Clean Energy Technology Pathways:

AN ASSESSMENT OF THE CRITICAL BARRIERS TO ACHIEVING A LOW-CARBON ENERGY FUTURE

National Commission on Energy Policy

Bipartisan Policy Center

Disclaimer

This white paper was prepared by the staff of the National Commission on Energy Policy (NCEP) with the aim of promoting a better shared understanding of issues and barriers surrounding the deployment of low-carbon energy technologies. While this paper was drafted with input from NCEP Commissioners, the views expressed here do not necessarily reflect those of individual NCEP Commissioners.

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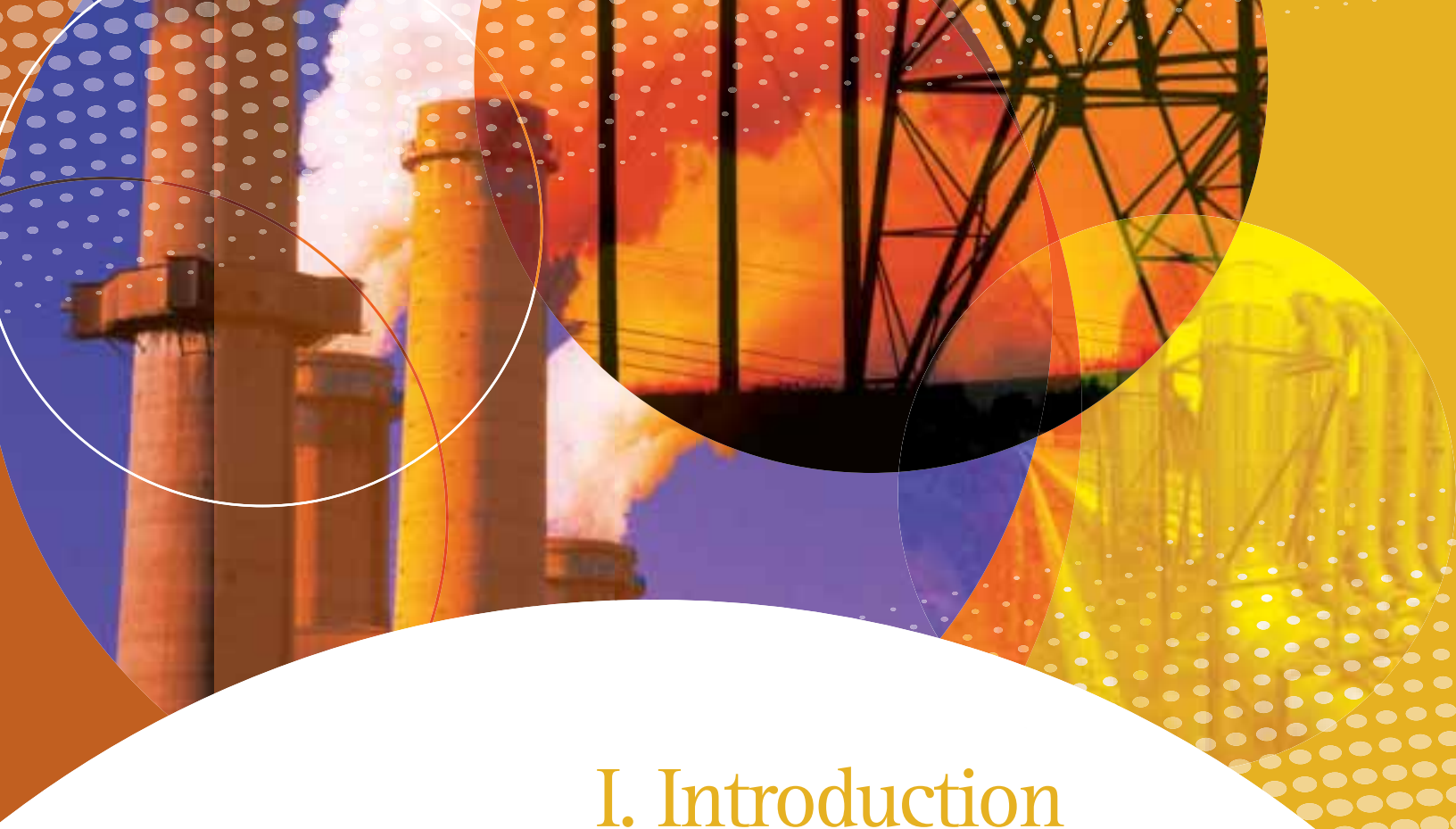


I. Introduction

Meeting the world's growing energy demands while reducing greenhouse gas (GHG) emissions is among the central challenges humanity confronts this century. Technology is at the heart of that challenge and technological transformation will be central to finding sustainable solutions. Starting with its first recommendations, published in the 2004 report *Ending the Energy Stalemate: A Bipartisan Strategy to Meet America's Energy Challenges*, the National Commission on Energy Policy (NCEP) has argued that expanding the scope and diversity of options available for meeting the nation's future energy needs is the essential pre-requisite for addressing critical long-term economic, environmental, and energy-security threats. Recognizing that the challenge at hand is fundamentally technological in nature, however, in no way diminishes the difficulties it presents. On the contrary, success requires much more than breaking through any particular set of cost or performance barriers. Rather, transforming our underlying energy systems will require attention to a whole array of factors—economic, structural, institutional, regulatory, and social—that play a role in determining whether new technologies will be commercially viable over the long term, on what scale, and under what conditions. For this reason, energy technology development and deployment has remained a major focus of subsequent Commission reports and analyses, including the Commission's June 2006 report on the siting of critical energy infrastructure and its updated recommendations to the President and the 110th Congress in 2007.[1] As we acknowledged in those reports, various legislative and other initiatives launched in the

No single technology, by itself, offers all or even most of the solution and all options have drawbacks and face hurdles that can be expected to slow or complicate their deployment.

[1] Past Commission recommendations are available at http://bipartisanpolicy.org/projects/national-commission-energy-policy.

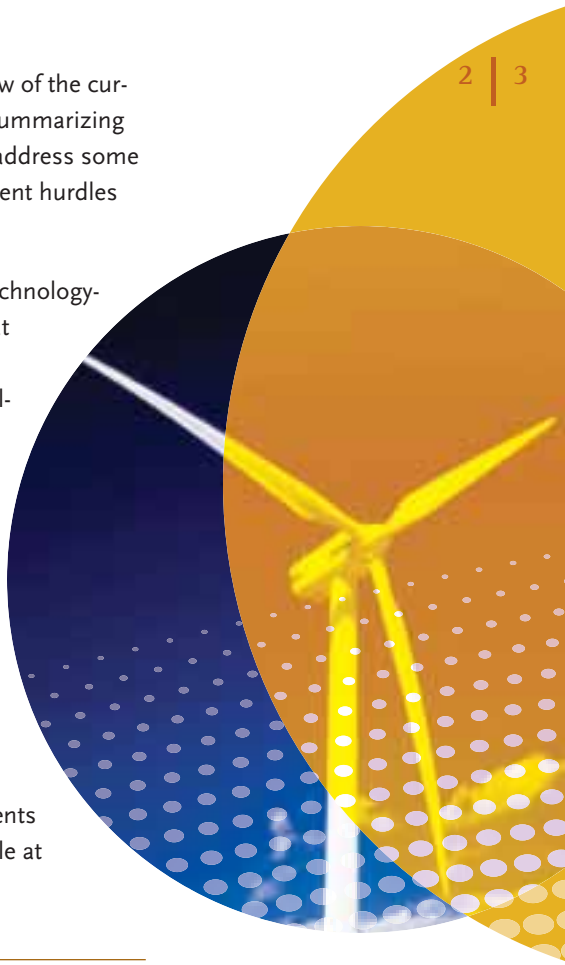
years since the Commission's inception have begun to address some of the technology needs we identified in 2004, but much remains to be done.

The sustainable energy challenge is complicated by another recurrent theme of past Commission reports: No single technology, by itself, offers all or even most of the solution and all options have drawbacks and face hurdles that can be expected to slow or complicate their deployment—particularly at the scales needed to make a meaningful dent in terms of overall energy supply, carbon emissions, or oil dependence. The energy and climate policy literature is replete with technology and cost assessments and scenario analyses that attempt to quantify the potential of particular technologies or categories of technology. This study, by contrast, focuses on the interaction between different technologies in the context of an overarching emissions-reduction imperative—that is, how assumptions about the availability of one type of technology increase or decrease the pressure on other types of technology—and on the cross-cutting deployment challenges that confront all of the major low-carbon energy options. For the discussion of technology interactions we rely heavily on a modeling analysis commissioned by NCEP and conducted by the Joint Global Change Research Institute (JGCRI) at Pacific Northwest National Laboratory (PNNL). The JGCRI research team was led by Dr. Jae Edmonds, a noted authority on the subject of climate technology and policy. The second major topic of this report—a discussion of cross-cutting deployment barriers—draws on NCEP staff expertise, the recent literature, and on input collected through a series of NCEP-sponsored technology workshops. The workshops, which were held over a roughly 12-month timeframe beginning in 2008, covered carbon capture and storage (CCS), bioenergy, advanced nuclear power, wind and solar power, building efficiency, and advanced vehicle platforms. Each one brought together knowledgeable individuals from private industry, NGOs, and the science and technology community, as well as regulators and policy makers with relevant interests and expertise. Background papers describing the status of each technology and the specific deployment barriers it confronts can be found in the appendices to this report.

This report is organized in three main parts. Following a short discussion of background and context in Section II, Section III discusses the results of the JGCRI modeling analysis and draws out some broad insights relevant to the overall scale and complexity of the low-carbon technology deployment challenge. Section IV focuses on cross-cutting barriers that are common to multiple types of energy technologies, including siting and permitting challenges, transmission rules, financing challenges, and workforce shortages. The report concludes with a summary of the main points that emerge from previous sections and suggestions for further areas for analysis and policy intervention. Several appendices follow the conclusion:

- Appendix I provides an overview of the current energy policy landscape, summarizing new and existing initiatives to address some of the technology and deployment hurdles discussed in prior sections.
- Appendices II–VII consist of technology-specific background papers that describe the key deployment barriers facing different technologies. The background papers were developed to help frame discussion at the NCEP technology workshops convened as part of this study.
- Appendix VIII provides a list of the organizations that participated in each workshop.

Additional information and documents referenced in this report are available at the NCEP website.[2]



[2] http://bipartisanpolicy.org/projects/national-commission-energy-policy/.

II. Background and Context

To make progress on the dual goals of reducing oil dependence and GHG emissions over the next two decades, new technologies will be needed not only to meet continued growth in energy demand, but to begin to displace existing, carbon-intensive sources of energy—particularly for electricity production and in the transportation sector. The enormity of the task is underscored by current business-as-usual forecasts, which suggest that transportation energy and electricity consumption will be higher in absolute terms by 2030 than they are today. The result, even under a set of assumptions that accounts for the impact of recent legislative initiatives and presumes a dramatic increase in renewable electricity production capacity and biofuels use, is a net *increase* of about 4 percent in projected energy-related carbon dioxide (CO_2) emissions between 2008 and 2030, according to the U.S. Energy Information Administration's (EIA's) most recent (updated 2009) reference-case Annual Energy Outlook forecast, which includes the energy provisions of the American Recovery and Reinvestment Act of 2009. For example, EIA's business-as-usual forecast assumes that wind generating capacity will more than quadruple over the next two decades, from 16 gigawatts (GW) in 2007 to 66 GW in 2030; it also assumes that 11 new GW of nuclear capacity will be added by 2030. If one accounts for the fact that several GW of planned nuclear plant retirements are also built into the base forecast, EIA's projections reflect an expectation that at least several large new nuclear plants will be built over the next twenty years. Expected changes in the transportation fuel supply are also dramatic, largely because of an ambitious ramp-up in biofuels

New technologies will be needed not only to meet continued growth in energy demand, but to begin to displace existing, carbon-intensive sources of energy.

production to meet the requirements of the federal renewable fuels standard (RFS).[3]

The magnitude of the task also comes into focus when one considers the scale of the infrastructure and technology investments needed merely to preserve and modernize existing energy systems. For example, a recent report commissioned by the Edison Foundation found that the electric utility industry will need to invest $1.6 trillion in new generation, transmission, and distribution by 2030 under business as usual.[4] Adding a price on GHG emissions raises the required investments to over $2 trillion.[5]

With energy policy issues near the top of the political agenda in recent years—in part due to growing awareness of climate change, but perhaps even more immediately because of a dramatic escalation in oil and other energy commodity prices from 2006 through the first half of 2008—a number of energy-technology initiatives were introduced at the local, state, regional, and federal levels. Most of these initiatives were introduced with the intent of reducing oil dependence or cutting greenhouse gas emissions, or both.

High energy prices also spurred a surge of private-sector interest and investment in alternative energy projects. The wind industry, for example, added approximately 8 MW in 2006 and 2007 alone, almost a two-fold expansion over its pre-2006 base of 8.7 GW. In part this burst of activity was in response to the growing number of states that had established renewable energy standards (RES) mandating that a minimum percentage of electricity supply come from renewable energy resources. At this point, 26 states plus the District of Columbia have adopted RES policies, in some cases designed to achieve renewable electricity penetration rates of as much as 20 or 25 percent by 2020. Additionally, a number of state and regional initiatives have emerged in recent years to address GHG emissions; the best known examples include the northeastern states' Regional Greenhouse Gas Initiative (RGGI) and California's Global Warming Solutions Act of 2008.

Meanwhile, two major pieces of federal energy legislation passed in the last few years—the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007—included numerous provisions directly or indirectly aimed at spurring investment in new technologies and improved energy infrastructure. For example, these bills included short-term extensions of the federal renewable energy production tax credit, loan guarantees for new nuclear power plants and other energy technologies, funding authorizations for CCS demonstration projects, investment incentives, energy efficiency standards (including a substantial increase in automobile fuel economy standards), and new federal authority to intervene to facilitate the siting of new electricity transmission infrastructure in "critical corridors."

In recent years...a number of energy technology initiatives were introduced at the local, state, regional, and federal levels.

The context for all of these policies and initiatives—and indeed for private and public sector investments in energy technology more generally—shifted dramatically in the fall of 2008. By precipitating a dramatic fall-off in energy prices and creating rapidly deteriorating economic conditions for all types of industries, but especially for "new energy" start-up companies that are still establishing themselves, the recent worldwide financial crisis has clearly complicated prospects

[3] The RFS was introduced as part of the Energy Policy Act of 2005 and subsequently amended by the Energy Independence and Security Act of 2007. Current law requires the use of approximately 15 billion gallons of renewable biofuels per year in 2012, growing to 36 billion gallons per year in 2022.

[4] The Brattle Group. Transforming America's Power Industry: The Investment Challenge 2010-2030. Nov. 2008.

[5] Ibid.

for investment in the clean energy arena. At the same time, a political realignment in Washington D.C. and a massive burst of stimulus spending have created the possibility of a concentrated national investment in energy infrastructure on a scale not seen perhaps in generations. Indeed, the $787 billion stimulus package passed in February of 2009 under the title "American Recovery and Reinvestment Act of 2009" (ARRA) included tens of billions of dollars for improvements to the electrical grid, energy technology research, development and deployment, and advanced vehicles. Much of this spending is designed to be concentrated in the very near term, however, and there are questions about how effectively it can or will be used to provide a foundation for truly next-generation technologies. Meanwhile, near-term spending could also—by adding to the national debt—have the effect of further constraining public resources available for technology investment in the medium to long term. Highlights of the most important energy policies and technology-related initiatives adopted in the ARRA and in other bills passed over the last few years are provided in Table 1.

Cost competitiveness, meanwhile, is not always the only—or necessarily the most important—barrier to new technologies, as the discussion elsewhere in this report illustrates. Regulatory hurdles, financing challenges, uncertainty, jurisdictional disputes, and even simple NIMBY-ism[7] can act as formidable deployment barriers. Unfortunately, many of these barriers are not amenable to simple policy prescriptions. Before reviewing the most important of these cross-cutting barriers, however, we turn in the next section to a more detailed exploration of the technology deployment challenge inherent in any policy that aims to substantially reduce U.S. GHG emissions over the next half century.

[7] NIMBY stands for "not in my backyard" and is the shorthand term often used to describe local opposition to new facilities or infrastructure.

Table 1: Summary of Major Recent Federal Energy Policies

POLICY		DESCRIPTION
ENERGY POLICY ACT OF 2005	Renewable Energy	■ Loan Guarantees—Guarantees up to 80% of project costs for eligible projects that reduce GHG emissions and employ innovative technologies (including renewable energy, advanced coal, and nuclear) ■ Renewable Electricity Production Credit—Extends a per kilowatt-hour (kWh) federal production tax credit (PTC) for electricity generated by qualified energy resources ■ Clean Renewable Energy Bonds—provides a tax credit to holders of clean renewable energy bonds ■ Investment Tax Credit—provides a 30% tax credit for residential investment in solar or fuel cell technology ■ Federal Purchase Requirement—renewable energy must represent a certain percentage of the federal government's electric consumption, rising from 3% in 2007 to 7.5% in 2013
	Biomass	■ Renewable Fuels Standards—requires gasoline to contain an increasing amount of renewable fuel, such as ethanol or biodiesel. Standard begins at 4.0 billion gallons of renewables in 2006 and reaches 7.5 billion gallons in 2012 ■ Biofuels Tax Credit—51 cent per gallon credit for producing fuel from nonconventional source counted as part of the general business credit
	Nuclear	■ Price-Anderson Act risk insurance extended for 20 years ■ Production tax credit (1. 8 cents/kWh) for up to 6,000 megawatts of new capacity for the first 8 years of operation ■ Standby support for legal/regulatory delays impacting new reactors of up to $500 million for the first two reactors and up to $250 million for the second four reactors
	Coal	■ Investment Tax Credit for advanced coal projects and qualified coal gasification projects ■ Clean Coal Power Initiative (CCPI)—Authorizes $200 million per year for the Department of Energy (DOE) to carry out a program to demonstrate large-scale capture of CO_2
	Transmission	■ Backstop Authority—allows use of federal power of eminent domain for rights-of-way for transmission lines in congestion zones designated by the DOE
	Vehicles	■ Alternative Motor Vehicle Credit—creates a new personal credit for purchase of advanced technology vehicles (including fuel cell, lean-burn, and hybrid technologies) ■ A 30% tax credit for installation of alternative fueling stations—including ethanol, natural gas, and hydrogen
	Efficiency	■ Establishes new efficiency standards for a range of appliances and commercial equipment ■ Energy and water use standards for federal building ■ Tax incentives for energy efficient construction or retrofits, commercial buildings, and appliances

Table 1: Summary of Major Recent Federal Energy Policies (continued)

POLICY		DESCRIPTION
ENERGY INDEPENDENCE AND SECURITY ACT OF 2007	**Transmission**	■ National Institute of Standards and Technology directed to establish standards for use of smart grid equipment/systems ■ Allows utilities to recover certain Smart Grid investments through their rate base ■ Orders DOE to report on potential security impacts of smart grid deployment
	Efficiency	■ Updates a number of appliance efficiency, lighting efficiency, and residential building efficiency standards ■ Establishes Efficiency and Conservation Block Grant program to support regional and local efforts to reduce GHG emissions ■ Accelerates energy efficiency programs for federal buildings and agencies ■ Promotes industrial energy efficiency through DOE RD&D to improve equipment and processes used by energy-intensive industries ■ Environmental Protection Agency assessment of the potential for economically feasible waste energy recovery and grant program
	Renewable Energy	■ Accelerated R&D programs for solar, geothermal, marine hydrokinetic, and energy storage
	Biomass	■ Renewable Fuels Standard increased to 9.0 billion gallons in 2008, rising to 36 billion gallons by 2022 (of which 21 billion gallons must come from advanced biofuels)
	Vehicles	■ Vehicle Fuel Economy standards—revises the previous Corporate Average Fuel Economy (CAFE) standards and sets target of 35 miles per gallon for the combined fleet of cars and light trucks by model year 2020 ■ DOE to establish competitive grants for deployment of plug-in electric vehicles and other electric transport projects ■ Establishes a $25 billion loan guarantee program to help manufacturers and suppliers retool facilities in order to produce more fuel-efficient vehicles and components
	CCS	■ Expands DOE's program for carbon capture and sequestration R&D and large-scale demonstration ■ Requires DOE and the National Academy of Sciences to study interdisciplinary requirements for large scale geologic sequestration ■ Requires Dept. of Interior to submit a report to Congress recommending framework for managing geological storage on public land

Table 1: Summary of Major Recent Federal Energy Policies (continued)

POLICY		DESCRIPTION
AMERICAN RECOVERY AND REINVESTMENT ACT	Transmission	■ $11 billion to upgrade transmission lines and to modernize the electricity grid through investments in smart grid technology
	Loan Guarantees	■ $6 billion additional loan guarantees for renewable energy and transmission; expected to leverage $60 billion in loans
	CCS	■ $3.4 billion for fossil energy research and development predominantly directed at CCS technologies
	Renewable Energy[6]	■ Extends the PTC for renewable sources through 2012 for wind facilities and through 2013 for other facilities (including biomass, solar, and geothermal) ■ Directs the Treasury to provide grants in lieu of PTCs for renewable energy facilities placed in service in 2009 or 2010 ■ Extends the tax credit and increases the credit cap for residential energy efficiency improvements through 2010 ■ Raises bond limit for Clean Renewable Energy Bonds to $1.6 billion (from $800 million) and qualified energy conservation bonds to $2.4 billion (from $800 million)
	R&D	■ $400 million for Advanced Research Projects Agency—Energy (ARPA-E), to support high-risk, transformational technologies
	Vehicles	■ $2 billion in loans and grants to support research and development of advanced battery technologies, including advanced lithium ion batteries, hybrid electrical systems and component manufacturing, and software designs ■ Federal Motor Vehicle Procurement—$300 million for the General Services Administration to purchase fuel-efficient vehicles for the federal fleet
	Efficiency	■ Federal High-Performance Green Buildings Program ($4.5 billion)—Dramatically expands federal energy management program authorized in previous legislation ■ $3.4 billion for the State Energy Program to support state energy offices' efforts to promote renewable energy and efficiency technologies ■ $3.2 billion for Energy Efficiency and Conservation Block Grants ■ Public Housing Capital Fund—$1 billion in funding for the Department of Housing and Urban Development's Public Housing Capital Fund to be directed at priority investments, including energy conservation retrofit investments ■ Weatherization Assistance Program—$5 billion in funding to support energy efficiency measures in low-income households

[6] A number of tax credits have been adjusted by other recent bills, including the 2008 Farm Bill and the Emergency Economic Stabilization Act of 2008 (EESA). For example, among many other provisions, EESA extended the production tax credit through 2010 for wind, refined coal, and other sources and extended the investment tax credit for solar energy property and qualified fuel cell property through 2016. The 2008 Farm Bill reduced the 51 cent-per-gallon ethanol tax credit to 45 cents per gallon beginning in 2009 and created a cellulosic biofuels credit of $1.01 per gallon through 2012.

III. The Scale of the Technology Deployment Challenge: Results from a Detailed Modeling Analysis

The cost and difficulty of achieving dramatic GHG reductions this century will depend very directly on society's ability to marshal and deploy a suite of advanced, low-carbon technologies over the next several decades.

As noted in the Introduction, NCEP commissioned an in-depth analysis by the Joint Global Change Research Institute (JGCRI) at Pacific Northwest National Laboratory (PNNL) to explore how different assumptions about future technology development and deployment influence the cost and energy-system outcomes associated with a given climate policy. Led by Dr. Jae Edmonds, the JGCRI research team investigated a range of technology scenarios under a representative climate policy designed to limit U.S. CO_2 emissions to 70 percent below 2005 levels by 2050 (the policy is assumed to go into effect in 2012). A full description of the analysis and its findings is available in a stand-alone report, accessible at http://www.globalchange.umd.edu/publications/. Key insights from the JGCRI study are worth summarizing here, however, since they provide important context for much of the discussion of deployment barriers that follows.

Dr. Edmonds and colleagues analyzed six different technology scenarios using the MiniCAM integrated assessment model developed by PNNL.[8] Each of the scenarios incorporates different assumptions about the availability, performance improvement, and deployment of a range of technologies in the two main energy production (or, more accurately, energy *transformation*) sectors, electricity and liquid fuel refining, and the three main energy end-use sectors: buildings, industry, and transportation. Table 2 provides a summary

[8] The MiniCAM integrated assessment model is a partial-equilibrium model that includes numerous energy supply technologies, accounts for agriculture and land-use, and includes a reduced-form climate model. The model covers three energy end-use sectors (buildings, industry, and transportation) as well as several energy supply sectors (fossil fuels, biomass, electricity, hydrogen, and synthetic fuels). More information can be accessed at http://www.globalchange.umd.edu/models/gcam.

of all scenarios assessed by PNNL. Specifically, the Advanced All (adv_all) technology scenario assumes substantial improvements—i.e., well above the historic rate of progress and above expectations based on current EIA forecasts—across a broad suite of energy supply and end-use technologies. By contrast, the Reference (ref) scenario assumes that these technologies improve at a pace consistent with past experience. Thus, the Advanced All scenario represents the most optimistic case modeled, while the Reference scenario represents the most pessimistic case. Between these two extremes, several additional scenarios were modeled to isolate the relative impact of accelerated progress in particular sectors (e.g. supply vs. end-use technologies) or with respect to specific low-carbon technologies (e.g. carbon capture and storage or CCS and nuclear power).

Each of the technology scenarios was modeled under the same representative carbon policy, consisting of annual caps on CO_2 emissions that decrease on a linear path between 2012 and 2050 to reach the 70 percent reduction target noted above. The Reference technology case was also modeled with no carbon policy at all (ref_no_policy) to

Table 2. Technology Assumptions Across Modeling Scenarios

TECHNOLOGY SCENARIOS						
Technology Area	ref*	adv_all	adv_ee	adv_ supply	adv_sup_ noccs	adv_sup_ nonuc
Carbon capture and storage		x		x		x
Expanded nuclear power		x		x	x	
Enhanced geothermal systems		x		x	x	x
Advanced grid for renewables		x		x	x	x
Low-cost solar power (PV, CSP)		x		x	x	x
Low-cost wind power		x		x	x	x
Advanced building technologies		x	x			
High-mpg ICE vehicles (e.g. HEVs)		x	x			
Plug-in vehicles (e.g. BEVs, PHEVs)		x	x			
Advanced manufacturing processes		x	x			
Advanced boilers and motor systems		x	x			
Commercial dedicated biomass crops		x				

**The technology assumptions are the same in both the ref_policy and ref_no_policy scenarios*

Different assumptions about technological progress–even with respect to a single type of technology, such as CCS or nuclear–lead to very different pictures of the future under a given emissions constraint.

explore how energy systems would be expected to evolve under a business-as-usual scenario in which no effort is made to curb future emissions.

Figures 1 and 2 show the projected energy supply mix for electricity production and transportation in 2050 under each of the scenarios. Both figures show significant changes in total energy consumption and in the projected energy supply mix for electricity production and transportation. Several insights are evident from even from a cursory examination of these results. The first is that different assumptions about technological progress—even with respect to a single type of technology, such as CCS or nuclear—lead to very different pictures of the future under a given emissions constraint. For example, if advanced nuclear is unavailable for whatever reason, CCS would be predicted to play a far larger role, and vice versa. Under reference case assumptions for all the energy supply options (in other words, under the Reference case and Advanced Energy End-use scenarios), wind power and natural gas play a much larger role—indicating that absent new nuclear and CCS, these remain the least costly low-carbon options for power generation.

Interestingly, electricity production increases in all the model scenarios compared to the reference, no climate policy case. That is because future carbon constraints drive some electrification of the vehicle fleet regardless of further technology assumptions. This result is also evident in Figure 2, where—because of electrification—overall transportation energy consumption declines in all scenarios compared to the reference, no-policy case. In general, the results for transportation show less change in the relative contribution of different energy sources under the different technology scenarios—presumably reflecting the lesser diversity of fuel options in this sector. The scenarios that assume no significant advances in vehicle energy efficiency (i.e., all of the adv_supply scenarios) show a greater continued role for conventional oil and less electrification. In the scenario that assumes advanced supply options but no advanced end-use technologies and no CCS (i.e., adv_sup_noccs), biofuels play a substantially larger role, presumably because there are no options for reducing carbon emissions from other fossil-based fuels such as unconventional oil or coal liquids. Indeed, all of the scenarios that do not include CCS show no role for coal-to-liquids, and a significantly smaller role for unconventional oil under the modeled emissions constraint.

Figure 1: 2050 Electricity Production by Technology Scenario

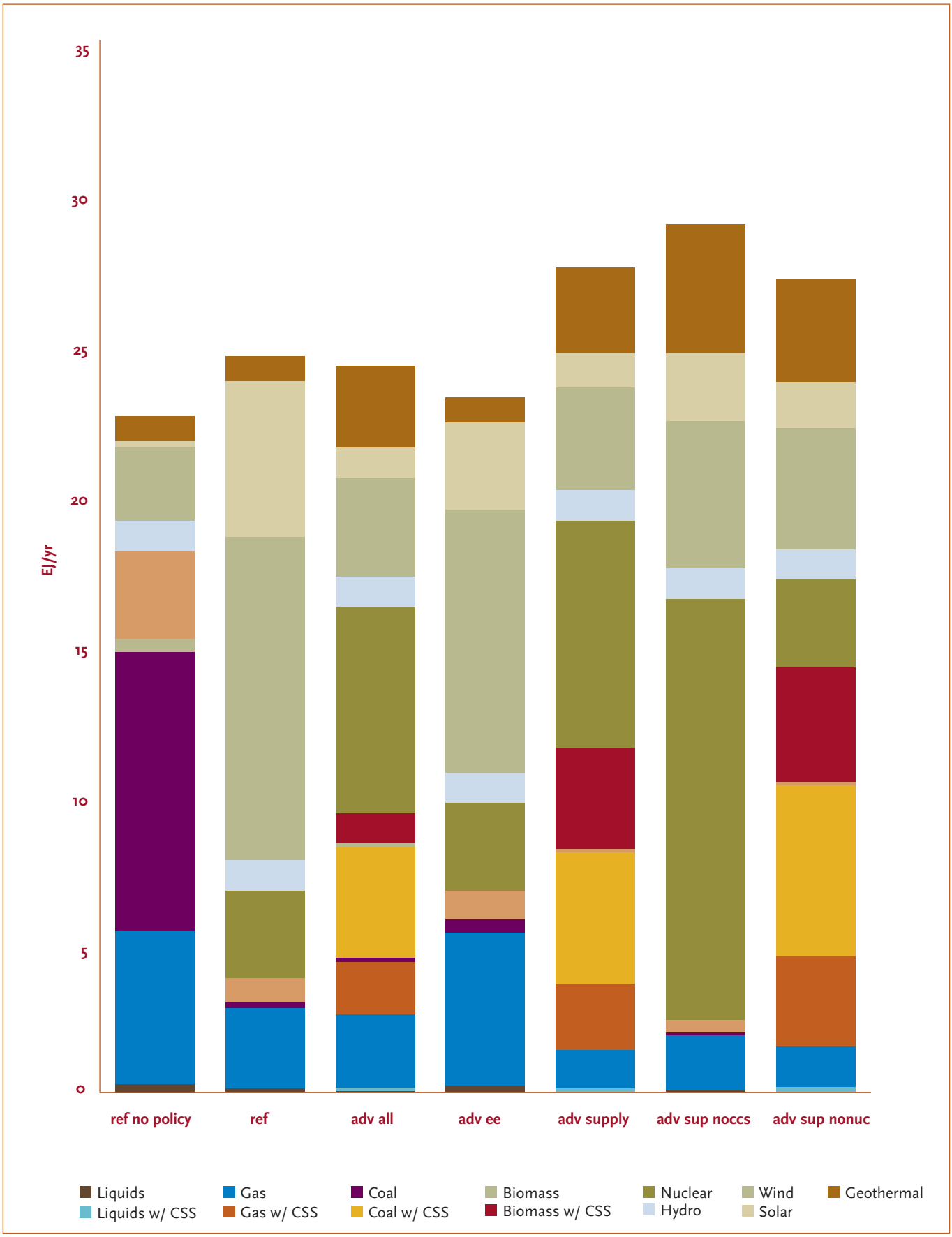
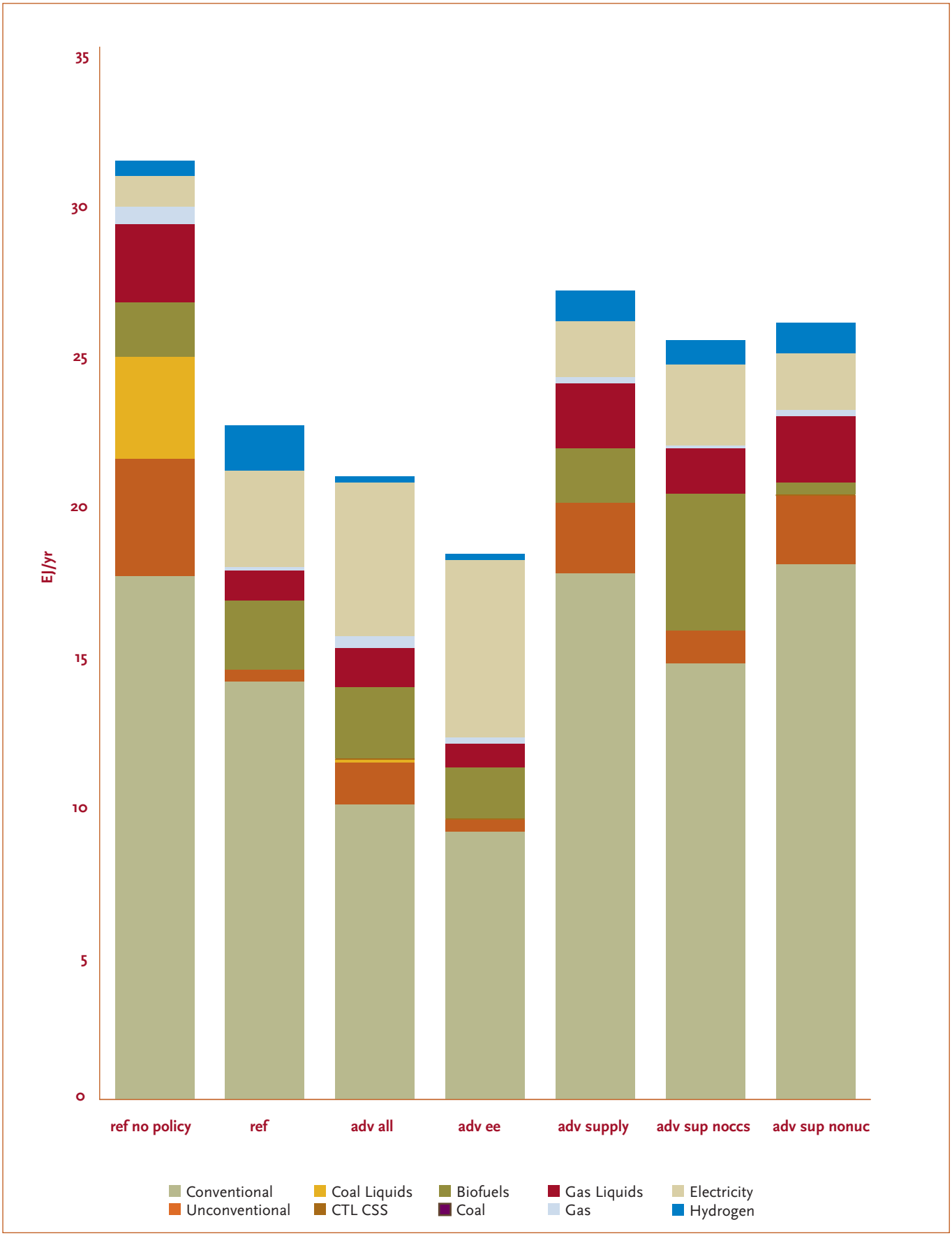


Figure 2: 2050 Transportation Energy Composition by Technology Scenario

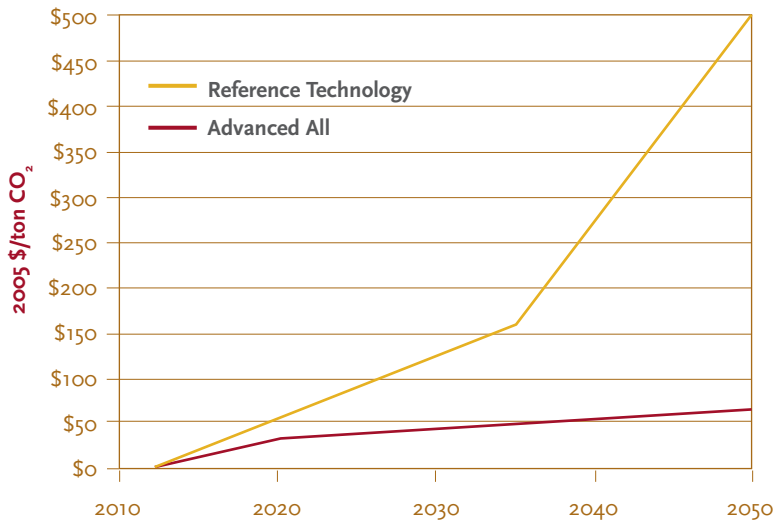


The JGCRI analysis shows that technology assumptions not only have a strong influence on the energy supply mix that might evolve in response to a carbon policy, they also have a strong influence on the cost of achieving a given emissions target. Figure 3 shows expected emission prices under the modeled policy in the reference technology scenario and in the advanced all technology scenario. These results were obtained by using MiniCAM to solve for the equilibrium CO_2 price needed to reduce emissions to the applicable cap level for each year of the policy.[9]

Clearly, costs are much higher in the reference technology scenario, which assumes modest technological improvement, no expanded nuclear contribution, and no CCS option. Moreover, costs escalate rapidly as the policy becomes more stringent over time. In fact, the modeled CO_2 price in the reference scenario increases ten-fold between 2020 and 2050, from $50 per ton to $500 per ton. By contrast, CO_2 prices rise much more gradually in the Advanced All technology scenario and exceed $50 per ton only after 2040. Overall, the availability of improved technology options means that projected costs are 75 percent lower in the Advanced All scenario than in the Reference scenario: specifically, the estimated cost in discounted net present value (NPV) terms over the 2012–2050 timeframe is $0.654 trillion for the Advanced All scenario, compared to $2.673 trillion for the Reference scenario.[10] A further interesting finding is that the overall cost reduction achieved through more efficient end-use (demand-side) technologies in the JGCRI analysis is roughly equal to the overall cost reduction achieved through improved supply technologies.[11]

The cost and difficulty of achieving dramatic GHG reductions this century will depend very directly on society's ability to marshal and deploy a suite of advanced, low-carbon technologies over the next several decades. That overarching challenge has at least two components: (1) improving the performance and reducing the cost of low-carbon alternatives and (2) overcoming barriers to their widespread deployment. Put another way, what does the JGCRI analysis imply about the pace and magnitude of technology improvement and deployment needed to achieve a 70 percent reduction in emissions over the next four decades? To get a sense of the magnitude of the technology improvement challenge (as distinct from the deployment challenge) it is useful to compare key technology assumptions in the Reference versus Advanced scenarios.[12]

Figure 3: CO_2 Prices under Reference Technology and Advanced All Technology



[9] Note that the modeled CO_2 price path is independent of the mechanism used to implement the policy (e.g. emissions tax versus cap-and-trade program). Assuming an efficient system, the CO_2 price in either case reflects the marginal cost of achieving the last unit of emission reduction needed to comply with the policy.

