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## PART 2

### Energy Policies

The political pendulum in the United States has swung away from the highly interventionist role governments played in energy markets following the oil price shocks of the 1970s toward deregulation in the 1980s and 1990s, and back toward much greater intervention in recent years. The latest shift reflects renewed concerns about energy security and the emerging threat of global climate change.

Naturally, there is some overlap between energy policy and some of the issues discussed in the sections on climate and transportation policy. This section covers various issues related to the economic implications of oil dependence, development of alternative energy technologies, specific energy policies, and the workings of energy markets.

A central concern about U.S. dependence on oil is the potential for future oil price shocks to disrupt the economy, to what extent (if any) taxation of oil is warranted to reduce vulnerability to price risks, and the possible causes of recent price spikes. A related issue is whether or not any military burden associated with protecting supplies from the Persian Gulf should be factored into energy taxes.

New technologies are affecting energy markets, and one of the most dramatic has been the rapid development of oil sands in Canada. With this new resource, Canada now has more oil reserves than any country other than Saudi Arabia. The future viability of the coal industry in a carbon-constrained world critically hinges on another emerging technology discussed here—carbon capture and storage. And much deeper into the future, is there any potential for satellite-collected solar power to supply electricity generation?

Specific energy policy issues that are discussed include the possibility for oil drilling in Alaska's Arctic National Wildlife Refuge; the design of policy to reduce the incidence of oil spills; the extent of, and case for removing, energy subsidies in the income tax code; whether there is a rationale for subsidizing solar photovoltaic installations; and practical obstacles to the siting of new energy infrastructure. Also discussed are market or other incentives for green building design, the functioning of markets for natural gas, and current issues in restructuring the power sector.

# 19. REFLECTIONS ON THREE DECADES OF U.S. ENERGY POLICY

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## Phil Sharp

has been president of Resources for the Future since 2005. His career in public service includes 10 terms as a member of the U.S. House of Representatives from Indiana and a lengthy tenure on the faculty of the John F. Kennedy School of Government and the Institute of Politics at Harvard University.

*Written from the perspective of someone heavily involved in crafting energy legislation for many years, this commentary describes how the political pendulum first swung toward, then away from, and then back toward an interventionist role for government in energy markets.*

Often the statement is made that America lacks an energy policy. In truth, we have a plethora of policies intended to reshape energy markets. What people really mean is that we lack a coherent vision, with policies that are strong enough to generate major, sustained changes in the ways energy is produced and consumed.

Over the past several decades, we have periodically engaged in intensive policy-making, usually in association with disruptive swings in energy prices. Each time, we have struggled to achieve a national consensus.

That struggle has focused on both ends and means. Essentially, there are four different goals that differing political factions have argued must be addressed.

The first is economic, namely, assuring that we can afford to fuel our homes, schools, industries, and commercial activities. All sorts of policy interventions to stimulate oil production, ethanol production, and so on have been defended on the grounds that they are important to our economic prosperity. Many of us have argued that efficiency and conservation additionally serve this purpose.

The second is protection of our national security. A host of concerns have been articulated: the threat of disruption of international oil and natural gas supplies by governments or terrorists; the pressure on our foreign policy to accommodate oil-producing states that are hostile to our values; the flow of wealth from U.S. consumers to rogue nations; and terrorism.

The third is guarding our environment—mitigating or preventing damage to our air, water, and land from the production and use of energy, such as burning coal in power plants, combusting gasoline in vehicles, and disposing of nuclear waste. Given federal ownership of massive land acreage and the outer continental shelf, major disputes arise over access for drilling and mining. Today, of course, climate change represents the mother of all environmental concerns, with calls for a radical overhaul of our energy systems in order to dramatically cut greenhouse gas emissions in the decades ahead. This issue had been identified by RFF scholars back in the 1970s.

A fourth goal has been addressing equity or fairness issues: concern for the poor and concern for regional impacts such as rising fuel oil prices for home heating in New England or gasoline prices for long-distance drivers in the West. When prices spike, political fights invariably erupt over how to protect the consumer from the producer. The intensity of equity fights rises and falls with prices.

Thus far, our political system has not been able to set priorities among these goals in a strong and sustained way. In the 2008 presidential campaign, the two major candidates essentially argued that we could serve all these goals, blurring the fact that policy that serves one goal may undercut another, such as support for “coal to liquids.”

We have seen a significant ebb and flow in government efforts to redirect our energy markets. Following the Arab oil embargo of 1973, there was a major drive to cut oil imports and shield the economy from expected disruptions and price spikes. Independence was the mantra. Price controls had long been in place for natural gas; oil-price controls were adopted in the 1970s as part of an economywide anti-inflation program of wage and price controls. Such controls proved to be counterproductive

to reducing oil imports. They deterred conservation and discouraged domestic production, and, further, they disrupted the internal shipment of fuels to consumers. We appear to have learned the lesson of such failure: during the recent run-up in oil prices, no political leaders called for price controls.

During the 1970s, there were other major market interventions, including mandates, public investment, loan guarantees, and tax incentives. Auto manufacturers were required to meet fuel economy standards, utilities were required to purchase electricity from other industries that cogenerated power, and utilities were prevented from building new natural gas facilities. On the public investment front, huge sums were appropriated for basic research into advanced energy technologies and for direct investment in large-scale demonstration projects meant to show, for example, that liquid fuels could be produced efficiently from coal. The tax code was reconfigured to provide incentives for a host of production and conservation activities, from installing solar panels to insulating homes, and taxes were levied on windfall profits from oil and on gas-guzzling vehicles.

Energy policy was radically overhauled during the 1980s: price controls on oil and natural gas were lifted; some mandates were ended; many tax incentives were repealed or allowed to expire; investment in large new demonstration plants ceased; and spending on research was cut back. Many of these changes derived from the Reagan administration's belief that energy developments should be left to the private markets, that the tax code should not be used for social engineering, and that government's role in research should be limited to advancing basic science. But change also resulted from the dramatic fall in oil prices in 1986 and the reversal in the conventional wisdom that had held that prices were only headed upward. Investors, consumers, and political leaders in both parties lost interest in the development of unconventional and renewable fuels, energy conservation, and efforts by government to intervene in the markets.

In the 1990s, policymaking was reenergized. On the heels of the Iraqi invasion of Kuwait came bipartisan passage of the Energy Policy Act of 1992. In the act, market liberalization continued with the drive to bring competition into electricity wholesale markets. (Several states also moved toward competitive retail markets—a movement substantially set back by the California electricity crisis in 2001.) In the 1992 act, tax incentives were again adopted, including the production tax credit, which was viewed as an improvement over the old investment tax credits as a technique for promoting renewable

power. Energy efficiency standards for select household appliances were also enacted. But the Democratic Congress and the Bush administration had no appetite for upgrading auto fuel economy standards or for public investment in large-scale technology projects.

With the passage of comprehensive energy bills in 2005 and 2007, we saw, on a bipartisan basis, the greatest market intervention since the 1970s. Mandates were imposed to promote ethanol production, to ban incandescent lightbulbs, to improve fuel economy, and to upgrade household appliances. A host of tax provisions were adopted to entice changes in investor and consumer practices, including speeding the purchase of hybrids and all kinds of energy equipment in the commercial and industrial sectors and pushing production of conventional and advanced fuels. Loan guarantees were reintroduced for advanced nuclear plants, advanced coal systems, and biofuel refineries. And there was a return to appropriations for big demonstration projects like the FutureGen coal plant.

In recent years, rising prices and policy initiatives by federal and state governments have heightened investor interest in unconventional fossil fuels and in renewable fuels. As gasoline prices reached previously unimaginable levels, consumers sharply shifted their vehicle purchases away from SUVs and even curbed their driving habits. In multiple ways, investors and consumers showed renewed interest in a host of energy-efficient technologies.

Recently, with a Katrina hitting Wall Street, the economy turning terribly sour, and oil prices plunging, all of these developments may be in jeopardy. Past experience suggests that investors, consumers, and political leaders will lose interest in greater efficiency and cleaner fuels.

This time, however, may be different. If the scientific community sustains and/or intensifies the latest assessment by the Intergovernmental Panel on Climate Change (IPCC), there should be greater motivation for action to curb greenhouse gas emissions. The stage was set by both presidential candidates calling for mandatory controls that would transform the energy sector. Indeed, both candidates connected that transformation to economic growth and to greater energy security. These connections are easier to make in rhetoric than in reality, but they represent a significant shift in the public discourse. Ahead remains the tough intellectual and political work to design, adopt, and sustain the policies that can meet the climate challenge and deliver economic growth, not only in the United States but around the globe.

## 20. THE OIL SECURITY PROBLEM

### “Déjà Vu All Over Again”

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#### Hillard Huntington

is the executive director of Stanford University's Energy Modeling Forum. His current research interests include modeling energy demand, energy price shocks, and energy market impacts of environmental policies.

*What is the likelihood of a future oil price shock, and if a price shock does occur, how much damage might it cause to the U.S. economy?*

Today, three of every five barrels sold on the world petroleum market originate from relatively insecure regions: the Persian Gulf, North Africa, Nigeria, Angola, Venezuela, Russia, and the Caspian states. Political, military, or terrorist events could disrupt oil markets and quickly double oil prices. If these events happen at a time when monetary authorities find it difficult to control inflationary expectations, a trend much more likely today than just two years ago, the world could return to the 1970s and stagflation.

Reducing our vulnerability to such events is the main task for oil security policy. Curtailing imports from our major oil trading partners (Canada and Mexico) is unlikely to benefit us, because these sources are relatively secure. But reducing our imports is important only if we can reduce the market share of vulnerable supplies in the world market. Doing so would mean that disruptions will remove less oil from the market and therefore cause less severe price shocks.

Our vulnerability also depends upon how closely our infrastructure is tied to petroleum use. When disruptions cause oil prices to double, the higher price applies to any oil used in the U.S. economy. It does not matter whether we are relying on imports, domestic supplies, or even close substitutes, like ethanol and other biofuel options. For this reason, efforts to reduce oil demand may be more valuable than efforts to simply replace vulnerable imported supplies with domestic supplies of oil or ethanol.

Pursuing energy security is relatively simple in conceptual terms. The nation is buying an insurance policy against future recessions caused by unanticipated oil price shocks. Today's insurance policy should cost no more than the value of avoiding these possible damages. Higher avoided damages could be due either to a greater probability of a disruption happening somewhere in the oil market or to more serious economic impacts from such a disruption.

Since experts disagree on both issues, it is often difficult to implement this principle empirically. For example, a recent Oak Ridge National Laboratory study computed the hidden social costs attributable to oil based upon a range of different views. Their estimates ranged widely from \$6 to \$23 per barrel, with a midpoint estimate of about \$13 per barrel.

Stanford University's Energy Modeling Forum recently completed two studies that may help resolve some of the uncertainties related to damage estimates associated with oil insecurity.

In the first effort, a working group of geopolitical and oil-market experts assembled to provide expert judgment on the risks of one or more disruptions at some point over the next 10 years. The experts identified specific disruption events and the conditions that could make them more or less likely. From there, they evaluated the probability that a certain set of events could happen and estimated the amount of oil removed from the market in each case. Four separate oil-producing regions were considered: Saudi Arabia, other Persian Gulf nations, Russia and the Caspian states, and a set of heterogeneous countries including Libya, Nigeria, and Venezuela.

