BACKGROUNDER

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The Prospective Role of Unconventional Liquid Fuels

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RESOURCES FOR THE FUTURE

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Abstract

This paper explores the prospective contribution to the U.S. oil supply of unconventional liquid fuels (*synthetic fuels*, or *synfuels* for short) over the next 20 years. The liquids in question are those derived from U.S. oil shale resources, U.S. coal, and Canadian oil sands. Of these, development of shale-based fuels is least advanced toward demonstrated technological viability, let alone commercialization and deployment. Coal-to-liquids (CTL) conversion is commercially well advanced in South Africa, but with little attention to greenhouse gas management—a major challenge to U.S. CTL development, even where use of a coal–biomass blend attenuates the greenhouse fallout. In terms of both technological and economic—though not environmental—terms, Canadian oil sands are far ahead of the other two synfuels, with current production capacity at well over a million barrels per day and steadily rising output expected between now and 2030.

The overwhelming share of Canadian oil sands production, now and prospectively, is destined for U.S. markets. To the extent that increased U.S. fuel imports from *anywhere* are judged to undermine U.S. energy security, supplies of Canadian origin would be no different from those originating in the Persian Gulf. A more nuanced perspective would treat Canadian supplies as a stabilizing, rather than destabilizing, factor in world oil markets.

As fossil resources, all three synfuels are more carbon intensive than petroleum products derived from conventional crude oil. The pursuit of carbon dioxide capture and long-term geologic containment are as vital a research and development imperative for these as for other energy conversion processes, such as coal-fueled electric generation. Moreover, a number of nongreenhouse environmental uncertainties remain to be fully addressed. Managing the toxic residues in wastes from oil sands production is a case in point.

Oil sands production and import magnitudes aside, standard U.S. projections show minimal output—not much more than a million barrels per day—from shale and CTL by the 2030 endpoint of the overall National Energy Policy Institute (NEPI) project, and even those expectations presuppose a world oil price close to $100 per barrel (in 2008 prices) by then. Even where the purely technical and economic conditions might point to an "overnight" output capacity of several million barrels per day by 2030, achieving such a level in the face of a variety of lead-in requirements (e.g., permitting, environmental impact statements, and land rights adjudication) could make such a target hard to attain. At the same time, a number of recent studies point to the likelihood of major progress in the course of the 2020–2030 decade. The *post*-2030 outlook can therefore be viewed as more upbeat than the flavor of this synopsis.

The one factor unlikely to impede that prospect is the matter of resource adequacy. Although they are nonrenewable, shale, oil sands, and coal exist in great abundance. In a post-2030 world, constraints

other than resource limitations may well kick in before the exploitation of these resources confronts scarcity and cost pressures.

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Introduction and Rationale

Concern over the reliability and long-term adequacy of crude oil has heightened interest in the potential contribution to U.S. energy supply of unconventional liquid fuels. Differentiated from conventional crude oil and often called *synthetic fuels* (or *synfuels* for short), these are liquids derived from coal, oil shale, and oil sands (commonly also labeled *tar sands*). This paper explores the prospective role of such fuels, with emphasis on the considerable uncertainty that still surrounds their economic and environmental viability.

Crude oil–based petroleum products have long served a vital need in modern energy and economic systems. In the United States, liquids presently constitute about 40 percent of available primary energy supply and around 55 percent of end-use energy deliveries, with the overwhelming share of that going into transportation.[1] Though less carbon intensive than coal, today's use of crude oil–derived liquids nonetheless accounts for 43 percent of the nation's carbon dioxide (CO_2) emissions from fossil fuel combustion. Summary statistics appear in Table 1.

Energy needs in transportation are commonly singled out for particular attention in synfuels discussions. Even with significant gains in fuel efficiency, fuel requirements in the transportation sector are—at least in the short-to-medium term—among the least substitutable energy options facing the country. (Residential energy requirements and those for electric power generation, by contrast, can be accommodated by a variety of fuels.) A major role for liquids from biomass is unlikely in the near future; thus the question, if not gasoline or diesel from

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[1] End-use deliveries are a higher percentage of the nationwide end-use totals because the latter include secondary products after conversion losses (largely accounted for by electric power) have been netted out.

conventional crude oil, then what? turns on more than academic curiosity. This paper, too, revolves around synfuels-derived transportation fuels.[2]

Table 1. Sectoral Distribution of Primary Energy Consumption and CO_2 Emissions, 2007

	Energy (%)	CO_2 (%)
Petroleum	40	43
(of which transportation)	(28)	(34)
Natural gas	23	21
Coal	22	36
Other	15	—
Total	100	100

Note: The "other" category in the table is composed largely of hydroelectric and nuclear power, whose operations are assumed to involve zero CO_2 emissions.
Source: EIA 2009.

