The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity

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Several states and countries have adopted targets for deep reductions in greenhouse gas emissions by 2050, but there has been little physically realistic modeling of the energy and economic transformations required. We analyzed the infrastructure and technology path required to meet California's goal of an 80% reduction below 1990 levels, using detailed modeling of infrastructure stocks, resource constraints, and electricity system operability. We found that technically feasible levels of energy efficiency and decarbonized energy supply alone are not sufficient; widespread electrification of transportation and other sectors is required. Decarbonized electricity would become the dominant form of energy supply, posing challenges and opportunities for economic growth and climate policy. This transformation demands technologies that are not yet commercialized, as well as coordination of investment, technology development, and infrastructure deployment.

In 2004, Pacala and Socolow (*1*) proposed a way to stabilize climate using existing greenhouse gas (GHG) mitigation technologies, visualized as interchangeable, global-scale "wedges" of equivalent emissions reductions. Subsequent work has produced more detailed analyses, but none combines the sectoral granularity, physical and resource constraints, and geographic scale needed for developing realistic technology and policy roadmaps (*2*–*4*). We addressed this gap by analyzing the specific changes in infrastructure, technology, cost, and governance required to decarbonize a major economy, at the state level, that has primary jurisdiction over electricity supply, transportation planning, building standards, and other key components of an energy transition.

California is the world's sixth largest economy and 12th largest emitter of GHGs. Its per capita GDP and GHG emissions are similar to those of Japan and western Europe, and its policy and technology choices have broad relevance nationally and globally (*5*, *6*). California's Assembly Bill 32 (AB32) requires the state to reduce GHG emissions to 1990 levels by 2020, a reduction of 30% relative to business-as-usual assumptions (*7*). Previous modeling work we performed for California's state government formed the analytical foundation for the state's AB32 implementation plan in the electricity and natural gas sectors (*8*, *9*).

California has also set a target of reducing 2050 emissions 80% below the 1990 level, consistent with an Intergovernmental Panel on Climate Change (IPCC) emissions trajectory that would stabilize atmospheric GHG concentrations at 450 parts per million carbon dioxide equivalent (CO_2e) and reduce the likelihood of dangerous anthropogenic interference with climate (*10*). Working at both time scales, we found a pressing need for methodologies that bridge the analytical gap between planning for shallower, near-term GHG reductions, based entirely on existing commercialized technology, and deeper, long-term GHG reductions, which will depend substantially on technologies that are not yet commercialized.

We used a stock-rollover methodology that simulated physical infrastructure at an aggregate level, and built scenarios to explore mitigation options (*11*, *12*). Our model divided California's economy into six energy demand sectors and two energy supply sectors, plus cross-sectoral economic activities that produce non-energy and non-CO_2 GHG emissions. The model adjusted the infrastructure stock (e.g., vehicle fleets, buildings, power plants, and industrial equipment) in each sector as new infrastructure was added and old infrastructure was retired, each year from 2008 to 2050. We constructed a baseline scenario from government forecasts of population and gross state product, combined with regression-based infrastructure characteristics and emissions intensities, producing a 2050 emissions baseline of 875 Mt CO_2e (Fig. 1). In mitigation scenarios, we used backcasting, setting 2050 emissions at the state target of 85 Mt CO_2e as a constrained outcome, and altered the emissions intensities of new infrastructure over time as needed to meet the target, employing 72 types of physical mitigation measures (*13*). In the short term, measure selection was driven by implementation plans for AB32 and other state policies (table S1). In the long term, technological progress and rates of introduction were constrained by physical feasibility, resource availability, and historical uptake rates rather than relative prices of technology, energy, or carbon as in general equilibrium models (*14*). Technology penetration levels in our model are within the range of technological feasibility for the United States suggested by recent assessments (table S20) (*15*, *16*). We did not include technologies expected to be far from commercialization in the next few decades, such as fusion-based electricity. Mitigation cost was calculated as the difference between total fuel and measure costs in the mitigation and baseline scenarios. Our fuel and technology cost assumptions, including learning curves (tables S4, S5, S11, and S12, and fig. S29), are comparable to those in other recent studies (*17*). Clearly, future costs are very uncertain over such a long time horizon, especially for technologies that are not yet commercialized. We did not assume explicit life-style changes (e.g., vegetarianism, bicycle transportation), which could have a substantial effect on mitigation requirements and costs (*18*); behavior change in our model is subsumed within conservation measures and energy efficiency (EE).

To ensure that electricity supply scenarios met the technical requirements for maintaining reliable service, we included an electricity system dispatch algorithm that tested grid operability. Without a dispatch model, it is difficult to determine whether a generation mix has infeasibly high levels of intermittent generation. We developed an electricity demand curve bottom-up from sectoral demand, by season and time of day. On the basis of the demand curve, the model constrained generation scenarios to satisfy in succession the energy, capacity, and system-balancing requirements for reliable operation. The operability constraint set physical limits on the penetration of different types of generation and specified the requirements for peaking generation, on-grid energy storage, transmission capacity, and out-of-state imports and exports for a given generation mix (table S13 and figs. S20 to S31). It was assumed that over the long run, California would not "go it alone" in pursuing deep GHG reductions, and thus that neighboring states would decarbonize their generation such that the carbon intensity of imports would be comparable to that of California in-state generation (*19*).

