Least-Cost Planning for Power Systems with Large Shares of Wind and Solar Power

*MATTHIAS FRIPP**

Environmental Change Institute, University of Oxford,
South Parks Road, Oxford, OX2 3QY, United Kingdom

December 23, 2011

Corresponding author contact information
e-mail: matthias.fripp@eci.ox.ac.uk
phone: +44 1865 285527

■ ABSTRACT

Wind and solar power are attractive sources of low-carbon electricity, but they are highly variable, so it is unclear how large a role they can play in future power systems. I introduce a new open-source model – Switch – that identifies the least expensive set of investments in wind, solar and conventional generators and transmission lines, to provide a reliable power supply for a large power system over a multi-decade period. I then use Switch to map out the tradeoff between electricity costs and emission reductions via renewable energy in California in 2012–27. I find that there is no firm limit to the use of wind and solar power – the cost of power will rise moderately if these resources are used on a large scale, but radical emission reductions are possible without severe increases in the cost of electricity. A large part of the reason power costs rise in systems with very large shares of wind and solar power is because these resources eventually begin to generate unneeded power during some hours. Consequently, policies that encourage loads to shift to the times when renewable power is most abundant (e.g., well-timed charging of electric vehicles) could make deep emission reductions possible at relatively low costs.

1. INTRODUCTION

There is a strong consensus that anthropogenic climate change must be limited to 2°C or less in order to avoid dangerous changes to the environment.[1] The best estimate is that this will require limiting cumulative CO_2 emissions to about 10^{12} tonnes of carbon before fossil fuels are completely phased out. However, it is possible that the safe emissions budget is as low as half this level – approximately the amount we have already emitted.[2] Achieving deep emission reductions early in the century will increase the chance of achieving the 2°C target, and/or raise the emission budget available later in the century.

Renewable power sources could make a major contribution to this effort. Wind and solar power are available on a much larger scale than human energy demand.[3,4] Wind power is now cost-competitive with natural gas plants in some locations[5] and the cost of solar power is falling rapidly.[6] Use of both wind power and solar photovoltaics have grown at over 25% per year for the last 25 years or more.[7,8]

However, it remains unclear how much it will cost to use these resources on a large scale. The cost of achieving any particular emission target depends on exactly which renewable and conventional electricity projects are developed, so answering this question requires two steps: first develop a least-cost plan for using renewable and conventional resources to reduce emissions while maintaining reliability, and then calculate the cost of following this plan.

Several models use stochastic linear programming to propose optimal deployment plans for wind, solar and conventional generators and transmission. These are chiefly distinguished by the amount of spatial and temporal detail they include.

Two proprietary models – ICF Consulting's Investment Planning Model (IPM) and Ventyx's System Optimizer – are able to model much of the detail of power systems on the scale of a U.S. state or interconnected region,[9] and may be able to consider enough different weather conditions to make optimal choices of wind and solar deployment at high penetration levels. However, these models are expensive and closed-source, making it difficult to judge their strengths and weaknesses.

Two peer-reviewed models also seek to optimize renewable energy deployment in power systems. The Regional Energy Deployment System (ReEDS)[10] optimizes the installation of wind farms, solar thermal electric plants and conventional generators in the U.S. over a 44 year period. This model has exceptional spatial detail but minimal temporal detail (16 weather conditions are considered in each 2-year planning period), so it may not accurately reflect the performance of power systems with very large shares of intermittent renewables. In contrast, DeCarolis and Keith[11] present a model that optimizes development of a small number of wind farms and conventional resources in order to serve electricity loads at one location. This model makes investment choices based on much more temporal detail than ReEDS – 5 years of hourly wind and load data – but it may not be extendable to study an entire power system.

In this work I introduce a new, open-source model designed to identify optimal power system investment plans under a variety of economic, technological and policy conditions. The Switch model (a loose acronym for "solar, wind, conventional and hydroelectric generation and transmission") provides a consistent, automated method for selecting optimal portfolios of renewable resources for deployment in large power systems. This makes it possible to investigate a variety of "what if" questions about the power system that could not otherwise be studied. Switch would also be useful as a portfolio selection tool for regional renewable energy integration studies, replacing the heuristic portfolio selection methods these studies usually use.