[10] These cost results are given in 2005 dollars and were calculated using a 5 percent societal discount rate, assuming strict annual emissions caps. Note that the JGCRI analysis also explored the impact of greater program flexibility, such as allowing year-to-year banking and borrowing of emissions allowances. Greater flexibility did have the effect of reducing cost, but the proportionate cost differences between technology scenarios remained roughly the same.

[11] For the Advanced Energy End-Use scenario (with no advanced supply technologies), the estimated cost in discounted NPV terms was $1.39 trillion; for the Advanced Supply scenario (with no advanced end-use technologies) the estimated cost was $1.21 trillion.

[12] Technology assumptions in the JGCRI analysis are reviewed in a separate report. See Chapter 3 of http://www.pnl.gov/science/pdf/PNNL18075.pdf.

Table 3. A Sampling of Advanced vs. Reference Case Technology Assumptions in the JGCRI Analysis

		REFERENCE TECHNOLOGY CASE		ADVANCED TECHNOLOGY CASE	
Energy Supply Technologies	**2005**	**2020**	**2050**	**2020**	**2050**
Cost of Gen III nuclear power (cents/kWh)	--	5.09	4.93	5.09	4.67
Capital cost of central photovoltaic (PV) power ($/kW)	6875	4525	2468	3446	1381
Capital cost of rooftop photovoltaic (PV) power ($/kW)	9500	6278	3583	4258	2246
Capital cost of wind power	1167	1124	1043	1082	931
Energy End-Use Technologies					
ICE automobile efficiency (BTU per passenger-km)	1977	1637	1366	1637	1122
Electric automobile efficiency (BTU per passenger-km)	667	643	596	629	557
Residential building shell efficiency (W/m^2)	0.232	--	0.182	--	0.163
Commercial building shell efficiency (W/ m^2)	0.281	--	0.217	--	0.214
Solid-state lighting efficiency (lumens/W)	100	--	112	--	156

Table 3 shows assumed cost reductions for several energy supply technologies in the Reference vs. Advanced scenarios, along with a sampling of assumptions concerning the magnitude of future efficiency improvements in some key end-use technologies.[13] Some technologies—notably solar power—are assumed to achieve large cost reductions relative to current technology over the next four decades in either scenario, with considerably more dramatic progress occurring under the advanced scenario. By contrast, the rate of cost reduction and performance improvement assumed in other technology areas, such as nuclear and wind and commercial building shell efficiency is less pronounced and the differences between the advanced and reference scenarios are smaller.

In addition, as already noted, the Advanced scenario assumes a substantial expansion of nuclear and CCS capacity. In the case of CCS, which has not yet been widely demonstrated in commercial-scale applications, a rapid build-up of capacity will be feasible only if early field experience, including a sufficient number of successful first-mover projects, builds confidence in the cost, performance, and reliability of CCS systems. Nuclear power is an established technology with a multi-decade track record, but even there the

[13] Table 3 does not include a comparison of assumed costs for CCS because CCS is not included in the reference scenario. Assumptions about CCS cost (in $ per ton carbon captured) and energy penalty (in gigajoules [GJ] per ton carbon) for several different types of energy systems (including electricity production, coal-to-liquids, and cement manufacturing, etc.) are provided in the JGCRI analysis referenced in the previous footnote. For coal-based electricity production, the JGCRI advanced scenario assumes capture costs of $28.81 per ton carbon ($7.86 per ton CO_2) and an energy penalty of 2.27 GJ per ton carbon in 2020. The cost and energy penalty for carbon capture with coal-fired electricity production are assumed to improve only slightly between 2020 and 2050, to $26.89 per ton carbon and 1.78 GJ per ton carbon in 2050. The additional cost for carbon storage is assumed to stay constant over time at $56 per ton carbon ($15.27 per ton CO_2).

industry faces a clear challenge in demonstrating that a new generation of reactors can be successfully sited and built, on time and within budget. For example, a nuclear plant currently under construction at Olkiluoto in Finland has experienced significant delays and cost overruns—if viewed as typical, such examples could cast a shadow over the industry's growth prospects for some time to come.[14]

To achieve substantial GHG reductions, low-carbon energy technologies not only have to be available, they have to be deployed. And the results of the JGCRI analysis suggest that the deployment challenge by itself is likely to be daunting, even if significant strides are made in reducing the cost and improving the performance of low-carbon technologies. Table 4 shows implied electric generating capacity requirements for the Advanced All and Reference scenarios, consistent with the year 2050 electricity generation totals shown in Figure 1. The authors caution that these results should not be taken too literally, in the sense that the real-world consequences of implementing an emissions policy would surely diverge from these modeling estimates. Nevertheless, the figures are indicative of the scale of low-carbon generating capacity that must be added within the 2050 timeframe to comply with the modeled emissions constraint. For example, they indicate that roughly 100 GW of new, no-carbon generating capacity (i.e., wind, solar, new nuclear, or CCS) would need to be added within roughly a decade—that is, by 2020. Over the following 15 years—that is, from 2020 to 2035—another 330 to nearly 400 GW of no-carbon capacity would

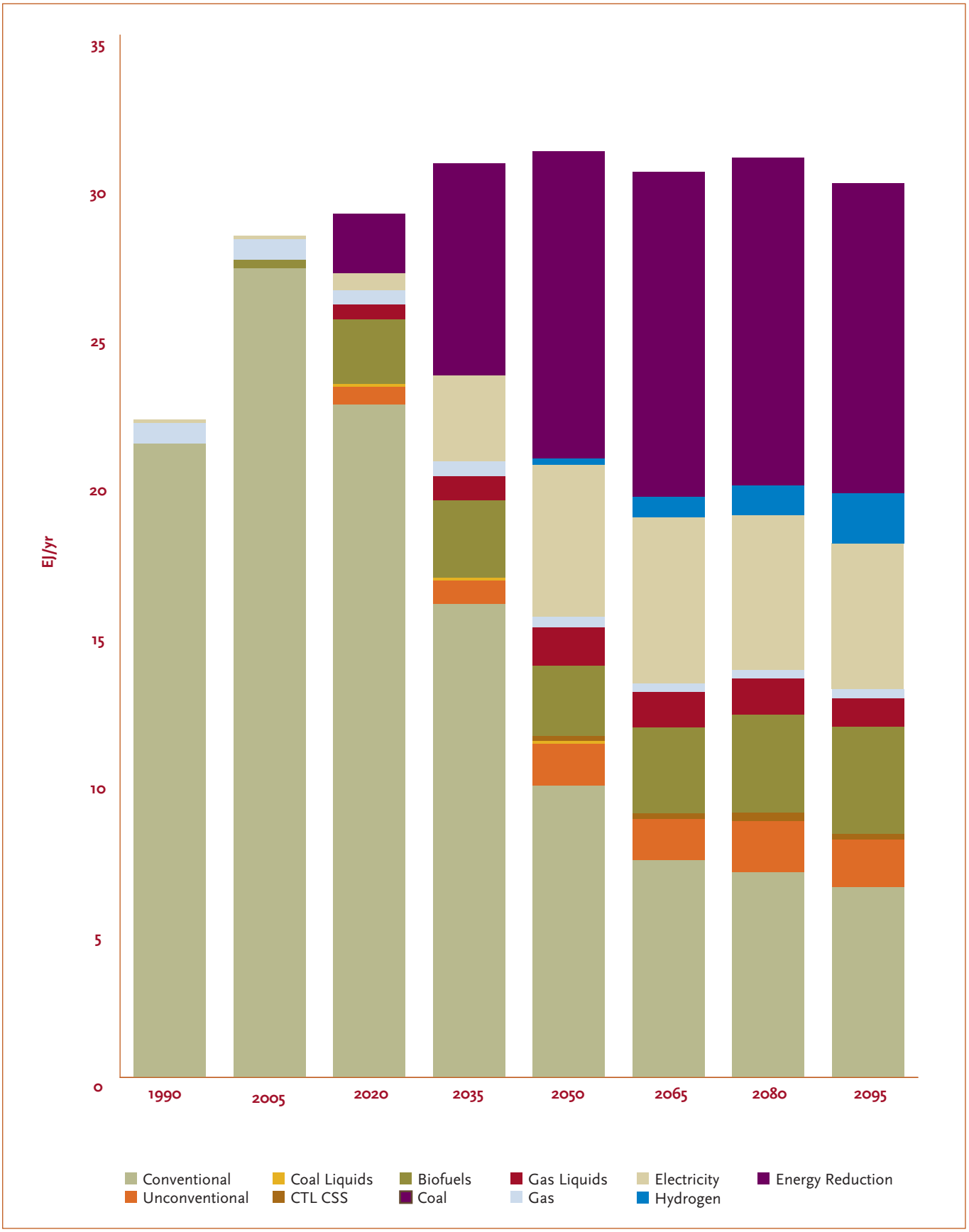
Table 4. Implied Eelectric Generating Capacity Requirements by Technology (in GW): Advanced All

	ADVANCED ALL			REFERENCE TECHNOLOGY		
	by 2020	by 2035	by 2050	by 2020	by 2035	by 2050
New Coal CCS	9	47	111	0	0	0
Retrofit Coal CCS	2	8	19	0	0	0
New Gas	1	8	8	13	58	58
Gas CCS	5	29	61	0	0	0
Biomass CCS	1	8	35	0	0	0
New Nuclear	12	89	141	0	0	0
Wind*	74	180	228	108	391	752
Solar*	19	63	93	16	101	468
Geothermal	2	32	83	2	24	24

**Capacity for wind and solar appears higher than for other technologies because they are assumed to have capacity factors in the range of approximately 25-45%, meaning it takes more capacity to produce an equivalent amount of electricity.*

[14] See, for example, http://www.nytimes.com/2009/05/29/business/energy-environment/29nuke.html.

Figure 4: Advanced All Technology: U.S. Transportation Use by Fuel



need to be added, depending on which scenario one assumes.[15]

It is worth highlighting that the scale-up challenge is daunting in *either* scenario, Advanced or Reference, because in both scenarios the energy system must deliver large CO_2 reductions to achieve the 75 percent emission-reduction target for 2050. In the Reference case, however, there are fewer options for achieving these reductions (no CCS, for example) and there is less of a decline in overall electricity demand from the deployment of advanced end-use technologies. As a consequence, more than three times as much wind and solar capacity must be in place by 2050 to comply with the policy. Given that existing wind and solar electric generating capacity in the United States stands at approximately 28.6 GW and less than 1 GW, respectively, at present, the implied pace of capacity growth for these renewable-energy technologies over the next four decades is aggressive, to say the least, under either set of assumptions.[16] For example, the wind industry would need to sustain an average annual rate of capacity growth above 5 percent per year from now until 2050 in the Advanced scenario and above 11 percent per year in the Reference scenario. Year-to-year growth rates of this magnitude are not unheard of—in fact, the U.S. wind industry was adding capacity at an annual rate of 30 percent or more in the years prior to the current economic crisis—but sustaining growth at these levels over the course of several decades would be an impressive feat for any industry. A similar caution applies to the projected deployment of CCS and new nuclear in the Advanced All scenario: only a few projects demonstrating CCS in commercial-scale power-plant applications are planned at present and none is yet in operation. In the case of nuclear, a commercial base totaling some 100 GW of capacity already exists but it has been more than two decades since a new nuclear power plant was constructed in the United States.[17] On the other hand, much of the nation's existing electric system—with more than 1000 GW of total generating capacity—was built over the course of the last several decades.

Figure 4 illustrates the technology deployment challenge implicit in the Advanced All scenario for the transportation sector. As with electricity production, the modeled emissions trajectory requires a rapid scale-up of efficiency improvements and lower-carbon transportation fuel alternatives such as biofuels and electricity.

Few (if any) factors will have a more profound effect on the cost and difficulty of achieving a meaningful emissions target than society's ability to deploy a suite of advanced, low-carbon energy supply and end-use technologies.

Taken together, these results illustrate a basic point that implicitly or explicitly permeates much of the energy and climate policy debate: few (if any) factors will have a more profound effect on the cost and difficulty of achieving a meaningful emissions target than society's ability to deploy a suite of advanced, low-carbon energy supply and

[15] Note that the Reference technology scenario requires a *larger* increment of new low-carbon generating capacity by 2035 and 2050 than the Advanced technology scenario. This is because the Reference scenario assumes no contribution from new nuclear and CCS, which forces a substantially greater reliance on wind and solar. Because wind and solar are intermittent resources, these renewable technologies have lower capacity utilization factors, which in turn means that more capacity needs to be installed to meet projected electricity demand.

[16] Data on installed wind energy capacity are from DOE; see http://www.windpoweringamerica.gov/wind_installed_capacity.asp.

[17] Worldwide, a small number of new nuclear plants are currently under construction or nearing completion, but several of those projects have experienced significant delays and cost overruns, casting doubt on the industry's prospects for further near-term expansion.

Potent barriers to new technology also exist at later stages in the progression from basic science to experimental technologies to demonstration and eventually full commercial deployment.

end-use technologies. For this reason, recent legislative proposals aimed at constraining U.S. GHG emissions have all included a technology component, typically dedicating some portion of the allowance value generated by a cap-and-trade program to expand funding for related energy RD&D. Such investments are supported by an extensive theoretical literature, which demonstrates that the private sector will generally *under*-invest in basic science and R&D relative to the societal gains that are obtainable from such investments.[18]

However, potent barriers to new technology also exist at later stages in the progression from basic science to experimental technologies to demonstration and eventually full commercial deployment. Siting challenges, lack of an adequate support infrastructure, workforce issues, regulatory conflicts, financing hurdles, and the tendency of capital markets and (in some cases) regulators to favor familiar, incumbent technologies all can stand in the way of deploying new technologies, even when those technologies have overcome significant cost and performance thresholds. The fact that many of these barriers are difficult to address through expanded government programs or policy interventions may help to explain why they have generally received less attention from lawmakers and stakeholders alike. In any case, the remainder of this report focuses specifically on deployment barriers, rather than on ways to expand and improve government-sponsored energy R&D.[19]

[18] See, for instance, Newell, R., 2007. *Climate Technology Research, Development, and Demonstration: funding Sources, Institutions, and Instruments.*

[19] The subject of energy R&D and of government's role in that arena is the subject of a rich literature. See for example, U.S. Government Accountability Office, 2006, *Department of Energy: Key Challenges Remain for Developing and Deploying Advanced Energy Technologies to Meet Future Needs*; Clean Air Task Force and Arizona State University, 2009, *Innovation Policy for Climate Change*; National Research Council, 2007; *Prospective Evaluation of Applied Energy Research and Development at DOE (Phase Two)*, Washington, DC: National Academy Press.

IV. Cross-Cutting Barriers to the Deployment of New, Low-Carbon Energy Technologies

Barriers to deployment exist for most conventional energy technologies as well as for newer, low-carbon alternatives—particularly where major infrastructure and large capital investments are involved. Such barriers can be especially difficult to overcome, however, in cases where the technology is unfamiliar or where features of the technology necessitate broader improvements or changes in the supporting energy infrastructure. For example, the dispersed and intermittent nature of many renewable energy resources may require enhanced grid integration and other grid improvements, as well as expanded transmission access to remote areas. Similarly, a substantial scale-up of biofuels production and CCS capacity could necessitate new, dedicated pipeline infrastructure.

> Barriers to deployment exist for low-carbon energy technologies—particularly where major infrastructure and large capital investments are involved.

Table 5 summarizes the most important barriers to deployment for the six low-carbon energy technologies included in the JGCRI analysis and this study: renewables, nuclear, CCS, biofuels, efficiency, and advanced vehicles. While every technology is different and therefore presents a somewhat different set of issues, a number of common challenges or barriers recur throughout the table. A more detailed discussion of each of these cross-cutting barriers follows the table. Additional discussion concerning deployment barriers for specific technologies can be found in Appendices II–VII.

A. Siting and Permitting Barriers

In recent years, siting energy facilities and supporting infrastructure in the United States has evolved into an ever more complex, multi-jurisdictional, and multidimensional process. The conventional siting process, plagued by time delays, legal battles, and regulatory uncertainty, is broken. In a

growing number of cases, the process of "decide-announce-defend" for new projects can be more accurately described as "decide-announce-defend-abandon" in the face of intense opposition from stakeholders.[20] More often than not, siting new facilities or infrastructure requires multiple stages of public meetings, stringent state and federal environmental reviews, project redesigns, permit applications, and high-priced legal proceedings. In some cases, proposed facilities are simply not getting built.[21] And at a minimum, opposition to development plans frequently lengthens the timeframe and increases the costs of completing projects. This would be problematic enough if it were only necessary to maintain and upgrade existing infrastructure to sustain the status quo. But given the more fundamental changes needed to respond to 21st century concerns like climate change, siting and permitting represents a critical roadblock to transforming modern energy systems.

Institutional and Regulatory Issues

Many siting and permitting problems arise in the institutions charged with regulating different types of energy facilities. For instance, institutional issues are seen as particularly problematic for CCS deployment, even at demonstration scale. At present, there is significant uncertainty in the federal government regarding which agency has jurisdiction and authority over several key aspects of CCS infrastructure.[22] First, pipeline siting is likely to take place under a patchwork of authorities and will likely include some combination of market-based negotiation for access and state-sanctioned exercise of eminent domain or condemnation. Most states allow for the use of eminent domain or condemnation authority to site infrastructure that benefits the public good, including pipelines and electricity transmission lines. Eminent domain authority does not currently extend to CO_2 pipelines, however. Indeed, none of the existing CO_2 pipeline infrastructure was sited using eminent domain, but rather was sited in most cases using market-based negotiation. Similar ambiguity in regulatory authority exists for any potential hydrogen pipelines.

In recent years, siting energy facilities and supporting infrastructure in the United States has evolved into an ever more complex, multi-jurisdictional, and multidimensional process.

Many experts view the Federal Energy Regulatory Commission's (FERC's) natural gas pipeline authority as a good model for how new CO_2 pipelines could be sited and regulated. Under the Natural Gas Act (NGA), FERC has authority to regulate the interstate transmission and sale of natural gas.[23] FERC's broad authority includes extension, improvement, or abandonment of natural gas facilities; granting certifications of public convenience and necessity; granting right of eminent domain for the construction of pipelines; and regulating the rates and conditions of service provided by interstate pipeline operators.[24] Under Section 7 of the NGA, the issuance of a certificate of public convenience and necessity allows

[20] National Commission on Energy Policy. "Siting Critical Energy Infrastructure: An Overview of Needs and Challenges," 2006, P. 9.

[21] For instance: development of a 600-mile high voltage power line planned by the Transmission Agency of Northern California—a group of 15 municipal power providers—was canceled earlier this summer. (http://www.sacbee.com/latest/story/2026793.html?mi_rss=Latest%20News); several solar thermal projects in the Southwest are also at risk of being canceled due to water concerns (http://www.nytimes.com/2009/09/30/business/energy-environment/30water.html?adxnnl=1&pagewanted=2&adxnnlx=1256666402-5MOFvirlvQncmPNDk12xmA).

[22] It should be noted, however, that many of these issues are addressed in CCS-specific provisions included in legislation currently moving through Congress, such as the American Clean Energy Leadership Act, the American Clean Energy and Security Act, and the Clean Energy Jobs and American Power Act.

[23] U.S. Department of Energy, Energy Information Administration, "Natural Gas Act of 1938," Available at http://www.eia.doe.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/ngact1938.html.

[24] "The Market Under Regulation," Naturalgas.org, http://www.naturalgas.org/regulation/market.asp#fercreg.

Table 5: Technology-Specific Barriers Summary Table

	TECHNOLOGY CHALLENGES	KEY DEPLOYMENT BARRIERS
Renewables	■ High up-front capital cost relative to natural gas combined cycle plants and other conventional options ■ Low energy density ■ Intermittency, grid integration—which in turn may require more cost-effective energy storage options and/or back-up generation options	■ Siting concerns, especially in environmentally sensitive areas ■ Transmission access ■ Financing
Nuclear	■ High up-front capital cost ■ New technology certification ■ Waste, safety, proliferation concerns	■ Financing ■ Long project lead-times and licensing timelines ■ Siting and permitting concerns, especially absent resolution of waste and safety issues
CCS	■ Post combustion options carry high cost and energy penalty; gasification options have not been widely demonstrated in commercial-scale power-plant applications	■ Need for pipeline infrastructure to transport CO_2 cost-effectively over long distances from point of generation to sequestration site. ■ Lack of existing regulatory and legal structure to govern transport, injection, monitoring, and long-term liability ■ Siting in the context of potential public safety concerns, NIMBYism, etc.
Biomass/ Biofuels	■ Low energy-intensity feedstocks and energy-intensive production processes ■ Cost relative to conventional fuels ■ Need to modify vehicle refueling systems for higher-concentration biofuel blends	■ Need for additional distribution and refueling capacity, especially for higher concentration biofuel blends ■ Regulatory conflicts, particularly with some Clean Air Act provisions governing evaporative vehicle fuel emissions ■ Competition between feedstock production and other land uses
Energy Efficiency in the Building Sector	■ Achieving further efficiency gains across a range of end-use devices, where those devices are characterized by a high degree of heterogeneity and are subject to numerous consumer criteria	■ Financing challenges, particularly in situations that feature split incentives ■ Information gaps, average versus marginal pricing, and other market failures ■ Slow turnover of the building stock and high retrofit costs ■ Inconsistent building efficiency codes and enforcement capacities between the states
Advanced Vehicles	■ Low battery power density and hence low range ■ Grid integration in the case of plug-in electric vehicles ■ Battery life and cost	■ Lack of distributed refueling infrastructure ■ Consumer acceptance

pipeline companies to charge customers for expenses associated with pipeline construction and operation.

A comprehensive framework for regulating and monitoring CO_2 injection for CCS is also lacking at present. Proposed and existing rules developed by the U.S. Environmental Protection Agency (EPA) under the Safe Water Drinking Act address many issues relevant to CO_2 sequestration, such as the siting, construction, operation, and closure of injection wells. However, the regulatory and legal authority for a number of other issues of great importance for CO_2 storage in the context of climate-change abatement—including property rights, long-term liability, and long-term monitoring of closed sites—remains unresolved.[25] This lack of a comprehensive policy and regulatory framework further increases the uncertainty associated with early CCS investment.

The new nuclear licensing and permitting process has not been tested since no plant has yet received a combined license.

Institutional issues have loomed large over the development of many renewable energy projects, particularly for projects proposed to be sited on federal lands.

Institutional issues have loomed large over the development of many renewable energy projects, particularly for projects proposed to be sited on federal lands. As of the second quarter of 2009, the Bureau of Land Management (BLM) had over 200 solar thermal projects awaiting approval.[26] In 2008, citing this backlog, BLM temporarily issued and then rescinded a moratorium on new project applications.[27] Such a backlog hints at the massive staffing shortages that BLM and other federal regulating agencies face. Renewable power companies complain that there are too few federal employees charged with reviewing permit applications and that these employees are often unfamiliar with renewable energy projects and technologies. Moreover, when counterparts must be consulted at corresponding agencies with jurisdiction over other parts of the siting process, long delays often result.[28] For instance, the United States Forest Service (USFS) must agree to geothermal development before BLM

[25] See Footnote 24: Legislation currently pending in Congress begins to address several of these issues.

[26] Power, Stephen, "In a Small Fish, a Large Lesson in Renewable Energy's Obstacles," The Wall Street Journal, 6/19/2009. Accessed 10/28/2009, http://online.wsj.com/article/SB124510519321116631.html.

[27] Frosch, Dan, "Citing the Need for Assessments, U.S. Freezes Solar Energy Projects," The New York Times, June 27, 2008, http://www.nytimes.com/2008/06/27/us/27solar.html.

[28] Vajhala, Shalini, "Siting Renewable Energy Facilities: A Spatial Analysis of Promises and Pitfalls," Resources for the Future Discussion Paper, July 2006, P. 4.

can issue leases, but frequently USFS and BLM do not confer. As a result, many geothermal developers have limited their activities to private lands. On a more positive note, Interior Secretary Ken Salazar recently announced the creation of four new renewable energy coordination offices to address these issues and speed permitting of renewable energy facilities on public land.[29]

Switching focus, nuclear power plants likewise face significant siting challenges. Nearly all of the 26 new nuclear reactors that have applied for a combined construction and operating license will be located at the site of an existing nuclear power facility, minimizing some siting challenges for the next generation of nuclear capacity. However, an important source of institutional uncertainty at present relates to nuclear waste storage, given that there are no centralized, or even interim, facilities for this purpose at present (instead, waste is being stored on an ad hoc basis, on the premises of existing nuclear plants). Failure to definitively resolve the waste issue may present additional siting challenges for proposed new plants, both as a source of concern for local communities and as a long-term financial and regulatory liability for investors.

In other areas, a number of steps have been taken to reduce siting and permitting hurdles to the construction of new nuclear plants. In 1989, the Nuclear Regulatory Commission (NRC) enacted rules to streamline the siting process and to address issues that had plagued the licensing process throughout the 1970s and 1980s when many companies made major financial commitments only to ultimately fail to obtain licenses. Specifically, the NRC implemented three major changes to its licensing process. First, the NRC made it possible to certify reactor designs through a public rulemaking process. Approved designs are valid for a 15-year period. Second, the NRC instituted an early site permitting process. This process allows companies to obtain a permit to build the project at a particular site early on in the licensing process so that site-specific issues can be resolved independent of the application for a construction and operating permit. These permits, if granted, are good for 10 to 20 years, and are renewable for an equal additional time period. Finally, the NRC allowed applicants to obtain a combined construction/operating license for new projects, making the overall process more efficient by eliminating the need for a separate application. Prior to implementing these changes, permitting delays had plagued the nuclear power industry; in fact, such delays are believed to be partly responsible for the long hiatus in new nuclear power plant construction in the United States over the last two decades. Still, the new licensing and permitting process has not been tested since no plant has yet received a combined license. Absent that experience, the NRC and the nuclear industry are learning together about how the streamlined process will work.

Duplicative state and federal environmental impact assessments have also emerged as a key regulatory hurdle to rapid and cost-effective siting of energy infrastructure in general.

State-Federal Interaction

Duplicative state and federal environmental impact assessments have also emerged as a key regulatory hurdle to rapid and cost-effective siting of energy infrastructure in general, and renewable energy projects in particular. The best wind, solar, and geothermal resources are often

[29] Power, Stephen, "In a Small Fish, a Large Lesson in Renewable Energy's Obstacles," The Wall Street Journal, 6/19/2009. Accessed 10/28/2009, http://online.wsj.com/article/SB124510519321116631.html.

CAPE WIND CASE STUDY

The Cape Wind project, a proposed 420 megawatt offshore wind farm in Massachusetts' Nantucket Sound, exemplifies the siting challenges that large energy facilities—especially when they involve new technology—often face. Cape Wind was the first offshore wind project to be proposed in the United States. As such, it prompted the development of new regulations for offshore wind farms and spurred the consolidation of applicable regulatory authority in the federal government. The project timeline provided below illustrates the complex and protracted nature of the siting and permitting process for Cape Wind to date. While that process has certainly been contentious, the hope is that it will help clear the legal and regulatory path forward for similar offshore wind projects in the future.

November 15, 2001	Cape Wind files permit application with 17 federal and state agencies, initiating federal and state reviews required under the National Environmental Policy Act and the Massachusetts Environmental Policy Act.
March 6-7, 2002	U.S. Army Corps of Engineers (USACE) holds public hearings in Boston and Yarmouth.
April 30, 2002	USACE & Massachusetts Executive Office of Environmental Affairs each issue "Scope of Work" documents for environmental impact reviews.
July 2, 2004	Massachusetts Energy Facilities Siting Board (MEFSB) issues Tentative Decision to approve Cape Wind's cables, following 21 days of evidentiary hearings, 3,000 pages of transcripts, and 1000 filed exhibits.
November 8, 2004	USACE issues largely favorable, nearly 4000-page-long, Draft Environmental Impact Statement (DEIS) and begins public comment period.
December 6-12, 2004	USACE holds four public hearings on DEIS in Boston and on the Cape and Islands.
February 24, 2005	DEIS public comment period ends, approx. 5,000 comments submitted.
March 8, 2005	Massachusetts Executive Office of Environmental Affairs issues a Certificate of Adequacy on the Draft Environmental Impact Report.
May 10, 2005	MEFSB votes to approve Cape Wind transmission cables.
October 6, 2005	Minerals Management Service (MMS) of the U.S. Department of Interior announces it is taking over lead federal agency review role for offshore wind farms, including Cape Wind, as a result of new authority and jurisdiction conferred by the Energy Policy Act of 2005.
May 30, 2006	MMS issues Federal Register notice seeking public comment on Cape Wind to help MMS prepare their DEIS.

December 18, 2006	The Massachusetts Supreme Judicial Court upholds MEFSB decision to approve Cape Wind application in response to court challenge by project opponents.
March 30, 2007	Massachusetts Secretary of Energy and Environmental Affairs Ian Bowles certifies Cape Wind Final Environmental Impact Report.
October 18, 2007	Cape Cod Commission issues procedural denial decision on electric transmission cables claiming they had insufficient time or information. Cape Wind replied the Cape Cod Commission had more time and more information about the electric cables than any Massachusetts Board had ever been given about a cable project.
November 21, 2007	Cape Wind files an Initial Petition with the MEFSB for a Certificate of Environmental Impact and Public Interest to seek remedy from the October 18 Cape Cod Commission decision.
January 4, 2008	MMS issues DEIS and begins a public comment period that is ultimately extended through April 21. MMS holds four public hearings in March and receives 42,000 written comments, over 40,000 of which are in support of the project.
July 22, 2008	Cape Wind receives a Permit to Access State Highway and Access Agreement from the Massachusetts Highway Department.
August 15, 2008	Cape Wind receives a 401 Water Quality Certification from the Massachusetts Department of Environmental Protection.
September 17, 2008	Cape Wind receives a License for Use and Occupancy from the Massachusetts Executive Office of Transportation.
November 13, 2008	Cape Wind receives a no jeopardy determination for the Endangered Species Act review by the National Marine Fisheries Service (NMFS). NMFS reviewed project impacts on endangered sea turtles and endangered whales.
November 21, 2008	Cape Wind receives a no jeopardy determination for the Endangered Species Act review by the U.S. Fish and Wildlife Service (USFWS). USFWS reviewed project impacts on endangered avian species.
December 23, 2008	Massachusetts Department of Environmental Protection grants Cape Wind a Chapter 91 Waterways License.
January 16, 2009	MMS Issues Final Environmental Impact Statement.
March 13, 2009	MEFSB grants approval for broad suite of state and local permits to bury electric cables.
October 26, 2009	The Aquinnah and Mashpee Wampanoag tribes request that the entire Cape Cod Sound be listed as a traditional cultural property on the National Register of Historic Places.
End of 2009	Secretary of the Interior, Ken Salazar, in consultation with Massachusetts state agencies, is expected to make a ruling on whether to approve the Cape Wind project by the end of the year.

Public opposition to the siting of energy facilities remains a major roadblock for many potential projects.

found in sensitive environmental areas, such as mountaintops, deserts, and near off-shore shoals. As a result, projects that seek to tap these resources often face an extra level of review. Siting can also be difficult in areas that are not pristine: for example, wind projects may encounter local codes or zoning regulations that limit the height of new structures. Wind technology is evolving rapidly and many current designs feature much larger and taller towers and turbines than the previous generation of machines. It is difficult for many municipalities, especially those with limited resources, to stay abreast of the latest developments in the wind industry.

