stalix.com/isolation.pdf)

$AF_{AREA,S}$ = adjustment factor accounting for the fact that the larger the state, the more likely there are to be sites for utility PV and CSP plants that have better insolation than for the representative city

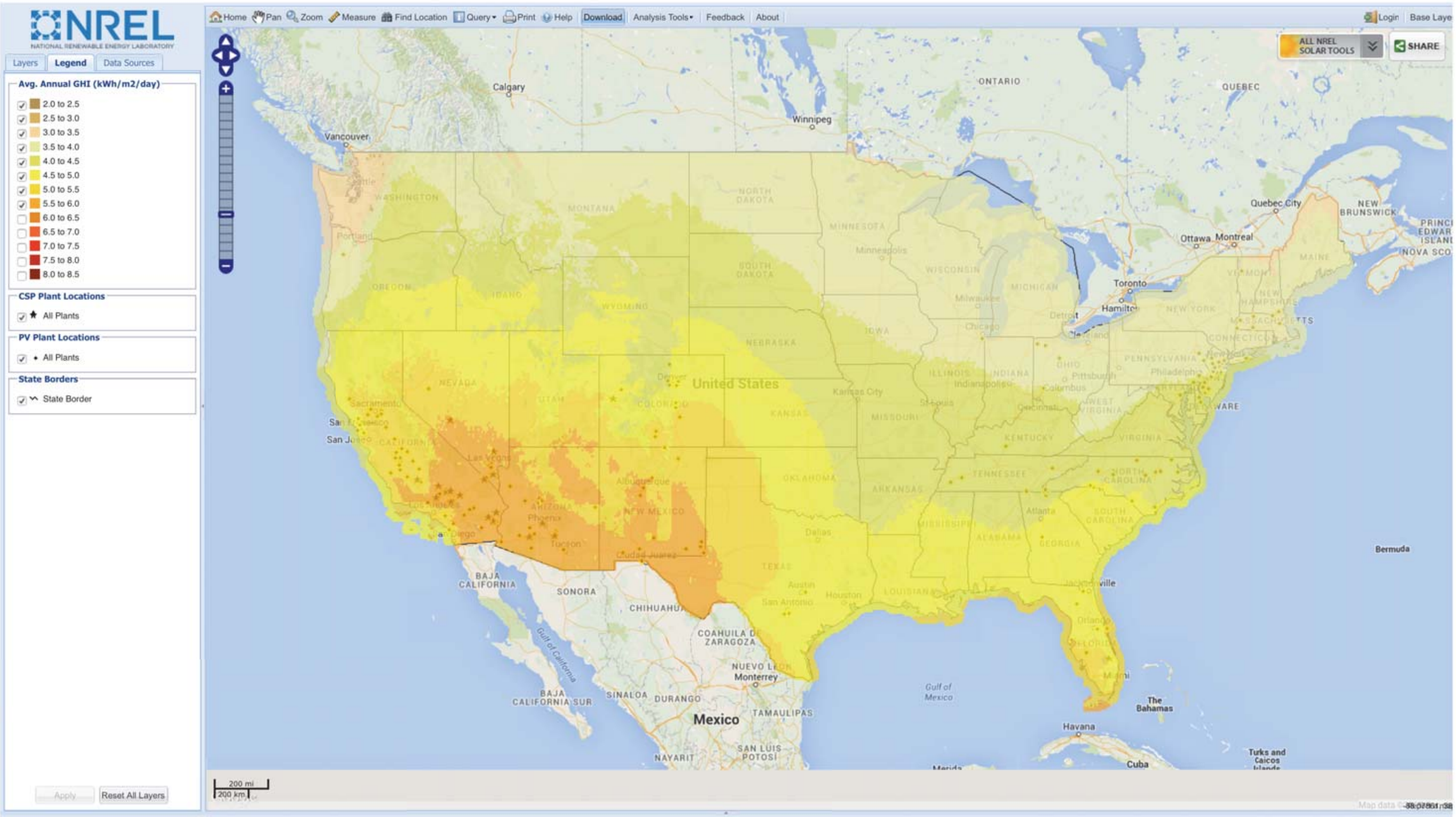
$AF_{LOC-CSP,S,Y_{CF}}$ = the ratio of average insolation at the location of CSP plants to the average insolation for the representative city, in the base year (see discussion below)

A_S = land area of state S (U. S. Census)
$A_{GEOMEAN-US}$ = the geometric mean state area in the U.S.
a = exponent (we specify this so that $AF_{AREA,S}$ is less than 1.10 for all states except Alaska)
$G_{CSP,S,Y_{CF}}$ = generation from CSP in state S in year Y_{CF} (sources for all WWS technologies: http://www.eia.gov/electricity/data/browser; Interstate Renewable Energy Council, 2014)

For states with PV and CSP plants in the base year, our assumptions for $AF_{LOC-CSP,S,Y_{CF}}$ are based on our assessment of the insolation at their actual locations in 2012 with respect to the insolation for the representative city (Figure S2). Our estimates for $AF_{LOC-CSP,S,Y_{CF}\rightarrow Limit}$ also are based on our assessment of the information shown in Figure S2, with consideration of two countervailing trends over time, i) the possibility of finding better (sunnier) locations within each state for certain types of technology, but also ii) the possibility of using up the sunniest spots first.

The relative capacity factor for WWS technologies in the BAU scenario.