Although the debate remains far from settled, some experts argue that a long-term history of relatively stable real oil prices may begin to be threatened by several forces, acting singly or in combination: a growing scarcity of U.S.—and, conceivably, worldwide—crude oil reserves and resources; the exercise of market power resulting from disproportionately large deposits in a few countries of the Persian Gulf; and disruptions in the flow of oil, whether politically deliberate or the result of unforeseen violence. The fact that U.S. net oil imports currently represent more than half of the nation's oil consumption underscores the anxiety evident in the policymaking and wider communities about such vulnerability.

A major appeal of the three unconventional resources highlighted in this paper arises from their undisputed abundance as well as their secure locations. Substantially augmenting global oil resources in less risky regions of the world could serve to hold prices in check, both because of expanded overall supplies and because greater geographic diversification could frustrate attempts to use oil as a strategic or political tool. To be sure, oil sands production—now and prospectively concentrated in Canada's northern Alberta region, with the preponderant share of that output destined for U.S. markets—is a significant factor in U.S. oil-*import* dependence, but it is a source of supply indisputably more secure and reliable than liquids originating elsewhere in the world. (For that matter, greater global, not just North American, output from

[2] Singling out transportation fuels is based on more than the prominence of the transportation sector. Especially in the case of coal conversion, the refining process favors the production of these products. (See discussion of the Fischer–Tropsch process in U.S. Department of Energy [DOE] 1982.)

still other places could benefit the United States, especially if such expansion promoted, rather than restricted, geographic supply diversity.)

Exploitation of synthetic fuels has, from time to time, been proposed as a backstop against the prospective scarcity of conventional crude oil. But because the expected rise in crude prices has repeatedly failed to occur and because synfuels production technology remained costly and stubbornly problematic, the advent of a synfuels era has never materialized in any significant fashion. That instance of unfounded expectation proved to be the case not long ago in the wake of the oil market upheaval of the 1970s with its dramatic price increases. That event revived the quest and overly ambitious near-term production targets for an assured, affordable, abundant source of liquid fuels, with particular emphasis on oil shale. But the short-lived existence of a government entity (the Synthetic Fuels Corporation, or SFC), designed to spur synfuels development, proved unsuccessful—undermined, once again, by declining crude oil prices that commenced in the early 1980s, and also by what seems in retrospect incredible optimism as to the ease with which a promising but fledgling technology could be transformed into large-scale production.[3]

Historical experience notwithstanding, it seems timely, given the clouded world oil picture, to give synfuels a fresh, but guarded, look—guarded because resource adequacy and location, despite the desirability of synfuels attributes, are obviously far from the whole story. Exploitation of each of these fossil-based energy sources poses significant environmental, economic, and technological challenges. The environmental challenge is dominated by, though not limited to, the need to deal with the disproportionately large volume of associated greenhouse gas emissions,[4] relative to those generated in the extraction of crude oil. (Threats to the preservation of water quality and quantity represent another important environmental issue.) The concurrent economic challenge involves achieving unit production costs roughly