Public Opposition

Public opposition to the siting of energy facilities remains a major roadblock for many potential projects. This problem is far reaching. Indeed, despite the near universal public support for renewable power, some high-profile renewable energy projects have been stymied by public opposition, which has become so commonplace that the term NIMBY ("not in my backyard") is increasingly being replaced by BANANA ("build absolutely nothing anywhere near anything").[30] Quaint acronyms aside, such opposition poses a real and difficult challenge to building new energy projects of all types, including those that employ low-carbon technology. In the current environment of resistance to any coal-fired facility, for example, many are skeptical that new plants—even those utilizing cutting-edge technology such as CCS—can be sited. Similarly, despite an apparent shift in expert and public opinion on the merits of nuclear power as a low-carbon generating option, local concerns are likely to be a potent factor in any effort to site a new facility. Siting concerns may also emerge as

[30] The proposed Cape Wind project off the coast of Massachusetts being perhaps the most notorious example of how concerted public opposition (in this case largely motivated by aesthetic concerns) can delay construction.

an issue for biorefineries and biopower plants given the large number of such facilities that could be needed to support current renewable fuels mandates and meet future GHG targets. Though typically smaller than petroleum refineries, biorefineries need to be sited near feedstocks to reduce transport costs. This could complicate siting decisions in some cases (for example, it might be difficult to site a biorefinery that utilized municipal solid waste as a feedstock near an urban area, both because of local environmental concerns and NIMBY issues).

B. Electricity Transmission Barriers

Modernizing and expanding America's electrical transmission system will be critical to the large-scale deployment of many low-carbon energy technologies, especially in the case of renewable energy and electric vehicle technologies. At the same time, grid improvements and capacity expansions are needed simply to address the effects of age and increasing congestion and to ensure the adequacy and operating reliability of existing infrastructure. The North American Electric Reliability Corporation (NERC) estimates that up to 50 percent of the U.S. transmission and distribution network is at least 40 years old and may require upgrades.[31] In recent years, the rate of growth in overall power demand and production has outpaced transmission-system investments, making the grid less flexible and resilient and interfering with reliability and efficient operation.[32] To some extent, 'non-wires' solutions—including distributed generation, demand-side investments, and better congestion management methods and systems—may reduce the need for new grid capacity. Nevertheless, further transmission investments are needed to accommodate new technologies and a growing population[33] and to access the potential of new generation sources that are often variable, geographically dispersed, or location-constrained.[34]

Unfortunately, siting the transmission infrastructure needed to support new electric generating capacity, including access to renewable energy resources that are often concentrated in remote, ecologically sensitive areas, is difficult at best. In recent years, the electric power industry has succeeded in adding transmission capacity at the state and local level. However, larger, interregional transmission infrastructure has proved very difficult and in some cases impossible to build. The hurdles are especially high in situations where transmission lines cross state boundaries and deliver unequal benefits to the different jurisdictions they pass through. To date, the grid has been able to function with a reasonable degree of reliability even though there has not been much change in its "backbone" transmission capacity. However, a patchwork approach to the system build-out that will ultimately be needed to keep up with projected electricity demand is not tenable over the long run. One key impasse encountered by many proposed interstate transmission lines is that the state-level public utility commissions with authority to approve transmission projects typically have mandates that preclude them from approving projects that don't benefit their state.

The hurdles are especially high in situations where transmission lines cross state boundaries and deliver unequal benefits to the different jurisdictions they pass through.

Policymakers have identified the state-driven siting model for long-distance or inter-state transmission infrastructure as a major problem.

[31] North American Electric Reliability Corporation (NERC). 2008. *2008 Long-Term Reliability Assessment.* October 2008. Page 40.

[32] NERC. *2007 Long-Term Reliability Assessment*. October 2007. Also: Edison Electric Institute. *Meeting U.S. Transmission Needs*. July 2005.

[33] NERC 2008. Pages 44-45.

[34] Ibid. Page 15.

Without advanced operational and forecasting capabilities, demand-side technologies including a "smart grid" cannot be effectively deployed and utilized, and the variable or distributed load from renewable resources cannot be reliably managed.

In an effort to address it, the Energy Policy Act of 2005 explicitly granted FERC backstop siting authority—meaning that the federal government gains siting authority if states cannot build projects that are deemed to be in the national interest within a defined period of time. This backstop authority is somewhat limited, however, and can only be used when a state does not grant permits for transmission expansion in areas where there is significant grid congestion. Because it hinges on the need to address congestion, federal backstop authority is unlikely to apply to new transmission projects aimed at moving power from remote areas where wind, solar, or geothermal projects might be built—such projects will most likely be left to state authorities. In fact, the limits of current FERC backstop authority for transmission infrastructure were recently challenged in a notable case, *Piedmont Environmental Council v. FERC*. In a February 2009 decision, the U.S. Fourth Circuit Court of Appeals held that FERC may not exercise its backstop siting authority in the event that a state regulatory commission has reviewed and rejected a siting application. The decision suggests that FERC's backstop authority may only apply in cases where a state fails to act on an application.

Substantially increasing the contribution from renewable resources not only requires new long-distance transmission capacity, but also grid improvements and the development of ancillary services like reactive power and voltage support to ensure reliable integration.[35, 36] Without advanced operational and forecasting capabilities, demand-side technologies including a "smart grid" cannot be effectively deployed and utilized, and the variable or distributed load from renewable resources cannot be reliably managed. Electrifying a large portion of the vehicle fleet will likewise require grid modernization—including improved system planning and communication—to manage the greater loads that will be placed on the transmission system and ideally even to make it possible to use the batteries in parked cars as a form of short-term storage to meet peak load demand. Further reliance on any of these technologies will not only require construction of new transmission lines, but also efforts to modernize system planning and communication.[37]

[35] NERC. *Special Report: Electric Industry Concerns on the Reliability Impacts of Climate Change Initiatives.* November 2008.

[36] Variable resources, like wind, pose integration issues. A large penetration of variable generation, long-distance transmission, or significant requirement for dispatchable reactive sources can cause voltage collapse.

[37] NERC 2008. Page 20.

C. Financing Challenges

The results of the JGCRI analysis suggest that realigning current energy systems to achieve deep GHG reductions over the next half-century will be an enormous undertaking—one that will require very substantial investments of private and public resources. To accomplish this realignment, the financial community, including venture capitalists, private equity investors, and other large financial institutions will need to be willing to direct significant resources to new, low-carbon energy technologies.

As a general rule, low-carbon energy technologies have higher fixed costs than do their conventional counterparts, often making project financing and market entry particularly daunting.

EXAMPLE OF INNOVATIVE FINANCING POLICY: PROPERTY ASSESSED CLEAN ENERGY LOANS

In 2009, NCEP convened a working group to explore new approaches to financing clean energy technologies. The group focused on a new financing mechanism known as "property assessed clean energy" or "PACE" bonds that allow property owners to finance energy efficiency or small renewable energy projects through a voluntary assessment on their property tax bill.* PACE bonds can be issued by municipal financing districts or finance companies, with proceeds used to fund clean energy retrofits for both commercial and residential properties.

By offering a low-cost financing option—PACE loans are typically repaid over a 20-year period—that is tied to the property itself, rather than to the original investor, this approach targets one of the most important barriers to clean-energy investment: the high, up-front capital cost of building improvements. The PACE model also offers high potential for success at low cost in terms of public spending, because in most cases the debt obligation incurred is small relative to the value of the property and among the first to be repaid in the event of property foreclosure.

The authority to implement PACE programs already exists in Florida and Hawaii; in several other states, enabling legislation has either recently passed (California, Colorado, Maryland, New Mexico, Texas, Vermont, and Virginia) or is pending (Arizona, Nevada, and Oregon). Federal support, in the form of loan or bond guarantees for PACE and other innovative financing programs, could greatly expand the scope of such programs and play a vital role in accelerating the deployment of clean energy technologies throughout the nation's building stock.

**For more information on the PACE approach see www.pacenow.org.*

Creative strategies for addressing these financing challenges, together with strong policy support, will be essential to accelerate the transition to a low-carbon energy infrastructure.

However, financing such technologies in today's energy marketplace poses significant challenges. As a general rule, low-carbon energy technologies have higher fixed costs than do their conventional counterparts, often making project financing and market entry particularly daunting. Even when a carbon price is in place, that price—at least in the early years of a new regulatory regime for GHG emissions—is unlikely to cover the full cost premium that separates advanced and conventional energy technologies. Investors and project developers will need to absorb high upfront costs, overcome the market's discomfort with often unproven technologies, navigate a patchwork of regulations and sometimes inconsistent policies, manage siting and permitting risks, operate across a diverse range of markets, and in many cases be willing to accept long payback periods. In the very near term, all of these challenges are exacerbated by the current economic downturn, which has led to increased uncertainty about future capital and fuel costs and tightened credit markets, thereby further adding to investment risk. Creative strategies for addressing these financing challenges, together with strong policy support, will be essential to accelerate the transition to a low-carbon energy infrastructure.

This section details several key financing issues as they relate to low-carbon energy technologies, summarizes the main public policy efforts designed to overcome them, and offers some reflections on how future policies could be designed or improved. In fact, many attempts have been made at the federal and state level to ameliorate the high costs and risks associated with new low-carbon technologies and to stimulate new markets for these technologies. Some of these attempts rely on incentives, such as production tax credits (PTCs), loan guarantees, or favorable tax treatment (e.g., accelerated depreciation schedules). Others seek to drive demand through mandates (e.g. renewable portfolio or renewable fuels standards). However, most of these mechanisms to date have been ad hoc, uncoordinated, and limited in scope or duration.

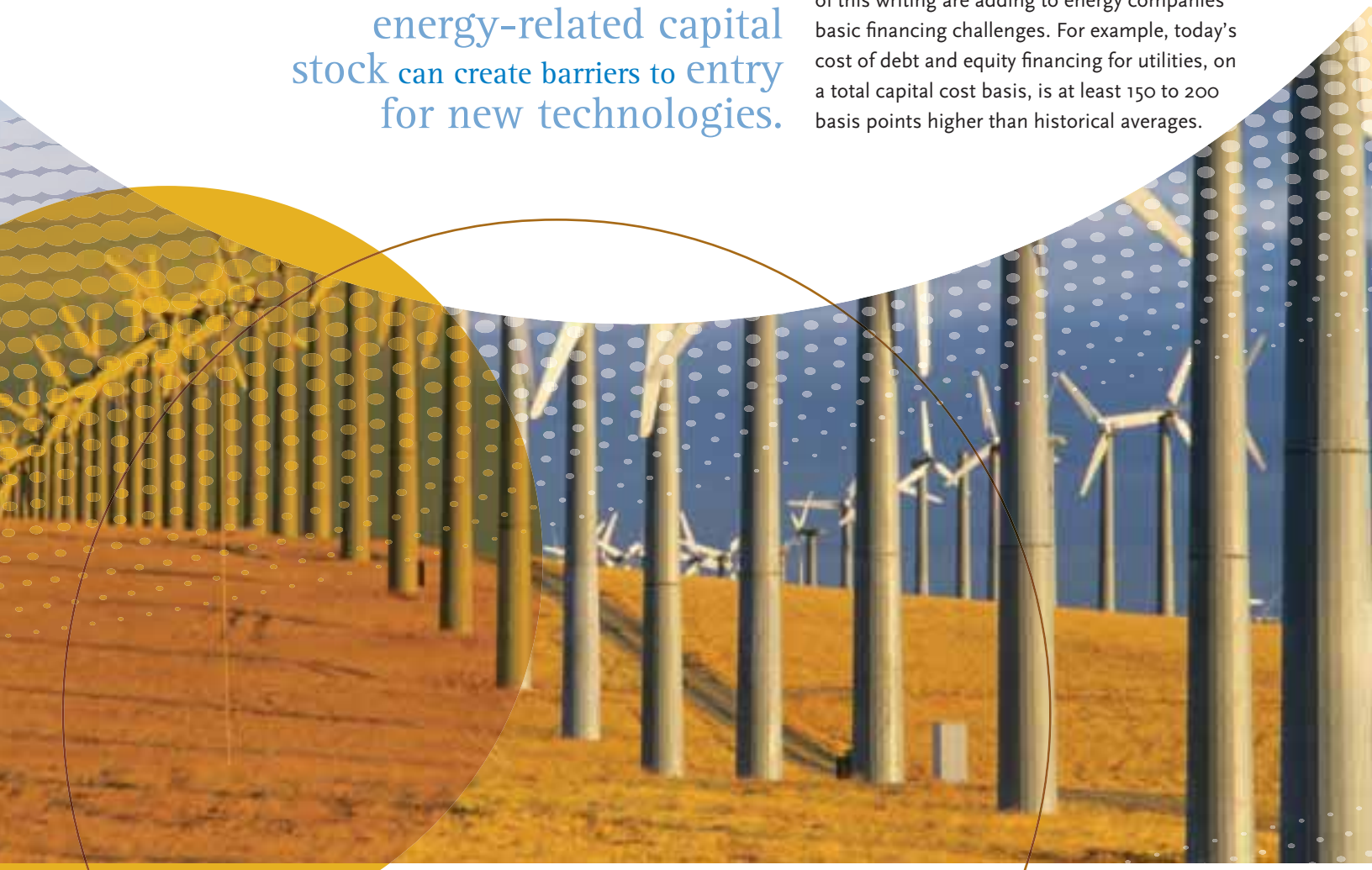
The energy sector and, in particular, the electricity industry is typified by long-lived assets with high fixed costs and low variable costs. For a new project to be profitable, investors must recover both fixed and variable costs. However, in electricity markets, wholesale prices are typically determined by the variable costs of the marginal unit serving the market, which are often far below the total cost of a new investment. As a consequence, entry is difficult, especially for new and oftentimes more expensive low-carbon technologies. For instance, a new, integrated gasification combined-cycle (IGCC) coal plant capable of carbon capture is significantly costlier to construct than even the most up-to-date "super-critical" conventional pulverized-coal plant *without* carbon capture because it requires more complicated designs, more materials, and more equipment, as well as engineers, builders, and operators who are familiar with the underlying technology. Fuel costs are also higher in part due to parasitic energy requirements although this occurs with any industrial plant—IGCC or conventional—employing CO_2 capture and compression technologies. The cost disparity for a new IGCC plant with CO_2 capture is even starker when compared to a new natural gas combined cycle plant, which is the technology most likely to compete with an IGCC plant. Indeed, some estimates suggest that the total production cost of an IGCC plant that captures 90 percent of CO_2 of could be more than 50 percent higher, even *before* accounting for costs to transport and store the captured CO_2.[38]

[38] NCEP/CATF Sponsored Analysis: http://www.catf.us/projects/power_sector/advanced_coal/20090809-Technology_Commercialization.pdf.

The slow turnover of much energy-related capital stock can also create barriers to entry for new technologies, especially when those technologies have long construction lead times, high upfront capital costs, and long payback periods. New nuclear power plants, for example, may reach economies of scale at generating capacities on the order of 1,000–1,350 MW, which implies an investment on the order of $4 to $5.5 billion (assuming $4,000 per kW in 2007 dollars).[39] Other low-carbon technologies are less "lumpy" (i.e., they can be scaled up in smaller increments)—this is the case for many renewable and end-use efficiency technologies—but they may still find it difficult to compete with the established, low-cost conventional option, which in the electric power sector has for some time been combined-cycle gas turbine generation. If the economics for new capacity are challenging, the economics for displacing existing assets are even more difficult. Most existing power plants are long-lived and retiring them early usually comes at significant costs. Moreover, once amortized, these capital assets are extremely profitable, which means there is a significant financial incentive to keep them operating.

The slow turnover of much energy-related capital stock can create barriers to entry for new technologies.

A major unknown at present, of course, concerns the longer-term impact of the global economic downturn and financial crisis that took hold in 2008. Certainly market conditions at the time of this writing are adding to energy companies' basic financing challenges. For example, today's cost of debt and equity financing for utilities, on a total capital cost basis, is at least 150 to 200 basis points higher than historical averages.



[39] MIT (2009)—*Update to the Future of Nuclear Power*. The actual price per kW for new nuclear plants is highly uncertain, however, with overnight estimates running as high as $6,000 per kW.

(This is equivalent to 1.5–2.0 percentage points, which would be in addition to a typical 9–11 percent cost of capital.) For merchant electricity generators, premiums may be even greater due to the higher level of investment risk associated with these projects. These financing costs can be expected to have a disproportionate impact on technologies (such as nuclear, coal with CCS and wind) that are particularly capital intensive compared to conventional power technologies such as natural gas fired turbines.

Practically speaking, this means that merchant generators may be unable to secure financing or, if they do, will have greater difficulty achieving a target rate of return. Similarly, regulated utilities may be unable to secure state approval to build or, if they do, may risk cost disallowances from their state regulators when the plant goes into service. This is because many public utility commissions are required by law to approve only the least-cost options for ratepayers, both for electricity generation and transmission. Additionally, in these markets, pricing policies (average vs. marginal) tend to mask the benefits of advanced technologies.

Underlying and exacerbating all of these financing challenges is the generic problem of uncertainty. There are many sources of uncertainty in energy markets, and most of them apply to established as well as new technologies. However, the degree of uncertainty—and hence perceived risk—tends to be higher for less proven technologies. Greater uncertainty means greater risk, and greater risk tends to promote a more conservative and incremental approach to technology investments. Hence, policy changes that reduce uncertainty can play a significant role in promoting technological change. Important categories of uncertainty include:

1. Technological uncertainty—includes uncertainty about the cost, performance, reliability, and durability of a new technology. Since most investors are risk-averse, developers faced with technology risk will often defer investments or require higher rates of return as compensation. As the industry gains operating experience with new technologies and as cost estimates become more reliable, investors are better able to evaluate and price these technology risks. However, gaining initial field experience is critical to this process. To help new technologies successfully bridge the "valley of death" between pre-commercial demonstration and commercial deployment, government funding or other support may be necessary.

2. Market uncertainty—includes uncertainty about future capital and fuel prices. These prices influence the cost structure of new investments and also their value relative to other incumbent assets. In recent years, capital, commodity, and fuel prices have experienced considerable volatility, which, in turn, poses significant risks for investors contemplating large-scale, long-lived energy projects.

Greater uncertainty means greater risk, and greater risk tends to promote a more conservative and incremental approach to technology investments.

3. Regulatory uncertainty—includes uncertainty about future regulatory conditions, incentive programs, etc. For example, uncertainty about the future value of avoided carbon emissions would have a direct impact on incentives for investment in low-carbon technologies. Similarly, uncertainty about the continuity of incentives like the federal PTC and investment tax credit has led to boom-bust cycles in the wind and solar industries. Regulatory uncertainty can be particularly important in energy markets, which have historically been heavily influenced by economic and environmental regulation.

REALIZING AMERICA'S FUTURE ENERGY JOBS

In January 2009, NCEP convened a diverse group of stakeholders with expertise in the workforce needs of the U.S. electric power industry. The group, called the NCEP Task Force on America's Future Energy Jobs, included representatives from labor, industry, and training and educational organizations. Its findings—based on an intensive six-month exploration of energy-sector workforce issues and needs—were subsequently published in a stand-alone report, available at http://www.bipartisanpolicy.org/library/report/task-force-americas-future-energy-jobs.

The Task Force report concludes with a number of recommendations for federal policy to address the most critical energy-related workforce challenges our nation will confront in coming decades. As the report points out, transforming U.S. energy systems to meet the ecological and economic needs of the 21st century not only requires new, low-carbon technologies—it requires people with the expertise to develop, plan, design, build, operate, and maintain those technologies.

Key recommendations from the NCEP Task Force on America's Future Energy Jobs

1. Evaluate regional training needs and facilitate multi-stakeholder energy sector training programs across the country.
2. Improve energy sector workforce data collection and performance measurement metrics and tools.
3. Identify training standards and best practices for energy sector jobs.
4. Provide funding support to individuals seeking energy sector-related training and education.
5. Aggressively focus on revitalizing the math and science skills, education, and career counseling of individuals who have the interest and skills to work in the energy sector.

D. Workforce Shortages

Workforce shortages represent another potentially important challenge to the large-scale deployment of low-carbon energy technologies, but this issue has typically received less attention in policy debates. In fact, the labor pool for many key energy industries—including the electric utility industry—is stretched and aging, with up to half of the current energy workforce eligible for retirement in the next decade. This issue is not limited to the skilled trades and construction segment of the workforce, it affects the entire value chain. Specifically, worker shortages are anticipated in both the professional and skilled workforces. Moreover these shortages would be a source of concern even if they did not coincide with efforts to transform the current energy system to address the climate problem.

Training in the professional skills necessary to support the energy sector has not been a national focus for many years. It has perhaps been taken for granted that this vital sector would always be able to draw from a deep pool of highly skilled, technically trained individuals. However, over the past two decades, two major trends have affected labor markets in the energy sector: (1) national education policy and cultural preferences shifted away from career and technical education to emphasize four-year college education and (2) the advent of a competitive market for electric power led to an increased focus on productivity, which resulted in reduced hiring and in-house training.

NCEP recently completed an extensive effort to explore these looming energy workforce challenges (see text box on page 42). Our Task Force on America's Future Energy Jobs brought together representatives from labor, the electric power industry, and the training and educational sectors in an effort to move beyond anecdotal talk of "green jobs" and toward a better understanding of labor market conditions and emerging gaps in the energy sector. Specifically, Task Force members commissioned Bechtel Power, Inc. to assess the electric infrastructure and workforce needs likely to be associated with a major effort to reduce GHG emissions in the power sector.

Training in the professional skills necessary to support the energy sector has not been a national focus for many years.

In addition to replacing retiring workers, the industry will need an unprecedented number of skilled workers to design, construct, and operate the next generation of electric-sector infrastructure.

Several key insights from this project are summarized below (Task Force recommendations are summarized in the text box in this section):

- *A decline in career and technical education over the last two decades has stressed the electric power industry's training capacity*. Since the mid-1990s, the number of high school students taking trade- or industry-related career and technical courses has declined 35 percent. Compounding this problem, national science assessment tests rate 47 percent of U.S. twelfth graders as having below basic proficiency in understanding scientific concepts (35 percent have a basic understanding, 16 percent are considered proficient, and only 2 percent are considered advanced). By this measure, at most 53 percent of high school graduates and probably only 18 percent are prepared to enter technical careers upon high school graduation. This means that among high school graduates who do not pursue secondary education at a college or university, the majority do not have the skills they need to succeed in technical apprenticeship programs or in-house training programs.

- *A large percentage of the electric power sector workforce is nearing retirement*. The electric power sector directly employs about 400,000 people, 30–40 percent of whom will be eligible for retirement or will leave the industry for other reasons within the next five years. Compounding the potential for a sharp demographic shift in the workforce, many workers appear to be delaying retirement due to the economic downturn. This could create a larger shortage if workers retire en masse when economic conditions improve.

- *Building and operating a low-carbon energy system will require more workers with new skills*. In addition to replacing retiring workers, the industry will need an unprecedented number of skilled workers to design, construct, and operate the next generation of electric-sector infrastructure. By the 2020s, design and construction needs in the electric power sector could require as many as 150,000 workers, roughly equivalent to 40 percent of the workforce employed to operate and maintain the current electric power sector. Similarly, by 2030, roughly 60,000 people will be needed to operate and maintain new generating assets, or 15 percent above the current workforce.

V. Conclusion

Previous chapters underscore the scale and difficulty of the low-carbon technology challenge that confronts our nation and the world in the decades ahead. To meet the energy demands of the future while simultaneously achieving deep cuts in GHG emissions, most, if not all, of the technologies discussed in this report will need to be deployed on a large scale, even as basic R&D efforts continue to develop new options. Jump-starting that process is the immediate policy challenge—one that requires attention to the numerous systemic barriers that stand in the way of deploying new technologies throughout the existing energy system. Imposing a price on CO_2—either via a cap-and-trade program or a tax—is clearly a critical first step, since without a market signal no incentive exists to favor new, low-carbon options over incumbent technologies. Because many of these technologies are likely to face additional deployment barriers, however, putting a price on CO_2 should be viewed as a necessary but not sufficient condition for transforming current energy systems. Particularly in the early years of a climate policy, when the price of carbon is likely to be relatively low, additional efforts will be needed to address the kinds of non-market barriers discussed in this report.

Unfortunately, these barriers—precisely because their market impacts are difficult to quantify—are often missing or under-emphasized in standard scenario modeling or technology assessment studies.

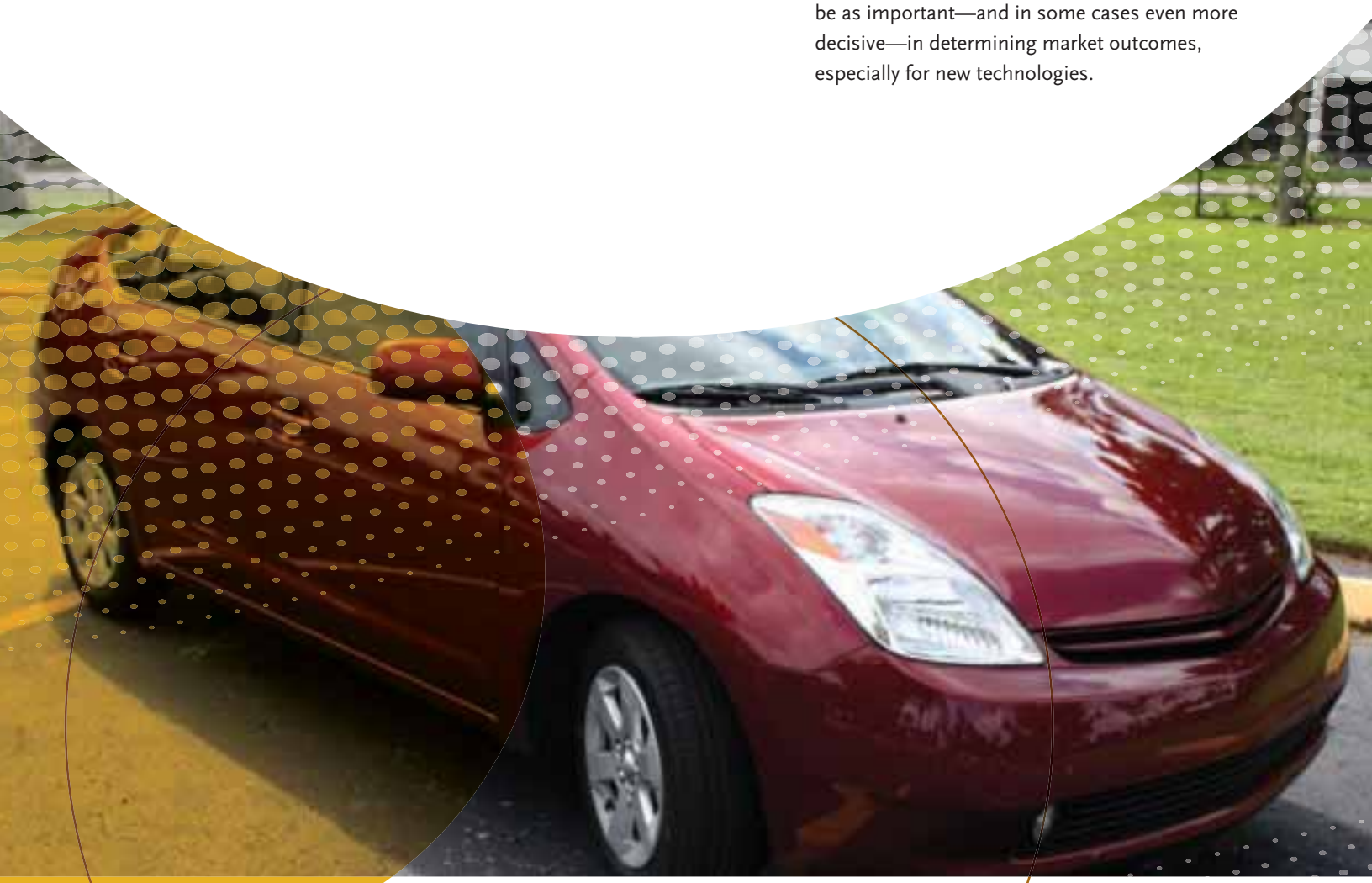
Unfortunately, these barriers—precisely because their market impacts are difficult to quantify—are often missing or under-emphasized in standard scenario modeling or technology assessment studies. Widely cited analyses, such as the CO2-abatement cost curves developed by Mckinsey & Company,[40] frequently find that substantial GHG abatement opportunities

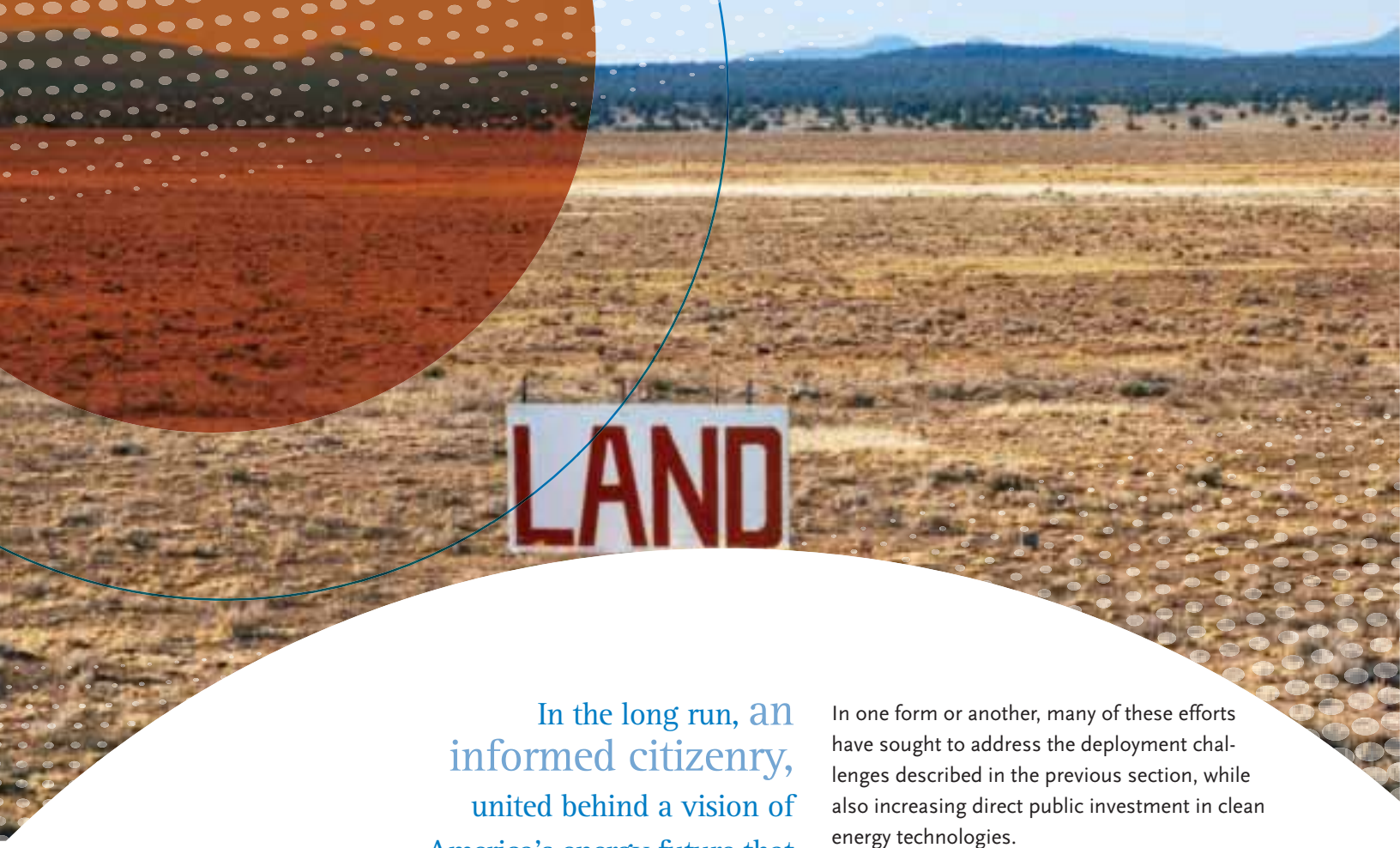
[40] McKinsey & Company, 2007. Reducing U.S. Greenhouse Gas Emissions: How Much at What Cost?

V. CONCLUSION

The last decade has been a particularly active one in the energy policy arena, with climate change emerging as a central concern of many government programs alongside more traditional concerns about economic competitiveness, grid reliability, national security, and reducing U.S. dependence on imported oil.

exist throughout the economy that would, at least in theory, more than pay for themselves—in many cases even absent a carbon price. These opportunities are especially abundant in the realm of end-use technologies where the higher up-front costs of a more efficient device can often be more than offset by expected long-term energy savings. The fact that many of these "negative-cost" options remain widely under-deployed is itself compelling evidence for the potency of systemic non-market factors. This is not to argue that traditional technology and cost assessments are irrelevant—on the contrary, they provide crucial information and a necessary starting point for policy discussions concerning the feasibility and appropriate role of government in pursuing various policy objectives. The point here is merely that engineering costs, by themselves, are far from the whole story and other factors can be as important—and in some cases even more decisive—in determining market outcomes, especially for new technologies.





In the long run, an informed citizenry, united behind a vision of America's energy future that can transcend strictly local or regional concerns, offers the best hope for overcoming NIMBYism, special-interest politics, simple institutional inertia, and the myriad other factors that often create a potent bias in favor of the status quo.

In implicit or explicit acknowledgement of this reality, the U.S. government has a long history of engagement with technology policy—in the energy sector and elsewhere. The last decade has been a particularly active one in the energy policy arena, with climate change emerging as a central concern of many government programs alongside more traditional concerns about economic competitiveness, grid reliability, national security, and reducing U.S. dependence on imported oil.

In one form or another, many of these efforts have sought to address the deployment challenges described in the previous section, while also increasing direct public investment in clean energy technologies.

Of particular significance, Congress has—as of late 2009—moved closer than ever to adopting a climate policy that would for the first time impose an economy-wide market price on CO_2 and other GHGs.[41] Other kinds of hurdles, however, are likely to continue to defy ready policy prescriptions. A good example is the increasing difficulty, in many parts of the country, of siting large energy facilities of any kind. More efficient and transparent permitting processes, enhanced resources and improved coordination across different agencies at different levels of government, and better communication between local communities, advocacy groups and other stakeholders, and project developers are all undoubtedly part of the solution—but all are also difficult to legislate. In the long run, an informed citizenry, united behind a vision of America's energy future that can transcend strictly local or regional concerns, offers the best hope for overcoming NIMBYism, special-interest politics, simple institutional inertia, and the myriad other factors that often create a potent bias in favor of the status quo.

[41] See Appendix I for a thorough summary of recent energy legislation in the United States.

