Fool's Gold in Alaska

Amory B. Lovins and L. Hunter Lovins

THE BOTTOM OF THE BARREL?

OIL PRICES have fluctuated randomly for well over a century. Heedless of this fact, oil's promoters are always offering opportunities that could make money—but on the flawed assumption that high prices will prevail. Leading the field of these optimists are Alaskan politicians. Eager to keep funding their state's de facto negative income tax—oil provides 80 percent of the state's unrestricted general revenue—they have used every major rise in oil prices since 1973 to advocate drilling beneath federal lands on the coastal plain of the Arctic National Wildlife Refuge. Just as predictably, environmentalists counter that the refuge is the crown jewel of the American wilderness and home to the threatened indigenous Gwich'in people. As some see it, drilling could raise human rights issues under international law. Canada, which shares threatened wildlife, also opposes drilling.

Both sides of this debate have largely overlooked the central question: Does drilling for oil in the refuge's coastal plain make sense for economic and security reasons? After all, three imperatives should shape a national energy policy: economic vitality, secure supplies, and environmental quality. To merit serious consideration, a proposal must meet at least one of these goals.

Drilling proponents claim that prospecting for refuge oil will enhance the first two while not unduly harming the third. In fact, not

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only does refuge oil fail to meet any of the three goals, it could even compromise the first two. First, the refuge is unlikely to hold economically recoverable oil. And even if it did, exploitation would only briefly reduce U.S. dependence on imported oil by just a few percentage points, starting in about a decade. Nor would the refuge yield significant natural gas. Despite some recent statements by the Bush administration, the North Slope's important natural-gas deposits are almost entirely outside the refuge. The gas-rich areas are already open to industry, and environmentalists would likely support a gas pipeline there, but its high cost—an estimated $10 billion—would make it seem uneconomical.

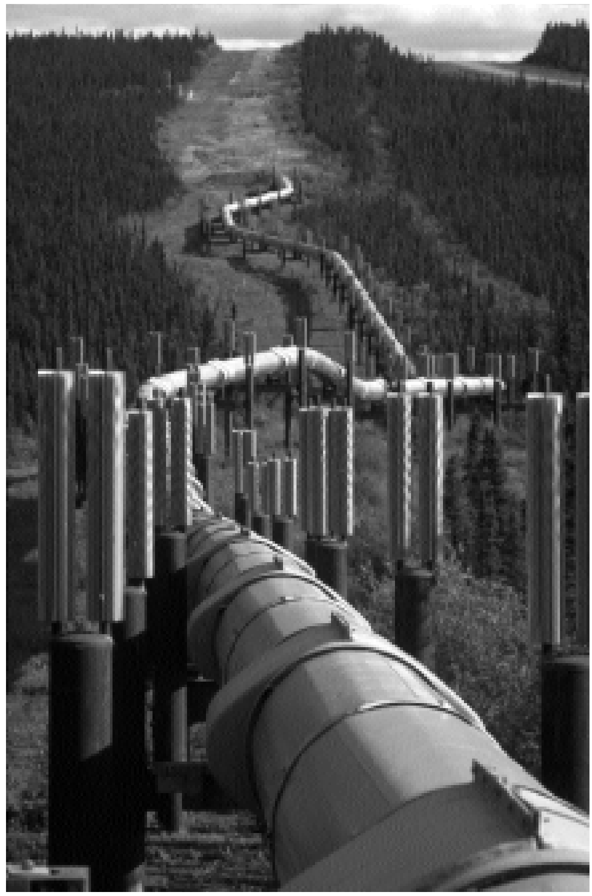
Furthermore, those who suppose that any domestic oil is more secure than imported oil should remember that oil reserves almost anywhere else on earth are more accessible and more reliably deliverable than those above the Arctic Circle. Importing oil in tankers from the highly diversified world market is arguably better for energy security than delivering refuge oil to other U.S. states through one vulnerable conduit, the Trans-Alaska Pipeline System. Although proponents argue that exploiting refuge oil would make better use of TAPS (which is all paid for but only half-full), that pipeline is easy to disrupt and difficult to repair. More than half of it is elevated and indefensible; in fact, it has already been bombed twice. If one of its vital pumping stations were attacked in the winter, its nine million barrels of hot oil could congeal into the world's largest Chapstick. Nor has the 24-year-old TAPS aged gracefully: premature and accelerated corrosion, erosion, and stress are raising maintenance costs. Last year, the pipeline suffered two troubling accidents plus another that almost blew up the Valdez oil terminal. If TAPS were to start transporting refuge oil, it would start only around the end of its originally expected lifetime. That one fragile link, soon to be geriatric, would then bring as much oil to U.S. refineries as now flows through the Strait of Hormuz—a chokepoint that is harder to disrupt, is easier to fix, and has alternative routes.

Available and proven technological alternatives that use energy more productively can meet all three goals of energy policy with far greater effectiveness, speed, profit, and security than can drilling in the refuge. The untapped, inexpensive "reserves" of oil-efficiency technology exceed by more than 50 times the average projection of what refuge drilling might yield. The existence of such alternatives makes drilling even more economically risky.

In sum, even if drilling in the Arctic Wildlife Refuge posed no environmental or human rights concerns, it still could not be justified on economic or security grounds. These reasons remain as compelling as they were 14 years ago, when drilling there was last rejected, and they are likely to strengthen further with technological advances. Comparing all realistic ways to meet the goals of national energy policy suggests a simple conclusion: refuge oil is unnecessary, insecure, a poor business risk, and a distraction from a sound national debate over realistic energy priorities. If that debate is informed by the past quarter-century's experience of what works, a strong energy policy will seek the lowest-cost mix of demand- and supply-side investments that compete fairly at honest prices. It will not pick winners, bail out losers, substitute central planning for market forces, or forecast demand and then plan capacity to meet it. Instead, it will treat demand as a choice, not fate. If consumers can choose optimal levels of efficiency, demand can remain stable (as oil demand did during 1975–91) or even decline—and it will be possible to provide secure, safe, and clean energy services at the lowest cost. In this market-driven world, the time for costly refuge oil has passed.

DOING MORE WITH LESS

UNSTABLE OIL PRICES have historically triggered new energy strategies. In the years following the oil-price jump in 1973, Presidents Richard Nixon and Gerald Ford sought to reduce U.S. dependence on oil imports by stimulating domestic energy supplies. With the country beset by inflation, however, they also controlled oil and gas prices, so the new supplies often appeared cheaper than they really were. President Jimmy Carter repeated this supply mistake by promoting a costly flop in synthetic fuels, but he also trusted the market enough to deregulate oil and gas prices. (Paradoxically, he discouraged exploration for natural gas by prohibiting its use in most new power plants.) The fall of the shah of Iran again hiked oil prices in 1979 and contributed to Carter's political demise. Yet that second shock also stimulated a nationwide, seven-year drive for greater energy efficiency. Cheaper ways of delivering "energy services" (e.g., hot showers and cold beer) by using energy more productively left the energy-supply industries with costly surpluses as their prices collapsed in 1985–86. This crash benefited consumers but punished the same energy producers that the Reagan administration had sought to help. Underlying this energy glut was not just a response to higher prices but a basic policy shift: Carter had emphasized the efficient use of energy, especially in cars, and Americans then discovered how quickly demand-side policies can swing the global oil market.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Don't be fuelish: the Trans-Alaska Pipeline

Greater efficiency bore dramatic results. Carter's policies made new American-built cars more efficient by seven miles per gallon (mpg) over six years. During Carter's term and the five years following it, oil imports from the unstable Persian Gulf region fell by 87 percent. From 1977 to 1985, U.S. GDP rose 27 percent while total U.S. oil imports fell by 42 percent, or 3.74 million barrels a day. That savings took away from the Organization of Petroleum Exporting Countries an eighth of its market. The entire world oil market shrank by a tenth; OPEC's share of it was slashed from 52 percent to 30 percent, while OPEC's output fell by 48 percent. The United States accounted for one-fourth of that reduction. More-efficient cars—each driving one percent fewer miles on 20 percent fewer gallons—were the most important cause; 96 percent of those savings came from smarter design, whereas 4 percent came from smaller size. Other countries also improved car efficiency, but they used higher fuel taxes instead of higher efficiency standards to do so.

In those eight years, U.S. oil productivity soared by 52 percent, demonstrating an effective new source of energy security and a potent weapon against high oil prices and supply manipulations. The United States showed that a major nation could respond to supply disruptions by focusing on the demand side and boosting its energy productivity at will. It could thereby exercise more market power than suppliers, beat down prices, and enhance the relative importance of less vulnerable, more diversified sources of energy.

If the United States had conserved oil at the same rate that it did in 1976–85, it would have needed no Persian Gulf oil after 1985.

Drilling proponents today ignore this lesson. Instead, they cite the imperative of displacing Middle East oil to justify drilling in every U.S. site where oil might occur. But even if this imperative existed, refuge oil would be a poor solution. After a decade of drilling and preparation, it could provide only modest, brief relief—totaling less than one percent of projected U.S. oil needs—and would cost much more than the efficiency-boosting alternatives. Repaying refuge-oil investments would require oil prices so high that, in the ensuing decade, they would elicit far greater efficiency. Those efficiency gains, in turn, would depress oil prices, displace the targeted imports, and make refuge oil unnecessary. That was what happened in the mid-1980s; repeating the same experiment will yield the same result.

The United States has exploited its reserves longer and more fully than has any other nation, so the essence of its oil problem is that finding and lifting the next barrel typically costs more at home than abroad. A market economy offers three possible solutions to this puzzle: protectionism, trade, and substitution. Protectionism means subsidizing domestic output, which deters efficient use, or taxing imports, which violates free-trade rules. Either way, market principles are scorned, competitiveness wanes, and domestic oil depletion is illogically countered by faster depletion. Most countries opt for the trade solution. Germany and Japan, for example, import all their oil and are adept at earning foreign exchange to pay for it. They rely on a global oil-trading and transport system so flexible that even the Persian Gulf War did not create lines at gas stations. Trade is hardly novel to the United States, which imports many vital commodities, including 52 percent of its oil last year at a cost of $109 billion. But if concerned Americans fear that higher costs or thorny questions of political instability make importing unattractive, a third option exists: substitution.

Substitution means displacing oil with more efficient use of oil or alternative energy sources. This strategy reduces dependence in the quickest and cheapest way and maximizes competition and innovation. Indeed, the United States has already partly followed this course; its oil productivity has already doubled since 1975. But the efficiency-promotion strategy could have gone much further if U.S. policymakers had not quickly combated and suppressed it after the 1986 oil-price collapse. (In that year, for example, a rollback of car and light-truck efficiency standards doubled U.S. oil imports from the Persian Gulf and wasted one "refuge" of oil.) If the United States had continued to conserve oil at the same rate that it did in 1976–85 or had simply bought new cars that got 5 mpg more than they did, it would no longer have needed Persian Gulf oil after 1985. Instead, policy in the 1980s discouraged energy efficiency, which was officially characterized as an intrusive, interventionist burden of curtailment and sacrifice. Efficiency also appeared needless when the 1986 price crash ushered in a decade of cheap oil, while deep budget cuts crippled technological innovation in energy productivity. Today, the dramatic gains in energy efficiency that the United States launched during the Carter years have been forgotten. Many journalists and political leaders no longer remember that efficiency gains are not only possible but profitable. Yet despite the neglect of efficiency from 1986 to 1996 (when efficiency began a sudden resurgence), the nation has still cut $200 billion off its annual energy bill.

U.S. oil imports crept back up in the late 1980s, spurred by low prices, abundant supplies, corporate inattention, and policy neglect. If the first Bush administration had required in 1991 that the average car get 32 mpg, that measure alone would have displaced all Persian Gulf oil imports to the United States. Instead, the United States fought a war that deployed tanks moving at 0.56 mpg and aircraft carriers moving at 17 feet per gallon. That effort cost the United States more than it would have cost to save (through investing in efficiency technology) all the oil imported from the Gulf. That lesson was ignored as Congress stalled most efficiency initiatives in the 1990s. By 2000, oil imports had rebounded to their record 1977 level, and oil prices spiked once more. The three-member Alaskan congressional delegation, chairing three of the four chief congressional committees controlling public lands, again pressed for drilling in the refuge. On January 22, 2001, aides to President George W. Bush claimed that California's electricity crisis showed that the nation desperately needs more fuel. In fact, California has no shortage of oil, and only one percent of its electricity comes from oil; nationwide, only two percent of oil is consumed to generate electricity. Curiously, the administration's response to the nation's supposed "energy crisis" has been to reject the notion of "doing more with less," the very definition of energy efficiency. It has halved key budgets for efficiency research, increased future power needs by 13 billion watts by weakening cost-effective air-conditioner standards, and centered its supply-side strategy on seeking—against all odds—congressional approval to exploit refuge oil.

OIL ROULETTE

THE REFUGE is one of the planet's most inhospitable and remote locations. For oil companies to invest profitably there, it must hold a lot of oil. Furthermore, world oil prices must stay high enough for a long enough time to recover costs and earn profits. But even official proponents of drilling have found its economics dubious.

In 1998, the U.S. Geological Survey (USGS) found that better (and fourfold cheaper) production technologies could probably draw 3.2 billion barrels from the refuge.[1] This oil would be worth recovering only if its long-term price were at least $22 per barrel in West Coast ports (the destinations that the USGS picked for its price calculations). But until it spiked up from $13 per barrel in 1998 to $30 per barrel in

[1] This is the mean of a range of projections, from 0.5 billion to 6.5 billion, from the USGS's 1998 study. The higher estimates that some drilling proponents cite, such as the 13.7 billion barrels mentioned by *The Wall Street Journal*'s editorial page, exceed the USGS's highest projection at any price, because they typically ignore recoverability, economics, and geographic location. All prices in this article are in 2000 dollars (fourth quarter).

late 2000, Alaskan oil did not exceed that level for 8 years. That spike was a blip, not a trend. In April 2001, Alaska's Department of Revenue forecast a steady price drop from $22 per barrel in 2001–2 to less than $13 per barrel in 2009–10—the earliest that any refuge oil might flow. Alaska's latest price forecast for 2020 is $18 per barrel. The U.S. Department of Energy predicts that world oil prices will not reach $23 per barrel until 2020; nearly all industry forecasts are lower.

But it is no longer necessary to speculate which forecast is correct; they all tend to converge on the prices discovered in the futures market. Alaska's forecasters agree that this convergence is unaffected by price spikes such as the one in 2000. Their projection for 2004–10 accordingly stays under $16 per barrel. (One of the world's largest oil companies does not even consider any prospect requiring a delivered price of more than $14 per barrel.) According to the USGS, that price is also the threshold below which there is probably no economically recoverable oil beneath the refuge. Even that threshold may be too high; volatile oil prices make drilling especially risky, requiring higher returns and prices in any high-cost area where exploration and development will be slow and difficult. And if the federal government were to demand lease fees, such as the multi-billion-dollar revenues that the Alaskan delegation inserts into budget bills, or if TAPS needed more maintenance, the price threshold would rise.

Some drilling advocates argue that technological advances in finding and extracting oil can still make refuge oil profitable. Those advances are indeed real and astoundingly rapid. From 1987 to 1999, they increased the discovery of new U.S. oil resources by an estimated three-fifths. One-ninth of all U.S. oil reserves discovered since 1859 were found just in the past decade, even as oil prices fell. Better technologies could make extracting refuge oil cheaper—but those same advances would also cut costs everywhere else, and just about anywhere else is easier and more attractive. Better technology makes global oil more plentiful and therefore cheaper, so it renders high-cost areas less competitive. During the 1990s, this process combined with increasing competition from energy alternatives to halve long-term forecasts of oil prices, which are still falling. The Department of Energy now forecasts that imported oil will cost three-fifths less by 2020 than what the Department of the Interior had forecast in 1987, when it predicted prices hitting $61 per barrel. If oil companies really believed in sustained high prices, they would be drilling everywhere—and they are not. On the contrary, when oil prices rose from $10 per barrel to $25 per barrel in 1998–99 and lifted the oil and gas revenues of major U.S. energy companies by more than 50 percent, those firms cut exploration and development outlays by 66 percent in the United States (onshore) and 38 percent worldwide. These companies believe that advancing technology will keep the world long awash in oil that is too cheap for refuge drilling to beat.

Who, then, is pushing for drilling—aside from the powerful Alaskan congressional delegation? Oil-service companies and Alaskan operations offices of major oil companies naturally want to extend and expand their activities and apply their special skills, but they would be risking others' money, not their own. Likewise, the TAPS consortium wants more revenue and a political commitment that might justify a later government bailout if the pipeline turned out to need costly repairs, but it too would not be the one making the huge investment. Conspicuously absent is a ringing endorsement from leaders of major oil firms. They understand the high risk and the prospect of poor rewards, and those that are more astute also fear global consumer boycotts. To the extent that any are interested, it is to seek a bargaining chip for other areas now off-limits or to avoid the social embarrassment of being left off the dance card if the government throws an oil party—not because there is a sound business case.

Finally, the rationale that refuge drilling is urgently needed to relieve U.S. dependence on OPEC oil is full of holes. Net U.S. oil imports have indeed risen past their 1977 peak, but OPEC's share of those imports has fallen by one-third. Only a quarter of the oil consumed in the United States now comes from OPEC members. Imports are diversified and come mainly from western hemisphere countries that offer major opportunities for expanding both oil and gas supplies. The more that imports are a concern, however, the stronger the case for substituting not just any option but the cheapest one—slashing America's energy bills by a further $300 billion a year by raising energy productivity.

IT'S EASY (AND LUCRATIVE) BEING GREEN

OIL IS becoming more abundant but relatively less important. For each dollar of GDP, the United States used 49 percent less oil in 2000 than it did in 1975. Compared with 1975, the amount that energy efficiency now saves each year is more than five times the country's annual domestic oil production, twelve times its imports from the Persian Gulf, and twice its total oil imports. And the efficiency resource is far from tapped out; instead, it is constantly expanding. It is already far larger and cheaper than anyone had dared imagine.

Increased energy productivity now delivers two-fifths of all U.S. energy services and is also the fastest growing "source." (Abroad, renewable energy supply is growing even faster; it is expected to generate 22 percent of the European Union's electricity by 2010.) Efficient energy use often yields annual after-tax returns of 100 to 200 percent on investment. Its frequent fringe benefits are even more valuable: 6 to 16 percent higher labor productivity in energy-efficient buildings, 40 percent higher retail sales in stores with good natural lighting, and improved output and quality in efficient factories. Efficiency also has major policy advantages. It is here and now, not a decade away. It improves the environment and protects the earth's climate. It is fully secure, already delivered to customers, and immune to foreign potentates and volatile markets. It is rapidly and equitably deployable in the market. It supports jobs all across the United States rather than in a few firms in one state. Yet the energy options now winning in the marketplace seem oddly invisible, unimportant, and disfavored in current national strategy.

Those who have forgotten the power of energy efficiency should remember the painful business lessons learned from the energy policies of the early 1970s and the 1980s. Energy gluts rapidly recur whenever customers pay attention to efficiency—because the nationwide reserve of cheap, qualitatively superior savings from efficient energy use is enormous and largely accessible. That overhang of untapped and unpredictably accessed efficiency presents an opportunity for entrepreneurs and policymakers, but it also poses a risk to costly supply investments. That risk is now swelling ominously.

In the early 1980s, vigorous efforts to boost both supply and efficiency succeeded. Supply rose modestly while efficiency soared.

From 1979 to 1986, GDP grew 20 percent while total energy use fell by 5 percent. Improved efficiency provided more than five times as much new energy service as the vaunted expansion of the coal and nuclear industries; domestic oil output rose only 1.5 percent while domestic natural gas output fell 18 percent. When the resulting glut slashed energy prices in 1985–86, attention strayed and efficiency slowed. But just in the past five years, the United States has quietly entered a second golden age of rapidly improving energy efficiency. Now, with another efficiency boom underway, the whole cycle is poised to repeat itself—threatening another energy-policy train wreck with serious economic consequences.

From 1996 to 2000, a complex mix of factors—such as competitive pressures, valuable side benefits, climate concerns, and e-commerce's structural shifts—unexpectedly pushed the pace of U.S. energy savings to nearly an all-time high, averaging 3.1 percent per year despite the record-low and falling energy prices of 1996–99. Meanwhile, investment in energy supply, which is slower to mature, lagged behind demand growth in some regions as the economy boomed. Then in 2000, Middle East political jitters, OPEC machinations, and other factors made world oil prices spike just as cold weather and turbulence in the utility industry coincidentally boosted natural gas prices. Gasoline prices are rising this year—even though crude-oil prices are softening—due to shortages not of crude oil but of refineries and additives. California's botched utility restructuring, meanwhile, sent West Coast electricity prices sky-high, although not for the oft-cited reasons. (Demand did not soar, and California did not stop building power plants in the 1990s, contrary to many observers' claims.)

The higher fuel and electricity prices and occasional local shortages that have vexed many Americans this past year have rekindled a broader national interest in efficient use. The current economic slowdown will further dampen demand but should also heighten business interest in cutting costs. Efficiency also lets numerous actors harness the energy market's dynamism and speed—and it tends to bear results quickly. All these factors could set the stage for another price crash as burgeoning energy savings coincide, then collide, with the new administration's push to stimulate energy supplies. Producers who answer that call will risk shouldering the cost of added supply without the revenue to pay for it, for oil prices high enough to make refuge oil profitable would collapse before or as supply boomed.

Policymakers can avoid such overreaction and instability if they understand the full range of competing options, especially the ability of demand to react faster than supply and the need for balancing investment between them. As outlined above, in the first half of the 1980s, the U.S. economy grew while total energy use fell and oil imports from the Persian Gulf were nearly eliminated. This achievement showed the power of a demand-side national energy policy. Today, new factors—even more powerful technologies and better designs, streamlined delivery methods, and better understanding of how public policy can correct dozens of market failures in buying efficiency—can make the demand-side response even more effective. This can give the United States a more affordable and secure portfolio of diverse energy sources, not just a few centralized ones.

A BARREL SAVED, A BARREL EARNED

If oil were found and profitably extracted from the refuge, its expected peak output would equal for a few years about one percent of the world oil market. Senator Frank Murkowski (R-Alaska) has claimed that merely announcing refuge leasing would bring down world oil prices. Yet even a giant Alaskan discovery several times larger than the refuge would not stabilize world oil markets. Oil prices reached their all-time high, for example, just as such a huge field, in Alaska's Prudhoe Bay, neared its maximum output. Only energy efficiency can stabilize oil prices—as well as sink them. And only a tiny fraction of the vast untapped efficiency gains is needed to do so.

What could the refuge actually produce under optimal conditions? Starting about ten years from now, if oil prices did stay around $22 per barrel, if Congress approved the project, and if the refuge yielded the USGS's mean estimate of about 3.2 billion barrels of profitable oil, the 30-year output would average a modest 292,000 barrels of crude oil a day. (This estimate also assumes that such oil would feed U.S. refineries rather than go to Asian markets, as some Alaskan oil did in 1996–2000.) Once refined, that amount would yield 156,000 barrels of gasoline per day—enough to run 2 percent of American cars and light trucks. That much gasoline could be saved if light vehicles became 0.4 mpg more efficient. Compare that feat to the one achieved in 1979–85, when new light vehicles on average gained 0.4 mpg every 5 months.

Equipping cars with replacement tires as efficient as the original ones would save consumers several "refuges" full of crude oil. Installing superinsulating windows could save even more oil and natural gas while making buildings more comfortable and cheaper to construct. A combination of all the main efficiency options available in 1989 could save today the equivalent of 54 "refuges"—but at a sixth of the cost. New technologies for saving energy are being found faster than the old ones are being used up—just like new technologies for finding and extracting oil, only faster. As gains in energy efficiency continue to outpace oil depletion, oil will probably become uncompetitive even at low prices before it becomes unavailable even at high prices. This is especially likely because the latest efficiency revolution squarely targets oil's main users and its dominant growth market—cars and light trucks—where gasoline savings magnify crude-oil savings by 85 percent.

New American cars are hardly models of fuel efficiency. Their average rating of 24 mpg ties for a 20-year low. The auto industry can do much better—and is now making an effort. Briskly selling hybrid-electric cars such as the Toyota Prius (a Corolla-class 5-seater) offer 49 mpg, and the Honda Insight (a CRX-class 2-seater) gets 67 mpg. A fleet that efficient, compared to the 24 mpg average, would save 26 or 33 refuges, respectively. General Motors, DaimlerChrysler, and Ford are now testing family sedans that offer 72–80 mpg. For Europeans who prefer subcompact city cars, Volkswagen is selling a 4-seater at 78 mpg and has announced a smaller 2003 model at 235 mpg. Still more efficient cars powered by clean and silent fuel cells are slated for production by at least eight major automakers starting in 2003–5. An uncompromised fuel-cell vehicle—the Hypercar℠—has been designed and costed for production and would achieve 99 mpg; it is as roomy and safe as a midsized sport-utility vehicle but uses 82 percent less fuel and no oil.[2] Such high-efficiency vehicles, which probably can

[2] Amory B. Lovins was the originator of this project. A private firm, in which he holds a minor financial interest, is preparing such vehicles for commercial production.

be manufactured at competitive cost, could save globally as much oil as OPEC now sells; when parked, the cars' dual function as plug-in power stations could displace the world's coal and nuclear plants many times over.

As long as the world runs largely on oil, economics dictates a logical priority for displacing it. Efficient use of oil wins hands down on cost, risk, and speed. Costlier options thus incur an opportunity cost. Buying costly refuge oil instead of cheap oil productivity is not simply a bad business decision; it worsens the oil-import problem. Each dollar spent on the costly option of refuge oil could have bought more of the cheap option of efficient use instead. Choosing the expensive option causes more oil to be used and imported than if consumers had bought the efficiency option first. The United States made exactly this mistake when it spent $200 billion on unneeded (but officially encouraged) nuclear and coal plants in the 1970s and 1980s. The United States now imports oil, produces nuclear waste, and risks global climate instability partly because it bought those assets instead of buying far cheaper energy efficiency.

Drilling for refuge oil is a risk the nation should consider taking only if no other choice is possible. But other choices abound. If three or four percent of all U.S. cars were as efficient as today's popular hybrid models, they would save the equivalent of all the refuge's oil. In all, many tens of times more oil is available—sooner, more surely, and more cheaply—from proven energy efficiency. The cheaper, faster energy alternatives now succeeding in the marketplace are safe, clean, climate-friendly, and overwhelmingly supported by the public. Equally important, they remain profitable at any oil price. They offer economic, security, and environmental benefits rather than costs. If any oil is beneath the refuge, its greatest value just might be in holding up the ground beneath the people and animals that live there.

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-Authors' Notes-

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Fool's Gold in Alaska

This title was created by the editors of Foreign Affairs, as were all crossheads within the article. The originally submitted title was "The Alaskan Threat to National Energy Security."

This article is gratefully dedicated to the memory of William P. Bundy, the Editor of Foreign Affairs responsible for refining and publishing Amory Lovins's Fall 1976 article "Energy Strategy: The Road Not Taken?"

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Hunter Lovins is a political scientist, sociologist, lawyer, forester, and cowboy. She holds BAs (Pitzer) in political studies and sociology, a JD (Loyola) with the Alumni Award for Outstanding Service, and two honorary doctorates. Coauthor of nine of their 27 books and many of their several hundred papers, she has won the LOHAS Award and shared with Amory two visiting academic chairs, the "Alternative Nobel," Mitchell, Shingo (Research), and Nissan Prizes, and the Lindbergh and Time "Heroes for the Planet" Awards. She serves on the local fire/rescure service as an EMT, rides rodeo, trains horses, and is a nationally ranked polocrosse player.

Amory Lovins, originally a consultant experimental physicist, studied at Harvard and Oxford. He has received an Oxford MA (by virtue of being a don) and seven U.S. honorary doctorates, briefed 15 heads of state, and received the shared awards just noted plus the Onassis Prize, Heinz and World Technology Awards, Happold Medal, Rocky Mountain Chapter AIA's Award of Distinction, and MacArthur Fellowship. He served on the Department of Energy's senior advisory board (1980–81) and a Defense Science Board task force (1999– 2001). The Wall Street Journal named him among 39 people in the world most likely to change the course of business in the 1990s; Car magazine, the 22nd most powerful person in the global automotive industry; and Newsweek, "one of the Western world's most influential energy thinkers." His avocations include mountain photography, music, and writing.

The Lovinses consult extensively for the private sector worldwide, mainly on advanced resource productivity and strategy for the energy, real-estate, automotive, and manufacturing sectors. Their latest book, with noted entrepreneur and business author Paul Hawken, is Natural Capitalism: Creating the Next Industrial Revolution (Little, Brown, 1999, www.natcap.org). They serve on various for- and nonprofit Boards. They created, incubated, and spun off E SOURCE (www.esource.com), which RMI sold to the Financial Times Group in 1999. Amory Lovins chairs Hypercar, Inc., RMI's fourth for-profit spinoff (www.hypercar.com), which with $5 million of private equity is commercializing his 1990–91 Hypercar concept.

Sample clients include: Allstate, Anheuser-Busch, Bank of America, Baxter, Borg-Warner, BP/Amoco, Bulmer, Carrier, CIBAGeigy, Coca-Cola, Dow, Equitable, General Motors, Hewlett-Packard, Interface, Lockheed Martin, Mitsubishi, Monsanto, Motorola, Norsk Hydro, Phillips Petroleum, Prudential, Royal Ahold, Royal Dutch/Shell, Shearson Lehman Amex, STMicroelectronics, Sun Oil, Union Bank of Switzerland, Westinghouse, Xerox, major real-estate developers, and over 100 electric and gas utilities. Public-sector clients have included OECD, UN, International Federation of Institutes for Advanced Study, Resources for the Future, the Australian, Canadian, Dutch, German, and Italian governments, 13 state governments, and the U.S. Congress and the Energy and Defense Departments. Hunter Lovins currently serves on the steering committee of the World Economic Forum's initiative on governance, and is one of four North American experts guiding preparations for the UN's 2002 Johannesburg global Conference on Sustainable Development.