The experts concluded that another disruption, given today's conditions, is very likely. At some point over the next 10 years, there is an 80 percent chance that at least one disruption of 2 million barrels per day (MMBD, or 2.4 percent of the total market) or more would last one month or longer. Those familiar with playing with

a well-shuffled deck of cards will immediately recognize this probability as exceeding the chances that you would draw a club or a red suit.

Compared to previous periods, the risks today are greater for smaller disruptions below 7 MMBD than for larger ones. Not only are there more insecure regions today than in the past, but fewer opportunities exist to reduce the size of any disruption with offsets from excess oil production capacity in undisrupted regions. These offsets tend to be highly concentrated in Saudi Arabia and hence are unlikely to be available if oil is disrupted in that country.

In the second study, macroeconomic experts gathered to discuss the likely economic impacts resulting from oil price shocks. An important distinction concerns the nature of an oil price increase. During the 1970s and early 1990s, oil supply disruptions caused prices to rise suddenly and sharply. These price shocks were fundamentally different from the price elevation occurring over recent years, when oil prices have been rising more gradually than during the 1970s. Price shocks are likely to create great uncertainty, forcing firms and households to delay their investment, producing spillover effects throughout the economy. Price elevation, on the other hand, may anger the car owner who fills his or her gasoline tank, but it is unlikely to delay investment and lead to a recession.

The other unknown is how economic policymakers will respond to disruptions. Over the last few years, inflationary fears around the world have been very low, which has allowed monetary authorities to ease the money supply to offset lost economic output without creating additional inflationary pressures.

Over the last two years, however, inflationary fears have grown and may become more intense yet. These developments would make it much more difficult for governments to intervene and offset lost output without exacerbating future inflation.

If inflationary fears tie Mr. Bernanke's hands, does the nation have a fallback position? Yes, although the political process will adopt these policies very slowly. First, the U.S. Congress has finally tightened fuel economy standards, reducing both vulnerable supplies and our economy's reliance upon oil. Second, policymakers are considering larger public oil stockpiles, but these expansions will have limited value without a more explicit "trigger" mechanism for releasing oil during emergencies. Third, domestic ethanol or Alaskan oil supplies could replace more vulnerable supplies, but these approaches do nothing for our infrastructure's oil dependence. And finally, automobile insurance rates could discourage excessive driving by being based partly on the miles driven by each person.

More than a half century ago, the very possibility of oil vulnerability shocked the Western world with the closure of the Suez Canal. Despite other major disruptions since that explosive event, there has been little evidence of "learning by doing" in current oil security policy.

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## 21. REASSESSING OIL SECURITY

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### Stephen P.A. Brown

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*Oil security might be defined in multiple ways. To what extent might consumption of domestic and imported oil by individuals impose broader costs on the economy, thereby warranting some level of oil taxation?*

World oil prices rose rapidly from 2002 before reaching an all-time high in mid-2008. As prices rose, they were punctuated by sharp swings resulting from supply disruptions. Although oil prices have since declined, expectations that prices will rebound and once again be unstable raise concerns about oil security. Past oil supply disruptions have resulted in sharply rising oil prices and reduced economic activity. Ten of the 11 post-WWII U.S. recessions—including the one we're in now—immediately followed episodes of sharply rising oil prices.

Politicians and scholars regularly emphasize the costs of U.S. dependence on imported oil, but oil's fungibility means that consumers cannot distinguish between domestic and imported sources. All oil prices move together on an integrated world oil market, and regardless of the source, the global price for a barrel of oil ultimately determines the price at the local gas pump. But the critical security difference between domestic and imported sources of oil, namely the instability of foreign suppliers, is what creates conflict in world oil markets and where policy can be used to good effect.

The desirability of promoting oil security arises only to the extent that the potential economic losses associated with reliance on insecure oil supplies are externalities—costs that are borne by society as a whole, rather than by the parties directly involved in a transaction.

### DIFFERENTIATING BETWEEN DOMESTIC AND IMPORTED OIL

Although domestic and imported oil look very much the same to the consumer, a disruption of foreign supplies would mean higher oil prices in the United States—even if it were importing no oil from the country whose production is disrupted. The reason why is that rising oil prices elsewhere in the world would divert secure supplies from the United States to other markets. Because no oil supplies are secure from price shocks, the increased consumption of either domestic or imported oil increases the economy's exposure to oil price shocks.

Nonetheless, the U.S. economy's exposure to oil price shocks does differ for domestic oil and oil imported from countries whose production is unstable. Rising U.S. oil imports reduces energy security by increasing the share of world oil supply that comes from those countries. Conversely, expanding U.S. oil production enhances energy security by increasing the share of world oil supply that comes from stable suppliers.

### OIL SECURITY EXTERNALITIES

To the extent that the economic losses associated with oil supply disruptions are negative externalities that are not taken into account in private actions, they become a concern for economic policy. A number of other costs may arise from potential oil price shocks, but not all of them may be externalities. Negative externalities occur only when a market transaction imposes costs or risks on an individual who is not party to the transaction. (Of course, oil use creates other externalities—such as air pol-

lution and greenhouse gas emissions—that are not associated with energy security.)

Oil security externalities include increases in GDP losses arising from oil supply disruptions and the expected transfers paid to foreign oil producers during disruptions. Other costs typically associated with oil imports—such as increased prices for oil imports during periods of stable supply, limits that oil imports place on U.S. foreign policy, and the defense spending and other government expenditures designed to reduce the effects of oil supply shocks—are not security externalities.

**GDP losses.** The increase in expected GDP losses resulting from increased oil consumption is likely an externality. Increased oil consumption ups the exposure of economic activity to disruptions. Moreover, individuals buying oil are unlikely to understand or consider how their own oil consumption affects others by amplifying the effects that oil supply disruptions have on overall economic activity—particularly because the GDP losses associated with an oil price shock are well beyond the possible increase in costs that an individual might expect as part of an oil purchase.

**Increased transfers.** An increase in U.S. oil imports increases the expected transfers to foreign oil producers during a supply shock, but only part of that increase should be regarded as an externality. When buying oil products, individuals should recognize the potential for oil supply shocks and higher prices. So, the expected transfer on the marginal purchase is not an externality. On the other hand, individuals are unlikely to take into account how their purchases may affect others by enlarging the size of the price shock that occurs when there is a supply disruption. So the latter portion is an externality.

**Increased prices for imported oil during periods of stable supply.** A rise in U.S. oil imports increases the price paid for all imported oil, and that means greater costs for those purchasing imported oil. Such an increase is considered a normal market development that does not result in market inefficiency, and it is not a security issue.

**Increased government expenditures.** Government actions—such as military spending in vulnerable supply areas and expansion of the Strategic Petroleum Reserve—are possible responses to the economic vulnerability arising from potential oil supply disruptions. Sound policy requires that these expenditures be balanced against the externalities of greater oil use rather than used as a measure of the externalities.

**Limits on U.S. foreign policy.** An overall dependence on imported oil may reduce U.S. foreign policy prerogatives. These limitations may not be greatly affected by marginal

changes in oil consumption, nor is it readily apparent how to quantify such effects. Therefore, they are omitted in quantitative estimates of the security externalities associated with increased oil consumption.

**Uses of oil revenue.** Americans may be unhappy with the uses to which some oil-producing countries put their revenue, but that does not mean the sale creates an externality. The oil purchase itself does not create the unwanted behavior. The absence of a direct foreign policy instrument may make it desirable to use policies that reduce world oil prices, but the use of such a blunt instrument will hurt all oil producers, not just those unfriendly to the United States.

## ESTIMATED OIL SECURITY PREMIUMS

In recent research, Hillard Huntington and I estimated the external security costs of U.S. oil consumption. The external security cost of the consumption of domestically produced oil has a mean value of \$2.81 per barrel in a range of \$0.19–8.70. (All dollar figures are in constant 2007 dollars.) The external security cost of the consumption of imported oil has a mean value of \$4.98 per barrel in a range of \$1.10–14.35.

These estimates suggest only a moderate oil policy is necessary to respond to the security issues associated with oil use. They are based on projections made by the U.S. Energy Information Administration that show oil prices rising from about \$40 per barrel in 2009 to more than \$130 per barrel in 2030. In comparison to these oil price projections, the estimated security externalities are relatively modest.

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## 22. THE 2008 OIL PRICE SHOCK

### Markets or Mayhem?

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#### James L. Smith

is the Cary M. Maguire Chair in Oil and Gas Management at the Edwin L. Cox School of Business at Southern Methodist University. His current research covers international oil markets, auction theory, real options, and energy finance and risk management.

*World oil prices rose from \$50 per barrel in early 2007 to \$140 per barrel in the summer of 2008, before falling to \$40 per barrel by the end of that year. Can this dramatic price shock be explained by market fundamentals—shifts in worldwide demand and supply for oil—or were speculative forces at work?*

Why did oil prices spike in 2008, and what role (if any) did speculators play? Perhaps a useful starting point is to observe that, while 2008 exhibited an extraordinarily large price swing, volatility in oil prices is ordinarily quite high because the underlying demand and supply curves are so inelastic. Demand is inelastic due to long lead times for altering the stock of fuel-consuming equipment. Supply is inelastic in the short term because it takes time to augment the productive capacity of oil fields. Price volatility provides incentives to hold inventories, but since inventories are costly, they are not sufficient to fully offset the rigidity of supply and demand.

The steep ascent in the price of oil between 2004 and 2008 coincided with the first significant decrease in non-OPEC supply since 1973 and an unprecedented surge in global demand. Although OPEC members responded by increasing their production, they lacked sufficient capacity after years of restrained field investments to bridge the growing gap between global demand and non-OPEC supply.

Even seemingly small shocks may have large effects. Can they help explain the spike in oil prices in the first half of 2008? It was definitely a time of significant upheavals, some with the potential for sustained disruption of supplies. In February 2008, Venezuela cut off oil sales to ExxonMobil during a legal battle over nationalization of the company's properties there. Production from Iraqi oil fields, of course, had still not recovered from wartime damage, and in late March, saboteurs blew up the two main oil export pipelines in the south—cutting about 300,000 barrels per day from Iraqi exports. On April 25, Nigerian union workers went out on strike, causing ExxonMobil to shut in production of 780,000 barrels per day from three fields. Two days later, on April 27, Scottish oil workers walked off the job, leading to closure of the North Forties pipeline, which carries about half of the United Kingdom's North Sea oil production. As of May 1, about 1.36 million barrels per day of Nigerian production was shut in due to a combination of militant attacks on oil facilities, sabotage, and labor strife. At the same time, it was reported that Mexican oil exports (10th largest in the world) had fallen sharply in April due to rapid decline in the country's massive Cantarell oil field. On June 19, militant attacks in Nigeria caused Shell to shut in an additional 225,000 barrels per day. On June 20, just days before the price of oil reached its historic peak, Nigerian protesters blew up a pipeline, which forced Chevron to shut in 125,000 barrels per day. Each of these events clearly registered in the spot market. It is not implausible to believe that, arriving in quick succession, they contributed heavily to the rapid acceleration in the spot price of oil.

Although the rising price of trend of 2004 to 2008 is consistent with changes in market fundamentals—surging demand and falling supply—the spectacular ascent especially in the first half of 2008 created widespread suspicion that “speculators” were responsible. But neither hedging nor speculation in the futures market exerts any significant effect on current (spot) oil prices. There are two main reasons: (1) due to the law of one price, the futures price must converge to the spot price as the expiration date draws near, and (2) virtually all futures contracts are settled for cash, which means that every futures contract purchased by a trader is subsequently sold by that same

trader before the contract expires. Buying pressure is offset by selling pressure and no oil ever changes hands.