Electrification required to meet 80% reduction target. Three major energy system transformations were necessary to meet the target (Fig. 2). First, EE had to improve by at least 1.3% $year^{-1}$ over 40 years. Second, electricity supply had to be nearly decarbonized, with 2050 emissions intensity less than 0.025 kg CO_2e/kWh. Third, most existing direct fuel uses had to be electrified, with electricity constituting 55% of end-use energy in 2050 versus 15% today. Results for a mitigation scenario, including these and other measures, are shown in Fig. 1. Of the emissions reductions relative to 2050 baseline emissions, 28% came from EE, 27% from decarbonization of electricity generation, 14% from a combination of energy

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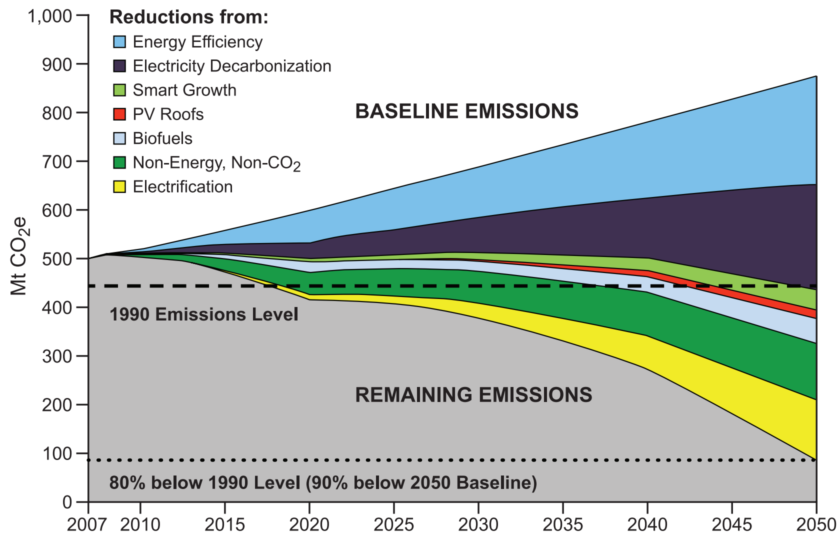
conservation and alternative energy measures [including "smart growth" urban planning, biofuels, and rooftop solar photovoltaics (PV)], 15% from measures to reduce non-energy CO_2 and non-CO_2 GHGs, and 16% from electrification of existing direct fuel uses in transportation, buildings, and industrial processes. Table 1 shows changes from 2010 to 2050 in primary and end-use energy and emissions by sector and fuel type for the baseline and mitigation cases, along with per capita and economic intensity metrics.

The most important finding of this research is that, after other emission reduction measures were employed to the maximum feasible extent, there was no alternative to widespread switching of direct fuel uses (e.g., gasoline in cars) to electricity in order to achieve the reduction target. Without electrification, the other measures combined produced at best 2050 emissions of 210 Mt CO_2e, about 50% below the 1990 level. The largest share of GHG reductions from electrification came from transportation, in which 70% of vehicle miles traveled—including almost all light-duty vehicle miles—were powered by electricity in 2050, along with 20% powered by biofuels and 10% powered by fossil fuels. Other key applications for fuel switching occurred in space heating, water heating, and industrial processes. Figure 3A shows that even with aggressive EE keeping other demand growth nearly flat, fuel-switching to electricity led to a doubling of electricity generation by 2050. "Smart charging" of electric vehicles was essential for reducing the cost of electrification, by raising utility load factors and reducing peak capacity requirements through automated control of charging times and levels (Fig. 3B).

In the electricity sector, three forms of decarbonized generation—renewable energy, nuclear, and fossil fuel with carbon capture and storage (CCS)—each have the potential to become the principal long-term electricity resource in California, given its resource endowments. All currently suffer from technical limitations and high cost relative to the conventional generation alternative, natural gas, so it is not obvious which of these (if any) will dominate in the long run. Therefore, we built separate high–renewable energy, high-nuclear, and high-CCS scenarios that met the target, plus a mixed case. Because these technologies have very different operating characteristics—CCS, when commercialized, is expected to be flexibly dispatchable generation that can follow demand; nuclear is baseload generation that operates at a constant output level; and the most abundant renewable energy resources (wind and solar) are intermittent—they also have very different needs for supporting infrastructures, including capacity resources, high-voltage transmission, and energy storage. Figure 3C shows the generation scenarios. The high–renewable energy case has the highest requirements for installed capacity, transmission, and energy storage; the high-nuclear case requires the largest export market for excess generation, along with an expansion of upstream and downstream nuclear fuel cycle infrastructure; and the high-CCS case requires construction of CO_2 transportation and storage infrastructure. In addition, water, land use, and siting issues are quite different for each of these options. Residual electricity-sector carbon emissions in 2050 came primarily from combustion of natural gas for peaking generation and CCS. CCS fleet-average carbon storage efficiency in 2050 was 90%, but new CCS units were required to reach 98% efficiency. Within the western grid of which California is part, all existing conventional coal plants were retired at the end of their planning lives of 30 years.