Sample speaking venues include: The Engineering Foundation, Association of Energy Engineers, American Institute of Chemical Engineers, ASHRAE, Society of Automotive Engineers, [UK] Institution of Electrical Engineers, [UK] Construction Industry Council, Industrial Design Society, [US] National Academy of Sciences, International Association for Energy Economics, Montreux Energy Forum, Urban Land Institute, Industrial Development Research Council, American Institute of Architects, Edison Electric Institute, Electric Power Research Institute, Central Research Institute of the [Japanese] Electric Power Industry, International Energy Agency, Georgetown Center for Strategic and International Studies, Hoover and Brookings Institutions, Royal Institute of International Affairs, Council on Foreign Relations, Daughters of the American Revolution, Commonwealth Club, Prince of Wales's Business & the Environment Programme, Fortune Editors' Invitational Conference, Keidanren, Conference Board, World Economic Forum, World Bank, Organization for Economic Cooperation and Development, Naval War College, National Defense University, Royal Society, and Royal Society of Arts.

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Although the Lovinses are informed by nearly three decades' (two for HL) consultancy for major oil companies, and checked the relevant facts and opinions for accuracy with many experts in such firms, no proprietary information was needed for the preparation of this article.

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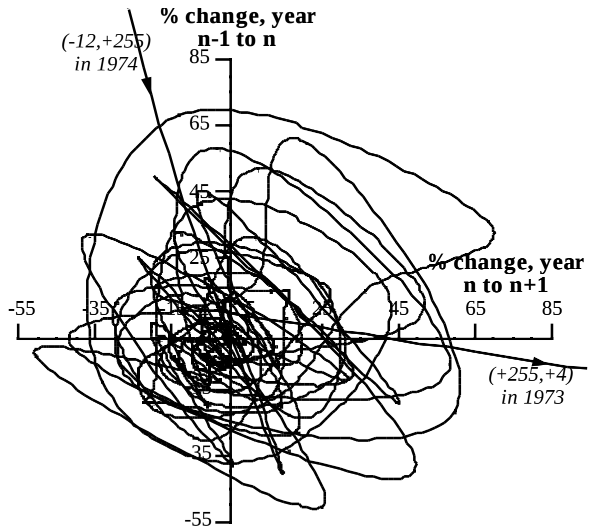
fluctuated randomly



World real oil price movements, 1881–1993
(BP, USDOE, and Worldwatch data)

This graph, in a style invented by H. Richard Holt (then at the U.S. Department of Energy), shows the year-over-year movements of the world real oil price for 113 years, with a one-year lag between the axes. If the fluctuations showed a secular trend rather than being random, their "center of gravity" would favor one quadrant over the others. In fact, the data set satisfies all statistical tests of randomness; all that happened after 1973 was that the volatility tripled. Such random behavior, similar to Brownian motion in physics, is typical of commodity prices.

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general revenue

Strictly speaking, unrestricted general-*purpose* revenue. The exact figure fluctuates from year to year; 80% is approximately valid through FY2003 according to p. 9 of the Alaska Department of Revenue (Tax Division) *Spring 2001 Revenue Sources Book*, www.tax.state.ak.us/sourcesbook/sources.htm. The 11 April 2001 edition, the most recent available when this article went to press, is relied upon throughout. Updates are posted quarterly and new editions semiannually; the July update introduced no material changes relevant to this article.

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rise in oil prices

Namely, the first oil shock in 1973, the second in 1979, and the lesser price runups in 2000–01. All occurred under or were closely followed by Republican Administrations generally sympathetic to exploitation of Refuge oil. In 1980, Congress postponed protection of the Refuge and authorized seismic exploration but not exploratory or production drilling. Congress rejected Refuge oil drilling in 1989 in the wake of the 24 March 1989 *Exxon Valdez* disaster. Another attempt in 1991, when oil prices blipped up during the Gulf War, died in the face of a threatened Democratic filibuster. Subsequent efforts to include Refuge drilling as supposedly veto-proof riders to spending bills were nonetheless vetoed by President Clinton. In late 2000, the Senate approved 51–49 a nonbinding budget resolution including projected Refuge lease income. At this writing, the House on 2 August 2001 had just approved an energy bill which, by a 223–206 vote, included Refuge drilling—the first time since 1979 that the House had been permitted an up-or-down vote on the Refuge. However, drilling advocates appeared in spring 2001 to be well short of the votes required for Senate approval, even before the Senate changed hands, so the bill faces an uncertain Senate prospect in autumn 2001.

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shock/second

historically triggered new energy

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coastal plain

The Coastal Plain comprises nearly 8% of the Refuge's 19.6 million acres (of which 8.9 million acres running south and east from the Coastal Plain were classified as wilderness in 1960 by President Eisenhower). The Coastal Plain is a strip of tundra wetlands on the Refuge's north coast between the Brooks Range and the Arctic Ocean. It is about 104 miles long and ranges from 16 to 33 miles wide, averaging about 25 miles wide. It is uniquely important and fragile to the whole Refuge's biological functioning; the U.S. Fish and Wildlife Service considers it the "biological heart" of the Refuge. The Coastal Plain is the nation's most important birthing and nursing ground for Arctic wildlife, including the 130,000 caribou of the Porcupine Herd, which annually migrates nearly 1,000 miles round-trip between the Coastal Plain and its wintering grounds south of the Brooks Range. It is also the part of the Refuge considered uniquely prospective for oil, even though nearly 95% of Alaska's North Slope is already open to oil development. The USGS's p. AO-5 states that it is "currently off-limits to petroleum exploration and without known petroleum accumulations....By all accounts, it is the only part of the Refuge with significant petroleum potential."(For further history and legislative background, see the Congressional Research Service's issue brief at www.cnie.org/nle/nrgen-23.html#_1_5.)

Of the Coastal Plain, 1.55 million acres is in the "1002 Area," so called because §1002 of the Alaska National Interest Lands Conservation Act of 1980 (the "Alaska Lands Act") designated it as a wildlife refuge but left it formally unprotected pending a seismic survey of its hydrocarbon potential. (For short, references to the "Refuge" and "Refuge oil" in this article—*Foreign Affairs'* editors lower-cased the "R"—are to the 1002 Area.) Congress deferred a decision on management of the 1002 area pending those survey results, and meanwhile specifically prohibited leasing or other activity that could lead to hydrocarbon production unless authorized by a future Act of Congress. (The House had twice voted to protect the Coastal Plain as wilderness, and the Senate seemed set to do the same when the bill was pulled from the floor and privately renegotiated.)

The 1,451-line-mile seismic survey was conducted by the oil industry in 1984–85 and reported by the Department of the Interior in 1987. The seismic findings were most recently reinterpreted, using modern methods, by the U.S. Geological Survey's authoritative 120-person-year 1998 assessment (*The oil and gas resource potential of the Arctic National Wildlife Refuge 1002 area, Alaska*, OFR [Open File Report] 98-34, 1999, 2-disk CD-ROM set orderable from dread@usgs.gov or clopez@usgs.gov, ISBN 0-607-90007-5, http://usgs-georef.cos.com/cgi-bin/getRec?un=1999-051937), although the industry consortium allowed only a small fraction of the detail revealed by the seismic reassessment to be published (p. AO-8). The data were checked with their industry sources and the methodology was peer-reviewed. The USGS reanalysis also took account of what was learned from 41 of the 59 wells drilled and oil fields discovered near the Refuge and other new geophysical, technological, and economic data. (Data are public from all but ten wells, one of which was drilled within a non-Gwich'in Native area inside the 1002 Area and two just offshore of the 1002 Area.) That 1 January 1998 USGS report, hereinafter cited as "USGS 1998," is the basis for all statements in this article about the economic geology of the Coastal Plain.

The 1002 area is not to be confused with the 23-million-acre (Indiana-sized) National Petroleum Reserve—Alaska area, which lies further west along Alaska's north coast. (Prudhoe Bay is in an unprotected area in between NPRA and the Refuge, so the Trans-Alaska Pipeline is about 50 miles west of the Coastal Plain's western boundary.) NPRA was declared by President Harding in 1923 as a petroleum reserve for use only in times of "pressing national need." It was to have been protected as wilderness in the House version of the Alaska Lands Act, but instead was left unprotected and was subsequently opened to leasing through a Senate rider to an appropriations bill. Portions of the NPR were in fact leased for oil and gas exploration in the early 1980s and late 1990s, but no oil has yet been extracted.

As of 1998 (USGS *Fact Sheet FS 0028-01* [supersedes Fact Sheet 040-98], http://geology.cr.usgs.gov/pub/fact-sheets/fs-0028-01/index.html)., 36 petroleum discoveries had been made in the whole of northern Alaska, including 15 billion barrels of oil and 45 trillion cubic feet of natural gas that could be commercially produced. In addition, on the Canadian side to the east of the Refuge, 48 discoveries had been made in the Mackenzie River delta, comprising 2 billion barrels of oil and 12 trillion cubic feet of natural gas, but no commercial production had occurred due to unfavorable economics.

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environmentalists

Typical statements can be obtained from the Alaska Wilderness League and Alaska Coalition (www.alaskawild.org), Natural Resources Defense Council (www.nrdc.org/land/wilderness/anwr/anwrinx.asp), or other groups cited at www.alaskawild.org/links_resources.html. The Alaska Conservation Foundation released on 22 February 2001 a study by University of Alaska economist Steve Colt, calculating that about one in four Alaskan jobs and almost $2.6 billion in annual income depends on a clean environment and a healthy ecosystem. It found that about 55,000 Alaskan jobs, including those in commercial and sport fishing, tourism, recreation, and hunting, depended on environmental quality—more than twice the total jobs in the state's petroleum, mining, and construction industries.

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Gwich'in

See www.alaska.net/~gwichin/index.html and www.corpwatch.org/climate/updates/2001/sjames4-01.html.

The roughly 7,000 Gwich'in are Athabascan Indians who live in 15 small villages along the southern edge of the Refuge (and eastward into Canada), live by hunting caribou, and strongly opposite drilling, with support from a wide range of tribal and religious coalitions and the highest levels of the Canadian government, which has protected the corresponding caribou calving and post-calving grounds on its side of the international boundary.

In contrast, the leaders of the more assimilated 8,000 Inupiat Eskimos who live mainly in small villages along the Coastal Plain favor onshore drilling—so long as it brings them wealth and doesn't interfere with their bowhead whaling, which has led them to oppose offshore drilling. About 250 Inupiat reside in the village of Kaktovik on Barter Island, on the north boundary of the Refuge. Although they supported wilderness protection for the Refuge until the early 1980s, their regional corporation teamed up with the State of Alaska and Chevron Corporation to drill one exploratory well near Kaktovik in 1986 under a 1983 land exchange, signed by Interior Secretary James Watt, that gave the Arctic Slope Regional Corporation (a *Fortune* 500 corporation) subsurface title beneath Kaktovik, but prohibits oil development unless Congress opens the Coastal Plain to such activity. The results of the exploratory well are secret.

Both Native groups depend on the caribou; the Gwich'in harvest about 3,000–5,000 caribou per year, the Inupiat about 100. The Inupiat leaders don't share the Gwich'in people's unified view that drilling would threaten the caribou by invading the only area where they can calve and nurse; nor, in general, do they share the Gwich'in's deep spiritual connections to the caribou and their habitat.

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human rights issues

See www.pirg.org/enviro/arctic/caribou/media/release4_24_01.html. At www.treatycouncil.org/pwjc1214200.html it is reported that the International Indian Treaty Council, which has consultative status with the UN Economic and Social Council, has been raising the issue with the UN Commission on Human Rights: see pp. 3–4 of www.unhchr.ch/Huridocda/Huridoca.nsf/0/e2d8f24c919881aac12569f10049bd82/$FILE/G0110453.pdf, www.oneworld.org/ips2/dec/transnationals.html, www.usask.ca/nativelaw/IITC.html, and www.wilderness.org/arctic/refuge/gwichin.htm. Litigation is understood to be contemplated if necessary, under human-rights instruments to which the United States is a party. Some of the legal background is summarized at www.uit.no/ssweb/dok/series/n02/en/112sandd.htm and www.firstpeoples.org/land_rights/united_states/international_relations.htm.

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international law

Other aspects of international law may also come into play, such as U.S. treaty obligations to protect polar bear denning habitats, the most important of which for the whole Beaufort Sea population are on the Coastal Plain.

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opposes drilling

The Canadian Minister for the Environment, David Anderson, has said Canada would fight, and he is "utterly opposed to," drilling in the Refuge: K. Jaimet, "Canada to fight Bush over Arctic oil drilling," *Ottawa Citizen*, 4 January 2001, www.ottawacitizen.com/national/010104/5042895.html.

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(footnotes for page 73)

economically recoverable oil

Oil is classified as "in place" (in the ground regardless of whether it can be extracted); "technically recoverable" with known technology regardless of cost; and "economically recoverable" at a specified price. (At p. EA-7, USGS 1998 defines economically recoverable reserves as "that part of the assessed technically recoverable resource for which the costs of finding, development, and production, including [transportation to the assumed West Coast market and] a return to capital, can be recovered by production revenues at a given price.") The USGS curves relating economically recoverable oil to price and probability are described below. (For technical reasons explained at pp. EA-11–12, these incremental cost functions are not identical to economic supply curves.) Obviously there is no point investing to find oil that cannot be economically (*i.e.*, profitably) recovered. Frequent statements by Senator Murkowski (R-AK), *Wall Street Journal* editorialists, and others tend to confuse these categories as well as the location of the oil (inside or outside the 1002 Area).

The USGS assessment's basic conclusion (p. AO-4, p. AO-23) is: "The mean estimate shows that at a market price of 15 dollars per barrel [1996 $] no economic oil exists in the 1002 area. At 16 dollars per barrel, about 1 BBO [billion barrels of crude oil] are economically recoverable, and at 20 dollars per barrel, about 3 BBO are economically recoverable." These prices are in 1996 dollars for North Slope oil delivered to the West Coast. Conventionally using the GDP Implicit Price Deflator, the USGS's $16/bbl is equivalent in the fourth-quarter 2000 dollars used throughout this article to $17.2, and the USGS's $20 to $21.6.

These figures are for the USGS mean estimate only. (Statistical theory makes components additive within the mean estimate but not within other estimates.) USGS finds at p. AO-5–6 that "At an $18 per barrel market price [*i.e.*, $19.4/bbl in 4Q2000 dollars], 2.4 BBO associated with the mean estimate and 6.4 BBO associated with the 5th fractile estimate [*i.e.*, a 5% finding probability] are economic to find, develop, produce and transport to market. For resources associated with the 95th fractile estimate [*i.e.*, a 95% finding probability], initial exploration costs are not compensated by the economic value of new finds until market prices reach at least $19 per barrel [*i.e.*, $20.5 in 4Q2000 dollars]. At the higher market price of $24 per barrel [in 1996 dollars, or $25.9 in 4Q2000 dollars], 47 percent of the oil assessed at the 95th fractile (2.0 BBO), 68 percent of the oil assessed at the mean (5.2 BBO) and 79 percent of the oil assessed at the 5th fractile (9.4 BBO) are economic to find, develop, produce, and transport to market." Oil companies contemplating an investment in Refuge exploration would obviously need to take these risk/reward relationships into account.

To summarize the 1998 USGS findings in another way: at $22/bbl (4Q2000 $), the mean reserve would be 3.2 Bbbl with a range of 0.5 at 95% probability to 6.5 at 5% probability. These figures increase to about 6, 3, and 10 Bbbl respectively at $43/bbl, and decrease to about 0, 0, and 3 Bbbl below $16/bbl.

If one were to assume that the investment required to find the oil had *already* been sunk, then the remaining investment required to extract it and transport it to market would be smaller, and oil reserves that could provide the desired rate of return on that reduced investment are called “commercially developable”— *if already discovered* (p. EA-20). This is the criterion used in an otherwise capable May 2001 *Scientific American* article, “The Arctic Oil and Wildlife Refuge,” by senior writer W. Wayt Gibbs. Mr. Gibbs’s more relaxed economic criterion led him to state larger reserves than are economically recoverable, adding to public confusion. RMI pointed out (*Scientific American* letter, Sept. 2001, p.13) that “at a sustained West Coast price of $24 in 1996 dollars, the mean expected economically recoverable reserve is 5.2, not 7, billion barrels; at $18, about 2.4, not 5, billion barrels; and at $15, zero, not a few hundred million barrels. (To convert these prices to 2000 dollars using the GDP Implicit Price Deflator, multiply by 107.67.) The USGS material at the website Gibbs cites [USGS 1998, Ch. EA] suggests that he apparently confused these prices required to support finding, developing, producing, and transporting oil (Fig. EA-5) with the lower prices for ‘commercially developable oil’ (Table EA-3)—oil that can be economically developed if already discovered (p. EA-20).” The authors of this article consider economically recoverable oil to be the correct criterion to use for public policy when deciding whether to permit drilling. As USGS states at p. EA-19 (emphasis in original), “*The results from [the USGS analytic]...procedure do not imply that every field determined to be commercially developable is worth exploring for.*” It is the exploration decision that is now at issue.

Mr. Gibbs assumes that all discovery costs would be incurred in the expectation of return. Since these are real resource costs, the authors think it proper to judge the whole province’s economic merits by its total investment and return. In economic theory, of course, this assessment should also include all *external* costs of finding, extracting, and using the resources, but as a conservatism, such externalities—the focus of the public debate so far—are explicitly excluded from this economic discussion.

The USGS assessment uses January 1996 costs, landed U.S. West Coast prices, and post-1993 tax law (p. EA-13). “In the absence of gas markets, the well-head price of gas was assumed to be zero. The well-head price of natural gas liquids was assumed to be 75 percent of the per barrel price of crude oil.” The assessment considers 1996-dollar landed West Coast crude prices in the range $15–30/bbl ($16.2–32.3/bbl in 4Q2000 dollars), and cautioned at p. EA-14 that “if real oil prices rise to $50 [1996 $] per barrel [$53.9 in 4Q2000 $], it is unrealistic to assume that constant real costs would hold. Historical experience has shown that oil and gas price increases lead to escalation in industry capital and operating costs....” That’s partly because higher oil prices increase discovery efforts, driving up rig rental rates and other factor costs (EA-25).

The USGS assessment is correctly stated to reflect many uncertainties. Pp. AO-16 and -17 state that the results are “conservative”—more likely to understate than to overstate oil reserves at a given price—because they used the technology of several years ago, and because except for accumulations below 130 MBO in the western subarea, accumulations were evaluated as standalone fields (p. EA-24) rather than in clusters. These assumptions could, for example, affect the assumed minimum recoverable field size (50 million BBO or 300 billion cubic feet of natural gas—p. EA-8) to which the results are quite sensitive. (As of the report’s writing in 1998, “Stand-alone fields as small as 120 to 150 million barrels (recoverable) [were]... currently under development [on]...the North Slope.” Of the mean Refuge crude oil considered technically recoverable, 42% was in accumulations of at least 500 and 65% of at least 256 million BBO.) However, the USGS report does not address the likelihood that similar technological progress applicable to non-Refuge oil resources, or to substitutions for oil, could render the *economic* assessment *un*conservative—likely to overstate *economically* competitive Refuge oil reserves. Arguments that the latter effects probably offset and may well outweigh the former are presented in this article.

There are further potential technical unconservatisms inherent in the USGS analysis that do not depend on oil’s competitive position in the marketplace. For example:

- The USGS assessment assumes that temporary ice roads, ice pads, and ice airstrips are used to minimize environmental impact (p. EA-15). The report does not address the contention (well made in the Gibbs *Scientific American* article cited above) that insufficient water is available in the area for a development of this magnitude without drying up all major bodies of freshwater in the surrounding countryside.
- The USGS assessment assumes, for its test of economic attractiveness, that investors require and earn a 12%/y aftertax return on capital. No risk premium was attached to this figure to reflect potential market perceptions of increased technical, political, market or environmental risk, including the risk that the oil could become unnecessary through the sort of efficiency spurt described in the article, or the risk that any substantial mishap with TAPS delivery could cause prolonged and possibly permanent interruption of the revenue stream. A sensitivity test to rate of return is discussed at p. EA-23. It shows that a 16% aftertax return target would reduce mean economic oil at $18/bbl (1996 $) by about 1.1 BBOE and would raise the price at which exploration becomes economic from $16 to $17/bbl (1996 $). Conversely, this threshold price could decrease to as little as $14/bbl (1996 $), or $15/bbl in 4Q2000 $, if investors required only an 8%/y aftertax return (p. EA-24).
- Similarly, USGS adopted the Alaska Department of Revenue’s estimates of TAPS carriage tariffs through 2020 (p. EA-15), averaging $2.72/bbl in 1996 $ or $2.93/bbl in 4Q2000 $. Substantially increased maintenance problems could incur higher carriage costs—possibly very much higher if significant rebuilding were required during the decades of TAPS operation that would be required starting in about a decade. Marine transport costs to the West Coast were assumed to average $1.73/bbl in 1996 $ or $1.86/bbl in 4Q2000 $, again assuming no significant increases due, for example, to the potential for more stringent hull, operational, cleanup-provision, or insurance requirements.
- Finally, USGS’s cost assessment assumed zero lease bonus. In contrast, the Alaskan delegation typically claims that the Treasury would receive multi-billion-dollar lease payments. Since the mean expected reserve is a few billion barrels, such lease payments could increase costs by up to about a dollar per barrel above those described in this article. For example, Senator Frank

Murkowski (R-AK) referred on 4 October 2000 to “some $3 billion” of anticipated Federal lease revenues excluding royalties (http://members.nbci.com/nuclearcom/CongressionalRecord/DailyFullText/cr-00-10-04.html). This would amount to some $0.94/bbl on mean economically recoverable reserves of 3.2 billion barrels, ignoring timing and discounting.

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USGS curves

range of projections

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confuse

a few percentage points

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fourth-quarter 2000 dollars

2000 dollars (fourth quarter)

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U.S. dependence

That is, the fraction of U.S. oil consumption that is imported. The Reference Case of the U.S. Energy Information Administration’s *Annual Energy Outlook 2001*, http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2001).pdf, shows at p. 127 that projected import dependence (Net Imports of Petroleum / Consumption of Petroleum Products) would rise from 67% in 2010 to 70% in 2020, *vs.* a projected 56% and an actual 49.6% (EIA, *Annual Energy Review 1999*, Table 5.7) in 1999. (EIA’s forecasts of oil demand and hence of price are unusually high, partly because the Reference Case assumes that the U.S. light-vehicle fleet will improve its average efficiency by only 1 mpg through 2020: p. 138.)

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a few percentage points

Compared with projected U.S. petroleum products consumption of 44.41 quadrillion BTU/y (Q/y) in 2010 and 50.59 Q/y in 2020 (www.eia.doe.gov/oiaf/aeo/pdf/0383(2001).pdf, p. 127), the *peak* crude-oil output from the USGS‘s mean expected economically recoverable reserve of 3.2 billion barrels (bbl) at a sustained price of $22/bbl (4Q2000 dollars) **(**http://geology.cr.usgs.gov/pub/fact-sheets/fs-0028-01/**)** would be on the order of one million bbl/d. **(**The Alaska Department of Revenue’s *Revenue Sources Book*, April 2001, App. E, forecasts 0.892 Mbbl of non-Refuge oil shipments in FY2010, leaving only 1.24 Mbbl/d of maximum potential capacity below the 2.136 Mbbl/d design capacity posted at www.alyeska-pipeline.com/Pipelinefacts/PipelineOperations.html; and so far, non-Refuge discoveries have consistently exceeded the state’s projections of declining TAPS throughput.**)** Since 1 bbl of U.S.-produced crude oil averages 5.8 million BTU (EIA *Annual Energy Outlook 2001*, *op. cit.*, p. 251), 1 million bbl/d is equivalent to 2.12 Q/y. Ignoring the nonequivalence between a barrel of crude oil and a barrel of petroleum products consumed, this would be 4.8% of the projected 2010 and 4.2% of the projected 2020 U.S. petroleum product consumption. Counting the equivalence more exactly, or counting refinery losses, would reduce these percentages.

It is normal oilfield practice to seek maximum production in the early years in order to accelerate payback of the multi-billion-dollar investment; sustained output at 1 million bbl/d would deplete a 3.2-billion-barrel field in only 8.8 years, which would probably be both unsound and infeasible from the perspective of reservoir engineering. Depletion for an entire complex of oil accumulations is normally phased over 30 years or longer; standard estimates for the Refuge assume a field life of 30–60 years. Thus a 1 million bbl/d output could last only briefly—probably for just a few years—based on the USGS mean reserve at $22/bbl (see below). Consistent with this, USGS’s economic assessment assumes (pp. EA-40–41 and Table EA-B4) that after 2–3 years’ buildup, a particular field of any size would yield only 2–3 years of peak production, then decline at 12%/y. That decline is somewhat sharper than is common in many Lower 48 provinces because, on current knowledge, enhanced recovery options for Refuge oil accumulations appear rather limited. This production schedule is notably faster than the one actually achieved for Prudhoe Bay.

Commonly encountered and repeated misconceptions about the oil output potential of the Coastal Plain are illustrated by the following statements downloaded 29 July 2001 from Senator Murkowski’s website [plus authors’ comments in brackets], www.senate.gov/~murkowski/oped/arcticdrilling.html:

“The findings [of the USGS 1998 study] predict there is a 5 percent chance—considered the norm in petroleum exploration—of finding 16 billion barrels of recoverable oil within the coastal plain of the refuge/reserve. There is a 95 percent chance of recovering 5.7 billion barrels, with a ‘mean’ estimate reaching 10.3 billion barrels.”

[The study actually estimated these *technically* recoverable resources—regardless of cost—*not* for the Coastal Plain but for the entire USGS assessment area, which includes Native lands and adjacent State offshore waters out to the 3-mile limit. The Senator repeats the claim of 6–16 billion “recoverable” barrels “in ANWR” in his September 2001 letter in *Scientific American.* He further claims that “Even if the mean estimate were discovered, it would be the largest oil field found worldwide in the past 40 years.” Even using his unrealistic metric of technically rather than economically recoverable oil (the mean technically recoverable USGS estimate is 7.67 billion bbl within the Refuge), that would pale beside the reported 8–50 billion bbl Kashagan field recently found in Kazakhstan (www.worldlink.co.uk/stories/storyReader$303), Iraq’s 15–50 billion bbl West Qurna, etc.]

“The estimates actually predict that the coastal plain—the area Alaskans call our oil reserve—really contains from 11.6 to 31.5 billion barrels of oil—the mean estimate being 20.7 billion barrels of oil in place....If true, the coastal plain will contain even more oil than the Prudhoe Bay field that has been supplying America with more than 20 percent of its domestic oil production for the past 23 years.”

[These estimates of in-place resources are for the Coastal Plain (the 1002 Area) but regardless of cost *or* feasibility of recovery. Their irrelevance—only slightly less than that of the enormous amount of gold in the world’s oceans—is illustrated by the West Sak reservoir, which may contain upwards of 20 billion barrels of heavy oil but as a practical matter, has so far proven 98% unrecoverable: the Alaska Department of Natural Resources estimates that only 0.37 billion barrels will be produced through 2020. (R. Fineberg, “Much Ado About Nothing,” 9 June 2000 report to Alaska Wilderness League, Richard A. Fineberg / Research Associates, PO Box 416, Ester, Alaska 99725.) The 45 Tcf of known but uneconomic natural gas on the North Slope offers another example. The supergiant Prudhoe Bay reservoir has relatively favorable geology; the Coastal Plain does not, and is therefore expected by USGS to prove far smaller in its economically recoverable resources.]

“The new estimates, made in part by using more reliable 3-D seismic data, than previous government estimates, means there is a good chance that the coastal plain will produce more oil than the neighboring Prudhoe Bay field, which has fueled America’s energy security since 1977.”

[Neither the USGS nor any other published or unpublished information known to us is consistent with this claim. Prudhoe Bay was the largest oilfield ever discovered in North America. Its reserves are far greater than USGS estimates of the Refuge’s total undiscovered technically recoverable oil regardless of cost. Moreover, the entire cumulative production of the Prudhoe Bay and neighboring deposits, totaling about 13 billion barrels since 1977, has amounted to about 20% of the 65.7 billion bbl of cumulative U.S. oil production during 1977–2000 (EIA, *Annual Energy Review 1999*, Table 2.4, and *Monthly Energy Review*, June 2001, Table 3.1a) or 8.5% of cumulative U.S. petroleum products supplied during that period (152.3 billion bbl per *id.*, Table 3.1a), and now, in its 24^{th} year of production, is supplying less than 0.6 Mbbl/d. That hardly seems to be “fueling America’s energy security.”

“Environmentalists, basing their arguments on the old data, have argued that the coastal plain wasn’t worth exploring since it, at most, contained only enough oil to meet America's needs for 200 days (six months). Such an argument is flawed—the refuge likely holding enough oil to meet every drop of America’s energy needs for three years.”