Recognizing that it is far easier to identify the challenges than it is to advance concrete and politically viable solutions, NCEP has launched a number of specific initiatives aimed at delving deeper into many of the issues identified in this report. Some of these activities are briefly summarized below.[42]

On the issue of siting and permitting bottlenecks and uncertainty, NCEP is undertaking a project on National Environmental Policy Act (NEPA) Best Practices. Because the construction and operation of an energy facility typically involves environmental impacts, a discretionary decision by DOE to provide financial assistance to a particular energy project usually triggers the NEPA review process. In most cases, a NEPA review must be completed before any decision to provide financial assistance can be made. Completing environmental reviews under NEPA can sometimes take years. Therefore, if DOE takes a "business as usual" approach to NEPA compliance, there is little chance that it will meet the statutory deadline for awarding assistance to many energy projects under the American Recovery and Reinvestment Act of 2009. To address this problem, NCEP is convening a task force of stakeholders to develop a set of NEPA "best practices" that can be used to expedite the process of reviewing and awarding DOE funds under ARRA and beyond.

On the issue of electricity sector transmission rules that don't work, NCEP has voiced support for legislation pending before the Senate Energy and Natural Resources Committee (S.1462) that is intended to improve regional planning for high-priority national transmission projects. NCEP has also offered several recommendations for improving the legislation, including recommendations related to transmission planning, project siting, and cost allocation policies. These recommendations were articulated in a letter on July 30, 2009 to Senate Majority Leader Reid and key members of the Energy and Natural Resources Committee.[43]

On the issue of financing, NCEP has convened a series of working groups to examine specific financing mechanisms that could expedite the launch of clean energy projects. Thus far, NCEP has focused its efforts around three topics:

- Improving DOE's 1705 Loan Guarantee Program;
- Creating a new public-private clean energy investment fund;[44] and
- Creating a new financing mechanism for energy efficiency and small renewable energy projects tied to commercial and residential real estate property—frequently referred to as Property Assessed Clean Energy (PACE) financing.[45]

A number of deployment hurdles, however, are likely to continue to defy ready policy prescriptions.

Following each of these working group meetings, NCEP drafted and transmitted letters outlining the key takeaway points and related policy options to the appropriate Congressional and Administration personnel.

In addition, NCEP is launching a Clean Energy Financing Working Group whose aim is to identify the most effective incentive mechanisms for low-carbon energy. Through a series of workshops and targeted analyses, this group will assess financing issues and offer suggestions on how to target scarce public resources to

[42] Additional information can be found at our website: http://www.bipartisanpolicy.org/projects/national-commission-energy-policy.

[43] The full letter can be accessed at http://www.bipartisanpolicy.org/library/research/letter-majority-leader-harry-reid.

[44] See http://www.bipartisanpolicy.org/library/national-commission-energy-policy/letter-clean-energy-public-private-investment-fund.

[45] See also text box on page 37 and NCEP letter at http://www.bipartisanpolicy.org/library/national-commission-energy-policy/letter-property-assessed-clean-energy-pace-financing.

No technological challenge the world confronts this century is more difficult, or likely to be more consequential in terms of its impacts on future generations, than that of reconciling 21st century energy needs with the ecological and economic imperative of managing climate change.

achieve maximum leverage in advancing the domestic renewable energy production goals of the federal government.

On the issue of workforce shortages, NCEP convened a group of stakeholders with expertise in the skill and labor needs of the U.S. electric power industry (see Text Box on page 42). Specifically, NCEP's "Task Force on America's Future Energy Jobs" brought together representatives from labor groups, the electric power industry, and the training and educational community to explore the existing demographic makeup and anticipated workforce needs of the electric power sector, along with the adequacy of training institutions and programs that currently serve this industry. The Task Force released its report, which contains several critical federal policy recommendations, on October 1, 2009.[46]

In sum, no technological challenge the world confronts this century is more difficult, or likely to be more consequential in terms of its impacts on future generations, than that of reconciling 21st century energy needs with the ecological and economic imperative of managing climate change. This report only begins to catalogue the different barriers that have slowed or stymied the diffusion of new energy technologies in the past. It is the Commission's hope that with a clear understanding and fuller accounting of these barriers—augmented by the NCEP initiatives described above and by related work at other organizations—policymakers and the public will be better equipped to find and implement solutions that are equal to the enormously daunting task at hand.

[46] The full report can be accessed at http://www.bipartisanpolicy.org/library/report/task-force-americas-future-energy-jobs.

Appendices

Appendix I: Addressing the Deployment Challenge for Low-Carbon Energy Technologies—An Update on the Current Policy Landscape

This section highlights the most significant policies included in three major 2009 legislative initiatives.[47] The American Recovery and Reinvestment Act of 2009 (ARRA) was signed into law on February 17, 2009. It included billions of dollars in energy-related spending intended to advance the dual goals of stimulating the economy and promoting clean-energy development. The American Clean Energy and Security Act of 2009 (ACES or H.R. 2454), a comprehensive energy and climate bill, was passed by the House of Representatives on June 26. It would establish an economy-wide cap-and-trade program to limit U.S. greenhouse gas emissions and contains numerous related provisions to promote low-carbon technologies. Finally, the Senate Energy and Natural Resources Committee reported the bipartisan American Clean Energy Leadership Act (S. 1462) in the summer of 2009. This bill would address a range of energy issues but does not include a mandatory program to reduce carbon emissions.

In the overview that follows, policies or programs are grouped by technology or (later in this section) by the specific deployment barrier they are intended to address.

Renewable Energy

The ARRA significantly increased incentives for renewable energy.

- Production Tax Incentives—ARRA extended the federal production tax credit (PTC) through 2012 for wind facilities and through 2013 for other renewable power facilities (including biomass, solar, and geothermal). The Treasury will provide grants in lieu of tax credits for facilities placed in service in 2009 or 2010, thus creating a particularly strong incentive for entities with no tax liability. In August 2008, the Treasury announced $502 million in grants to the first round of renewable projects, issued to twelve distinct wind and solar projects in eight states. The program is expected to provide more than $3 billion in grants and to support around 5,000 projects.

- Loan Guarantees—ARRA provides an additional $4 billion in DOE loan guarantees to cover the credit subsidy costs of a new program for renewable energy and transmission projects that begin construction before September 30, 2011. The additional loan guarantees are expected to leverage ten times their guaranteed value in loans. The original authorization for the loan guarantee program was $6 billion, but $2 billion was diverted to fund the extension of the Car Allowance Rebate System (or "cash for clunkers" program).

- Clean Renewable Energy Bonds (CREBs)[48]—The Emergency Economic Stabilization Act of 2008 originally extended the zero-interest CREB program; subsequently, ARRA expanded the bond limit to $2.4 billion. The CREB program was first established by the Energy Policy Act of 2005 (EPAct05). It has distributed a total of $1.2 billion in its first two rounds of funding to 922 projects involving solar, wind, landfill gas, hydropower, biomass, trash combustion, and refined coal technologies. CREBs are tax credit bonds issued by power producers such as government entities and electric cooperatives to finance public-sector renewable energy projects. In practice, they provide interest-free loans. This mechanism provides an incentive comparable to the PTC and is applied to similar qualifying technologies, though the financial benefit of the PTC is received only after electricity is generated.

Recent energy and climate bills considered in the Senate and House of Representatives include additional policy options specifically aimed at furthering the deployment of renewable energy technologies.

- Renewable electricity standard—Would establish a federal requirement for a minimum percentage of electricity generation to be derived from renewable energy sources. Current proposals differ slightly in the targets they set and how they define qualifying renewable sources. Typical targets for the minimum renewable contribution range from 15 to 20 percent by 2020, with up to one quarter of the requirement eligible to be satisfied by energy efficiency. Generation from existing hydropower, municipal solid waste generators, and new nuclear plants or nuclear plant uprates is typically excluded from the baseline.

[47] Information on earlier policy initiatives and past Commission recommendations is available at http://www.bipartisanpolicy.org/projects/national-commission-energy-policy.

[48] http://apps1.eere.energy.gov/state_energy_program/update/feature_detail.cfm/start=1/fid=89.

- Support for renewable energy RD&D—Both H.R. 2454 and S. 1462 contain provisions to increase federal funding for renewable energy RD&D. The Senate bill doubles the level of DOE's energy R&D program from $3.28 billion in fiscal year 2009 to $6.5 billion in fiscal year 2013. ACES (H.R. 2454) uses emission allowances to support investments in energy efficiency and renewable energy, carbon capture and storage (CCS), advanced vehicle manufacturing, and basic R&D. It also uses allowances to fund State Energy and Environment Development (SEED) Accounts, establishes energy innovation hubs across the United States, and funds DOE's new Advanced Research Projects Agency—Energy (ARPA-E).[49]

Efficiency

The 2009 stimulus bill (ARRA) significantly increased funding for several important energy efficiency programs.

- The Weatherization Assistance Program provides small-scale grants (up to $6,500 per home) for energy-efficiency retrofits undertaken by low-income households. Under ARRA this program received $5 billion in additional funding to raise the eligible income level and increase the level of funding assistance available per home. Each state runs their own weatherization program and coordinates with weatherization service providers to install cost-effective efficiency measures free of charge in existing low-income residences.

- The Public Housing Capital Fund in the Department of Housing and Urban Development (HUD) received $1 billion for priority investments, including energy conservation retrofits. These funds flow to public housing agencies to support development and modernization programs in public housing developments.

- Funding for state energy programs increased dramatically (from $125 million annually to $3.1 billion). These funds enable state governments to provide grants for energy efficiency and renewable energy projects and programs. Each state energy office determines how to use the funds, though the ARRA stipulates that the governor of each state must promote earnings opportunities for efficiency investments made by utilities, establish stringent residential and commercial building codes, and develop a plan to achieve 90 percent compliance with updated building energy codes in new and renovated buildings.

- Funding for the Energy Efficiency and Conservation Block Grant Program was expanded to $3.2 billion over five years (this is an increase from the $2 billion authorized over the same time period under the Energy Independence and Security Act of 2007). This program provides federal grants to reduce energy use and emissions, and to improve energy efficiency.

- Funding in the amount of $300 million was dedicated to the existing Energy Efficient Appliance Rebate and ENERGY STAR® Programs. These funds go to state energy offices which are responsible for developing state-specific plans for eligible appliances, setting rebate levels for each type of product, and recycling old appliances. The DOE recommends that funds be focused on promoting ENERGY STAR® appliances including central air conditioners, boilers, clothes washers, dishwashers, freezers, refrigerators, and water heaters.

- The Emergency Economic Stabilization Act of 2008 included a number of incentives for improving building efficiency, including:

  - An extension of the 30 percent tax credit for investments in residential solar electric systems through 2016 together with the elimination of the previous cap of $2,000. The tax credit for geothermal heat pumps remains capped at $2,000. A credit for residential small wind is added, with a cap of $4,000 per qualified project.

  - An extension of the $1.80-per-square-foot tax deduction for buildings that achieve a 50 percent energy-savings target through 2015.

  - Extension of the credit for energy-efficient new-home construction through December 31, 2009. New homes that achieve a 30 percent reduction in heating and cooling energy consumption (relative to a similar home) are eligible for a $1,000 credit; homes that achieve a 50 percent reduction are eligible for $2,000.

- The tax credit for energy-efficiency improvements to existing homes was extended through 2009 in the Emergency Economic Stabilization Act of 2008. ARRA further extended this credit through 2010, increased the credit to 30 percent of the cost of improvements, and established new criteria for eligible improvements and equipment.

[49] ARPA-E is modeled on the Department of Defense's DARPA agency for advanced research in defense technologies and was established to undertake high-risk, high-reward energy research. It was originally established under the America COMPETES Act of 2007 but didn't receive significant funding until the ARRA provided it with $400 million.

H.R. 2454 and S. 1462 share many common provisions for improving energy efficiency. These include:

- National goals for energy efficiency and building efficiency. Specifically, both bills would set a national target for improving building energy efficiency by 2.5 percent per year through 2030 and establish an overall efficiency improvement goal of 50 percent by 2016.
- Financing for Property Assessed Clean Energy (PACE) programs. Both bills authorize grants to states to capitalize state revolving funds that finance building retrofit programs, including municipal programs that allow owners to finance energy improvements through property tax liens.
- Appliance efficiency. Both bills provide for increasingly stringent appliance standards and continued support for the ENERGY STAR Programs.
- Industrial efficiency. Both bills establish a revolving industrial loan fund to help manufacturers implement more efficient technologies.

Carbon Capture and Storage (CCS)

ARRA authorized $3.4 billion for fossil energy R&D. Subsequently, Energy Secretary Chu announced that $1 billion will be directed toward reviving the FutureGen clean coal demonstration project, and $2.4 billion will support related DOE projects such as the Clean Coal Power Initiative and the Industrial Carbon Capture and Storage and Geologic Sequestration Site Characterization projects.[50, 51]

S. 1462 establishes a national indemnity program for up to ten commercial-scale CCS projects to support early development and deployment of this technology. The bill also establishes a framework for regulating final closure and assigning long-term responsibility for geological storage sites. Similarly, H.R. 2454 authorizes the U.S. Environmental Protection Agency (EPA) to (1) develop a coordinated approach to certifying geologic sequestration sites, (2) resolve issues related to the Safe Drinking Water Act, and (3) establish regulations for long-term monitoring of sequestration sites.

H.R. 2454 also includes several incentives for CCS as part of a broader strategy to address climate change. For example, it would levy a surcharge on electricity generated from fossil fuels (coal, gas, and oil) to collect up to $10 billion over ten years to support early commercial-scale CCS deployment. The bill would also create a Carbon Storage Research Corporation, consisting of private and public stakeholders, to manage these funds and provide assistance for commercial-scale CCS demonstration plants. It further stipulates that 2 percent of the total allowance pool under a new greenhouse-gas cap-and-trade program would be used to create a "bonus allowance" mechanism. This mechanism in turn would create a price incentive for sequestering captured CO_2, ranging from $50 to $90 per ton depending on the capture efficiency. The bonus allowance value is increased by $10 per ton if capture occurs prior to 2017. Once 6 gigawatts (GW) of CCS capacity have been deployed, a reverse auction would be used to allocate bonus emissions allowances but EPA would retain discretion to adapt an appropriate allowance distribution mechanism.

Nuclear Power

Neither ARRA nor H.R. 2454 includes provisions directly intended to benefit nuclear power. However, the renewable electricity standard (RES) in both H.R. 2454 and S. 1462 excludes capacity additions from new nuclear plants and from uprates at existing plants from the baseline used to calculate the RES. Such provisions aim to remove any disincentive for new nuclear power that might otherwise arise if utilities had to compensate for additional nuclear capacity with more renewable power.

S. 1462 creates a new National Commission on Nuclear Waste. Commission members would be appointed by the President and would be authorized to examine issues pertaining to nuclear waste and waste management. The Commission's purview would include alternative waste management strategies, review of the Yucca Mountain program, evaluation of the costs and benefits of nuclear waste reprocessing, and methods to manage and fund disposal projects.

Biomass

Nearly $800 million from the ARRA is divided into four main programs to accelerate R&D programs and commercialization efforts related to biofuels. The largest amount, $480 million, will be given out by DOE in the form of 10 to 20 awards for biorefineries at various scales and designs, all to be operational in the next three years. Funding is capped at $25 million for pilot-scale and $50 million for demonstration-scale projects.

[50] Department of Energy Techline. "Secretary Chu Announces Agreement on Futuregen Project in Mattoon, Illinois" http://www.fossil.energy.gov/news/techlines/2009/09037-DOE_Announces_FutureGen_Agreement.html.

[51] Department of Energy Techline. "Secretary Chu Announces $2.4 Billion in Funding for Carbon Capture and Storage Projects" http://www.fossil.energy.gov/news/techlines/2009/09029-DOE_Announces_Stimulus_Funding.htm.

Funding will be awarded for work to accelerate and validate integrated bio-refinery technologies that produce advanced biofuels, bioproducts, and heat and power in integrated systems. Another $176.5 million will be used to increase the federal funding ceiling on two or more commercial-scale bio-refinery projects that were selected and awarded within the past two years. Fundamental research in key program areas will receive $110 million. The money will be divided for purposes of (1) expanding the resources available for sustainability research, (2) creating an advanced research consortium to develop technologies and facilitate demonstration through competitive solicitation, and (3) creating an algae biofuels consortium to accelerate the demonstration of algae-based production processes through a competitive solicitation. Lastly, $20 million will fund a competitive solicitation for the purpose of optimizing flex-fuel vehicles designed to operate on high-octane 85-percent ethanol blends (E85), evaluating the impact of higher ethanol blends in conventional vehicles, and upgrading the existing refueling infrastructure to be compatible with fuels up to E85.[52]

H.R. 2454 likewise contains several provisions to support the development of biofuels and biomass-based energy technologies:

- Includes biomass, biogas, and biofuels derived exclusively from eligible biomass under the definition of renewable energy resources that may satisfy the Rrenewable electricity standard;
- Amends the federal Renewable Fuels Standard definition of "renewable biomass" to include a greater range of biomass feedstocks from federal lands (e.g., dead, damaged, or diseased trees) and to include residues and byproducts from pulp and paper industry facilities;
- Authorizes the U.S. Department of Transportation (DOT) to require vehicle manufacturers to produce light-duty vehicles capable of operating on ethanol and methanol-based fuels upon a finding that these fuels would help meet the nation's energy independence and environmental goals;
- Expands the Title XVII loan guarantee program to include renewable fuel pipelines as eligible technologies; and
- Establishes a National Bioenergy Partnership to support the deployment of biomass fuel infrastructure and bioenergy technologies.

Advanced Vehicles

The ARRA provided funding for a range of clean transportation programs, from advanced battery research to direct federal procurement of fuel-efficient vehicles.

- DOE received $2.4 billion to award research loans and grants for the development of advanced battery systems produced in the United States. Eligible recipients include manufacturers of advanced lithium ion batteries, hybrid electrical systems, electric vehicle components, and software designers. Forty-eight grants were awarded in August 2009 using this funding, including nearly $300 million to Johnson Controls, Inc. for an advanced cell and battery manufacturing facility; $105 million to General Motors for the construction of a U.S. facility for manufacturing electric drive components; and $100 million to Nissan and its partner for the demonstration of 5,000 electric vehicles with a 100-mile range.
- The General Services Administration (GSA) received $300 million to purchase fuel-efficient vehicles for the federal fleet, including hybrid-electric vehicles, electric vehicles, and commercially available, plug-in hybrid vehicles.
- The ARRA also provided funding for several tax credits for advanced vehicles:
  - A $2,500–$7,500 credit for qualified plug-in electric-drive vehicles, with the amount of the credit to be determined by battery capacity.
  - A credit of 10 percent of the cost of a plug-in electric vehicle, up to a maximum of $2,500.
  - A 10 percent credit for the cost of a plug-in electric-drive conversion kit, up to a maximum of $4,000.
  - A provision that allows the Alternative Motor Vehicle Credit to be applied against the Alternative Minimum Tax starting in 2009.

Following adoption of the ARRA, President Obama in May 2009 clarified national policy on vehicle fuel economy standards and vehicle greenhouse gas emissions to support collaboration between the DOT, EPA, and various state agencies. Federal vehicle fuel-economy standards for the years 2011

[52] DOE: http://www.energy.gov/news2009/7375.htm.

through 2016 will increase by 5 percent each year, reaching an industry average of 35.5 miles per gallon (mpg) in 2016 (an average increase of 8 mpg per vehicle).[53]

H.R. 2454 contains two subtitles that address clean transportation and transportation efficiency. These provisions include:

- Support for utilities to develop plans to support vehicle electrification and integration with smart grid systems.
- DOE assistance for the regional deployment of plug-in vehicles, including financing for the incremental cost of plug-in hybrid-electric vehicles (PHEVs) and battery or charging infrastructure.
- DOE funding to retrofit manufacturing facilities to produce PHEVs or batteries.
- Increased loan guarantees for advanced vehicle technology manufacturing. Such loan guarantees were first established by the EISA07 and will be increased to $50 billion. Direct loans will be issued to U.S. manufacturers of advanced technology vehicles and components. In June 2009, DOE announced $8 billion in conditional loan commitments, including $5.9 billion to Ford Motor Company to produce more fuel-efficient models; $1.6 billion to Nissan to convert a facility to manufacture advanced electric vehicles and to build an advanced battery manufacturing facility; and $465 million to Tesla Motors to manufacture electric drive trains and vehicles.

H.R. 2454 also distributes emission allowances to car manufacturers to support PHEV manufacturing and deployment.

Electricity Transmission

As noted above, the ARRA provides an additional $4 billion to cover credit subsidy costs for the DOE loan guarantee program for renewable energy and transmission projects that begin construction before September 30, 2011. The additional loan guarantees are expected to leverage $40 billion in loans. In July 2009, the DOE announced a solicitation for these loan guarantees, building on the lending authority extended by the ARRA. A total of $750 million will support transmission projects.

Under the ARRA, the DOE Office of Electricity Delivery and Energy Reliability will also conduct a resource assessment and analysis of future electricity demand and transmission requirements. In addition, $4.5 billion is authorized for investments in smart grid technology to modernize the electricity grid.

Both the House and Senate Energy Committee climate bills (H.R. 2454 and S. 1462, respectively) include transmission provisions aimed at addressing the regulatory and financial constraints that have hindered the development of intrastate, high-voltage transmission lines. Specifically, both bills include provisions to improve planning and development processes for new transmission lines, particularly high-priority national transmission projects such as long-distance high-voltage lines and feeder lines to renewable energy projects. They also grant the Federal Energy Regulatory Commission (FERC) greater authority to plan, site, and allocate costs for such projects. FERC will also promulgate planning principles for the development of an interconnection-wide transmission plan, exercise expanded backstop siting authority if states are unable to site a project or have denied siting applications, and have authority to establish methodologies for allocating the costs of transmission projects across a broad region. S. 1462 establishes the Department of the Interior as the lead agency for coordinating planning and siting approval for transmission projects on public lands.

Workforce Issues

ARRA provided $500 million to fund the Workforce Investment Act of 1998, which supports research and job training projects that prepare workers for careers in energy efficiency and renewable energy.

Similarly, H.R. 2454 supports several programs at DOE and the U.S. Department of Labor (DOL) to advance workforce training.

- DOE is authorized to provide grants to universities and colleges that develop programs for training workers in renewable energy, energy efficiency, and other areas related to climate change mitigation and adaptation.
- Funding for the Energy Worker Training Program originally authorized by EISA07 is increased from $125 million to $150 million. A worker training fund is established in the Treasury and is funded by a small percentage of emission allowances in the first two years of the cap-and-trade program established under the legislation.
- DOL is directed to support technical education and job training programs for renewable energy industries by creating an information and resources clearinghouse.

[53] Blanco, Sebastian. Obama: CAFE increase to unified national standard of 35.5 mpg by 2016. Autoblog. May 19, 2009. Accessed July 20, 2009 from http://www.autoblog.com/2009/05/19/obama-cafe-increase-an-historic-agreement-to-help-america-brea/.

Financing Challenges

As described in the preceding summary, the ARRA dramatically expanded funding for a range of low-carbon technologies. The policies poised to have the greatest impact on ameliorating financing challenges for renewable energy and efficiency technologies likely include the loan guarantee program, adjusted tax incentives, and funding for a suite of state programs that support advanced energy and energy efficiency technologies.

In addition to the various technology-specific provisions included in H.R. 2454 and S. 1462, both bills would create a new agency, known as the Clean Energy Deployment Administration (CEDA), that would have the sole mission of fostering widespread deployment of clean energy technology. Emission allowance value would be used to fund key programs under this agency. CEDA staff would have strong financial expertise and the Agency itself would have the ability to use a range of financial instruments—including direct loans, letters of credit, and loan guarantees, among others—to create an attractive and diversified portfolio of investment incentives for the demonstration and deployment of new clean energy technologies, including especially high-risk, high-reward technologies. CEDA would be a self-sustaining institution, meaning that returns on successful investments would be used to fund future programs. The House and Senate versions of this concept differ in several key details, including the status of the program either within DOE or as a distinct agency, and the level of funds authorized. However, both bills provide a high level of initial funding for CEDA, ranging from $7.5 billion in the House bill to $10 billion in the Senate bill.

Under H.R. 2454, a significant amount of emissions allowances are used to fund several technology initiatives including State Energy and Environment Development (SEED) Accounts, programs to achieve national building code efficiency targets, international deployment of clean-energy technologies in eligible countries, support for manufacturing and deploying advanced vehicles, and a bonus allowance mechanism to create a price incentive for electricity generators and industrial entities to deploy CCS technology. By 2025, this bill would invest $190 billion in energy efficiency, renewable energy, CCS, advanced vehicle technology, and basic energy R&D.

Appendix II: Barriers to CCS Deployment

Introduction

Carbon capture and storage (CCS) refers to an array of technologies that are used to capture and compress, transport, inject, and store large volumes of carbon dioxide (CO_2) in deep underground geologic sites. Coal-fired electric power plants are considered the primary target for CO_2 capture, though other types of industrial facilities—including natural gas refineries, ethanol plants, cement plants, and steel mills—also generate large volumes of CO_2 suitable for capture and storage. Preliminary assessments suggest that there is enormous capacity for geologic CO_2 storage, both around the globe and in the United States. Overall, the potential to mitigate CO_2 emissions with CCS appears quite large; thus, the deployment of CCS technologies is likely to play an important role in efforts to stabilize atmospheric greenhouse gas concentrations.

There are three general options for separating and compressing CO_2 emissions from industrial sources: post-combustion capture, pre-combustion capture, and oxy-fuel combustion capture. For each option, several capture technologies exist today and many more are in the research and development phase. Captured CO_2 must be substantially compressed to facilitate economic transport and injection. Although compressed CO_2 can also be transported by ship, rail, or truck, economic considerations are likely to favor pipeline transport. Hence, pipelines are the sole transport option discussed in this paper. Injection can be accomplished using equipment that is already commonly used in the oil and natural gas industries—indeed, these industries provide very useful analogies for CCS more generally. Compressed CO_2 can be stored in a variety of subsurface rock formations or be used for enhanced oil (or natural gas) recovery. Major candidate storage sites include saline formations, mature natural gas and oil reservoirs, unmineable coal seams, and basalt formations, among others.

This paper highlights some of the key barriers—economic, technical, infrastructure, social, and policy-related—to the deployment of fully integrated CCS projects and to the commercial development of component technologies. An overarching barrier worth highlighting at the outset is the lack—absent mandatory CO_2 constraints—of a financial incentive for deploying CCS technologies. Without such an incentive, CCS only adds cost to energy production and industrial processes and is unlikely to be implemented on a significant scale.

Large-Scale Integrated CCS Projects

During the last few years, a few large-scale CO_2 sequestration projects have been constructed or started, but none of these integrate power generation, carbon capture, and sequestration. Indeed, several integrated projects have been tabled—most notably the U.S. Department of Energy's (DOE's) FutureGen project, which was restructured in early 2008 due in large part to cost considerations.

The fact that several projects have been dropped and that none of the projects that are moving ahead are located in North America or Europe is troubling to those who argue that commercial deployment of CCS must be achieved in the 2020–2030 timeframe. Indeed, several recent reports have cited the need for large-scale integrated demonstration projects: for example, members of the G8 recently called for 20 large-scale CCS demonstration projects to be implemented by 2010. Such projects are critical to advancing the requisite technologies along a learning curve, driving down costs, and building public and investor confidence.

A number of inter-related barriers have slowed the deployment of large-scale integrated projects. Combined, these barriers give rise to a "Catch-22" conundrum. On the one hand, the lack of a price signal for reducing CO_2 emissions makes it uneconomic for private industry to invest heavily in CCS technology. And on the other hand, lack of certainty about the cost, reliability, and social acceptability of CCS technology may leave policy-makers wary of imposing limits on CO_2.

Policy Barriers: Despite a plethora of legislative proposals at the state and federal levels, only a handful of states have enacted mandatory limits on CO_2 emissions to date. Without such limits, no financial incentive exists to deploy CCS technologies on large-scale electricity generation or industrial facilities. Moreover, because most current proposals are designed to produce a gradually escalating carbon price over time, it is not clear that any price signal they would generate in the initial years of implementation would be adequate to overcome cost hurdles to CCS deployment, especially in the early phases of commercialization when technology costs are likely to be relatively high. Thus, there are concerns that power companies and other facility owners would opt to avoid investments in CCS technologies until there is a substantial decline in cost, opting instead to meet near-term emissions reductions goals by fuel switching or through offsets.

Another major policy barrier is the absence of a comprehensive legal and policy framework for managing stored CO_2. A number of important issues must be resolved as part of such a framework.

- Property rights: There appears to be growing consensus that the owner of the surface rights to a property also owns the pore space beneath the surface. However, this still leaves a number of questions to be answered, including whether (a) both surface and mineral rights must be acquired for areas where minerals are currently or may be produced; (b) property rights need to be acquired for both the injection plume and the area of elevated pressure; and (c) models in which pore space is enlisted to serve the public good (e.g., waste disposal and water storage in aquifers) can supersede trespass claims.

- Regulatory oversight of injection: The U.S. Environmental Protection Agency (EPA) has drafted rules through its Underground Injection Control (UIC) program to regulate CO_2 injection. There are three relevant well classes in the existing rule: Class I for industrial waste; Class II for oil and gas wells; and Class V for experimental projects. In addition, EPA has proposed a new Class VI for CO_2 sequestration. However, these rules do not resolve all regulatory issues related to CO_2 injection in oil and gas fields, nor do they resolve issues related to state boundaries.

- Stranded assets: How can first-mover investments in CCS be protected from becoming stranded assets under a future CO_2 policy?

- Long-term management: Provisions for the long-term management of closed CO_2 storage sites will be needed, both to ensure responsible maintenance of these repositories and to help developers mitigate investment risk.

Economic Barriers: Although many of the component technologies for implementing CCS have already been deployed in some way for other industrial purposes, scaling them up to manage the kinds of CO_2 flows generated by large industrial sources such as power plants and fully integrating them at new or existing facilities is a costly proposition that bears significant financial risk.

The first challenge is the high cost of large-scale, fully integrated CCS systems. Costs have escalated drastically over the past several years. This is partly because construction costs have increased throughout the industrial sector generally—and throughout the electric power sector in particular—as a result of rising costs for oil and for the transport of raw materials, as well as increased global demand for steel, cement, and other construction materials and equipment. Moreover, absent a regulatory obligation to reduce CO_2 emissions, companies seeking to demonstrate integrated CCS technologies can expect to face additional hurdles. Several utilities have filed requests for CCS cost recovery with their state public utilities commission and in several cases these requests have been rejected. AEP was granted approval to recover costs for pre-construction activities related to a CCS project but has not yet won approval to recover construction costs. Duke Energy has received significant encouragement, including approval of cost recovery, to construct an integrated gasification combined-cycle (IGCC) coal plant but is still determining what level of capture and sequestration this project might support. In both cases, it is not yet known where such plants would stand in the dispatch order even if they were constructed. Additional public financing or incentives will likely be necessary to encourage such investments.

The structure of government funding can present further challenges. As is typical for incentive programs, the U.S. government has committed to an overall level of funding for clean coal and CCS technologies that is subject to annual budget appropriations. The FutureGen case is a good example of a project that appeared likely to be funded as promised—until the funding failed to materialize. Other forms of government incentives such as production tax credits are often enacted with sunset provisions that contribute to market uncertainty. Federal production tax credits for wind power, for example, have recently been extended in two-year increments. As each two-year cycle approached its end, investments virtually stopped until the next extension was granted.

Another economic barrier is the financial and investment risk inherent in first-mover, commercial-scale projects, particularly when these involve complex "state-of-the-art" facilities. In contrast to the chemical industry, the power industry is interested in building baseload power plants that can reliably operate upwards of 80–90 percent of the time. Failure to guarantee similar levels of reliability can open power companies to other financial risks.

Technical Barriers: As indicated above there are a set of technical challenges associated with developing large-scale, fully integrated CCS demonstration projects, including the challenge of combining multiple new component technologies in a single facility. This tends to compound the uncertainties associated with implementing any one component of a new

type of system. For example, when American Electric Power (AEP) first integrated large-scale control devices for sulfur and nitrogen oxides, it found that emissions from the sulfur dioxide control device reacted with water vapor from the nitrogen oxide control device. This resulted in the creation of a visible blue cloud of sulfuric acid. To resolve this issue, AEP ended up buying all of the lots adjacent to the plant where these control devices were first implemented.

Infrastructure and Resource Barriers: Widespread CCS deployment will require major investments in the infrastructure needed to transport captured CO_2. While pipeline technology is well developed, challenges remain in terms of optimizing the overall transport system, covering the high cost of pipeline materials and maintenance, and gaining public acceptance for the siting of CO_2 pipelines.

Another hurdle to scaled-up deployment lies in the difficulty of securing drilling rigs and obtaining construction equipment, including, for example, the tubular and other steel components of injection wells. Recently, one of the Regional Carbon Sequestration Partnerships had to negotiate with a Scotland-based steel manufacturing company to develop the piping used in an injection well because they could not find a U.S. company that could manufacture piping to the desired standards in a timely manner. As the number of projects underway increases, this constraint could pose a significant challenge; indeed, it may point to the need for revitalized manufacturing capacity in the United States more generally.

Social Barriers: Over the last few years a number of stakeholder groups (including environmental NGOs, energy consumers, ground water protection officials, business associations, miners, unions, and others) have become increasingly aware of the importance of CCS—and the issues associated with CCS deployment. This has led to a set of somewhat conflicted attitudes toward this CO_2 mitigation option. Some strongly support CCS as a critical option for cost-effectively addressing climate change while managing energy security and cost concerns. These groups call for rapid deployment of CCS demonstration and commercial projects.

Still others see the promise of CCS fading. Given how little demonstration activity is occurring at present, these groups express concern that it is becoming increasingly difficult to envision plausible scenarios for wide-scale deployment of CCS within a timeframe that would be meaningful for climate protection. In their view, the urgency of stabilizing atmospheric greenhouse gas concentrations precludes a staged or phased approach to CCS development. Under staged development, the first step would be to insure that large IGCC units can be reliably operated. Then, CO_2 capture would be added to those plants. Many stakeholders want to see utilities start with high levels of capture, not the lower percentages that can easily be achieved with already commercial technologies. And finally, some see investment in CCS as detracting from investment in energy efficiency, renewable energy and other low-carbon technologies. For these groups, any investment in new coal-fired electric plants is undesirable, even with CCS, because it delays the transition to inherently cleaner forms of energy.

CCS Component-Specific Barriers

While many analyses call for large-scale demonstration projects to accelerate the development and deployment of CCS technologies, a complementary path to commercial readiness is to continue smaller demonstration projects that involve a subset of the processes and technologies involved in large-scale, integrated projects. Although smaller-scale projects will not resolve the issues related to large-scale integration, they can help advance the commercial readiness of component technologies and begin to answer questions that are important from the standpoint of designing appropriate regulations and policies to govern broad-based CCS deployment. The following table briefly summarizes barriers that apply to specific CCS technologies.