We have assumed that the $R_{CF,j,M:S\in M,BAU}$ is 1.00 for all technologies, including WWS technologies, in the BAU scenario. Why do we make state-specific adjustments for the capacity factor for WWS technologies in the 100% WWS scenario but do not make EMM-region-specific adjustments in the BAU scenario? In general, we estimate state-specific parameters, relative to national-average parameters, so that i) we can report state-level costs, and ii) we can estimate a national-average LCOE based on a different set of state weights than those used to calculate the state-specific relative adjustment parameters. As discussed above, in the 100% WWS scenario the national-average capacity factors we estimate are based *implicitly* upon state generation shares that are different than the shares that we actually assume; thus, in the 100% WWS scenario, we need to know individual state capacity factors in order to estimate a national-average LCOE consistent with the state generation mix we actually assume. However, in the BAU all national-average capacity factors are taken from the EIA's *AEO*, and presumably the EIA's national average estimate is built from EMM-level capacity factors. If so, then in the BAU, there is no need to estimate the relative regional capacity factors for WWS technologies, at least for the purpose of calculating the national-average LCOE. (The use of relative regional capacity factors would change the reported state-level costs ever so slightly, but this difference is minor.)



Avg. Annual GHI (kWh/m2/day)

- ☑ 2.0 to 2.5
- ☑ 2.5 to 3.0
- ☑ 3.0 to 3.5
- ☑ 3.5 to 4.0
- ☑ 4.0 to 4.5
- ☑ 4.5 to 5.0
- ☑ 5.0 to 5.5
- ☑ 5.5 to 6.0
- ☐ 6.0 to 6.5
- ☐ 6.5 to 7.0
- ☐ 7.0 to 7.5
- ☐ 7.5 to 8.0
- ☐ 8.0 to 8.5

CSP Plant Locations

- ☑ ★ All Plants

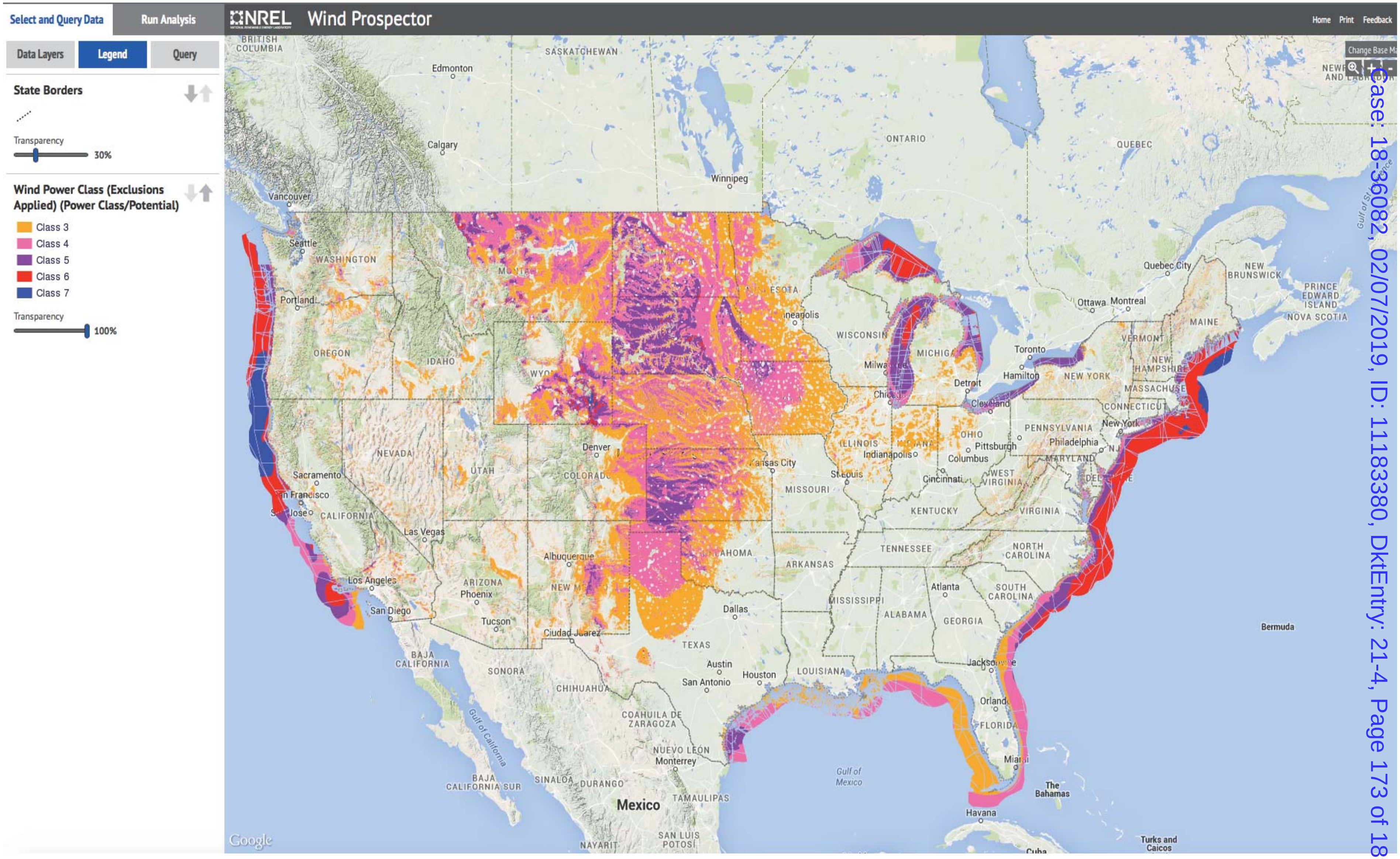
PV Plant Locations

- ☑ • All Plants

State Borders

- ☑ State Border

Exhibit E 121



State Borders

Transparency 30%

Wind Power Class (Exclusions Applied) (Power Class/Potential)

- 🟧 Class 3
- 🟪 Class 4
- 🟪 Class 5
- 🟥 Class 6
- 🟦 Class 7

Transparency 100%

Figure S3. Wind power classes in the, U.S. (https://mapsbeta.nrel.gov/wind-prospector/).