[Three years’ U.S. primary energy consumption at the 2000 rate totals 297.3 Q, equivalent to 51 billion barrels—4.7 times USGS’s maximum (5%-probability) 10.8-billion-bbl estimate of potential Refuge reserves at or above $43/bbl—so evidently the Senator misspoke. Three years’ U.S. *oil* consumption at the 2000 rate of 38.404 Q/y totals 19.9 billion barrels—still 1.8 times that maximum. The Senator’s 19.9 billion bbl even exceeds USGS’s mean (7.7) or 5%-probability (11.8) billion bbl estimate of *technically* recoverable oil in the 1002 area, regardless of economic recoverability. The 5%-probability technically recoverable estimate was still under 16 billion bbl.]

“A more rational way of thinking, however, (because all other domestic oil sources won’t dry up at the same moment) is that the ‘1002 Area’ of the coastal plain may produce enough oil to offset all of our imports from Saudi Arabia for 30 years! It would likely supply America with about a fifth of its domestic oil supplies for decades.”

[If “decades” means, say, 30 years, the EIA Reference Case implies cumulative U.S. oil consumption around 400 Q during 2010–20, rising more or less linearly, so on the order of 1,611 Q during 2010–40 based on a linear extrapolation. One-fifth of that consumption (not“domestic supplies”) would be about 60 billion bbl, so the “domestic supplies” contemplated must be a very small fraction of that. Long-term imports from Saudi Arabia are difficult to estimate because its reserves will tend to dominate Gulf production over such a long period, but there is evidently something wrong with the Senator’s figures, because the $22/bbl USGS Refuge mean reserve of 3.2 billion bbl would equal imports from Saudi Arabia at the actual 2000 rate (1.572 Mbbl/d: Table 3.3b, *Monthly Energy Review*, June 2001) for only 5.75 years, not 30, with no allowance for growth in those imports.]

“The truth is that the latest U.S. Geological Survey estimates are that the entire ‘1002 Area’ contains up to 16 billion barrels of recoverable oil.”

[No; as noted above, this is for the entire assessment area. The corresponding figures for just the 1002 Area are a mean of 7.7 billion bbl, ranging from 4.2 at 95% probability to 11.8 at 5% probability. As shown on the USGS curves, the *economically* recoverable reserves are substantially smaller than these *technically* recoverable figures except at very high oil prices, when most of the technically recoverable oil may become economically recoverable.]

“If found, this oil could replace all of our imports from Saudi Arabia for more than 30 years! The reserve could prevent our dependence on foreign oil from getting any worse for decades. Rather than being 56 percent dependent like we are now, it could cut our dependence to around 50 percent, according to the Energy Information Agency.”

[As noted above, the Saudi claim is in error by a large factor. EIA’s Reference Case (*Annual Energy Outlook 2001*, Table A1) shows U.S. net petroleum imports growing from 21.12 Q/y in 1999 to 35.22 Q/y in 2020. Displacing just this difference, let alone thereafter, would imply Refuge production sustained at about 6.5 Mbbl/d by 2020—about six times a physically plausible rate of Refuge production, and three times the total (not just net available) capacity of TAPS. Holding oil import dependence to 50% of EIA’s projected 2020 petroleum consumption would still imply net imports of 4.18 Q/y over the 1999 level, or 1.92 Mbbl/d—well over a plausible rate of Refuge output, 42% above EIA’s aggressive (and implausible) case mentioned below, and 90% of TAPS’s maximum capacity—implying that almost any non-Refuge production by then is either depleted or shut in.]

Senator Ted Stevens (R-AK), in a September 2001 letter (http://www.sciam.com/2001/0901issue/0901letters.html) in *Scientific American*, page 124, further claims that the Refuge “is predicted to hold about the same quantity of oil as we have imported from Saudi Arabia during the past 30 years. It will keep the Alaskan pipeline full for at least the next 30 years.” W. Wayt Gibbs correctly responds (*id.*): “According to the 2000 Annual Report of the U.S. Energy Information Administration, Saudi Arabia sent 10.7 billion barrels of oil to the U.S. from 1969 to 1999. That is half again as much as the best guess for the 30-year production from the 1002 area [*i.e.*, roughly USGS's 7.67 billion bbl *technically* recoverable mean estimate regardless of cost]. EIA analysts predict a maximum production rate from the refuge of about half a million barrels a day 10 years after the development begins, with a peak of nearly a million barrels a day about a decade after that. To 'keep the Alaska pipeline full' requires 2.1 million barrels a day, but only 1.1 million barrels flowed through it in 1999, and production is falling steadily. Alaska's Division of Oil and Gas estimates that 20 years from now North Slope oil fields outside of the 1002 Area will produce only 408,000 barrels a day." To put it another way, the April 2001 *Revenue Sources Book*, App. E, predicts average TAPS flow of 1.02 Mbbl/d for 2001–10 with no Refuge output. TAPS's rated peak capacity is 2.136 Mbbl/d. If Alaska's projection of 2001–10 non-Refuge flow and its subsequent decline to 2020 were followed by no further decline to 2030, the remaining flow needed to "keep the pipeline full" for the next 30 years would total about 15 Bbbl—nearly twice USGS's mean *technically* recoverable estimate of 7.67 Bbbl. Evidently Senator Stevens too is misinformed.

Senator Murkowski arranged for the U.S. Energy Information Administration, a branch of the Department of Energy, to compile a hasty 23 May 2000 digest of the USGS report, "Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge: Updated Assessment" (www.eia.doe.gov/pub/oil_gas/petroleum/analysis_publications/arctic_national_wildlife_refuge/anwr101.htm). It is not one of EIA's more distinguished efforts. It is also not a new study, although the Senator and other drilling advocates often cite it as if it were both new and an independent DOE work product, and it has been so quoted in some leading newspapers (*e.g.*, J. Fialka, "Energy Agency Raises Its Estimate of Oil in Alaska Wildlife Refuge," *Wall St. J.*, 23 May 2000). In fact, the EIA report seriously misrepresents the USGS findings. EIA quotes *technically* recoverable oil without mentioning that USGS had also assessed *economically* recoverable oil and found about 58% less of it (the exact ratio depending on price). EIA also quotes the USGS figures for the entire assessment area, without mentioning that USGS had found 26% of its oil to lie outside the Coastal Plain. And EIA applies simplistic formulas for potential extraction rates to *technically* recoverable oil, thus probably overstating potential peak production rates (in an aggressive case, 1.35 Mbbl/d) by a factor on the order of two or more. Finally, EIA multiplies technically recoverable oil by the EIA forecasting model's assumed oil price in the year 2020 to obtain a gross value around $125–350 billion—an exercise so sophomoric it would ensure a failing grade in any economic geology class. It does, however, leave the erroneous impression that EIA has performed an economic analysis—precisely what it failed to do.

The usual journalistic misunderstandings of EIA's misrepresentations have since clouded the issue further: for example, the *Anchorage Daily News* reported (B. Spiess, "Bonanza Pictured in ANWR: Refuge's oil could rival North Slope, study says," 27 May 2000) that the EIA's highest estimate of *peak* production rate, 1.1 million bbl/d, was the *average* output. This figure, apparently extended over several decades, appears to underlie President Bush's overstatements of the Refuge's oil potential: he remarked on 17 May 2001, for example, that the Refuge could sustain 600,000 bbl/d output for 40 years (remarks to Capital City Partnership, St. Paul, MN, White House press release). This would total 8.8 billion bbl, or 15% higher than USGS's mean technically recoverable resource estimate. USGS's economically recoverable reserve estimates from the Coastal Plain show a cumulative output of 8.8 Bbbl only at 5% probability and with sustained prices above $25/bbl (4Q2000 $).

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exceeded

only half-full

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nonequivalence

yield

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faster

a decade

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curves

range of projections

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a decade

All expert commentary on Refuge exploitation states that under favorable political and economic conditions, approval, design, exploration, and construction of production infrastructure would take about a decade, *i.e.*, until roughly 2010 or later; some commentators believe it would take longer. USGS (1988) points out at p. EA-25 that at recently prevailing North Slope wildcat drilling rates, such drilling alone could take about a decade if not accelerated to a level that would drive up costs significantly beyond those justified at incremental costs of $18/bbl (1996 $).

For comparison, the more straightforward exploitation of the supergiant, highly concentrated, relatively accessible Prudhoe Bay oilfield, at a time of far looser environmental regulation, took nine years from discovery to first flow. (Of this period, construction of the Trans-Alaskan Pipeline itself took only 27 months—38 months for the entire TAPS project.) From first flow to peak output took a further 11 years—a total of *20* years, not ten.

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natural gas

The U.S. Geological Survey's 1998 assessment (OFR 98-34, *op. cit. supra*) found in the 1002 Area (Table AO-3) mean *technically* recoverable resources of 3.5 trillion cubic feet of nonassociated gas, with a 5% probability of 10.0 but a 95% probability of zero; Figure RS5 shows a 16% probability of 0–1 Tcf and a 65% probability of 0–5 Tcf. Table RS14 shows *technically* recoverable resources of 0.26 million barrels-equivalent of natural-gas liquids from associated and nonassociated dissolved gas (see Table EA3 for economics)—3.3% of the technically recoverable crude oil—and 3.6 trillion cubic feet of associated dissolved gas. Table EA4 shows that on mean estimates, the NGL and associated gas correlated with oil would reach, for example, 0.04 BBNGL and 1.43 Tcf respectively at $21/bbl (1996 $) or $22.6/bbl (4Q2000 $), rising to 0.10 BBNGL and 2.79 Tcf at $30/bbl (1996 $) or $32.3/bbl (4Q2000 $). These resources are very small relative to either the mean Refuge crude oil resource (respectively 4.0 and 6.3 BBO) or the cheap natural gas already known but stranded elsewhere on the North Slope. Specifically, a few Tcf in the Refuge contrast with 45 Tcf already proven in NPR and other exploitable North Slope locations (USGS *Fact Sheet FS 0028-01* [supersedes Fact Sheet 040-98**]**, http://geology.cr.usgs.gov/pub/fact-sheets/fs-0028-01/index.html) but with no way to reach southern markets.

All the natural gas in the Refuge "is considered to be non-economic for at least two decades" (p. AO-4), so the *economically* recoverable gas reserves were considered to be zero for the policy purposes of the USGS economic analysis (p. AO-16, EA-12). USGS did study the option of transporting North Slope gas southwards and exporting it in liquefied form to Asia, but found this would be uncompetitive until at least 2015. USDOE projects no Alaskan natural gas would be transported to the lower 48 states before 2020. USGS concludes (p. EA-12): "In Northern Alaska 30 TCFG of associated gas has already been discovered that can be produced cheaply if a gas market develops. Associated gas produced with oil is typically stripped of its liquids and re-injected into the oil field or used as fuel on the least. Some of the recovered natural gas liquids are mixed with crude oil and transported through the Trans-Alaska Pipeline System and some are re-injected as a miscible fluid flood for enhanced oil recovery." For these reasons, dominated by the lack of an affordable way to transport the gas to market, gas is not currently considered an economically viable extractable resource in the Refuge, nor indeed in its large resources already known in other parts of the North Slope currently open to industrial exploitation.

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estimated $10 billion

This cost could be considerably reduced, quite possibly to an economically attractive level, if a pipeline were constructed jointly with Canada along the more direct Mackenzie River delta route to the east. Then it could also pick up the 12 Tcf of stranded gas there. Environmentalists would also favor such an alignment over one crossing the Refuge and hence the Brooks Range. However, the Bush Administration opposes it, apparently because revenues would then flow more to Canada than to Alaska, whose Congressional delegation is the main source of pressure to drill in the Refuge. The Canadian Government is also unlikely to be receptive to Mackenzie pipeline collaboration to move gas if the U.S. continues to push for Refuge oil drilling which, as noted earlier, Canada vigorously opposes. This political tangle has a longer history: the Trans-Alaska Pipeline System passed the U.S. Senate on Vice President Spiro Agnew's casting vote after the State Department misled the Senate into thinking that Canada opposed the less controversial alternative of an oil pipeline along the Mackenzie River. The true, and opposite, Canadian position became public only after the Senate vote, and nobody was held responsible for lying to the Senate.

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delegation

chairing

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the Trans-Alaska Pipeline System

This remarkable engineering achievement, constructed during 1975–77, is owned and operated by Alyeska Pipeline Service Company, a consortium owned and run by major oil companies or their pipeline subsidiaries: 50.01% BP/Amoco, 24% Phillips, 20% ExxonMobil, 3% Williams, 1.5% Amerada Hess, 1.4% Unocal. Its operation is supervised by a Federal-Alaska Joint Pipeline Office. Its original 30-year leases and approvals expire in 2004 and are currently up for renewal. Through 2001, TAPS had carried about 13 billion barrels of crude oil at a rate that peaked in 1988 at 2.1 million barrels per day (Mbbl/d) and currently fluctuates around 1.0 Mbbl/d. (One barrel of oil is 42 U.S. gallons or 159 liters.) "At the time," notes Alyeska, "construction of the pipeline was the largest privately financed construction project ever attempted, and cost over $8 billion [1977 dollars] when completed." Counting only monetary inflation, that would be equivalent to roughly $18 billion in 4Q2000 dollars, excluding interest and post-1977 construction. The mammoth initial construction effort took three million tons of imported materials and a peak workforce of over 28,000.

Alyeska's homepage (www.alyeska-pipe.com) correctly states: "The United States depends on the Trans-Alaskan Pipeline System to deliver 17% of its domestic oil production [in 2000]. Without this vital link to North Slope Oil Fields, the entire nation would be affected." Alyeska also agrees (www.alyeska-pipe.com/Photolibrary/Pipeline.html) that TAPS "is the only way to get oil off the formidable Alaskan North Slope and down to tankers waiting at Valdez...." Alyeska apparently considers these truths an advantage rather than a national-security risk. The risk is summarized at pp. 183–184 of A.B. & L.H. Lovins, "Reducing Vulnerability: The Energy Jugular," Ch. 10 in R.J. Woolsey, ed., *Nuclear Arms: Ethics, Strategy, Politics*, Institute for Contemporary Studies (San Francisco), 1984); A.B. & L.H. Lovins, "The Fragility of Domestic Energy," *The Atlantic Monthly*, Nov. 1983, pp. 118–126. It is described in greater detail in A.B. & L.H. Lovins's 499-page *Brittle Power: Energy Strategy for National Security*, Brick House

(Andover MA), 1982, originally a report to the Defense Civil Preparedness Agency, USDOD, and documented with some 1,200 references.

TAPS is a 48-inch, 800-mile-long hot-oil pipeline, stretching from its northern terminus—gathering the Prudhoe Bay and related oil output—250 miles north of the Arctic Circle—to Valdez, the northernmost ice-free port in the United States. The thousand-acre Valdez terminal has 9.1 million barrels of oil storage, or about nine days' worth at the current average rate of throughput. The pipeline crosses three mountain ranges, including the rugged Brooks Range; more than 800 rivers and streams, 34 of them major (four via long bridges—in all there are 11 conventional and two suspension bridges); and three earthquake faults (nearby portions are designed for quakes up to Richter 8.5). It also passes near five massive but mobile glaciers. It has 71 gate (shutoff) valves and 80 check valves. The pipe has steel walls 0.462 or 0.562 inches thick. For about 420 miles it is held aloft on stanchions 5–15 feet above permafrost; the rest is buried. Most of its length is readily accessible by road or floatplane. State highways lead to its five southern pumping stations.

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only half-full

Awkwardly, Alaska has turned out to have more non-Refuge oil than expected. In 1987, Interior forecast that Prudhoe Bay depletion could largely idle TAPS by now. Prudhoe did peak in 1988, but its decline was eased by other North Slope fields whose rising output should surpass it in 2001, keeping TAPS flowing at or above the 2000 rate through 2008. (Historic and forecast flow data are in the Alaska Department of Revenue's revenue forecast, *op. cit.*) Flows forecast for 2005 have septupled in the past 15 years. It is natural for the owners to want to use their half-idle asset more fully and for longer. But this asset-utilization mentality brings with it an energy-security peril that is as much a public as a private risk.

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elevated and indefensible

The Army demonstrated this through "black-hat" exercises in the 1970s, and concluded that it was impossible to prevent determined saboteurs from shutting down TAPS for a year or more (L. Pryor, "The 'Invaders'—A Test for the Pipeline," *L.A. Times*, 18 November 1975, pp. 1:1, 18, and 21; W. Endicott, "All Flows Smoothly for Alaskan Pipeline," *id.*, 1 April 1979, pp. 1 & 11; "Alaska Pipeline Sabotage Held Impossible to Stop," *N.Y. Times*, 11 March 1977, p. 10). Alyeska reported perceiving no security threat (U.S. General Accounting Office, *Key Crude Oil and Products Pipelines Are Vulnerable to Disruptions*, EMD-9-63, 27 August 1979, at p. 30), and spent each year on security roughly 0.1% of TAPS's replacement cost.

Not much has changed since then, except that more subnational groups and even apparently very small groups have demonstrated the capability to perform sophisticated paramilitary terrorist attacks on major U.S. assets, such as the bombing of barracks in the Middle East, embassies in Africa, the *USS Cole* in Yemen, and the Murrah Federal Building in Oklahoma City. That those competent bombers were elsewhere engaged while TAPS was incompetently bombed twice should not be reason to feel reassured. In fact, shaped charges used in the pipeline industry to shear or perforate pipe are commercially available, and oil pipelines have been widely attacked—in Colombia and very frequently—around the world.

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bombed twice

Alyeska's posted operational history (www.alyeska-pipe.com/Pipelinefacts/PipelineOperations.html) ends in 1999, though other parts of the website, as of July 2001, were updated through March 2001. Its history of attacks on the pipeline appears to be materially incomplete. For example, it records "two bullet indentations" repaired in September 1977 with a four-foot-diameter, three-foot-long welded steel sleeve, and another similarly handled indentation, "possibly" from a bullet, in April 1980. Alyeska's chronology does not mention reports (L. Ponte, "Target for Terrorists," *National Observer*, 4 July 1977, pp. 1 & 13) that two short sections of pipe had been peppered, though not pierced, by more than 50 bullets.

Alyeska's chronology reports that a one-inch hole caused by "sabotage" at Steele Creek shut down the line for 21.5 hours in February 1978 and leaked 16,000 barrels—6% as much as the *Exxon Valdez* grounding. However, the U.S. General Accounting Office (*Key Crude Oil and Products Pipelines Are Vulnerable to Disruptions*, EMD-79-63, 27 August 1979) reported that the hole was two inches across, it was caused by a bomb, and it cost over a million dollars to clean up the spill. Earlier, on 20 July 1977, three dynamite charges exploded under TAPS near Fairbanks without penetrating the pipe wall; damaged supports and insulation were found five days later. But this incident, reported in the press at the time, no longer appears in Alyeska's posted history. Neither does the reported September 1977 deliberate opening of a valve at Pump Station 3, north of the Yukon River, which spilled 3,500 gallons of diesel fuel, adding spice to an extortionist's threat ("Alaskan Pipeline Leak Attributed to Sabotage," *N.Y. Times*, 21 September 1977, p. 16).

On 8 July 1977, the building at Pump Station 8 was destroyed by an explosion and fire caused by operator error. One worker was killed and five were injured. Despite an intensive rebuilding effort and a relatively accessible site, the pump building wasn't recommissioned until the following March. Alyeska's chronology states that the pipeline was undamaged, and doesn't mention downtime (because the incident occurred during startup), but at the time, it was reported that the station took ten days to bypass and the line then resumed pumping at half capacity (W. Turner, "Alaska Oil Flow Reaches Valdez After Delays and Pipeline Mishaps," *N.Y. Times*, 30 July 1977, pp. 1 & 5). The relevance of this incident is that had the station been one lifting oil over a major mountain range, especially during the winter when repairs are slow or impossible, pipeline capacity "would have been reduced substantially more, or even curtailed altogether" (USGAO, *op. cit.*, at p. 30).

The importance of pump stations' uninterrupted operations is emphasized by two further incidents reported by Alyeska. Soon after the pipeline began operation, its worst operational shutdown (110 hours) was caused on 15 August 1977 by a problem laconically described as "PS 9 sump overflow." Another explosion and fire, at the northernmost Pump Station 1, caused a 10-hour shutdown on 9 November 1985. The eleven pump stations, of which nine were in actual use in 1996 and one is generally considered a reserve station, obviously provide some extra capacity margin nowadays when flow is slightly below half of peak capacity; but this margin would vanish as Refuge oil flows peaked.

The operational history and published design suggest that certain locations, such as the problem-prone 4,739-foot Atigun Pass and long river-crossing bridges, probably represent particular vulnerabilities. So do the uninsurably unique facilities at the north (input) terminal of TAPS, where damage to a labyrinth of pipes—evocatively called "Hollywood and Vine"—could take, at least as of the 1970s, upwards of eight months to remake the special pipe plus two to it ship it from the single Japanese factory that can make it. And so, of course, do the powerful pump stations: the pipeline is reported by Alyeska's website to use 0.56% of its throughput for pumping. If that is a currently typical figure rather than a nominal full-throughput figure, it would imply a total pumping power of roughly 1.15 trillion BTU/y or 385 mechanical MW or 516,000 hp. Alyeska has not yet confirmed the value. Whatever the actual figure, damage to more than one adjacent pump station lifting the hot oil over major mountain ranges could be particularly damaging. Some of the hardware, qualified for Arctic operation, is reportedly special-order with lead times from a half-year to a year or more (GAO 1979, *op. cit.*). (Alyeska may have quietly stockpiled some critical items. Whether this is prudent has long been controversial, since onsite storage could speed repairs but could also invite saboteurs to destroy the spares at the same time; whereas remote location of spares could make them undeliverable in winter.)

In late 1999, a Canadian machinist/engineer was arrested in Vancouver, BC, four months before completing an elaborate eight-year plot to detonate 14 sophisticated high-explosive bombs at three strategic locations along TAPS, including two river crossings, amidst expected Y2K confusion at the dawn of 2000. His goal was to make a fortune in the oil futures markets while avenging his previous conviction and deportation in the U.S. He had already obtained PETN explosive, timers, and bomb casings, built components for the 14 bombs, and tested for operability in winter cold. A spokesman for the U.S. arresting agency stated that without a tipoff from an invited U.S. accomplice, an explosives-trained former Green Beret who had once sold roughly 18 homemade bombs to undercover agents, the plot wouldn't have been uncovered (L. Hoffman, "Ex-inmate tips off bizarre bomb plot," *Albuquerque Tribune*, 24 August 1999, www.abqtrib.com/y2k/082499_y2k.shtml; M. Hume, "Alaska Pipeline Target: Party night won't be a blast for bomb suspect," *National Post*, 24 December 1999).

TAPS has been subject to apparent security alerts at other times, but information on any threats received has not been released. Security cameras along TAPS were recently upgraded, though sometimes without proper administrative or environmental qualification of certain components (http://corecom.net/JPO/12-06-00.html). *The Wall Street Journal* reports (D.S. Cloud, "Half-Baked Alaska," 23 December 1999, p. A1) that "a fairly extensive security system protects the pipeline, including a number of permanently manned security stations. Fenced perimeters bolstered by various detection devices surround the frail-looking suspension bridges that carry the pipeline across rivers." But nobody is claiming that these or any other feasible arrangements could prevent a knowledgeable and determined attack.

Such possibilities were foreseen as TAPS was opening. In 1977, the U.S. Senate's Judiciary Committee ("The Trans-Alaska Pipeline—Problems Posed by the Threat of Sabotage and the Impact on Internal Security," Subcommittee to Investigate the Administration of the Internal Security Act and Other Internal Security Laws, 95th Congress, 1sts Sess., USGPO) investigated TAPS's vulnerability. It reported being "stunned at the lack of planning and thought given to the security of the pipeline before it was built," and urged the Department of Energy to set up an Office of Energy Security. The proposed legislation sank without trace. TAPS is mentioned in the glossary of acronyms but not in the text of *Critical Foundations: Protecting America's Infrastructures*, the October 1997 Report of the President's Commission on Critical Infrastructure Protection, implying that a textual reference to it may have been removed.

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congeal into the world's largest Chapstick

Major parts of TAPS are inaccessible by air or ground for up to weeks at a time in the winter due to harsh Arctic weather. Alyeska's website states at www.alyeska-pipe.com/Pipelinefacts/PipelineOperations.html that if pumping is interrupted in winter, TAPS is designed to keep pumping oil for at least three weeks before so much heat is lost (chiefly through its 3.5-inch aboveground insulation) that the oil becomes too gooey to pump. This number appears to be outdated for three main reasons:

- Though the line is now handling only half as much as oil as it was originally designed to, implying some surplus pumping power, its nine-million-barrel linefill has of course not changed (it can't run on a mixture of oil and air), implying a roughly doubled transit time and hence more time for hot oil to cool.
- An increasing fraction of the oil now comes from satellite fields whose crude is waxier, making the mix of crudes more viscous and more prone to low-temperature solidification. (An uninsulated Siberian line was once shut down for more than a year by solidification of waxy crudes.)
- Alyeska has reportedly lowered the original 145˚F oil input temperature to 115˚F, reducing the safety margin: oil that used to enter Valdez at ~100˚F is now only about 65˚F (Joint Pipeline Office, personal communication, 31 July 2001).

The Joint Pipeline Office is inquiring into the net effects of these changes, and ordered Alyeska to prepare a Cold Restart Final Report that was due in May 2000 (J. Brossia & W.G. Britt, Jr., 5 November 1999 letter #99-083-JH, File #PT 5.50, D1210, F2000, from Joint Pipeline office to D.C. LeBlanc, Alyeska Pipeline Service Co.), but has not yet publicly reported any findings. Nor is it clear how far laboratory experiments and simulation modeling can realistically predict actual field conditions. Obviously it is not an experiment one would like to try, since at a nominal (say) $20/bbl, holding up a 2-Mbbl/d proposed flow would cost the oilfield operators some $1.2 billion a month in lost revenue. What is clear is that in TAPS operations, as the Joint Pipeline Office (JPO) put it in the Executive Summary of its 1999/2000 *Comprehensive Monitoring Reports* (2001),

> The most significant issue has been Alyeska's lack of an approved cold restart process for TAPS. To oversimplify, in wors[t] case conditions, restarting TAPS could become difficult five to seven days after shutdown. Reduced available horsepower due to pump station shutdowns and changing crude characteristics all play a part.
>
> Considerable work on this topic has been completed. In fact, a cold restart procedure is currently under review by JPO. JPO's concern about completing this study was clearly expressed in our February, 1999 [Comprehensive Monitoring Program] report for Operations. JPO subsequently issued an order on this subject primarily to emphasize JPO concern about the priority of this study and to insure prompt scheduling of this complex, multistep-engineering evaluation.

More precisely, JPO's *Comprehensive Monitoring Program Report: A Look at Alyeska Pipeline Service Company's Operation of the Trans-Alaska Pipeline System 1999/2000*, February 2001, states at pp. 14–15:

> 1999 Status: The ramp down of PS [Pump Stations] 6, 8, 10 combined with modifications made at PS 5 made the original TAPS Design Basis cold restart plan unusable. This situation was not addressed by Alyeska during the ramp down planning process. Ongoing communications between Alyeska and the JPO regarding the cold restart were unsuccessful in producing a new cold restart procedure.
>
> 2000 Status: On November 5, 1999, JPO ordered Alyeska to provide a reliable schedule for the final development and implementation of a cold restart procedure. On October 31, 2000, Alyeska delivered a draft interim cool restart plan. The cool restart plan is designed to assure that the pipeline will not be overpressured if the pipeline is restarted with crude oil temperatures below 40 ˚F. It does not provide assurance that the pipeline could be restarted in extended winter shutdown conditions. The data necessary to determine if the pipeline could be restarted under the design basis requirements of a 21-day shutdown with an ambient air temperature of –40 ˚F is still being analyzed by Alyeska. To assure restart, under extended winter shutdown conditions, Alyeska indicates that it will install additional equipment in 2001. After the equipment is installed. Alyeska will provide a final cold restart procedure [reportedly by Winter 2001]. Until Alyeska has a final cold restart procedure and has adequate equipment in place to implement this plan, Alyeska is not in compliance with the TAPS Design Basis (DB-180), and its ability to restart the pipeline under these extreme conditions remains uncertain.

The basis of the problem is the unexpected cold viscosity of the crude oil mix currently being pumped (p. 15):

> The fundamental problem identified in the studies is that the oil had higher than expected strength (yield point) at low temperatures. This high yield point would greatly increase the required pressure during startup of the pipeline after an extended shutdown under winter conditions. Earlier Alyeska crude tests had not indicated problematic yield strengths. Later tests in which Alyeska cooled the oil more slowly, more akin to what would happen in a real world cold shutdown, indicated a significant rise in yield strengths.

It is also possible for an intact and fully operational TAPS to have its flow stopped by problems at the southern end, *e.g.*, in the gale-prone Valdez Narrows. In 1979, this almost occurred when tanker shipments were delayed for nearly as long as the Valdez storage tanks could accommodate (W. Endicott, "All Flows Smoothly for Alaskan Pipeline," *L.A. Times*, 1 April 1979, pp. 1 & 11). Damage to certain critical components of the Valdez terminal could also deprive TAPS of an outlet for up to a year or two, just as certain kinds of damage at the north end of the pipeline could cause protracted interruptions of oil input.