Some studies suggest that 100% of future electricity requirements could be met by renewable energy, but our analysis found this level of penetration to be infeasible for California (*20*, *21*). We found a maximum of 74% renewable energy penetration despite California's large endowment of renewable resources, even assuming perfect renewable generation forecasting, breakthroughs in storage technology, replacement of steam generation with fast-response gas generation, and a major shift in load curves by smart charging of vehicles. Using historical solar and wind resource profiles in California and surrounding states, the electricity system required 26% nonrenewable generation from nuclear, natural gas, and hydroelectricity, plus high storage capacity to maintain operability. It would be possible to forecast higher



Wedge Category:	Emissions Reduction Mt CO_2e (% of Total) 2030	2050	Types (and Numbers) of Measures Used	Key Attributes in 2050
Energy Efficiency	102 (33%)	223 (28%)	Building EE (18); Vehicle EE (9); Other EE (6)	Energy efficiency improved 1.3% per year on average for 40 years
Electricity Decarbonization	72 (23%)	217 (27%)	High renewables, high nuclear, high CCS, and mixture of the three	90% of generation requirement met with CO_2- free sources. Equivalent decarbonization in each scenario
Smart Growth	13 (4%)	41 (5%)	Reductions in vehicle miles traveled (VMT) (6)	VMT reduced in light duty vehicles (LDV) by 10%; freight trucks 20%; other transportation 20%
Rooftop PV	8 (3%)	21 (3%)	Residential and commercial PV roofs (2)	10% of electricity demand displaced by rooftop PV
Biofuels	18 (6%)	49 (6%)	Transportation biofuels; ethanol, biodiesel, biojet fuel (9); Residential, commercial, industrial biomethane (3)	2% of natural gas use in buildings displaced by biomethane, and 10-20% of petroleum-based fuels for vehicles displaced by biofuels
Non-Energy, Non-CO_2	67 (22%)	116 (15%)	Cement, agriculture, and other (3)	Non-fuel; non-CO_2 GHG emissions reduced 80% below baseline
Electrification	29 (9%)	124 (16%)	Transportation electrification (9); Other end-use electrification (5)	75% of LDV gasoline use displaced by PHEVs & electric vehicles; 30% of fuel use in other transport sectors electrified; 65% electrification of non-heating/ cooling fuel use in buildings; 50% electrification of industrial fuel uses
Baseline Case Emissions	688	875		
Mitigation Case Emissions	380	85		
Total Reduction	308	790		

Fig. 1. Emission reduction wedges for California in 2050. **Top:** Measures grouped into seven "wedges" reduce emissions from 875 Mt CO_2e in the 2050 baseline case to 85 Mt CO_2e in the mitigation case. In the 2020 model results, the wedge contributions are consistent with implementation plans for California's policy objectives (AB32) for 2020. **Bottom:** Reductions by wedge are shown for the 2030 and 2050 mitigation cases, in Mt CO_2e and as a percentage of total reductions. The top three contributions are from energy efficiency (EE) (28%), electricity decarbonization (27%), and electrification of direct fuel uses (16%). For each wedge, the types of measures included and key assumptions are shown.

penetration in cases with a higher resource base and/or much lower energy demand—for example, as a result of lower population growth or lower economic growth.

Unprecedented energy efficiency; limited contribution from biofuels. The rate of EE improvement required to achieve the target and enable feasible levels of decarbonized generation and electrification—1.3% $year^{-1}$ reduction relative to forecast demand—is less than the level California achieved during its 2000–2001 electricity crisis (*22*) but is historically unprecedented over a sustained period. This level is, however, consistent with the upper end of estimates of long-term technical EE potential in recent studies (*23*, *24*). In our model, the largest share of GHG reductions from EE came from the building sector, through a combination of efficiency improvements in building shell, HVAC systems, lighting, and appliances. EE improvements were complemented by other measures to reduce new energy supply requirements for electricity, transportation, and heating. EE in combination with on-site distributed energy resources (in the form of solar hot water and rooftop PV) reduced the net consumption of grid-supplied electricity and fuels in new residential and commercial buildings to zero by 2030 (*25*). Structural conservation in the form of "smart growth" urban planning to reduce driving requirements was responsible for 5% of total emission reductions in 2050.

Biofuels, although essential (because not all transportation can be electrified), made only a modest 6% contribution to the 2050 emissions reduction when feedstocks were constrained to be carbon-neutral, produced in the United States, and limited to California's consumption-weighted proportional share of U.S. production (*26*–*28*). This feedstock was sufficient to provide 20% of transportation fuels in the form of cellulosic ethanol and algal biodiesel, assuming that these technologies achieve commercialization (fig. S15). In our model, biofuel feedstocks were dedicated to the production of transportation fuels as their highest-valued economic use, and these fuels were allocated to applications for which electrification is not a practical option, such as long-haul freight trucking and air travel. A small amount of biomethane was used in power generation.