Note that this reasoning also means that, for the purpose of accurately estimating national average costs, we did not have to estimate regional relative fuel costs, $R_{FUEL,j,M:S\in M,Y}$, because presently we use the EIA's *AEO* projections to estimate both relative regional costs and the national average cost used in the overall national LC calculation. Nonetheless, we have incorporated $R_{FUEL,j,M:S\in M,Y}$ into our model to accurately report state-specific costs and to allow for the possibility, in future analy of calculating national-average costs with a different set of state-specific fuel-use weights than those used to calculate s $R_{FUEL,j,M:S\in M,Y}$.

However, even though we don't estimate region-specific capacity factor adjustmen the BAU, we do estimate a national-average adjustment to the wind capacity factor the BAU in the TY to account for the effect, discussed in the previous section, of expanding the size of wind farms. The EIA's (2014c) reference-case projections of tl capacity factor for wind power – the starting point of our estimates of energy use ir BAU – do not account for this effect of reduction in kinetic energy on the capacity f for wind power, so for our BAU scenario we must adjust the EIA estimates accordi We use the method described for the 100% WWS scenario, except that we assume t in the BAU the state shares of onshore wind generation approach the long-run saturation limit at 20% of the rate in the 100% WWS scenario, and that each state's of total national wind generation is equal to its share in the base year.

Note on the cost of installed WWS capacity by state

We use the same state/national capital-cost multipliers and capacity-factor multipl to calculate the total installed capacity and the total cost of installed capacity by sta The total cost of installed capacity by state is used in the calculation of the amount time it takes for energy-cost savings, air-pollution benefits, and climate-change ber to payback the initial installed capacity cost.

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EXHIBIT F

Low-cost solution to the grid reliability problem with 100% penetration of intermittent wind, water, and solar for all purposes

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This study addresses the greatest concern facing the large-scale integration of wind, water, and solar (WWS) into a power grid: the high cost of avoiding load loss caused by WWS variability and uncertainty. It uses a new grid integration model and finds low-cost, no-load-loss, nonunique solutions to this problem on electrification of all US energy sectors (electricity, transportation, heating/cooling, and industry) while accounting for wind and solar time series data from a 3D global weather model that simulates extreme events and competition among wind turbines for available kinetic energy. Solutions are obtained by prioritizing storage for heat (in soil and water); cold (in ice and water); and electricity (in phase-change materials, pumped hydro, hydropower, and hydrogen), and using demand response. No natural gas, biofuels, nuclear power, or stationary batteries are needed. The resulting 2050–2055 US electricity social cost for a full system is much less than for fossil fuels. These results hold for many conditions, suggesting that low-cost, reliable 100% WWS systems should work many places worldwide.

energy security | climate change | grid stability | renewable energy | energy cost

Worldwide, the development of wind, water, and solar (WWS) energy is expanding rapidly because it is sustainable, clean, safe, widely available, and, in many cases, already economical. However, utilities and grid operators often argue that today's power systems cannot accommodate significant variable wind and solar supplies without failure (1). Several studies have addressed some of the grid reliability issues with high WWS penetrations (2–21), but no study has analyzed a system that provides the maximum possible long-term environmental and social benefits, namely supplying all energy end uses with only WWS power (no natural gas, biofuels, or nuclear power), with no load loss at reasonable cost. This paper fills this gap. It describes the ability of WWS installations, determined consistently over each of the 48 contiguous United States (CONUS) and with wind and solar power output predicted in time and space with a 3D climate/weather model, accounting for extreme variability, to provide time-dependent load reliably and at low cost when combined with storage and demand response (DR) for the period 2050–2055, when a 100% WWS world may exist.

Materials and Methods

The key to this study is the development of a grid integration model (LOADMATCH). Inputs include time-dependent loads (every 30 s for 6 y); time-dependent intermittent wind and solar resources (every 30 s for 6 y) predicted with a 3D global climate/weather model; time-dependent hydropower, geothermal, tidal, and wave resources; capacities and maximum charge/discharge rates of several types of storage technologies, including hydrogen (H_2); specifications of losses from storage, transmission, distribution, and maintenance; and specifications of a DR system.

Loads and Storage. CONUS loads for 2050–2055 for use in LOADMATCH are derived as follows. Annual CONUS loads are first estimated for 2050 assuming each end-use energy sector (residential, transportation, commercial, industrial) is converted to electricity and some electrolytic hydrogen after accounting for modest improvements in end-use energy efficiency (22). Annual loads in each sector are next separated into cooling and heating loads that can be met with thermal energy storage (TES), loads that can be met with hydrogen production and storage, flexible loads that can be met with DR, and inflexible loads (Table 1).

Most (50–95%) air conditioning and refrigeration and most (85–95%) air heating and water heating are coupled with TES (Table 1). Cooling coupled with storage is tied to chilled water (sensible-heat) TES (STES) and ice production and melting [phase-change material (PCM)-ice] (*SI Appendix*, Table S1). All building air- and water-heating coupled with storage uses underground TES (UTES) in soil. UTES storage is patterned after the seasonal and short-term district heating UTES system at the Drake Landing Community, Canada (23). The fluid (e.g., glycol solution) that heats water that heats the soil and rocks is itself heated by sunlight or excess electricity.

Overall, 85% of the transportation load and 70% of the loads for industrial high temperature, chemical, and electrical processes are assumed to be flexible or produced from H_2 (Table 1).