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accelerated corrosion

Erosion (some it internal and in unexpected sites) and the stress of pumping cooler, gooier oil are taking their toll. Four valve replacements have occurred since 1996 (a major and costly operation requiring shutdown and inert atmosphere). Metal fatigue is also becoming an issue; for example, an Alyeska contractor found in 2000 that with 12 shutdowns a year, "it would take 24 years to reach a cumulative design fatigue damage of 100%" with a backpressure system working to prevent oil bubble collapse that causes metal-fatiguing vibrations—sooner (with a 2% chance of crack initiation in 1.5 years) if the backpressure system were offline (as it was for 23 days during repairs after a 30 January 2000 "runaway pig" accident). (Joint Pipeline Office, *Comprehensive Monitoring Program Report: A Look at Alyeska Pipeline Service Company's Operation of the Trans-Alaska Pipeline System 1999/2000*, February 2001, p. 25).

Most worryingly, corrosion is faster than expected and appears to be accelerating. The posted maintenance chronology (www.alyeska-pipe.com/Pipelinefacts/PipelineOperations.html)—though, as noted earlier, it does not appear entirely reliable—shows a disquieting rise in corrosion-related problems and repair requirements. Planned maintenance shutdowns seem to be getting both longer and more frequent, and extensive anti-corrosion sleeving and other retrofitting has already occurred. This is officially ascribed to larger-than-expected "telluric currents" (ground currents induced by the same charged-particle flows, concentrated by the near-Polar intensity of the Earth's magnetic field, that cause the *aurora borealis*). This explanation is not wholly convincing, and the apparent acceleration of corrosion may even cast suspicion on the initial metallurgical quality of the 48-inch steel pipe. The Joint Pipeline Office's *Comprehensive Monitoring Program Report: TAPS Maintenance Program 1999/2000*, January 2001, at p. 19, concludes:

> Review of TAPS corrosion control and monitoring programs for TAPS crude oil piping revealed that corrosion to the mainline and related facilities is of significant concern to the long-term viability of TAPS operations. In response to this concern, [Alyeska] has instituted rigorous corrosion control and monitoring programs which have been effective in identifying where corrosion threatens the integrity of the TAPS mainline pipe and related facilities, and has implemented timely corrective actions. Consequently, JPO/USDOT/OPS [the federal Office of Pipeline Safety] has concluded that at this time, [Alyeska] is in compliance with...stipulations and regulatory requirements.
>
> However, corrosion continues to present a significant maintenance challenge for [Alyeska], and this review identified some specific concerns which [the Joint Pipeline Office] will continue to monitor.

Another issue is that the rapid climatic warming being experienced in the Arctic is “likely to expand the active zone throughout regions of Alaska’s permafrost; this could affect pipeline foundations and more than 25,000 [Vertical Support Members] currently subject to movement. Further, 84% of all heat pipes along TAPS have some degree of blockage, potentially causing diminished heat transfer performance. The combination of warming permafrost and reduced heat pipe performance can result in frost heaving. Frost heaving presents a potential threat to VSM supports as it can cause ‘jacking’ of the member up and out of the ground, thereby reducing VSM embedment, resulting in further jacking and reduced load bearing potential. This is a complex problem....Continued ground thawing will only exacerbate the porblem. A comprehensive long-term corrective action plan is necessary” (Joint Pipeline Office, *id.*, pp. 15–16; TAPS has about 78,000 VSMs, supporting the aboveground mainline pipe every 60 feet, and 61,000 heat pipes).

Some in the industry believe that as soon as ~2006–11, perhaps even before Refuge oil could start flowing, the rising cost of corrosion repairs could make TAPS too costly to operate. Refuge oil that is economically dubious using the existing pipeline would of course become prohibitively costly if it had to be replaced. The entire exploration and development investment in Refuge oil could then be lost even if economically extractable oil were found, because there would be no way to deliver it.

Federally commissioned studies of TAPS’s maintenance and life expectancy by consultants Aladon Ltd. and Spearhead System Consultants Ltd. are underway and will inform potential renewal of its original 30-year right-of-way permits when they expire in January and May 2004, though the Bush Administration seems unlikely to examine too closely any issues that might inhibit relicensing. (The Federal permit must be renewed “so long as the project is in commercial operation and maintained in accordance with all the provisions of this section” [PL93-153, Title I, Duration of Grant]—which, strictly speaking, it hasn’t been.) Yet confidence in TAPS’s mission-critical reliability naturally dwindles with age. By the time any Arctic Refuge oil output were peaking around 2030–40, TAPS would be 53–63 years old; as that flow tapered off, TAPS would be nearing its centenary. Even if recent corrosion experience weren’t so discouraging, prolonging America’s dependence on such a weak link would seem imprudent.

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two troubling accidents

On 17 April 2000, a pressure hammer “tripped seven pipeline anchors, sheared steel bolts on the anchor frames and moved the pipeline...up to 23 inches”—a dangerous shift that went undetected for over a month. and, investigation disclosed, had been preceded by two undetected similar events (Joint Pipeline Office [www.corecom.net/JPO/index.htm], *Comprehensive Monitoring Program Report: A Look at Alyeska Pipeline Service Company’s Operation of the Trans-Alaska Pipeline System 1999/2000*, February 2001, pp. 29–32). In July 2000, the pipeline was probably not improved when a quarter-ton, four-feet-across, two-inch-thick steel valve ring was stretched into an oval (33 instead of ~47 inches across) by being accidentally dragged through it—for 400 miles (*id.*, pp. 33–34; no damage has been reported, but studies of how to check for it continue). On 19 May 2000, a scheduled underground corrosion check discovered five areas of mechanical gouges, the deepest going 80% through the pipe wall, apparently caused by mechanical equipment during construction; this “severe mechanical damage” had not been detected by tests intended to detect it. DOT’s Office of Pipeline Safety is pursuing a Notice of Probable Violation of repair and operational safety conditions (*id.*, pp. 18–19).

Alyeska may face fines over a 19 October 2000 mishap in which a spark, caused by unsupervised workers, luckily failed to blow up the Valdez oil terminal (J. Carlton, “Alyeska Pipeline May Face Fines Amid Charges of Poor Oversight,” *Wall St. J.*, 4 December 2000, p. C15). (The Joint Pipeline office, http://corecom.net/JPO/11-03-00.html, agreed that “had the right conditions been present, a fire or explosion could have occurred.”)

In the first quarter of 2001, *The Wall Street Journal* reported that at six of BP/Amoco’s 21 drilling platforms, or pads, 10–30% of the emergency shutoff valves—10% of the total in the company’s entire operation in western Prudhoe Bay—failed to close on test (J. Carlton, “Alaska Finds 10% of BP’s Safety Valves in Huge Prudhoe Bay Oil Field Fail Tests,” 26 April 2001, p. A4; see also J. Carlton, “Oil and Ice: In Alaska Wilderness, ‘Friendlier Technology’ Gets a Cold Reception,” 13 April 2001, p. A1).

Confidence is not increased by a new $200 million fiber-optic control system with defects so pervasive Alyeska wouldn’t accept it (J. Carlton, “Alyeska Says Fiber-Optic System For Alaska Pipeline Needs Repairs,” *Wall St. Journal*, 12 November 1999, p. B4), nor by the failure of TAPS’s earthquake-monitoring system, installed in 1998, to detect a Richter-5.7 temblor two years later (J. Carlton, “A Pipeline Device Failed in Detecting Alaska Earthquake,” *Wall St. Journal*, 15 December 2000, p. A4).

TAPS has a long history of officially substantiated complaints of intimidation and harrassment of workers who try to call attention to safety and maintenance deficiencies (J. Carlton, “Whistle-Blowup: A Push for Reform Along Alaska Pipeline Runs Into Resistance,” *Wall St. Journal*, 9 November 1999, p. A1). Efforts to solve these problems have not been wholly successful; the Joint Pipeline Office’s latest survey found decreasing worker satisfaction with resolution of their warnings and continued harrassment reported by 108 of 900 workers interviewed (J. Carlton, “Pipeline Workers Still Face Difficulties,” *Wall St. Journal*, 13 November 2000, p. B18; Joint Pipeline Office [Anchorage, 907/271-5070], “Joint Pipeline Office Assessment—Employee Concerns Program, 2000 Survey Results,” December 2000).

Another important part of the problem is that as oil companies have “held back on much-needed investments in replacement parts and equipment” to maintain the aging infrastructure, Alaska’s Legislature has “gutted the state agencies responsible for regulating oil-field safety. Indiana, which takes a full year to produce the amount of crude oil that Alaska pumps in three days, employs nine oil-field safety inspectors. Alaska has five.” Moreover, Indian’s inspection budget is $1.4 million a year for 480 square miles, while Alaska’s five inspectors, stretched over 3,500 wells and 1,000 icy square miles, can’t do surprise inspections, but do not schedule them in advance. The Legislature recently denied a $0.5-million petition by the Alaska Department of Environmental Conservation (whose budget has been cut 55% since 1991, compared with a 15% overall decline in state spending) to monitor pipeline corrosion and study spill-prevention techniques—but the Legislature voted $3.6 million to lobby for Refuge drilling. (J. Carlton, “Bush’s Oil-Drilling Proposal Fuels Controversy in Alaska,” *Wall St. Journal*, p. A1, 10 July 2001.)

These conditions have produced a steady and seemingly increasing sequence of generally minor breaks, spills, and other accidents in the North Slope oil infrastructure (Reuters, “Alaska oil spills raise worries ahead of ANWR vote,” 27 July 2001). These indicate aging infrastructure and strained institutional support. Some, however, have narrowly missed larger consequences, and others probably lurk undetected—such as the likelihood that clogged pipes may prevent delivery of firefighting foam to as many as five of the Valdez terminal’s 18 giant oil storage tanks (Carlton, “Whistle-Blowup,” *loc. cit. supra*).

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the Strait of Hormuz

Crude-oil input to U.S. refineries in 2000 averaged 15.07 million bbl/d, of which TAPS carried 0.97 million bbl/d, or 6.4%, or 11% of domestic oil production (EIA, *Monthly Energy Review*, June 2001, pp. 46–47).

The Strait of Hormuz, between Oman and Iraq, is by far the world’s most important oil chokepoint, carrying in 2000 about 15.6 million bbl/d—about two-fifths of all oil in world trade and 89% of oil exports from the 600-mile-long Persian Gulf (www.eia.doe.gov/emeu/cabs/pgulf.html). The Gulf in 2000 had about 65% of proven world oil reserves, 34% of proven world natural gas reserves, nearly 30% of world oil production capacity, and 28% of actual world oil production. Of the Gulf’s net oil exports of 17.5 Mbbl/d in 2000, 44% came from Saudi Arabia, 15% from Iran, 13% each from Iraq and the United Arab Emirates, 11% from Kuwait, and 5% from Qatar. The Strait narrows to 34 miles wide, and includes an inbound and an outbound tanker channel and a buffer zone, each two miles wide. If the Strait were closed, presumably by hostilities, more roundabout and costlier alternatives could be used unless also interdicted. These include the 5 Mbbl/d East-West Pipeline across Saudi Arabia to the port of Yanbu (which in 2000 carried just under 1 Mbbl/d), the Abquaiq-Yanbu NGL pipeline across Saudi Arabia to the Red Sea, the pipeline from Kirkuk, Iraq to the Turkish port of Ceyhan, and perhaps a proposed Yemeni route to the Gulf of Aden. (Minor exports currently occur also by truck to Jordan and by smugglers’ trucks and small boats.) Both Iran and Iraq attacked tankers in the Persian Gulf during the Iran-Iraq war, leading the US to reflag Kuwaiti tankers and step up Naval patrols in the Gulf. Several territorial disputes persist in the region.

Since oil is fungible in world markets, it is not possible to state exactly how much oil flows to the U.S. through the Strait of Hormuz. Saudi oil, for example, could well be transshipped to the U.S. via (say) Rotterdam, or even refined somewhere en route and imported as product apparently originating from the country of refining. However, *direct* flows to the U.S. through the Strait of Hormuz can be estimated. The U.S. in 2000 imported directly from the Persian Gulf an average of 2.41 net Mbbl/d of crude oil and 2.50 of total petroleum (the difference is imported refined products). Of the total petroleum imports, 63% came from Saudi Arabia, 25% from Iraq, 11% from Kuwait, and the rest from Qatar and the UAE. Essentially all of the Kuwaiti, UAE, and Qatari petroleum imports, totaling 0.297 Mbbl/d, flowed through the Strait of Hormuz. The 0.62 Mbbl/d of Iraqi petroleum typically avoided the Strait and flowed instead through the pipeline to Ceyhan or via the Gulf port of Mina al-Bakr. Of the 1.572 Mbbl/d of Saudi petroleum, about 1.37 Mbbl/d could have passed through the Strait of Hormuz if prorated on total Saudi net exports of 7.8 Mbbl/d (of which about roughly 1 Mbbl/d flowed through the East-West Pipeline and south through the Bab-el-Mandab, though no specific breakouts of destinations are available; Saudi flows through the Suez Canal/Sumed pipeline have been about 40k–60k bbl/d in the past few years, but none recently). On this assumption, petroleum *directly* shipped to the U.S. through the Strait of Hormuz in 2000 was on the order of 1.67 Mbbl/d. Of this, about 1.59 Mbbl/d was crude oil—comparable with TAPS flows to U.S. refineries.

A broader answer to the question would be that about 15.6 Mbbl/d of oil transited the Strait of Hormuz in 2000 bound for world trading markets, which totaled 42.7 Mbbl/d in 2000 (BP, *World Energy Review 2001*, p. 18). From the world market, the U.S., which accounts for about 26% of the world’s total oil demand, imported 10.42 net Mbbl/d in 2000 (*EIA Monthly Energy Review*, June 2001, p. 15), mainly from non-Persian Gulf sources; in 2000, the U.S. got an eighth of its oil and 22% of its oil imports from the Persian Gulf. These figures illustrate the importance of the Strait of Hormuz to world oil trade, and the likelihood that disruption of Strait shipments would raise oil prices everywhere, but that reflects an economic rather than a logistical perspective on oil flows.

In 2000, therefore, direct flow of crude oil through TAPS was about 61% of the flow of crude oil to U.S. refineries through the Strait of Hormuz. In 2010, about the earliest that TAPS oil might flow, U.S. refinery crude-oil input is projected in EIA’s Reference Case (*loc. cit.*) to total 16.7 million bbl/d, but Refuge oil would be hoped to bring TAPS to, and keep it for some years at, its full capacity of 2.136 million barrels a day using all ten normal pumping stations plus the relief station. If this occurred, TAPS would be carrying about 13% of U.S. refineries’ crude input—approximately the same *fraction* as is now imported through the Strait of Hormuz (about 11%). In absolute terms, the TAPS flow would be roughly 134% of year-2000 direct crude-oil flows to U.S. refineries through the Strait of Hormuz. If the EIA’s 2001 Reference Case forecast were realized, its roughly one-third increase (*Annual Energy Outlook 2001*, p. 60) in Persian Gulf Imports to 2010 would imply a TAPS flow roughly comparable to crude flows through the Strait at a similar time.

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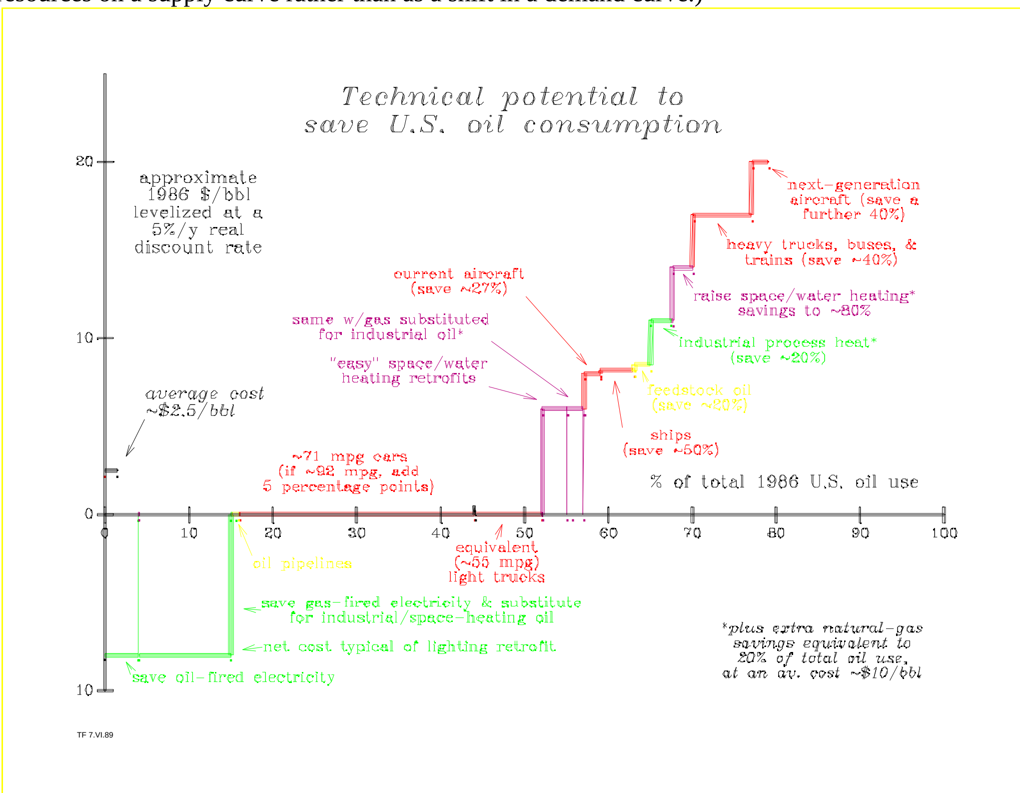
50 times the average projection

This figure, and the projected reserve with which it is compared, are documented below.

The supply curve of potential U.S. oil savings prepared by A.B. Lovins for Royal Dutch/Shell Group in 1986–87 is shown below and reprinted in "Make Fuel Efficiency Our Gulf Strategy" (*N.Y. Times*, 3 Dec. 1990, annotated as RMI Publ. #S90-26), and documented further in "Drill Rigs and Battleships Are the Answer! (But What Was the Question?)," in Reed & Fesharaki, eds., *The Oil Market in the 1990's: Challenges for a New Era*, Westview (Boulder), 1989, RMI Publ. #S91-15. The supply curve is now known to be conservative in each term, and in both the quantity and the marginal cost of the savings shown: technological progress since it was analyzed has more than outpaced the exhaustion of the cheaper opportunities. (In energy efficiency analysis it is conventional to show efficiency resources on a supply curve rather than as a shift in a demand curve.)



The supply curve shows a 1986 potential, by full retrofit (or replacement in the case of vehicles) with the best demonstrated 1988 technologies, to save ~80% of U.S. oil use at an average cost of ~$2.5/bbl (1986 $ levelized at a 5%/y real discount rate). That cost is equivalent to $3.6/bbl in 4Q2000 $. U.S. oil consumption (EIA, *Monthly Energy Review*, June 2001, Table 1.4) was 19% higher in 2000 than in 1986 (38.404 / 32.196 Q), so an 80% saving scaled to 2000 is equivalent to 30.72 Q/y, or (Table A3) 15.79 Mbbl/d, or 54.1 times the 292,000 bbl/d that would be obtained by exploiting a 3.2-billion/bbl mean Refuge reserve over 30 years. The average cost, $3.6/bbl in 4Q2000 $, is 6.1 times smaller than the $22/bbl that USGS (1998) found was necessary to recover that mean reserve.

The supply-curve analysis assumes no lifestyle changes nor intermodal transportation shifts. The second block from the left represents savings of gas used to run power stations (saved by electric end-use efficiency), freeing up the gas to displace oil used to heat buildings or industrial processes. The costs shown above ~$10/bbl were rather uncertain at the time, but had little effect on the result, and in any event proved conservative. The analysis reflects many conservatisms: *e.g.*, omitting any light-vehicle efficiency improvements whose marginal cost exceeds zero, and translating the negative-cost lighting retrofits (which save the oil- and gas-fired electricity) directly into equivalent $/bbl without taking credit for the *value* of the utility fuel thereby displaced. (The lighting retrofits, which more than suffice to save all the oil and gas used in U.S. power plants in 1986, are documented in A.B. Lovins & R. Sardinsky, *The State of the Art: Lighting*, RMI / Competitek, 348 pp., 1988.) The overall uncertainty assessed at the time was roughly ten percentage points in tota quantity and less than a factor two in average cost. Nowadays, it is quite possible that the larger potential still remaining untapped for most or all terms (especially in light of Hypercar developments, which were not yet invented in 1986–87) would yield considerably larger savings—perhaps even 100%, or even more, when combined with the saving potential for gas fungible for oil.

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equivalent

2000 dollars (fourth quarter)

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during 1975–91

U.S. petroleum consumption was 32.731 Q/y in 1975 and 32.845 Q/y (0.35% higher) in 1991: EIA, *Monthly Energy Review*, June 2001, p. 7). During that period, real GDP grew by 63.5% (*id.*, p. 16).

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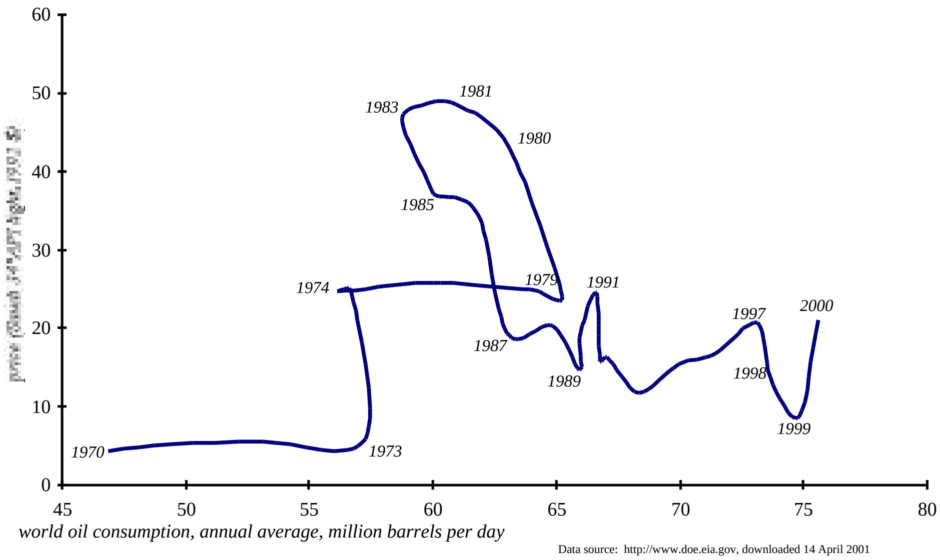
historically

Many details are provided in J.J. Romm & A.B. Lovins, “Fueling a Competitive Economy,” *Foreign Affairs*, Winter 1992/93, pp. 46–62.

The following graph illustrates the volatility of world real oil prices over the past three decades. Note that the second (1979) oil price shock was so severe that world oil demand actually fell—so far that price went down too, causing demand to drift up again.



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deregulate oil and gas prices

This is commonly misattributed to President Reagan. As EIA’s “World Oil Market and Oil Price Chronologies: 1970–2000” reminds us (www.eia.doe.gov/emeu/cabs/chron.html), phased decontrol of oil prices began 1 June 1979, involving a gradual 28-month increase of “old” oil price ceilings and a slower rate of increase on “new” oil price ceilings. On 28 January 1981, soon after taking office, President Reagan, by Executive Order, lifted the remaining petroleum price and allocation controls that were originally scheduled to expire in September 1981. The price controls on crude oil and the two-tier price system had originally been imposed by President Nixon’s Cost of Living Council on 17 August 1973, and had been elaborated by Congress during the Ford Administration.

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collapsed

EIA’s *Annual Energy Review 1999* reports that during 1984–86, the average U.S. real price of domestic crude oil (refiner’s acquisition price), unleaded regular retail motor gasoline, domestic wellhead natural gas, and composite domestic fossil-fuel production fell respectively by 51% (p. 157), 28% (p. 163), 31% (p. 183), and 41% (p. 63). The graph on p. 62 shows how oil and gas prices started to slip in 1985, then (especially for oil) plunged in 1986. The downward drift continued thereafter for both, amidst a long-term background of gradually declining coal and electricity prices, which were more subject to long-term contracts and, for electricity, regulated average prices dominated by fixed costs.

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seven miles per gallon

The sales-weighted-average domestically made new car got 18.7 mpg in model year (MY) 1978, 25.5 in 1984, 26.3 in 1985, hence a gain of 7.6 mpg: Table 7.16, *Transportation Energy Data Book: Edition 20—2000*, ORNL-6959, Oak Ridge National Laboratory, 2000, http://www-cta.ornl.gov/data. CAFE standards, not price, achieved most or all of the dramatic gain in U.S. new-car efficiency: D. Greene, "CAFE or Price?: An Analysis of the Effects of Federal Fuel Economy Regulations and Gasoline Prices on New Car MPG, 1978–89," Oak Ridge National Laboratory/USDOE Office of Policy, Planning & Analysis draft, 10 May 1989.

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fell by 87 percent

Table 5.4, *Annual Energy Review 1999*, USEIA, shows net petroleum imports from the Persian Gulf (Bahrain, Iran, Iraq, Kuwait, Qatar, Saudi Arabia, United Arab Emirates) of 2,448 Mbbl/d in 1977 and 311 in 1985, an 87.3% drop. These are gross imports, not net, because Table 5.7, showing net imports, shows data unavailable for Gulf net imports before 1981.

Interestingly, during 1977–85, Alaskan output rose from 0.464 to 1.825 Mbbl/d, an increase of 1.361 Mbbl/d, while Gulf imports, as just stated, fell by 2.137 Mbbl/d. But net petroleum imports meanwhile fell by 4.29 Mbbl/d, while total petroleum products supplied in the U.S. fell from 18.43 to 15.73 Mbbl/d, a difference of 2.70 Mbbl/d. The net changes were thus:

Change in demand cuts imports	–2.70
Increase from Alaska cuts imports	–1.36
Decreased non-AK domestic output raises imports	+0.64
Other domestic oil inputs rose, decreasing imports	–0.19
Stocks increased, raising imports	+0.39
Total notional decrease in need for imports	–3.22
Net imports actually decreased	–4.27
Of which Gulf imports decreased	–2.14

So one can reasonably conclude that decreased demand was twice as important as increased Alaskan output, or 3.7 times as important as the net increase in total domestic output, or 5.1 times as important as all net supply-side factors. While the Alaskan increased output was significant, therefore, its value in displacing Gulf imports was far outweighed by that of the demand-side response.

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1977 to 1985

We choose 1977 as the year of peak oil imports and 1985 as their local minimum, illustrating the dramatic shift in just eight years. Using *Annual Energy Review 1999* USEIA data, real GDP rose from $4.5118 to $5.7171 trillion 1996 chained dollars (Table 1.5). Net petroleum imports fell by 48%, from 18.54 to 11.53 Q/y (Table 1.4), or from 8.585 to 4.286 Mbbl/d (Table 5.7), but the article gives the more conservative 3.74 Mbbl/d decrease in gross imports, which fell 42% from 8.807 to 5.067 Mbbl/d (Table 5.4). U.S. gross imports from OPEC (*id.*) fell from 6.193 to 1.830 Mbbl/d, a difference of 4.36 Mbbl/d. OPEC's output (Table 11.4) meanwhile fell 48%, from 30.89 to 16.18 Mbbl/d. World oil production shrank 10% from 59.71 to 53.98 Mbbl/d (Table 11.4). OPEC's share of world production therefore shrank from 30.89/59.71 = 52% to 16.18/53.98 = 30%. Of the 14.71 Mbbl/d drop in OPEC's output, the U.S. decrease in gross imports from OPEC, 4.36 Mbbl/d, accounted for 30%, or for 14% of OPEC's 1977 output (one-seventh; the article conservatively says one-eighth). The U.S. decrease in net imports from all sources, 3.74 Mbbl/d, was equivalent to 25% of the 14.71 Mbbl/d drop in OPEC's output.

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savings

This is an uncorrected editorial error for "That saving" or "Those savings."

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More-efficient cars

Table 2.9 of USEIA's *Annual Energy Review 1999* states that from 1977 to 1985, average miles driven per U.S. passenger car fell from 9,517 to 9,419, while their gallons per year fell from 656 to 538 and their average miles per gallon rose from 14.1 to 17.5. These figures include motorcycles too, but the Oak Ridge *Transportation Energy Data Book* shows their effect is immaterial, accounting for only 0.3% of automotive gasoline in recent years (Table 2.5).

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96 percent

P. Patterson, "Periodic Transportation Energy Report 1," DOE CE-15, U.S. Department of Energy (Washington DC), 202/586-9118, 16 November 1987, showed that for 1976–87, "If the 1976 size class shares for autos were applied to the 1987 car class fuel economies, the resulting new car MPG would be 27.7 in 1987 (just 0.4 MPG less than the actual values). Thus, if in 1987 the nation had reverted back to the 1976 new car size mix, the eleven year gain of 10.9 MPG would have been reduced by only 4 percent." This is not true, however, for light trucks, whose efficiency jumped dramatically in the late 1970s as small imported pickup trucks entered the fleet: this truck downsizing, which was more a phenomenon of marketing to new, more urban segments than of sacrificing comfort among traditional pickup drivers, accounted for 42% of the 1976–87 improvement in light-truck efficiency (*id.*).

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U.S. oil productivity

USEIA's *Annual Energy Review 1999* shows that from 1977 to 1985, real GDP rose from $4.5118 to $5.7171 trillion chained 1996 dollars (Table 1.5), while petroleum consumption fell from 37.122 to 30.922 Q (Table 1.3). Their ratio therefore rose from 0.1215 to 0.1849 $/kBTU, an increase of 52.1%.