TECHNOLOGY	BARRIER
Coal Fired Power Plants	■ Policy: There is a fear of stranded assets for coal-fired power plants if no mandatory policy for reducing long-term CO_2 emissions is implemented (i.e. power plant owners invest in CCS capability, but carbon constraints do not materialize). In addition, there is the concern that early investments in emissions mitigation will not be credited in future emission control programs. Finally, a related concern is the lack of accounting protocols for capture and subsequent sequestration of CO_2. ■ Economic: The high capital and operating and maintenance (O&M) costs of CO_2 capture systems represent a significant deterrent to deployment. To overcome this cost barrier, incentive programs utilizing tax credits, grants, and allowance allocations have been proposed. In many cases, however, these incentives are designed to cover initial capital costs, not ongoing O&M costs. As a result, those added O&M costs can move facilities with CCS down the dispatch order (in competitive markets, those generators with the lowest marginal or operating costs are typically dispatched first). ■ Technical: Currently all capture technologies incur a large energy penalty. For example, a power plant utilizing CCS can require as much as 30 percent more energy to generate the same amount of power because of the additional energy requirements associated with CO_2 capture and compression. Another technical barrier concerns the ability of large IGCC plants to provide reliable baseload generating capacity. Large IGCC turbine systems are more complex than conventional pulverized coal steam systems and are considered relatively unproven under high heat conditions. ■ Social: Public attitudes toward CO_2 capture are still evolving. On the one hand, a growing number of stakeholders view IGCC as a better technology than pulverized coal or oxy-fired plant designs because IGCC is available, offers more options for producing different energy carriers (e.g., hydrogen and synthetic fuels, as well as electricity) from different fuel feedstocks, and has greater potential for cost reductions, including the potential to reduce control costs for other pollutants besides CO_2. In fact, several companies have proposed developing IGCC plants that would capture only the relatively small percentage of total CO_2 emissions (20–40 percent) that could be readily separated without significant changes in combustion heat or substantial added costs. On the other hand, almost all of these projects have been challenged by NGOs, rejected by public utility commissions, or dropped for other reasons—often related to cost.
CO_2 Capture from Other Industrial Sources	■ Policy: The policy barriers to CO_2 capture from other industrial sources are similar to those for coal-fired power plants. In addition, there is a "slippery slope" concern that reduction requirements might not affect industrial sources of CO_2 outside the power sector until later in a greenhouse gas control regime and therefore that owners of industrial facilities should not capture CO_2 voluntarily lest by doing so they hasten the extension of mandatory CO_2 limits to a broader set of sources. Additionally, policymakers and the public tend to focus on the climate impacts of large coal-fired power plants; less attention has been paid to other large industrial sources of CO_2. As a result, opportunities to capture CO_2 more cost-effectively at facilities other than coal-fired power plants may have been largely overlooked to date. ■ Economic: Given the current high price of oil, there is strong interest in securing inexpensive sources of CO_2 for enhanced oil recovery (EOR). Several projects have been initiated to capture CO_2 from ethanol and natural gas refining plants for use in EOR. Such facilities are especially attractive for this application because they produce high-quality, pure CO_2 waste streams that can be easily captured and utilized for oilfield injection. However, even CCS deployment for EOR applications has proceeded more slowly than might be expected, due in large part to concerns about the volatility of oil prices, the uncertainty of CO_2 supplies, and the cost of developing associated infrastructure. Moreover, the existing CO_2 pipeline infrastructure is near capacity. So increasing throughput and reaching new sources will require additional pipelines, which are expensive and difficult to site. When coupled with uncertainty about the reliability of CO_2 sources, the overall effect is a disincentive for broad investment. A related concern is that the development of a substantial CO_2 transport infrastructure could—by increasing the number of potential sources that could be tapped—cause market prices for CO_2 to drop, undermining the economics of the existing infrastructure. While it might be possible to address this volatility concern through long-term contracts, it is not clear that market participants will want to enter into such contracts if they think they may be able to secure CO_2 at much lower cost in the future. ■ Infrastructure: Existing CO_2 pipeline infrastructure is not sufficient to support a major expansion of the use of captured CO_2 for EOR. As discussed below, the biggest obstacle in developing new pipeline infrastructure is often public opposition to siting.

TECHNOLOGY	BARRIER
Transport via Pipeline	■ Policy: Large-scale deployment of CCS is expected to require new pipeline capacity for transporting CO_2 at the scale of the existing natural gas pipeline system. Relying on emerging carbon markets to drive the development of a CO_2 pipeline system is likely to be less efficient than developing needed infrastructure in a way that anticipates future needs. For this reason some states are contemplating developing pipeline trunk lines to support the development of CCS. Additional federal support could help further these efforts. Furthermore, pipeline siting is likely to take place under a patchwork of authorities and to include both market-based negotiation for access and possibly state-sanctioned eminent domain or condemnation. Most states allow for the use of eminent domain or condemnation authority to site infrastructure that benefits the public good, including pipelines and electricity transmission facilities. Eminent domain authority does not currently extend to CO_2 pipelines, however—indeed none of the existing CO_2 pipeline infrastructure was sited using eminent domain. ■ Economic: Costs for pipeline construction are rising along with construction costs for all types of new infrastructure and industrial facilities. Reasons include increased global demand for steel, cement, and other construction materials and high transportation costs. In addition, routine pipeline maintenance costs are likely to be high, given the corrosiveness of CO_2. ■ Technical: Technical challenges for pipeline deployment primarily relate to sizing and locating pipelines in a way that optimizes the overall efficiency and cost-effectiveness of the system. ■ Social: Public opposition is perhaps the major non-economic obstacle to building pipeline systems. Concerns about pipeline safety, impact on property values, visual impairment and other factors often play a role in local opposition.
Sequestration in Saline Reservoirs	■ Policy: Proposed and existing EPA rules that govern injection address many issues relevant to sequestration, such as the siting, construction, operation, and closure of injection wells. However, EPA does not have the authority to address a number of tangential issues that are also of great importance for CO_2 storage in the context of climate-change abatement, including property rights, greenhouse gas accounting, and long-term maintenance of closed sites. This lack of a comprehensive policy and regulatory framework further increases the uncertainty associated with early CCS investment. ■ Economic: Relative to existing oil and gas fields that are already well-characterized, saline reservoirs must undergo extensive site characterizations before CO_2 injection can occur. This leads to larger upfront costs. Additionally, initial uncertainty about the characteristics of saline reservoirs can translate into financial risk and higher cost, especially for first movers. Uncertainty about the timeline and conditions for project closure creates another source of financial risk for CCS investments. The 50-year default period in the EPA draft rule may be shortened or extended based on the characteristics of the reservoir. There is a good chance that CO_2 injected into vast saline reservoirs may continue to move at very slow rates for long periods of time after injection ceases. As a result, it may be difficult to initially understand what the long-term monitoring and maintenance needs will be at different sites. This uncertainty again increases financial risk. ■ Technical: Better information is needed about the characteristics of different geologic storage options, especially in the case of saline reservoirs. In particular, additional information is needed to understand the behavior of injected CO_2, estimate the capacity of potential reservoirs, develop guidelines for long-term reservoir-wide management, assess potential water quality impacts, compare the potential efficacy of various approaches to mitigating leakage or unintended migration, gauge the usefulness of various monitoring techniques, explore secondary trapping mechanisms, and address site closure and long-term maintenance issues. ■ Social: Public opposition to the siting of sequestration sites may reflect concerns about CO_2 leakage, impairment of mineral rights, visual impairment of views, pipeline safety, increased truck traffic (at least during construction), and perceived risks related to seismicity and the potential for catastrophic releases of CO_2. Community relations with any company undertaking a sequestration project will also factor into public attitudes toward individual projects. Local concerns about a project can materialize in the form of opposition to permits, protests, lawsuits, and other actions that delay, increase the expense, or even preclude the development of projects.

TECHNOLOGY	BARRIER
Sequestration in Oil and Gas Reservoirs	■ Policy: The new draft EPA Class VI UIC rule explicitly omits Class II wells that are used for oil and gas production or waste disposal (i.e., EOR wells). In theory, this means that one could use the existing Class II regime to permit wells that are going to be used for EOR and sequestration, but not for wells that were solely focused on sequestration in oil fields. As in the case of saline reservoirs, the EPA rule does not address property rights or greenhouse gas accounting. Some states are beginning to address this issue on their own. Wyoming, for example, has passed legislation explicitly indicating that EOR is not sequestration. However, it is also in the process of developing rules specifically governing CO_2 sequestration. At this point it remains unclear whether Wyoming's intent is to purposefully exclude CO_2 sequestered through EOR from being credited for achieving CO_2 reductions. Other states seem more interested in figuring out ways to incentivize investment in EOR, including by counting permanently sequestered CO_2 as an emissions reduction. Under any policy framework, CCS and carbon policies should not provide benefits to operators who are removing non-anthropogenic CO_2 from underground reservoirs for use in EOR operations. ■ Economic: Currently, CO_2 provides value through repeated re-use in EOR—not through permanent sequestration. In addition, there are potential financial liabilities associated with attempting long-term storage of CO_2 at this time, before a legal and regulatory structure to govern long-term storage is in place. As a result, oil producers currently lack incentives to take on the extra costs for monitoring and storage that would be necessary to support sequestration. In sum, absent a carbon price, there is no financial incentive to incur the opportunity cost of permanently sequestering CO_2 as opposed to recovering injected CO_2 for future EOR operations. Further, in order to prove that injected CO_2 was being sequestered in oil and gas fields, operators would need to take on additional monitoring costs beyond what is required for EOR. ■ Technical: There are a few key technical questions related to EOR sequestration. A primary concern is how much CO_2 can be safely sequestered. Oil and gas fields have demonstrated the ability to hold large volumes of buoyant fluid and should therefore be good candidates for sequestration. However, these areas also tend to have features that need to be evaluated for impacts on storage integrity—these include a larger number of deep wells and reservoir stimulation (e.g., fracturing of the oil field to make it easier for the oil to flow to the well). In some cases, oil fields are located in relatively shallow locations (thereby making it more difficult to use pressurized CO_2 for injection). ■ Infrastructure: The main resource barrier has been alluded to above—namely, it is hard to find technically qualified personnel who can design and oversee injection projects given how much demand currently exists for the same people in the oil industry. ■ Social: The same general concerns the public is likely to have about sequestration in saline reservoirs can be expected to also apply to sequestration in oil fields. However, there are a few differences. Local populations tend to have more experience with oil and gas drilling and injection. So, they may be more inclined to believe that project-related risks to human health and the environment can be managed. On the other hand, they are also likely to be savvier about the value of their pore space and more concerned about protecting any mineral rights that they may own. This could complicate efforts to acquire necessary property rights and provide a basis for opposition to permit applications. Finally, sequestration projects that are paired with EOR operations may encounter ambivalence, or even opposition, from some environmental advocates who perceive a contradiction when sequestration is used to increase the supply of a fuel—in this case, oil—that, when used, will produce additional CO_2 emissions. Indeed, some may argue that the climate "dis-benefits" of increased oil production need to be counted against the climate benefits of sequestration. Others argue that the oil would be produced anyway and that EOR, by maximizing output from existing fields, may help to prevent or delay oil production in new areas (so-called 'greenfield' development). In any case, the longer-term sequestration potential associated with EOR projects is limited by the amount of CO_2 needed for EOR operations. This amount is smaller than the amount of CO_2 that would need to be sequestered for CCS to play a major role in climate abatement. In fact, most EOR operations require significantly smaller amounts of CO_2 than would be emitted by a single large power plant. As a result, EOR is likely to be relevant primarily in the early development and demonstration phase of CCS technology, where it can help provide more favorable economic conditions for first-mover projects.

TECHNOLOGY	BARRIER
Sequestration in Other Geologic Reservoirs	■ General: Other geologic formations under investigation for potential CO_2 storage opportunities include un-mineable coal seams, basalts, and saline reservoirs in the sub-seabed. In all three cases, the ability to access these geologic reservoirs may be very useful in areas that do not have easy access to other suitable options. As has been discussed above, it is expensive to conduct research. In addition, what resources do become available are likely to flow first to the options that are viewed as most promising (in this case saline aquifer and EOR options). Technical questions remain about the physical properties and efficacy of CO_2 sequestration in coal seams and basalts. These questions are actively being researched today In general, the same barriers in terms of public acceptance apply to almost all types of geologic sequestration (with the exception, perhaps, of sub-seabed sequestration, which probably raises a different set of issues). These kinds of barriers are not likely to be significant for small-scale, short-duration research or demonstration projects. They can, however, be expected to become more prominent as CO_2 storage is pursued on a large scale.

Appendix III: Barriers to Renewable Power Deployment

Introduction

Technologies that generate electricity from renewable sources of energy such as wind or solar radiation represent an important alternative for serving the nation's electricity needs while simultaneously reducing greenhouse gas (GHG) emissions from the electric power sector. This appendix reviews barriers associated with the large-scale deployment of the most prominent renewable electricity technologies available in the near term—that is, wind, solar, and geothermal power. It does not cover biomass, which presents a somewhat different set of issues, nor does it discuss forms of renewable energy further from commercialization, such as tidal and wave energy.

Wind, solar, and geothermal power technologies all have the potential to make large contributions toward meeting future U.S. electricity demand with little or no GHG footprint. Their resource potential is fairly well understood, with most assessments indicating that the ability to cost-effectively harness even a small fraction of the theoretically available resource base would be sufficient to cover a large part of the nation's overall electricity needs. Implicit in the phrase "cost-effectively harness," however, lurk formidable technological, social, and economic challenges. Despite their many advantages, especially at a time of rising fossil-fuel prices and mounting concern about climate change, renewable energy technologies continue to face a number of significant deployment hurdles. In the sections that follow, we review a set of cross-cutting barriers that are common to all of the prominent renewable energy options before turning to some of the specific problems that confront individual technologies.

Common Barriers to Wind, Solar, and Geothermal

Several barriers to further commercial deployment—especially in large-scale, grid-connected applications—are common to wind, solar, and geothermal technologies in the United States. These barriers can be grouped in the following categories: transmission, investment certainty, R&D support, and siting and permitting.

Transmission: Unlike fossil or nuclear fuels, which can be extracted in one location and moved elsewhere to generate electricity, renewable energy must be produced where the sun shines, the wind blows, or the geothermal reservoirs exist. Unfortunately, the most promising concentrations of these resources tend to be found in locations that are fairly remote from large population centers. And in many cases, the infrastructure needed to transmit electricity from resource-rich areas to end-use consumers is inadequate or even non-existent. Transmission capacity thus emerges as a critical barrier to the economic expansion of wind, solar, and geothermal energy production on a large scale.

Increasing transmission capacity where insufficient infrastructure exists is often difficult and expensive—extending the grid to wholly new areas is even more so, especially if doing so entails the construction of long-distance, high-voltage power lines. A first obstacle is cost. To give one example: the U.S. Department of Energy (DOE) has estimated that developing 200–400 gigawatts (GW) of new wind capacity over the next 20 years will require 19,000 miles of transmission lines and grid investments on the order of $60 billion. By comparison, the electric industry's current transmission investments for all purposes, not just to support wind projects, are estimated to average between $7 and $8 billion per year.[54]

As an obstacle to grid expansion, transmission costs are intimately linked to other barriers—such as investment certainty and siting difficulties—discussed in this overview. The result can be a classic 'chicken-vs.-egg' failure of coordination: On the one hand, renewable energy developers will be reluctant to invest in new generating capacity if the transmission infrastructure to deliver their product is lacking; at the same time, investors will be understandably reluctant to finance new transmission lines to locations where new generating capacity may be planned but does not yet exist. This difficulty is compounded by the fact that the benefits of transmission investments are often spread across several different groups with disparate interests, including ratepayers, utilities, local governments, and project developers. The fact that all of these parties have strong incentives to free-ride complicates the ability to recover costs.

In addition to being costly, new transmission investments often face additional obstacles—including opposition from the affected public and a confusion of state and federal siting

[54] Edison Electric Institute. *Actual and Planned Transmission Investment by Shareholder-Owned Electric Companies (2000-2010)*, Retrieved September 21, 2008, http://www.eei.org/common/images/industry_issues/Energy_Data_Alert/bar_Transmission_Investment.jpg.

authorities in the case of interstate transmission lines. Existing line constraints and transmission planning processes may prevent new projects from being built even where some transmission infrastructure already exists. Overcoming these critical barriers requires, among other things, the coordination of transmission projects with renewable energy projects, clarification of cost-recovery rules for new regional transmission projects, and cross-boundary and inter-jurisdictional planning and cooperation—no easy feat by any stretch of the imagination.

Investment Certainty: Government incentives—notably production tax credits (PTC) in the case of wind and geothermal and investment tax credits (ITC) in the case of solar—have played critical roles in promoting renewable energy development in the United States to date. Unfortunately, uncertainty about the long-term continuity of these incentives has also emerged as a serious challenge for the renewable energy industry going forward.

For example, the federal PTC provides qualifying wind projects with an inflation-indexed 2-cent per kilowatt hour (kWh) tax credit over a 10-year period. In recent years the window during which projects could qualify for the PTC has been extended for at most two to three years at a time and on five occasions since 1999 it has expired before being renewed. This uncertainty has created "boom and bust" cycles of growth in the wind industry, slowing deployment and pushing turbine manufacturers to seek offshore markets that offer more certain incentives. When Congress let the program expire in 2000, 2002, and 2004, wind capacity installations in those three years fell 93 percent, 73 percent, and 77 percent, respectively, from the previous year.

Similar uncertainty applies to the PTC for geothermal energy and the ITC for solar power; as a result both industries—like the wind industry—place a high priority on establishing more long-term certainty with respect to key incentive programs. In all cases, the lack of certainty has a disruptive effect in the short term and—by discouraging steady investments and precluding reductions in technology costs—even more deleterious effects in the long run. Uncertainty about the level and availability of future incentives also has secondary impacts on other barriers to renewable energy deployment. For example, by producing "lumpy" growth in demand for these technologies, intermittent incentives may discourage effective long-term planning for complementary investments in transmission and technology R&D.

R&D Support: Continued progress toward developing better conversion and storage technologies is critical to maximizing the long-term economic resource potential of all the major renewable energy options. Work on improved energy storage options is particularly important to address the intermittent nature of wind and solar resources; in the case of geothermal, R&D is needed to develop enhanced or engineered geothermal systems that could produce more electricity at lower cost than conventional systems. Unfortunately, private investment in energy R&D remains incommensurate with the challenges and opportunities at hand, while public R&D support has been inconsistent and generally flat or declining for many technologies.[55] In many cases, the R&D funding authorized by Congress is not matched by later appropriations; in other cases, funding materializes but for political or institutional reasons is not used as effectively as it could be. Without a better track record of sustained and well-managed public investment in energy R&D, the specific technology challenges discussed in later sections of this paper are likely to continue to stand in the way of realizing the nation's full renewable energy potential.

Siting and Permitting: Although public support for renewable energy technologies in the United States is generally very high, local opposition to the siting of specific projects has emerged as a significant issue in a number of high-profile cases. In addition, as we have already noted, siting is a major cross-cutting challenge for the transmission grid enhancements that would be needed to support large-scale deployment of renewable technologies, especially in remote locations. Aesthetic impacts, especially in locations with sensitive view sheds, are often an issue; ecosystem impacts—including impacts on native vegetation and wildlife—are another common source of concern. Wind power, for example, has confronted a number of questions: from the potential for turbines to cause increased bird and bat mortality, to concerns about noise, to—in the case of off-shore developments—the potential for interference with ship traffic. In the case of geothermal power, developers have sometimes encountered opposition based on the misperception that geothermal facilities produce air pollution emissions similar to fossil fuel power plants.

Even where local opposition is less of a factor, permitting delays can present a significant problem, especially for projects sited on public lands. For a brief period in 2008, for example, the Bureau of Land Management put a moratorium on new

[55] Nordhaus, Ted et al. "The Investment Consensus," (Washington, DC: The Breakthrough Institute and The Nathan Cummings Foundation, 2007), 11. http://www.thebreakthrough.org/blog/Investment%20Consensus.pdf.

applications for solar development on public lands, citing environmental concerns. Although, the moratorium was reversed quickly, project delays continue. Similarly, many wind, solar, and geothermal projects have encountered significant permitting delays. To obtain permits, these types of projects must go through all phases of environmental review. Permitting time varies by state, but averages around two years for a utility-scale project. Projects on federal lands have been known to experience long delays on the order of years or even decades. The leasing backlog can be traced back to an insufficient number of trained personnel working to process geothermal applications on public lands and a lack of inter-agency coordination. The United States Forest Service (USFS) must agree to geothermal development before the Bureau of Land Management (BLM) can issue leases, but often the USFS and BLM do not confer. As a result, many geothermal developers have limited their activities to private lands.

Workforce and Resource Constraints: Project costs are rising for all of these technologies, for a number of reasons. One factor is the increased cost of commodities such as concrete, fuel, and steel—this trend obviously affects all types of generation technologies and has impacts beyond the power sector. Another factor in rising costs is the use of more sophisticated component technologies (an example would be the introduction of variable speed turbines that improve the grid performance of wind generators). A third factor is limited competition: as long as the market for renewable technologies is uncertain and characterized by stop-and-start oscillations, relatively few manufacturers will be willing to enter. With relatively few competitors, those manufacturers can raise prices to enhance profitability when demand for renewable technologies is high.

Increasingly, workforce availability is emerging as an issue for renewable energy development. Though a number of educational programs now exist to train personnel to implement wind power projects, the industry continues to suffer from a shortage of skilled and available workers. This problem that is likely to grow more acute if deployment of these technologies accelerates in the future.[56]

Finally, access to ample supplies of water is a potential constraint for geothermal and concentrating solar thermal projects in arid regions. Water is needed to generate steam in concentrating solar thermal systems; water is also a key input in enhanced geothermal projects that inject water below ground to extract the energy stored in subsurface thermal reservoirs.

Remaining sections of this paper provide more detailed information about the resource potential and specific deployment barriers associated with wind, solar, and geothermal power technologies.

Wind Power

Overview: Wind power is one of the fastest-growing forms of renewable energy, both nationally and internationally. Spurred by the federal PTC and state-imposed renewable portfolio standards (RPS), installed wind capacity in the United States has grown rapidly in recent years to a total of nearly 12 GW in 2008.

Investments to date have only begun to tap the nation's vast on-shore and off-shore wind resources. A recent assessment by the Department of Energy suggests that more than 8,000 GW of on-shore wind energy are available at a levelized busbar cost ranging from $70 per megawatt-hour (MWh) to $85 per MWh, depending on wind class.[57] Shallow off-shore wind resources are estimated to total roughly 1,500 GW with levelized busbar costs ranging from $100 per MWh to $130 per MWh.[58] Finally, the nation's deep off-shore wind resources are estimated to total roughly 4,000 GW, with a levelized busbar cost ranging from $130 per MWh to $170 per MWh.[59]

Projections by the American Council on Renewable Energy, a trade association, indicate that the total wind power potential that could be economically developed by 2025 ranges from 37 GW to 248 GW.[60]

Deployment Barriers: As indicated under the foregoing discussion of cross-cutting barriers, transmission capacity and uncertainty regarding the continuity of the federal PTC are key issues for the further development of on-shore wind energy resources in the United States. Siting has also proved difficult for some wind projects—the proposed Cape Wind project off

[56] U.S. Department of Energy, Energy Efficiency and Renewable Energy, *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply* DOE/GO-102008-2567 (Washington, DC: Office of Energy Efficiency and Renewable Energy, 2008), 73.

[57] U.S. Department of Energy, Energy Efficiency and Renewable Energy, *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply* DOE/GO-102008-2567 (Washington, DC: Office of Energy Efficiency and Renewable Energy, 2008), 149.

[58] Ibid, 150, Fig. A-2.

[59] Ibid.

[60] American Council on Renewable Energy. "The Outlook on Renewable Energy in America Volume II: Joint Summary Report," March, 2007, 7.

the coast of Massachusetts being perhaps the most notorious example of how concerted public opposition (much of it, in this case, motivated by aesthetic concerns) can delay construction. Finally, higher prices and the reduced availability of many raw materials such as steel have increased costs for wind projects.

In addition, uncertain regulatory authority is emerging as a major barrier to the development of off-shore wind resources. Permitting authority for offshore wind projects has been inconsistent—a problem that lawmakers sought to remedy in the 2005 Energy Policy Act which transferred permitting authority for offshore wind projects from the U.S. Army Corps of Engineers to the U.S. Minerals Management Service (MMS). MMS has a great deal of experience in permitting oil and gas projects, but has comparatively little experience permitting wind projects.

Technology Challenges: The variability of the wind resource is a disadvantage in competing with other types of generators that can supply energy on demand. Because wind power is available only when the wind blows, the capacity value of wind generators—that is, the amount they can be assumed to run and actually generate electricity expressed as a fraction of their theoretical output if they ran continuously at their maximum nameplate rating—is typically between 30 and 40 percent.[61] As a result, wind turbines (unless they are paired with back-up generators) cannot count toward total system capacity requirements—which are usually set on the basis of expected peak load—in the same way that conventional generators do. The intermittent nature and higher variability of wind power therefore requires careful regional planning and cooperation to maintain desired levels of grid stability and reliability.

There are a number of other grid integration issues associated with increased wind penetration, which include increased demand uncertainty, frequency control problems, reactive power supply issues, and maintaining adequate voltage support. According to the Utility Wind Integration Group, at penetrations of up to 20 percent of system peak demand, wind variability (which results in fluctuations in net load) can increase system-wide operating costs by as much as $5 per MWh, or approximately 10 percent of the wholesale value of wind energy.[62] The primary driver of this additional cost is the uncertainty of day-ahead wind forecasts, which increase the uncertainty of day-ahead unit commitments. State-of-the-art forecasting can reduce day-ahead uncertainty and associated costs, but is not widely used.[63]

A related technical barrier is the lack of a commercialized technology for storing wind energy. One particularly promising option at present appears to be compressed air storage: when available, excess wind power would be used to compress air, which would be stored in an airtight underground cavern. The compressed air could be used at a later point in time to generate electricity on demand. Compressed air and other energy storage options have the potential to reduce or eliminate the disadvantages associated with intermittent renewable resources like wind and solar energy along with the grid management challenges that this intermittency creates. The successful implementation of cost-effective storage technologies would not only increase the capacity factor of wind generators, but it would also enable wind to function as a baseload source of power and more generally play a greater role in meeting overall electricity needs.

Solar Power

Overview: Solar power systems harness energy from the sun, converting either light (photovoltaic) or heat (thermal) energy to electricity. The three most common technologies are solar photovoltaic (PV), solar thermal, and concentrating solar power (CSP). This section will discuss barriers to CSP and grid-connected PV, as well as storage options applicable to both types of technologies.

Photovoltaic cells convert light directly into electricity and are usually made from silicon. The most common type of solar cell is made from a wafer of crystalline silicon; solar cells can also be made using a thin film of amorphous silicon. The latter technology requires significantly less silicon and has the potential to substantially reduce manufacturing costs, but it remains for now less efficient at converting light to electricity.

Concentrating solar power (CSP) systems can include concentrating solar thermal (CST) systems and concentrating solar photovoltaic (CPV) systems. CST systems use lenses or mirrors and tracking systems to focus a large area of solar radiation into a small beam. These systems produce high temperatures which are then used to create steam that can be used to generate electricity. Since these systems concentrate

[61] U.S. Department of Energy, Energy Efficiency and Renewable Energy, *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply* DOE/GO-102008-2567 (Washington, DC: Office of Energy Efficiency and Renewable Energy, 2008), 88, Tab. 4-2.

[62] Utility Wind Integration Group, "Utility Wind Integration State of the Art, 2006, 3.

[63] Ibid, 3.

heat, it is possible to store the heat before it is converted into electricity for later use, such as generating power at night or on cloudy days. CPV systems use optical concentrators to focus solar radiation onto solar cells for conversion into electricity.

Recent years have seen extremely rapid growth in the deployment of solar technology worldwide: over the period 2000–2005, global installed solar capacity grew at a compound annual growth rate of 47 percent.[64] To date, solar PV technology has been most successful as a distributed generation technology.

Deployment Barriers: High up-front capital costs represent a major deployment hurdle for solar power technologies, which remain at present significantly more expensive than competing fossil-fuel technologies. While the overnight capital cost for one megawatt of natural gas combined-cycle generating capacity is in the range of $1–$2 million, the per megawatt capital costs for CSP and solar PV are estimated to range from $3 to $4 million and $5 to $7 million respectively.[65] Unlike conventional fossil fuel derived power, solar PV and CSP have no fuel costs. Despite this advantage in operating costs and despite a dramatic decline in solar capital costs over the past decade, total system costs for solar power still typically exceed the costs of non-renewable options. At present, concentrating thermal solar technologies offer the lowest-cost option for utility-scale solar power generation at 10 MW or above, with costs for some very large concentrating systems approaching parity with fossil-generated power.[66, 67]

All of the cross-cutting deployment barriers discussed in foregoing sections with respect to transmission capacity, investment certainty, R&D support, and siting and permitting apply to the major large-scale solar energy options. Concerns have been raised, for example, about solar power development in the western and southwestern United States in terms of impacts on public lands (including, for example, concerns about the desert tortoise and Mojave ground squirrel in California), plans for site reclamation after a facility is retired, and the potential for added strains on an already congested transmission network.[68]

Moreover, the PV industry faced production constraints in 2008 related to the supply of polysilicon, a key component of photovoltaic systems. These constraints limited new PV shipments in late 2008 and remain a risk to expanded PV production. In fact, 2007 was the first year that the solar PV industry used more silicon than the semiconductor industry, a historic shift that exacerbated the worldwide shortage of silicon. Silicon producers have been slow to expand production to meet demand from the solar industry due to lingering concerns about the overcapacity that decimated the industry following the technology bust of 2001. Even if the current shortage eases within the next several years, continued rapid growth in PV production could result in future supply problems. Silicon prices jumped from $25 per kilogram in 2001 to $250 per kilogram in 2008.[69]

Technology Challenges: Solar energy faces some of the same intermittency problems already discussed with respect to wind power. Though storage technologies exist for solar power systems, stored solar energy is generally used at night, when it must compete with typically less expensive power from baseload conventional power plants. As a result, most storage options are designed to supply electricity in markets where peak demand and peak output from solar power plants differ by a few hours. The most promising utility-scale storage technologies are applicable to concentrating solar thermal systems and include heat storage options such as underground steam storage, molten salt, and hot water.[70] Even given the increased reliability of solar systems when they are paired with storage technologies, cost competitiveness remains a key issue.

In addition, many currently available storage technologies have prohibitive or limiting shortcomings with respect to

[64] Frantzis, Lisa and Paula Mints, "PV Economics and Markets," February 15, 2006, 5, Presentation to the American Bar Association, http://www.abanet.org/environ/committees/renewableenergy/teleconarchives/021506/2-15-06Navigant.pdf.

[65] Pernick, Ron and Clint Wilder, "Utility Solar Assessment (USA) Study: Reaching Ten Percent Solar by 2025," (Washington, DC: Clean Edge Inc. and Co-op America Foundation, June 2008), 19, http://www.solarcatalyst.com/utilitysolarstudy.pdf.

[66] Pernick, Ron and Clint Wilder, "Utility Solar Assessment (USA) Study: Reaching Ten Percent Solar by 2025," (Washington, DC: Clean Edge Inc. and Co-op America Foundation, June 2008), 40, http://www.solarcatalyst.com/utilitysolarstudy.pdf.

[67] Sandia National Lab, "CSP Technologies Overview," http://www.energylan.sandia.gov/sunlab/overview.htm#business.

[68] Concerns about site reclamation took on new prominence when BLM cited this issue as one of the main reasons for its recent moratorium on accepting new permit applications for solar power plants on federal lands. Although the moratorium was lifted shortly after it was announced, concerns about site reclamation may remain.

[69] The Economist, "Silicon Rally," 4/28/2008. http://www.economist.com/business/displaystory.cfm?story_id=12010071.

[70] Pernick, Ron and Clint Wilder, "Utility Solar Assessment (USA) Study: Reaching Ten Percent Solar by 2025," (Washington, DC: Clean Edge Inc. and Co-op America Foundation, June 2008), 62, http://www.solarcatalyst.com/utilitysolarstudy.pdf.

the duration of time that they are capable of operating, the efficiency of system components, the ability to operate on a large scale, and the supply or cost of the raw materials and structural components used to create storage capacity. Thus there is a need for further improvement in all storage-related components of solar power systems, including batteries, hydrolizers, and inverters.

Technology barriers specific to concentrating solar power installations include the need for advanced receiver designs, the need for improved heat transfer fluids, and a general need for more R&D funding. New thin-film PV technologies, such as cadmium telluride and nano solar production processes, confront a number of unique technical barriers pertaining to conversion efficiency. If these barriers can be overcome, thin-film production processes have the potential to become significantly more cost competitive.

Geothermal Power

Overview: In very simple terms, geothermal power systems tap the Earth's interior heat to generate electricity. Most geothermal installations in the United States exploit existing hydrothermal systems, where hot water or steam has naturally collected in an underground reservoir. Enhanced geothermal systems represent a more recent technological development: such systems use engineering to enhance the energy-producing potential of natural subsurface thermal reservoirs. The enhancement could be modest, such as widening existing pores in the rock so as to better access trapped water or steam. Alternatively, the engineering intervention could be more radical, such as drilling deep wells into hot rock and injecting water to create a new hydrothermal reservoir where none existed before.

In existing commercial geothermal systems that use natural accumulations of geothermal fluid, the fluid is usually a hot, sometimes salty, mineral-rich liquid or vapor. Typically it is withdrawn from underground and then used to turn a turbine-generator and create electricity. Condensed steam is then injected back into the reservoir. Other types of systems have been proposed, but only hydrothermal systems are being commercially deployed today. Geothermal power plants are structured similarly to traditional power plants and can provide baseload generation. Approximately 2.8 GW of geothermal electric capacity has been developed in the United States; globally, geothermal capacity totals approximately 9 GW.[71, 72] In 1979 the U.S. Geological Survey (USGS) estimated that while the identified geothermal resource base may support as much as 22,000 MW of potential generating capacity, the unidentified resource base could total 100,000MW or more—these figures, obviously, are quite dated.[73, 74] At present, commercialized geothermal systems are quite competitive with fossil generation, with busbar costs ranging from $41 to $75 per MWh.[75, 76, 77]

As noted, a potential future application of geothermal energy is EGS, or enhanced geothermal systems (sometimes referred to as engineered geothermal systems), which are defined by DOE as "rock fracturing, water injection, and water circulation technologies to sweep heat from the unproductive areas of existing geothermal fields or new fields lacking sufficient production capacity."[78] Enhanced systems function like conventional hydrothermal systems, but the subsurface characteristics of the reservoir are enhanced or engineered to create a hydrothermal environment. Thus EGS systems involve manually injecting fluid, rather than relying on a natural accumulation of hot water or steam. Essentially, they require only a supply of heat and water—fluid is injected and circulated into the system, and the fractures or reservoirs are artificially created.

For purposes of this discussion we focus on hydrothermal and EGS applications: hydrothermal because it is commercially deployed today and EGS because it has the most significant potential for large-scale deployment in the future. Up until September 2008, the magnitude of geothermal energy potential remained uncertain, however, because of a lack of adequate, up-to-date information on the geothermal resource base in the United States. Until then, the USGS figures cited previously were three decades old. However, in September 2008 the USGS released a long-awaited assessment

[71] American Council on Renewable Energy. "The Outlook on Renewable Energy in America," January, 2007, 38.

[72] International Geothermal Association, "Installed Generating Capacity." Retrieved September 21, 2008 from http://iga.igg.cnr.it/geoworld/geoworld.php?sub=elgen.

[73] U.S. Geological Survey Circular 790, 1979, 41, Tab.

[74] American Council on Renewable Energy. "The Outlook on Renewable Energy in America," January, 2007, 41.

[75] Renewable Northwest Project, "Geothermal Energy Tehcnology," http://www.rnp.org/RenewTech/tech_geo.html.

[76] Sanyal, S. "Levelized Cost of Geothermal Power—How Sensitive Is It?" GeothermEx, Inc. http://www.geothermex.com/files/Sanyal_2005-8.pdf.