I then use this Switch to investigate the cost of radically reducing greenhouse gas emissions from the California power system by 2027 through large-scale use of wind and solar power. California is the world's 13th largest electricity consumer (just ahead of Spain, South Africa, Taiwan and Australia). It often leads the U.S. in expanding environmental policy, and indeed has adopted some of the most ambitious greenhouse gas targets in the world. The state has effectively banned construction of new nuclear (or coal) plants for the foreseeable future, potentially making this a difficult challenge. On the other hand, California has significant wind and solar potential.

2. MODEL

Switch identifies which generator and transmission projects to build in a power system in order to satisfy electricity loads at the lowest cost over a multi-decade period, while reducing carbon dioxide emissions. For this work I use Switch to model the optimal evolution of the California power system between 2012 and 2027 under increasingly tight constraints on greenhouse gas emissions. Below, I first describe the design of the model (applicable to any power system), and then describe the specific configuration used for this work.

Model Design. Switch is a multi-period stochastic linear programming model. Its objective is to minimize the present value of the cost of power plants, transmission capacity, fuel and a per-ton carbon dioxide adder, over the course of several multi-year investment periods.

Switch has two major sets of decision variables:

(1) At the start of each investment period Switch decides how much generation capacity to build in each of several geographic "load zones," and how much power transfer capability to add between these zones. Switch also chooses whether to operate existing generation capacity during the investment period or temporarily mothball it to avoid fixed operation and maintenance costs.

(2) For a set of sample days within each investment period, Switch makes hourly decisions about how

much power to generate from each dispatchable power plant, store at each pumped-hydroelectric facility, or transfer along each transmission corridor.

These decisions are constrained by a requirement that hourly electricity loads must be satisfied in every load zone, and the system must also include enough generation and transmission capacity to meet loads 15 percent higher than the forecast. Additional constraints ensure that the system includes enough intrazonal transmission and distribution capacity to move bulk power to loads, that hydroelectric facilities are operated in accordance with their historical limits, and that baseload capacity is run at a constant level (or not at all) during each investment period. Existing power plants are automatically retired at the end of their expected life.

For each sampled hour, Switch uses electricity loads and renewable power production based on actual conditions during a corresponding historical hour, so that its decisions reflect weather-driven correlation between these elements.

Hourly operational choices are made on an expected-value basis: power production from each facility and transfer capability along each transmission corridor are de-rated based on the facility's forced outage rate, to reflect the average amount of capacity available from that facility on any given day. This derating is not used when choosing resources to meet the 15% planning reserve margin, since the purpose of the reserve margin is to compensate for these outages. (A full definition of the model is given in the online Supporting Information and an earlier version is described in Ref. 14.)

After the optimization phase, Switch is used in a second phase to test the proposed investment plan against a more complete set of weather conditions and add backstop generation capacity to ensure the planning reserve margin is always met. Finally, in a third phase, costs are calculated by freezing the investment plan and operating the proposed power system over the full set of weather conditions.

Simplifications. It is computationally infeasible to include a full model of the transmission network in a large-scale capacity expansion model. Instead Switch uses a transport model, which represents the transfer capabilities of the underlying network and the cost of expanding those capabilities, rather than modeling the node-by-node current and voltage. In the future Switch will incorporate a full power-flow model into the post-optimization assessment of each power system design. (Transmission modeling is discussed in more detail in the online Supporting Information.)

Switch does not currently include spinning reserves that will be needed to compensate for wind and solar forecast errors during day-to-day operations. Fripp[12] estimates that the emissions from natural gas reserves used to completely firm up wind power in regions the size of California (250-1000 km across) could be in the range of 3-10% of the expected emission savings from the wind projects. Solar photovoltaic projects have similar variability to wind[13], and solar thermal electric plants would be less variable than photovoltaic projects, due to thermal lags. The combined variability of wind and solar projects will also be lower than either alone due to statistical smoothing. Consequently, 3–10% probably represents an upper limit on the emissions due to compensating for renewable energy forecast errors.

If spinning reserves come from natural gas power plants, they may raise emissions above the levels I report below, especially for the lower-emission scenarios. However, in low-emission scenarios these reserves may come from non-emitting sources such as hydro plants, curtailed wind or solar projects, batteries, flywheels, instant-start generators or demand response, in which case they may have a negligible effect on emissions.