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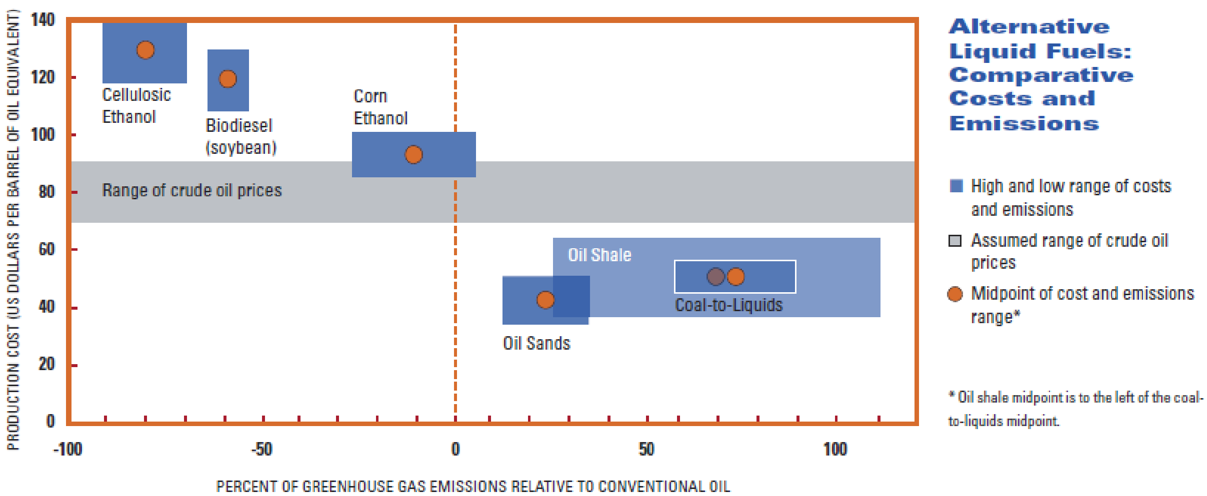
[3] With large-scale financial support by SFC, established in 1980, it was viewed as entirely realistic to expect a volume of synfuel liquids output (composed of shale oil and/or liquefied coal) of no less than 500,000 barrels per day by 1987 and several million daily barrels by the early 1990s. A 1980 congressional report observed that the required technologies were “ready for deployment [needing only] financial incentives to proceed to production” (U.S. House of Representatives 1980, p. 12). In reality, virtually no production materialized, and SFC was terminated in 1986.

[4] Our primary emphasis, as with most climate studies, is on CO_2. But some studies cited or consulted here conduct their analysis in terms of the more inclusive metric of CO_2-equivalents (or CO_2e), thus accounting not only for CO_2, but also additional greenhouse gases like methane and nitrous oxide. In the United States, CO_2e emissions are an approximately 1.2 times CO_2 emissions alone. Emissions from transportation are virtually all in the form of CO_2.

competitive with a broad range of world oil prices. Pursuing this dual challenge, as Figure 1 reminds us, is no simple matter. In a somewhat stylized schematic, the figure points up a key dilemma across a spectrum of alternative liquid fuels: environmentally attractive sources are costly, and promising competitive sources face serious environmental problems. Thus, although oil sands and coal-to-liquids (CTL) technologies have made significant commercial and technological progress in recent decades—the latter particularly in South Africa—few would argue that their environmental hurdles have been largely overcome. That cautionary reminder applies particularly to oil shale extraction, which is far lower on the learning curve in both technical and environmental respects than the other two resources. The rest of this paper will more specifically take up some of the key issues highlighted by Figure 1.

Figure 1. Alternative Liquid Fuels: Comparative Costs and Emissions



Notes: Imagine a downward-sloping line from the upper-left quadrant to the lower-right quadrant and you'll appreciate the paradox conveyed by this figure: liquids that are CO_2-friendly are widely judged to be costly; those that seem competitive with crude oil are CO_2-intensive. The vertical and horizontal ranges of each bar reflect uncertainty about, respectively, cost and emissions. (Note that, although the text discussion centers mostly on CO_2, the figure covers all greenhouse gases; these sum to about a 1.2 multiple of CO_2 alone.) Cost and emissions data for alternatives to crude oil are estimated to roughly approximate 2008–2009 conditions. The $70- to $90-per-barrel range of crude oil prices is intended to reflect the situation prevailing toward the end of 2009 rather than the much higher projected level and range of those inflation-adjusted prices by EIA for the year 2030. Emissions (for both crude oil and its alternatives) are calculated on a *lifecycle* (*well-to-wheel*) basis, spanning extraction or production at one end to use and combustion at the final demand stage. Technological advances that could spur a clustering of various fuel options in the "clean-and-cheap" bottom-left area is obviously a desirable, though for now, still elusive goal.
Source: This figure is a revised version of one appearing in Resources for the Future's magazine *Resources*, Fall 2006.