The only avenue by which speculative trading might raise spot prices is if it incites participants in the physical market (for example, producers and/or refiners) to hold oil off the market—either by amassing large inventories or by shutting in production. If participants in the physical market are convinced by speculative trading in the futures market that spot prices will soon rise, their reaction could cause inventories to rise and/or production to fall. However, neither phenomenon was observed during the recent price spike.

Finally, we might ask whether price fixing, rather than speculation per se, might be responsible for the dramatic increase in price. OPEC does engage in price fixing, and oil prices would not have reached \$145 per barrel if OPEC had not previously restricted investment in new capacity. But OPEC did not actually take any positive action in 2007 or 2008 that precipitated the price spike. OPEC aside, there is no evidence of price fixing on the part of anyone else, which includes both speculators and the oil companies.

What combination of factors then explains the collapse in oil prices that occurred during the second half of 2008? Surely the primary factor is that demand for oil dropped sharply around the world due to the economic decline, which in early 2008 few analysts were predicting would turn out to be so deep.

The world oil market operates subject to the familiar laws of supply and demand, and market fundamentals are the dominant influence on price. The market is subject to shocks, and when these shocks are taken together with short-run rigidities and high costs of adjustment, the resulting price volatility is largely inherent, rather than contrived by speculators, cunning producers, or anyone else.

In the longer run, the effects of shocks will average out, and the effects of structural trends are paramount. The most conspicuous trend, by far, is the rapid pace of economic development in China and other emerging nations. If that continues, oil's high income elasticity implies a proportionate increase in demand.

The long-run trend has been for OPEC to restrict the expansion of new production capacity. But many OPEC members also have a fundamental tendency to ignore the cartel's attempts to rein in surplus production. For as long as the current economic slowdown persists, it will be difficult for OPEC to boost the price of oil of its own volition.

The sustainability of oil supplies from non-OPEC producers is also of fundamental importance. Proven oil reserves of non-OPEC producers have been rising—but resource depletion puts constant upward pressure on costs. For decades, the oil industry has been able to use technological innovation to offset the impact of depletion by finding and producing oil in ways that held the marginal cost of output in check. Although we cannot expect further technical advances to prevent the supply of conventional oil from ever declining, in the longer term, ample supplies of unconventional petroleum resources and other substitutes for crude oil should prevent oil prices from surpassing the mid-2008 peak on any sustained basis. But too many technological and political uncertainties exist to permit a definite prediction.

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## 23. THE COST OF PROTECTING OIL IN THE PERSIAN GULF

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is a research scientist at the Institute of Transportation Studies at the University of California, Davis, specializing in economic, environmental, engineering, and planning analyses of current and future transportation systems.

*How much of the U.S. defense budget might be attributable to protecting oil supplies from the Persian Gulf is a contentious issue. To what extent should motorists pay for military spending in higher fuel taxes?*

With the United States still bogged down in the war in Iraq, rancorous debate continues in the halls of Congress regarding the political and economic costs of America's involvement in the Persian Gulf. Many contend that U.S. interests center primarily, if not exclusively, on the region's huge reserves of oil, and that, as a result, U.S. military expenditures amount to a massive "hidden cost" of oil use by the United States. Some have argued that these hidden costs, estimated to range from essentially zero to upward of \$1 per gallon, are, in effect, a subsidy that should be recovered by taxes on motor fuel. The figures vary widely because analysts disagree profoundly about whether military expenditures are related at all to oil use (specifically transportation fuels) and about the magnitude of any expenditures that putatively are related.

Here I examine this debate from a slightly different perspective. What might happen if U.S. consumers and companies hauling freight curtailed their oil use? Would the federal government reduce its military commitment in the Persian Gulf? To evaluate this, the first step is to look at the mechanism—if X happens, what happens to Y?—and the second is to examine the motives of the key decisionmaker, the U.S. federal government, which determines whether resources are available to address those risks and (presumably) authorizes military spending accordingly.

However, predicting how (or even whether) Congress and the president would adjust military spending is scarcely a straightforward process. There is no line item in the defense budget for protecting U.S. oil supplies in the Persian Gulf, and no official congressional formula that relates oil imports to Department of Defense (DOD) spending. Instead, the defense budget is itemized by general functional or cost areas, such as "operations and maintenance," which cover more than one region or program.

How Congress views the relationship between regional threats and defense spending is subject to wide interpretation. Some argue that all multiregional costs and all noncombat, DOD-wide "overhead" costs are essentially fixed with respect to changes in threats in the Persian Gulf, while other analysts argue that all such costs are variable. As a result, estimates of the peacetime costs of maintaining a military presence in the region have ranged wildly, from as little as \$0.5 billion to over \$100 billion per year.

However, there are good reasons to doubt the claim that multiregional costs and DOD-wide "overhead" costs are essentially independent of threats in a specific region. In the first place, the cost of policing several regions at once presumably is a function of the nature and number of threats in all of the regions, which means that if any one regional threat is mitigated, then generally there is less to defend. Second, in the long run there are few, if any, truly fixed overhead costs—those that are the same regardless of the size of defense forces or the magnitude of a threat—except perhaps those related to upper-level administration, like the salaries of senior DOD staff.

Assuming that fixed multiregional and overhead costs are only a small fraction of total defense costs, I estimate that the long-run variable costs of defending all interests in the Persian Gulf in peacetime are on the order of \$30 billion to \$75 billion per year—a substantial fraction of the roughly \$300 billion per year spent by DOD during peacetime.

The next step in this policy "proof" is to determine the importance of oil among

all of our interests in the Persian Gulf. Although it is not well known, numerous military planning documents and senior officials have clearly stated that our overall military objective in the region is to preserve U.S. and Western access to the oil. Given this, two specific questions need to be addressed: (1) if we start with our estimate of the total cost of defending all interests in the region, what fraction of that is related to oil interests specifically, and (2) what is the nature of the relationship? After reviewing estimates by others and considering the true “fixed” costs of defense, I estimate that over 50 percent of the total cost of defending the Persian Gulf is related to oil, and that this annual defense cost is proportional to the annual amount or value of oil produced there.

Expected wartime costs related to oil can be estimated roughly by multiplying the annual probabilities of regional wars of various magnitudes by the estimated annualized cost of such wars and the fraction of wartime costs that are “attributable” to oil. Considering that the current Iraq war will end up costing on the order of a trillion dollars, and that there is evidence that the desire to protect our access to oil is a major factor in the U.S. response to conflicts in the region, I estimate that if there were no oil in the Middle East, the United States would reduce wartime military spending by up to \$10 billion per year. Note that this is specifically an estimate of monetary costs; it does not include the very real costs of lives lost and catastrophic injuries, which perhaps could add billions of dollars per year to the total. It also does not include the virtually impossible to quantify geopolitical costs of wars and U.S. Persian Gulf policy in general.

Finally, after accounting for the portion of the oil defense cost that is not related to the consumption of highway fuels in the United States (roughly half), the bottom line is that oil used by all motor vehicles in the United States (light-duty and heavy-duty) carries a modest premium: the price of peacetime plus wartime defense spending comes to somewhere between \$3 billion and \$30 billion per year, over the long haul. This amounts to about \$0.02 to almost \$0.20 per gallon of all gasoline and diesel motor fuel used in 2004. While not necessarily trivial, this range is lower than other analysts have estimated, and lower than other environmental- and energy-related external costs of motor-fuel use.

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## 24. WHAT ROLE FOR “SYNTHETIC” LIQUID FUELS?

### A Look at Canadian Oil Sands

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*One concern about the rapidly expanding oil sands industry in Canada is the extra energy required to extract oil, compared with conventional oil sources. Would oil sands remain commercially viable if production costs were to rise with an aggressive program to control greenhouse gas emissions?*

A vocal debate about an early peak in the global capacity to produce conventional crude oil has been going on for some time now. To some, a dramatic run-up in oil prices in recent years—in part, attributable to sharply accelerated demand by China, India, and other fast-growing economies—has given added weight to the notion of a long-run supply constraint, even though global recession has brought about a pronounced price drop from the near-\$150 per barrel level recorded in 2008.

But even if worldwide oil productive capacity poses little likelihood of early decline, a steadily rising share of total output will most likely originate in regions posing geopolitical disruption risks as well as able to exercise market power in world oil. Translating that dual prospect into a future that may be subject to high and volatile oil prices makes it worth taking another look at liquid fuels for their abundance and reliability. Here I will focus on the prospective role of Canadian oil sands. (The outlook for a viable U.S. coal-to-liquids industry is far more problematic.)

Oil sands deserve attention for two reasons: their underlying resource base is vast, and they are being profitably produced in large amounts. At the same time, however, their long-term viability may depend on success in managing the significant carbon dioxide (CO<sub>2</sub>) emissions inherent in their production.

#### OIL SANDS FACTS

Canada's proven recoverable reserves of some 180 billion barrels—exceeded only by Saudi Arabia's conventional oil reserves—are concentrated in the Athabaskan region of northern Alberta. Oil sands, valued for their hydrocarbon content (called bitumen), occur as a near-solid, tarlike substance whose overall volume is a huge multiple of its energy content—thus creating a major waste management burden.

Oil sands extraction takes place by one of two techniques: surface mining (not unlike open-pit coal mining) or underground (in situ) extraction. For now, oil sands production is dominated by mining. But because overall reserves occur predominantly in deep deposits, in situ recovery is likely to dominate over the long run.

When mined, the stripped overburden—removed by giant shovels—must be upgraded by a complex, multistage chemical transformation process to yield a conventional petroleum-equivalent product. In situ extraction typically involves, as a prior step, the injection of steam to make the bitumen less viscous and capable of being forced to the surface for upgrading.

In either case, conversion is an energy-intensive process that accounts for one of its most problematic features—significant CO<sub>2</sub> release. The CO<sub>2</sub> emissions associated with oil sands, compared to those associated with conventional crude oil, exceed the latter by about 20 percent on a life cycle or—in more catchy terms—“well-to-wheel” basis.

## TRENDS AND PROJECTIONS

Oil sands production currently amounts to well over a million barrels a day—a significant proportion of Canada’s total oil production of around 3.5 million barrels a day. Over the next decade, a ramp-up in oil sands output to over 5 million barrels a day is widely foreseen. Because Canada is the leading source of U.S. oil imports—with a rising share of those imports derived from oil sands—that prospect is both reassuring, in that Canadian imports are certainly more secure, and worrisome because of the CO<sub>2</sub> implications just described.

The fact that, absent CO<sub>2</sub> emissions restrictions, oil sands production is currently competitive with conventional crude oil provides little comfort about the situation in a CO<sub>2</sub>-constrained regime. A major thrust of a 2008 RAND report (see Further Reading) was an effort to consider how that competitive status might play out with severe CO<sub>2</sub> restrictions, whether met by adoption of carbon capture and sequestration (CCS) technology or by purchase of carbon credits. Such credits can be represented by a “shadow price” of CO<sub>2</sub>, reflecting, say, payment of a carbon tax or purchase of cap-and-trade permits.

The RAND report provides a cautiously favorable picture of the long-term ability of oil sands to remain commercially attractive even while obliged to comply with formidable CO<sub>2</sub> restrictions. More specifically, there are several noteworthy conclusions that emerge from the report. (Dollar figures refer to 2005 price level.)