In the baseline forecast, 2050 emissions of non-energy CO_2 (e.g., from cement manufacturing) and non-CO_2 GHGs [e.g., methane and nitrous oxide from agriculture and waste treatment, and high–global warming potential (GWP) gases used as refrigerants and cleaning agents] were 145 Mt CO_2e, more than the entire economy-wide target of 85 Mt CO_2e. Relative to CO_2 emissions from energy sectors, scientific understanding of long-term mitigation potential for these sectors is poorly developed (*29*–*32*). Nevertheless, it was clear that if these emissions were not abated, the 2050 target could not be met. We modeled mitigation by extrapolating California's AB32 implementation plan for 2020 (*7*) in three broad areas. Agricultural and forestry measures contributed 47 Mt CO_2e of reductions, cement-related measures contributed 8 Mt CO_2e, and industrial and other measures contributed 61 Mt CO_2e, for a total reduction of 116 Mt CO_2e below the 2050 baseline, which maintained the current share of non-energy/non-CO_2 in overall emissions.

There is evidence that the three key energy system transformations identified here are broadly generalizable to developed economies. A recent report on 80% GHG reductions in the European Union found that similar transformations were required, including electrification of transportation and buildings (*33*). In other studies, where reductions rely on EE and generation decarbonization but not electrification, lower GHG reduction levels were achieved. For example, in a recent International Energy Agency study of technology paths in Organization for Economic Cooperation and Development member countries as a whole, the most aggressive scenario had a 2050 reduction of about 50% below 1990 levels, with a 6% contribution from electrification (*34*). The consistency among these results is predictable, in that developed economies broadly share the same challenges for reaching deep reduction targets—the need to virtually eliminate fossil fuel use in electricity supply and in final consumption, especially in vehicles and buildings.

Infrastructure deployment and technology investment require coordination. In contrast to the findings of Pacala and Socolow, we found that achieving the infrastructure changes described above will require major improvements in the functionality and cost of a wide array of technologies and infrastructure systems, including but not limited to cellulosic and algal biofuels, CCS, on-grid energy storage, electric vehicle batteries, smart charging, building shells and appliances, cement manufacturing, electric industrial boilers, agriculture and forestry practices, and source reduction/capture of high-GWP emissions from industry (*35*).

Not only must these technologies and systems be commercially ready, they must also be deployed in a coordinated fashion to achieve their hoped-for emission reduction benefits at acceptable cost. For example, switching from fuels to electricity before the grid is substantially decarbonized negates the emissions benefits of electrification; large-scale deployment of electric vehicles without smart charging will reduce utility load factors and increase electricity costs; and without aggressive EE, the bulk requirements for decarbonized electricity would be doubled, making achievement of 2050 goals much more difficult in terms of capital investment and siting. Figure 3D shows the impact of aggressive EE on three key metrics of decarbonized electricity supply:

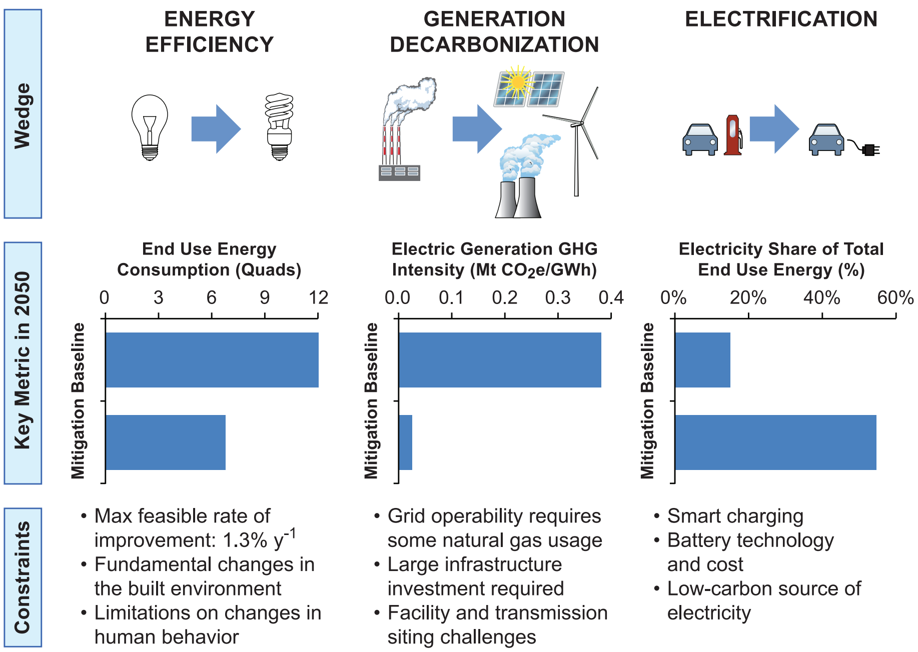


Fig. 2. The three main energy system transformations required to reduce GHG emissions 80% below 1990 levels by 2050 in California. End-use EE must be improved very aggressively (annual average rate 1.3% $year^{-1}$), electric generation emissions intensity must be reduced to less than 0.02 kg CO_2e/kWh, and most direct fossil fuel uses in transport, buildings, and industry must switch to electricity, raising the electricity share of end-use energy from 15% today to 55% in 2050. Both economics and the current state of technology development suggest a staged deployment in large-scale infrastructural transformation. Without aggressive levels of EE, the scale of decarbonized generation required to simultaneously replace fossil plants and meet both existing and newly electrified loads would be infeasible. Until high levels of electricity decarbonization are achieved, emission benefits from electrification would be limited. Without electrification, constraints on the other measures would limit total reductions to about 50% below 1990 levels.

generating capacity, energy storage, and miles of high-voltage transmission line. For the mixed-generation case, achieving the 2050 target with baseline levels of EE raised the requirement for annual construction of decarbonized generation from a very formidable 3.7 GW year^{-1} to a practically unachievable 7.0 GW year^{-1}, and the requirement for new transmission lines from 400 to 960 miles year^{-1}.