Model Data. For the California case study reported below, I use Switch with 16 load zones within California and two external zones for power imported from the northwestern and southwestern U.S. Investment options include wind farms, solar thermal electric troughs, distributed solar PV or combined-cycle natural gas (CCGT) plants at a total of 622 sites distributed among the 16 California zones. The power system can also continue to use existing coal, natural gas, hydroelectric and nuclear plants.

Future electricity loads in each zone are based on hourly demand in 2004, scaled up to match forecasts of average and peak loads in 2012-27.[15-17] Power output from 306 potential wind farms in California is based on a simulation of weather conditions at each site in 2004,[18] and power output from 114 potential solar thermal electric sites and 186 potential PV zones are based on measurements of solar irradiance at nearby locations.[19]

Investment periods begin in 2012, 2016, 2020 and 2024. Decisions within each investment period are optimized based on 12 days of sampled data: two for each even-numbered month. One day in each month corresponds to conditions that occurred on the peak-load day of the same month in 2004. The second day of data for each month corresponds to a randomly selected day from the same month in 2004. Costs on the "typical" days are given 29–30 times more weight than the peak-load day, so that the peak-load day primarily influences reserve margin planning and the typical day has more effect on the resources chosen for day-to-day operation of the system.

The transfer capability along existing transmission corridors is derived from the Path Rating Catalog published by the Western Electricity Coordinating Council.[20] The efficiency, capacity and retirement age of existing power plants are derived from power plant surveys published by the U.S. Energy Information Administration.[21,22]

Future costs of fuel and new power plants come from the California Energy Commission's Cost of Generation Model.[5,23] The cost for transmission upgrades are assumed to be \$1000 per MW · km capacity. This is halfway between the cost of building a new single-circuit 230kV line or adding a circuit to an existing 230kV corridor,[24] scaled by 1/0.62 to reflect the ratio between individual line ratings and transfer capability along existing California transmission corridors.[20]

The capital costs of power plants and transmission capacity are amortized over the life of each project, and the portion of these that occur during the study period are then discounted to a present value in 2012. The amortization uses a real finance rate of 3% (corresponding to home equity finance) for distributed PV systems, and a real finance rate of 6% (corresponding to the cost of capital for a regulated utility) for all other projects. The calculation of present value in 2012 uses a real discount rate of 3% (corresponding to a public-policy perspective). These rates would be equivalent to nominal rates (including inflation) that are 2–3% higher.

3. RESULTS

For this work, I use Switch to investigate least-cost designs for the California power system under a variety of conditions, varying the carbon-cost adder to drive the model toward cleaner system designs. I assume the adder represents a revenue-neutral cross-subsidy within the power system (e.g., a "feebate" where proceeds from a carbon tax are rebated to all customers in proportion to the amount of electricity they consume). Consequently, the carbon adder changes the choice of what to build, but isn't itself included in the cost of power to customers. The resulting system represents the cheapest possible way to achieve any particular level of emission reductions by choosing among the generation and transmission options available within the model. (Switch is able to investigate the effect of higher electricity costs on electricity consumption, but that was omitted in this work.)

Example system designs. Figure 1 shows two possible approaches for hourly power production during a ten-day period surrounding the peak day of electricity demand in 2024–27 (the first Wednesday in September), found using Switch. Figure 1(a) shows operation of the least-cost power system designed with no constraint on carbon. Because the best wind sites are projected to provide power at a lower cost than natural gas, this system obtains 24% of its power from wind, and has emissions 25% lower than 1990 levels. This power system also continues to rely heavily on natural gas, as well as a small amount of imported coal power (among other existing resources).

In contrast, Figure 1(b) shows operation of the least-cost power system designed to reduce greenhouse gas emissions 86% below 1990 levels. This system produces wind and solar power equal to 83% of the annual electricity load, displacing most fossil power production. Hydroelectric facilities store power intensively, raising electric loads during windy mornings and returning the power in the evening after solar production drops.

So much wind and solar power is developed that this system discards power equal to 20% of average electricity loads (e.g., on the first and last days of Figure 1(b)). These curtailments are the main reason it would cost more to achieve deeper emission reductions. For example, if additional solar troughs or wind farms were added to this system, 64-70% of their power output (respectively) would come at times when loads are already satisfied by non-fossil sources. Consequently, the cost of *usable* power from these additional projects would be roughly tripled.