- Even with CCS, oil sands production costs in 2025 are competitive with conventional crude at near the \$60 per barrel world oil price projected in the Department of Energy/Energy Information Administration (DOE/EIA) “reference case” (published in the 2007 Annual Energy Outlook).
- A DOE/EIA “high oil price” projection, close to the recent \$100 per barrel, makes the competitive advantage of oil sands still more robust.
- That advantage would prevail at a shadow carbon price from zero all the way to around \$100 per ton of CO<sub>2</sub>. (By way of context, the price has hovered around U.S. \$33 per ton in the current EU carbon market.) Up to a shadow carbon price of around \$60 per ton of CO<sub>2</sub>, the economics favor paying the shadow price rather than installing CCS. Beyond that point of “indifference,” CCS becomes progressively more attractive.
- It is to be noted that oil sands extraction and upgrading currently rely principally on use of natural gas. Variations in natural gas prices can therefore signify lower or higher overall unit production costs.

In its detailed and wide-ranging scope, the RAND analysis lends considerable credibility to these findings. Nonetheless,

we are dealing with a number of unprecedented technological and environmental challenges whose ultimate success cannot simply be taken for granted but requires a sustained commitment to research and reevaluation as experience dictates.

Consider just one elusive goal being pursued in a major research effort in Saskatchewan: CO<sub>2</sub> sequestration that promises long-term geologic stability and integrity. It is frequently observed that CO<sub>2</sub> has routinely been injected into operating oil reservoirs so as to achieve enhanced oil recovery. But there is no assurance that such CO<sub>2</sub> will remain locked in place and not seep into the atmosphere over the long-term future. Thus, the “sequestration” element in CCS may prove a more formidable challenge than the “capture” phase.

Additionally, oil sands operations involve numerous non-carbon environmental challenges. Companies must comply with regulations governing land reclamation, water-use management, and extended monitoring of tailing ponds containing mining spoils. In principle, such costs are embodied in unit production costs. But unforeseen externalities have a habit of arising in many natural resource development projects.

Even with oil sands production rising to a level of over 5 million barrels a day, with a significant share of that increment destined for the U.S. market, it’s useful to place that number in the wider perspective of the world oil market. True, in security terms, a marginal barrel of oil originating in Canada trumps the alternative of that marginal barrel from a politically problematic source in the Eastern Hemisphere. All the same, even an oil sands contribution in excess of 5 million barrels a day has to be seen in relation to world oil demand of 100 million barrels a day a decade or so from now. In that sense, to the extent that the U.S. energy system remains significantly oil-based, relief provided by Canadian oil sands—whether in economic or security terms—may be meager. Indeed, it is one—but only one—element within the broad-based energy strategy that is in this country’s interest.

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## 25. FUTUREGEN

### How to Burn Coal—Maybe—Without Contributing to Climate Change

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*FutureGen is a joint venture by the Department of Energy and a private consortium to develop a coal gasification plant that will capture and permanently store carbon dioxide emissions underground. If successful, it represents the type of transformational technology needed if carbon dioxide emissions are to be substantially reduced in the future at acceptable cost.*

In its ups and downs, FutureGen is encountering all the policy issues that confront the hope of making electricity from coal without contributing to global warming.

In 2003, President Bush established FutureGen to build a pilot coal-fired generator, on an industrial scale, that would capture and sequester underground its emissions of carbon dioxide. In early 2008, the Energy Department abruptly suspended the project and called for its reorganization, citing soaring cost estimates.

In June 2009, the Obama administration restarted the planning and design process, promising a firm decision in early 2010 whether to proceed with construction. The signs strongly suggest that the decision will be affirmative.

FutureGen is a public-private partnership, nonprofit, between the federal government and, currently, nine big mining and power companies, both American and foreign. As it stands now, the partnership intends to build a 275-megawatt plant at Mattoon, Illinois, using integrated gasification combined cycle (IGCC) generating technology and capturing 90 percent of the carbon dioxide emissions. The cost is projected at about \$1.5 billion, of which two-thirds would come from the government and the rest from the private partners.

A growing consensus now holds that the key question is not whether carbon capture and sequestration (CCS) technology can be developed, but rather how fast it can be deployed. In the words of one recent report, *The Future of Coal* (MIT 2007), CCS is the “critical enabling technology that would reduce carbon dioxide emissions significantly while also allowing coal to meet the world’s pressing energy needs.” Both of the world’s largest emitters of carbon, China and the United States, have massive coal reserves, and it is not plausible that either will refrain from using them. It is difficult to envision truly aggressive action to reduce carbon emissions without widespread use of CCS technology.

FutureGen is not an isolated effort. A list maintained by MIT counts more than three dozen CCS projects, of which 14 are in the United States, 15 in Europe, and 2 in China. They range from small experimental operations to plants larger than FutureGen, and most are farther along than FutureGen.

Estimates of the cost of capturing carbon have risen sharply in the last several years, and at the same time they have become much less precise. In early 2007, *The Future of Coal* reported that the cost of CCS would run about \$20 to \$40 per ton of carbon dioxide, depending on the technologies used. Less than two years later, several MIT researchers published a paper (Hamilton et al. 2009) pointing out that, since 2004, construction costs for power plants had been rising around four times as fast as the consumer price index. The cost of capture in early 2009, they calculated, would be above \$50 per ton of carbon dioxide for a plant using the supercritical pulverized coal technology. They could give no estimate for the cost using the integrated gasification combined cycle (IGCC) technology, they said, because of the “tremendous uncertainty in the true costs and performance characteristics of such new technology.” In August 2009, American Electric Power, which is retrofitting

an existing plant in New Haven, West Virginia, for carbon capture, estimated that it will cost about \$100 a ton.

A careful review by Mohammed Al-Juaied and Adam Whitmore published in July 2009 by Harvard's Belfer Center concludes that the cost of capture would be about \$150 per ton of carbon dioxide for a first plant built, a figure that with experience would drop into the range of \$35 to \$70 a ton for later plants—in their terminology, the “nth plant.” But if construction costs were to fall back to the 2005–2006 level, they add, the cost of capture would be \$90 to \$135 a ton for a first plant and anywhere from \$25 to \$50 for the nth plant. (These calculations assume that the learning curve slopes sharply downward. Steve Mufson of the *Washington Post* has pointed out that in two cases—commercial nuclear power and the overseas transport of liquefied natural gas—that has not proved to be the case.)

The estimates by Al-Juaied and Whitmore do not include the costs of sequestration—that is, transporting the carbon dioxide to the burial site and injecting it underground. The paper by Hamilton et al. uses a figure of \$10 a ton of carbon dioxide to cover transportation and storage, although that would vary widely with the location of various projects.

One obvious implication of all these estimates is that at least the early plants in the development of the capture technology will have to be subsidized heavily. A cost of \$150 per ton of carbon dioxide avoided is the equivalent of 10 cents per kilowatt hour. The average price of electricity delivered to a residential customer in this country in 2008 was 11.36 cents.

Congress is well aware that the early plants would not produce power at competitive prices. The American Clean Energy and Security (Waxman-Markey) Bill, passed by the House of Representatives in July 2009, would provide bonus emissions allowances amounting to a subsidy of \$90 a ton to pioneer plants that capture and sequester 85 percent of their carbon emissions, and \$50 a ton to those that capture and sequester 50 percent.

Cost is hardly the only concern for FutureGen and the developers of CCS technology. Another is the reality that FutureGen can demonstrate only one solution, when there are many that need to be tested.

The methods of achieving high efficiency in coal-fired power generation fall into two groups. One burns highly pulverized coal. The other turns the coal into a gas, burns it to

run a gas turbine, and then uses the hot exhaust to make steam that then runs a steam turbine. That's the IGCC technology. Several IGCC plants are in operation, but the great majority of coal generators currently use pulverized coal. The IGCC technology has a reputation for being difficult to manage reliably, and it is somewhat more expensive than pulverized coal as long as there is no constraint on carbon emissions.

But the gasification process makes the sequestration of carbon dioxide less costly than in conventional combustion and, where sequestration is required, IGCC becomes, in theory, the more economical choice. That's why FutureGen is going to use it. But there may be circumstances in which pulverized coal is preferable, and the ability to combine it with carbon capture needs to be demonstrated as well.

The further reality is that if CCS is to be a national policy, the technology will also have to be applied to plants now in operation through retrofitting, as at the AEP plant in West Virginia. A generating plant is built with a life expectancy of 60 years or more, and to apply carbon capture only to new plants would mean very slow progress in deploying the concept.

FutureGen continues to be a highly important experiment. With rising concerns about climate change and the realization that the use of coal is unavoidable, it is arguably more important now than when it was first conceived. But it is only one of many experiments, as governments and energy companies have concluded that, without successful and reliable CCS technologies, action to reduce the world's carbon emissions would be much harder to envision.

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## 26. THE ECONOMICS OF NEW GREEN TECHNOLOGY INVESTMENT

### The Case of Satellite Solar Power

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*Satellite-collected solar power is a possible technology for generating clean electricity, albeit for the distant future. This commentary describes the technology, its economics, and the difficulties in modeling uncertainty about investment in the technology.*

An old but newly revisited proposal for clean electricity is to collect the sun's energy using antennas in space, then to beam the energy to Earth for distribution via the electricity grid. First proposed in the 1960s, space solar power (SSP) has since appeared occasionally in assessments of new energy technologies but was deemed not yet ready for practical use (for example, see Schurr et al. 1979). More recently, however, the governments of Japan and Germany, as well as NASA and the U.S. Departments of Energy and Defense, have funded large-scale studies of the engineering design for SSP to account for improvements in space and related technologies.

To many skeptics, SSP is yet another sci-fi, pie-in-the-sky idea. Arguably, pretty much all of today's technology was at first merely a gleam in the eye. But at some point the computer replaced the abacus, and Lindbergh's flight led to commercial aviation. Is SSP likely to cost-effectively power a lightbulb anytime soon?

The answer depends partly on whether we choose to invest in further development of the technology. Such a decision is made difficult because of the challenges in modeling and estimating investment under technical and economic uncertainty.

At the request of NASA, the National Science Foundation, and the Electric Power Research Institute, we carried out one of the few studies of the economics of SSP. We asked several questions in an attempt to quantify some of the issues. First, given that many technological hurdles remain for SSP, we asked what they are, what costs would be incurred to overcome them, and how soon they would be achieved. These questions were important particularly because in the time it may take to develop, test, and deploy SSP, innovation will have proceeded apace in competing technologies.

For example, many experts suggest that SSP could be ready for deployment in 2020 in quantities to meet growth in electricity demand. If so, then the relevant basis for comparison would be the expected generation cost per kilowatt hour of SSP compared with that expected in 2020 for its competitors. These most likely include advanced, gasified coal-based and natural gas-based combined cycle gasification technology (CCGT) and advanced (terrestrial) renewable energy. (To make a fair comparison, we used generation costs because SSP would use the existing electricity grid for transmission and distribution.)

Proponents of SSP also note its green advantages. We sought a comparison, then, of quality-adjusted generation costs by adding a carbon penalty to coal and natural gas. To do this, we used a range of values, including prices at which carbon dioxide emissions permits were selling on the European and Chicago climate exchanges and estimates by other researchers of the mean monetary values of impacts from carbon-related environmental damages. Also included were penalties for coal, natural gas, biomass, and solar thermal power due to the thermal effluent that occurs with these technologies through their use and discharge of reject heat into streams and other water bodies. This adjustment was based on how much it would cost the power plant to avoid the externality entirely. Another quality adjustment is reliability; we assumed that there would be low-cost ways to maintain and repair SSP during its operating lifetime and thus SSP could be as reliable as terrestrial power sources.