Our model shows a net mitigation cost to California, relative to the baseline, of 0.5% of gross state product (GSP) in 2020, 1.2% in 2035, and 1.3% in 2050 ($65 billion or $1200 per capita) (Fig. 4 and fig. S34). The transportation sector bore the highest share of these costs, reflecting the cost of fleet electrification. These results are highly sensitive to both measure costs and fuel price assumptions; using the upper value of the U.S. Energy Information Administration (EIA) long-term crude oil price forecast makes net mitigation costs negative (fig. S12). Cumulative net costs from 2010 to 2050 were $1.4 trillion. The average cost of carbon in 2050 was $90/t CO_2e, whereas the highest average cost by measure type was $600/t CO_2e for electrification measures (*36*). Because mitigation measures reduce fuel use by investing in energy-efficient infrastructure and low carbon generation, a much higher percentage of energy cost will go to capital costs; our model indicates a cumulative investment of $400 billion to $500 billion in current dollars (figs. S35 and S36) for electricity generation capacity in the mitigation case, a factor of about 10 higher than the baseline case (*37*).

The transition to an energy-efficient, low-carbon, electrified infrastructure thus requires mobilizing investment and coordinating technology development and deployment on a very large scale over a very long time period. How best to achieve this is the focus of active debate over the relative roles of markets, government, carbon pricing, R&D policy, regulation, and public investment (*38*). Many consider carbon pricing the key to achieving efficient investment and providing incentives for consumer adoption; others argue that carbon

Table 1. Primary and end-use energy and emissions by sector and fuel type in 2010 and 2050. The numerical difference between primary and end-use energy is due to conversion and other losses. Sources for population and economic data are given in the supporting online material.

	Energy consumption (EJ)					Emissions (Mt CO_2e)		
	2010	2050 Baseline	2050 Mitigation	2010 (%)	2050 Mitigation (%)	2010	2050 Baseline	2050 Mitigation
Primary energy consumption and emissions, by sector								
Residential	1.60	2.56	0.52	18%	8%	71.3	117.1	5.4
Commercial	1.68	2.60	0.94	19%	14%	70.9	114.5	10.0
Industrial	1.41	1.39	0.96	16%	14%	67.4	67.3	6.4
Petroleum	0.81	0.82	0.58	9%	9%	46.7	47.5	5.6
Agriculture	0.34	0.52	0.21	4%	3%	16.3	27.1	1.0
Transportation	2.86	5.67	3.60	33%	53%	189.4	374.1	45.0
Non-energy, non-CO_2 GHG emissions						56.4	127.8	11.4
Total all sectors	8.70	13.56	6.81	100%	100%	518.4	875.4	84.8
Primary energy consumption and emissions, by fuel type								
Direct fuel use								
Natural gas	2.73	3.40	0.38	31%	6%	148.9	185.1	20.5
Gasoline	2.09	4.36	0.13	24%	2%	135.9	283.4	8.3
Diesel	0.73	1.23	0.39	8%	6%	50.2	84.7	26.6
Jet fuel	0.04	0.08	0.04	0%	1%	3.3	6.0	3.4
Biomethane and biofuels	0.00	0.00	0.73	0%	11%	0.0	0.0	0.0
Total direct fuel use	5.59	9.06	1.67	64%	25%	338.3	559.2	58.8
Electric generation (primary)								
Natural gas (non-CCS)	1.45	2.90	0.01	17%	0%	72.1	135.3	0.4
Coal (non-CCS)	0.49	0.49	0.00	6%	0%	43.2	43.2	0.0
Fossil fuel w/ CCS	0.00	0.00	2.18	0%	32%	0.0	0.0	10.6
Nuclear	0.30	0.26	0.74	3%	11%	0.0	0.0	0.0
Renewables and hydroelectricity	0.71	0.66	2.04	8%	30%	0.4	0.4	0.8
Other	0.16	0.18	0.16	2%	2%	8.0	9.6	2.9
Total electric generation	3.11	4.49	5.14	36%	75%	123.7	188.4	14.7
Non-energy, non-CO_2 GHG emissions						56.4	127.8	11.4
Total all fuel types	8.70	13.56	6.81	100%	100%	518.4	875.4	84.8
End-use energy consumption and emissions, by fuel type								
Total direct fuel use	5.59	9.06	1.67	85%	45%	338.3	559.2	58.8
Electricity (end-use)	0.98	1.63	2.03	15%	55%	123.7	188.4	14.7
Direct fuel use + electricity	6.57	10.69	3.70	100%	100%	462.0	747.6	73.4
Non-energy, non-CO_2 GHG emissions						56.4	127.8	11.4
Total end use by fuel type	6.57	10.69	3.70	100%	100%	518.4	875.4	84.8
Intensity metrics								
CA population (millions)	38.8	56.6	56.6					
Per capita energy use rate (kW/person)	7.1	7.5	3.8					
Per capita emissions (t CO_2e/person)	13.3	15.5	1.5					
Energy intensity ($/GJ)	$249	$383	$762					
Economic emissions intensity (kg CO_2e/$)	0.239	0.169	0.016					
Electric emissions intensity (kg CO_2e/kWh)	0.42	0.39	0.02					