[77] Oregon Geothermal Working Group, "Geothermal Energy—Meeting Changing Demands and Supply," 7, http://www.oregon.gov/ENERGY/RENEW/Geothermal/docs/OGWG8_PGE.pdf.

[78] U.S. Department of Energy Geothermal Glossary. Retrieved September 21, 2008 from http://www1.eere.energy.gov/geothermal/glossary.html#e.

of geothermal resources in the U.S. The new assessment focused largely on the western United States and found that the U.S. has over 9 GW of power generation potential from already-identified, conventional geothermal systems; 30 GW from conventional but undiscovered geothermal resources; and over 500 GWs from unconventional EGS resources.[79]

Deployment Barriers: As with the other renewable technologies discussed here, investment certainty—and certainty about the future availability of the federal PTC in particular—is extremely important to the geothermal industry. Because geothermal projects typically take longer to bring online than other renewable power technologies—around three to five years for conventional hydrothermal systems—the industry sees a major problem, not only in the intermittency of the PTC, but also in that program's placed-in-service requirements, which specify the date by which a facility must be producing electricity if it is to qualify for the ten-year PTC.

The PTC is important because, as with other renewable energy options, cost remains a major barrier for new geothermal systems. EGS holds promise, but the need to inject water for these systems also increases their upfront costs. Drilling is often a major component of overall cost, especially for EGS sites where the drilling environment includes less porous rock and, in many cases, requires deeper drilling. Likewise, well costs for hydrothermal projects are often high, and can be expected to be so for enhanced systems as well. In fact, well costs can easily comprise 60 percent or more of total capital costs in certain cases. Although these costs can be reduced with improved, more efficient well technologies, they are likely to remain prohibitive for many projects. Cost barriers are often further compounded by project risk, especially where sites are not well characterized.

Other significant barriers to geothermal expansion include transmission constraints, especially to reach remote sites; delays developing geothermal facilities on public lands; and (as already noted) inadequate resource assessments by the USGS. Geothermal technology—perhaps to an even greater extent than other low-carbon technologies—is plagued by inadequate levels of federal R&D funding. The DOE recently increased its EGS commitment to $90 million over three years. If this amount is appropriated, and if similar amounts are made available in subsequent years, the budget for this program over five years would total $450 million—not insignificant, but short of the $600–$800 million estimated to be needed to achieve large-scale deployment, according to a recent study conducted by MIT.[80] A further contrast with solar and wind power is that geothermal technology does not enjoy the same level of general public support, or even awareness. Many people simply don't know what geothermal energy is or, if they do know, assume that this resource has already been fully exploited. Because almost every new geothermal facility must withstand public scrutiny in order to be brought online, public awareness and education about geothermal energy is crucial.

Finally, the drilling rigs needed to develop geothermal sites are in high demand and are not always available. In fact, geothermal developers must often compete with oil and gas developers, who typically are better funded and are working on larger projects, for access to drilling rigs; these rigs must usually be ordered ahead of time and can delay projects if they are not ordered with sufficient lead time. As with other types of projects, the current high cost of raw materials, especially for steel, can add significant cost to the drilling stage of geothermal well development. Finally, in addition to raw materials and improved technology, human expertise is needed to successfully locate and implement geothermal projects. The geothermal industry faces a lack of skilled personnel and an aging workforce. To sustain itself and grow, it needs a younger generation of engineers and developers. This need exists on every level, from researchers to operators to maintenance technicians.

Technology Challenges: Although conventional hydrothermal systems have been commercially deployed, EGS technology has not been commercialized. There are several technology hurdles that must be overcome in order to bring EGS costs down. Overcoming many of these hurdles will also lower costs for conventional hydrothermal projects. For example, developers do not fully understand many technical aspects of reservoir characteristics. Wells must be drilled to significant depths for EGS (around 30,000 feet), which can be challenging and costly. Well flow rates are not ideal, and well design changes are needed. Today's wells are not designed to deal optimally with hard rock formations that are typical of EGS systems. Well diameters and production intervals—the amount of time it takes for liquid to flow through the system—may need to be considered on a site-specific basis, which tends to increase costs and creates general project uncertainty. In this context,

[79] USGS: http://pubs.usgs.gov/fs/2008/3082/.

[80] Tester, Jefferson W et al. "The Future of Geothermal Energy—Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century," (Paper, MIT Department of Chemical Engineering, 2007), 1-6, http://web.mit.edu/newsoffice/2007/geothermal.html.

technology priorities include improving the success rate and reducing the drilling costs associated with EGS systems. Additionally, there is a need for better "down-hole" tools that can measure temperature, pressure, and flow rate, and function optimally within high temperature wells.

Finally, concerns have been voiced that geothermal power plants could potentially emit harmful chemicals contained in the hydrothermal fluid. While it is true that these natural fluids often consist of complex chemical mixtures, which in some cases contain potentially hazardous elements such as mercury, the fact that these fluids are usually injected back into the producing reservoir should help alleviate the risk of contamination.[81]

[81] Sterret, F.S. "Alternative Fuels and the Environment," CRC Press, 1995, Chapter 2.

Appendix IV: Barriers to Advanced Nuclear Energy Deployment

Introduction

Nuclear power is an existing low-carbon technology option for generating large quantities of baseload electricity. At present, there are 104 operating nuclear power units in the United States with an aggregate electric-generating capacity of 100 gigawatts (GW). These plants produce roughly 20 percent of total electricity and nearly 70 percent of all zero-carbon electricity generated in the United States.[82] However, the current nuclear fleet is aging. The U.S. nuclear power industry has not received a new construction and operating license since 1979 and has not constructed a new plant since 1996. Amid projections of growing electricity demand and increasing concern about global climate change, nuclear power generation has attracted renewed interest. A majority of U.S. nuclear plants have received or applied for extensions to their initial 40-year operating licenses.[83] However, efforts to build new nuclear capacity have stagnated due to a number of barriers. Although the nuclear power industry has been operating commercially for more than 50 years, there remain regulatory, economic, technical, infrastructural, and social obstacles to building the next generation of new nuclear plants.

Recent policy initiatives, particularly the Energy Policy Act of 2005 (EPAct05), have provided a range of incentives aimed at jumpstarting the construction of new nuclear power plants. Notably, EPAct05 extended the Price-Anderson Act through 2025,[84] included a 1.8 cent-per-kilowatt-hour tax credit, and established a loan guarantee program for new energy technologies.[85] In addition, the Nuclear Regulatory Commission (NRC), which is the body responsible for licensing and regulating commercial nuclear power plants, has streamlined its licensing and construction permitting processes. Yet despite these recent initiatives, barriers to a new wave of nuclear plant construction remain formidable. NCEP's original 2004 report (*Ending the Energy Stalemate*) and its subsequent 2006 staff paper (*Siting Critical Energy Infrastructure*) address some of these barriers and advance several policy recommendations. This section further details the most important remaining technology-specific barriers, including financing, licensing, permitting and siting, operation constraints, and research and development avenues.

Financing: Building a nuclear power plant is a large, capital-intensive project. High up-front capital costs—as much as several billion dollars for a single plant—present perhaps the most significant barrier to further nuclear development. Licensing and construction times for new plants are often long, which means that project timelines can be exceeded by several years and substantial cost overruns can occur. Such conditions create significant financial risks, especially relative to the market value of the utility companies that would seek to build new nuclear plants. Because the market capitalization of utility companies is low relative to the capital investment required to construct a new nuclear plant, many companies are reluctant to undertake new plant construction without federal assistance.

The next generation of plants for which design certification and licensing are being pursued in the United States are larger than 1,000 MW and are expected to cost between $6 and $8 billion each.[86] The risks associated with financial commitments of this magnitude are compounded by a lack of recent construction experience and volatile commodity prices, both of which contribute to significant uncertainty about total costs. Because the capital requirements for a new nuclear plant are so large and highly uncertain, the challenge of financing the first several new plants may only be slightly eased by current federal support mechanisms—in particular, the Department of Energy's (DOE's) Loan Guarantee Program. Without federal support, financiers may be quick to delay or cancel construction, heavily penalizing first-adopters. To help address these financial risks, Title XVII of EPAct05 authorized $18.5 billion in loan guarantees for nuclear facility development. Currently, the DOE has applications for $93.2 billion in loan guarantees from ten electric power companies to support the construction of sixteen nuclear power plants. Yet, the existing authorization will likely only support two or three "first movers." Without

[82] Nuclear Regulatory Commission: http://www.nrc.gov/reactors/power.html Accessed June 9, 2009.

[83] As of March 2009, 52 of 104 units had received extensions and applications for 20 additional units were under review. United States Nuclear Regulatory Commission. Semiannual Status Report on the Licensing Activities and Regulatory Duties of the United States Nuclear Regularity Commission. October 2008-March 2009.

[84] The Price-Anderson Act provides indemnification insurance in the event of a nuclear or radiological incident. Currently, nearly $10 billion is available to compensate affected members of the public.

[85] http://www.eia.doe.gov/oiaf/aeo/otheranalysis/epact2005.html.

[86] 2008 dollars. Nuclear Energy Institute. Financing New Nuclear Power Plants. January 2009.

such guarantees, uncertainty about high capital costs and other construction risks may pose significant challenges to financing additional plants.

- **Advanced Nuclear Reactor Capital Cost Estimates:** Estimates of the capital cost of a new nuclear power plant are subject to large uncertainties, with recent estimates of overnight capital cost ranging from $3,000 to $5,000 per kilowatt of capacity.[87] Considering that most of the Combined Operating License applications submitted to the NRC in recent years reference 1.1 to 1.7 GW reactor designs, the total overnight cost of a new nuclear power plant is estimated to range from roughly $3.3 billion to $8.5 billion. Unanticipated cost overruns during the permitting and construction phases can, however, increase the total capital cost by upwards of 175 percent of the overnight capital cost. In fact, cost overruns for the 75 nuclear power plants built between 1965 and 1986 averaged 207 percent of initial cost estimates.[88]

- **Commodity and Material Costs**: An additional cost concern stems from the recent, rapid price inflation of most electricity generation components, paralleling the surge in demand for new capacity. Between 2003 and 2008, the producer price index (PPI) for electric power generation grew by 45 percent.[89] To put this in perspective, a new nuclear power plant costing roughly $2.75 billion in 2003 would cost nearly $4 billion in 2008. Because nuclear power plants are capital intensive, this potential for a rapid inflation of costs (or deflation in the case of the current global recession) adds uncertainty to the long-term return, and creates a difficult financing environment, especially when potential investors are relatively risk averse.

Licensing, Permitting, and Siting: All the nuclear power plants currently operating in the United States were licensed under a two-step process that required both a construction permit and an operating license. However, in 1989, the NRC adopted a new licensing procedure under Title 10 of the Code of Federal Regulations Part 52: Licenses, Certifications, and Approvals for Nuclear Power Plants. The intent was to create a more stable, efficient, and predictable licensing process for new nuclear power plants.[90] The prior regulatory framework required applicants to obtain a construction permit separate from, and prior to submitting, an application for an operating license. The inefficiency and financial uncertainty introduced by this two-step process created situations where utilities had to pay interest on construction loans while earning no revenue from electricity production and sales. Under Part 52 the licensing process was restructured to include early site permits (ESP), design certification, and combined construction and operating licenses (COL). Although no proposed power plant has yet completed this modified licensing process, the NRC has certified four Generation III reactor designs, approved three ESPs, and is reviewing seventeen COLs. Though many projects are in the pipeline, no nuclear power plant has been fully certified using the Part 52 process and none are expected to be certified until 2011. Therefore, it is too early to determine what improvement, if any, in stability, efficiency, and predictability has been realized under Part 52 in the licensing process for new nuclear power plants.

Siting challenges are especially significant for nuclear waste storage facilities. Most stakeholders agree that the lack of a long-term waste repository in the United States is not a major barrier to near-term expansion of nuclear power capacity. In its updated 2007 recommendations, NCEP noted that spent nuclear fuel can be (and, in fact, is being) safely managed with currently licensed and regulated technology, including on-site, dry cask storage. However, the inability to permit and site one or more permanent storage facilities may hinder large-scale expansion in the long-term. In particular, the uncertain future of the Yucca Mountain repository has raised serious questions about the federal government's national strategy for waste management, though it does not—in and of itself—prevent the construction of new nuclear plants.[91] Public opposition and NIMBYism may prove similarly problematic for the development of interim regional storage facilities.

[87] http://web.mit.edu/nuclearpower/pdf/nuclearpower-update2009.pdf Accessed July, 1 2009; http://www.eia.doe.gov/oiaf/aeo/assumption/electricity.html Accessed July, 1 2009.

[88] Congressional Budget Office (CBO) based on data from Energy Information Administration, An Analysis of Nuclear Power Plant Construction Costs, Technical Report DOE/EIA-0485 (January 1, 1986).

[89] Bureau of Labor Statistics http://data.bls.gov/PDQ/servlet/SurveyOutputServlet;jsessionid=f030d7c55aa1$3F3$3F$ Accessed June 19, 2009toward nuclear waste disposal.

[90] Diaz, Niles J. 2005 "Concerning Nuclear Power 2010 Initiative—New Nuclear Power Generation in the United States" Testimony before the Committee on Energy and National Resources united States Senate April 26, 2005 http://energy.senate.gov/hearings/testimony.cfm?id=1476&wit_id=570 Accessed June 15, 2009.

[91] The development of the Yucca Mountain repository has stalled since the DOE submitted a license application to the NRC in June 2008. President Obama's FY2010 budget scales back DOE funding to cover only those costs necessary to answer inquiries from the NRC while the Administration devises a new strategy toward nuclear waste disposal.

Workforce and Resource Constraints

Workforce: The nuclear industry, like the energy sector as a whole, faces considerable workforce shortages related to plant construction and operation as well as component manufacturing. The Nuclear Energy Institute conducted a 2007 nuclear work force survey that pointed to a rapidly aging workforce and high future demand for qualified workers. The survey found that 25 percent of current nuclear utility employees will be eligible to retire by 2012 and that roughly 25 percent of the workforce within the vendor community will be eligible for retirement in the same timeframe.[92] For each new nuclear power plant constructed in the future, NEI anticipates demand for between 1,400 and 1,800 workers, including skilled craftsmen. Areas of particular concern with respect to the workforce needs of the nuclear power industry include a shortage of qualified nuclear engineers and manufacturing capacity for component fabrication. The American Physical Society has noted a dramatic decline in the number of advanced nuclear science and engineering degrees earned at U.S. universities, largely due to the limited number of universities with active research programs.[93] Although the number of nuclear-related degrees conferred is rising, the safe and reliable operation of nuclear power plants requires an experienced workforce and the effective transfer of institutional knowledge.[94]

Raw materials/fuel costs: Uranium production and processing capacity is not anticipated to be a significant barrier to the deployment of a next generation of nuclear power plants due to the relative abundance of uranium reserves and the small impact that fluctuations in uranium price typically have on the cost of electricity generated by nuclear power plants.

Supply Chain Constraints and Long Lead times: There is a limited supply chain for nuclear components that may constrain future construction of nuclear reactors. It is often pointed out, for example, that Japan Steel is the only company in the world that fabricates nuclear steam supply system components. But Japan Steel only has the capacity to produce components for a handful of plants a year. Because the United States has had no recent construction experience with new nuclear reactors, it remains to be seen how significant these supply chain constraints might be. Much depends on the rate of nuclear construction globally, and on the overall level of demand for general commodities and components necessary to build all types of electric sector infrastructure.

Proliferation Concerns

Concerns about proliferation and about the security of nuclear materials are not likely to emerge as a major barrier to the deployment of next-generation nuclear power plants in the United States. However, the United States has an opportunity to provide international leadership in developing technology options to address global proliferation concerns. Advanced reactor and fuel cycle R&D initiatives should continue to explore opportunities to minimize proliferation risks.

Research and Development

Nuclear Power 2010: The key risks associated with constructing a nuclear power plant—including risks associated with applying a new generation of technology, uncertain construction lead times and capital costs, and long-payback periods—are further compounded by an uncertain regulatory framework. Recent DOE initiatives, including the Nuclear Power 2010 program, are intended to support the industry and the NRC during the first few rounds of licensing proceedings for new plants in order to test the revamped licensing process.

Waste Management: While advanced fuel cycles may not be cost-effective with current technology, the topic of waste management offers fertile ground for R&D. NCEP has recommended that the United States invest in R&D on waste recycling or reprocessing techniques that reduce the volume, heat, and toxicity of nuclear wastes without intensifying proliferation concerns. In January 2010, the Administration announced a new blue ribbon panel to address a range of nuclear waste issues, including not only the future of the Yucca Mountain repository, but also other efforts to evaluate reprocessing techniques and assess alternative waste management strategies. A robust R&D program to explore technological alternatives to the once-through fuel cycle and direct geologic waste disposal would help to inform the country's future waste strategy.

Advanced Reactor Technology: The next wave of reactors likely to be built in the United States would probably utilize so-called Gen III and Gen III+ technology, which represents

[92] Berrigan, Carol L. Director, Industry Infrastructure, Nuclear Energy Institute. Testimony before the U.S. Senate Committee on Energy and Natural Resources. November 6, 2007.

[93] http://www.aps.org/units/fps/newsletters/200901/mtingwa.cfm.

[94] IAEA "The Nuclear power Industry's Aging Workforce: Transfer of knowledge to the Next Generation" June 2004.

an incrementally evolutionary step forward from the pressurized water reactors (PWRs) and boiling water reactors (BWRs) currently in operation. However, R&D efforts can continue to be directed to more advanced reactor designs (Gen IV) that have potential to further reduce capital and operating costs, improve fuel efficiency, and minimize the risk of proliferation. Current Gen IV reactor concepts involve the utilization of recycled reactor fuel, modular construction, and hydrogen production.[95]

[95] Department of Energy. Office of Nuclear Energy, Science, and Technology.

Appendix V: Barriers to Advanced Low-Carbon Vehicle Technologies

Introduction

There are three basic ways to reduce greenhouse gas (GHG) emissions from transportation sources: (1) reduce "vehicle miles traveled" (VMT), (2) improve vehicle fuel efficiency, or (3) replace carbon-rich fuels with low- or no-carbon alternatives. All of these approaches will be critically important in reducing the ultimate carbon impact of vehicles. For reasons outlined below, however, only the replacement of carbon-rich fuels offers the opportunity to truly transform the transportation sector's long-term emissions profile.

Reducing travel demand is possible, but dramatic GHG reductions from strategies designed to impact VMT are unlikely for several reasons. Not only does our current infrastructure lock people into certain travel patterns with few alternatives to choose from, but population trends suggest that baseline transportation activity will continue to grow for the foreseeable future. Therefore, reducing VMT is not likely to play a dominant role in achieving climate-related objectives in the transportation sector. Improving vehicle efficiency is perhaps a more straightforward mechanism for reducing GHG emissions, since efficiency changes directly alter the amount of fuel used and carbon emissions generated for any given level of travel. When viewed in the context of current and possible future VMT levels, however, and when considering the technical possibilities offered by efficiency improvements in fossil-fuel based engines, it is clear that continued reliance on vehicle efficiency improvements will also not be sufficient to reach likely GHG reduction targets.

The key to a de-carbonized transportation sector is the replacement of the current portfolio of carbon-rich petroleum-based transportation fuels with low- or no-carbon alternatives. This paper focuses on the issues associated with moving toward transformative vehicle technology platforms: namely electricity- and hydrogen-fueled vehicles.

- **Electricity**: The widespread use of electricity as a vehicle fuel would open the transportation sector to a diverse range of energy sources, all producing a fungible form of energy over a common and generally pre-existing distribution network. While significant hurdles would need to be overcome and while the net carbon benefit of this approach would depend on how the electricity used to charge electric vehicles is produced and distributed, there are several reasons to believe that an electricity platform can support a low-carbon transportation network. Moreover, the successful commercialization of hybrid-electric vehicles (HEVs) points to a promising option for bridging the gap between a petroleum-dominated present and an electric future.

- **Hydrogen**: Although hydrogen faces considerable barriers, it also holds transformative potential as a transportation fuel. As the most abundant substance in the universe, sources of hydrogen are virtually unlimited. Hydrogen normally exists in compound form with other elements and must be liberated from those other elements to tap its energy potential, but the production of hydrogen can be powered by any number of other energy sources. Once isolated, hydrogen has high energy content on a mass basis. Because it is a gas, however, it must be stored at greater density—either as a compressed gas or liquid—to be practical as a fuel for vehicles. Emerging technologies show promise for developing safe, reliable hydrogen-powered cars with attributes equivalent to those of conventional vehicles.

As part of a low-carbon transformation of the transport sector, hydrogen fuel would have to be produced in a manner that minimizes carbon emissions. A critical issue is whether the overall energy balance associated with hydrogen production, distribution, and storage can be competitive with the energy required to extract, transport, refine, distribute, and store petroleum-based fuels. This represents a formidable challenge, but nonetheless merits closer evaluation given the low-carbon potential of hydrogen.

This appendix outlines the most pressing challenges facing the commercialization, integration, and scale-up of electric and hydrogen vehicle technology platforms over the next several decades.

Common Barriers for Electric and Hydrogen Vehicles

Policy: Historically, with the exception of California and at least eleven other states that have moved to adopt California's program for light-duty vehicles, emissions of GHGs (including

CO_2) from transportation vehicles and equipment have not been directly regulated. Fuel economy standards can only be viewed as a proxy for CO_2 emission standards when all, or nearly all, vehicles operate on the same petroleum-based fuels. In the past, fuel economy requirements did not treat a gallon of high-carbon fuel differently than a gallon of low-carbon fuel, so that a vehicle getting 50 mpg on a low-carbon fuel has had no advantage (from a fuel economy standpoint) over a 50 mpg gasoline or diesel vehicle. An actual CO_2 (or GHG) standard is needed to create an incentive for vehicle and equipment manufacturers to move to low-carbon fuels. In an attempt to address this need, the Obama Administration in 2009 issued a proposed joint rulemaking for the Department of Transportation (DOT) and the Environmental Protection Agency (EPA) to administer a coordinated federal GHG and fuel economy program. If finalized, these standards would apply to passenger cars, light-duty trucks, and medium-duty passenger vehicles built in model years 2012 through 2016.[96]

Economics: Until recently, the relatively low price of petroleum combined with the lack of any financial cost for carbon emissions has resulted in limited investment in low-carbon fuels and technologies for vehicles and equipment. The recent introduction of GHG (or CO_2) emission standards for light duty vehicles in both California and the European Union, along with a sharp run-up in petroleum prices have generated increased interest in low-carbon technology. Nevertheless, cost issues remain a significant hurdle due to the relative infancy and small scale of the low-carbon vehicle and equipment market.

Social Issues: Consumers can be expected to adopt new vehicle technologies only if the performance of these technologies with respect to safety, range, performance, and familiarity is similar to, or better than, that of existing technologies. Because both electric and hydrogen vehicles face challenges and misconceptions in meeting these expectations, issues of consumer acceptance merit more in-depth discussion as part of an exploration of the deployment hurdles that confront each technology.

Infrastructure: Both electric and hydrogen vehicles face significant infrastructure hurdles with respect to energy production, distribution, and refueling stations/integration. These challenges are discussed further in the next section.

Barriers to Electric Vehicle Technology

Technology: While electric drive systems consist of more than energy storage systems—other key components include the motor, transmission, and control electronics—energy storage represents the primary technology hurdle for plug-in hybrid electric vehicles (PHEVs) and electric-only vehicles. It is the cost-effectiveness of energy storage that dictates the cost-effectiveness of an electricity-powered vehicle platform. To date, it has not been possible to use available energy storage technologies—like batteries, ultracapacitors, and flywheels—to cost-effectively store sufficient amounts of onboard energy to compete with internal combustion engine vehicles. In addition to cost, available storage systems face range and charge-time challenges.

As mentioned, HEVs can and are serving as a bridge between traditional internal combustion engine (ICE) vehicles and PHEV and all-electric vehicles. PHEVs, as the next generation of transitional technology, will allow for both off-board electrical energy system recharge and limited electric-only operation. The technology improvements that are making PHEVs viable also hold promise in advancing the development of electric-only vehicles that have the potential to be suitable for mass market deployment.

The widespread application of electric-only technology is generally limited by battery cost and associated issues of battery range, recharging, and durability. Lithium ion batteries have demonstrated the potential to provide electric-only vehicles with conventional vehicle performance for up to roughly 200 miles of operation. But while a 200-mile driving range is substantial, it is still only about half the typical driving range of a conventional vehicle. PHEV technology can play an important role in bridging this performance gap—in fact, both lithium ion and nickel metal hydride (NiMH) batteries (the technology currently used in HEV applications) have demonstrated the potential for PHEV electric-only performance for up to 40 miles. From a cost standpoint, of course, PHEVs incur the burden of both electric and internal combustion propulsion systems. Conversely, electric-only vehicles can accrue significant cost savings due to the ability to completely eliminate the traditional internal combustion engine and its myriad associated support systems. On the other hand, they incur significantly higher battery costs.

[96] Additionally, under EPA's proposed fuel economy rule, fuel economy credits are available to manufacturers who produce alternative fuel vehicles or other advanced platforms, such as electric and plug-in hybrid vehicles.

The bottom line is that the technologies needed to support electric-only operational capabilities for all or part of an average vehicle trip are currently available. However, continuing breakthroughs are important to (1) improve battery durability and (2) increase energy density and power density to allow for greater driving range and greater peak output. This could include potential developments in alternative energy storage systems such as ultracapacitors and flywheel systems. As with any developing technology, significant cost reductions are also necessary to make the vehicle purchase price more competitive with that of conventional vehicles.

Infrastructure

- **Generating Capacity**: Transitioning a major portion of the transportation sector to electricity will place significant additional demand on the electricity generating industry. Current energy consumption in the transportation sector is equivalent to about 56 percent of the total electrical energy generated in the United States. Thus, a complete transition to electricity would necessitate a significant increase in current electricity generation capacity. Of course, this kind of shift would not occur over a short period of time.

  In the short term, any increase in electricity use by the transportation sector would have to be handled using existing electricity generation capacity. Daily recharging patterns would be an important factor in determining how efficiently current capacity can be used and how much new electricity generation would be needed. If vehicles were to be charged primarily at night they could use existing capacity that is currently underutilized during off-peak periods, thereby filling "valleys" in the electricity demand curve. Assuming this is the case, some researchers have estimated that total generating capacity would have to increase by only about 8 percent to support 30 percent of light-duty vehicle travel in electric-only operating mode. Clearly, there is sufficient electricity generating capacity to begin a transition to an electric transportation fleet, but as that transition progresses it will have to be coordinated with supporting developments in the electricity generation sector.

- **Generation Sources**: Since the overall carbon reductions associated with electric vehicles depend directly on the carbon intensity of the sources used to generate the electricity, movement towards a low-carbon electric generating infrastructure should accompany any movement toward the electrification of the transport system. The technologies used to supply new electricity demands from the increased use of electric vehicles will in turn affect the overall carbon intensity of the generating sector.

- **Vehicle Recharging**: There are two key recharging issues: the location of recharge connections/infrastructure and the speed of recharging. It is expected that initial recharging of electric vehicles will be accomplished using home-based grid connections. However, the development of a ubiquitous recharging infrastructure is critical to the long-term success of electric vehicles. Eventually it should be possible to recharge electric vehicles at home, at the workplace, or elsewhere. This could require either the development of fast recharge systems or storage system (e.g., battery) replacement facilities (similar to current gasoline and diesel refueling stations) that can quickly replace empty systems with fully charged counterparts. Battery systems that take hours to recharge do not offer the freedom of operation that many consumers will demand. Therefore, the inability to quickly and efficiently recharge depleted energy storage systems could significantly limit the penetration of electric-only vehicles.

- **Economics**: As described in the preceding sections, cost reductions will be required before electric-only vehicles and PHEVs can be cost competitive with conventional ICE vehicles. Depending on the relative cost of electricity and petroleum-based fuels, it is possible to recoup initial purchase price premiums during vehicle use if high-volume production battery cost estimates are accurate (this includes the cost of electric-only vehicles if battery durability issues can be resolved). Regardless, continuing cost reductions are required if initial purchase cost premiums are to be removed as a significant barrier to an electrified transportation sector.

Additional cost concerns arise with the potential need for battery replacement during a vehicle's lifetime—especially if consumers directly face those expenses. This is especially problematic at low-volume battery production costs, and still quite significant at high-volume battery costs. Long-term battery durability may be critical to broad electric vehicle deployment. It is important to note that a recharging infrastructure based on battery replacement rather than recharge could alleviate this issue as the recharging infrastructure would bear the burden of battery cycle issues. This approach could make it possible to spread associated costs over the entire fleet.

Social Issues

- **Safety**: Electric propulsion offers some safety advantages and some potential disadvantages relative to gasoline. Electrical energy is not combustible, so the risks associated with large reservoirs of combustible fuel are not an issue with electric vehicles. However, battery technology does present a specific set of safety issues. The most basic issue is related to the potential for energy discharge either through failure or accidental damage. Although lithium ion batteries have been known to overheat and cause fires in small electronic applications such as laptop computers, the batteries used in such systems include none of the safety systems employed in vehicle battery applications (due to cost and weight issues). No significant issues have been encountered in vehicle applications where these safety systems are in place.

  Various testing protocols and requirements have also been established by a number of organizations including the Society of Automotive Engineers, the United Nations (which restricts the international transport of unsafe systems), and the U.S. DOT (including the crash testing of vehicles with functional battery systems).

- **Performance**: The performance of PHEVs and electric-only vehicles can be as good as or better than that of conventional ICE vehicles. Electric drive systems offer maximum torque from startup, resulting in impressive vehicle acceleration characteristics. The overall performance characteristics of a well-designed PHEV or electric-only vehicle need not be an issue, but consumer dissatisfaction with early generation "underdesigned" (possibly low-cost) systems, if such systems were mis-marketed, could emerge as a lingering barrier to deployment.

- **Range**: The operating range of electric vehicles is currently limited by the amount of energy that can be efficiently stored onboard. This concern does not apply to PHEVs, but significant improvements in battery energy density will be required, along with concurrent reductions in charging time, before electric-only vehicles will find acceptance in the mass market.

- **Environmental Issues**: The development of an efficient battery recycling infrastructure is an important element of the movement toward an electrified transportation sector. To a large extent, the basic infrastructure for such a system is already in place because current ICE vehicles utilize small lead-acid batteries. Currently, over 95 percent of such batteries are recycled. It is also important to recognize that lithium ion batteries contain no toxic materials and could be safely landfilled, although recycling is certainly preferred.

- **Familiarity**: While there will be some minor differences, electric vehicles will generally look and function similar to conventional vehicles for the average driver. Nevertheless, drivers will need to get accustomed to certain differences, including differences in driving range. While PHEV technology is unlikely to encounter significant familiarity issues once drivers understand basic recharging operations, electric-only vehicles will suffer from significant challenges, both with respect to the time it takes to recharge and with respect to the locations where recharging is available. Consumers will also need to become comfortable with the somewhat different safety concerns that apply to electric vehicles.

Barriers to Hydrogen Vehicle Technology

Technology: Barriers to the widespread use of fuel cell technology in vehicles result from the relative immaturity of fuel cell systems (leading to high cost and uncertain durability) and the difficulty of carrying sufficient onboard hydrogen (leading to high cost).

- **Fuel Cells**: Although various fuel cell designs are possible (different designs are distinguished primarily by their use of different electrolytes), designs that use the polymer electrolyte membrane (also known as the proton exchange membrane) are generally recognized as having the greatest potential for application in the transportation sector.[97] While a fuel cell would generate the energy required to operate a hydrogen-powered vehicle, the vehicle would also require energy storage (e.g., battery) systems similar to those of hybrid electric vehicles along with an electric powertrain.

  Reducing the high cost of fuel cell systems will generally require further advances in fuel cell design, energy density and conversion, and economies of scale. Since this technology remains in the development stage, existing fuel cell systems are generally produced in very low volumes and are very expensive as a result.

[97] The primary reason for favoring PEM fuel cells is their low operating temperature. While other designs operate at temperatures ranging from 300°F to 1800°F, PEMs operate at 150°F, allowing them to achieve operability quickly, as consumers expect in transportation applications.

In terms of basic functionality, however, fuel cell technology is proven, although durability remains an issue. Current fuel cell systems are expected to last from three to ten years; by contrast, a 15-year life is necessary to compete with conventional gasoline vehicles.

- **Hydrogen Storage**: Efficient onboard hydrogen storage represents an important barrier to the widespread deployment of fuel cell vehicles. Storing enough fuel to achieve acceptable driving range currently involves liquefying or compressing the hydrogen—either of which presents challenges.

  Analysis suggests that to provide the equivalent range of a gasoline vehicle with a 15 gallon fuel tank, fuel cell vehicles would have to store about 6 kilograms (kg) of hydrogen (22.5 gallons of liquid hydrogen, 65 gallons of hydrogen compressed to 5,000 pounds per square inch (psi), or 38 gallons compressed to 10,000 psi). The advanced tanks required to store hydrogen at high pressure are bulkier and weigh more than conventional gas tanks, raising concerns about how to achieve performance and space characteristics similar to conventional vehicles.

Costs for hydrogen fuel tanks are also significant and will need to decline for this vehicle technology to be cost competitive with ICE vehicles. Advances in either storage tank technology or alternative storage media will be required for cost targets to be met. Alternative onboard storage technologies such as solid hydrides and carbon nanostructures have yet to be demonstrated in practical applications; although they hold promise, they will require further technology improvements.

Infrastructure: The refueling infrastructure required to support large-scale deployment of hydrogen vehicles does not currently exist and any associated development is subject to significant logistical, economic, and practical barriers. Moreover, barriers exist all along the hydrogen production and distribution chain.

- **Hydrogen Production**: The production of hydrogen requires significant energy input. The most inexpensive current sources of hydrogen also contain significant carbon, as do the majority of energy sources used to supply energy for hydrogen production processes.[98] Natural gas is the dominant source of hydrogen today, but petroleum, coal, and water electrolysis are also used. In fact, 96 percent of all current hydrogen production is based on the use of high-carbon sources.

  In the absence of carbon capture and storage (CCS), natural gas reforming is far superior as a source of hydrogen than the use of petroleum and coal feedstocks—at least from a CO_2 emissions standpoint. But for hydrogen to be a true low–carbon transportation fuel, CCS would have to be included at any large-scale production facility that uses natural gas or coal (or any other carbon-containing fuel); alternatively, hydrogen would need to be produced on a massive scale from renewable energy sources or nuclear power. Thus barriers to the expanded deployment of CCS, renewable energy, and nuclear power are also barriers to the viability of hydrogen as a low-carbon vehicle fuel.

  Ideally, hydrogen would be produced from water since water contains only hydrogen and oxygen. Electrolysis, the use of electricity to break apart the hydrogen and oxygen atoms that constitute water, is a mature technology used to produce high-grade (i.e., very pure) hydrogen. Again though, unless the electricity source is itself low carbon, net fuel-cycle carbon emissions can be significant. Other potential sources of hydrogen include thermochemical decomposition of water using high temperature heat from nuclear power plants and hydrogen produced biologically. Such processes, while understood, are not yet adequately developed for practical application.

- **Distribution**: If hydrogen production is to benefit from economies of scale, centralized production plants are required. This in turn means that hydrogen will need to be delivered from production facilities to refueling stations, which will require either the construction of adequate pipeline infrastructure or the development of an adequate fuel delivery system using compressed or liquefied hydrogen. Alternatively, hydrogen could be produced onsite at refueling facilities using existing natural gas pipelines or grid electricity. Onsite production at the refueling station eliminates significant economies of scale, but also eliminates the need for an extensive hydrogen delivery infrastructure.