Organization of the Paper

The balance of this paper comprises eleven sections. It begins with an assessment of the resource base underlying each of the three liquid fuel feedstocks considered and is followed by a brief description of their respective conversion technologies.

I next look at observable trends in U.S. synfuels (virtually nil except for access to Canadian oil sands) and baseline projections over the period to 2030, with the recently issued Energy Information Administration (EIA) *Annual Energy Outlook 2009* and estimates by Canada's National Energy Board (NEB) serving as points of departure for considering that future perspective.

Building on the foregoing and supplemental material, an economics discussion provides suggestive, but duly qualified, indications as to the long-run competitive standing of each of the three liquid fuel categories. But because experience with oil sands and coal liquefaction—and, therefore, a basis for judgement about economics—is appreciably further along than with oil shale, primary attention is directed to the first two resources.

By means of a *lifecycle* (or *well-to-wheels*) orientation—spanning resource extraction to refined transportation fuel deliveries to end-use consuming sectors—three ensuing sections address greenhouse gas and other environmental and social externalities and implications for, respectively, oil sands, CTL, and oil shale. In principle, economics and environmental issues might be treated under a common topical framework. After all, numerous environmental problems—say, an obligatory reclamation of mined land—often translate into explicit components of a firm's total cost burden. On the other hand, among the three synfuels technologies considered in this paper, prevalent and looming environmental issues have not yet been reflected, or only inadequately so, in quantifiable social or internalized private costs. Hence, the separate treatment accorded economics and the environment here.

Although the paper focuses almost exclusively on fossil-based synfuels, it is useful to take note of the extent to which a blend of fossil- and biomass-derived fuels may prove both to be feasible and to offer beneficial environmental and economic outcomes compared with fossil fuel inputs alone. A brief section discusses that issue.

The final section of the paper presents principal conclusions. The exposition draws on a number of recent studies, including those of the RAND Corporation, the National Research Council (NRC), the National Energy Technology Laboratory (NETL) of the U.S. Department of Energy (DOE), and several other American and Canadian reports. In that respect, it should largely be viewed as a distillation of, and observations about, those studies rather than findings stemming from independent research.

The Resource Base

Whatever the economic, technological, and environmental uncertainties surrounding the three conversion systems, the adequacy of their respective resource endowments is generally undisputed.[5]

Coal

The most recent effort to probe the U.S. coal resource situation was a congressionally mandated study by NRC (2007). Although the report declined to affirm the frequently-expressed notion that there is a sufficient supply of coal for several hundered years, it does express confidence of a magnitude sufficient to meet the nation's needs for at least 100 years at current rates of consumption. Given the 20-year perspective of this report, that judgement allows us to concentrate on exploring the viability of innovative coal liquefaction technologies, though it is worth noting that the NRC study does have particular relevance to the present effort in one respect: the importance with which it views the identification of geologic formations available for the sequestration of CO_2 associated with coal use.

Oil Shale

EIA data (in *Annual Energy Outlook 2009*) show a conventional crude oil resource base of 169 billion barrels, of which 23 billion are proved and 146 billion unproved. In contrast, based on rock containing at least 30 gallons per ton, recoverable oil from shale is estimated at some 400 billion barrels, predominantly concentrated in the Green River Formation, covering portions of Colorado, Wyoming, and Utah.[6] A more relaxed criterion—deposits exceeding 15 gallons per ton—yields a resource total approaching one trillion tons. Even those magnitudes may be serious underestimates. An updated U.S. Geological Survey (USGS) assessment reckons the in-place quantity of shale in just the Piceance Basin of Western Colorado at more than 1.5 trillion barrels.

[5] The present paper limits its scope to liquids largely derived from coal, oil shale, and oil sands resources. But, assuming a continuation of recent successes in natural gas discoveries and reserve additions, it is not far-fetched to consider a fourth route to unconventional liquid fuel supply—one based on natural gas feedstocks.

[6] Domestic U.S. oil shale resources are estimated at roughly equal to those located in widely scattered countries elsewhere in the world (USGS 2006).