pricing is insufficient and requires complementary policies to address market failures, public goods, and coordination problems (*16*, *39*, *40*). Some make the specific case that pollution pricing is effective in encouraging technology adoption but not technological innovation (*41*, *42*). Others are concerned that the venture capital model is mismatched with the scale and timeline of investment required for an energy transformation (*43*) and with the risks created by the need for multiple technologies to achieve commercialization in parallel (*44*). These concerns have led to calls for novel public-private partnerships to address investment failures through government absorption of private capital risk (*43*) and to address coordination and sequencing through industry-government road-mapping (*45*).

Electricity's role in future energy costs and climate policy. Another model result deserving special attention is the expanded role of electricity, which increases from 15% to 55% of end-use energy, essentially switching places with petroleum products, which fall from 45% to 15% (Table 1). If electricity does become the dominant component of the 2050 energy economy, the cost of decarbonized electricity becomes a paramount economic issue. Our results show that generation mixes dominated by renewable energy, nuclear, and CCS, in the absence of cost breakthroughs, would have roughly comparable costs, raising the present average cost of electricity generation by a factor of about 2—a result also noted by other researchers (*17*). These findings indicate that minimizing the cost of decarbonized generation should be a key policy objective. By some estimates, aggressive R&D policies could reduce the cost of low-carbon generation in the United States from 2020 to 2050 by about 40% or $1.5 trillion (*17*).

For electrified transportation, the inherently higher efficiencies of electric drivetrains would still allow a net reduction in fuel costs even with electricity prices doubled and oil prices at $100 per barrel, as well as shifting cash flows away from foreign oil imports toward domestic purchases of electricity. On the other hand, electrification of direct fuel uses will increase costs in the residential, commercial, and industrial sectors, especially for heating; hence, there is a need for EE and design of new infrastructure in these sectors to minimize lifecycle costs. Because much of the required technology and infrastructure for a basic transformation of the energy system is not yet commercialized, comparative lifecycle costs are highly uncertain. However, because decarbonized generation technologies are dominated by capital costs and are insensitive to oil and natural gas price volatility, an electrified economy would have a long-term cost stability that could lower investment risk and make the optimal level of EE more certain (*46*). Even varying measure costs from one-half to twice the nominal values in the mitigation scenario produced no more variation in overall energy system costs than did varying crude oil prices in the baseline scenario over the range in the EIA's long-term forecast (fig. S12).

The climate policy community has proposed a suite of policies to complement carbon pricing (e.g., EE standards, renewable energy standards, and R&D support) that reflect not only economic and technology goals but also sociopolitical considerations such as equity, local initiative, and adaptability (*16*). The central role of electricity in our results suggests the importance of electricity-sector governance as a tool of climate policy, but this has received relatively little attention until recently (*47*). Although some argue that regulation impedes innovation and increases implementation costs (*43*), state-level electricity regulation has existing tools for pursuing many climate policy goals, through both market mechanisms and direct regulation. Regulators can require that utilities procure renewable generation, limit carbon intensities, implement customer EE and distributed energy programs, and set retail electricity rates that encourage conservation and electric vehicle charging, internalize pollution costs, and allocate the