[98] Although not currently used for transportation purposes, a mature hydrogen production industry already exists—primarily to support the production of ammonia for fertilizer and hydrotreating operations in petroleum refineries to convert heavier crude oil components into lighter gasoline-grade blendstocks. However, the size of this industry is dwarfed by the energy needs of the transportation sector. Research suggests that current hydrogen production capacity would have to increase more than tenfold to support a transportation system *entirely* powered by hydrogen. As with electricity, such an increase would occur over time so that this need not be viewed as a significant barrier to a hydrogen-based transformation of the transportation sector.

- **Refueling Stations**: Refueling facilities will be required regardless of whether centralized or onsite hydrogen production is preferred. At this time, there is no incentive for investment in such facilities since there is no assurance that fuel cell vehicles will be produced and sold in large numbers. This, in turn, limits the attractiveness of such vehicles to consumers (assuming they can be offered for sale at a competitive price). Some means of simultaneously assuring vehicle producers a refueling infrastructure and refueling investors a vehicle market will be required to overcome this chicken-or-egg situation.

Economics: Substantial cost reductions will be required before hydrogen fuel cell vehicles can be cost competitive with either conventional ICE or electric hybrid vehicles. Although currently low production volumes translate to considerable uncertainty about likely cost in a mass production context, current estimates of the cost reductions required to make hydrogen fuel cell vehicles competitive—both with respect to the fuel cell system itself and the onboard hydrogen storage system—range from a factor of two to as much as an order of magnitude. Cost reductions will require both technical advances and economies of scale. Assuming that adequate durability can be demonstrated, fueling costs are currently competitive with petroleum-based fuels but initial vehicle purchase costs present a significant barrier. Research suggests that hydrogen fuel production can be cost competitive with gasoline using current production technology. If R&D efforts pay off, future per-kg hydrogen production costs could be cost competitive even using zero-carbon sources such as wind and solar to provide process energy.

Social Issues

- **Safety:** From a safety standpoint, hydrogen has some advantages and some disadvantages relative to gasoline. The fact that it is lighter than air means that it dissipates quickly when released, whereas pools of petroleum-based fuels pose a high risk of ignition. However, the flammability range of hydrogen is much wider than that of gasoline or diesel and the energy required to ignite a hydrogen mixture is also quite low—so low, in fact, that static electricity alone can provide the necessary energy for ignition. While hydrogen will burn over a wider range of concentrations, however, it actually takes a greater concentration of hydrogen to reach its lower limit of flammability than is the case for either gasoline or diesel. Once ignited, a hydrogen fire is nearly invisible in daylight and the heat released is much less intense than that released by a gasoline or diesel fire, so that a hydrogen fire might not be detected until the actual flame is encountered. Leaks in enclosed spaces (e.g., garages) are of particular concern, especially since hydrogen is odorless and colorless, making it hard to detect. Hydrogen is non-toxic and non-poisonous, but like all gases (other than oxygen) it can cause asphyxiation.

  Safe high-pressure storage tanks (and associated valves and fittings) have been largely demonstrated for other compressed gases, although none have been widely used in the transportation sector. Similarly, liquid storage tanks (and associated valves and fittings) must be designed to withstand expected (and unexpected) conditions. Venting of any accumulated vapor must be performed safely. Both compressed and liquid hydrogen present significant safety issues during refueling (due to high pressure and low temperature respectively).

  Safety codes exist to govern the use of hydrogen specifically and high-pressure storage systems generally, but these might be so stringent as to unduly restrict the use of safely designed hydrogen storage systems. For example, operation in tunnels, garages, or other structures would currently be prohibited. To the extent that hydrogen risks are mitigated by rigorous design standards, these prohibitions will need to be revised accordingly.

- **Performance**: Assuming continued improvement in the specific power of fuel cell systems (as would be consistent with recent experience), the performance of fuel cell vehicles should be comparable to that of conventional vehicles. The energy density, weight, and efficiency of fuel cells have improved significantly in recent years. In short, there is little reason to assume that fuel cell vehicles can't offer both near and long-term performance characteristics equal to or better than those of conventional vehicles.

- **Range**: With current-generation fuel cell technology, vehicle range is limited by the amount of hydrogen that can be stored onboard while maintaining acceptable passenger and cargo space. High-pressure or low-temperature hydrogen storage tanks are bulky and require significantly more space than conventional gasoline fuel tanks. While vehicle range is an issue with current hydrogen storage technology, reasonable driving ranges are possible.

Should alternative hydrogen storage systems become feasible and cost effective, it is likely that the driving range of fuel cell vehicles will exceed that of conventional vehicles due to the much higher energy efficiency of fuel cell vehicles.

A factor that currently limits the practical operating range of fuel cell vehicles is the availability (or rather non-availability) of refueling facilities. A significantly expanded refueling infrastructure will be required before fuel cell vehicles can be viewed with the same "get in and go" freedom associated with conventional petroleum fueled vehicles.

- **Familiarity**: While the average driver will find that fuel cell vehicles have the look and function of conventional vehicles, consumers will undoubtedly need to overcome a familiarity barrier if these vehicles are to gain widespread acceptance in the marketplace. Refueling, in particular, will pose a challenge since high-pressure and ultra-low-temperature refueling procedures will be new and possibly intimidating to some drivers. New and different safety issues are also nearly certain to arise, especially if these concerns necessitate modifications to vehicle garages or other infrastructure, or to typical vehicle usage practices.

Appendix VI: Barriers to Increased Energy Efficiency in the Buildings Sector

Introduction

Technology studies consistently find that energy efficiency is among the most promising options for achieving large near-term, low-cost greenhouse gas reductions. Indeed, a number of assessments conclude that substantial energy savings are available throughout most industrialized economies at negative net cost—that is, the cost of the efficiency improvement is more than offset by prospective energy-cost savings.[99] A significant share of this potential can be found in residential and commercial buildings, which account for roughly 40 percent of overall U.S. energy consumption. Besides reducing energy-related greenhouse gas emissions, efficiency improvements in buildings generate immediate reductions in electricity and fuel bills and have the potential to reduce loads—especially peak loads—on electric utilities at lower cost than building new generating capacity. Reducing end-use demand for electricity and natural gas has other important benefits as well: it can help avoid or defer the need for new transmission and distribution investments, improve grid reliability, enhance energy security, and alleviate upward price pressures and price volatility in tight energy markets.

Over the last 35 years the overall energy intensity of the U.S. economy has declined steadily: energy consumption per real dollar of gross domestic product (GDP) fell by approximately half between 1970 and 2006. At the same time, however, per capita energy consumption declined only slightly. Moreover, it is not clear that the energy intensity of the economy will continue to decline, or continue to decline at the same rate going forward. A key question, therefore, is whether and how historic trends in efficiency improvement can be sustained and, if possible, accelerated so that more of the theoretically cost-effective energy savings potential in new and existing buildings is captured. Doing so will entail effective strategies for overcoming a number of pervasive barriers that—in contrast to the deployment hurdles that confront many prominent supply-side carbon mitigation options—are *not* primarily technological in nature.[100] Fortunately, future efforts can draw from substantial field experience: historically, a variety of market interventions and policy tools have used in the United States and elsewhere to promote energy efficiency. Well-known examples include building codes and appliance standards, utility DSM programs, financial incentives (such as tax credits), and information programs (including consumer labels). The challenge for policymakers will be to strengthen and improve on these mechanisms and develop new ones. The remainder of this background document provides a brief review of generic barriers to energy efficiency investment.[101]

Barriers to Increased Energy Efficiency

The key barriers to full market penetration of energy efficiency pertain to building codes and land-use policy, informational gaps, economics, and technology availability. This section reviews the most important categories of such barriers. Additional barriers may apply to specific building technologies or design options.

Policy Barriers: A number of policy barriers impede the uptake of energy efficient technologies in the buildings sector.

- **Tax Incentives:** For example, the federal tax code acts as a disincentive to investments in energy efficiency because building operating costs (including energy) can be treated as expenses and deducted from taxable income, whereas capital expenditures (e.g., building improvements) must be depreciated over a period of time. This

[99] Examples include recent studies by McKinsey & Co. (2007), the Electric Power Research Institute (2007), the World Wildlife Fund, and the American Council for an Energy Efficient Economy (ACEEE) (2004).

[100] For example, McKinsey & Co. has estimated that energy efficiency improvements in the residential and commercial sectors could offset more than half of expected overall energy demand growth in the United States to 2020, producing annual carbon dioxide reductions of as much as 700 billion metric tons in 2020 (http://www.mckinsey.com/mgi/reports/pdfs/wasted_energy/MGI_wasted_energy.pdf). But they have also emphasized that high hurdle rates stand in the way of realizing this potential. Similarly, a 2004 meta-analysis of available state-level studies of energy efficiency potential conducted by ACEEE finds a significant gap between estimates of "technical" and "economic" potential and "achievable" potential: whereas most estimates of the technical and economic potential for end-use electricity and natural gas savings range from 10 to 30 percent, estimates of achievable potential are more typically near—or in some cases below—10 percent. Overall, these and other assessments suggest that while some fraction of the cost-effective efficiency potential of the U.S. economy could be captured through a relatively straightforward application of existing policy mechanisms (such as codes and standards), capturing the full potential is likely to be challenging and may require a substantially stronger and broader set of policy interventions.

[101] An extensive literature exists on this topic; our purpose here is not to revisit the evidence for different barriers or to re-engage long-running arguments about the extent to which consumer and business choices about energy use can be explained by a series of pervasive market failures or rather reflect a more complex set of preferences and dynamics that aren't well captured by analyses that focus on cost and technology potential—or both.

places energy efficiency investments at a disadvantage. Other tax incentives—normally in the form of tax deductions— for energy efficient products and equipment also exist at the federal and state level. However, in the past, many of these tax programs have been difficult to account for on federal tax forms, especially for residential consumers. Many have also been allowed to expire, creating programmatic inconsistency.

- **Building Codes:** Building codes are the main mechanism used for assuring minimum standards of energy efficiency. Codes have been developed over many decades to address structural integrity and protect the health and safety of occupants, but were later used to also require improvements in energy performance. Many states find it too time consuming and expensive to develop their own codes and use model building codes as the basis for state requirements. Nevertheless, building codes are often inconsistent from state to state—both in terms of their stringency and in terms of enforcement. Not only do antiquated (and often unduly restrictive) codes impede the deployment of the latest technologies, but the lack of standardized regulations across states and regions increases transaction costs for actors serving multiple markets. While "performance contracting"—a mechanism that enables facility owners to make upfront, capital investments financed by future energy savings—has proven to be a valuable tool for improving energy efficiency in federal buildings, many state constitutions prohibit performance contracting because this financing mechanism involves the obligation of funds in advance of their being appropriated.

- **Appliance and Equipment Standards:** Stemming from the Energy Policy and Conservation Act of 1975 and subsequent energy legislation, the DOE is obliged to establish energy efficiency standards for a range of commercial and residential products, including lighting and major household appliances, by certain deadlines. The Energy Policy Act of 2005 (EPAct) required the DOE to expedite rulemakings for the energy efficiency standards that remained to be set at that time and the Energy Independence and Security Act of 2007 (EISA) made many existing energy efficiency standards, including standards for lighting and appliances, more stringent and included additional product categories. Even today, standards for many products remain to be set or updated. For manufacturers, this uncertainty poses a barrier to investing in the next generation of energy-efficient appliances and equipment. In February of 2009, President Obama issued a memorandum to the Secretary of Energy calling for DOE to expeditiously develop the standards required under previous laws.

Economic Barriers: Decisions concerning the deployment of energy-efficient technologies in buildings generally focus on the first cost of technologies, as opposed to life-cycle costs. This barrier is especially important in the context of new construction, where decisions made during the design phase can have a decisive impact on the energy performance of a building throughout its useful life. For builders who are trying to win a bid or come in under budget, first costs may be the only relevant consideration because it is the owner and/or tenant, not the builder, who has to bear the lifetime energy-related operating costs of the building. These sorts of "split incentives"—where the party making the decision to purchase (or not purchase) an energy-efficient technology is different than the party responsible for paying utility bills—are present in other instances as well. For example, a landlord whose tenants pay their own utilities may not see the value in undertaking energy efficiency enhancements in tenant spaces—since the landlord would bear the capital expenditure while the tenant would enjoy lower operating costs.

Property owners as well are often driven by first-cost considerations because they are uncertain whether up-front investments in energy efficiency measures can be recouped later (e.g., upon sale or refinancing). Capital constraints among end-users mean that investments in novel energy-efficient technologies must compete with other investment opportunities. This leads to a number of commonly-observed outcomes. For example, when competing head-to-head for funding, energy efficiency upgrades often lose out to non-efficiency capital improvements that have well-defined value propositions and paybacks. This is often seen in the commercial real estate sector, where short holding periods for investment properties can lead to the belief that there is not enough time to recoup savings from energy investments. Furthermore, owners may be more inclined to invest in easily-marketable aesthetic upgrades, as opposed to relatively "invisible" energy efficiency enhancements.

Infrastructure and Information Barriers: The diversity of actors present in the buildings sector, combined with the high transaction costs of coordinating activities across a large number of small firms, leads to a situation in which design processes are not optimized, and where even the best intentions with regard to efficient design can be undone by subsequent actors in the supply chain. A key barrier that results

from this market fragmentation is the lack of accurate and/or complete information that building owners and operators can draw upon when deciding whether or not to adopt particular technologies. It is widely acknowledged, for example, that maximizing whole-building energy efficiency requires the ability to understand buildings as integrated systems, as opposed to collections of discrete technologies. Unfortunately, the marketplace suffers from a lack of specialized knowledge about building system operations and optimization. Faced with limited information and expertise, consumers and building professionals alike may eschew integrated design in favor of "rules of thumb," such as first cost considerations and over-sizing of installed systems. As a result of these informational gaps, building technologies continue to be addressed on a system-by-system basis, leading to lost opportunities for energy and cost savings. Even when buildings are designed to include advanced technologies, potential energy efficiency benefits can be nullified through a lack of integration. Building commissioning continues to be the exception, rather than the norm, meaning that buildings may enter into service without having been tuned, balanced, adjusted, etc. As a result, individual technologies may not be operating as intended, and may not be interacting correctly with other building systems. Fortunately, several energy efficiency information programs have come into the mainstream, which have helped with both consumer awareness and acceptance. Prominent examples of informational programs include:

- EPA's Energy Star® program is a labeling program that identifies energy-efficient models for heating and cooling appliances, computers and electronics, and office equipment. The program has also begun certifying new homes and commercial and industrial buildings. The Energy Star® program covers over 60 product categories and thousands of models. Certification criteria vary across product categories.[102]

  The United States Green Building Council (USGBC) developed the Leadership in Energy and Environmental Design (LEED™) standard. LEED™ ratings minimize environmental impacts from building projects, such as site impacts, construction waste, and water and energy use. Membership in the USGBC and the number of LEED™ certified building projects have grown quickly. Studies have indicated that energy use per square foot per year in LEED™ certified buildings is about 24 percent less than the average energy use of the U.S. building stock overall.[103] Other standards exist for rating building energy performance, such as the Green standard developed by the National Association of Homebuilders (NAHB).

Social Barriers: When multiple energy-efficient technologies are competing for consumer purchases, the comfort and certainty that comes with selecting more traditional or "familiar" technologies may be favored as opposed to the perceived risk of new technologies (regardless of efficiency and/or savings claims). When combined with the long lifespan of buildings, this tendency can lead to technology "lock-in"—the tendency to repeatedly favor "incumbent" technologies when it is time to replace old equipment.

Research and development (R&D): R&D investments and expenditures in the U.S. building industry are substantially lower than the national average across all industries. DOE attributes this to the substantial fragmentation of the building industry, noting that many disparate players and specialties are involved throughout the life-cycle of buildings, from construction through operation. Small firms that tend to dominate the industry are generally not of a sufficient size to undertake R&D, nor would they be expected to realize proportionate benefits from this research. As a result of this fragmentation, market actors in the buildings sector cannot achieve the level of coordination necessary to engage in robust R&D activity. Furthermore, the small firms that make up the buildings sector are often unable to fund demonstration projects to prove the savings potential of new technologies to the broader marketplace. In the absence of such demonstrations, new technologies are more likely to be viewed as risky, and although this perception may be unfounded or exaggerated, it can lead to pervasive informational barriers that preclude technology uptake.

- **Cutting-Edge Technologies and Potential R&D Priorities:** While many existing energy-efficient building technologies have yet to penetrate the market, new technologies continue to evolve. The following table briefly summarizes barriers that apply to specific categories of building energy end-use technologies.

[102] For example, Energy Star® refrigerators must save 20 percent over the minimum applicable efficiency standards. Televisions and dishwashers require savings of 30 percent and 41 percent, respectively. To receive the Energy Star® designation, whole residential buildings must use at least 15 percent less energy than standard homes and combine insulation, windows, heating and cooling systems, appliances, lighting, and water heating systems which are all more efficient than conventional alternatives (Energy Star 2007).

[103] In this study, the energy use of LEED™-certified buildings was compared to the energy use of typical buildings based on the 2003 Commercial Building Energy Consumption Survey (CBECS); the 24 percent figure represents an average across multiple building types including offices, schools, retail spaces, etc.

TECHNOLOGY	DESCRIPTION
Electrochromic windows	■ Electrochromic windows can be darkened or lightened electronically, controlling the amount of light and heat that pass through them. This allows heat and light transmission to be maximized or minimized as needed. This technology is in the demonstration phase with support from DOE and its national laboratories. One manufacturer, Sage Electrochromics, is involved in DOE-sponsored R&D and has begun to bring the products to market.[104] There are a few technical issues that still need to be resolved, such as durability due to heat shock and effectiveness in large-glazed windows. Some have raised aesthetic concerns because in the clear sate, windows may have a yellowish tinge. The price also needs to come down significantly. The price of electrochromic glass is currently at $100 per square foot, significantly higher than the price of low-e windows at $10—$15 per square foot. DOE expects the technology to be commercialized by 2015.
Phase change wall materials	■ Phase change materials (PCMs) absorb, store and release heat when they change state (e.g., from a solid to a liquid). When temperature rises above a PCM's transition temperature, the PCM absorbs heat and melts. When air temperature decreases, the PCM solidifies and releases the stored heat. In addition to improving conventional building efficiency, PCM wallboard reduces some cost and design limitations of passive solar homes and improves the performance of mass-produced solar-heated homes.[105] This technology still confronts some technical barriers and more reliable thermal data are needed. Also, the paraffin-treated wallboard in PCM presents a potential fire hazard. This is being addressed by limiting the concentration of PCM in wallboard, or treating the wallboard with fire retardant. Prices remain high and there is currently only one manufacturer with capacity to produce PCM.[106]
Vacuum insulation panels	■ Vacuum insulated panels (VIPs) consist of a core panel enclosed in an airtight envelope, to which a vacuum is applied. VIPs provide insulative value three to seven times that of other insulation materials of equivalent thickness. VIPs are used in commercial and industrial refrigeration applications[107] and are now being considered for use in the building market. VIPs have greater potential in building renovation, where room is scarce.[108] Some technical issues remain, such as the gradual loss of vacuum over time. The largest drawbacks of this technology at present include cost and uncertainty about the lifespan of VIPs due to variable environments and climate zones.
Advanced LED ("solid-state") lighting	■ Solid-state lighting (SSL) refers to a type of lighting that uses semiconductor light-emitting diodes (LEDs), organic light-emitting diodes (OLED) or polymer light-emitting diodes (PLED) instead of electrical filaments, plasma, or gas. SSL creates a visible light with less heat and is several times more efficient than incandescent lighting. However, the technology is still nascent. There is some concern over the low light output and color quality of LED products. In addition, LED prices are 50 times higher than prices for incandescent bulbs and seven times more expensive than compact fluorescent lights (CFLs) for equivalent light output. While LED costs are expected to decline, costs are expected to remain higher than comparable lighting for some time.
Integrated daylighting	■ Integrated daylighting combines a network of dimmable fluorescent ballasts with light and occupancy sensors to provide optimal lighting conditions with minimum energy requirements. However, there is some concern about how components of a daylighting system will interact with other lighting systems, like electrochromic windows. Also, retrofitting buildings for advanced lighting control systems is expensive, partly because of wiring.
Solar-assisted water heating	■ Solar assisted hot water heaters use solar thermal energy to heat water halfway towards the temperature required for domestic uses. Generally they are supplemented by existing electric back-up storage water heating systems. The cost and availability of solar water heating equipment remain the largest barriers to full market penetration. So far, manufacturers have not achieved economies of scale to drive down costs.
Ground source heat pumps	■ Also called geothermal heat pumps, ground source heat pumps (GSHPs) are essentially heat-exchangers that use the earth's relatively constant temperature to heat or cool water or air. GSHP technology offers one of the most efficient heating/cooling systems available. These systems are already available but have not reached a high level of market penetration. Initial equipment costs are about 10 percent higher than comparable air-source heat pumps but payback can be achieved within a few years. GSHPs face a lack of consumer awareness and supply-chain actors (designers, architects, engineers) tend to ignore this option in favor of known technologies.
Ductless residential heat pumps and air-conditioning units (also called mini-splits).	■ Traditional central air-conditioning requires a series of ducts to distribute cool air to multiple rooms. Ducts are often leaky and can lose up to 30 percent of the energy used to heat and cool. In contrast, ductless units have distribution losses of about 1–5 percent. This technology is likely to be cost effective for retrofits and new construction applications.

[104] http://www.sage-ec.com/index.html.

[105] http://www.p2pays.org/ref/19/18085.htm.

[106] http://www.micronal.de/portal/basf/ien/dt.jsp?setCursor=1_290823.

[107] http://www.toolbase.org/Technology-Inventory/Interior-Partitions-Ceilings/vacuum-insulation-panel.

[108] http://eetdseminars.lbl.gov/seminar.php?seminar=218.

Appendix VII: Barriers to Bioenergy Deployment

Introduction

In the most general sense, the term "bioenergy" refers to the conversion or combustion of plant material (and sometimes, industrial waste products) into usable energy products. Biofuels broadly encompasses a wide range of liquid fuel energy products, while biopower connotes electricity generated by combusting or gasifying biodegradable materials. Biomass power accounted for approximately 10 percent of total renewable electric generating capacity in the United States in 2007, generated mostly from agriculture and forest residues. The most commonly produced biofuel is ethanol, which, in the United States, is made almost exclusively from corn feedstocks. However, cellulosic bio-feedstocks constitute a potentially much larger resource base, one that could include agricultural and industrial wastes as well as dedicated energy crops.

In policy discussions, bioenergy products are frequently categorized as first or second generation. While there is no hard distinction between these two categories, which term applies frequently depends on the type of feedstock from which the bioenergy product is made. Alternatively, products can be classified as first or second generation by the process used to convert plant material to fuel or electricity. First generation products typically come from starches, sugars, and seeds which are converted through fermentation or transesterification or are combusted in a boiler. Second generation products, on the other hand, are produced biochemically or thermochemically using lignocellosic biomass feedstocks such as grasses, wood, and agricultural and forestry residues. This appendix reviews barriers associated with the large-scale deployment of a new generation of biofuels and biopower technologies.

Advanced forms of bioenergy have the potential to play a major role in the nation's future energy mix and to provide substantial greenhouse gas (GHG) abatement benefits, if produced in a sustainable manner. Despite their many advantages, however, advanced bioenergy products continue to face a number of significant deployment hurdles. We begin by reviewing a set of cross-cutting barriers common to the most prominent bio-feedstock options before turning to the technologies available for converting bio-feedstocks to liquid fuel or electric power. A discussion of further deployment barriers, along with a summary of issues specific to particular types of feedstocks and conversion technologies is included at the end of the document.

Common Barriers to Bio-Feedstock Development and Use

Second generation bio-feedstocks fall into two broad categories: (1) waste and agricultural residues (e.g., corn stover, sugarcane bagasse, woody waste) and (2) dedicated energy crops (e.g., microalgae, switchgrass, miscanthus, short rotation willows and hybrid poplars). Large-scale use of bioenergy products will require robust and sustainable feedstocks, along with the ability to economically cultivate, harvest, transport, and store those feedstocks—which are inherently more dispersed and have lower energy density than conventional fossil fuels. The remainder of this section identifies a number of issues that are common across most types of bio-feedstocks.

Costs: Cultivating economic and ratable quantities of bioenergy feedstocks—that is, quantities that can consistently be estimated and delivered—is critical to developing a large-scale bioenergy production infrastructure. While there are issues that must be addressed relating to sustainability and GHG accounting, keeping cumulative costs low throughout the entire feedstock supply chain poses one of the biggest challenges to realizing reliable and sufficient supplies of biomass feedstocks. In fact, high feedstock transportation and distribution costs can limit the maximum distance that feedstocks can cost-effectively be transported to a bioenergy production facility to 50 miles or less.[109] Thus more efficient methods of harvesting, preparing, transporting and distributing feedstocks are critical.

Production and Collection Issues: Although agricultural residues and organic wastes are already available as byproducts from the production of other commodities, to date they have not been collected for large-scale bioenergy production. Large-scale efforts to collect these types of feedstocks may be complicated by the need for high manual labor inputs and/or specialized harvesting equipment, sensitivities to climatic conditions, and high costs. Dedicated energy crops may face different or additional types of barriers, including a lack of commercial experience in growing these feedstocks, which

[109] Amos et al, "Biopower Technical Assessment: State of the Industry and Technology," NREL, ORNL, March 2003, p. 2-5. http://www.nrel.gov/docs/fy03osti/33123.pdf

creates cost uncertainty. Moreover, long harvest times and specific climate requirements may hinder energy crop development, or at least constrain such crops geographically, thereby increasing transportation costs.

High Quality Storage Requirements: The ideal bioenergy supply chain would have a ratable stream of raw materials flowing to production facilities to ensure a predictable supply of energy products. The process would minimize the storage of raw materials, which would tie up working capital and could pose quality issues if the raw materials are perishable or if their quality deteriorates during storage. Some types of bio-feedstocks (e.g., wood residues, microalgae, and municipal solid waste) can be supplied at a relatively constant rate throughout the year. However, many potentially promising feedstocks have seasonal production patterns. This means that significant investments may be needed to provide infrastructure for storing seasonal crops or residues, either off-site or at biofuel production facilities. These storage costs and logistics will have to be factored into overall production costs and investment decisions.

Transportation: Due to the large volumes of feedstock required for large-scale bioenergy production, there are inherent challenges in coordinating the transportation logistics from collection to a biofuels or biopower plant. For instance, a biorefinery[110] designed to produce 56 to 63 million gallons of ethanol per year using corn stover must process at least 700,000 dry tons (dt) of corn stover each year. This translates to roughly 2,000 dt of corn stover shipped to the biorefinery every day. A truck pulling a 53-foot flatbed trailer can legally (that is, without exceeding its load limit) haul approximately 25 dt of corn stover with a 25 percent moisture content. Thus, taking daily delivery of 2,000 dt of corn stover means the biorefinery must receive nearly 100 truck shipments each day.[111] The costs associated with obtaining and fueling large transport trucks and the logistics involved in coordinating collection, loading, and delivery processes will vary for each feedstock and biorefinery supply chain, but they are likely to be significant in most cases.

Consistency in the Composition of Bio-Feedstocks: Variation in the composition and availability of feedstocks can pose problems for bioenergy plant operators. This is especially true for biopower plants, which may operate with different emissions and heat rates depending on the composition and quality of the feedstock used. Variable feedstock heat content can also affect plant efficiency and boiler calibration.

Sustainability and Land Issues: Current concerns about the food-price and land-use impacts of corn-based ethanol production have also raised awareness about broader sustainability challenges surrounding bio-feedstock production and collection more generally. Virtually all second generation biomass sources will impact the land in some way, and poorly managed biomass production could have significant negative environmental consequences. Potential problems may include soil erosion, nutrient depletion, habitat destruction, fertilizer run-off, and water quality degradation. Minimum management standards may be required to protect water and soil quality and biological diversity on lands used to produce bio-feedstocks. Otherwise, failure to address these sustainability issues could emerge as a major long-term constraint on significant bio-feedstock development.

Resource Requirements

- **Equipment and Labor Requirements**: Producing, harvesting, transporting, and storing bio-feedstocks will require specialized equipment and a range of labor skills. Specific expertise will be needed to optimize operations at all points in the bioenergy supply chain.

- **Water Requirements**: Water is a key resource requirement for large-scale bio-feedstock production. Cultivating energy crops and microalgae will require water, as will storing agricultural residues. At the same time, water resources available for irrigation and other purposes are becoming increasingly scarce in many areas.

GHG Accounting Issues: Accurately assessing the GHG impacts of land-use changes associated with large-scale bioenergy production will also be a significant challenge. Some land-use changes, such as growing crops or trees on degraded land, could be beneficial from a GHG standpoint. Others, such as clearing forests for the cultivation of energy crops, might cause a net increase in CO_2 released to the atmosphere. To accurately assess the life-cycle GHG impacts of bioenergy development, GHG emissions from land-use changes will have to be measured domestically as well as internationally. Consistent and transparent policies and scientifically validated assumptions about GHG impacts must be in place to ensure that

[110] "Biorefinery" is a generic name for a biofuel manufacturing facility.

[111] Perlack, Robert D., and Anthony F. Turhollow. "Assessment of Options for the Collection, Handling, and Transport of Corn Stover." Oak Ridge National Laboratory. 2002. Accessed at http://bioenergy.ornl.gov/pdfs/ornltm-200244.pdf .

investors have a clear picture of project economics in a world with a price on CO_2.

R&D Requirements: Expanded R&D efforts are needed to ensure reliable and economical supplies of bio-feedstocks. Genetic modification may offer the potential to increase yields, lower resource requirements, and improve feedstock characteristics such that they are more favorable for bioenergy utilization. Additional research aimed at improving collection, harvest, and storage techniques and assessing land-use impacts should also be targeted.

Bioenergy Technology Options

This section briefly reviews the primary conversion technologies that could be used to produce biofuels or biopower from second-generation biomass feedstocks.

- **Biochemical biofuels conversion.** Biochemical processes are generally used to convert herbaceous (not woody) feedstocks into biofuel. These feedstocks include perennial grasses, crop and municipal waste residues, and microalgae. For all of these feedstocks, excluding microalgae, the conversion process consists of the following five main steps: (1) pretreatment of the biomass through milling and solvent treatment to break down the lignin and hemicellulose; (2) conversion of the cellulose to glucose (sugars) through enzymatic or acid hydrolysis processes; (3) fermentation, as is currently done with corn and sugar cane; (4) distillation; and (5) purification to obtain fuel-grade quality.

- **Microalgae biofuels.** While also a biochemical process, converting microalgae into biodiesel differs from other biochemical methods to produce biofuels. Microalgae are grown in raceway ponds or tubular photobioreactors. Both these methods produce a broth-like substance from which microalgal oil is extracted through filtration, centrifugation, or other means. Once microalgal oil has been extracted from the algae, biodiesel is produced from the oil through transesterification. This process produces biodiesel and glycerol, which are then cleaned and separated.

- **Thermochemical biofuels conversion:** Thermochemical processes rely solely on chemical reactions and conversions whereby certain materials are mixed under specific combinations of temperature and pressure. These processes include pyrolysis, combustion, and gasification—all of which change biomass into intermediate products for conversion to biofuels. Thermochemical conversion is primarily used to produce biofuels from woody residues and wood-based energy crops, but these processes can accommodate a wide range of organic feedstocks of various types, sizes, and moisture contents. Generally, conversion proceeds in two main steps. First, biomass is converted into a synthetic gas (syngas), which is a mixture of hydrogen and carbon monoxide, using gasification or pyrolysis technology. Second, the cleaned syngas is passed over a catalyst and converted to a liquid fuel. This process is commonly known as Fischer-Tropsch synthesis and it can be used to produce a variety of commercial liquid fuels, such as ethanol, methanol, or diesel fuel. Electricity is also produced as a by-product of this process. In fact, some of the most some of the most exciting possibilities for bioenergy development are those having to do with integrated thermochemical facilities that produce both fuels and electricity using biomass.

- **Biopower:** Typical biopower facilities burn a biomass feedstock to produce steam. The steam drives a turbine, which then turns a generator. Ideally, the spent steam from the power plant is not wasted but is used to supply heat for manufacturing processes or for space heating in buildings. Such combined heat and power systems greatly increase the overall energy efficiency of the bioenergy conversion process. Paper mills, the largest current producers of biomass power, generate a combination of electricity and process heat in the course of recovering chemicals used in the pulping process.[112] The biopower technologies discussed in this paper include biomass direct-firing, biomass co-firing, and biomass gasification systems. Biomass direct-firing involves burning the biomass directly, in place of coal or oil, to produce steam. This process is very similar to conventional power production. Biomass co-firing involves essentially the same process, except that the biomass is burned in combination with a fossil fuel, often coal, in a high-efficiency boiler. At present, utility companies utilize biomass co-firing primarily to reduce overall air pollution emissions, notably emissions of sulfur and CO_2. According to one estimate, for example, co-firing a conventional coal plant with 15 percent biomass can reduce life-cycle GHG emissions by 19 percent, conventional air pollution emissions by 15 percent, and fossil fuel consumption by

[112] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, "Biomass FAQs." http://www1.eere.energy.gov/biomass/biomass_basics_faqs.html.

12 percent.[113] Finally, biomass gasification systems are distinct from direct-fired or co-fired systems but are quite similar to the initial steps of thermochemical biofuel conversion. These systems create a syngas, which is then used in a turbine to generate electricity. This process has inherent advantages over combusting biomass, given that combined-cycle gas turbines are among the most efficient of all power generation technologies. Although biomass gasification is not yet widely used in large power plants, it has the potential to be highly efficient and very clean. Because biomass gasification plants and thermochemical biofuel conversion plants share similar characteristics, they also share many of the same barriers.

Common Barriers to Bioenergy Conversion Technologies

Primary barriers to the large-scale deployment of second-generation bioenergy conversion technologies revolve around economics, policy, R&D needs, and resource constraints.

Costs: Biorefineries are key assets in the biofuel supply chain. Upfront capital costs for constructing large-scale biofuel production facilities, especially thermochemical plants, are high, as are operating costs (i.e., catalyst conversion, syngas clean-up, pretreatment and enzyme use). Both types of cost (capital and operating) must be lowered to ensure that biofuels are economically competitive over a wide-range of oil prices. Continued R&D during the development stages and learning during the commercialization stages can be expected to produce cost reductions over time, but financial incentives will most likely be needed to overcome cost hurdles in the near term. The volatility of oil prices in recent years is particularly problematic for the commercialization of second-generation biofuels.

Capital Investment Requirements: Government incentives, including grants and loan guarantees, are likely to be a key, but limited, source of capital for the development and production of biomass energy. For instance, high capital costs represent a major deployment barrier for biomass power technologies, which are likely to remain more expensive than competing fossil-fuel technologies—i.e., natural gas combined cycle plants. For existing plants, biomass co-firing requires a capital investment to modify boilers and fuel handling infrastructure. The U.S. Energy Information Administration (EIA) estimates that the cost of these modifications would range from $115,000 to $265,000 per megawatt of biomass capacity.[114] This cost is relatively low, particularly in comparison to other renewable energy sources, such as solar power. Cost remains a significant issue, however, in terms of attracting private investment in first-of-a-kind second-generation biofuel and biopower facilities. Current overnight capital cost estimates for biomass IGCC generating capacity are approximately $3 million per megawatt.[115] Although subsidies and mandates can improve the economic viability of bioenergy plants, capital markets will need to have confidence that production costs can be lowered enough to ensure adequate profit margins if the industry is to achieve broad commercial deployment. Moreover, any uncertainty about the continuity of government incentives, subsidies, or mandates amplifies this challenge. In the near term, meanwhile, the current global credit squeeze, the recent drop in oil prices and general economic turmoil will undoubtedly make financing commercial-scale facilities more difficult.