In Figure 1(b), the peak hour for demand from natural gas power plants has shifted from Wednesday (the peak load day) to Tuesday, when loads are slightly lower but much less wind power is available. Even though wind or solar power are available during many high load times, some high loads must still be met using mostly conventional generators. Although the average output from coal and gas generators in Figure 1(b) is 81% lower than in Figure 1(a), the peak output from these generators is only 33% lower. In other words, wind and solar power reduce the need to *operate* fossil power plants much further than they reduce the need to *build* them.

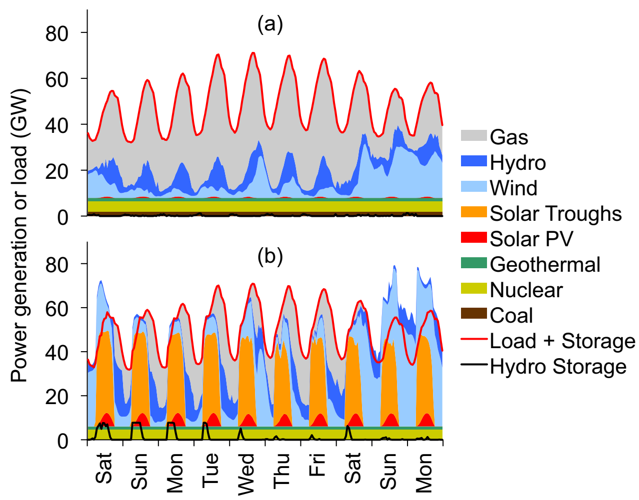

Figure 1. Power production and loads during the period of highest electricity demand (first week of September), for 2024–27 study period

Optimal system design for many different emission targets. Figure 2 shows the share of electricity demand provided by renewable and fossil plants in power systems optimally designed to achieve emissions equal to 10–75% of California's 1990 level. The vertical slices marked with red dots correspond to the examples shown in hourly detail in Figure 1. At the right edge, the cheapest possible power system has emissions 24% below 1990 levels. In order to achieve lower emission targets (moving left), coal and gas are gradually replaced by wind power (and to a minor extent photovoltaic power), until emissions are about 50% below 1990 levels. At this point, about 80% of the available wind sites have been developed, and it becomes more cost-effective to achieve further emission reductions by adding solar thermal trough systems (while continuing to expand the wind portfolio slightly). In the cleanest power system shown (at the left edge), solar and wind generate power equal to 98% of the system's power demand, but about one third of this power is discarded, since it comes at times when it cannot be used. Gas is used to meet 6% of projected electricity demand in the 90% cleaner power system, and coal plays a negligible role in systems with CO_2 targets below 50% of 1990 levels.

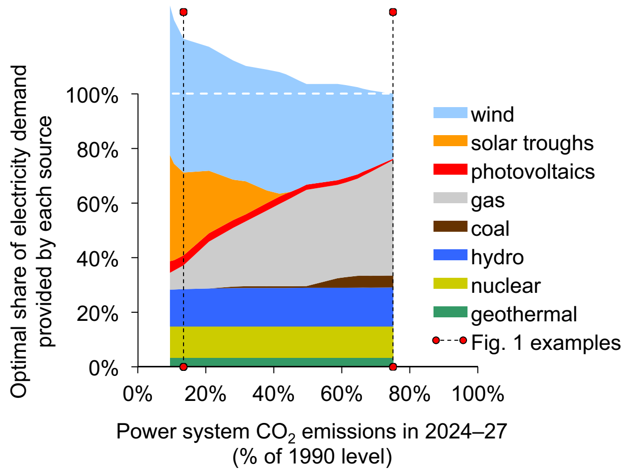

Figure 2. Shares of electricity provided by renewable and fossil power plants, for power systems with emissions equal to 10–76% of 1990 levels

Sensitivity analyses. The black trace in Figure 3(a) shows the average cost of producing power in 2024–27 for each of the power system designs in Figure 2, as well as CO_2 emissions from each of these systems. Red dots in Figure 3(a) highlight the high- and low-emission systems from Figure 1. This curve can be thought of as a frontier showing the limits of what is possible for future power system designs – it is possible to design power systems with emissions and costs higher than this curve, but not lower (the ideal power system would be plotted in the lower, left corner of Figure 3(a)).