Six types of storage are treated (*SI Appendix*, Table S1): three for air and water heating/cooling (STES, UTES, and PCM-ice); two for electric power generation [pumped hydropower storage (PHS) and phase-change materials coupled with concentrated solar power plants (PCM-CSP)]; and one for transport or high-temperature processes (hydrogen). Hydropower (with reservoirs) is treated as an electricity source on demand, but because reservoirs can be recharged only naturally they are not treated as artificially rechargeable storage. Lithium-ion batteries are used to power battery-electric vehicles but to avoid battery degradation, not to feed power from vehicles to the grid. Batteries for stationary power storage work well in this system too. However, because they currently cost more than the other storage technologies used (24), they are prioritized lower and are found not

Significance

The large-scale conversion to 100% wind, water, and solar (WWS) power for all purposes (electricity, transportation, heating/cooling, and industry) is currently inhibited by a fear of grid instability and high cost due to the variability and uncertainty of wind and solar. This paper couples numerical simulation of time- and space-dependent weather with simulation of time-dependent power demand, storage, and demand response to provide low-cost solutions to the grid reliability problem with 100% penetration of WWS across all energy sectors in the continental United States between 2050 and 2055. Solutions are obtained without higher-cost stationary battery storage by prioritizing storage of heat in soil and water; cold in water and ice; and electricity in phase-change materials, pumped hydro, hydropower, and hydrogen.

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Table 1. Projected 2050 CONUS load by sector and use in sector and projected percent and quantity of load for each use that is flexible and/or can be coupled with storage

(1) End-use sector	(2) 2050 total load (GW)*	(3) Percent of sector load (%)†	(4) Percent of load that is flexible (F) or coupled with TES (S) or used for H_2 (H) (%)‡	(5) 2050 load that is flexible or coupled with TES (GW)§	(6) 2050 load used for H_2 production and compression (GW)¶
Residential					
Air conditioning	17.44	6.2	85 (S)	14.82	0
Air heating	116.7	41.5	85 (S, H)	99.23	0
Water heating	49.79	17.7	85 (S)	42.32	0
Other	97.33	34.6	15 (S, H)	14.60	0
Total residential	**281.3**	**100**	**60.78**	**171.0**	**0**
Commercial					
Air conditioning	23.19	7.91	95 (S)	22.02	0
Refrigeration	17.12	5.84	50 (S)	8.56	0
Air heating	106.3	36.26	95 (S, H)	100.95	0
Water heating	22.51	7.68	95 (S)	21.39	0
Other	124.0	42.31	5 (S, H)	6.20	0
Total commercial	**293.1**	**100**	**54.29**	**159.1**	**0**
Transportation	**292.6**	**100**	**85.0 (F, S, H)**	**108.9**	**139.8**
Industry					
Air conditioning	6.61	0.936	95 (S)	6.28	0
Refrigeration	16.92	2.40	50 (S)	8.46	0
Air heating	37.44	5.304	95 (S)	35.57	0
On-site transport	5.07	0.72	85 (F)	4.31	0
Hi-T/chem/elec procs	615.4	87.19	70 (F, H)	390.44	40.35
Other	24.35	3.45	0	0	0
Total industry	**705.8**	**100**	**68.77**	**445.05**	**40.35**
All sectors	**1,572.8**		**67.66**	**884.03**	**180.2**

Bold indicates a total amount.

*Total 2050 loads for each sector are from ref. 22 and include inflexible and flexible loads and loads coupled with storage. Column 2 minus columns 5 and 6 is inflexible load. Loads by category in each sector are obtained by multiplying the percent loads in column 3 by the total load in column 2.

†Percent load is estimated from refs. 33, 34, and 35 for the residential, commercial, and industrial sectors, respectively.

‡A percent of load that is flexible is applied only to categories for which 100% of the load could theoretically be supplied from storage (air and water heating, water cooling, refrigeration, some transportation, and some industrial processes) or shifted in time (some transportation, some industrial processes). The percentages are then reduced to <100% to account for some on-demand energy (*SI Appendix*, Section S1.J).

§Obtained by multiplying column 2 by column 4 then subtracting column 6.

¶From ref. 22.

to be necessary for a reliable system. Nevertheless, they could still be incorporated, but at higher cost, in this system.

PHS is limited to its present penetration plus preliminary and pending permits as of 2015. CSP is coupled with a PCM rather than molten salt because of the greater efficiency and lower cost of the PCM (25). The maximum charge rate of CSP storage (thus mirror collector size) can be up to a factor of 5 the maximum discharge rate of CSP steam turbines to increase CSP's capacity factor (26). Here, the maximum CSP charge rate is ~2.6 times the maximum discharge rate (*SI Appendix*, Tables S1 and S2), but more CSP turbines are used than needed solely to provide annual CONUS power to increase the discharge rate of stored CSP power during times of peak power demand.

The 2050 annual cooling and heating loads (Table 1) are distributed in LOADMATCH each 30-s time step during each month of 2050–2055 in proportion to the number of cooling- and heating-degree days, respectively, each month averaged over the United States from 1949 to 2011 (27). Hydrogen loads and flexible loads are initially spread evenly over

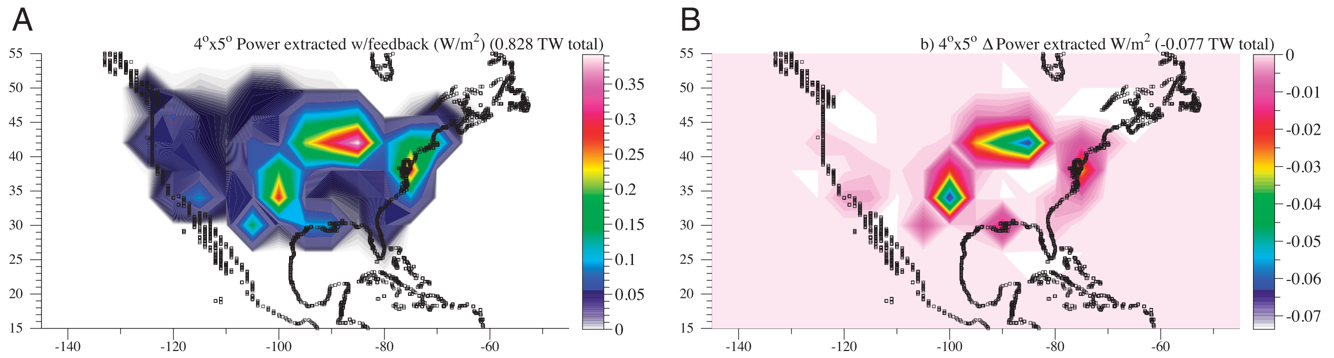

Fig. 1. (*A*) Difference in GATOR-GCMOM modeled (at 4° × 5° horizontal resolution) 100-m wind speed, averaged over 6 y, due to extracting kinetic energy from the wind by ~335,400 onshore and ~154,400 offshore 5-MW wind turbines placed state by state in the CONUS. (*B*) Loss in total power extracted by the turbines due to the competition for kinetic energy among them in *A*.