Our last set of adjustments is associated with the uncertainty surrounding projections of the cost and capability of a new technology. For instance, other researchers have shown that an optimistic bias usually leads engineers to underestimate the likely costs of new technology (Quirk and Terasawa 1986). Consequently, the “point” estimate of our various parameters are expressed together with distributions of possible values, informed by interviews with a variety of experts and review of experience in other space- and power-related technologies. Statistical methods were used to draw sample values repeatedly and randomly from these distributions. On the assumption that SSP would most likely be phased in as additions to baseload-generating capacity in response to increased demand, different rates of technology adoption were included in the simulations.

Finally, a unique attribute of SSP is that it can transmit power anywhere depending on its location in space. Therefore, we looked at the comparative advantage SSP could have in a variety of locations, including places where renewable energy could be abundant and thus give SSP a good run for its money. Our sample included California, the U.S. Midwest, Germany, and India.

What did our findings suggest? SSP could be competitive under the very stringent assumptions we have described—that is, if there are penalties for the externalities of competing technologies and rapid adoption of fully reliable SSP available at a price per kilowatt-hour (kWh) promised by engineering models. Under these assumptions, deploying SSP would provide net benefits from \$27 million to \$100 million, depending on the region. If any of these assumptions is relaxed, however, the net benefits from SSP are on average an order of magnitude less than those from other types of renewable energy, particularly wind and biomass. When the uncertainty of the cost of SSP is taken into account, its cost advantages are not only smaller, but negative in some cases.

The technological hurdles remain large. For example, in order to collect enough solar energy so as to have a large amount after beaming it the huge distance from the sun to Earth (depending on the efficiency of solar cells and trans-

mission frequencies, energy is lost en route), the transmitting antennas have to be truly enormous. Their size requires multiple rocket launches and an as yet not fully developed ability to robotically assemble the array of antennas in space. The receiving antennas on the ground must also be large, covering hundreds of acres, and are likely to encounter “not-in-my-backyard” concerns.

Another possible shortcoming that is repeatedly pointed out (although not in our model) is that SSP has not been tested as a possible source of the health and environmental effects associated with concentrated amounts of electromagnetic energy—long a concern for many conventional technologies and for which, even now, long-term epidemiological data are lacking.

So, should we invest further in the next steps toward demonstrating SSP? Might it help us hedge against uncertainty about other future technologies—carbon capture and storage, for example? The decision rests much on willingness to invest in complementary technologies (low-cost launch, robotic assembly methods), satisfactory solutions to facility siting, health and environmental concerns, and of course, whether optimism about cost-reducing innovation in our conventional energy technologies in the coming decades bears fruit.

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## 27. OIL AND THE ARCTIC NATIONAL WILDLIFE REFUGE

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*A highly contentious issue in the debate over energy policy is the extent to which domestic oil production should be enhanced by allowing drilling in the Arctic National Wildlife Refuge (ANWR) and other areas. What are the benefits and costs of drilling in ANWR, and how might the revenue from royalty taxes be used to promote environmental objectives?*

To drill or not to drill? That is the question once again in Alaska's Arctic National Wildlife Refuge (ANWR). Proponents of drilling promote the advantages of a decrease in the price of oil and reduced reliance on foreign imports. Opponents argue that the only benefit would be windfall profits for oil companies, and that drilling in ANWR would destroy one of the last great wilderness areas on the planet. While advocacy on both sides of the issue is widespread, reliable information and balanced discussion are surprisingly absent.

So how much oil are we really talking about? At prices around \$100 per barrel, the U.S. Geological Survey estimates the amount of economically recoverable oil in the federal portion of ANWR to be approximately 7.69 billion barrels of oil (BBO)—an amount roughly equal to U.S. consumption in 2007. Accounting for uncertainty, the estimates range from a low of 4.25 BBO with 95 percent certainty to a high of 11.8 BBO with 5 percent certainty. For purposes of comparison, the estimated amount of oil beneath the outer continental shelf is approximately 86 BBO. Under any scenario, however, it would take several decades to extract all of ANWR's oil, and forecasts predict a peak around 2025, at which time ANWR would account for 3 percent of all domestic consumption.

These estimates immediately challenge the two benefits that proponents of drilling most frequently advance. Because ANWR would increase the world's proven reserves by only 0.6 percent and oil prices are determined in a world market, any effect on the price of oil would be negligible. What is more, with ANWR supplying such a small fraction of domestic consumption, even at its peak, U.S. imports of foreign oil would remain significant even if ANWR were tapped.

The real benefit of drilling in ANWR would be the revenue from selling the oil. Consider that 7.69 BBO at a price of \$100 per barrel generates revenue of \$769 billion. Subtracting the estimated costs of finding, developing, producing, and transporting this oil, the financial net benefit of ANWR's oil is substantial—\$613 billion. And if prices continue to rise, as many analysts predict, this number could grow substantially larger.

But what about the environmental costs? There is no doubt that ANWR protects a broad spectrum of natural habitats that are unparalleled in North America. These habitats support a number of large animals—including caribou, musk oxen, wolves, wolverines, and polar bears—and some 135 different bird species. While the specific environmental effects of drilling remain uncertain, it is clear that even with minimal adverse effects, many people would feel a loss if ANWR were developed. This is because many are likely to hold substantial "nonuse" values for ANWR; that is, even people who never visit ANWR may benefit from simply knowing that it exists in a pristine state.

The challenge is to place an economic value on these nonuse benefits for ANWR in order to compare them against the financial benefits of drilling. While a large body of research suggests that the nonuse benefits for ANWR might be substantial, it is

reasonable to question whether they would be large enough tip a cost–benefit analysis in favor of not drilling.

Nevertheless, when it comes to policy questions as symbolic and contentious as ANWR, cost–benefit analysis is typically—and perhaps appropriately—employed as a decision tool rather than a decision rule. Beyond economic efficiency, distributional concerns play an important role. Consider how the financial benefits of ANWR’s oil would be divided. We find that the financial net present benefits of \$613 billion, based on the \$100 per barrel scenario, would be partitioned as follows: \$271 billion in industry profits, \$72 billion in Alaskan state tax revenues, and \$270 billion in federal tax revenues.

These numbers obviously shape the political economy of ANWR today. It is not surprising why the state of Alaska and oil companies favor drilling. And beyond opposition from environmentalists, many people are unlikely to support policies that further increase the profitability of oil companies, which continue to earn high profits while people pay high prices. So ANWR continues to be contentious.

But perhaps the ANWR question can be recast to minimize conflict and create an opportunity. We should all acknowledge that drilling in ANWR would negligibly satisfy our addiction to oil. Nevertheless, it could provide a massive source of revenue to fund scientific innovation, renewable energy, energy efficiency, and climate change policy. The revenue could be earmarked specifically out of ANWR’s tax revenue or taken out of what would otherwise be industry profit.

Consider that the president’s 2008 budget for all climate change activities was \$7.37 billion. This number generously accounts for all expenditures related to science, technology,

international assistance, and energy tax provisions. Clearly, the scope of these programs would change dramatically if even a modest portion of ANWR’s \$613 billion were directed their way. But, of course, any policy that aims to accomplish this objective would need to ensure safeguards against the types of corruption and incompetence that were recently uncovered in the Interior Department’s collection and spending of oil and gas royalties.

We are in serious need of new ideas for simultaneously satisfying our demand for energy and meeting the challenge of global climate change. While helping to satisfy our demand for oil, drilling and redistributing ANWR’s benefits might provide a somewhat counterintuitive opportunity—one that is at least worth contemplating. It is possible the environmental community might be willing to trade off uncertain impacts of drilling in a remote area in exchange for real efforts to address other environmental concerns.

### Further Reading

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## 28. OIL SPILLS

### The Deterrent Effects of Monitoring, Enforcement, and Public Information

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*Although regulations introduced following the 1989 Exxon Valdez accident have helped reduce the number of oil spills, oil pollution in coastal waters remains an important policy problem. What are the appropriate roles of deterrence, monitoring, and targeted enforcement policies in reducing the frequency and size of oil discharges?*

A single pint of oil can spread into a film covering an acre of water surface area, degrading the environment and ultimately threatening human health. To encourage compliance with laws prohibiting the discharge of oil, government agencies can hike the penalty for a violation or increase monitoring activities to raise the likelihood that an offender will be caught and punished.

In theory, less monitoring coupled with higher penalties is always beneficial. Taking economist Gary Becker's "crime and punishment" model (1968) to its logical conclusion, the optimal penalty is arbitrarily high, and the optimal expenditure on monitoring approaches zero. In reality, however, such a policy would bankrupt any firm that spilled even a few pints and thus stifle commerce: who would take such a risk?

Consequently, we need a policy that includes a significant amount of monitoring and well-designed penalties for noncompliance. EPA and the Coast Guard both have enforcement powers and conduct monitoring to prevent oil spills. Should a spill occur, U.S. law also requires that the responsible firm report it and clean it up. In the event of an oil spill, EPA and the Coast Guard may assess administrative penalties and require remedial actions, and courts may impose civil or even criminal sanctions on responsible individuals and corporations.

Much has changed in the past two decades. The 1990 Oil Pollution Act (OPA), passed a year after the Exxon *Valdez* spilled more than 10 million gallons of crude into Prince William Sound, states that a company cannot ship oil into the United States until it presents an acceptable plan to prevent spills; it must also have a detailed containment and cleanup plan in case of an oil spill; and all vessels entering U.S. waters must eventually be double-hulled. Since then, the number and volume of spills in U.S. waters have declined considerably, primarily due to the introduction of double-hulled vessels, which have prevented many of the largest spills from occurring. For example, the Coast Guard reports the number of spills to have dropped from about 700 to 400 annually, and the volume of oil spilled reduced from about 5 million gallons to 600,000 gallons annually since OPA was enacted.

But those numbers do not tell the whole story. Not all spills are large and many are not even accidental: vessel operators have been known to clean their bilges out near a port in order to save money, and some spills simply occur through faulty or negligent transfer operations.

Aside from technological mandates such as double-hulled tankers, how effective are the various approaches—monitoring, enforcement, penalties—in deterring oil spills, and what is the best mix?

Assessing data on compliance and enforcement is not an easy task. A reported increase in enforcement activities might indicate more frequent spills, but it could also reflect better monitoring and detection, or more vigorous prosecution. Empirical studies must be carefully designed to sort out the effect that these variables have on actual spill frequency versus spill detection.

Monitoring oil transfer operations has been found effective in reducing oil spill

volumes: the crew of a tanker apparently takes more care when the Coast Guard is watching. Such monitoring might also have a general deterrent effect on all vessels that transfer oil: if their captains believe they might be monitored in the future, they probably train their crews and check their equipment more thoroughly, even if they are never actually monitored. Random port patrols looking for oil sheens have a similar influence because they raise the probability of detection for all vessels entering that port. However, compliance inspections themselves have not been found to be as effective as the other two mechanisms.

## ALTERNATIVE APPROACHES

Because government monitoring is expensive, three alternatives have been tested: targeted monitoring for vessels thought likely to be out of compliance or likely to spill oil; differential penalties based on prior compliance history, with higher penalties for frequent violators; and mandatory self-reporting, with higher penalties for vessel operators who do not voluntarily report their spills.

**Targeted monitoring.** In the early 1980s, the Coast Guard began classifying ships as low risk (to be monitored only occasionally) and high risk (always monitored). This two-tiered enforcement policy has been found to be effective in reducing the cost of enforcement without having a negative effect on the environment.