Notably, the cost-vs-emissions curve does not have a sharp corner or "hockey stick" shape: within the range of emission targets studied for this work, there is no level beyond which the cost of power suddenly rises toward infinity. Instead, costs rise gradually as deeper emission reductions are sought, all the way down to 10% of the 1990 level.

The least-expensive power system on this curve (with no carbon target) would emit at 76% of 1990 levels and deliver power at a cost of 10.5¢/kWh (right edge of black trace). The cleaner example from Figure 1(b) would emit CO_2 at 14% of 1990 levels, with an average power cost of 14.9¢/kWh.

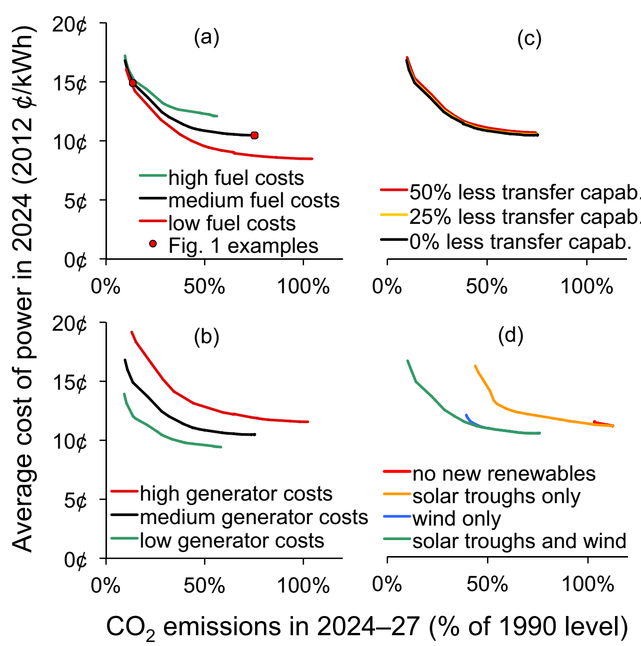

Figure 3. Tradeoff between cost of electricity and emissions from the California power system, under base case and other economic and technological assumptions

The rest of Figure 3 shows how these findings change as key assumptions are varied. The green and red traces of Figure 3(a) show the cost-vs-emissions frontier if the system is optimized for the California Energy Commission's (CEC's) high and low fuel cost projections,[5,23] which are about 50% above and below the base-case assumption (see Supporting Information). With lower fuel costs, gas-based power system designs become more attractive relative to wind, and the least-cost system has emissions 4% higher than 1990 levels (right edge of red trace). If gas costs less, the cost of power is reduced regardless of the emission target, but the price difference between the cleanest and dirtiest options grows (right vs. left edge of red trace). Higher fuel costs have the reverse effect – raising prices across the board, but shrinking the cost difference between high-emission and low-emission options (and indeed, with higher fuel prices the least-cost system design would be 44% cleaner than 1990, even with no emission target). The cost of all three scenarios converges at the low-emissions end, since fuel becomes a minimal part of system costs.

Figure 3(b) shows the effect of using the CEC's high and low capital cost assumptions for fossil and renewable generators.[5,23] During the final investment period these differ from the base case assumption by +35%/–36% for gas plants, +96%/–40% for wind farms, or +21%/–29% for solar thermal troughs. Higher generator costs raise the cost of achieving any emission target, and also make the least-cost system dirtier (since renewable technologies become less attractive relative to natural gas), while lower generator costs have the reverse effect. The difference in cost between 40% and 90% cleaner systems is about the same in all three cases.

Figure 3(c) tests the effect of assumptions about the transfer capability of the existing transmission network and the cost of expanding this capability. In the cases described thus far, I assume that if two regions are joined by transmission lines with total ratings of 1 GW, then 0.62 GW of power can be reliably transferred between them without overloading those lines or causing loop flows that overload nearby lines. Figure 3(c) shows two cases with more conservative values. The orange and red traces, respectively, show the cost-vs.-emissions tradeoff if transfer capability is de-rated by an additional 25% or 50% relative to the base case. This is equivalent to assuming California has 25–50% less inter-zonal transfer capability to begin with, and that expanding this capability will cost 33–100% than in the base case. Neither of these assumptions has a strong effect on the total cost of achieving large emission reductions. This is because the renewable-intensive scenarios tend to improve local self-sufficiency (reducing the need for inter-zonal transmission), and in all scenarios transmission expansions are small compared to the existing network. Consequently, new transmission investments make up only a small share of the total cost of power.