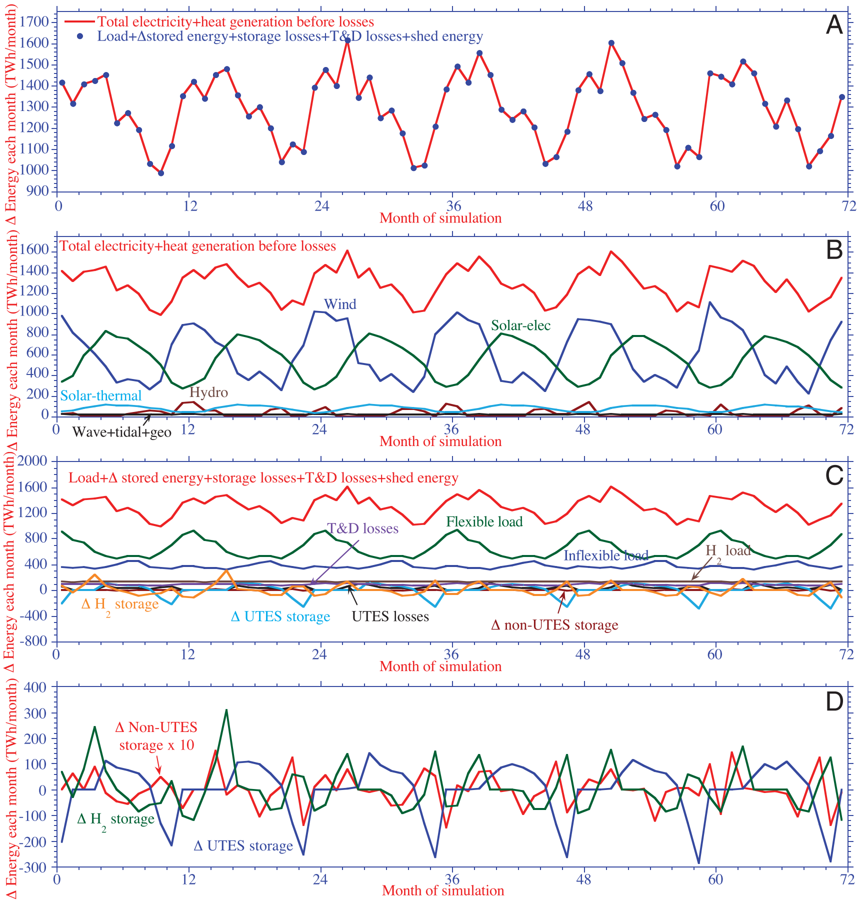

Fig. 2. (*A*) Six-year (72-mo) time series comparison of modeled CONUS-aggregated power generation vs. load plus losses plus changes in storage plus shedding. (*B*) Breakdown of power generation for the same period. (*C*) Breakdown of load plus losses plus changes in storage plus shedding. (*D*) Breakdown of changes in storage.

each year. Annual 2050 and 2051 inflexible loads are scaled by the ratio of hourly to annual 2006 and 2007 CONUS-aggregated loads, respectively (*SI Appendix*, Figs. S2 and S3) (28) to give hourly 2050 and 2051 inflexible loads, which are then applied alternately between 2052 and 2055 and distributed evenly each 30-s time step each hour. DR allows initial flexible loads to be pushed forward in 30-s increments but by no more than 8 h in the base case, at which point they are made inflexible loads. However, sensitivity tests indicate that the system is also stable with no DR (*SI Appendix*, Fig. S14).

Electric Power and Heat Supplies. To maximize the environmental and social benefits of energy production and use, all 2050 loads are supplied only with WWS technologies: onshore and offshore wind turbines, rooftop photovoltaic (PV) systems, utility PV plants, CSP plants, geothermal plants, hydropower plants, tidal devices, wave devices, and solar collectors for heating fluid. *SI Appendix*, Table S2 provides the proposed CONUS 2050 installed capacities and capital costs of each generator type, both of which are preestimated state-by-state based on resource and load constraints, to provide 2050 all-purpose end-use power in each state (22).

The state-by-state wind and solar installations are input here into the Gas, Aerosol, Transport, Radiation-General Circulation, Mesoscale, and Ocean Model (GATOR-GCMOM), a 3D global climate/weather model (29, 30) (*SI Appendix*, Section S1). Wind turbines are placed near each of 42,000 existing US turbines (31, 32). Utility PV and CSP (*SI Appendix*, Section S1.I) are sited in deserts or low-latitude regions of states where they exist. Rooftop PV is placed in urban areas. The model predicts time-dependent winds, accounting for competition among wind turbines for limited kinetic energy at the 100-m hub height of turbines (*SI Appendix*, Section S1.H). It also calculates direct and diffuse solar and infrared radiation accounting for time-varying gases, aerosols, and clouds and the cooling of underlying surfaces by all PV and CSP during energy extraction. It further calculates heat release to the air during electricity use. Modeled solar and wind resources are aggregated spatially to obtain CONUS totals each 30-s time step from 2050 to 2055.