Federal Financial Incentives: Increased utilization of ethanol as a vehicle fuel in the United States in recent years has been driven primarily by state and federal policies and regulations. These have included mandates such as the Renewable Fuel Standard (RFS), which was expanded in the Energy Independence and Security Act of 2007 (EISA); various financial incentives included in the latest farm and energy bills; various state mandates for ethanol in gasoline; and reformulated gasoline standards in many major markets that require refiners to blend ethanol. In addition, numerous other policies have been established to protect and promote growth in the domestic ethanol industry. These include a 54 cent per gallon tariff on imported ethanol, a 46 cent per gallon incentive for blending ethanol in gasoline, production incentives for small ethanol producers, and multiple state and local incentives aimed at stimulating ethanol use. Currently, cellulosic ethanol producers are eligible to receive a credit valued at 40 cents per gallon; beginning in January 2009 and continuing through 2012, cellulosic producers will be eligible for a $1.01 per gallon credit. Agri-diesel and biodiesel producers are currently seeking to extend their tax credit of $1.00 per gallon. Given the volatility of recent oil prices, however, it is unclear if the current framework of federal incentives will prove adequate to building out the next generation of biofuel technologies.

[113] Spath & Mann, "Biomass Power and Conventional Fossil Systems with and without CO2 Sequestration –Comparing the Energy Balance, Greenhouse Gas Emissions and Economics," NREL, January 2004.

[114] United States Department of Energy, Energy Information Administration, Annual Energy Outlook 2008 With Projection to 2030 DOE/EIA-0383 (Washington, DC: Energy Information Administration, 2008), "Assumptions to the Annual Energy Outlook 2008." http://www.eia.doe.gov/oiaf/aeo/assumption/electricity.html.

[115] Ibid.

Biomass power generation in the United States is projected to increase in the future due to a combination of state-level renewable energy mandates, such as renewable portfolio standards (RPS), and as a result of government-funded renewable energy incentive programs, such as production tax credits, accelerated depreciation, and mandates. However, uncertainty regarding the availability of the federal production tax credit (PTC), along with uncertainty about the distinction between "open loop" and "closed loop" systems[116] in terms of qualifying for the PTC, present hurdles to continued biopower investments going forward. Biomass electric projects using "open-loop" biomass receive the PTC at only half the rate for wind, solar and geothermal energy projects. Closed loop biomass power plants, by contrast, are eligible to receive the full 2-cent-per-kWh PTC. However, no closed loop biomass power plant has been built in the United States to date due to "challenging economics and long development horizon."[117] Moreover, the short window of PTC availability, which Congress has typically extended only in one- or two-year increments, is particularly challenging to biomass power, as projects typically have long construction lead times and take many months to complete.

Absence of Developed Feedstock Markets: Unlike first generation biofuel feedstocks, there are no established commodity markets to support adequate year-round supplies of second-generation feedstocks. Without such markets, fuel or power producers must assume the burden of determining how best to reliably produce, store, and transport feedstocks to consistently ensure feedstock supplies throughout the year. Clearly, a reliable feedstock supply chain is a prerequisite for financing and constructing a biofuel production facility. Therefore, establishing a ratable, sufficient, and sustainable infrastructure capable of supplying biomass in concert with production demands is critical.

R&D Requirements: The level of R&D work underway in the bioenergy arena is significant and growing, particularly for second generation biofuels. Still, continued and prioritized R&D is required to build out the industry and lower costs. For example, additional R&D efforts are required to improve the efficiency of enzyme and pretreatment techniques for biochemical processes, which, in turn, will lower production costs. Production costs are likely to be lower for thermochemical conversion technologies than for biochemical processes, but capital costs are higher. Nevertheless, additional R&D efforts are needed to enhance the efficiency of syngas cleaning and catalyst utilization. For power plants, co-firing with high percentages of biomass fuel (i.e., above 15 percent) creates technical challenges for boiler performance, while biomass integrated gasification combined-cycle (IGCC) plants have yet to be demonstrated at scale.

Resource Requirements

- **Water**: Biorefineries and steam boilers require large quantities of water to convert solid biomass fuel into liquid fuels. Although the amounts of water required by biorefineries are relatively smaller than the quantities of water required for crop production, water demand for biorefineries is often concentrated within small areas, which may impact local water supplies. For instance, the water requirement of a biorefinery producing 100 million gallons of biofuel per year is equivalent to the water requirements of a small town with a population of 5,000.[118] Ensuring adequate water supplies is becoming an issue of increasing concern for industrial facilities given growing overall water demands. Dry mill ethanol plants today are able to recycle a large portion of their process water and it will be important for the entire bioenergy industry to thoroughly investigate efficiencies in water use.

- **Materials and Construction Equipment**: Competing demands for materials and building equipment have extended construction timeframes for new large-scale industrial facilities of all types, including new biorefineries and biopower plants. Prior to the recent global economic downturn, demand for new construction projects, particularly in the Far East and Middle East, had begun to strain global capacity to deliver projects on schedule. While construction patterns could change as the world emerges from recession, significant numbers of refineries, petrochemical plants, liquefied natural gas (LNG) facilities, and biorefineries are already in or likely to enter the construction or planning phases. This has the potential to contribute to inflated commodity and material prices; reduced competition among engineering, procurement, and construction (EPC) firms; and prolonged construction lead times, all of which can increase the price tag for

[116] The term "closed loop" refers to biopower systems where feedstocks are grown specifically for purposes of power generation such that any biomass consumed in these systems could be assumed to be replaced by future feedstock growth; the term "open loop" refers to systems that use waste biomass material—such as wood waste and lignocellulosic residues—for power generation.

[117] Kotrba, Ron. "The Power of Association," Biomass Magazine, June 2008. http://www.biomassmagazine.com/article.jsp?article_id=1675.

[118] The National Academies. "Water Implications of Biofuels Production in the U.S." Report in Brief. October 2007.

new large-scale industrial facilities. Although this barrier is difficult to mitigate in the short-term, it is an important consideration for investors and may delay or slow the expansion of second-generation bioenergy plants.

- **Build-out Challenges**: The process of commercializing new energy systems typically involves building smaller-scale pilot plants to identify technology or process issues, and then building a commercial-sized facility that incorporates lessons learned in the pilot phase. Experience has demonstrated that both petroleum refineries and first-generation biorefineries have evolved from smaller facilities to larger ones over time in order to realize economies of scale. Second generation biorefineries and biopower plants will most likely benefit from similar economies of scale. However, they may also encounter additional hurdles in this scaling-up process due to possible feedstock-supply constraints and technical challenges, such as those that can arise when co-firing a high percentage of biomass. Thus, the scale advantages of larger biorefineries and biopower plants might be offset to some extent by the need to overcome additional logistical challenges and/or higher costs for large feedstock volumes, or to address other technical hurdles. These issues can create additional barriers to the commercialization of bioenergy technologies.

- **Labor**: Many of the labor skills needed to support the expansion of an advanced biofuels and biopower industry overlap with those required in the existing corn ethanol and power generation industries. Still, such an expansion is likely to create demand for several types of specialized expertise that are specific to advanced bioenergy technologies. Commercializing biofuels production from lignocellulosic feedstocks, for example, would increase demand for both skilled and unskilled labor. Microbiologists, biochemists and bioengineers will all be needed to advance feedstock development and conversion processes. Industrial and mechanical engineers who can improve process efficiencies will also be crucial. Lastly, because the petroleum, chemical, and biotech industries require skills that overlap with those needed in biofuels processing, educated workers who have these skills will be in high demand, especially during a bioenergy-industry boom. Colleges and universities will likely play a central role in ensuring that adequate human resources are available to meet these specialized workforce demands. Additionally, as demand for bioenergy grows in the future, related jobs in construction, industrial chemicals, utilities, maintenance and repair, and business services will also grow. For these reasons, it is imperative to develop the broad pool of labor skills that will be needed to support growth in the bioenergy industry.

Siting and Permitting Issues: Although biorefineries and biopower plants are typically less capital-intensive and smaller than petroleum refineries, siting and permitting issues are likely to emerge as significant challenges given the large number of new production facilities that will be needed to support the implementation of current biofuels mandates. The concerns that cause citizens and interest groups to oppose the local development of petroleum refineries or other industrial facilities (chemical plants, for example)—often referred to as the NIMBY effect—are likely to also apply to biorefineries and biopower plants. For investors, it will be important that siting and permitting processes are in place that will allow the construction of well-designed and appropriately located facilities to go forward in a reasonable timeframe. Developing specific permitting protocols and regulations for second generation biorefineries and biopower plants might help to mitigate this potentially important deployment hurdle.

Other General Barriers

A number of other general barriers may need to be addressed to accelerate the large-scale deployment of bioenergy production technologies.

Distribution and Market Access: In most cases, the issues that arise in distributing second-generation biofuels to customers through wholesale and retail avenues are similar to those that apply to first generation fuels, such as corn-produced ethanol. Other biofuels that are more comparable (or equivalent) to conventional fuels, such as Fischer-Tropsch diesel, will be able to utilize the current fuel distribution infrastructure. Because ethanol is by far the most prevalent biofuel in the market, the discussion below assumes that compliance with RFS requirements after 2015, when the mandate requires increasing quantities of cellulosic and advanced ethanol on top of the "maximum" 15 billion gallons per year to be supplied using corn feedstocks, will require widespread use of higher-level ethanol blends (i.e., blends with more than 10 percent ethanol content). Investors will be reluctant to capitalize the scaled-up production facilities needed to supply large quantities of cellulosic and advanced ethanol without confidence that the distribution infrastructure exists to bring these higher-level blends to market.

- **Product Quality and Standards—Integration into Fuels Markets**: Gasoline-ethanol blends with 10 percent ethanol

content (E-10) have become common in many areas. Current EIA modeling assumes that, by 2015, virtually all gasoline sold in the United States will be E-10. Because mandated volumes of additional, advanced biofuels grow rapidly after 2015 under the national RFS, the use of ethanol blends above E-10, such as E-85, will also have to increase substantially within the next decade.

Currently, EPA regulations preclude the use of ethanol blends above 10 percent except in certified flex fuel vehicles (FFVs). It is therefore critical to the advanced biofuel industry that (a) greater numbers of FFVs enter the fleet to create adequate market demand for E-85 and (b) that barriers to the distribution of ethanol blends higher than 10 percent are resolved. Because higher ethanol content in gasoline may impact several components of existing automobile fuel systems, technical issues need to be researched and resolved prior to increasing blend levels. Higher ethanol blends may also require modifications in fuel distribution, storage, and refueling infrastructure. These issues are well known, but implementing necessary infrastructure changes or additions could still represent a major deployment hurdle, especially in the current investment environment.

Other biofuels will face different hurdles related to product integration and will have to meet specific standards prior to distribution.[119] All biofuels will need to comply with common standards in order to guarantee acceptable market access.

- **Pipeline Network**: At present, most corn-based ethanol production is located in the Midwest. Rail and truck transportation, along with some barge shipments, are the primary modes used to transport ethanol from the Midwest to fuel markets on the coasts. The production of biofuels from second generation biomass sources, by contrast, is likely to be more geographically dispersed. For instance, ethanol from corn stover will still be produced in the Midwest but ethanol from switchgrass or miscanthus may be produced in regions outside the "corn belt." Biodiesel can be produced in many locations, including major metropolitan areas, and biodiesel production from microalgae may be focused in the south and southwest.

The oil industry has benefited from the geographic concentration of refinery capacity along the Gulf Coast, which facilitated the development of pipeline networks from production centers to market hubs. Thus far, development of a dedicated ethanol pipeline from the Midwest to major markets has not been economic. As ethanol production from both corn and cellulosic feedstocks continues to grow, however, sufficient economic incentive may exist to support the construction of a dedicated ethanol pipeline system to serve growing distribution markets. However, constructing any pipeline requires addressing a number of economic and regulatory barriers. Investors in pipeline projects need assurance that there will be adequate revenue to generate a return on capital and that business risks—both in terms of future market and regulatory developments—are manageable. Pipeline construction also requires that land-use issues be resolved and that secure right-of-way access and relevant permits can be obtained from the many entities likely to be involved. These issues are often difficult to resolve due to competing interests, safety concerns, and NIMBY-type local opposition. Even with a dedicated pipeline network, further distribution-infrastructure hurdles will need to be overcome:

- Facilities will be needed to aggregate and store ethanol from disparately located biorefineries;
- A regional distribution network will be needed to serve key markets such as the New York Harbor area, Los Angeles, Houston/Dallas, the mid-Atlantic region, and potentially Florida and the Southeast; and
- Facilities to integrate ethanol storage and blending operations with existing petroleum supply terminals will be needed in destination markets.

It is unlikely that pipeline connections to all the existing terminals in the United States will be economically viable. Therefore, what is most probable is that ethanol will be moved from biorefineries to key destination markets and then stored for redistribution to regional terminals by rail, truck, or barge. The alternative to a pipeline network would be a significantly expanded reliance on long-distance rail, barge, and truck movements. These options are more expensive and carry other attendant risks, which are discussed below.

[119] As an example, biodiesel produced from microalgae that complies with the ASTM Biodiesel Standard D6751 still requires additional processing to avoid fuel oxidation before it can be distributed in the market. Alternatively, microalgal biodiesel producers are working to produce fuels that meet the requirements of ASTM D975, the standard specification for diesel fuel. Producing biodiesel that adheres to this standard obviates any need for further fuel integration steps and allows the fuel to be distributed in the current diesel infrastructure.

Rail and Truck Availability: Truck and rail transport is currently used in several stages of biofuels distribution, including:

- Movement of biofuels from biorefineries to destination terminals in key markets (at least until pipelines are constructed for this purpose),
- Movement of biofuels from destination terminals in key markets to blending terminals (this can also occur via barge), and
- Final movement of biofuel/gasoline blends to service stations.

Existing truck and rail infrastructure will need to be improved to handle a large increase in the volume of biofuels transferred to blending terminals and ultimately to retail establishments. The existing ethanol distribution system "works" adequately at current production levels of 7–8 billion gallons per year but the prospect of a significant expansion raises a number of issues that must be thoroughly investigated and understood. Until a pipeline network is constructed, transport is likely to represent an important logistical challenge—one that is compounded by the fact that key destination markets coincide with large population centers where capacity to expand rail and road infrastructure is already substantially constrained.

- **Downstream Tankage**: In addition to expanded transport capacity, an increase in biofuels use will require additional tankage (storage) infrastructure. This may translate to adding new, dedicated biofuel tanks or converting existing gasoline tanks to store biofuels at fueling terminals. However, the ability of terminal owners to add this capacity is highly dependent upon state and local processes for permitting and approving new storage facilities for combustible products. Even in some states that have mandated the increased use of ethanol, state permitting processes have made it difficult for terminal owners to complete required changes.
- **End Use Demand**: E-10 is already being sold at thousands of service stations across the United States; its use generally does not necessitate changes to refueling infrastructure or vehicle systems. As already noted, however, compliance with RFS requirements will necessitate increased use of higher ethanol blends beginning in 2015, if not earlier. At present, FFVs certified to operate on E-85 or other higher-level ethanol blends constitute only a small fraction of the overall light-duty vehicle fleet. Their numbers will have to increase substantially to create adequate market demand for mandated quantities of biofuels after 2015. It is possible that automakers, with adequate study, may find it possible to raise ethanol blends to 20 percent in the current car fleet, but additional research is necessary before moving in this direction. Meanwhile, consumers may be unaware that enabling widespread distribution of E-85 will necessitate significant infrastructure changes at service stations and may object if they find the per-mile cost of operating on E-85 is higher than the cost of operating on conventional gasoline as a result of ethanol's lower energy density. This may impact retailers' ability to sustain E-85 sales if conventional fuels are available at more competitive prices.

GHG Accounting Issues: The GHG impacts of expanded bioenergy use vary widely, depending on choices made at each step of the bioenergy value chain. Net lifecycle GHG emissions for biomass-based transportation fuels depend largely on the upstream emissions associated with feedstock production and conversion—not on emissions generated at the point of fuel combustion itself. Different production pathways (including the type of conversion technology involved and the fuels used to supply process energy) can result in significantly different GHG footprints. Further, uncertainty about the net emissions impacts of any land-use changes that are directly or indirectly prompted by expanded cultivation of bioenergy crops makes GHG accounting for biofuels and biopower especially difficult. While it is possible to estimate GHG emissions from land dedicated to growing energy crops, it is far more difficult to account for indirect emissions that result when land is converted from other uses for this purpose. It is also often difficult to account for emission changes when lands are dedicated to growing different types of crops that have dissimilar carbon sequestration capacities.[120] Specific crop choices and management practices—such as no-till farming, quantities of fertilizer used, and length of crop rotations—also affect GHG emissions from bioenergy production.

The carbon content of biofuels is likely to be regulated in the future: Not only does the existing RFS include benchmark standards for the GHG emissions of "advanced" and "cellulosic" biofuels, carbon management legislation—either in the form of an economy-wide cap on GHG emissions or a low-carbon fuel standard—will likely be implemented within the next several years. Such policies will require a careful assessment of the

[120] Pena, Naomi. "Biofuels for Transportation: A Climate Perspective" for Pew Center on Global Climate Change, June 2008.

life-cycle GHG impacts of all fuels. Calculating these emissions is not a simple task; depending on the standards and GHG accounting protocols in place, some biofuels may be disadvantaged. In any case, investors will want to clearly understand the carbon implications of different feedstock and conversion technology pathways before committing to specific projects.

Feedstock-Specific Barriers

The following table briefly summarizes barriers that apply to specific categories of bioenergy feedstocks.

FEEDSTOCK	BARRIERS
Agricultural Residues (corn stover, sugarcane bagasse, etc.)	■ Harvesting: An assessment is needed of the optimal amount of residue that should be left on the field to prevent soil nutrient deficiencies that would eventually result in lower yields. ■ Collection and Storage: Wet seasons could disrupt supply given the climate-specific conditions needed to store these residues. Adequate farm equipment and labor (including equipment operators and baling crews) will need to be available to collect the volumes necessary for large-scale production. Although dry storage is the most common option for storing corn stover today, there are many challenges and costs associated with this practice. Moving to wet storage techniques may alleviate many of these concerns but this practice brings higher water demands, which also impose a potential constraint on production.
Wood wastes	■ Collection: Wood waste is often expensive to assemble and difficult to manage. For example, woody material cannot be mechanically extracted from forest floors, instead it must be collected manually and then aggregated in sufficient quantities prior to transport. Paper and lumber mills may be more economic feedstock sources, at least initially, although securing adequate supplies could be a concern if a single mill is the sole feedstock source for a plant.
Municipal Solid Waste (MSW)	■ Collection: Most MSW jurisdictions manage operations independently, which could require that bioenergy producers enter into agreements with several surrounding jurisdictional entities to ensure ratable supplies of MSW throughout the year adequate to support economic operation of a given facility. Entering into long term agreements with multiple local governments might be difficult and time-intensive. ■ Siting: MSW is mostly available in or near major metropolitan areas. Ideally, biorefineries would be sited proximate to feedstock sources. However, metropolitan areas are precisely where siting is the most difficult, both because of local environmental concerns and NIMBY issues.
Switchgrass and Miscanthus	■ R&D Needs: Switchgrass and miscanthus would benefit from increased R&D to improve crop yield per acre and to increase the ratio of hemicellulosic content to lignin content in the feedstock. Both of these characteristics would allow for higher energy yields. Considerable work is being done in this area at many institutions but it has not been applied so far on a commercial scale. Cultivating the quantities of switchgrass needed to support commercial-scale biofuels production will require large areas of land. Because switchgrass is a seasonal crop, maintaining feedstock quality through long periods of storage is another critical issue. In order for miscanthus to become a reliable feedstock, the first hurdle to be crossed is identifying a non-invasive strain. Once this is achieved, other barriers such as the long time it would take to establish miscanthus and its high production costs will also have to be addressed. ■ Transport and Storage Issues: Switchgrass and miscanthus may face high transport and storage costs because the grasses are not dense and hence take up a lot of space. Transport will require numerous trucks or railcars, and large structures will have to be built to accommodate the grasses at storage sites. ■ Resource Requirements: Widespread cultivation of energy crops has the potential to encroach on cultivated land currently devoted to other purposes. Energy crops could compete with food crops and with plant material that is used for animal feed, or timber products.

FEEDSTOCK	BARRIERS
Microalgae	■ R&D Needs: The cost of producing microalgal biodiesel can be reduced substantially by using a biorefinery based production strategy, improving the energy potential of microalgae through genetic engineering, and advances in the engineering of photobioreactors. Genetic and metabolic engineering are likely to have the greatest impact on improving the economics of microalgal biodiesel production. There is also a need to identify possible biochemical triggers and environmental factors that favor the accumulation of oil in microalgae. Also, there is ample potential to significantly improve tubular photobioreactor technology. ■ Resource Constraints: Large-scale production of microalgae will require large amounts of sunlight, CO_2, inorganic salts, and water. ■ CO_2: There is no lack of CO_2 for the growth of microalgae, but it may not be available in the concentrations needed for optimal growth in areas where raceway ponds or photobioreactors are situated. One method of providing adequate CO_2 involves the use of GHG emissions from power generation plants as an input to microalgae raceway ponds and photobioreactors. However, this integration remains in the development phase. Development of these types of integrated facilities could help reduce production costs for microalgae biodiesel. ■ Inorganic Salts: Inorganic salts that consist of nitrogen, phosphorous, iron and, occasionally, silicon, are also necessary for the growth of microalgae, but these are expensive to obtain. Although the availability of inorganic salts is not currently a barrier, large-scale developments of microalgae may impact the availability of some inorganic salts, resulting in shortages of critical nutrients in the proportions required for cultivating microalgae in raceway ponds or photobioreactors. ■ Water: Accessing adequate water sources is also a key issue in the cultivation of microalgae. One of the most economic methods of producing microalgae would be to pump saline water from the ground in Southwestern states. Not only does saline water provide the inorganic salts used to feed microalgae, it also reduces the pressure on freshwater supplies which are in demand for human consumption and irrigation of farmlands. However, the need to wash raw biodiesel with acid and then water to remove free glycerol and methanol during transesterification means that a reliable source of fresh water is also needed, even where saline water is available. Consequently development of sites to produce microalgae, particularly outdoor raceway ponds, must consider access to multiple sources of water.
Short Rotation Willow and Hybrid Poplars	■ R&D Needs: The use of short rotation willow as a feedstock for producing biofuel is relatively new. There has been little testing to demonstrate the resistance of short-rotation willow against pests, droughts, and other maladies.[121] Also, short-rotation willow requires three to four years to mature and involves labor-intensive harvesting. R&D in these areas is necessary if short-rotation willow is to become a major bioenergy feedstock. ■ Cultivation Issues: Climatic conditions optimal for growing short-rotation willow are very specific, which may make this crop less competitive than miscanthus and switchgrass in terms of yield and cost. The most suitable conditions for growing willow can be found in cold and wet climates with ample freshwater sources. These types of habitat can only be found in certain parts of the United States. These limitations may accentuate competition with other land uses in suitable areas and may make it difficult for a "willow-only" biofuel processing site to be viable for investors. ■ Hybrid poplar shares many of the challenges that apply to short-rotation willow as a commercial feedstock for biofuel production. In addition, it has an even longer rotation time for crop cycles (8–10 years vs. 4–5 for willow).[122]

[121] Houghton, John, et al. "Breaking the Biological Barriers to Cellulosic Ethanol: A Joint Research Agenda." Office of Science. June 2006.

[122] Worldwatch Institute. Biofuels for Transportation: Global Potential and Implications for Sustainable Agriculture and Energy in the 21st Century. Earthscan Publications Ltd.: August 2007. Page 48.

Technology Specific Barriers

The following table briefly summarizes barriers that apply to specific categories of bioenergy conversion technologies.

TECHNOLOGY	BARRIERS
Biochemical	■ Costs: The cost of biochemical conversion is very high compared to current corn-based ethanol production. The most expensive part of the procedure is pretreatment, which costs nearly $0.30 per gallon of ethanol.[123] In addition, although enzymatic hydrolysis produces higher yield and lower amounts of toxic byproducts than acid hydrolysis, it still requires expensive enzymes. Acid hydrolysis techniques remain the more mature method for converting hemicellulose to complex sugars and cellulose into simple sugars but the high cost of acid, together with low process efficiencies, inhibits the economics of this process. ■ R&D Needs: A top R&D priority of DOE's biomass program is advancing biochemical conversion technology. Because production costs are high, R&D should focus on reducing costs by improving pretreatment techniques, engineering more efficient enzymes and more robust organisms to digest sugar, and combining pretreatment and fermentation steps into a single process.
Microalgae	■ Costs: Although the techniques for growing and harvesting microalgae and producing biodiesel through transesterification have been well known for several years, the process still faces high cost barriers due to two primary technological challenges. First, despite high yields per acre, the land requirements for developing raceway ponds are very large.[124] Second, the more volumetrically productive method of using tubular photobioreactors is expensive because of the high costs of the technology used to maintain optimized light and temperature for microalgae cultivation.[125] Thus, either method of producing microalgae encounters costs constraints. Establishing markets for by-products of microalgae transesterification—such as glycerol and animal feed—could help defray some of these costs. However, costs will need to come down significantly in order for microalgae to be competitive with traditional fuels. ■ R&D Needs: Dedicated programs addressing microalgae cultivation and production are needed to lower the costs of biodiesel. Additional work on the genetic modification of microalgae to produce higher oil yields and high productivity in a range of growing conditions is also needed.
Thermochemical	■ Costs: Although thermochemical processes used to produce biofuels from cellulosic biomass are technically proven, they are still quite expensive due to high capital costs, challenges associated with efficiently feeding biofeedstocks into pressurized gasifiers, and the need to effectively clean the syngas prior to successive reaction.[126] While high capital costs can be overcome through creative financing, high costs of production must be reduced for thermochemical processes to become commercially viable. ■ R&D Needs: Continued efforts to address these cost factors are needed.[127] Additional work on developing options to ferment syngas may also provide a low-cost pathway for synthetic biofuels.

[123] According to the Florida Renewable Energy Technologies Grants Program, the greatest barrier to commercializing ethanol produced from sugar cane bagasse is the cost and efficiency of the pretreatment process. Even if pretreatment and consequent hydrolytic process effectively convert cellulose and hemicellulose into fermentable sugar, the cost of this procedure makes up at least 50 percent of the cost of producing ethanol from sugar cane bagasse.

[124] Sheehan, J. et al. "A Look Back at the U.S. Department of Energy's Aquatic Species Program: Biodiesel from Algae." National Renewable Energy Laboratory. July 1998. Page 245-246.

[125] Ibid.

[126] Larson, E. "Biofuel production technologies: status, prospects and implications for trade and development." Prepared for United Nations Conference on Trade and Development. 2008.

[127] Ibid.

TECHNOLOGY	BARRIERS
Biopower	■ Technical issues: Weak boilers can present problems for biomass co-firing due to variability in the heat contents of different biomass feedstocks. Wide implementation of biomass co-firing requires predictable and known requirements for boiler strength and biomass heat rate. Biomass co-firing rates are typically restricted to 15 percent. However, it is technically possible to co-fire at rates up to 50 percent. Co-firing at higher rates can pose problems in existing coal-fired boilers. There are technical concerns about the potential deterioration of boiler performance and integrity due to co-firing with higher proportions of biomass. ■ Biomass IGCC is a relatively new technology that has only recently been demonstrated. There have been no utility-scale demonstration of the requisite gasification technology to date, although there have been high profile demonstrations in the United States and in Sweden. For biomass IGCC to achieve wide-scale deployment, several technical challenges must be confronted. First, the technology must be demonstrated at utility scale. Scrubber efficiency needs to be improved to achieve gas clean up and reduce emissions. Many of the technical barriers associated with biomass IGCC are being addressed through research sponsored by the DOE Clean Coal Program—many of the improvements developed in this program can be transferred to biomass projects with minor adjustments. ■ Regulatory Barriers: Existing Clean Air Act regulations provide an incentive to co-fire with biomass to reduce sulfur dioxide (SO_2) and nitrogen oxide (NOx) emissions. However, some power plant operators are hesitant to retrofit existing plants to co-fire with biomass because of concern that doing so could trigger New Source Review.[128]

[128] Amos et al, "Biopower Technical Assessment: State of the Industry and Technology," NREL, ORNL, March 2003, p. 2-4. http://www.nrel.gov/docs/fy03osti/33123.pdf.

Appendix VIII: NCEP Technology Workshop Participants

The following organizations participated in the six workshops NCEP convened as part of this project. All participants provided valuable input. However, it should be noted that the participating organizations did not take part in crafting the final report. The insights and feedback provided during the workshops helped inform NCEP's work on each low-carbon technology, but the findings and conclusions in the final report should be attributed to NCEP staff alone.

NCEP Carbon Capture and Storage Workshop
September 17, 2008
Washington, DC

Participating Organizations

1. Belfer Center for Science and International Affairs, Harvard University
2. World Wildlife Fund
3. United Steelworkers
4. Exelon Corporation
5. Sustainable Finance, Ltd.
6. Lawrence Livermore National Laboratory
7. Alstom Power, Inc.
8. SAIL Venture Partners LLC
9. FutureGen Alliance
10. CH2M Hill
11. Electric Power Research Institute
12. Natural Resources Defense Council
13. U.S. Environmental Protection Agency
14. Hydrogen Energy
15. JP Morgan Chase
16. Edison Mission Marketing and Trading
17. BP America, Inc.
18. Air Products and Chemicals, Inc.
19. World Resources Institute
20. Summit Power Group
21. Duke University
22. Resources for the Future
23. Excelsior Energy
24. Chevron Corporation
25. ICF International
26. Clean Air Task Force
27. Center for Science and Technology policy, Hubert Humphrey Institute of Public Affairs, University of MN
28. Hudson Clean Energy Partners
29. Joint Global Change Research Institute, Pacific Northwest National Lab/U. of Maryland
30. Meridian Institute

NCEP Renewable Energy Technology Workshop
October 2–3, 2008
Denver, CO

Participating Organizations:

1. Belfer Center for Science and International Affairs, Harvard University
2. National Renewable Energy Laboratory
3. CH2M Hill
4. SunPower
5. Exelon Corporation
6. Union of Concerned Scientists
7. Chevron Corporation
8. Department of Environmental Protection, State of Pennsylvania
9. Geothermal Energy Association
10. GridPoint
11. General Compression
12. Iceland America Energy
13. Natural Resources Defense Council
14. MMA Renewable Ventures, LLC
15. OptiSolar
16. University of Denver
17. Clean Energy Group
18. Clean Energy States Alliance
19. Edison Mission Marketing and Trading
20. Pew Center on Global Climate Change

21. Xcel Energy
22. BP Solar
23. Vestas American Wind Technology, Inc.
24. NORESCO
25. North American Electrical Reliability Council
26. MidAmerican Energy Holdings Company
27. Lawrence Berkeley National Laboratory
28. Joint Global Change Research Institute, Pacific Northwest National Lab/U. of Maryland
29. Meridian Institute

NCEP Advanced Nuclear Power Workshop
October 15, 2008
Chicago, IL

Participating Organizations:

1. U.S. Department of Energy
2. Environmental Defense Fund
3. Natural Resources Defense Council
4. Clean Air Task Force
5. Wisconsin Institute of Nuclear Systems, University of Wisconsin
6. Exelon Corporation
7. Nuclear Energy Institute
8. Massachusetts Institute of Technology
9. Westinghouse Electric Corporation
10. Oak Ridge National Laboratory
11. JP Morgan Chase
12. Idaho National Laboratory
13. CH2M Hill
14. BlueWater Strategies, LLC
15. Energy Future Holdings
16. George Mason University
17. Carnegie Institution of Washington
18. Electric Power Research Institute
19. The Keystone Center
20. The NorthBridge Group
21. Luminant
22. Standard & Poor's
23. FPL Group
24. Sigma Xi
25. Joint Global Change Research Institute, Pacific Northwest National Lab/U. of Maryland
26. Meridian Institute

NCEP End-Use Efficiency in the Building Sector Workshop
October 28, 2008
Washington, DC

Participating Organizations:

1. Belfer Center for Science and International Affairs, Harvard University
2. World Wildlife Fund
3. Natural Resources Defense Council
4. American Society of Heating Refrigerating and Air-Conditioning Engineers
5. JP Morgan Chase
6. Alliance to Save Energy
7. State Capitol Preservation Board, State of Utah
8. Center for American Progress
9. U.S. Green Building Council
10. Lawrence Berkeley National Laboratory
11. Madison Engineering
12. CH2M Hill
13. Resources for the Future
14. NORESCO
15. U.S. Department of Energy
16. ARUP
17. Southern California Edison
18. Duke University
19. Department of Energy Resources, State of Massachusetts
20. Joint Global Change Research Institute, Pacific Northwest National Lab/U. of Maryland
21. Meridian Institute

NCEP Vehicle Technology Platforms Workshop
November 6, 2008
San Francisco, CA

Participating Organizations:

1. California Clean Energy Fund

2. Environmental Defense Fund
3. Chevron Technology Ventures
4. American Honda Motor Company
5. California Energy Commission
6. Rocky Mountain Institute
7. Sacramento Municipal Utility District
8. PSEG
9. Electric Power Research Institute
10. Electric Drive Transportation Association
11. Dueco, Inc.
12. California Fuel Cell Partnership
13. Efficient Drivetrains, Inc.
14. The Energy Foundation
15. Natural Resources Defense Council
16. International Council on Clean Transportation
17. Institute for the Analysis of Global Security
18. Coulomb Technologies
19. Meszler Engineering
20. Green Car Congress
21. Tesla Motors
22. Fuel Cells 2000
23. Hewlett Foundation
24. Valence Technologies
25. CH2MHill
26. Center for Energy Efficiency and Renewable Technologies
27. Southern California Edison
28. Johnson Controls
29. Institute for Transportation Studies, UC Davis
30. Joint Global Change Research Institute, Pacific Northwest National Lab/U. of Maryland
31. Meridian Institute

NCEP Workshop on Bioenergy Participants
November 18. 2008
Washington, DC

Participating Organizations

1. Pew Center of Global Climate Change
2. Mendel Biotechnology, Inc
3. World Wildlife Fund
4. AJW, Inc.
5. Department of Energy Resources, State of Massachusetts
6. United Steelworkers
7. Institute for the Analysis of Global Security
8. ConocoPhillips
9. Novozymes
10. BP America, Inc.
11. Harvard University
12. Enerkem
13. Clean Air Task Force
14. U.S. Environmental Protection Agency
15. Booz Allen Hamilton
16. Ceres, Inc.
17. New York State Energy Research and Development Authority
18. Center for Energy Efficiency and Renewable Technologies
19. Natural Resources Defense Council
20. Xcel Energy
21. Chevron Corporation
22. Carnegie Mellon University
23. Princeton University
24. Joint Global Change Research Institute, Pacific Northwest National Lab/U. of Maryland
25. Meridian Institute

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