**Differential penalties.** A 2000 study by Weber and Crew found penalties ranging from \$.01 to \$280 per gallon, and estimated that increasing the fine for large spills from \$1 to \$2 a gallon decreased spillage by 50 percent. They concluded that the current penalty policy—relatively high per-gallon fines for small spills and very low per-gallon fines for large spills—undermined deterrence. Their results parallel mine, that the Coast Guard's statutory maximum penalty of \$5,000 was too small relative to the optimal penalty required. Under OPA, the potential penalties considerably increased, up to \$1,000 per barrel of oil (about \$24 per gallon) discharged.

**Self-reporting.** To increase deterrence and lower the cost of government monitoring, vessel operators are told they must report any spill, and if the government detects a spill that was not voluntarily reported, the penalty is higher and may include a criminal sanction. Firms found to be out of compliance are more likely to self-report violations in subsequent periods. This suggests that firms try to regain credibility with the government so that they will be taken off a target list.

**Firm reputation.** Information that a firm has been sanctioned for violating environmental laws may be of interest to shareholders or lenders if the monetary sanction reduces the expected value of the firm and therefore its share price or bond rating. It may also give lenders and insurers pause

about risking more capital on that particular firm. Other costs might include future debarment from government contracts, targeted enforcement by EPA, and lost sales to green consumers. Several studies looking at bad environmental news, such as oil or chemical spills or the announcement of civil or criminal enforcement actions, have demonstrated a negative stock price effect; however, the evidence is mixed as to whether or not this price effect simply reflects the expected cost of penalties and cleanup as opposed to any additional reputation penalty.

## POLICY IMPLICATIONS

Despite OPA's success in reducing oil spills, costs are still significant. A recent Coast Guard study estimated the total cost of removal and damages from oil spilled since 1990 to be \$1.5 billion. If the government's goal is to improve the environment at the least cost to society, then firms that are the most likely to cause significant harm need to be identified along with those most likely to be responsive to enforcement activities as well as compliance assistance. This kind of empirical evidence can help government agencies plan targeted enforcement measures. Additional evidence on the costs of enforcement and compliance must be gathered, however, to conduct a cost-benefit analysis.

In terms of sanctions, the evidence to date shows little deterrent effect from fines that are only a few thousand dollars. To have any real effect, significantly larger fines and/or targeting individuals instead of firms may be appropriate.

Finally, community pressure and social norms can be important factors in compliance. External market pressures may exert some influence on firm behavior and help prevent oil spills from occurring. Being known as a polluter may induce firms to take precautions, lest consumers and shareholders exact their own form of punishment.

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## 29. TAKING A CLOSER LOOK AT ENERGY SUBSIDIES IN THE FEDERAL TAX CODE

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*The federal government effectively subsidizes various forms of energy production, through favorable tax treatment. How large are these subsidies, what activities do they affect, and is there an economic rationale for these subsidies?*

According to the Office of Management and Budget in President Bush's FY2009 budget submission, the federal government provided over \$10 billion in energy-related subsidies through special tax deductions and credits in 2007. But the evidence is mixed on their effectiveness. On the one hand, an increasing share is flowing to nonpolluting energy sources, such as production tax credits for renewable electricity generation. On the other, the tax code continues to provide wasteful subsidies, many of which work at cross purposes with desirable energy policy goals; an example here would be the provision of more generous percentage depletion rather than cost depletion for oil and gas drilling. This does nothing to reduce our reliance on oil and natural gas while probably doing little to encourage increased production given current energy prices.

Tax-based energy subsidies are an increasingly important policy tool: in constant dollars, these subsidies have more than tripled between 1999 and 2007. So how do these subsidies work, and are we getting our money's worth? First, we'll look at the subsidies by fuel type.

Subsidies for renewables currently account for nearly 40 percent of the overall total, with the exemption for ethanol from the federal excise tax on motor vehicle fuels comprising a high percentage. Production tax credits for power generated from renewable sources have been important for encouraging the growing wind market, although they account for less than 7 percent of total tax-based subsidies to energy.

Coal accounts for 25 percent of tax-related subsidies, and 90 percent of that goes to refined coal. (Refined coal is a fuel produced from coal or high-carbon fly ash that is modified to increase its energy content and reduce certain emissions.) This particular subsidy, however, phased out at the end of 2008. Other coal subsidies include, among other things, capital gains tax treatment of royalty payments to owners of land on which coal is mined.

Oil and natural gas received 20 percent of the tax-related subsidies in FY2007. Expensing exploration and development costs and allowing independent producers to use percentage depletion rather than cost depletion account for over three-quarters of this total. President Obama has called for an end to these subsidies, but as of September 2009, Congress had not taken up his request.

Deductions and credits for installation of energy-efficient appliances, solar panels and fuel cells, and home improvements or construction totaled \$790 million in 2007. This area is small in the grand scheme but has grown rapidly, from 3 percent of tax subsidies in 1999 to its current 8 percent share. (The remaining subsidies are non-fuel-specific subsidies for the electricity sector.)

### CHALLENGING THE STATUS QUO

Three rationales are often cited to support these subsidies: externalities (in this case, the unreimbursed environmental costs) from energy production and consumption, national security, and market failures in energy conservation markets. While externalities are a significant concern, providing subsidies comes with two important caveats. First, a more efficient approach would be to tax the offending activity rather than

subsidize clean alternatives, because subsidies lower the cost of consuming energy and so increase demand. Second, subsidies do not always operate on the right margin. For example, subsidizing the production of electric cars exacerbates rather than alleviates congestion on our nation's roadways.

National security concerns suggest a shift from oil and gas—increasingly being supplied by politically unstable countries—toward renewable energy sources. Subsidies for domestic oil and gas production are often touted as contributing to national security, but this ignores the fact that these fuels are priced in world markets. An oil price shock affects the domestic economy whether we are consuming domestic or imported oil. Corn-based ethanol poses an additional problem. By competing with the use of corn as feed, ethanol production drives up agricultural and meat prices, a painful reality that has been well documented in the media. In effect, we are swapping one risk for another: lower energy prices for higher food prices.

The role of market failures in discouraging energy-efficient capital investment cannot be overlooked. Consumers often lack sufficient incentives to change their behavior. Rental housing provides a good example. Tenants who pay directly for their utilities may desire more energy-efficient housing and appliances, but landlords may be reluctant to make necessary improvements out of concern that they cannot recoup their incremental investment through higher rents. And tenants who live in buildings that are not individually metered have no direct incentive to save. The appropriate policy response in this situation is to provide investment tax credits for tenants or landlords for such green investments.

We can do better than our current system of subsidies by taking a three-pronged approach. First, the United States should implement a carbon tax that—for political reasons, as I discuss elsewhere (see Further Reading)—is neutral in terms

of both revenue and distribution. The tax rate should be raised gradually and predictably over the next several decades as recommended by—among others—William Nordhaus. Second, the United States should double the federal gasoline tax rate, as supported by the research of Ian Parry and Ken Small (2005), and index it for inflation. The increment over the current tax rate of 18.3 cents per gallon should be earmarked for an Energy Independence Fund and rebated to households on an equal per capita basis. Finally, the United States should double its spending on basic energy-related research and development from the current levels of roughly \$3.5 billion a year as recommended by Richard Newell in a recent Hamilton Project presentation (2007).

For the United States to move toward a carbon-free future and reduce our reliance on oil will require harnessing market forces and unleashing the creativity of our scientific and engineering community. This kind of retooling could come at less than half the cost of our current system of energy subsidies.

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## 30. LEARNING BY DOING AND THE CALIFORNIA SOLAR INITIATIVE

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*What are some possible rationales for California's program of subsidies for solar photovoltaic installations? In particular, a transitory subsidy is potentially warranted if, by producing a new (immature) technology, firms lower their production costs over time through "learning by doing," and this confers benefits to later producers of the technology.*

California has been at the forefront of environmental policy in the United States for the past several decades, with policies like energy efficiency standards and air quality standards often preceding similar legislation at the national level. Recently, California has undertaken one of the largest renewable energy incentive programs in the world: the California Solar Initiative (CSI). The CSI provides for a significant rebate (in dollars per watt) on solar photovoltaic (PV) installations that begins at roughly \$3.50 per watt and phases out progressively over the 10 year span of the policy. This ambitious program has spurred the California solar market, but, to this day, solar PV technology remains quite expensive when compared to grid electricity, leading to the question: does this significant investment make sense?

### **SOLAR POLICY IN CALIFORNIA**

Let's first examine how solar policy has evolved in California. The state's interest in solar energy is not at all surprising—California enjoys copious sunshine and has strong environmental values, as well as an enviable base in high technology. In fact, solar policy in California is nothing new; a sizable rebate per installation was in place before 1998, and a tax credit has been in place since 2001. These have served to foster a rapidly growing solar PV industry—from under 5 megawatts (MW) installed in 2000 to nearly 198 MW installed by the end of 2006.

Nevertheless, the solar PV market in California has faced two major hurdles: cost and uncertainty. Electricity from solar PV systems is much more costly than grid-based electricity, due to the high up-front cost of PV installation. Solar PV electricity often costs roughly 20 cents per kilowatt-hour (kWh), which is much greater than the price of grid electricity—in the order of 12 to 15 cents per kWh in California. Prior to the initiative, solar subsidies were subject to renewal each year, leaving investors and solar installers with variable prospects. For these reasons, solar energy makes up only a tiny fraction of the total electricity supply in California—even today it is less than 0.5 percent.

In January 2004, Governor Schwarzenegger set in motion the plan that would eventually become the CSI, through his evocatively named Million Solar Roofs Initiative. The California Public Utilities Commission's January 12, 2006, rulemaking implemented key elements of this original vision and created the CSI, providing the assurance of incentives over 10 years, at a revenue cost of approximately \$3 billion per year.

The incentives are implemented as a rebate in dollars per installed watt, paid for by an electricity ratepayer surcharge. They can be applied to residential, commercial, industrial, or even government installations, but not to central generation solar (solar thermal plants, for example). Importantly, the incentives are designed to be progressively phased out over the 10-year policy life span, corresponding to an expected decline in the cost of solar PV technology due to learning by doing, as explained

below—a key element of the justification in Sacramento for the solar incentives.

## RATIONALE FOR SOLAR INCENTIVE POLICIES

If solar PV technology is so much more expensive, why should California bother to subsidize it? A few primary arguments stand. The first is the most well-known: more electricity from solar will mean less electricity from fossil fuels, thereby avoiding the well-known environmental externalities. The second is that peak solar radiation is highly correlated with times of high electricity spot prices, such as in the middle of a summer day, and consumers do not take this correlation into account because they only face the mean price of electricity, namely the price for kilowatts per hour.

A third argument is more controversial, but turns out to be critical. There is evidence suggesting a learning-by-doing (LBD) effect, whereby the cost of solar installations declines as cumulative solar installations increase. On the surface, LBD may not seem to provide motivation for public policy. But if the installation of an additional solar PV system today leads to less expensive solar PV systems for all firms in the future—that is, there is a spillover effect that the individual firm cannot capture—then the profit-maximizing firm will install fewer systems today than what would result in socially optimal environmental and consumer benefits.

## IS THE CSI JUSTIFIED?

We aimed to answer this question by developing a model of the California solar market. Our results suggest that LBD spillover effects that cannot be fully captured by the individual firm are critical to justifying the CSI. We find that without these effects from LBD, the CSI cannot be justified by the combination of its environmental and temporal correlation benefits alone. However, by inclusion of these LBD effects, we find an important result: the CSI can be justified on the grounds of improving economic efficiency. The consumer benefits from reduced PV installation costs in the future, resulting from additional installations today, greatly outweigh the environmental benefits—tipping the balance in favor of the CSI. Moreover, we find that the socially optimal policy may be quite similar to the CSI.