Priorities for Satisfying Load in Grid Integration Model. The 2050–2055 loads and intermittent resources described above are input into LOADMATCH, which prioritizes load matching, to determine whether and at what cost supply can match load.

When more instantaneous WWS electricity supply is available than needed for current inflexible plus flexible electricity loads during a time step, both loads are met immediately with the supply. Excess supply then goes first to fill non-UTES storage up to the storage limit, then to produce H_2 up to its storage limit, then to fill UTES storage up to its storage limit, and last to shedding.

When instantaneous WWS electricity supply exceeds inflexible load (including H_2 load not met from storage) but is less than inflexible plus flexible load during a time step, inflexible plus flexible load up to WWS supply is first satisfied with supply, and the remaining flexible load is pushed to the next 30-s time step. Any flexible load not satisfied during the previous 8 h is converted to inflexible load that is immediately satisfied first with current instantaneous supply, then with stored electricity, and last with hydropower.

When instantaneous WWS electricity supply is lower than inflexible load for a given time step, the difference is made up first from stored electricity and then from hydropower, which is used only as a last resort.

All instantaneous heat from non-CSP solar-thermal collectors first satisfies instantaneous heat load. Any excess then goes into UTES. WWS electricity can also increase UTES, but only when all of the following constraints are met: instantaneous WWS electricity supply exceeds inflexible plus flexible electricity load; all non-UTES storage is filled; and H_2 storage is filled. Although UTES is not an efficient way to store excess electricity, it is more efficient than simply shedding the excess.

When instantaneous heat load exceeds instantaneous solar-thermal collector heat, the excess load is drawn from UTES. If UTES is depleted, the energy for meeting the heat load is drawn first from current WWS electricity, then in order from stored PCM-CSP electricity, PHS, and hydropower.

Hydrogen demand each time step is first met with stored hydrogen. If hydrogen storage is depleted, the remaining demand is met with electrolysis using

Exhibit F 3

current electricity. Hydrogen is produced, compressed, and added to storage when more electricity is available than can be put into non-UTES storage.

The model assumes a short- and long-distance transmission (T&D) system that carries power from distributed and centralized WWS generators to storage and load centers. Costs of and power losses during T&D are accounted for (Table 2, footnote), but power flows through individual lines or substations are not explicitly modeled. The model also accounts for storage costs and power losses during charging/discharging (*SI Appendix*, Table S1).

Results

LOADMATCH is run first with a 30-s time step for 6 y, using the parameters in Table 1 and *SI Appendix*, Tables S1 and S2 and time-dependent wind and solar resources derived from GATOR-GCMOM. An ensemble of 19 additional simulations with different time series of wind, solar, and load inputs is also run to test the model's robustness (*SI Appendix*, Sections S1.K and S1.M). The GATOR-GCMOM simulations account for extraction of and competition for kinetic energy by wind turbines (Fig. 1). The power extracted among all onshore plus offshore turbines when accounting for competition among ∼489,809 5-MW onshore plus offshore CONUS turbines (*SI Appendix*, Table S2) is ∼0.828 TW (Fig. 1*A*), giving a wind capacity factor of ∼33.81%, vs. ∼36.95% when competition is ignored. Thus, competition among turbines reduces aggregate power output by ∼0.0769 TW (Fig. 1*B*), or ∼8.5%, and peak wind speeds averaged over 400- × 400-km regions by up to ∼1 m/s.

Table 2, Figs. 2–4, and *SI Appendix*, Figs. S4–S6 summarize results from the baseline LOADMATCH simulation. Zero load loss occurs for the base case (Table 2 and Fig. 2) and all sensitivity cases (*SI Appendix*, Table S3 and Figs. S7–S19). For the base case, ∼11% of all WWS energy potentially available is lost during transmission, distribution, maintenance downtime, and storage. Zero electricity shedding occurs because all excess electricity goes into either hydrogen production or storage. Some excess solar heat is shed when UTES storage is full (Table 2). Energy summed over all storage at the end of the simulation slightly exceeds that at the beginning (Table 2).

Figs. 2–4 and *SI Appendix*, Figs. S4–S6 indicate supply exactly matches load plus losses and changes in storage at all times. Solar and wind are complementary seasonally (Fig. 2) and diurnally (Figs. 3 and 4 and *SI Appendix*, Figs. S4–S6). Seasonally, CONUS-aggregated wind peaks during winter; solar peaks during summer. Daily, wind peaks at night and is often lowest when solar is greatest during the day.

Table 2. Summary of energy loads met, losses, energy supplies, changes in storage, and costs during the base 6-y (52,548-h) simulation

Energy load, supply, or loss	Energy (TWh) or cost
Total load met over 6 y	82,695
Electricity load for H_2 production/compression	9,469
Electricity load not for H_2	67,170
Heat load from solar collectors and UTES	6,056
Total losses[a]	**10,189**
Transmission, distribution, maintenance losses	6,334
Losses CSP storage	52.7
Losses non-CSP, non-UTES storage	238.9
Losses UTES storage	2,365
Losses from shedding heat	1,198
Total load plus losses (energy required)	***92,884***
Total WWS supply before T&D losses	**92,979**
Onshore + offshore wind electricity[b]	43,509
Rooftop + utility PV + CSP electricity[c]	39,901
Hydropower electricity[d]	2,413
Wave electricity[e]	320.8
Geothermal electricity[f]	1003.8
Tidal electricity[g]	113.0
Solar heat[h]	5,718
Net energy taken from (+) or added to (−) storage	**−95.4**
Net energy taken from (+) CSP storage	0
Net energy taken from (+) non-UTES storage	0
Net energy taken from (+) UTES storage	205.8
Net energy taken from (+) H_2 storage	−301.2
Total energy supplied plus taken from storage	***92,884***
Capital cost ($ trillion) new generators + storage[i]	**14.6 (12.0–17.2)**
Capital cost ($ trillion) new generators	13.9 (11.8–16.0)
2050 total LCOE (¢/kWh-to-load) in 2013 dollars	**11.37 (8.5–15.4)**
Electricity + heat + short-distance T&D (¢/kWh)[j]	10.26 (8.12–13.1)
Long-distance transmission (¢/kWh)[k]	0.32 (0.081–0.86)
All storage except H_2 (¢/kWh)[l]	0.33 (0.062–0.75)
H_2 prod/compress/stor. (excl. elec. cost) (¢/kWh)[m]	0.46 (0.22–0.69)

All units are TWh over the CONUS, except costs, which are either $ trillion or ¢/kWh-delivered-to-load. Bold indicates a total amount. Bold italics indicates a sum of totals. T&D, transmission and distribution.