But, as USGS notes (and as is discussed further below), the development of "oil shale has significant technological and environmental challenges and no economic extraction method is currently available in the U.S. Therefore it is unknown how much of the assessed in-place … resource is recoverable" (USGS 2009). A 2005 RAND report similarly reminds us that, because oil shale production has not been profitable in the United States—whether through underground extraction or surface retorting—"such estimates do not yield useful information" (Bartis et al. 2005, p. 5). It seems sufficient to note that the shale resources of western Colorado alone are equal to the total of the world's proven crude oil reserves.

Canadian Oil Sands

As is the case with oil shale in the United States, Canada's estimated oil sands reserves are a large multiple of the country's reserves of conventional crude: the respective numbers are 174 billion for the former and 5 billion for the latter. (Although both resources bear the label *proved*, one wonders how confidently the oil sands magnitude can be characterized as largely recoverable under "prevailing economic and technological circumstances"—the dual criteria customarily applied to proved resource estimation. As with U.S. oil shale, the economic and technological uncertainties remain significant.) Oil sands deposits occur both in strata shallow enough to permit recovery by means comparable to strip mining in coal extraction and in situ, at depths far below the surface and obtainable only by underground mining aided by subsurface heating to coax the organic material (bitumen) to the surface. The deep deposits constitute the overwhelming proportion of Canadian oil sands.

Alone among the three liquid feedstocks considered in this report, oil sands have progressed to the point of significant commercial-scale development, with current output of more than one million barrels per day, or a third of Canada's aggregate oil production.

The assessed magnitude of Canadian oil sands swamps the estimated amount of the resource in the United States, with only between 12 and 19 billion barrels judged present in Utah (Argonne National Laboratory 2008). Realistic expectations of significant future oil sands production volumes might as well focus on the Canadian contribution.[7]

[7] But one should note the (so far minimally exploited) heavy oils of the so-called "Orinoco Tar Belt" of Venezuela. EIA (2009) reports estimated recoverable resources of between 100 and 270 billion barrels. In its *International Energy Outlook* of May 2009, EIA estimates output reaching a million barrels per day by 2030.

The Three Technologies in Brief

With the adequacy of the underlying resource base taken as a given, what are some major impediments to the commercialization of each of the three technologies reviewed in this study? Highly abbreviated, they are as follows.

Canadian Oil Sands

This resource comprises extensive sand formations that, analogous to conventional petroleum deposits, are permeated by organic (i.e., hydrocarbon) substances. The developmental challenge is that of removing the hydrocarbons (in the form of bitumen) from the sand by adapting traditional mining techniques. The techniques in question are either surface removal, similar to strip mining in coal production, or deep (in situ) recovery, facilitated by a process in which the heated bitumen can be coaxed to the surface. According to an Alberta government estimate, an overwhelming proportion of the province's oil sands resources can only be tapped through in situ recovery techniques.

Among numerous associated difficulties, oil sands production is complicated by a high proportion of materials to contained liquids; frigid temperatures that can damage equipment; a pace of development that can overwhelm the social infrastructural base; and environmental degradation through both solid wastes and gaseous emissions, notably a rate of CO_2 releases that, per unit of delivered petroleum product (reflecting particularly high CO_2 intensity at the upstream extraction stage) significantly exceeds those associated with conventional oil production.

Coal

Significant experience with coal liquefaction antedates that with shale and oil sands. Applying the Fischer–Tropsch (F–T) process and several other techniques developed some years earlier, the German government produced costly coal-based liquids to compensate for the country's limited access to conventional crude oil during World War II. For their part, South Africa's Sasol plants have carried on CTL operations for half a century. (The acronym refers to the "South African Coal, Oil and Gas Corporation"–and integrated energy and chemicals company.) During the country's apartheid era, the decision to pursue coal liquefaction was driven by perceived political necessity—in particular, uncertainty about the country's ability to meet its oil requirements on the world market. In the post-apartheid years, however, the country, which is richly endowed in coal resources, has progressed with advanced liquefaction techniques to the point where it is currently viewed as a technological world leader, though government subsidization and import protection cloud a full economic assessment. Recent production levels of South African coal-based liquids stood at around 180,000 barrels per day (largely produced by Sasol), which is more than 35 percent of the nation's overall oil consumption and a significant share of the country's transportation fuel requirements (EIA 2008).