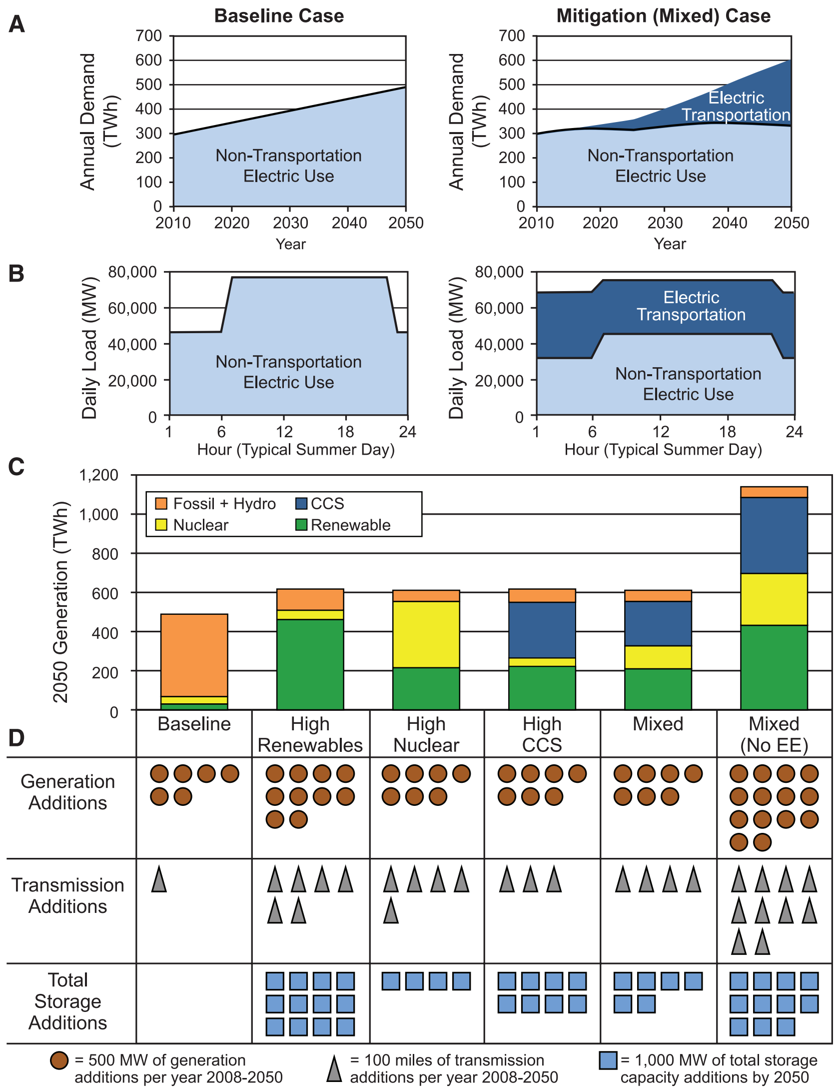


Fig. 3. Electricity consumption, load profiles, and fuel mix in baseline and mitigation scenarios. (**A**) In the mitigation case, aggressive end-use efficiency flattens baseline load growth. However, electrification of transportation adds a major new load, so that 2050 consumption is similar in both cases. (**B**) Smart charging of electric vehicles flattens the average daily load curve, reducing capacity requirements. (**C**) In the 2050 baseline scenario, load growth is met primarily with natural gas generation. Four mitigation scenarios are shown with different fuel mixes, constrained by California's existing fuel mix and policy requirements (e.g., 33% renewable portfolio standard, continued licensing of existing nuclear generation). The mixed case, which contains all three generation types, yields the results discussed in this paper and shown in Figs. 1 to 4. (**D**) New capacity requirements for each generation fuel mix are shown for generation, transmission, and energy storage. Without aggressive EE, new capacity requirements increase by roughly a factor of 2. The high–renewable energy case has higher new-capacity requirements than the high-CCS and high-nuclear cases; however, the high–renewable energy case does not have the high-CCS case requirements for CO_2 transmission and storage capacity, or the high-nuclear case requirements for upstream and downstream nuclear fuel cycle facilities.

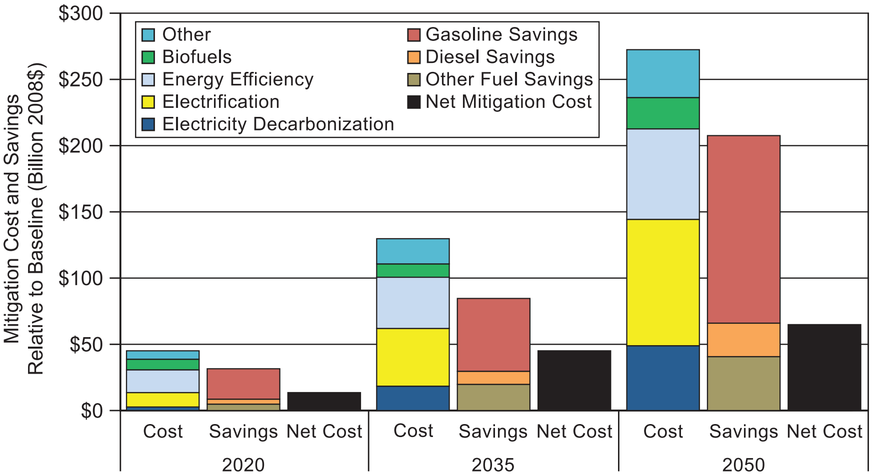


Fig. 4. Mixed-case net cost by mitigation type in 2020, 2035, and 2050. For each year shown, the left column shows incremental mitigation costs in excess of baseline costs, the center column shows incremental savings relative to baseline fuel costs, and the right column shows net cost (the difference between cost and savings). "Other" mixed-case costs include measure implementation costs not associated with EE, electrification, generation decarbonization, or biofuels. "Other" savings include jet fuel and natural gas purchases for direct use (e.g., heating). Net costs are $15 billion in 2020, $45 billion in 2035, and $65 billion in 2050. This is equivalent to $320 per capita or 0.5% of the statewide GSP in 2020, $910 per capita or 1.2% of the statewide GSP in 2035, and $1200 per capita or 1.3% of the statewide GSP in 2050.

costs of these policies equitably (*7*, *48*). Given the political challenges of achieving comprehensive federal climate legislation, it is worth further exploring decentralized electricity governance as a climate policy mechanism.