[a] Transmission/distribution/maintenance losses are 5–10% of electricity generation for all generators except rooftop PV (1–2%) and solar thermal (2–4%). Transmission losses are averaged over short and long-distance (with high-voltage direct current) lines. Maintenance downtime is discussed in *SI Appendix*, Section S1.L. Storage efficiencies are given in *SI Appendix*, Table S1. Excess electricity is either stored or used to produce H_2, so is not shed. Only excess heat is shed if heat storage is saturated.

[b] Onshore and offshore wind turbines, installed in the climate model, are REpower 5-MW turbines with 126-m-diameter rotors, 100-m hub heights, a cut-in wind speed of 3.5 m/s, and a cut-out wind speed of 30 m/s.

[c] Each solar PV panel for rooftop and utility solar, installed in the climate model is a SunPower E20 435 W panel with panel area of 2.1621 m^2, which gives a panel efficiency (Watts of power output per Watt of solar radiation incident on the panel) of 20.1%. The cell efficiency (power out per watt incident on each cell) is 22.5%. Each CSP plant before storage is assumed to have the characteristics of the Ivanpah solar plant, which has 646,457 m^2 of mirrors and 2.17 km^2 of land per 100 MW installed power and a CSP efficiency (fraction of incident solar radiation that is converted to electricity) of 15.796%, calculated as the product of the reflection efficiency of 55% and the steam plant efficiency of 28.72% (36).

[d] The capacity factor for hydropower from the simulation is 52.5%, which also equals that from ref. 22.

[e] The assumed capacity factor for wave power is 23.3% (22).

[f] The assumed capacity factor for geothermal is 92.1% (22).

[g] The assumed capacity factor for tidal power is 26.1% (22).

[h] The efficiency of the solar hot fluid collection (energy in fluid divided by incident radiation) is 34% (23).

[i] Capital costs for new generators are derived from *SI Appendix*, Table S2 and for storage are derived from *SI Appendix*, Table S1.

[j] The electricity plus heat plus local transmission costs here are derived from capital costs in *SI Appendix*, Table S2 assuming a discount rate of 3.0 (1.5–4.5)%, a facility lifetime/amortization time of 30 (35–25) y for all technologies except geothermal [35 (30–40) y] and hydropower [55 (50–60) y], an annual O&M cost that varies by technology as in ref. 22, a short-distance transmission cost of 1.15 (1.1–1.2) ¢/kWh (22), a distribution cost of 2.57 (2.5–2.64) ¢/kWh (22), decommissioning costs of 1.125 (0.75–1.5)% of capital costs (22), and the annualized load met in Table 2.

[k] Long-distance transmission costs are 1.2 (0.3–3.2) ¢/kWh for 1,200- to 2,000-km lines (37). The base case assumes that 30% of all wind and solar electric power generated are subject to long-distance transmission lines. This percent is varied in sensitivity tests in *SI Appendix*, Fig. S13.

[l] Storage costs are the product of the storage capacity and the capital cost per unit of storage capacity of each storage technology (*SI Appendix*, Table S1), summed over all technologies, annualized with the same discount rates and annual O&M percentages as for power generators, and divided by the annual-average load met in Table 2 (i.e., the total load met over 6 y divided by 6 y).

[m] H_2 costs are 4.0 (1.96–6.05) ¢/kWh-to-H_2 for the electrolyzer, compressor, storage equipment, and water. This cost equals 2.36 (1.16–3.57) $/kg-$H_2$ divided by 59.01 kWh/kg-H_2 required to electrolyze (53.37 kWh/kg-H_2) and compress (5.64 kWh/kg-H_2) H_2 (38). These costs exclude electricity costs, which are included elsewhere in the table. The overall cost of H_2 in ¢/all-kWh-delivered is equal to the cost in ¢/kWh-to-H_2 multiplied by the fraction of delivered power used for hydrogen (11.46% = Table 1, column 6 divided by column 2).