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less than one percent

Peak output on the order of 1 Mbbl/d, probably sometime during 2010–20, could for a few years be equivalent to ~4–5 percent of U.S. projected oil consumption (22.7 Mbbl/d in 2010, 25.8 in 2020, according to EIA's Reference Case, *Annual Energy Outlook 2001*). However, averaged over a nominal field life of 30 years, the USGS (1998) mean expected reserve of 3.2 billion bbl (at $22/bbl) would have an annual output of 0.29 Mbbl/d, or about one percent of U.S. oil needs projected for the same timeframe.

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Peak output

a few percentage points

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essence of its oil problem

The authors previously published this argument in "The Avoidable Oil Crisis," *The Atlantic Monthly* 260(6):22–30, December 1987, and Letters, 261(4):10–11, April 1998. (Due to an editorial error, the next-to-last sentence in the authors' response to Gov. Cowper's letter should say not "every *month*" but "every *nine days*".)

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free-trade rules

Actually, subsidizing domestic output also (in principle) violates free-trade rulers and could probably elicit a WTO complaint from competitors eager to export to U.S. markets.

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import all their oil

According to the U.S. Energy Information Administration (www.eia.doe.gov/emeu/cabs/pgulf.html), although the U.S. in 2000 (preliminary data) obtained 12.5% of its petroleum from the Persian Gulf region, the corresponding figures for Western Europe and Japan were respectively 22% and 73%. The percentage of net oil imports coming from the Gulf was 22.1% for the U.S., 45% for Western Europe, and 75% for Japan.

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oil last year

EIA's *Monthly Energy Review*, June 2001, reports in Table 3.1b that net imports in 2000 were 10.419 Mbbl/d, equivalent to 22.38 Q (Table 1.5). That was 52.9% of the 19.701 Mbbld of petroleum products supplied in 2000 (Table 3.1a)—the conventional metric (Table 1.8). (The 52% stated in the article came from preliminary data EIA had published earlier.) It is also 58.3% of the 38.404 Q of petroleum consumption (Table 1.4), and cost $109 billion net (Table 1.6)—considerably above the ~$50–60 billion norm of most previous years, due to a rise in world oil prices in 2000.

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oil productivity

EIA's *Monthly Energy Review*, June 2001, reports (Table 1.4) petroleum consumption of 38.404 Q in 2000, *vs.* 32.731 Q in 1975. Real GDP (Table 1.9) meanwhile rose from $4.0844 to $9.3185 trillion chained 1996 dollars. The GDP/oil ratio thus rose from 0.1248 to 0.2426 $/kBTU, an increase of 94.4%, or an intensity decrease (barrels per dollar GDP) of 48.6%. The GDP/oil-plus-natural-gas ratio was slightly higher, rising by 94.6%. Overall primary energy productivity rose by 66% due to the lower productivity increase for electricity (and directly used coal).

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for example

The history, now remembered only by students of the subject, may bear reviewing for today's general readers. The Corporate Average Fuel Economy (CAFE) standards became law in 1975 because Congress appreciated the need to correct well-known market failures cause chiefly by fuel's being a small fraction of total ownership cost, subject to high implicit consumer discount rates, and typically about offset by higher sticker price for more efficient models. Under CAFE, which remains in force today but has been heavily gamed, buyers could choose any car they liked and, if it weighed under 6,000 pounds and got less than 22.5 mpg, pay a tax (up to $3,850 for a 10-mpg 1987 Rolls-Royce). Manufacturers had to meet a fleet-average efficiency standard rising from 18 mpg for model year (MY) 1978, which began in calendar 1977, to 27.5 mpg for MY 1985–88. In practice, however, sales of 1986 and 1987 cars beat the 27.5-mpg standard only because Americans bought record numbers of imported cars averaging over 30 mpg. Domestic cars' 26.6 and 26.7 mpg flunked, as they did through MY1983–87. Although Chrysler met the standards in every year, Ford and GM flunked them for at least six years running, starting with MY1983.

Through an administrative proceeding, for which apparently only the automakers had standing to obtain judicial review, the Reagan Administration rolled back the 1986–88 CAFE standards from 27.5 to 26.0, 26.0, and 26.5 mpg. These were chosen as levels that Ford and GM could readily beat, so that they could *retroactively* offset with credits for "overcompliance" more than $1 billion (the exact figure is an official secret) in statutory fines for their willful noncompliance in 1985. (Their earlier noncompliance had already been offset by credits for "overcompliance" in the early years of CAFE, when fleets improved faster than the standards rose. CAFE didn't originally allow such carryforward credits, but was so amended in 1979 at the behest of the automakers. But in MY1985, they ran out of credits, so their noncompliance incurred an automatic fine calculated by its degree and the number of noncompliant cars sold. When even the 1986–88 rollback wasn't enough to bail out GM, the Reagan Administration even considered a retroactive rollback of the 1985 standard.)

This 1986–88 rollback, undertaken entirely for the benefit of Ford and GM, competitively penalized Chrysler's consistent compliance; told GM and Ford they could defy Congress with impunity; and emboldened them to intensify their ferocious marketing (via rebates and other incentives) of their least efficient models. Their sales crusade was aided by the inability of two-thirds of new-car buyers to get a copy of the government's "Gas Mileage Guide," whose print run was reduced by 70% in apparent reliance on the Telepathic Theory of Market Information.

The result of these initiatives was not, as the Department of Transportation's press release trumpeted in announcing the 1988 rollback, "to enhance U.S. global competitiveness and protect jobs"; rather, it was to turn a 12-year string of gains in U.S. car-fleet efficiency into a 1985–86 *loss* of 0.07 mpg (Federal Highway Administration, *Highway Statistics* 1998, 1999, and www.fhwa.dot.gov, quoted in *Transportation Energy Data Book: Edition 20–2000*, ORNL-6959, Table 7.2). Concurrent rollbacks in efficiency standards for light trucks (two-axle/four-tire models including pickup trucks, vans, and SUVs) cut their fleet improvement in 1985–86 by 25%. For new domestically made cars and light trucks, the increase in efficiency in 1985–86 was less than half its average rate for the previous six years (Table 7.16). This 1986 stall in previously steady improvement in light-vehicle efficiency *doubled U.S. imports from the Persian Gulf*, and hence was responsible for half of the trebling of Gulf imports during 1985–86. The calculation follows. (For simplicity, model years are equated to calendar years, although they actually begin in the previous calendar year, nominally on 1 October but actually on a schedule that varies between manufacturers and even between models of the same manufacturer. Also, the DOT data are interpreted here as showing actual on-the-road mpg, and hence not requiring the normal DOE-methodology correction of dividing CAFE test mpg by 1.15 to approximate actual on-the-road mpg.)

In MY1986, the average U.S. registered passenger car was driven 9,770 miles. Had it achieved the average MY1979–85 improvement of 0.482 mpg/y, it would have had an efficiency of 17.91 mpg rather than the actual 17.36 mpg (Table 7.1), so it would have used 17.3 gal/y less gasoline. Multiplying by the 1986 fleet of 130 million cars (*id.*), that's 146,564 bbl (@ 42 gal/bbl) of gasoline per day. In 1986, it took 2.188 bbl of crude oil to make 1 bbl of gasoline (Table 1.8, DOE data), so since marginal imports are driven by light-product demand, the increase in crude-oil imports was 146,564 × 2.188 = 320,681 bbl/d of crude oil. (Using aggregated total-car-fleet characteristics in this way avoids the difficulty of trying to correct for the extra driving done by new cars. Table 6.6 shows that in 1998, a car in its first year was driven 32% more than its lifetime average, and that such new cars were 6.1% of the fleet. Table 6.7 shows that the corresponding data for light trucks in 1998 were respectively 26% and 7.9%.)

For light trucks (*Transportation Energy Data Book 2000*, Tables 7.2 and 7.6), the MY1986–87 new fleet gain was 0.29 mpg, compared with the MY1979–86 average gain of 0.39 mpg/y. The average light truck in 1986 was driven 10,764 miles. The MY1987 shortfall of 0.10 mpg made the average light truck in the 1987 fleet get 14.58 instead of 14.68 mpg, using an extra 4.9 gal/truck-y, times 39.38 million light trucks in use in 1986, times 2.188, equals 20,947 bbl/d of crude oil.

The total extra crude oil thus required in 1986 by the collapse of the 1979–85 rate of light-vehicle efficiency improvements was thus roughly 320,681 + 20,947 = 341,628 bbl/d, uncorrected for the energy needed to operate refineries, pipelines, and fuel delivery vehicles (which would probably add another 5–10%). That exceeds 1985 net Gulf imports of 309,000 bbl/d (*Annual Energy Review 1999*, Table 5.7). This extra crude-oil requirement also exceeds the 30-year average rate (295,000 bbl/d) at which the Interior Department in 1987 was hoping to extract oil from beneath the Refuge, based on an economically recoverable (fully risked) reserve essentially identical to the 3.2 billion barrels assessed (at $22/bbl in 4Q2000 $) by USGS in 1998.

It is also noteworthy that during 1975–84, the fuel economy of the entire light-vehicle fleet rose 62% with no loss of performance as measured by 0–60-mph acceleration times. However, CAFE standards weren't updated; indeed, since FY1996, Congress has prohibited changing or even studying potential changes in CAFE. Automakers therefore applied continuing technological improvements to acceleration, which became on average 25% quicker; size and occupant protection (average vehicle mass rose 20%); and other attributes. (National Research Council, *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards*, 30 July 2001, www.nas.edu, in Executive Summary, Finding 4.)

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took

yield

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conserve oil

We chose 1977–85 because it is the calendar years during which the Corporate Average Fuel Economy standards enacted in 1975 remained in force in their original statutory form. (As described above, the standards came into effect with MY1978 vehicles and were subsequently rolled back for MY1986–88 vehicles.)

The U.S. in 1977 consumed 37.122 Q of petroleum (*Annual Energy Review 1999*, Table 1.3) to fuel a $4.5118-trillion (chained 1996 $) GDP—a ratio of 8,228 BTU of petroleum per dollar. For 1985, these figures were 30.922 Q, $5.7171 trillion, and 5,409 BTU/$. The compound rate of decrease in oil intensity of GDP thus averaged (ln[5,409/8,228])/8 = 5.244%/y. Had this rate of improvement been sustained during 1986–89, for example, the oil intensity in 1989 would have been $5{,}409(1–0.05244)^4$ = 4,361 BTU/$, which times the 1989 GDP of $6,591.8 trillion (still in chained 1996 $) would have yielded petroleum consumption of 28.744 Q. Actual 1989 petroleum consumption was 34.211 Q. The difference, 4.809 Q, was equivalent at the 1989 average petroleum-import heat value of 5.833 million BTU/bbl (Table A2) to 2.259 million bbl/d. Net imports from the Persian Gulf in 1989 were 1.858 million bbl/d (Table 5.7). Thus a 2.259 million bbl/d reduction in U.S. oil requirements probably would, and certainly could, have extinguished 1.858-million-bbl/d imports from the Gulf.

The same is true for each subsequent year. For example, in 2000, when gross Gulf imports reached 2.409 million bbl/d (*Monthly Energy Review*, June 2001, Table 3.3b), reapproaching their 1977 peak of 2.448 million bbl/d, petroleum consumption was 38.404 Q (*id.*, Table 1.4), GDP was $9.3185 trillion chained 1996 $ (Table 1.9), and average imports contained 5.849 million BTU/bbl (Table A2). Had the 1977–85 rate of decrease in petroleum intensity been sustained through 2000, then using the same methodology as above, petroleum consumption would have been 23.71 Q. The difference, 14.69 Q, is equivalent to 6.863 million bbl/d, or 2.85 times actual imports from the Persian Gulf.

Gulf imports had been nearly eliminated by 1985, falling to only 0.309 million bbl/d (Table 5.7)—an 87% reduction from their 1977 peak of 2.448 million bbl/d (gross imports, Table 5.4; net imports from the Gulf for that year appear to be immaterially smaller but are shown in Table 5.7 as not available). That 1985 Gulf import level was so low that it could have been entirely eliminated by a further 1-mpg improvement in the efficiency of the U.S. car fleet: the *Transportation Energy Data Book: Edition 20—2000* shows at Table 7.1 that the 127,885,000-car 1985 fleet got 17.43 mpg and drove 9,749 average miles per car, so an 18.43-mpg fleet would have used 0.723 bbl/y less gasoline per car, or 253,348 bbl/d less gasoline in all per EPA ratings, or 220,203 bbl/d less gasoline, or (at the 45.6% motor-gasoline yield typical of 1985 per Table 1.8), 0.483 million bbl/d of crude oil, uncorrected for refinery and shipping inputs and losses. But instead of continuing down to zero in and after 1986, Gulf imports *rose* by 1.4% during 1985–86—chiefly because of the sudden, and deliberate, 1986 collapse of previously steady improvements in light-vehicle efficiency.

To eliminate the 2000 level of Gulf imports, 2.409 million bbl/d (virtually all crude oil—Table 5.3 shows that 5% of total 1999 U.S. oil imports was gasoline, but little of it came from the Gulf), would by the same methodology require a fleet improvement larger than 1 mpg. Using the most recent preliminary EIA data available at this writing (*Monthly Energy Review*, June 2001, Table 2.1), the average passenger car in the U.S. fleet in 1999 drove 11,850 miles at 21.4 mpg. A further 5-mpg improvement would thus save 2.497 bbl/y of gasoline per car. The Federal Highway Administration's August 2000 *Trends and Forecasts of Highway Use* (www.fhwa.dot.gov/policy/hcas/final/two.htm) forecast a 2000 car population (the actual data weren't yet available) of 167.7 million cars, excluding a further 63.3 million light trucks. Making such a car fleet, 5 mpg more efficient than the 1999 fleet would thus save 1.146 million bbl/d of gasoline. EIA's *Petroleum Supply Annual 2000*, Vol. 1, Table 19, reports that U.S. refineries averaged in 2000 a 46.2% yield of finished motor gasoline, so producing 1.146 million bbl/d of gasoline required 2.481 million bbl/d of crude oil, plus refinery and delivery inputs and losses. This amount exceeds U.S. oil imports from the Persian Gulf in 2000.

In August 1988, Carmen Difiglio, K.G. Duleep, & D.L. Greene published a U.S. Department of Energy paper, "Cost Effectiveness of Future Fuel Economy Improvements," that was republished in late 1989 in *The Energy Journal*. It described 15 available, demonstrated technological improvements that could be incorporated into normal car production and "would not reduce performance, ride, or capacity over 1987 levels." (These plus two more such measures, good for an additional ~4.5 mpg, were summarized by M. Ledbetter & M. Ross in "A Supply Curve of Conserved Energy for Automobiles," *Procs. 25th Intersoc. En. Convers. Eng. Conf.*, Reno, 12–17 August 1990, Am. Inst. Ch. Engs., NY.) These 15 measures, if fully used in an average 1987 new car sold in the U.S. (domestic or imported), would collective improve its actual on-road fuel efficiency from 28.3 to 39.4 mpg. The DOE authors subsequently adjusted this downward to ~38 mpg. This improvement is nonetheless twice as large as that required to eliminate Gulf imports. Similar technologies are also applicable, to ~70% the extent and at about half the unit cost, to light trucks, as described by Ledbetter & Ross, Att. B to ICF, *Preliminary Technology Cost Estimates of Measures Available to Reduce U.S. Greenhouse Gas Emissions by 2010*, August 2000 draft report to UESPA. Even the most conservative interpretation of the difference between rated and on-road efficiency would still yield at least 33.7 mpg, more than satisfying the no-Gulf-imports goal. The total marginal cost in 1987 $ was equivalent to buying gasoline at ~$0.53/gallon, about half the current real price, so adopting such measures would decrease the total cost of driving. The technological assumptions are also very conservative with regard to platform physics (mass and drag).

This analysis was partly updated in the National Research Council's 30 July 2001 report *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards*, searchable and downloadable from www.nas.edu. However, the analysis continued a long tradition of component-based incrementalism (*e.g.*, assuming that more efficient vehicles must cost more to make) and of technical conservatism, especially with regard to platform physics. The panel was offered but apparently did not examine information on Hypercars, which overcome these two apparent obstacles.

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above/collapse

for example

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imports

U.S. oil imports

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discouraged energy efficiency

In the 1980s, light-vehicle efficiency standards were rolled back (as described above), appliance standards originally approved by Congress without a single dissenting vote were first pocket-vetoed and then stalled by issuing a standard that there shall be no standard (until the courts demurred), and programs to inform citizens about energy efficiency were stifled. (For example, key public information centers were forbidden to release their phone numbers, and many Government Printing Office publications on saving energy—even a Department of Agriculture yearbook featuring this subject for farmers—were pulped or declared out of print.) Federal R&D for energy efficiency was cut 70%; for renewables, nearly 90%. Most subsidies to fossil and nuclear fuels, totaling tens of billions of dollars per year, were maintained, while smaller subsidies to efficiency and renewables were generally eliminated. Some similar philosophies appear to be reemerging in 2001.

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technological innovation

These issues are described in the November 1997 President's Council of Advisors on Science and Technology *Report to the President on Energy Research and Development for the Challenges of the Twenty-First Century*, www.ostp.gov/Energy/index.html, notably in Chapter 2.

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cut $200 billion

This figure, widely used in the early 1990s, may by now be conservative. EIA's *Monthly Energy Review*, June 2001, Table 1.3, shows that at 1975 levels of primary intensity, producing the 2000 GDP would have required an additional 66 Q of primary energy. At the $4.72/million BTU average consumer cost of primary energy in 1997 (1997 $, from *Annual Energy Review* 1999, Table 3.3), this extra energy, ignoring any tendency of such additional demand to raise its price, would cost over $300 billion. (The average 1997 consumer cost of total energy including electricity was $8.82/million BTU, but most of the productivity gains since 1975 have been in direct fuels, not electricity.) As a reality check, Table 3.4 shows 1997 expenditures of $391 billion for primary energy and $567 billion for total energy, both in 1997 $. An extra 66 Q/y needed in 2000 would have been equivalent to a 70% increase in 1997 primary energy consumption, worth (on a hypothetical *pro rata* basis) some $274 billion. (Obviously a more disaggregated and precise calculation, based on intensities for each energy carrier or source, would be possible, but probably not very illuminating.)

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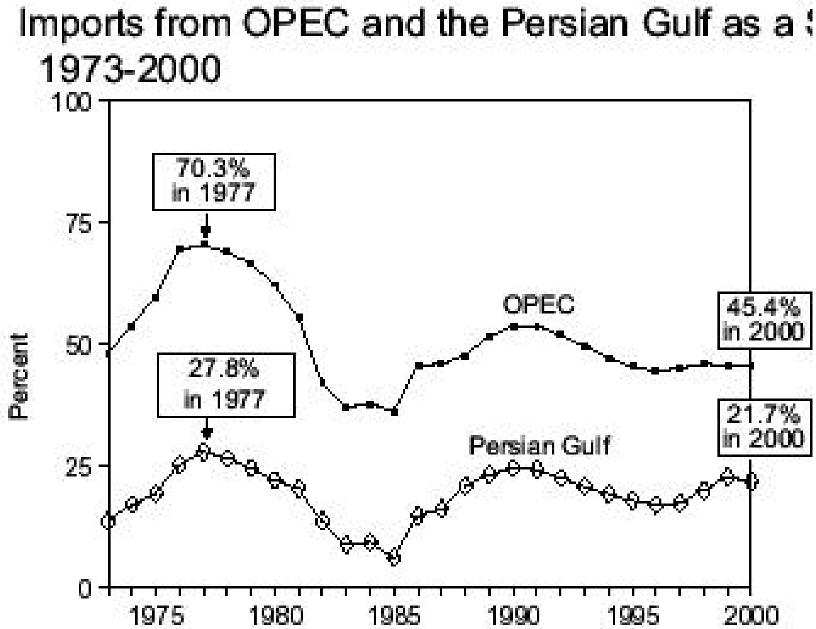
U.S. oil imports

EIA's *Monthly Energy Review*, June 2001, p. 14, presents the following graphic summaries of "Overview of Petroleum Trade":
(see graph on following page)

Imports from OPEC and the Persian Gulf as a Share of Total Imports
1973–2000



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the average car get 32 mpg

For methodology, please see hyperlink to "conserve" in the previous paragraph. Oak Ridge National Laboratory's *Transportation Energy Data Book: Edition 20—2000* shows in Table 7.1 that in 1991, 128.3 million passenger cars averaged 10,586 miles each at 21.12 mpg. Improving them to 32 mpg would have saved 170.4 gal/car-y, or 1.426 million bbl/d of gasoline. At the 45.7% motor gasoline refinery yield of 1991 (Table 1.8), that would require 3.12 million bbl/d of crude oil, excluding refinery and delivery inputs and losses. For comparison, Gulf imports in 1991 averaged 1.833 million bbl/d (*Annual Energy Review 1999*, Table 5.7).

The 32-mpg figure in the article is thus quite conservative if taken literally. The sense intended, however, is that as new vehicles at 32 mpg worked their way into the fleet, they would more than offset growing Gulf imports. The "conserve" hyperlink cited above shows that a 26.4-mpg rather than the actual 21.4-mpg car fleet in 1999, for example (with no improvements in light trucks), could have more than eliminated U.S. oil imports from the Persian Gulf in 2000. A 32-mpg figure leaves an ample safety margin for a fleet many years into the future with a considerably larger U.S. population and GDP.

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deployed tanks

For numerous opportunities to save the Defense Department much if not most of its fuel and money while improving its warfighting capability, and a penetrating analysis of why that hadn't already been done, see Defense Science Board, *More Capable Warfighting Through Reduced Fuel Burden*, May 2001, Office of the Under Secretary of Defense for Acquisition and Technology, Washington DC 20301-3140. (One of us [ABL] was a member of the Task Force that wrote that report.) Rocky Mountain Institute has elaborated the Naval portion of its conclusions in a June 2001 report to the Office of Naval Research, mentioned on p. 53n of the DSB report: *Energy Efficiency Survey Aboard* USS Princeton *CG-59.*

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cost the United States

The Gulf War directly cost the United States in purely financial terms a sum on the order of $61 billion gross and $7 billion net (after financial contributions by Gulf States and allies), according to data from Appendix P of the 1992 DOD report to Congress, *Conduct of the Persian Gulf War.* The data are conveniently summarized at http://comp9.psych.cornell.edu/Horan/gulf/GW_cost/GW_payments.html. RMI Publication #S90-26, cited next, documents at n. 29 estimates of the peacetime cost of U.S. forces whose primary mission is to intervene in the Gulf, and how these can raise the effective U.S. cost of Gulf oil to $100+/bbl. Consistent with those estimates, ORNL's *Transportation Energy Data Book: Edition 20–2000*, Table 1.6, presents Gulf-related U.S. military costs mainly in the tens of billions of 1996 dollars per year.

In 1986–87, one of us (ABL) prepared for Royal Dutch/Shell Group a supply curve of the technical potential to save U.S. oil. It was published in the annotated version (RMI Publication #S90-26) of "Make Fuel Efficiency Our Gulf Strategy" (published without annotation as a *New York Times* op-ed 3 December 1990), and documented in the authors' "Drill Rigs and Battleships Are the Answer! (But What Was the Question?," pp. 83–138 in Reed & Fesharaki, eds., *The Oil Market in the 1990s: Challenges for a New Era*, Westview (Boulder), 1989, RMI Publication #S91-15. The supply curve shows that ~80% of 1986 U.S. oil consumption, or ~13 million bbl/d, could have been saved in 1986 by full application of then-proven technologies whose average cost was ~$2.5/bbl saved and which delivered unchanged or superior services. Since that analysis, each of its elements has turned out to be conservative, both understating quantity and overstating cost of the savings achievable with more modern technologies.

Assuming that the average oil-saving measure lasts 20 years, and using the assumed 5%/y real discount rate, the $2.5/bbl (1986 $) or $3.3/bbl (1996 $) average levelized cost of the ~80% oil-saving potential shown by RMI in the late 1980s implies an up-front *average* cost of $31.15/bbl-y (1986 $) or $41.4/bbl-y (1996 $). Investing $7 billion (1991 $) or $7.8 billion (1996 $) at the *average* cost of those enormous savings could thus buy savings equivalent to 516,000 bbl/d, equivalent to 28% of the 1991 Gulf imports of 1.833 million bbl/d. However, in practice it would make more sense to buy the cheapest savings first, not those of average cost over the entire quantity of potential savings, which is seven times larger than 1991 Gulf imports. Inspection of the supply curve shows that this quantity, equivalent to 11% of 1986 U.S. oil consumption, could be saved at an average cost considerably less than zero. That is because both oil and gas used to make electricity (the saved gas then being fungible for oil usable in industry and space-heating) could be saved at a negative net cost, on the order of –$8/bbl, just through lighting retrofits that themselves have a negative cost, because their technologies and installation are more than repaid by saved maintenance cost before they even start saving electricity. (Details are exhaustively provided in A.B. Lovins *et al.*, *The State of the Art: Lighting*, RMI / COMPETITEK, 1989.) Nowadays, less oil but more gas is used to make U.S. electricity, electrical efficiency potential is even larger and cheaper, and this conclusion therefore remains conservative.

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Supply curve

documented below

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(footnotes for page 78)

oil imports had rebounded

Net oil imports were 8.565 million bbl/d in 1977, and have exceeded that level in each year starting in 1997 (Table 5.7, *Annual Energy Review 1999*). In 2000, they reached 10.419 million bbl/d (Table 3.3b, *Monthly Energy Review*, June 2001).

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oil prices spiked

The causes were complex, and included: a global shortage of refinery capacity suited to light, sweet crudes; self-fulfilling predictions and behavior by oil-industry executives in the refining sector; and perhaps most importantly, an industry-government consensus that everyone is better off with oil prices in the mid-$20s range than in the mid-teens range (I.C. Bupp, personal communication, 4 January 2001).

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chairing

At the time of writing the article, Senator Ted Stevens (R-AK) chaired the Senate Appropriations Committee and served on the Rules and Commerce Committees; Senator Frank Murkowski (R-AK) chaired the Senate Energy and Natural Resources Committee and was a member of the Senate Finance Committee; and Rep. Don Young (R-AK) chaired the House Resources Committee. The two Senators' Chairmanships subsequently became Ranking Minority Memberships when the Democrats took control of the Senate. Rep. Young has now switched to chairing the House's Transportation and Infrastructure Committee.

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President George W. Bush claimed

At the National Press Club, 1 November 2000, Senator Frank Murkowski (R-AK) stated: "Just the intention of reducing our dependence on imports by initiating exploration in the Arctic National Wildlife Refuge, in my opinion, the psychological impact, would be to lower the price of oil by $10 a barrel." He pointed out that the oil price dropped $4 a barrel when President Clinton ordered 30 million barrels of crude to be released the previous month from the Strategic Petroleum Reserve (C. Doering, "US senator says Alaskan drilling will cut oil price," Reuters, 2 November 2000).

His view was promptly rebutted by many oil experts (and by the Cato Institute) on the obvious grounds that oil markets are global and are dominated by supply decisions of the largest suppliers, such as Saudi Arabia, not by relatively small and marginal resources.

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electricity comes from oil

The California Energy Commission (www.energy.ca.gov/electricity/electricity_gen_1990-1999.html) shows 55 TWh of in-state oil-fired generation, all by utilities, in 1999, the most recent year shown—0.02% of total generation. It was somewhat higher in the previous two years, averaging 0.022%. It last approached 1% in 1993–94. The state's utilities sold their oil- or dual oil-/gas-fired capacity in the late 1990s, generally removing the oil-fueling capability first. The article stated 1% as a conservatism because the sources of the northwest and southwest imports (which totaled 17.9% of 1999 generation) are not specifically known. However, virtually all the imports appear to be hydropower, probably nuclear (Palo Verde), some gas, and probably some short-term coal (according to www.energy.ca.gov/electricity/gross_system_power.html, out-of-state coal power from California-owned plants or those under long-term contracts are classified as coal, not imports).

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oil is consumed

Table 7.2 of EIA's *Monthly Energy Review*, June 2001, shows that 2.9% of U.S. total electric generation was oil-fired in 2000, down from 3.3% in 1999. Table 7.6 shows that the liquid oil input for this purpose totaled 172.769 million bbl, broadly defined to include liquid propane or butane, methanol, kerosene, crude oil, oil waste, sludge oil, and tar oil as well as fuel oils and distillates. (An additional 4.255 million short tons of petroleum coke was used to generate electricity; it acts like coal and isn't normally thought of as oil, even though it's a byproduct of petroleum refining.) That broadly defined liquid oil and LPG use, equivalent to 472,046 bbl/d, was 2.4% of the 19.701 Mbbl/d of petroleum products supplied in 2000 (Table 7.1a).

There is a possible caveat. Although the data above appear to reflect nonutility as well as utility use, EIA's *Annual Energy Review 1999*, Diagram 5, shows a higher oil-fired electricity fraction for 1999 (the corresponding diagram for 2000 has not yet been published). For 1999, nonutility producers are shown as using 0.37 Q of petroleum to make electricity, while utilities used 0.97 Q. These totaled 1.34 Q, or 3.6% of the total petroleum consumption of 37.706 Q (Table 1.3). For comparison, for 1999, Table 7.6 of the June 2001 *Monthly Energy Review* shows electric generation as consuming 195.971 million liquid bbl, or the equivalent of 218.049 including 4.416 million short tons of petroleum coke counted at its liquid energy equivalent. The higher of these figures would be 3.1% of the 19.519 Mbbl/d of petroleum product supplied in 1999. The difference between this figure and 3.6% is of unknown origin.

In any event, it is important to note that oil consumption to generate electricity is dominated by heavy oil. Much of this is residual oil, an otherwise useless byproduct of refining that is practically never made for its own sake and hence cannot drive marginal demand for crude oil, domestic or imported.