Here's why. The cost of a solar PV installation can be broken into three major components: the module made up of the PV cells, the electric inverter to convert the electricity generated by the cells, and the remainder, which covers the balance of the system—namely, marketing, management, supply chains, and the physical installation, which combined make up roughly just under half of the total cost of an installation. It is this last component of the total cost that is the most relevant here, for there is some evidence to suggest localized LBD. The idea is pretty straightforward: as installers gain more experience, some of this knowledge will spill over to other California installers. This benefit, not captured by the individual installing the system now, is large enough to justify the CSI subsidy on economic efficiency grounds. However, our key result is that without this LBD effect, the cost of the CSI cannot be justified on economic grounds.

The model quantifies these separate impacts. The present value of the decreased costs of future installations due to LBD caused by one additional installed kilowatt of solar is estimated to be \$1,140; the present value environmental benefit from reduced carbon dioxide (CO<sub>2</sub>), even if we assume a CO<sub>2</sub> damage of \$50 per ton of CO<sub>2</sub>, is only \$192. This numerical estimate indicates that the primary motivation for solar policy in California should be LBD. If we do not believe that there are LBD spillovers, the environmental reasons alone are not sufficient to justify the ambitious CSI.

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# 31. OPPOSING THE CHICKEN OR OPPOSING THE EGG?

## New Challenges in Siting Networked Energy Facilities

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studies and maps the social implications of environmental and economic policies. This commentary was written while she was a full-time fellow at Resources for the Future.

*Meeting the ever-rising demand for electricity, as the U.S. population and real income continue to grow, implies a steady expansion in electricity transmission infrastructure and the number of power plants. For this expansion to occur smoothly, it is critical that policymakers address various obstacles to siting new energy infrastructure at the local level.*

Everyone is talking energy these days. With record-high oil prices and the looming prospect of a price on carbon, citizens and policymakers alike are calling for major changes in our energy systems. Some are pushing for a large-scale shift to renewable energy resources, while others are calling for expansion of existing low-carbon technologies, like nuclear power. And still others are looking to entirely new technologies, like geologic carbon sequestration, to reduce greenhouse gas emissions and meet demand.

Change is in the air, but what is not clear is where that change will show up on the ground. Everyone seems to agree that, as a whole, our nation's energy infrastructure is in need of upgrading at minimum and complete restructuring at the other end of the scale. But the process of siting, or finding locations for specific facilities on the ground, remains a daunting challenge. There is little agreement on what the energy future should look like, especially locally, and protests continue to rage against new projects. Even if there is broad support for change, it is not certain that there will be support for any given project. Take, for example, Cape Wind in Nantucket Sound. This proposal, for 130 wind turbines off the coast of Massachusetts, has moved slowly through years of regulatory reviews and high-profile opposition.

The Cape Wind project is an extreme example of the types of siting difficulties that can plague energy projects. More commonly, there are three main causes of siting difficulty that affect a wide range of energy facilities: environmental barriers, regulatory roadblocks, and public opposition. Environmental conditions, such as inhospitable terrain, are often dealt with quietly, early on in a project's design and proposal phases. In contrast, public opposition is the siting hurdle that receives the most attention, because it frequently arises after a project proposal is submitted for regulatory approval. Moreover, opposition can extend project timelines from a few years to decades or block projects altogether.

The seriousness of the problem is evident in the acronyms that are now synonymous with public opposition and siting difficulty: NIMBY (not in my backyard) to BANANA (build absolutely nothing anywhere near anything). In the midst of this siting alphabet soup, it is often overlooked that people generally oppose a project's location, not the service it provides. In fact, we demand that electricity and transportation fuel be widely available and extremely reliable whenever we want to flip a switch or fill up the tank. We just don't want to look at the power plants and refineries that provide these services.

### HINGED INFRASTRUCTURES

This is especially true for the networked infrastructures—power lines and pipelines—that support the services that everyone wants but no one wants to see. These “hinged infrastructures” face unprecedented siting challenges. As the push for energy system transformation has grown stronger, opposition to different types of energy facilities

has also strengthened. Opponents of a specific project or a new technology now have the option of opposing a project itself, and then if that fails, they can oppose the power lines or pipelines that connect the project to a larger network, effectively stifling the entire project at a key choke point—the link to the network. In the case of Cape Wind, opponents of the project split their attention among the impacts of the wind turbines, the cables buried in the seabed to carry electricity to the shore, and the power lines on land.

The chicken-and-egg relationship between energy facilities and the networks that support them has evolved recently, in the wake of industry deregulation. Electric utilities are no longer vertically integrated as they once were. Now separate companies manage generation, transmission, and distribution assets. This means that large-scale generation capacity additions and upgrades to the grid as a whole are no longer evaluated jointly. Instead, additions are considered on a facility-by-facility basis. Without *existing* power lines, many projects are unlikely to cross the threshold of economic viability, and without adequate generation capacity in place to justify new transmission construction, investment in new lines also is unlikely to occur.

## A HOUSE OF CARDS

This piecemeal approach to expanding and upgrading our energy networks has profound implications for making any large-scale shift to new resources or technologies. Major energy facilities are constrained by the different fuels they use, and resources are located in very different places—with different trade-offs. For example, a site that would support 100 MW of wind power will not likely be the same spot that would most effectively produce 100 MW of solar power, or the same size as one that would support most cheaply a coal plant with carbon sequestration. Therefore, developers cannot easily switch projects or sites. In other words, Cape Wind will never become Cape Coal to keep the lights on in coastal Massachusetts.

As a result, opponents to *local* energy projects are faced with few clear trade-offs: if they win, they keep their beautiful views and their reliable power, while developers find other sites or projects. But eventually, something will have to give. Before this happens, policymakers must work to realign our energy network priorities to smooth joint siting processes for primary facilities and secondary network infrastructure, ranging from power lines for renewables to pipelines for CO<sub>2</sub> sequestration, especially in areas that are isolated from existing grids.

The Energy Policy Act of 2005 made some encouraging early steps in this direction with mandates to develop integrated energy corridors on federal lands in the western United States and National Interest Electric Transmission Corridors across the country. However, implementation of these mandates and the resulting corridor designations have generated controversy and opposition in and of themselves. Despite setbacks, these and other initiatives to identify publicly acceptable solutions to coordinated network development are critical. Without them, the push for energy system transformation, no matter how strong, could grind to a halt with local opposition to either the chicken or the egg.

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## 32. THE GREENING OF BUILDINGS

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*A quiet grassroots revolution has been taking place in the design of new buildings, which has important implications for the environment. Why do so many designers seek to obtain green building certification without any prodding from the government, and how might the current rating system for green buildings be improved?*

Spontaneous actions below the federal level are emerging as a burgeoning source of efforts to improve the environment. One such trend is the growing green building movement, which encompasses many cities, educational institutions, other nonprofit organizations, and private developers.

The central idea is to focus more holistically on buildings as a source of multiple environmental effects. Design features that determine how an entire building affects environmental goals are considered. A strong case can be made for this approach: according to the U.S. Green Building Council (USGBC), the operation of buildings accounts for nearly 40 percent of primary energy use, 71 percent of electricity consumption, and nearly 40 percent of carbon dioxide emissions in the United States.

Buildings offer impressive opportunities for pollution abatement. A report by McKinsey (Creyts et al. 2007) singles out buildings as a cluster with particularly great abatement potential. Promoting green buildings conserves energy and water, reduces greenhouse gas emissions, and provides state-of-the-art modern facilities for office and residential use.

A major catalyst to the growth of the green building movement has been the green building rating system known as Leadership in Energy and Environmental Design (LEED), promulgated by the USGBC. Earning LEED certification announces to the world that a building has met strict green standards. LEED for new construction (LEED-NC) began through pilot programs in the 1990s and was established as a rating system in 2000 for new commercial buildings. Since 2000, LEED has been expanded to include existing commercial buildings and residential homes, and is now being used cooperatively in evaluating the greenness of entire communities. USGBC expects that by 2010, approximately 10 percent of new commercial construction will be LEED certified.

The green building movement offers a significant and novel advantage over traditional environmental protection efforts, in that it is essentially free. Emanating from grassroots support, it comes at no cost to the federal government, either in tax dollars or in the burden of federally mandated regulations, since LEED certification is above and beyond existing building codes. The green building movement has come so far and so quickly for several reasons.

A first, perhaps primary reason for growth is that green buildings can reduce overall building costs and therefore contribute to a builder's bottom line. In the normal course of events, architects change a variety of things over time, ranging from building layout to details of heating choices and the like, in response to changing material prices and technological developments. Organizations such as USGBC are, in part, vehicles for helping building designers keep up with the times. Claims of cost reductions that are made by green building proponents are consistent with the fact that these practices are being adopted voluntarily.

A second reason for going green is that it will appeal to potential tenants. Going green can be a good marketing strategy; a green building may command higher rents, quicker sales, and greater retention than a traditional one.

A third reason for the spread of green buildings is the influential role played by architects in shaping building aesthetics. Building styles are inevitably influenced to a greater or lesser extent by incentives to keep down costs, but final design choices are still made by architects in conjunction with their clients.

A fourth reason helping to explain why developers provide green buildings is local and governmental impetus. Some cities put LEED-certified buildings first in line in issuing permits and other regulatory matters that a builder faces. Policies such as Chicago's green permits, or Los Angeles's ordinance that requires all privately built projects over 50,000 square feet to meet a "standard of sustainability," rely on LEED ratings for implementation. U.S. government policy now states that new federally owned buildings will be LEED certified.

But the LEED system is experiencing growing pains: while now being treated as a standard for new construction, it was originally designed as a reward system and not a set of building codes with such widespread implications. LEED-NC also lacks standard operating or maintenance requirements, which raise concerns about the long-term effectiveness of the current version for reaching policy objectives. USGBC is aware of these and other issues and is actively working on more systematic rating systems for future versions of LEED.

Green building certification in its present state is not perfect, but, after all, no practical environmental tool ever is. Nevertheless, we have some recommendations.

**Sort out the goals toward which green building measures are aimed.** Points toward green building certification can be earned for approximately 70 different individual measures, which are categorized under six objectives: sustainable sites, water efficiency, energy and atmosphere, materials and resources, indoor environmental quality, and innovation and design. A challenge is to recognize differences in the importance of the individual measures—first, to the related objective, and second, to a balancing among objectives. For instance, reduction of greenhouse gas emissions and reduction of dependence on foreign oil might well be given explicit recognition as important objectives, in view of the fact that they are externalities from the point of view of individual behavior that need special encouragement.

**Estimate the typical effect of each recommended measure in quantitative terms, and rank the measures that contribute to a given common goal by their effectiveness in contributing to the goal.** As an example, among the eight measures that can earn points toward certification under the sustainable sites objective, brownfield redevelopment and light pollution reduction can both earn 1 point each, suggesting that they are of equal

importance. It should be possible to choose a metric for measuring sustainability and to quantify the effects more precisely than giving each equal weight.

**Rethink the weights given to different goals.** The points given to each of the 70 possible measures that can earn qualification depend in part on the weights given to the overarching goals. For example, the maximum possible number of points for measures contributing to indoor environmental quality is 15, while for energy and atmosphere the number is 17. At first glance, these two goals appear equally important, though the number of possible measures under each is similar. Underlying a point system, either implicitly or explicitly, is a choice of the relative importance of different goals. While all the measures are commendable, how commendable are they in relative terms? More thought needs to be given to this dilemma.