Assuming plausible technological advances, we find that it is possible for California to achieve deep GHG reductions by 2050 with little change in life-style (although the potential for life-style change deserves further study). The logical sequence of deployment for the main components of this transformation is EE first, followed by decarbonization of generation, followed by electrification. This transformation will require electrification of most direct uses of oil and gas. In California, no single generation technology (renewable energy, nuclear, or CCS) can be used to decarbonize all electricity; a mixed generation portfolio is required. If it is true that the low-carbon path features electricity, then the question is how best to mobilize investment and coordinate R&D and infrastructure rollout to achieve this end, and what climate policy modalities will be most effective. If the oil economy is replaced by the electric economy, it is instructive to consider the implications of the price of a decarbonized kilowatt hour replacing the price of a barrel of oil as a benchmark for the overall economy.

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states, the timing of technology adoption in California is driven by policy as much as by markets, leading to the adoption of high-cost options (e.g., rooftop PV) concurrently with low-cost options (e.g., EE).
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Acknowledgments: We thank the anonymous reviewers. We are grateful for the contributions and helpful comments of R. Orans, B. Horii, L. Alagappan, A. Whitmore, J. Shipley, D. Fridley, J. Koomey, A. Sanstad, R. Socolow, J. Zysman, W. Denn, and C. Greacen. The early modeling work was carried out with partial support from Hydrogen Energy International. The contributions of M.S.T. were supported by the Office of Science, Office of Biological and Environmental Research, Climate and Environmental Science Division, U.S. Department of Energy, under contract DE-AC02-05CH11231 to Lawrence Berkeley National Laboratory.

Supporting Online Material
www.sciencemag.org/cgi/content/full/science.1208365/DC1
Materials and Methods
SOM Text
Figs. S1 to S36
Tables S1 to S22
References

13 May 2011; accepted 3 November 2011
Published online 24 November 2011;
10.1126/science.1208365

Subparticle Ultrafast Spectrum Imaging in 4D Electron Microscopy

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Single-particle imaging of structures has become a powerful methodology in nanoscience and molecular and cell biology. We report the development of subparticle imaging with space, time, and energy resolutions of nanometers, femtoseconds, and millielectron volts, respectively. By using scanning electron probes across optically excited nanoparticles and interfaces, we simultaneously constructed energy-time and space-time maps. Spectrum images were then obtained for the nanoscale dielectric fields, with the energy resolution set by the photon rather than the electron, as demonstrated here with two examples (silver nanoparticles and the metallic copper–vacuum interface). This development thus combines the high spatial resolution of electron microscopy with the high energy resolution of optical techniques and ultrafast temporal response, opening the door to various applications in elemental analysis as well as mapping of interfaces and plasmonics.

Substantial progress has been made in the imaging of matter at the smallest length scale and shortest time response, using a range of optical and electron-based methods. Recent developments in electron microscopy have enabled studies of nanostructures with remarkable spectral and spatial resolution (*1*–*4*). However, a single nanoparticle-probing method with simultaneously high spatial, temporal, and spectral resolution has not hitherto been reported.

Here, we report ultrafast spectrum imaging (USI), with subparticle spatial resolution, in electron microscopy. The electron beam is focused down to the nanometer scale, the electron packet has femtosecond duration, and the energy resolution, optically induced, is in the millielectron-volt range; the energy and temporal resolutions are no longer limited to those of conventional microscopy imaging. At every probe position across a nanoparticle, or at an interface, the electron energy-gain spectrum can be acquired as a function of the time delay between femtosecond optical and electron pulses, and imaging is complete when the focused probe is simultaneously scanned.

We conducted two sets of experiments to demonstrate the potential of the technique. For plasmonic Ag particles, we observed the polarized electric field distribution, the femtosecond dielectric response, and the nanometer spatial localization of a single particle. For the Cu metal–vacuum interface, we determined the effective decay length (nanometer scale) and the evolution (femtosecond resolution) of the plasmonic field, and identified the strong and weak regions of the field by scanning the probe away from the interface. We anticipate a broad range of applications of USI because of the dimensions it simultaneously enables for imaging in space, time, and energy.

Knowledge of the dielectric response of materials and biological systems to an optical excitation is essential to the determination of the strength and extent of interaction between electromagnetic waves and systems under study. For example, bulk materials' reflection and absorption are dictated by such responses at the incident wavelengths. At the nanoscale, where the boundaries can have a marked effect on the way light manifests itself, the response can include spatially localized plasmonic fields (*5*, *6*). It follows that an understanding of the dynamics at the microscopic level, with combined spatial, spectral, and temporal resolutions, would be indispensable, both at the fundamental level and for various applications.

For bulk systems, there exist various optical techniques for measuring the dielectric response; these include ellipsometry, Fourier transform infrared spectroscopy, and Raman spectroscopy. In the frequency domain, these techniques can readily reach the energy resolution necessary to differentiate vibrational and rotational modes in molecules (meV and sub-meV) and collective vibrational excitations in solids (phonons). In the spatial domain, however, these techniques are limited by diffraction effects, and hence they exhibit a typical resolution of several hundred nanometers at the visible wavelengths. Modern optical methods have enabled improvement of resolution (*7*–*9*) beyond the diffraction limit in certain circumstances, but they cannot provide the spatial resolution of

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