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reject the notion

Vice President Dick Cheney's two main initial speeches on national energy policy both declared his opposition to "doing more with less" while stating his support for energy efficiency through better technologies. The first time, *The New York Times* reported as follows (J. Kahn, "Cheney Promotes Increasing Supply as Energy Policy," 30 April 2001):

> Mr. Cheney indicated that the administration would put some emphasis on energy efficiency. New technology—like computer screens that use far less power and energy-efficient light bulbs—have an important role because they can save energy without reducing living standards, he said. But he said he would oppose any measure based on the premise that Americans now "live too well" or that people should "do more with less."

"The aim here is efficiency, not austerity," he said. "Conservation may be a sign of personal virtue, but it is not a sufficient basis for a sound, comprehensive energy policy."

The second paragraph seems self-evident, the first self-contradictory. This mystery was never publicly resolved, but only deepened when the Vice President repeated the same statement a day or two later, reversing the impression of many readers that the first speech must have been misreported.

Roughly one-third of Americans, according to most polls, interpret the word “conservation” as meaning doing less to use less—*i.e.*, as privation, curtailment, or discomfort incurred (voluntarily or not) when shortages make reduced use necessary. Rocky Mountain Institute avoids the ambiguous term “conservation” and says what it endorses, namely “efficiency” or “improved energy productivity,” to indicate getting the same (or, often, more or better) services from less energy by using less money and more brains.

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halved key budgets

The Bush Administration’s initial FY2002 budget request for the Department of Energy cut energy efficiency R&D by $180 million, or 29%. Some key areas, such as energy-efficient building technologies and industrial processes, would be cut by nearly 50%. The only significant energy efficiency increase would be an extra $120 million for low-income weatherization, which develops no innovations and is best regarded as a social program that in most countries would fall under a budget like HUD’s.

Even a 10–20% budget cut is devastating to efficiency RD&D programs that were already cut to the bone, and beyond, in the 1980s and 1990s (see PCAST’s 1997 report cited earlier). Most of the budget is needed simply to keep organizations together and functioning; seemingly small reductions in their flexible funding on the margin eliminate their room to innovate. Budget cuts also tend to make the best people leave rather than spending their time fighting for their fiscal lives. It typically takes a decade or more to rebuild such groups afterwards.

Some of the initial cuts have since been at least partly restored under intense political pressure. Further restorations may come from Congress—a common pattern for the past few decades, but one that destroys sensible program planning by making budgets unstable and unpredictable until it’s too late to act effectively on whatever the final numbers turn out to be.

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air-conditioner standards

The outgoing Clinton Administration announced on 18 January 2001 that, after years of research, analysis, and negotiations, the Congressionally mandated minimum efficiency standard for new central air conditioners would be raised by 30% starting in 2006. The Bush Administration suspended publication of the implementing regulation and later rolled back the increase to 20%. The difference represents a coincident peak load of 12,900 megawatts—one-third of the 138 300-MW power plants whose construction the 30% improvement would have avoided. (Analysis by Alliance to Save Energy, Washington, DC, based on USDOE data.)

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economics dubious

The previous major push to allow drilling in the Refuge was by the U.S. Department of the Interior around 1987, summarized mainly in a Draft Environmental Impact Statement. Interior’s analysis assumed tax breaks that no longer existed (they’d been repealed in 1986: W.T. Goerold, “A Simulation Model to Determine the Probability of Finding Economically Producible Petroleum in the Arctic National Wildlife Refuge (ANWR), Alaska,” *En. J. / Procs. Intl. Assn. En. Ecs.–N. Amer.* 386–397, Houston, 31 Oct. – 2 Nov. 1988).

DOI also assumed oil prices nearly twice actual ones (they assumed $61/bbl in 1986 $ in 2010). And DOI assumed twice the likelihood of finding twice the oil that the State of Alaska’s geologist forecast from fuller data. (W.T. Goerold, “Environmental and Petroleum Resource Conflicts: A Simulation Model to Determine the Benefits of Petroleum Production in the Arctic National Wildlife Refuge, Alaska,” *Materials and Society* **11**(3):279–307 (1987), at 287. Alaska’s state geologist, who had the benefit of State-lands survey data unavailable to the Federal government, estimated one-sixtieth as much oil at 95% finding probability. Interior had his findings but didn’t mention them. Interior never published its computer model or its assumptions, nor permitted independent review of either.)

The results were presented in an unusual “conditional” form expressing the probability of finding various amounts of oil *if* any economically recoverable oil (at the assumed very high prices) were found at all. This conditionality was hidden in the fine print and wasn’t even mentioned in the DEIS’s Executive Summary, so most observers missed it. However, all the odds were actually $5^{1}/_{4}\times$ less favorable than stated, because they had to be “risked”—multiplied by 0.19 to correct them for the inconspicuously stated 81% probability of finding no economically recoverable oil. Thus the *risked* mean oil claimed to be findable was not 3.23 billion barrels as claimed (a 6-month national supply) but only 0.21 billion barrels (a 13-day supply). At realistic oil prices, these probabilities dwindle to zero, as noted below.

Despite its generous handicapping, Interior found the *risked* odds were 5:1 against finding *any* economically recoverable oil, 15:1 against finding as much as six months’ national supply (enough to cut today’s imports by a few percent for a decade or two), and over 100:1 against another supergiant Prudhoe Bay oilfield.

Independent analysts using realistic assumptions about both oil price and tax law (*e.g.*, Goerold 1998, *op. cit.* and the U.S. General Accounting Office’s 1993 review of the 1991 BLM study, GAO/RCED-93-130—see USGS 1998 at p. AO-20) later found, in effect, that the mean expected reserves would be closer to six *days*, because DOI had overstated the finding probability by up to fivefold and assumed unrealistically high oil prices, and the producers could well lose money (Goerold 1987, *op. cit.*, at p. 298; A.B. Lovins, 16 April 1988 invited comments to Chairman G.E. Studds, Subcommittee on Fisheries & Wildlife Conservation & the Environment, Committee on Merchant Marine and Fisheries, USHR).

Interior claimed a net-present-valued benefit of $14.6 billion from Refuge drilling. This figure reflected all the methodological errors noted above, and hence was grossly in error. But even if it were accurate, it would represent a risked benefit of about one or two thousandths of one percent of U.S. energy bills during Refuge exploitation—hardly important. Interior's DEIS also relied on a USDOE energy forecasting model, but Interior neglected to mention that the same model had a case analyzing modest gains in energy efficiency—enough to displace the projected Refuge oil output 2.5 times over if unrisked or 38 times if risked. (The USGS 1998 assessment is, as it should be, fully risked, not conditional.)

The one fact unchanged since 1987 as each of the drilling advocates' rationales evaporated, starting with their claims of an economic bonanza, is that—as even Interior's DEIS delicately agreed in 1987—the Refuge's most critical habitat, modest in area but irreplaceable in biology, would be trashed. (The DEIS foresaw "inevitable...long=term losses" and "widespread, long-term changers" in fish and wildlife resources and in wilderness values, and predicted that "Industrial development could profoundly affect the Native culture.") In 2001, the Bush Administration, in contrast, was claiming little or no material environmental harm need result, but this did not reflect a formal environmental assessment process based on scientific evidence, and at least as publicly presented, appeared to rest on assumptions clearly at odds with USGS's findings (*e.g.*, about the relative dispersion of any oil deposits likely to be found).

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$22 per barrel

Rounded to the nearest dollar (the exact value, though its apparent precision is spurious, is $21.56) and expressed in the fourth-quarter 2000 (4Q2000) constant dollars used throughout this article (except as noted), converted from the USGS's convention of 1996 dollars using the conventional broad measure of monetary inflation—the GDP Implicit Price Deflator published by the U.S. Department of Commerce.

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Implicit Price Deflator

2000 dollars (fourth quarter)

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destinations

USGS (1998, p. EA-15) assumed that Refuge oil would cost (converting to 4Q2000 $) $2.93/bbl to transport through TAPS and $1.86/bbl to haul by marine tanker to West Coast ports—a total of $4.79. (For comparison, in roughly equivalent Alaskan FY2000 $, the actual costs in 2000 were $2.74 and $1.60 respectively, according to p. 22 of the Alaska Department of Revenue's *Spring 2001 Revenue Sources Book*.) Transportation costs from wellhead to TAPS are also estimated and included by USGS, but vary by location and field size, so they are not so easily expressed; for example, Table EA-B1 shows that transportation costs from a 600-Mbbl field to TAPS would be about $1.20/bbl from the western or $1.79/bbl from the eastern subarea. Since 84% of the technically recoverable oil and probably a larger fraction of the economically recoverable oil (perhaps nearly all of it) is in the undeformed (western) area, ~$1.30/bbl, the average weighted by technically recoverable resource, may be a reasonable estimate of delivery cost to TAPS. This would imply a total wellhead-to-West-Coast transportation cost of about $6.09/bbl. Methodologically, USGS assumed (*id.*) that wellhead cost must equal West Coast ANS (Alaska North Slope) oil price minus all transportation costs from the wellhead in order for the oil to be saleable at a profit.

Historically, such costs have fluctuated considerably. The Alaska Department of Revenue's *Spring 2001 Revenue Sources Book*, App. D, www.tax.state.ak.us/sourcesbook/sources.htm, shows that the difference between ANS West Coast and ANS Wellhead, reflecting all transportation costs in between, was $4.91 in "real 2001 $" (probably FY2001, i.e., essentially equal to 4Q2000 $ using the calendar year). In the same terms, during the twelve years [FY] 1990–2001, this quantity ranged from $4.20 to $8.11/bbl with a mean of $5.70 and a standard deviation of $1.22. The Department projects (*id.*) transportation costs, in the same terms, to be flat from [FY] 2006, averaging $4.45/bbl. (The projection includes an abrupt 34% drop to $3.23/bbl in [FY] 2004, rebounding 38% the next year; this is probably an error.)

The roughly $6/bbl wellhead-to-West-Coast transportation cost assumed by USGS appears broadly reasonable in comparison with the 1990s average of $5.70 from TAPS entry to West Coast, bearing in mind that the cost of delivery from existing fields around Prudhoe Bay to TAPS is far lower (it was only $0.11 in 2000) than it would be from new Refuge fields, saving more than a dollar of the latter's roughly $1.30 delivery cost to TAPS. However, major maintenance investments in TAPS could sharply raise its carriage tariff above historic levels. So could other major investments in the supply system, such as upgrading most of the tankers that carry Valdez oil southward from single to double hulls; Phillips Petroleum and BP have lately ordered double-hulled tankers, but Exxon still has not, and this slow shift could be accelerated by any further mishap.

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4Q2000 $

2000 dollars (fourth quarter)

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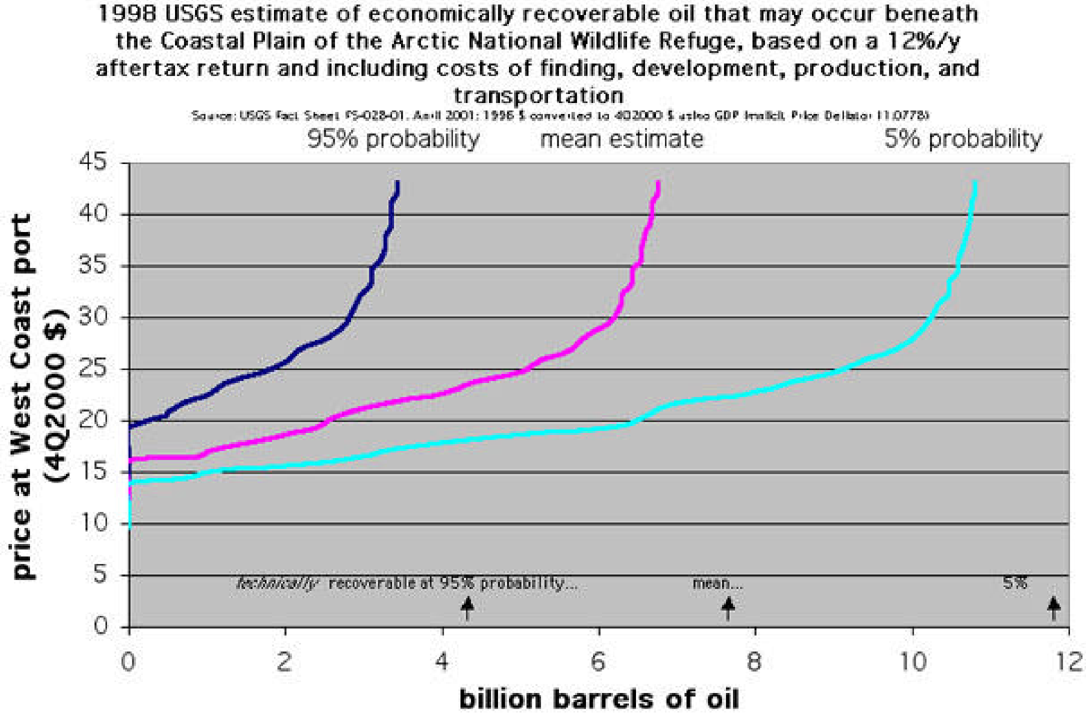
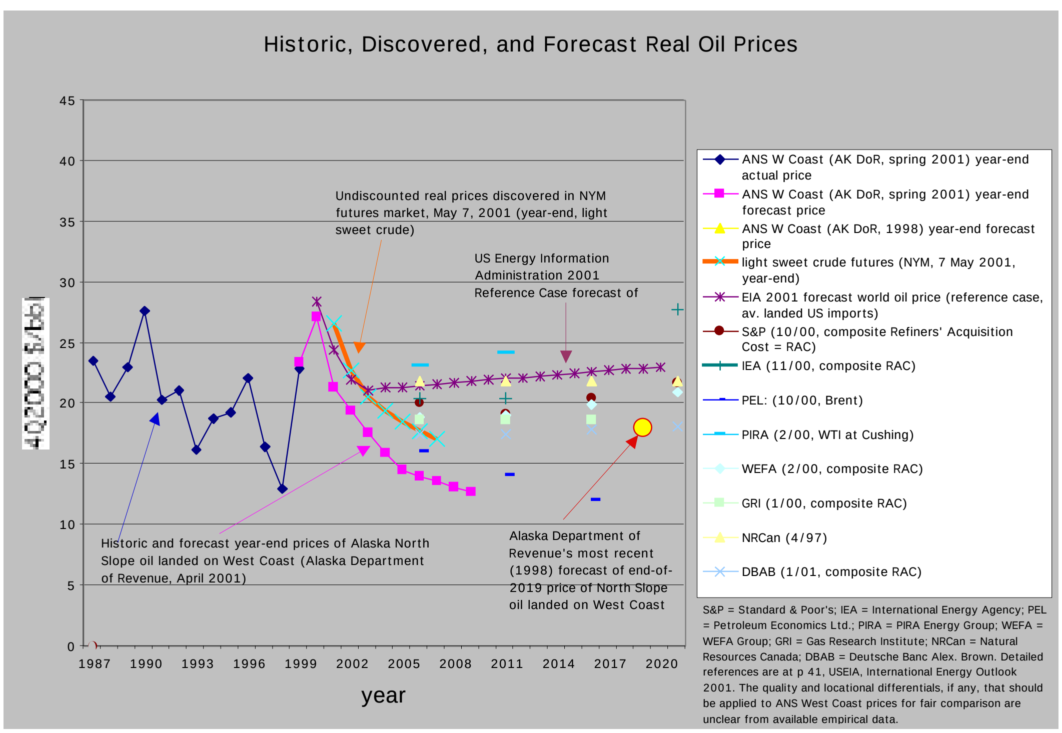
range of projections

The USGS (1998) estimates are expressed not as single point estimates but, properly, as the following curves relating economically recoverable oil to price at three finding probabilities—5% and 95%, with a mean estimate in between (detailed data kindly provided by report's authors for our re-graphing, converting from 1996 $ to 4Q2000 $, using the GDP Implicit Price Deflator):



For comparison, the relevant oil-price historical data and projections discussed below, plotted on the same vertical scale, are as follows (*NB:* such crudes as Brent and West Texas Intermediate are considerably sweeter (lower-sulfur) than Alaska North Slope crudes, hence command a higher price; this accounts for most of the difference between the futures-market prices and the Alaska Dept. of Revenue projections shown). As University of Alaska economics professor, oil-industry consultant, and former Senate Energy Committee chief economist Arlon Tussing remarks (*Oil & Gas J.*, 5 July 1999), "we are not aware of any mainstream forecasting authorities that now anticipate long-term delivered prices for ANS crude oil greater than $15 [in 1996 $]. Taken at face value, the USGS assessment implies only a small probability that any crude oil resources at all will be developed, or produced from or immediately offshore of the ANWR 1002 Area."



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4Q2000 $

2000 dollars (fourth quarter)

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2000 dollars (fourth quarter)

This article corrects for inflation using the GDP Implicit Price Deflator, the conventional and broadest measure of monetary inflation. The USGS 1998 study expresses all its costs in constant 1996 dollars (p. EA-13); we interpret that to mean, as economists would mean, mid-1996 dollars, although the costs assumed in the report are those of January 1996. (The difference is an immaterial 0.6%.) The GDP Implicit Price Deflator is shown in many places in the Bureau of Economic Analysis / U.S. Department of Commerce website, including a query form at http://www.bea.doc.gov/bea/dn/nipaweb/TableViewFixed.asp. Using the conventional metric of chained 1996 $, the deflator values relevant to this article, revised to 27 July 2001, include:

1977 dollars	0.4502
1986 dollars	0.7531
1987 dollars	0.7758
1990 dollars	0.8651
1Q96 dollars	0.9939
1996 dollars	1.0000 (by definition)
1997 dollars	1.0195
1998 dollars	1.0320
1999 dollars	1.0465
2000 dollars	1.0704
4Q2000 dollars	1.0778
2Q2001 dollars (prelim.)	1.0926

Thus to convert from 1996 dollars to the 4Q2000 dollars used throughout this article (unless otherwise noted), multiply by 1.0778. To convert from 1977 dollars to 1996 dollars, divide by 0.4502.

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Alaskan oil

Historic and projected prices are given in the Alaska Department of Revenue's *Spring 2001 Revenue Sources Book*, www.tax.state.ak.us/sourcesbook/sources.htm, both in real and nominal dollars (App. D). The years referred to in its statistics are generally Alaskan Fiscal Years, which start on 1 July of the previous calendar year.

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Alaska's Department of Revenue forecast

Alaska's forecasters agree

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4Q2000 $

2000 dollars (fourth quarter)

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forecast for 2020

In the 1998 *Revenue Sources Book* (converted to 4Q2000 $ using the GDP Implicit Price Deflator); no forecast beyond the next decade has been issued since 1998.

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U.S. Department of Energy predicts

U.S. Energy Information Administration, *Annual Energy Outlook 2001*, Reference Case, converted to 4Q2000 $ per barrel, using the GDP Implicit Price Deflator, shows a world oil price, defined as average refiner acquisition price for imported crude oil, as follows:

	2005	2010	2015	2020
Reference	$21.45	$22.01	$22.54	$23.08

In addition, EIA presents two other cases:

Low	$15.55	$15.55	$15.55
High	$27.46	$29.07	$29.27

which are stated (p. 58) to be "based on alternative assumptions about oil production levels in OPEC nations: higher production in the low price case and lower production in the high price case." The differences between these cases do *not* depend significantly on assumed differences in U.S. energy policy (and hence are of little use in understanding the consequences of that policy). For example, Table F4 shows the following projections for the light-vehicle fleet's on-the-road efficiency, *vs.* 20.5 mpg in 1999:

Low	20.4	20.3	20.1
Reference	20.9	21.2	21.5
High	22.3	23.7	25.1

These modest improvements reflect the gradual, unaccelerated adoption of the following new-vehicle average efficiencies: for new cars, essentially a frozen 2001 efficiency (vs. 27.9 in 1999) in the Low case and so-called "High Technology" in the High case:

Low	29.6	29.6	29.7
Reference	32.3	32.4	32.5
High	36.3	38.0	39.2

and for new light trucks, *vs.* 20.8 in 1999:

Low	22.0	22.1	22.1
Reference	23.2	24.0	24.7
High	28.4	30.3	31.5

For comparison, the equivalent on-the-road efficiency for the 2001 Toyota *Prius* (the same size as the *Corolla*, one of the most popular cars in U.S. sales) is 42 mpg (conservatively dividing its 48-mpg EPA rating by 1.15 as is normal for Otto-engine nonhybrid cars but probably unnecessary for hybrid-electric cars). The simulated efficiency of the Hypercar, Inc. (www.hypercar.com) November 2000 *Revolution* concept car, which is equivalent or superior to the best-selling SUV and could be in volume production around 2005–06, is 99 mpg-equivalent before further design improvements, although in fact it is powered by a hydrogen fuel cell and hence consumes no gasoline.

Comparisons between average refiner acquisition cost and other projections require consideration of different sulfur content and, in some cases, different delivery location. Historic comparisons are complicated by the difference between Alaskan fiscal years and calendar years, but it appears that during the 1990s, the Alaska North Slope Real First Purchase Price has averaged about $0.53/bbl higher (in 4Q2000 $) than the average real refiner acquisition cost for crude oil imported to the U.S. (data respectively from Alaska Department of Revenue, *Spring 2001 Revenue Sources Book*, www.tax.state.ak.us/sourcesbook/sources.htm, App. D, and EIA, *Annual Energy Review 1999*, Table 5.19).

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Revolution

Hypercar[SM]

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Comparisons

range of projections

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projections

industry forecasts are lower

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sulfur

The market value and price of crude oil depends on its sulfur content: sweeter (lower-sulfur) crudes are worth more because they require less desulfurization at the refinery to yield the low-sulfur products that most markets demand and many require by law. App. D of the Alaska Department of Revenue's *April 2001 Revenue Sources Book* shows that Alaska North Slope (ANS) crude's West Coast price was below that of the similarly sour West Texas Intermediate, the standard U.S. marker crude, by the following differentials (years shown are Alaska Fiscal Years starting the previous July):

1988	–3.61 $/bbl
1989	–3.35
1990	–3.90
1991	–4.43
1992	–5.07
1993	–3.47
1994	–3.11
1995	–2.04
1996	–1.62
1997	–1.78
1998	–3.92
1999	–1.42
2000	–1.58

for a mean of –2.25 and a standard deviation of 1.73, but with an apparent downward trend. R.A. Fineberg's 20 June 2001 analysis "Understanding the U.S. Geological Survey Analysis of Estimated Oil Beneath the Coastal Plain of the Arctic National Wildlife Refuge" (Research Associates, PO Box 416, Ester AK 99725, prepared for Alaska Wilderness League) notes at pp. 13–14:

> The differential widened to over $5.00 per barrel during the winter of 2000–2001, then returned to normal levels. Some analysts have suggested that the forecast price necessary to achieve a given result should be increased to reflect this differential. USGS, on the other hand, believes this adjustment is not necessary because the ANS discount results from a quality differential that its geologists say is unlikely to exist in the case of Arctic Refuge discoveries.
>
> Today almost all ANS is sold into the West Coast market. When it was marketed on both coasts, it was likely to sell for more on the Gulf Coast than on the West Coast. This fact indicates that part (if not all)of the ANS/WTI differential may be related to factors other than quality, including transportation costs and the nature of the transactions by which much ANS is marketed [i.e. often under long-term contracts]. Additionally, at times in the past the shutdown of West Coast refineries that normally use ANS has discernibly depressed the price of ANS relative to other crude oils because ANS temporarily diverted from those refineries must then compete with other oil on the market....On the other hand, arguing against assigning a differential to ANS is the fact that over the past decade a basket of OPEC crude oils has been priced at [a] discount to WTI similar to that of ANS.
>
> This discussion indicates that it would be appropriate in future economic analyses of potential North Slope developments to consider the possibility of reducing the value of potential ANS. However, the limited data reportedly publicly on spot and contract market prices do not provide a clear indication as to whether—or by how much—the forecast prices necessary to sustain future North Slope development need be increased to account for an ANS differential.

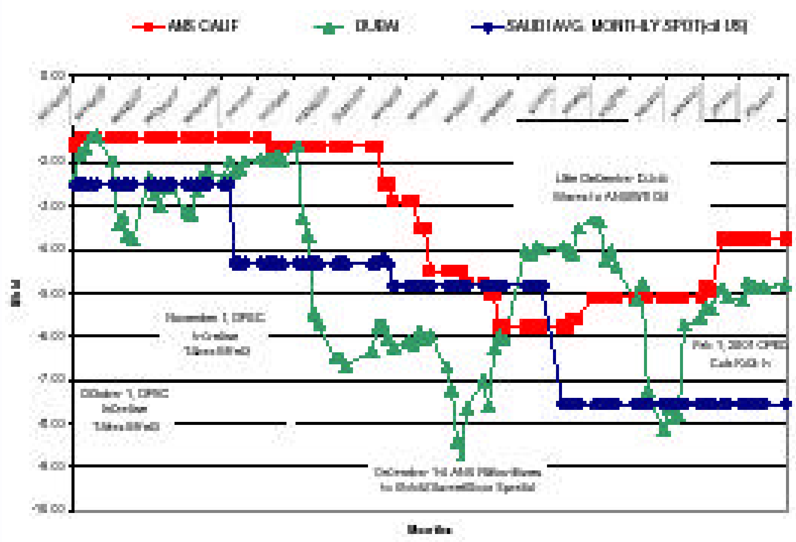
Fineberg concludes that applying an ANS differential to the EIA long-term price forecast would probably leave it above the USGS threshold for finding Refuge oil, though in lower amounts. This question doesn't arise when using the Alaska Department of Revenue's oil-price forecasts, which are specifically for ANS. The Department's April 2001 forecast of ANS discount to WTI, in the same terms as above, is:

2001	–2.65
2002	–2.54
2003	–2.25
2004	–2.23
2005	–2.15
2006	–2.09
2007	–2.02
2008	–1.96
2009	–1.90
2010	–1.84

This is consistent with the Department's short-term analysis (p. 21):

Alaska North Slope. ANS West Coast prices came tumbling down in December. Interestingly, roughly $4 per barrel of the drop from an average of $32.75 per barrel in November to an average of $23.75 per barrel in December was the result of a widening of the ANS differential to West Texas Intermediate (WTI). WTI is the key price marking crude oil in the United States. WTI is traded every day – both in cash markets and in the New York Mercantile Exchange paper market. The following chart demonstrates that several important globally traded prices, marking sour crude oils similar to ANS, also experienced this relative loss in value during the period from November through December. In the case of ANS, the differential to WTI averaged roughly $1.50 per barrel in November and widened to $5.76 per barrel in late December.

Figure 8. World Crude Oil Differentials to WTI



Although there are a number of reasons mentioned for the widening spread, basically it reflected a surge of sour heavier crude oils from OPEC into the market and into a refining system that was not easily able to process them for the fuels demanded. Currently the ANS differential to WTI is running between $1.65 and $2.50 per barrel. Since OPEC is planning on production cuts of mostly ANS-quality oil, we expect the differential to remain around this level.

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industry forecasts are lower

EIA, *Annual Energy Outlook 2001*, p. 102, Table 20, shows that the Low and High cases of the IEA forecast span six of the eight other mainstream forecasts cited (the exceptions are IEA on the high side and PEL on the low side). IEA's reference case for 2010 is the highest of all nine forecasts but one (PIRA); for 2010, the highest of all six but one (IEA). Converted to 4Q2000 $, the comparisons are:

	2005	2010	2015	2020
EIA Ann. En. Outlook 2001				
Ref	21.45	22.01	22.54	23.08
Low	15.55	15.55	15.55	15.55
High	26.82	27.46	29.07	29.27
S&P 10/00	20.05	19.21	20.46	21.79
IEA 11/00	20.42	20.42		27.85
PEL 2/00	16.10	14.18	12.10	
PIRA 10/00	23.23	24.29		
WEFA 2/00	18.94	19.03	20.00	21.02
GRI 1/00	18.71	18.71	18.71	
NRCan (4/97)	21.88	21.88	21.88	21.88
DBAB (1/01)	17.59	17.49	17.86	18.21

The comparative forecasts are graphed elsewhere, and compared graphically with the USGS 1998 finding that finding any economically recoverable oil in the Refuge probably requires sustained prices higher than most of these forecasts. The full references are given by EIA, *loc. cit.* The EIA, S&P, GRI, WEFA, and DABA projections are for refiner acquisition prices; PEL for Brent crude, which is sweeter than Alaska North Slope oil; and PIRA for West Texas Intermediate (WTI) crude at Cushing, which is roughly comparable to ANS in sulfur content.

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4Q2000 $

2000 dollars (fourth quarter)

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elsewhere

range of projections

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sweeter

sulfer

<back to article>

futures market

Futures markets enable one to buy oil today, at a price that is currently known, for delivery at a specific future date. Such newspapers as *The Wall Street Journal* publish daily the market price for West Texas Intermediate purchases roughly seven years from now. Private market-makers go further out—in some cases reportedly for about 20 years—though those markets are less deep and far less transparent.