**Choose the total point requirement for certification so as to maximize program effectiveness.** If the total number of points required for certification is too low, qualifying will be too easy and the certification will lose its meaning. If too high, it will be viewed as impossible to achieve and lose effectiveness as an incentive.

**Estimate the contribution of the green building movement to achieving national and world environmental improvement.** Suppose the United States were to make a commitment to reducing greenhouse gas emissions by 10 percent. In order to carry this out, how could green buildings contribute to this goal? The answer would influence the emissions reductions to be sought from other sources.

This list is by no means exhaustive. Green buildings offer a promising approach to improving the environment. This approach deserves more attention from economic researchers and environmental policy analysts than it has yet received.

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# 33. WHY INTERNATIONAL NATURAL GAS MARKETS MATTER IN TODAY'S ENERGY AND ENVIRONMENTAL PICTURE

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*What are the recent trends in natural gas markets? How vulnerable is the United States to worldwide disruptions in the supply of natural gas and possible abuse of market power by a group of OPEC-like countries?*

In recent years, the environmental and economic value of natural gas has soared, making it an ever-important fuel for power generation, industrial operations, as well as residential and commercial use. Natural gas holds a favorable environmental position relative to coal and oil, all the more important given the current move toward a low-carbon world. In the United States, demand for natural gas rose over 33 percent in the period 1986–2006, driven by a multitude of factors. In Europe, geopolitical issues are more pronounced, as almost half of the European Union's imports of gas come from Russia. Additionally, there is now competition in both the Atlantic and Pacific basins for liquefied natural gas (LNG) from exporting countries. The overall picture then is one of a global competition for this important fuel source.

Two other trends have emerged over the last two and a half decades that have helped to spur both domestic and international natural gas consumption. The first was the enactment of regulations geared at liberalizing gas markets. In the United States, the Federal Energy Regulatory Commission required interstate pipeline companies to unbundle, or separate, their sales and transportation services in order to promote competition and mitigate their potential market power. Similar legislative measures were enacted in the European Union that promoted third-party access and legal splitting of gas sellers and network operators.

The second trend is the rise of liquefied natural gas trading. LNG is the liquid form of this fuel, achieved by cooling the normally gaseous substance to about  $-260^{\circ}$  and removing certain components. By using specialized cryogenic tankers, natural gas can be moved much more easily around the world, but this process is costly. While there is not yet a common "world gas price" as in the case with oil, there are some very large producers. Nearly 75 percent of the world's natural gas reserves can be found in the Middle East and Eurasia, with reserves in Russia, Iran, and Qatar combined accounting for nearly 60 percent of this total, resulting in geopolitical market power. For example, the influence of Russian production and control of key pipelines was felt in Ukraine and Western Europe in the winter of 2005–2006, when Russia temporarily cut off gas to Ukraine over a price dispute, which affected downstream Europe.

In the United States, dependence on natural gas from other countries has been rising over time. Imports of natural gas as a percentage of total consumption rose from just over 4 percent in 1986 to almost 16 percent in 2006. Colleagues and I have created detailed game theoretic models of market equilibria in which producers (or their marketing arms) may withhold production in order to achieve higher profits. The resulting simulations indicate that market power can raise natural gas prices considerably. Compared with an assumption of perfectly competitive producers in Europe (that is, producers not having the ability to influence market prices by withholding production), the effects of market power raise European prices by some 27 percent. This is further exacerbated if a major supplier such as Algeria is shut down or gas from Russia is curtailed through a transit country such as Ukraine.

While the demand for natural gas is rising, this is not cause for immediate concern if you consider the reserves-to-production ratios, which give an estimate of the number of years left if current production rates hold into the future. For example,

the worldwide reserves-to-production ratio is 65 years, with higher values for certain regions such as Russia (80 years) and the Middle East (more than 100 years).

Despite a number of years of available gas left, many countries are seeking to diversify their supply sources and mitigate the market power held by the major suppliers. Rather than rely on pipelines to deliver gas, several “downstream” European countries have set up and are increasing their numbers of LNG regasification (import) terminals, which convert natural gas back to gaseous form for use in regional pipelines.

The impact of building more LNG regasification terminals can be a greater choice of prices and other contractual terms for the downstream countries. More LNG terminals are in the works also for the United States. The current five LNG import terminals, accounting for just over 5.8 billion cubic feet per day, will be supplemented with four new ones being constructed in the Gulf of Mexico, which will more than double LNG import capacity. Also, Japan already is a huge LNG importer, buying over 40 percent of the worldwide share in 2005. Thus, LNG’s importance is a worldwide phenomenon.

How will these global and regional factors affect international natural gas markets in the future? First, in order to satisfy growing demand, exploration efforts will need to increase, which will undoubtedly require larger amounts of capital for harder-to-reach sources and thus, all things being equal, lead to higher prices. These prices may be raised further by the effects of market power, especially in Europe, whose dependence on gas from other countries is significant. Second, the formation of a “gas cartel” like OPEC may be in the offing if major pro-

ducers like Russia, Iran, and Qatar deem it economically in their interests to cooperate with each other, which could have broad ramifications for gas-consuming countries. Third, while downstream customers are looking for ways to ensure greater security of supply by building LNG facilities and additional pipelines, producers are also interested in “demand security.” Specifically, they are looking for assurances that if they spend large sums of money on natural gas infrastructure, their investments will be economically viable. Producing countries could start buying stakes in downstream operations and markets to hedge their positions. Lastly, the importance of natural gas in the cap-and-trade carbon markets that are forming should not be underestimated. If the price of natural gas rises significantly, this increase affects these markets as coal then becomes more economically appealing, causing allowance prices to go up.

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## 34. ASSESSING ELECTRICITY MARKETS

### Prospects and Pitfalls

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*The electricity sector is a critical piece of the U.S. economy, on which our society depends heavily. Over the past 10 to 15 years, electricity markets have been opened and restructured, and competition has been introduced. How have these changes affected prices, consumers, and reliability?*

The electricity sector garners considerable attention and deservedly so. On size alone, it represented about 2.4 percent of GDP in 2005—more than we spend on motor vehicles or gasoline. Large as it is, the sheer size of the sector belies its significance to our society and economy, which literally cannot operate without it. Perhaps the most reported aspect of natural disasters such as hurricanes, following casualty figures, is the extent and persistence of power outages. It is therefore crucial to study and assess the effects of policies that, over the last 10 years, have introduced competition into the previously regulated electricity sector.

Prior to the mid-1990s, the sector was dominated by regulated private utilities that generated, transported, and sold their own electricity. Following the wave of largely successful moves from regulation to competition in other sectors such as telecommunications and transportation—finance is looking a little shaky these days—electricity markets were opened. The federal government began by setting rules for allowing independent generators access to still-regulated transmission networks. A number of states followed by opening retail markets under their control, giving consumers choice over competing retail providers, although generally leaving the traditional utilities in place.

#### **HAS OPENING MARKETS LED TO BETTER (NOT NECESSARILY LOWER) PRICES?**

Whether opening electricity markets has helped or hurt consumers is a matter of considerable controversy. From the public's perspective, the case for competition has taken three significant hits: the California market meltdown in 2000–2001, the Northeast Blackout in August 2003, and the rapid rise in electricity rates in many states. Maryland, for example, saw increases in excess of 70 percent in 2006–2007. Partly for these reasons, much of the country retains traditional regulation of monopoly utilities. Only Texas, Illinois, Michigan, and most of the mid-Atlantic and northeastern United States (except Vermont) currently have open electricity markets. Many states, including California and Virginia, have suspended their deregulatory policies.

The public controversy is matched by disagreement among researchers as to the effects of opening electricity markets. Contrary to what competition advocates might expect, a number of studies have found higher prices in areas of the country where electricity markets were opened. Such studies, however, face considerable difficulties. Among these are that the states and regions opting to open markets are likely to be those where prices would have been above average in the first place, creating a spurious correlation between competition and high prices.

Moreover, higher electricity prices under open markets aren't necessarily bad. Because electricity cannot be stored, it has to be produced exactly when needed to avoid blackouts. Consequently, generation capacity has to be in place, to be used only for those few summer hours when demand peaks to run all of our air conditioners. To cover the cost of that capacity, prices in these critical few hours have to be very high,

up to 50 times the price at more normal “baseload” times.

These higher prices need not reflect dysfunctional markets or monopoly power, any more than do high summer rates for beachfront hotels. Rather, they can provide suppliers and users with the right signals, so we might turn down our air conditioners and defer optional uses when electricity becomes extraordinarily expensive to generate. A virtue of competition is not that it makes prices lower, but that it ties prices to the costs of producing the electricity needed to meet demand, whether those costs are high or low. But because every supplier gets to charge the high price, this economic virtue comes at a political cost, as electricity bills and generator profits rise. Voters may not have the patience to wait for new generators to come online and drive overall rates and profits back down to competitive levels. If regulators set ceilings on electricity prices to mitigate this effect, funds to pay for peak generation units have to come from other sources. This has led to the institution of wholesale markets in “capacity” on top of those for electricity itself.

### DO CONSUMERS WANT MORE CHOICES?

Consumers may be upset about losing their regulatory insulation from facing high prices, but they may also simply not find competition worth the trouble. In most jurisdictions where residential users have been given the opportunity to choose new electricity suppliers, few have done so. A recent Maryland Public Service Commission (MDPSC) study reported that entrants supplied only about 2 percent of residential electricity use in that state.

Although residual rate regulation may have something to do with this, consumers simply may not want to be bothered. A measure of the hassle is the “helpful” assistance many states provided, which effectively told consumers that determining whether they would save money by switching suppliers was about as simple and pleasant as filling out a tax return. It is hardly surprising that most consumers would rather stick with their old utility rather than go to the trouble of switching to save a few dollars a month. That said, the rate of switching by commercial and industrial users is far higher—almost 70 percent of their load, according to that MDPSC report. On that score, the “electricity competition” glass is considerably more than half full.

### HAS COMPETITION THREATENED RELIABILITY?

The biggest impediment to opening electricity markets, however, has long been the potential conflict between the independence necessary to realize the fruits of competition and

the cooperation potentially needed to maintain reliability. Because electrons take all available paths to get from where electricity is generated to where it is used, the grid operates as a single entity even if different utilities own different lines. If one supplier fails to meet its customers’ needs, not only will those customers lose power—the entire grid may go down.

The grid’s vulnerability implies the need for some degree of central control—but how much? Ensuring reliability may need only relatively minimal rules, such as reserve requirements, enabling transmission and distribution system operators to obtain energy to get over unexpected emergencies. The challenge to competition is whether control needs to go deeper.

Fostering competition has generally led to the undoing of the traditional integrated utility structure—why opening electricity markets is called “restructuring.” Both local distribution lines and regional transmission systems are monopolies. Regulation is unlikely to replace competition of those “wires” in the foreseeable future. If companies owning generation control these lines, they may be able to subvert competition by denying reasonable access to rivals. This concern has motivated regulators to limit such control by requiring separate, independent operation of transmission lines. On the other hand, needing to coordinate large-scale transmission and generation investments may undercut the entrepreneurial initiative that drives the benefits of competition.

The fundamental question in assessing electricity markets is whether they are consistent with keeping the grid efficient, growing, and reliable. The fact that today’s controversies about the merits of electricity markets focus on prices, and not on repeats of the California meltdown or the Northeast outage of the early 2000s, suggests that the worst fears regarding reliability have not come to pass—so far. Whether we have been skillful or lucky remains to be seen.

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