Benefits of combining wind and solar power. Figure 3(d) assesses the benefit of drawing on multiple renewable technologies instead of relying on only one. The red trace shows the cost-vs.-emissions possibilities if no new renewable resources can be developed. In this highly simplified case, California's only option for reducing emissions is to build new gas power plants to replace existing coal plants or less-efficient gas plants. Given this narrow range of options, the only achievable emission targets are in the range of 3 to 12% above 1990 levels, all at costs around 11¢/kWh. If solar troughs are available but not wind, moderate emission reductions can be achieved in exchange for higher power costs (orange trace). If wind is available but not solar troughs, there is a step change in possibilities to lower-emission and lower-cost power systems (blue trace). With either wind or solar alone it is only possible to reduce emissions about 60% below 1990 levels at costs below about 16¢/kWh. However, if both resources are available (green trace), it becomes cheaper to achieve emission cuts around 60%, and it also becomes possible to achieve emission cuts as low as 89% below 1990 levels while staying within a 16¢/kWh budget. That is, deeper emission reductions can be achieved at a lower cost by choosing the right mix of both wind and solar power than by using either resource alone.

Electric vehicles and electricity conservation. I noted above that power systems that rely heavily on renewable resources may have to discard large amounts of unneeded power at some times, driving up the cost per usable kWh produced. This is one of the dominant factors raising the cost of high-renewable scenarios. Figure 4 assesses the value of using demand-side flexibility to synchronize power consumption with production, making better use of otherwise-surplus power. All of the scenarios shown in this figure include extra electricity production to charge electric vehicles or plug-in hybrid electric vehicles, replacing half of California's gasoline consumption. The black trace shows the base case, without electric vehicles. This is identical to the base case in Figures 3(a–c), except that the x-axis has been expanded to include the CO_2 emissions from half the state's gasoline consumption.

The green trace in Figure 4 shows the cost-vs.-emissions tradeoff when electric vehicles are introduced and charged uniformly around the clock (10.5 GW of additional electricity load at all times). This gives a large emission reduction with little effect on the average cost of electricity. This suggests very clean power systems could be expanded to serve the vehicle fleet without driving up costs for electricity consumers. This approach could also be attractive to vehicle owners: electricity at a cost of \$0.10–\$0.15/kWh would displace gasoline at a cost of \$1.60–\$2.20/gallon (including taxes).

The orange trace in Figure 4 shows costs and emissions if electric vehicles are charged at the optimal time of day (e.g., via automated response to time-varying power prices). In this scenario, the cost-vs-emissions frontier moves significantly down and to the left – offering the possibility of lower power costs, lower emissions or both.

Finally, the red trace in Figure 4 represents a power system with optimally charged electric vehicles and electricity loads held constant from 2012 until 2024 (instead of the forecast 15% increase). Emissions are reduced directly when less electricity is produced. Costs are also reduced because the system can use good-quality wind sites to serve a larger share of the remaining loads, foregoing development of more expensive wind or solar sites.

With these changes, it is possible to reduce emissions from both the electricity sector and half the light vehicle fleet by 85% (point B in Figure 4) while keeping the cost of power at the same level as the least-cost system in the base-case scenario (point A). Alternatively, it is possible to reduce emissions by 90% (point C), while raising the average cost of power by only 27% above the least-cost base-case system design.