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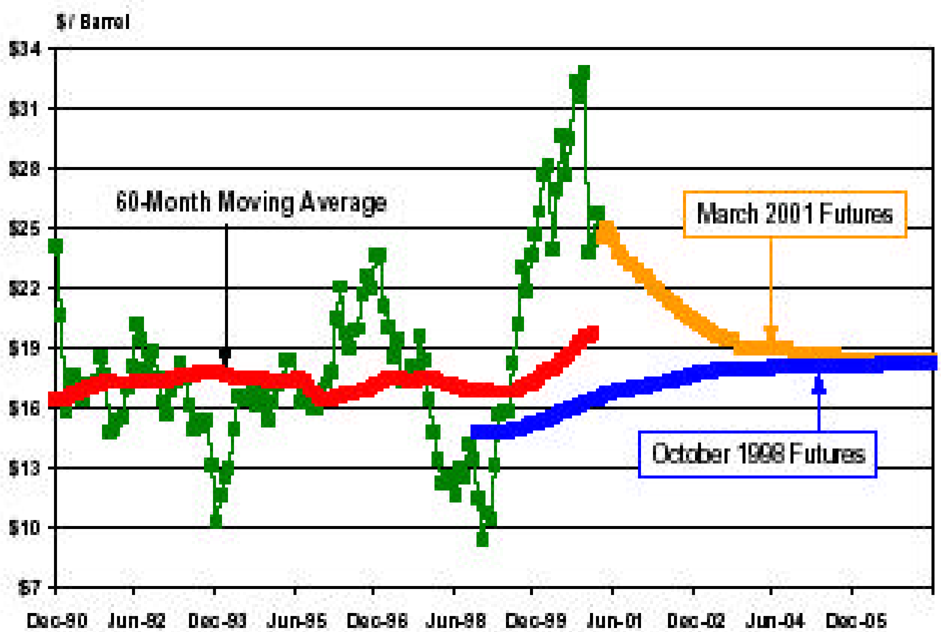
Alaska's forecasters agree

Alaska Department of Revenue (Tax Division), *Spring 2001 Revenue Sources Book,* App. D, www.tax.state.ak.us/sourcesbook/sources.htm, converted to 4Q2000 dollars using the GDP Implicit Price Deflator. (The July 2001 update was virtually identical.) Note that the more commonly quoted forecasts on p. 9 are in current dollars not corrected for inflation, which is generally assumed by the Department to be 3.25% per year compounded.

Page 10 of the same source contains the following convincing demonstration that short-term market fluctuations have little effect on long-term price prospects as discovered in the oil futures market:

> The figure below clearly illustrates the volatility of month-to-month crude oil prices. ANS West Coast prices during the pertinent time period ranged from just under $10 per barrel to over $32 per barrel. The average of the 60-month moving averages shown in the figure below is $17.30 per barrel. Finally, the derived futures market prices reflected below show that participants in that market anticipate a continuation of the post-1986 historic levels for oil prices. The derived futures price for ANS demonstrates a convergence tendency after three years whether the current price is very low (as it was in October 1998) or very high (as it was in March 2001).

Figure 2. ANS West Coast and Futures Market Oil Prices



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stays under

Specifically (App. D), in "real 2001 $" that are virtually identical to 4Q2000 $ (because they're for the Alaskan Fiscal Year from July 2000 through June 2001), $16.24 for FY2005 (*i.e.*, 7/04–6/05); $14.74 for FY2006; $14.28 for FY2007; $13.83 for FY2008; $13.39 for FY2009; and $12.97 for FY2010. These are lower than the commonly quoted forecast prices on p. 22 ($17.30/bbl for FY2006–2010) because those are in current dollars uncorrected for inflation, rather than in constant FY2001 dollars adjusted for inflation.

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that price

That is, $16/bbl in 4Q2004 dollars. (The authors sought unsuccessfully, due to the late stage of proof corrections, to move the preceding parenthesis up to the end of the preceding paragraph where it logically belonged.)

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no economically recoverable oil

This is for the mean expectation in the USGS 1998 graph (Fig. AO20); its numerical value is $15.30/bbl in 1996 $ or $16.49/bbl in 4Q2000 $. This corresponds to an economically recoverable quantity of 0.795 billion bbl. To achieve 95% finding probability would require $18.9/bbl (1996 $) or $20.4/bbl (4Q2000 $) and correspond to a quantity of 0.437 billion bbl; alternatively, at a 5%

finding probability, the threshold price might drop to \$13.4/bbl (1996 \$) or \$14.4/bbl (4Q2004 \$) and correspond to a quantity of 0.683 billion bbl. These figures are all subject to the conservatisms mentioned earlier.

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4Q2000 $.

2000 dollars (fourth quarter)

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earlier

economically recoverable oil

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demand lease fees

USGS's cost assessment assumed zero lease bonus (pp. EA-5 & EA-16). In contrast, the Alaskan delegation typically claims that the Treasury would receive multi-billion-dollar lease payments. Since the mean expected reserve is a few billion barrels, such lease payments could increase costs by up to about a dollar per barrel above those described in this article. For example, Senator Frank Murkowski (R-AK) referred on 4 October 2000 to "some \$3 billion" of anticipated Federal lease revenues excluding royalties (http://members.nbci.com/nuclearcom/CongressionalRecord/DailyFullText/cr-00-10-04.html). This would amount to some \$0.94/bbl on mean economically recoverable reserves of 3.2 billion barrels, ignoring timing and discounting.

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more maintenance

accelerated corrosion

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advances

J. Rauch, "The New Old Economy," *The Atlantic Monthly* **287**(1):345–49, January 2001.

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halve long-term forecasts

Comparing EIA's 2001 with its ~1991 forecasts, each 20 years ahead and otherwise equivalent.

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three-fifths less

That is, the EIA 2001 Reference Case (\$23.08/bbl in 2020 in 4Q2000 \$) is 62% below the \$61/bbl (4Q2000 \$) assumed by the U.S. Department of the Interior in its 1987 analysis in support of Refuge drilling (though that figure wasn't included in Interior's Draft Environmental Impact Statement).

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Reference Case

U.S. Department of Energy predicts

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really believed

As former Energy and Defense Secretary James Schlesinger wrote ("The Oil-Price Roller Coaster," *The Washington Post*, 7 March 2000, p. A17), "This time, as opposed to periods of high prices in the '80s and '90s, the oil companies have been very cautious in expanding exploration and production. Burned in the past, they doubt that the price will remain high."

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cut exploration and development

US Energy Information Administration, "Major U.S. Energy Companies Cut Expenditures for Oil and Gas Exploration and Development Despite Surge in Oil Prices and Cash Flow," 19 January 2001, www.eia.doe.gov/neic/press/press173.html. The \$10 and \$25/bbl prices given just above are in nominal, not constant, dollars.

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congressional delegation

chairing

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Conspicuously absent

This view is widely held at the highest levels of most if not all major oil companies. As a former senior official of one emphatically remarked, "[Expletive deleted] no. We don't want ANWR—we want to go to areas where we know the reserves, know the recovery costs, and know how to get it out without screwing up the environment."

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global consumer boycotts

Such as the one now beginning against ExxonMobil in protest of its efforts to stop international moves toward climate protection.

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OPEC's share

EIA's *Annual Energy Review 1999*, Table 5.7, shows that in 1999, net imports from OPEC were 50.3% of total net imports and 24.9% of total U.S. consumption—a lower share of imports than in ten of the previous 13 years, and 30.4% below OPEC's 72.3% share of net imports in 1977, when OPEC supplied a record 33.6% of U.S. oil consumption.

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imports

U.S. oil imports

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quarter of the oil

OPEC's share

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western hemisphere countries

EIA's *Annual Energy Review 1999*, Table 5.7, shows that in 1999, 24.9% of U.S. oil consumption came from OPEC and 24.7% from non-OPEC foreign sources, chiefly Canada (14% of total net imports), Mexico (11%), Britain (4%), the U.S. Virgin Islands and Puerto Rico (3%), and other non-OPEC sources (18%). Imports from Canada plus Mexico exceeded those from the Persian Gulf.

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$300 billion a year

This would correspond to saving half of U.S. energy consumption at 1997 levels and real prices ($567 billion in 1997 $: EIA, *Annual Energy Review 1999*, Table 3.4). In practice, however, a disproportionate share of the dollar savings would come from efficient use of electricity, which in 1997 was 2.3 times as expensive as average energy purchases in all forms (*id.*, Table 3.3), so the fraction saved could be substantially below half.

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more abundant

Worldwide, not in the U.S.

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49 percent

EIA's *Monthly Energy Review*, June 2001, reports (Table 1.4) petroleum consumption of 38.404 Q in 2000, *vs.* 32.731 Q in 1975. Real GDP (Table 1.9) meanwhile rose from $4.0844 to $9.3185 trillion chained 1996 dollars. The GDP/oil ratio thus rose from 0.1248 to 0.2426 $/kBTU, an increase of 94.4%, or an intensity decrease (barrels per dollar GDP) of 48.6%. The GDP/oil-plus-natural-gas ratio was slightly higher, rising by 94.6%. Overall primary energy productivity rose by 66% due to the lower productivity increase for electricity (and directly used coal).

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Compared with 1975

According to EIA's *Monthly Energy Review*, June 2001, producing the 2000 real GDP at 1975 intensity would have required 69.29 Q more primary energy than the 99.09 Q that was actually used. This is 5.6 times the 12.358 Q of domestic oil production, 1.8

times the 38.40 Q of oil consumption (Table 1.4), 3.1 times the 10.419 Mbbl/d or 22.304 Q of net oil imports (Tables 1.8 and A2), and 13.0 times the 2.488 Mbbl/d or 5.326 Q of Persian Gulf oil imports (*id.*). The statements in the article are more conservative in order to leave room for readers' possible inclusion of natural-gas liquids.

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energy efficiency/energy productivity

Strictly speaking, a combination of reduced intensity (energy used per unit of service delivered), shifts in composition of economic output, and possibly some behavioral change. It would be more technically correct for the article to say "reduced intensity" than "increased efficiency" or "increased energy productivity," but that would confuse many nonspecialist readers, and in fact, most of the reduced intensity in the past quarter-century has resulted from increased efficiency rather than from the other factors.

Obviously "efficiency" is used here, and throughout the article, in its normal engineering sense—physical outputs per unit of physical inputs—rather than in the economic sense of achieving least-cost equilibrium through perfect free-market competition.

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two-fifths

That is, the 69.29 Q of energy saved in 2000 by reduced intensity compared with 1975 is 41% of the total of that amount plus the actual consumption of 99.09 Q.

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compared

Compared with 1975

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fastest growing "source"

U.S. energy intensity (primary energy consumption per dollar of real GDP) declined at an average rate of 3.1% during 1996–2000 (EIA, *Monthly Energy Review*, June 2001, Table 1.9). No domestic supply category appears to have grown faster except photovoltaics (18%/y during 1996–98, the last number in Table 10.7 of EIA's *Annual Energy Review 1999*).

For comparison, 1996–2000 average annual growth rates for U.S. domestic crude oil, gas, coal, and nuclear power production were respectively –2.6%/y, +0.3%/y, –0.02%/y, and +2.8%/y (from increased operation of five fewer plants): EIA, *Monthly Energy Review*, June 2001, Tables 1.3 and 8.2.

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22 percent

EIA, *International Energy Outlook 2001*, DOE/EIA-0484(2001), p. 98.

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after-tax returns

This is consistent with extensive retrofit data from Rocky Mountain Institute's and other practitioners' recent field experience in diverse U.S. industries. Some are described in P. Hawken, A.B. & L.H. Lovins, *Natural Capitalism: Creating the Next Industrial Revolution*, www.natcap.org, Little Brown (NY) and Earthscan (London), 1999, and in E. von Weizsäcker & A.B. & L.H. Lovins, *Factor Four*, Earthscan (London), 1997.

The methods of advanced electric end-use efficiency required to achieve such returns through integrative design are described technically in the voluminous *Electronic Encyclopedia* published by RMI's 1992 spinoff E SOURCE (www.esource.com). Its encyclopedic *Technology Atlas* series was originally prepared at RMI under Amory Lovins's direction. Less technical examples are documented in "Negawatts: Twelve Transitions, Eight Improvements, and One Distraction," *En. Pol.* **24**(4);331ff (April 1996), RMI Publication #U96-11, www.rmi.org/images/other/E-Negawatts12-8-1.pdf, and A.B. Lovins, "Negawatts for [Chip] Fabs," Stanford/NSF/SRC/SEMATECH tech. sympos. keynote, 6 August 1998, RMI Publ. #E98-3, www.rmi.org/images/other/E-NegawattsForFabs.pdf.

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fringe benefits

See *e.g.* W.D. Browning & J. Romm, "Greening the Building and the Bottom Line," www.rmi.org/images/other/GDS-GBBL.pdf; and for the retail sales report and another on 20–26% faster learning in daylit schools, www.h-m-g.com/Daylighting/order%20daylighting.htm. Such side-benefits are often worth one, sometimes two, orders of magnitude more than the direct energy savings.

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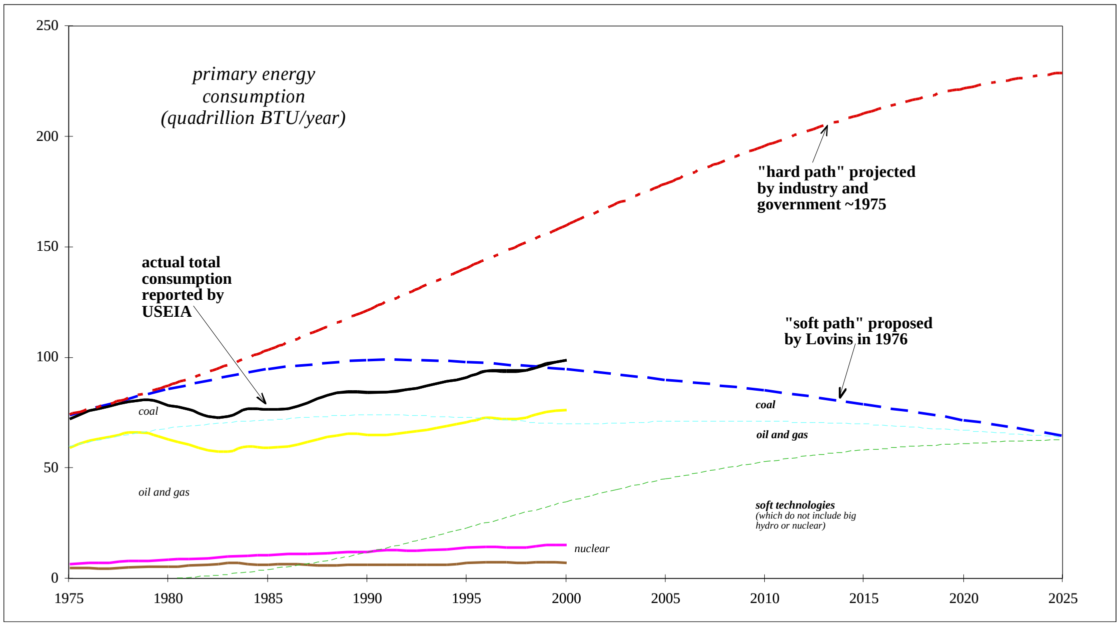
energy efficiency

This power was correctly foreseen in A.B. Lovins, "Energy Strategy: The Road Not Taken?," *Foreign Affairs* **55**(1):65 (1976), letters *id.* **55**(3):636 (1977), **55**(4):891 (1977). That article redefined the energy problem from what is now known as the end-use /

least-cost perspective: rather than seeking *more energy*, of any kind, from any source, at any price, it sought just the amount, quality, and scale of energy supply that would deliver each desired service (such as hot showers, cold beer, comfort, or mobility) at the lowest economic [or, if desired, social] cost.) This approach enhanced understanding of market competition between increased supply and improved energy productivity, and hence offered better foresight than was possible with the previous approach of projecting demand and building to meet it—an approach revived by the Bush Administration in 2001 to the astonishment of most energy-policy veterans, since it is clearly less economically efficient, practical, and risk-manageable than competition at honest prices to yield a balanced portfolio of demand- and supply-side investments.

The value of the end-use / least-cost approach is illustrated by the following graph, which shows that the "soft energy path" graph published in *Foreign Affairs* 25 years ago is within a few percent of actual U.S. energy consumption (all data through 2000 from EIA, *Annual Energy Review 1999* and *Monthly Energy Review*, June 2001; hard- and soft-path projections from Lovins, *Foreign Affairs*, Fall 1976, *loc. cit.*; lowest wedge on left, below nuclear power, is renewables):



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1979 to 1986

Primary energy consumption was 81.042 Q in 1979 but only 77.065 Q in 1986, down 4.91%; oil consumption fell from 37.123 to 32.196 Q, down 13.3% (EIA, *Annual Energy Review 1999*, Table 1.3). Real GDP meanwhile grew from $4.912 to $5.912 trillion chained 1996 dollars, up 20.4% (Table 1.5).

Producing the 1986 GDP at 1979 intensity would have required an additional 1986 energy consumption of 20.495 Q or 21%. Coal and nuclear production meanwhile expanded by only 1.969 Q and 1.695 Q respectively (Table 1.2), a total of 3.664 Q or 5.6 times less than the primary energy consumption avoided by reduced intensity.

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energy prices

EIA's *Annual Energy Review 1999* reports that during 1984–86, the average U.S. real price of domestic crude oil (refiner's acquisition price), unleaded regular retail motor gasoline, domestic wellhead natural gas, and composite domestic fossil-fuel production fell respectively by 51% (p. 157), 28% (p. 163), 31% (p. 183), and 41% (p. 63). The graph on p. 62 shows how oil and gas prices started to slip in 1985, then (especially for oil) plunged in 1986. The downward drift continued thereafter for both, amidst a long-term background of gradually declining coal and electricity prices, which were more subject to long-term contracts and, for electricity, regulated average prices dominated by fixed costs.

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competitive pressures

Such coverage in the business press as the May 1999 *Fortune* feature were particularly influential in boardrooms. Although energy is only a few percent of the total costs of most businesses, saved energy, like any saved overhead, drops straight to the bottom line, so even a modest energy saving can significantly increase tight net margins.

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side benefits

fringe benefits

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structural shifts

See J. Romm's book-length exposition at http://www.cool-companies.org/energy/.

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1996–99

EIA's *Annual Energy Review 1999*, Table 1.5, shows that after a decade of stagnation, primary energy intensity suddenly fell 3.66% in 1996–97, 3.89% in 1997–98, and 1.89% in 1998–99—an average rate of decrease of 3.15%/y—due to a not-yet-fully-known combination of shifts in composition, technical decreases in intensity, and [probably minor or countervailing] shifts in behavior. This occurred despite such obviously contrary trends as increased adoption of inefficient sport-utility vehicles. The remarkably low retail real energy prices shown in Tables 5.21, 6.9, and 8.13 range between local and global minima. (Many real prices then ticked upward again in 2000–01: EIA, *Monthly Energy Review*, June 2001, Section 9.)

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Gasoline prices

That was true at the time of initially drafting the article, but ceased to be true well before it was published on 2 July 2001. EIA's *Monthly Energy Review*, June 2001, Table 9.4, shows that the peak passed in June 2000 (and the same at wholesale level: Table 9.6) even in nominal dollars.

The article's reference to a "shortage of refineries" is also overcondensed: what was short was specialized kinds of capacity in particular regions for producing a plethora of "boutique" gasoline specifications from particular crudes, not refining capacity in general. The economic case for building more U.S. refinery capacity remains weak to vanishing. Indeed, by July 2001, *The Wall Street Journal* was reporting that many refiners, very exceptionally, were doing their autumn shutdowns in August due to weak demand for gasoline.

More specifically, as RMI Managing Director and oil economics expert Tom Feiler notes (personal communication, 7 August 2001):

- Regional price disparities in gasoline markets result from the "Balkanization" of air quality regulation. Absent Federal leadership on local nonattainment problems, states have individually made rules on the oxygen content of motor fuels and how to achieve it. This uncoordinated state action, plus some states' parochial interests (such as farm states' requiring that oxygenates come from corn-based ethanol), have led to a proliferation of "boutique" refined product markets that have little competition and hence little price discipline. Seasonal changeovers to such boutique blends, and their coordination with local availability of crudes compatible with the required product slates, have also complicated refinery logistics and raised costs. This issue is widely recognized in the industry, and EPA Administrator Whitman announced in early August that she intends to help resolve it.
- Contrary to conventional wisdom and most press reports, there is no shortage of refinery capacity in the United States. Capacity margins are much smaller than in the past, but this does not equate to a shortage.
- The reason no new refineries have been built in the U.S. for more than 15 years (though many have been debottlenecked and otherwise improved) has nothing to do with environmentalists and everything to do with supply/demand fundamentals. Similar to the electric power industry, the last building boom in refineries, in the late 1970s, left a huge capacity overhang. No new refineries were subsequently built because none were needed. Over the past decade, a booming economy and inefficient light vehicles, notably SUVs, have removed much of the slack from the system. Wall Street has applauded the increased capacity utilization of the downstream oil industry by pushing P/E ratios to new highs.
- The notion that environmentalists are to blame for tight refinery capacity is not only untrue; it's backwards. The cleanup requirements on retired refineries are so onerous and costly that many refineries continue to operate that would otherwise have been shut down. Environmental regulations are therefore, surprisingly, responsible for there being more refinery capacity rather than less. As refinery expert Kevin Lindemer at Cambridge Energy Research Associates puts it, "the downstream oil industry is like a lobster trap—much higher barriers to exit than entry."
- Refined products, like natural gas and many other commodity markets, have annual price swings. The onset of summer raises motor fuel prices just as the onset of winter raises heating oil prices. As in all competitive markets, this is due to a mixture of fundamentals and psychology.

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utility restructuring

A fuller description of what happened, and what didn't happen, was presented in A.B. Lovins's Commonwealth Club of San Francisco talk (11 July 2001) and Worldwatch Institute Aspen talk (22 July 2001). The latter is posted at http://www.rmi.org/sitepages/pid171.php. Rebuttals to published claims (in *The American Spectator* and *The Weekly Standard*) about soaring demand, lack of new plant construction, etc. are posted at www.rmi.org/sitepages/pid171.php. A summary of California electricity events was included in the draft of this article, but was deleted to fit *Foreign Affairs*'s non-footnote house style.

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price crash

This happened not only nationwide in 1985–86, but also in California electricity in 1984–85. Specifically, in 1984, California had a peak load of 37 GW, supplied 27 GW by thermal and 10 GW by hydroelectric and geothermal plants. By 1984, the state had committed 12 GW and was negotiating for another 7 GW of demand-side resources (for installation through 1994), of which ultimately 10 GW was procured and 9 GW abandoned. In addition, private generators, attracted by generous fixed-price standard offers (though many would later still bid in the early 1990s under highly competitive conditions), had by March 1985 offered 20.3 GW of independent power production, 57% of which was built or being built and most of which was renewable. Most astonishingly, new offers of private generation, most of them real, were arriving at a rate of 9 GW—one-fourth of total peak demand—*per year*. When the CPUC slammed on the brakes and suspended most private contracting on 17 April 1985, 13.1 GW of private generation had already been procured and another 8+ GW was in negotiation. Had that gold-rush continued through 1985, it would have displaced all 27 GW of thermal capacity in the state. The transition from scarcity to glut took only two years—yet even for years after it had finished, two dozen other states and provinces were all still trying simultaneously to sell their power surpluses to California. Both California and the U.S. are now seeking to reproduce this experiment; both are almost certainly already in overshoot (*Barron's*, cover story, 6 April 2001). The same result as in the mid-1980s can be expected, wasting more tens if not hundreds of billions of dollars and rendering their financiers unable to recover their investment from slackening demand.

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1985–86

EIA's *Annual Energy Review 1999* reports that during 1984–86, the average U.S. real price of domestic crude oil (refiner's acquisition price), unleaded regular retail motor gasoline, domestic wellhead natural gas, and composite domestic fossil-fuel production fell respectively by 51% (p. 157), 28% (p. 163), 31% (p. 183), and 41% (p. 63). The graph on p. 62 shows how oil and gas prices started to slip in 1985, then (especially for oil) plunged in 1986. The downward drift continued thereafter for both, amidst a long-term background of gradually declining coal and electricity prices, which were more subject to long-term contracts and, for electricity, used regulated average prices dominated by fixed costs.

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overreaction and instability

On 19 January 2001, the *Daily Oklahoman* (R. Robinson, "Oklahoma Energy Companies Try to Combat Boom-Bust Cycle") quoted Charles J. Mankin—director of both the Sarkeys Energy Center and the Oklahoma Geologic Survey at the University of Oklahoma, and an advocate of increased drilling on public lands—as saying that "If anything, boom-and-bust cycles have become more extreme….Every time government tries to tinker with something, they overreact and we end up with a California situation." The essence of this risk in the Refuge context is that its development would be very slow relative to the far faster, as well as far larger, developments likely on the demand side meanwhile.

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react faster

As Californians illustrated when, in the first six months of 2001, they undid the previous 5–10 years' demand growth by reducing weather-corrected peak load and electricity usage per dollar of real GDP by 14% and 12% respectively: www.energy.ca.gov/electricity/peak_demand_reduction.html.

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powerful technologies

after-tax returns

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delivery methods

Many of these were developed at RMI and are described in P. Hawken, A.B. & L.H. Lovins, *Natural Capitalism: Creating the Next Industrial Revolution*, www.natcap.org, Little Brown (NY) and Earthscan (London), 1999, and in E. von Weizsäcker & A.B. & L.H. Lovins, *Factor Four*, Earthscan (London), 1997.

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market failures

A.B. & L.H. Lovins, "Climate: Making Sense *and* Making Money," esp. pp. 11–20, 1997, www.rmi.org/images/other/C-ClimateMSMM.pdf.

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world oil market

The world oil market (oil in world trade) was reported by BP as 42.7 Mbbl/d in 2000 (BP, *World Energy Review 2001*). EIA, however, reports it as 53.3 Mbbl/d in 1998 and projects it in the Reference Case to reach 86.5 Mbbl/d in 2020 (EIA, *International Energy Outlook 2001*, Table 13, p. 39). In contrast, peak Refuge output,at or somewhat before 2020, might slightly exceed 1 Mbbl/d. Extrapolation of the Reference Case shows that the $22/bbl mean Refuge reserve would be 1.6% of U.S. oil consumption, or <0.5% of world oil production, during 2010–2040.

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output

a few percentage points

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2020

a decade

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claimed

President George W. Bush claimed

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giant Alaskan discovery

The 1002 Area is estimated in USGS's mean assessment to contain about 16 oil accumulations larger than 128 million BO (totaling about 83% of the technically recoverable oil), of which 3–4 are estimated to exceed 512 million barrels and contain about 42% of the total estimated oil. At p. AO-16, USGS comments: "Oil accumulations in the 500 million to 2 billion barrel size range are small only in comparison to the 13 billion barrel Prudhoe Bay oilfield. They are significant when considering that the largest onshore discovery in the U.S. during the last eighteen years was 350 million barrels and the last discovery larger than a billion barrels (Kuparuk River) was made almost 30 years ago." In contrast, the 30-year equivalent of a year-2000 U.S. light vehicle fleet that averaged (say) 30 instead of 20.4 mpg, generously equating a gallon of gasoline to a gallon of crude oil, would be an oilfield yielding 2.59 Mbbl/d, equivalent over a typical 30-year field life to 28.4 billion barrels—8.85 times the USGS 1998 mean estimate for the Refuge reserve at $22/bbl. At the actual 2000 yield of 0.462 bbl gasoline from each bbl of crude oil, a 30-mpg light vehicle fleet would be equivalent to 19 Refuges' mean reserves.

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generously

yield

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larger than the refuge

Prudhoe Bay, with a good deal still left after 24 years' output, has already produced over 10 billion barrels, projected by the State of Alaska to reach 13 billion barrels by 2020. In contrast, USGS (1998) found only a 5% probability of as much as 10.8 billion barrels beneath the Coastal Plain of the Refuge even if prices were sustained at or above $43/bbl, and expects the largest potential field size to be just 1 billion bbl, plus a few smaller and scattered fields. No responsible geologist projects any possibility that Refuge oil might rival Prudhoe Bay; its geology is now known to be far more complex and less favorable (USGS 1998), so the Department of the Interior has stated that no Prudhoe Bay-class find should be expected in the Refuge.

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all-time high

The falsity of this correlation is evident from the data (all price in 4Q2000 $), from EIA's *Annual Energy Review 1999*, Tables 5.22 and 5.19, and the Alaska Department of Revenue's *Spring 2001 Revenue Sources Book*, App. E:

	1976	*1978*	*1980*	*1985*	*1988*
Prudhoe Bay output (Mbbl/d)	0.	0.702	1.421	1.534	1.605
U.S. crude (refin. acq. cost)	$20.53	$23.71	$45.78	$38.99	$19.81
Import crude (refin. acq. cost)	$34.35	$32.56	$64.03	$39.48	$19.56
unleaded regular gasoline/gal	$1.56	$1.50	$2.35	$1.76	$1.27

As one would expect, crude and product prices were determined by exogenous events—chiefly by the global supply/demand balance. Since world oil consumption in 1988, when Prudhoe Bay output peaked, was 40 times as large as Prudhoe's output (68.42

Mbbl/d, Table 11.9), Prudhoe made no discernible difference to that balance. Twice as important was the 3.13 Mbbl/d drop in U.S. petroleum product consumption during 1978–85 (Table 5.11).

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30-year output

That is, 3.206 billion bbl (the USGS 1998 mean estimate at a nominal $20/bbl in 1996 $ or $21.56/bbl in 4Q2000 $), divided by 365.26 days a year for 30 years, is 292,577 average bbl/d. It is quite possible that the field life would stretch to 40–50 years, but less likely, based on normal practice, that it would be much shorter than 20. The actual production profile would of course depend on geology, technology, and economics, among other factors, and is contingent on the ability of TAPS to sustain the required throughput for the required decades.