Exhibit F 4

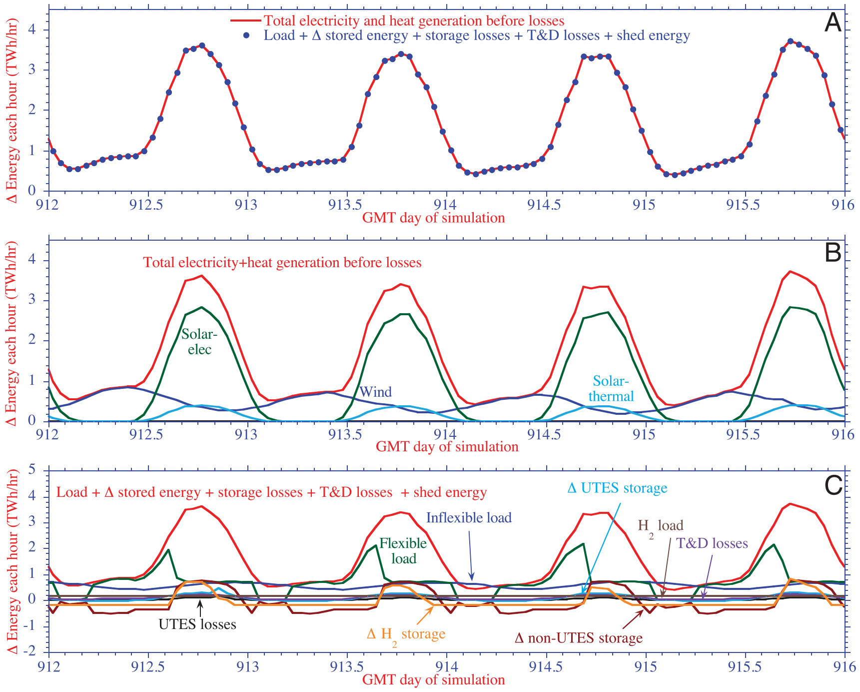

Fig. 3. (*A*) Time series comparison each hour of modeled CONUS-aggregated power generation vs. load plus losses plus changes in storage plus shedding for July 1–4, 2052. (*B*) Breakdown of power generation for the same period. (*C*) Breakdown of load plus losses plus changes in storage plus shedding.

Collected solar heat is added to UTES during summers and removed primarily during winters. Conversely, electricity is drawn from storage other than UTES during summers to provide peaking electricity. Hydropower is used only sporadically and only when other storage is depleted.

Discussion and Conclusions

The 2050 delivered social (business plus health and climate) cost of all WWS including grid integration (electricity and heat generation, long-distance transmission, storage, and H_2) to power all energy sectors of CONUS is ~11.37 (8.5–15.4) ¢/kWh in 2013 dollars (Table 2). This social cost is not directly comparable with the future conventional electricity cost, which does not integrate transportation, heating/cooling, or industry energy costs. However, subtracting the costs of H_2 used in transportation and industry, transmission of electricity producing hydrogen, and UTES (used for thermal loads) gives a rough WWS electric system cost of ~10.6 (8.25–14.1) ¢/kWh. This cost is lower than the projected social (business plus externality) cost of electricity in a conventional CONUS grid in 2050 of 27.6 (17.2–54.4) ¢/kWh, where 10.6 (8.73–13.4) ¢/kWh is the business cost and ~17.0 (8.5–41) ¢/kWh is the 2050 health and climate cost, all in

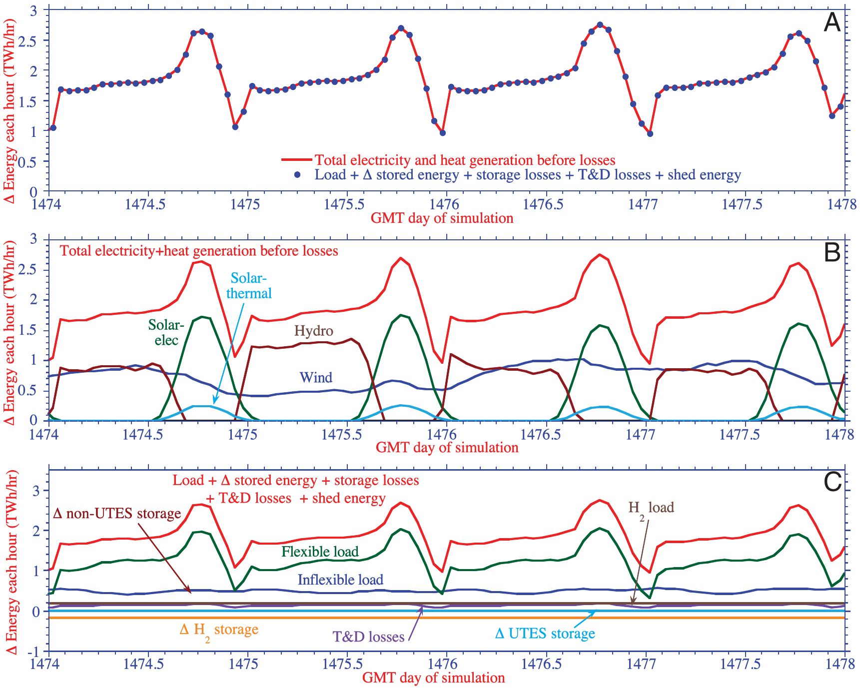

Fig. 4. (*A*) Time series comparison each hour of modeled CONUS-aggregated power generation vs. load plus losses plus changes in storage plus shedding for January 14–17, 2055. (*B*) Breakdown of power generation for the same period. (*C*) Breakdown of load plus losses plus changes in storage plus shedding.

2013 dollars (22). Thus, whereas the 2050 business costs of WWS and conventional electricity are similar, the social (overall) cost of WWS is 40% that of conventional electricity. Because WWS requires zero fuel cost, whereas conventional fuel costs rise over time, long-term WWS costs should stay less than conventional fuel costs.

In sum, an all-sector WWS energy economy can run with no load loss over at least 6 y, at low cost. As discussed in *SI Appendix*, Section S1.L, this zero load loss exceeds electric-utility-industry standards for reliability. The key elements are as follows: (*i*) UTES to store heat and electricity converted to heat; (*ii*) PCM-CSP to store heat for later electricity use; (*iii*) pumped hydropower to store electricity for later use; (*iv*) H_2 to convert electricity to motion and heat; (*v*) ice and water to convert electricity to later cooling or heating; (*vi*) hydropower as last-resort electricity storage; and (*vii*) DR. These results hold over a wide range of conditions (e.g., storage charge/discharge rates, capacities, and efficiencies; long-distance transmission need; hours of DR; quantity of solar thermal) (*SI Appendix*, Table S3 and Figs. S7–S19), suggesting that this approach can lead to low-cost, reliable, 100% WWS systems many places worldwide.

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Exhibit F 6