In contrast to oil sands and oil shale, which involve extraction and conversion to liquids of the embedded organic matter, coal liquefaction requires chemical transformation. Several alternative techniques exist for achieving that transformation, the choice dictated in part by whether the desired output is oil and gas or just oil. Broadly speaking, these techniques are characterized as either indirect liquefaction or direct liquefaction.

To date, the F–T method, using indirect CTL conversion, remains the dominant transformation process. In this process, an intermediate product—*syngas*—is condensed to yield a liquid which, in turn, can be refined into transportation fuels or, less optimally, a variety of other petroleum products. (The use of natural gas as an alternative, or complementary, feedstock to coal is discussed in Box 1.)

Oil Shale

Although halting efforts to exploit oil shale resources date from the 19th century (particularly in Sweden, Scotland, and the Baltics), major interest developed only within the last 50 years, especially following the world oil price turmoil of the 1970s. This long-delayed interest was spurred by two factors. First, the cheap price of crude oil was, for a long time, an economic disincentive to go after shale in a serious way. And second, looming technological hurdles compounded the hesitancy. Thus, although the Colorado complex of Union Oil Company (now a subsidiary of Chevron) was the only commercial facility to have operated even briefly, its 10,000 barrel per day operation during the 1980s produced only cumulative losses, forcing a shutdown of the activity at the end of the decade.

Box 1. Why Not GTL Instead of CTL?

A coal-based building block to produce synfuels has largely eclipsed interest in natural gas as a possible feedstock. But a natural gas-to-liquids (GTL) process is a relatively advanced (and, of course, attractively low-carbon) technology. And GTL projects in Qatar and Malaysia are well along toward full operational status. In the United States, recent natural gas exploratory and developmental success, along with solid price declines, might well justify serious consideration of GTL as a significant—or, at least, complementary—route to liquefaction.

Natural gas reserves have grown at an annual rate of roughly 5 percent during the last five years, with a momentum tending to show each year's reserve additions exceeding that year's production by a growing margin. That record of reserve expansion reflects, in large measure, the inclusion of formerly unconventional and technologically problematic deposits, such as shales in the Williston Basin of Montana and surrounding states, the Marcellus Appalachian shales, and the Barnett Field of Texas. Concurrently, real natural gas prices declined by more than 50 percent.

Whether this favorable record of reserve additions and price declines will endure over our 20-year projection span is, of course, uncertain. (For the record, EIA's *Annual Energy Outlook 2009* projects modest annual price *increases* of 1.2 percent for gas and 0.6 percent for coal.) And in terms of energy content, the volume of coal reserves embody many times the British thermal unit content of gas reserves, but also many times the carbon content.

As part of a broad picture, GTL strategy could look to the rapidly growing international liquefied natural gas market to bolster domestic supplies, but that reassurance could potentially make for a two-edged sword with disproportionate dependence, as in the case of crude oil, on Persian Gulf producers.

Finally, it is conceivable that in time, the promise of still much greater expansion of competitively priced natural gas could materialize as a result of breakthroughs in the extraction of methane hydrates. That could revive an interest—albeit delayed—in a GTL scenario.

Oil shale contains organic matter (kerogen) that, when heated to temperatures of close to 1,000°F, can yield liquids comparable to conventional crude oil. There are two possible ways of extracting these liquids. One technique involves mining the material (using methods similar to those used for deep coal), with the oil removed in aboveground retorts through a distillation process. The other technique—potentially more attractive on both economic and environmental grounds, but so far tested only at a very small scale—involves in situ combustion designed to liquefy the contained oil.

Technological hurdles aside, shale oil production presents problems which, if different from those unique to oil sands, are just as real. One issue relates to geography. Instead of being located in the oil sands region of frigid Alberta, the Rocky Mountain shale deposits portend intrusion into a fragile topographic and ecological environment of its own. In the case of surface retorting, a large ratio of overburden to liquids creates a major challenge of responsible management. And, considering the shale oil fuel cycle leading up to final delivery of, say, a gallon of gasoline or other petroleum product, one must reckon on a disproportionately high CO_2 emissions rate.