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estimate

This naturally depends on price and probability. The USGS 1998 mean estimate ranges from 0.8 billion bbl at $16.5/bbl (4Q2000 $), or zero below that price, to as much as 6.8 billion bbl at $43.1/bbl (but no more at higher prices). The 95% probability estimate ranges from 0.4 billion bbl at $20.4/bbl, or zero below that price, to 3.4 billion bbl at $43.1/bbl (but no more at higher prices). The 5% probability estimate ranges from 0.7 billion bbl at $14.4/bbl, or zero below that price, to 10.8 billion bbl at $43.1/bbl (but no more at higher prices). Since the EIA Reference Case, among the highest, envisages prices reaching the $22 range only around 2020, the mean estimate would require implausibly high sustained oil prices to support an economically recoverable volume much above 3.2 billion bbl.

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depends/ranges

range of projections

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Asian markets

Until April 2000, about 5–7% of Alaskan oil was shipped to Asia after Senator Murkowski's 20-year campaign to lift the original ban on such exports succeeded in 1995. The most recent year's exports were 28 million barrels, nearly equaling President Clinton's 30-million-barrel release from the Strategic Petroleum Reserve to stabilize spiking world oil prices. The exports to Asia were more profitable because Asian customers would pay more than West Coast refiners, who were slightly in surplus. For example, the Alaska Department of Revenue, in its 1997 *Revenue Sources Book*, noted that lifting the export ban probably added $40 million per year to Alaskan oil's price in West Coast markets.

The exports continued from 1996 to April 2000, costing West Coast consumers tens of millions of dollars a year in higher petroleum product prices, then were voluntarily suspended by BP/Amoco after mergers enabled it to use all the crude in West Coast refineries. Exports could, however, be legally resumed at any time—in which case any energy-security arguments for Refuge oil would diminish accordingly.

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yield 156,000 barrels

Generously assuming that 1 bbl of crude oil produces 0.534 bbl of finished motor gasoline, and ignoring all pipeline, tanker, delivery, and refinery input energy. In fact, even after strenuous efforts to tilt toward the light side of the barrel in product slates, the 2000 U.S. average motor gasoline yield was only 0.462—EIA, *Petroleum Supply Annual 2000, Vol. 1*, Table 19—and it has not exceeded 0.476 (1983) since at least 1978—*Transportation Energy Data Book, Edition 20—2000*, Oak Ridge National Laboratory, Table 1.8. However, by the cruder measure of the ratio of motor gasoline production to gross input to distillation units (EIA, *Annual Energy Review 1999*, Tables 5.9 and 5.11), ratios around 0.54 have been achieved in the past few years. The difference is due to subtraction of blending components, natural gas plant liquids, other hydrocarbons, and oxygenates. As a conservatism, we use here, for most purposes, the broader measure of yield, tacitly assuming that all these other inputs are derived from sources other than crude oil.

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2 percent

The Oak Ridge National Laboratory *Transportation Energy Data Book: Edition 20–2000*, Tables 7.1 and 7.2, shows total 1998 U.S. fuel use of 72.2 billion gallons by passenger cars and 50.6 by light trucks, a total of 122.8 billion gallons or 2.92 billion bbl or 8.01 million bbl/d. Two percent of that is 160,000 bbl/d. (This is almost all gasoline; the correction for the small fraction of diesel fuel is unimportant. For example, in 1988, motor gasoline was 98.3% of the fuel consumed by the household vehicle fleet.)

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0.4 mpg more efficient

Oak Ridge National Laboratory's *Transportation Energy Data Book: Edition 20–2000*, Table 7.1, shows as the most recent available data a 1998 passenger-car fleet of 131.8 million cars driven 1.546 trillion miles and using 72.2 billion gallons, an average of 21.4 mpg. (EIA's *Monthly Energy Review*, June 2001, Table 1.10, shows 21.6 mpg for 1998 and a preliminary estimate of 21.4 mpg for 1999.) Driving the average car 11,730 miles at 21.8 instead of 21.4 mpg would save 10.06 gal/car-y or 1.326 billion gal/fleet-y or 31.562 billion bbl/fleet-y or 86,410 bbl/d of gasoline. Table 7.2 shows a 1998 light-truck fleet of 71.8 million vehicles traveling 866.3 trillion miles (an average of 12.061 mi/vehicle-y) on 50.6 billion gallons of fuel at an average 17.1 mpg. Making this 17.5 mpg would save 16.15 gal/vehicle-y or 1.16 billion gal/fleet-y or 27.611 billion bbl/fleet-y or 75,591 bbl/d of gasoline. The total gasoline saved by a 0.4-mpg improvement in the light-vehicle fleet is thus 162,000 bbl/d.

It is unimportant to correct these calculations for the fraction of the light-vehicle fleet that uses diesel fuel instead of gasoline; the ORNL *TEDB*, Table 2.5, shows that in 1998, only 1.4% of the U.S. car fleet and 3.9% of the U.S. light truck fleet used diesel fuel.

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5 months

Oak Ridge National Laboratory's *Transportation Energy Data Book: Edition 20—2000*, Table 7.16, shows that during MY1979–85, CAFE standards for cars rose at an average rate of 1.42 mpg/y and the CAFE ratings of new cars (sales-weighted averages) by 1.17 mpg/y domestic (*i.e.*, with at least 75% domestic content), 0.90 imported, and 1.22 combined (a larger total because of a shift to imports that were on average more efficient than domestic models). For light trucks, DOT standards were introduced in MY1982 (17.5 mpg) and rose to 19.5 mpg for MY1985, while new domestic light trucks improved by 0.32 mpg/y, imports by 0.95 mpg/y, and combined by 0.42 mpg/y. The combined new light-vehicle fleet improved by 0.88 mpg/y, or 0.37 mpg every five months.

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replacement tires

Rolling resistance accounts for nearly one-third of the tractive load of the U.S. light-vehicle fleet: U.S. National Academy of Sciences, *Automotive Fuel Economy: How Far Can We Go?*, 1992, http://bob.nap.edu/books/0309045304/html/, at Table 2.1. A 20% decrease in rolling resistance improves fuel economy by about 4%: *id.*, Table B-2 and p. 213. The coefficient of rolling resistance for aftermarket tires averages about 20% higher (worse) than for those sold with new cars (refs. 3–5 in Natural Resources Defense Council, *A Responsible Energy Policy for the 21st Century*, App. A, "Oil Savings from Fuel-Efficient Tires and Higher Fuel Economy," www.nrdc.org/air/energy/rep/app.asp). NRDC presents a simple model showing a 5.4-billion-barrel potential saving from this cause (equivalent to 1.7 times the mean USGS 1998 estimate of Refuge reserves at $22/bbl) over 50 years, very conservatively equating 1 bbl gasoline with 1 bbl crude oil. Using a conservative yield of 0.54 bbl gasoline/bbl crude would increase the factor 1.7 to 3.1.

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Full

The original text, seeking not to imply inaccurately a plenitude of oil, said "Refuges' worth."

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superinsulating windows

Prof. A.H. Rosenfeld (then head of the national effort on energy-efficient building technologies at Lawrence Berkeley National Laboratory, then senior science advisor at the U.S. Department of Energy, and now a California Energy Commissioner) has published calculations showing that full conversion to ~R-4 windows (those whose insulating value is roughly that of four sheets of glass) can save half as much oil and gas (fungible for oil) as the U.S. was getting from Alaska in the late 1980s. However, such windows are now commercially available in the ~R-11–12 range (center-of-glass ratings), *i.e.*, with up to two-thirds lower heat flow, at scarcely higher prices. Dr. Steven Selkowitz of LBNL has shown that just ~R-7 windows yield a net winter heat gain facing in any direction in any U.S. climate below the Arctic Circle, thus reducing the windows' heat loss to zero *or less*; this occurs because even facing north, diffuse skylight brings more heat in than the window loses. (This is especially true in snowy climates where the incoming light is supplemented by reflection off the snow.) Furthermore, Prof. Rosenfeld's calculations conservatively counted only space-heating savings, not space-cooling savings too, but superwindows do both. Savings in south- and west-facing Sunbelt windows appear to be comparable to those in north-facing Frostbelt windows.

To illustrate the size of the savings available, EIA's *Monthly Energy Review*, June 2001, shows that in 2000, U.S. households used 5.8 Q of natural gas, 1.5 Q of oil, and 4.1 Q of electricity (Table 2.2), while commercial buildings (Table 2.3) used 3.4 Q of natural gas, 0.7 Q of oil, and 3.9 Q of electricity. Nonindustrial buildings thus used 11.4 Q of direct oil and gas plus 8.0 Q of electricity. Table 7.2 shows that 19% of U.S. electricity is gas- or oil-fired; Table 7.5 shows that at least 62% of U.S. electricity is used in nonindustrial buildings; and it is conservative to prorate this consumption across the generators' fuel mix, since the relatively peaky nature of building loads results in their being more likely than average loads to be gas- or oil-fired (using peaking and intermediate-load-factor plants) rather than powered by coal or nuclear baseload plants. Tables 7.2, 7.6, A3, and A4 shows a weighted-average thermal efficiency of 0.314 for gas- and oil-fired generation, so 8.0 Q of electricity, of which 19% was gas- and oil-fired at that efficiency and incurred the national-average 7% grid loss, consumed about 5.2 Q of gas and oil to generate it. Thus at least 11.4 + 5.2 = 16.6 Q of gas and oil was consumed by nonindustrial buildings—27% of the total consumption of these fuels (Table 1.4).

Of this ≥16.6 Q/y of oil and gas used directly or indirectly in nonindustrial buildings, equivalent to and fungible for ≥7.8 Mbbl/d of oil, EIA's *Annual Energy Review 1999*, Tables 2.5 and 2.11, show that in 1997, roughly 45% in houses and 31% in commercial buildings was used for space heating. Specifically, Table 2.5 shows 1997 household usage of 3.61 Q of gas, 0.91 Q of oil, 0.26 Q of LPG, and 0.40 Q of electricity for space heating, plus 0.42 Q of electricity for air conditioning. Treating the electricity as above, this is a primary oil-and-gas total of 5.04 Q (including LPG) for space heating plus 0.27 Q of oil and gas to make electricity for air conditioning, a total of about 5.31 Q.

In the commercial sector for 1995 (just-published newer data are still preliminary), Tables 2.11 and 2.12 show end-use energy of 1.70 Q for space heating and 0.52 Q of space cooling and air handling (probably an underestimate according to other data sources). If we make the simplifying assumptions that all the space heating is direct-fueled by oil, gas, and LPG (as most of it is) and that all the space cooling and air handling is electric (as almost all of it is), then the implied primary oil-and-gas consumption for these uses, including LPG, is about 1.70 + 0.34 = 2.04 Q. Total space-conditioning hydrocarbon use in nonindustrial buildings is thus about 7.35 Q/y, equivalent to roughly 3.5 Mbbl/d.

About a third of buildings' heat loss is through windows (Rosenfeld, personal communication, 2 Dec. 1990, although he conservatively reduces this to one-fourth for commercial buildings, which used one-fourth of space-heating energy). Essentially all of that window heat loss can be displaced by superwindows—and more, since R>7 versions would yield a net passive-solar heat gain that displaces additional space-heating fuel. It's also reasonable to assume that a third of the average building's space-cooling load is also due to windows (actually more, because fan and pump loads to deliver the coolth vary as the cube of flow and hence diminish sharply with modest load reductions); modern superwindows can be theoretically about perfect in admitting light without unwanted heat. The space-conditioning load caused and correctable by windows and currently met by hydrocarbons thus totals about 2.1 Q/y for heating and 0.18 for cooling and associated air-handling, a total of about 2.3 Q/y or 1.1 Mbbl/d—roughly the potential peak output of Refuge oil, or about four times the 30-year average output associated with the 3.2-billion-bbl mean expected reserve at $22/bbl.

This doesn't count superwindows' net passive winter gain, which could displace much, and ultimately about all, of the two-thirds of the space-heating load *not* due to windows. (For example, RMI's headquarters, in an 8,700F˚-d/y climate that can go to –47˚F, is 99% passively heated by superwindows.) This ability to save more heat than the original inefficient windows lost would up to triple the potential oil and gas saving from superwindows. Superwindows' marginal cost is a few $/bbl considered as a component; on a whole-building basis, it is typically zero or negative because the extra cost of superwindows is generally more than offset by the avoided capital cost of mechanical equipment thereby downsized or eliminated. This has been demonstrated in temperatures from –47˚F (RMI's HQ) to +113–115˚F (the Davis and Stanford Ranch houses in PG&E's 1990s "ACT^2" experiment posted at the Pacific Energy Center website). Even in the severe cooling climate of Bangkok, a 90% reduction in air-conditioning energy in a ~3,600-ft^2 house has been demonstrated by architect Prof. Suntoorn Boonyatikarn (Chulalongkorn University) at zero marginal construction cost.

In corroboration, the Solar Energy Research Institute (now the National Renewable Energy Laboratory) published in 1981 a major analysis, *A New Prosperity*, showing that careful retrofits with 1979 technology could save 50% or 75% of U.S. space-heating energy at average costs of $10/bbl and $20/bbl respectively (~1979 $)—severalfold cheaper than the then retail price of heating oil. Superwindows entered the U.S. market over the several years following; they insulated 2–4 times as well as triple glazing, but cost less. In the mid-1990s, for example, Hurd Insol-8 units with center-of-glass ratings of R-8.1, in small retail quantities in competitive markets, were selling for only 15–20% more than double glazing, but had four times the insulating value.

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54 "refuges"/a sixth of the cost

documented below

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uncompetitive

As Shell Hydrogen CEO Don Huberts, fuel-cell pioneer Geoffrey Ballard, and former Saudi Oil Minister Sheikh Yamani more concisely remarked, "The Stone Age did not end because the world ran out of stones, and the Oil Age will not end because the world runs out of oil."

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85 percent

Conservatively assuming 54% gasoline yield from each barrel of crude oil.

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24 mpg

For cars and light trucks combined; strictly speaking, this sentence should have referred to "light vehicles," not "cars."

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much better

The industry has indeed *been* doing better, but during 1987–2000, vehicle weight rose 12%; during 1981–2000, 0–60-mph acceleration times fell 22%; and horsepower increased >70%. Thus major improvements in technical efficiency were swallowed up by increased performance or luxury rather than being expressed in saved fuel. Honda calculates that "if the new technologies [for saving automotive fuel] were used solely for fuel economy instead of performance and other attributes—if the current car fleet were still at 1981 performance, weight and transmission levels—passenger car cafe would be almost 36 mpg rather than the current level of 28.1 mpg. Since 1987, technology has gone into the fleet that could have improved fuel economy by 1.5 percent per year if it had not gone to other attributes demanded by the market. Thus, while fuel economy did not increase, the fuel efficiency of vehicles did." —John German, Manager of energy and environmental analyses, Product Regulatory Office, American Honda, remarks to U.S. Senate, Committee on Commerce, Science, and Transportation, 10 July 2001.

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Toyota *Prius*

See http://prius.toyota.com/.

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Honda *Insight*

See www.honda2001.com/models/insight/index.html?honda=intro.. The 2001 model is EPA-rated at 64 mpg, though drivers report mileage that can vary considerably, either way, depending on driving habits.

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26 or 33 refuges

Oak Ridge National Laboratory's *Transportation Energy Data Book: Edition 20—2000*, Table 7.1, states that the 1998 U.S. car fleet had 131.8 million vehicles traveling 1.546 trillion miles and using 72.21 billion gallons at 21.4 mpg. Table 7.2 gives the same data for the light-truck fleet: 71.8 million vehicles, 866.2 billion miles, 50.6 billion gallons, and 17.1 mpg. The vehicle-miles-weighted average of the fleet was thus 20.4 mpg. However, the *new* fleet (table 7.16) was rated at 24.5 mpg in 1999, so in view of its slight decline in the past few years, we use 24 mpg as a nominal value for the current new fleet. We also adopt EIA's estimated 1999 driving distances (*Monthly Energy Review*, June 2001, Table 1.10): 11,850 mi/car, 11,958 mi/light truck, hence 11,884 mi/light vehicle-y, weighted by 1998 vehicle population. Finally, we assume 4.6% growth in the light-vehicle fleet (for which the data have not yet been published), to 213 million, from 1998 through 2000—two years of unusually brisk sales (*e.g.*, 8.646 million cars and 8.004 million light trucks in 1999, from Tables 7.5 & 7.6 of the *TEDB*). This estimate may be conservative in view of the Department of Transportation's 1997 *Trends and Forecasts of Highway Use* (www.fhwa.dot.gov/policy/hcas/final/two.htm), which projected 167.7 million cars and 63.3 million light trucks, a total of 231 million, by 2000—12% above the estimate used here.

A hypothetical light-vehicle fleet that achieved a *Prius*-like 49 instead of 24 mpg to drive the same number of vehicles for 11,884 miles would save 252.63 gal/vehicle-y, or 53.8 billion gal/fleet-y, or 1.28 billion bbl/fleet-y, or 3.508 Mbbl/d of gasoline, or 7.592 Mbbl/d of crude oil at the actual 2000 gasoline yield of 46.2%, or 83.2 billion bbl over 30 y—26 times USGS's 1998 mean estimate of Refuge reserves at $22/bbl (3.206 billion bbl). (The refinery yield is approximately equivalent to the 54% obtained by ignoring non-crude inputs, when corrected for refinery and distribution inputs and losses.)

For a 67-mpg Honda Insight (the rating of its original model), the corresponding saving is 317.8 gal/vehicle-y, or 67.7 billion gal/fleet-y, or 1.611 billion bbl/fleet-y, or 4.412 Mbbl/d of gasoline, or 9.551 Mbbl/d of crude oil, or 104.6 billion bbl over 30 y—32.6 Refuges' worth.

The article as submitted to *Foreign Affairs* included a footnote explaining the refinery-yield adjustment, and stating that "Ignoring this reality of refining and counting pure energy equivalence would correspondingly decrease the number of ANWR reserves displaced." The editor unfortunately deleted the footnote in accordance with house style, but too late to restore this caveat to the text.

refinery-yield

yield

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testing family sedans

Such as the GM *Precept* (82 mpg gasoline-equivalent), Dodge *ESX-3* (72 mpg), and Ford *Prodigy* (72 mpg) (ORNL *Transportation Energy Data Book: Edition 20—2000*, p. 9-11, and Bob Purcell (GM), personal communications, 2000). These and other test vehicles typically grew out of the Federal/Big Three's Partnership for a New Generation of Vehicles, which aimed at preproduction prototypes of uncompromised *Taurus*-class family sedans by 2003. All three firms have met or exceeded that goal. Indeed, all three have announced or shown even more efficient fuel-cell versions slated for production later in this decade.

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Volkswagen

These are respectively the *Lupo* 4-seat subcompact, rated at 3 L/100 km (78 mpg), and its 1-L/100-km version announced by Chairman Piëch (most recently in September 2000) for 2003 production start. The latter is a small city car, possibly of *Smart* class, with a carbon-fiber body. Both cars use a direct-drive diesel, and the latter is probably hybrid-electric. Neither uses a fuel cell. The efficiency of the latter could be approached with a fuel-cell Hypercar version at least as big as the former.

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Fuel cells

Fuel cells reverse the electrolysis one did in the high-school chemistry experiment where an electric current split water into hydrogen and oxygen. A fuel cell chemically recombines these gases (the oxygen being part of unseparated air) at a catalyst-dusted plastic membrane to produce electricity, hot water, and nothing else. Volume production of "PEM" (proton-exchange-membrane) fuel cells is beginning in 2001. Honda recently confirmed its plans for 2003 production start on its first fuel-cell car; Toyota had previously announced similar plans. The 2003–05 group also includes DaimlerChrysler, GM, and Ford.

Rocky Mountain Institute presented at the National Hydrogen Association meeting in April 1999 "A Strategy for the Hydrogen Transition," describing how to overcome the oft-cited infrastructure problems of a hydrogen economy, profitably at each step, starting now. This strategy (www.rmi.org/images/other/HC-StrategyHCTrans.pdf) is being rapidly adopted by major energy and car companies. It is greatly facilitated by Hypercar[SM] vehicles, because their tractive load (the power needed to propel the car) is reduced severalfold by making the car ultralight and ultra-low-drag. This makes the fuel cells small enough to afford and the ultra-strong carbon-fiber hydrogen storage tanks small enough to fit conveniently in the vehicle. The costly and problematic onboard "reformer" to convert gasoline or methanol into hydrogen thus becomes unnecessary, and the vehicle becomes lighter, simpler, cheaper, more efficient, and more reliable. See the Transportation section of www.rmi.org and RMI's Hypercar-related technical publications, cited there, for details.

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Hypercar[SM]

Hypercar vehicles are ultralight, ultra-low-drag, hybrid-electric cars, light trucks, vans, SUVs, etc., of any desired size and style. Their design is radically simplified, highly integrated, and software-rich. They can use an engine hybrid or a fuel-cell hybrid driveline, but are peculiarly well suited to the latter, using direct hydrogen with no onboard reformer.

Hypercar, Inc. (www.hypercar.com) is a young for-profit company spun off from Rocky Mountain Institute in 1999, initially funded with $5 million of angel and institutional private equity, and currently raising second-round capital. In November 2000, with a few million dollars and in eight months, it completed the initial development of the *Revolution* concept car, with the following appearance in an illustrative "active lifestyle" flavor (easily changed to many other sizes and styles):

The basic attributes of this manufacturable and production-costed concept car include:

- Midsize sport utility vehicle, comparable to Lexus *RX-300* or Ford *Explorer*
- Comfortably seats 5 adults; 69 ft^3 / 1.96 m^3 cargo with rear seats folded flat; flexible interior packaging—*e.g.*, can contain two adults and two kayaks
- 99 mpg-equivalent (EPA 115 city, 84 highway) (2.38 L/100 km) with compressed H2—5× Lexus *RX300* efficiency, 5.5× Ford 2000 *Explorer* efficiency
- Goes 55 mph (89 km/h) on just the power used by a normal car's air conditioner; its own a/c needs only about a fifth that much
- 0–62 mph (0–100 km/h) in 8.3 s; all-wheel digital traction control, responding vastly faster than today's ABS; body 1.5× stiffer than that of a good sports sedan
- Top speed governed to 89 mph (otherwise could go much faster).
- 330-mile / 530-km range on 7.5 lb / 3.4 kg of hydrogen stored with exceptional safety
- Efficient packaging—6% shorter overall than a similarly spacious *Explorer*—with attractive styling
- 47% of *RX300*'s weight (1889 lb / 857 kg), but carries a similar load (1014 lb / 460 kg), even up a 44% grade
- Emits only clean hot water; doesn't harm the earth's climate if fueled with sustainably sourced hydrogen
- Ground clearance from 5" / 13 cm at highway speed to 7.8" / 20 cm off-road, with unique suspension control choices

- Excellent aerodynamics; low-rolling-resistance tires can run flat for 125 miles (202 km) at 50 mph / 81 km/h, requiring no spare tire
- Occupant safety cell undamaged in a 35-mph / 56 km/h simulated head-on wall crash—just replace the front end
- Designed to meet the Federal 30-mph / 48 km/h fixed-barrier occupant safety standard in a head-on collision with a vehicle twice its weight, each car moving at 30 mph
- Composite body doesn't dent, rust, or fatigue—bumpers bounce back unharmed from a 6-mph / 10 km/h collision
- Software-rich, open-architecture functionality offers numerous customization and upgrade paths
- Diagnostics, tune-ups, and seamless upgrades performed via broadband wireless with many value-added options
- Highly redundant data systems and steer- and brake-by-wire controls increase safety
- Safety-enhancing, handicapped-friendly sidestick, sending the car in the direction in which you point it, automatically compensating for sidewinds and other outside influences; no hazardous steering column or pedals; safer driver airbag
- Very simple, intuitive driver display and controls; minimal driver distractions; automatic navigation to refueling sites
- Consistent with a 200,000-mile / 322,000-km warranty; lifetime brakes; repair shop visits should be very rare

The platform combines uncompromised feature level and performance—a vehicle meeting and expanding expectations for functionality, esthetics, and environment—with similar breakthroughs in manufacturability, competitiveness, and profitability:

- Advanced-composite design and manufacturing processes tuned for new, affordable volume production methods
- No traditional body shop and no paint shop—traditional automotive assembly's two biggest costs
- A single worker can lift each body part unaided; body parts snap together in self-aligning, ultra-strong adhesive joints
- Far lower tooling and equipment cost, with modular manufacturing equipment investments phased as output grows
- Nominal model plant's preliminary cashflow projection implies operating profit at 1/6 volume in year one and cumulative cashflow profit (including payoff of all development and production investments) at 2/3 volume in year two
- Production-plant scale flexible downwards and modular upwards
- Potential for short product cycle times, supporting a diverse, agile, and rapidly evolving model portfolio
- Low breakeven volume and financial risk per model brought to market; more robust financial performance
- Financial risk/reward profile for manufacturers is therefore the opposite of the traditional car industry's

Hypercar, Inc. is not an automaker but a developer of highly integrated automotive designs. The firm intends to license its vehicle designs and its manufacturing, system, and subsystem technologies to automakers and their suppliers. Such vehicles should sell because they're *better*—superior products that redefine customers' expectations—rather than because they're clean and efficient. A business model based on selling or leasing such vehicles can therefore rest solely on value to the customer and competitive advantage to the manufacturer, rather than relying on such random variables as fuel price or tax, climate or smog policy, mandates or subsidies, or other government interventions in the market.

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82 percent less

A normal midsize SUV gets 18 (*Explorer*) to 20 (*RX-300*) mpg. The 82% comparison is with the 2000 Ford *Explorer*, the best-selling U.S. SUV. In terms of oil, however, the saving would be not 82% but 100%, since the hydrogen would normally be made from natural gas (or, if cheaper, from offpeak retail electricity, preferably renewable) rather than from oil.

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hydrogen

fuel cells

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save globally

OPEC exported about 24.5 Mbbl/d in 1998 (EIA, *International Energy Outlook 2001*, Table 13), or 46% of the 53.3 Mbbl/d traded worldwide. In 2020, EIA's Reference Case (*id.*, Tables 11 and 13) forecasts OPEC output of 59.3 Mbbl/d and exports of 48.6 Mbbl/d (56% of 86.5 Mbbl/d traded worldwide); transportation gasoline consumption around 63 Mbbl/d (www.eia.doe.gov/oiaf/ieo/images/figure_84.pdf); and world gasoline and diesel consumption for transportation around 47 Mbbl/d (www.eia.doe.gov/oiaf/ieo/images/figure_88.jpg), the difference being due to aviation fuel, marine bunker, train fuel, and the like. Total transportation fuel consumption worldwide in 2020 is projected at 67.5 Mbbl/d (EIA, *International Energy Outlook 2001*, Table E1), comprising 29.8 Mbbl/d gasoline and 21.5 Mbbl/d diesel (Tables E2 & E3), plus 9.8 jet fuel (E4), 2.9 residual oil (E5), and 3.3 other (E6). Of this, 50.8 Mbbl/d is for road transport (E7). Using the current fraction (78% in 1997–98: ORNL *Transportation Energy Data Book: Edition 20—2000*, Table 2.6) of highway transport energy used by cars and light trucks yields ~40 Mbbl/d for those purposes. Essentially all of that would be saved by full use of Hypercar vehicles. To the extent those were hydrocarbon engine hybrids rather than hydrogen fuel-cell hybrids, so they saved ~4/5ths of the oil rather than all of it, one need only extrapolate a bit further into the future (as would be required anyhow for Hypercar vehicles to saturate the fleet) and take account of a growing population of people and vehicles. In contrast, OPEC's output in mid-2001 was only about 27 Mbbl/d, or about 30 including non-crude-oil liquids: see www.eia.doe.gov/emeu/cabs/opec.html.

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nuclear plants

Hypercar vehicles can be readily designed to plug in as portable power plants, typically in the 20–40 kW range, when parked, which private cars are ~96% of the time. They can be leased to people who work in or near buildings where fuel cells will by then have been installed for power, heating, and cooling. The “hydrogen appliance” that makes the hydrogen (typically from natural gas) to run that in-building fuel cell is sized for peak building loads that seldom occur, so most of the time it has spare capacity to produce hydrogen for fueling cars parked nearby. They can then be plugged into that spare hydrogen capacity and into the electric grid, and operated to sell back electricity, at the real-time price and at the time and place where it is most valuable—turning a previously 96%-idle second-biggest household asset into a profit center that can repay about a third to a half the cost of leasing the car (under U.S. conditions; more under European or Japanese conditions). The marginal investment required (in greater fuel-cell durability, in-building hydrogen storage and delivery to cars, and car connection to the electric grid) are small compared to the benefits of using the hydrogen source, fuel cell, and inverter that are already paid for.

It doesn’t take many drivers’ liking this new value proposition to put the world’s thermal power stations out of business, because a full fleet of Hypercar light vehicles in, say, the United States (~204 million in 1998: ORNL *Transportation Energy Data Book: Edition 20–2000*, Tables 7.1 & 7.2), times ~20–40 electric kW per vehicle, equals ~4–8 TW or billion kilowatts, *vs.* 1999 U.S. installed net summer capability of 0.78 TW). It could therefore displace all the fossil-fueled and nuclear stations (0.66 TW in 1999) about 6–12 times over, subject to due allowance for matching the timing of generation and demand.

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designed

fuel cells

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three or four percent

The USGS’s $22/bbl mean reserve estimate of 3.2 billion barrels would be displaced by making 4% of the U.S. car fleet equivalent to a Toyota *Prius*, 3% to a Honda *Insight*, or 2.3% to Hypercar, Inc.’s 99-mpg midsize SUV *Revolution* concept car. These figures are simply the reciprocals of the number of equivalent Refuges calculated earlier.

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