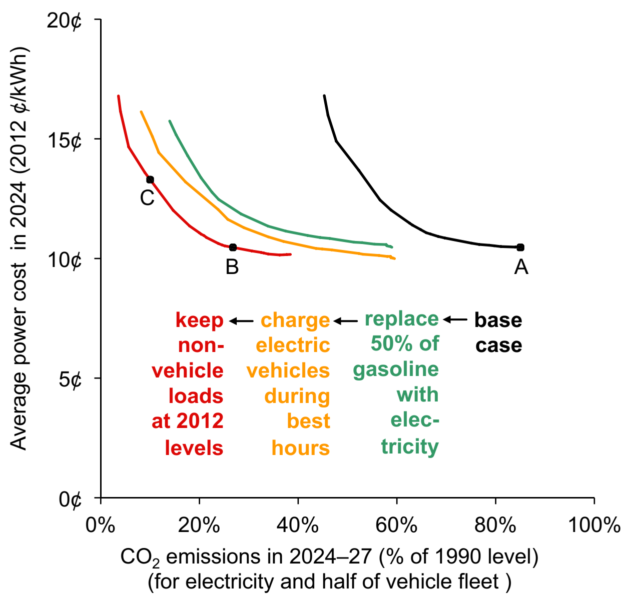

Figure 4. Cost vs. emissions tradeoffs for California electricity and transport, with or without electric vehicles and optimally timed charging. Point A is the least expensive power system with no electric vehicles. Points B and C show that deep emission reductions are available with zero or moderate increase in the cost of electricity, by adding electric vehicles, charging them at the right time, and avoiding growth in other electric loads.

4. DISCUSSION

This work introduced Switch, a new open-source optimization model for long-term planning of power systems with large shares of renewable energy. Using this model I found that it is possible to develop power systems with greenhouse gas emissions radically lower than current levels (or even 1990 levels) using already invented technology at a moderate cost. This runs counter to much popular discussion that suggests we will need carbon capture plants, large-scale electricity storage or a dramatic increase in nuclear power to avoid anthropogenic climate change.

In all the scenarios above, the cost-vs-emissions frontier has approximately the same shape – renewable power can be used to achieve moderate emission reductions with little or no increase in the cost of power, and costs rise gradually as deeper emission reductions are sought. There is no point beyond which additional emission reductions suddenly become unaffordable. Rather, there is a gradual increase in costs as more marginal renewable energy projects are developed and as additional renewable energy projects produce larger shares of surplus power relative to the amount of fossil power they displace.

Using this information, it is possible to identify policy measures that could significantly improve the cost-vs-emissions tradeoff. If electricity loads are rescheduled to use otherwise-surplus power, the cost of emission reductions can be brought down dramatically. In this respect there could be very strong synergies between renewable energy and electric vehicles or plug-in hybrid-electric vehicles: these vehicles could provide reschedulable loads that ease integration of renewable power, while also providing a route for large amounts of renewable energy to be enter the transportation sector. Other time-shiftable electricity loads (e.g., water pumping, water heating, dishwashing, pre-cooling of buildings and cold storage) could also help in a similar way. Reducing electricity demand could also reduce the cost of power in high-renewable systems, since it allows the best renewable energy projects to meet a larger share of electricity demand.

Much previous research has focused on the question of whether wind and solar power can reduce the need to build fossil power plants. I found that wind alone may not displace much fossil plant *construction*, but it is still worth building in order to avoid *running* fossil plants. This should not be surprising, since most of the cost of natural gas power comes from the fuel and less than a third comes from the cost of building the plant. But it does suggest that more attention should be given to the fuel-saving (and emission-saving) benefits of renewable power, rather than focusing primarily on their firm peak-serving contribution. Furthermore, I found that wind and solar power together can provide more firm capacity than either can alone, since they generate power at complementary times. (This issue is discussed further in Ref. 14.)

Some limitations to the work presented here should be noted. Every power system analyzed in this work is able to provide enough power to meet loads and reserve margins under all the weather conditions that occurred in 2004. However, if 2004 had an unusual amount of wind or sun, it could have skewed the estimates the relative cost of fossil and renewable power (although it appears unlikely to change the overall shape of the cost-vs-emissions curves presented here).

The most important limitation of Switch may be that it assumes perfect foresight in the operation of the power system – it neglects the fast-responding reserves that will be needed to keep the system secure against an unforecasted drop in renewable power production. As noted above, these could reverse up to 10% of the expected emission savings. However, this impact could be smaller in the very high-renewable scenarios I studied because (a) these scenarios include significant amounts of surplus renewable power during many hours, which would allow output to fall somewhat before loads begin to go unmet; and (b) the resources that provide inter-hour load shifting (e.g., electric vehicles) may also be able to ramp demand down quickly if renewable power drops off suddenly.

■ ASSOCIATED CONTENT

Supporting Information. Online Supporting Information includes a complete description of the Switch model, including cost calculations, constraints and technological options, as well as descriptions of all the data sources used for the California study.

■ ACKNOWLEDGMENT

This research was funded by a Science To Achieve Results fellowship from the U.S. EPA, a Doctoral Dissertation Research Improvement Grant from the National Science Foundation and a research fellowship from NextEra Energy Resources. The findings were not subject to approval or review by any of the funders.

■ REFERENCES

(1) Randalls, S., History of the 2°C climate target. *Wiley Interdisciplinary Reviews: Climate Change 1*, (4), 598-605.

(2) NRC, *Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia*. National Research Council of the National Academies: Washington, DC, 2011.

(3) Lu, X.; McElroy, M. B.; Kiviluoma, J., Global potential for wind-generated electricity. *Proceedings of the National Academy of Sciences* 2009, *106*, (27), 10933-10938.

(4) Lewis, N. S.; Nocera, D. G., Powering the planet: Chemical challenges in solar energy utilization. *Proceedings of the National Academy of Sciences* 2006, *103*, (43), 15729-15735.

(5) Klein, J. *Comparative Costs of California Central Station Electricity Generation Technologies: Final staff report*; CEC-200-2009-07SF; California Energy Commission: Sacramento, CA, January, 2010.

(6) Barbose, G.; Darghouth, N.; Wiser, R.; Seel, J. *Tracking the Sun IV: An Historical Summary of the Installed Cost of Photovoltaics in the United States from 1998 to 2010*; Lawrence Berkeley National Laboratory: Berkeley, California, September, 2011.

(7) C. Breyer, A. G., Global Overview on Grid-Parity Event Dynamics. In *25th European Photovoltaic Solar Energy Conference and Exhibition / 5th World Conference on Photovoltaic Energy Conversion*, Valencia, Spain, 2010; pp 5283 - 5304.

(8) EIA International Energy Statistics. http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm (November 15, 2011).

(9) Neuhoff, K.; Ehrenmann, A.; Butler, L.; Cust, J.; Hoexter, H.; Keats, K.; Kreczko, A.; Sinden, G., Space and time: Wind in an investment planning model. *Energy Economics* 2008, *30*, (4), 1990-2008.

(10) Short, W.; Blair, N.; Sullivan, P.; Mai, T. *ReEDS Model Documentation: Base Case Data and Model Description*; National Renewable Energy Laboratory: Golden, Colorado, August, 2009; p 95.

(11) DeCarolis, J. F.; Keith, D. W., The economics of large scale wind power in a carbon constrained world. *Energy Policy* 2006, *34*, 395-410.

(12) Fripp, M., Greenhouse Gas Emissions from Operating Reserves Used to Backup Large-Scale Wind Power. *Environmental Science & Technology* 2011, *45*, (21), 9405-9412.

(13) Mills, A.; Wiser, R. *Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power*; LBNL-3884E; Lawrence Berkeley National Laboratory: Berkeley, California, September, 2010.

(14) Fripp, M. *Optimal investment in wind and solar power in California (doctoral thesis)*; University of California, Berkeley: Berkeley, 2008.

(15) CAISO California ISO: Locational marginal pricing (LMP) studies. http://www.caiso.com/docs/2004/01/29/2004012910361428106.html (January 21, 2008).

(16) FERC Form 714 data. http://www.ferc.gov/docs-filing/eforms/form-714/data.asp (September 29, 2005).

(17) Marshall, L.; Gorin, T. *California energy demand 2008-2018: Staff revised forecast*; CEC-200-2007-015-SF2; California Energy Commission: Sacramento, November, 2007.

(18) GE Energy *Western Wind and Solar Integration Study*; National Renewable Energy Laboratory: Golden, Colorado, May, 2010; p 535.

(19) CIMIS California Irrigation Management Information System. http://wwwcimis.water.ca.gov/ (October, 2006).

(20) WECC *FERC Form no. 715, Annual transmission planning and evaluation report*; Western Electricity Coordinating Council: Salt Lake City, UT, March 30, 2007.

(21) EIA Form EIA-906 and EIA-920 databases. http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html (November 7, 2007).

(22) EIA Form EIA-860 database: Annual electric generator report. http://www.eia.doe.gov/cneaf/electricity/page/eia860.html (November 7, 2007).

(23) Klein, J. *Cost of Generation Model User's Guide Version 2*; CEC-200-2010-002; California Energy Commission: Sacramento, California, April, 2010.

(24) Fuldner, A. H., Upgrading transmission capacity for wholesale electric power trade. *Electric Power Monthly* 1996, xi-xxii.