Alternative Projections of Synthetic Fuels Output

A report citing a number of alternative projections requires several cautionary comments. It is especially risky to read too much into comparisons *among* projections. Without an effort—which goes beyond the scope of this paper—to develop a standardized basis of comparison (say, with respect to such things as methodology, timelines, assumed technological advances, policy assumptions, and financial features), such comparisons may reveal useful insights but, at the same time, should be viewed with a discriminating eye. To put it another way, identical forecasts need not necessarily signal consensus because different forecasts may nevertheless be built up from numerous common underpinnings.

Oil Shale and CTL in EIA's *Annual Energy Outlook 2009*

Unsurprisingly, oil shale and CTL remain negligible in *Annual Energy Outlook 2009* (hereafter AEO 2009), which contains projections of U.S. liquids production to 2030. But it is worth getting at least a cursory sense of the magnitudes one might reasonably contemplate over the next several decades. Shale oil fares least optimistically, with output foreseen for 2030 at little more than the 140,000 barrels per day in AEO 2008, even with an assumed reference case oil price rising to $128 per barrel (in 2008 prices) by that year. Of course, such assessments are driven not just by changing oil market conditions, but by stubborn technological impediments, prompting EIA to view 2023 as probably the earliest date for the start of commercial production..

CTL prospects are judged to be more promising, both in EIA's reference case and in its high–oil price projections. In the former case, CTL first appears as a contender in 2015, expanding thereafter to reach 260,000 barrels per day in 2030. The high–oil price case ($200 per barrel in 2030, expressed in 2008 prices) raises that figure to 290,000 barrels per day. But neither number represents more than a tiny fraction of the nation's total projected liquid fuel consumption. Nor would it displace more than a trivial portion of the country's coal output.

A technologically more optimistic scenario than one circumscribed—as in this case—by EIA's perhaps overly conservative assumptions cannot be dismissed.[8] It nevertheless seems prudent, in line with the perspective of the present report, to view CTL, let alone shale, as best approached in terms of their still uncertain economic, technological, and environmental features rather than with expectations of a consequential contribution to the country's suite of energy choices 20 or 25 years in the future. Indeed, it is worth noting that, among unconventional (not just synthetic) liquid fuel feedstocks, biomass is projected to be the leading contender within that time frame, reaching 328,000 barrels per day in 2030.

Canadian Oil Sands

Projections by Canada's NEB should not be viewed as directly comparable (whether in underlying assumptions, time horizon, or methodology) to those of EIA. But they convey a clear sense of how one of the government's leading energy analysis bodies sees the unfolding oil sands pathway (NEB 2007). From a recent annual output level of approximately 1.2 million barrels per day—or around 45 percent of Canada's total oil production—NEB projects that output will approach 4 million barrels per day by 2030.[9] Oil sands could then represent as much as 90 percent—and probably no less than 70 percent—of Canada's total oil production.

Even though the outlook is less dimmed by the uncertainties surrounding shale and CTL prospects, the projected growth in, and profitability of, oil sands depends on a large number of underlying economic and technical assumptions—not least expectations about world oil prices. In that respect, whether NEB's assumption of an oil price of around $55 per barrel (in 2007 prices) in 2030 is consistent with its oil sands output trajectory deserves critical scrutiny.[10] As these comments are being written (in the fall of 2009), a world oil price not far above that level seems to have markedly slowed investment in oil sands producing capacity, although that hesitancy in capital commitments may also be due to the unprecedented volatility in an oil price that peaked at $150 per barrel in 2008 before dropping to around $50 per barrel currently, not to mention a concurrent global recession of extraordinary severity. But the outcomes of other

[8] One can, of course, find judgements—commercial interests prominent among them—that contemplate output possibilities much higher and earlier than in the AEO (see Toman et al. 2008, 43).

[9] This figure is also used in EIA's 2009 *International Energy Outlook*, op cit. A high oil-price assumption ($200 per barrel in 2008 prices) raises 2030 output to six million barrels per day.

[10] As does NEB's conspicuously lower world oil price expectations compared with those of EIA—though that may reflect time lags in the projection–preparation cycle.

uncertainties will govern the developing growth of oil sands—for example, reductions in learning curve operating costs for in situ recovery such that they match those experienced in mining processes. (For the present, production is about equally split between surface mining and in situ recovery, but that situation, as noted, is not likely to endure.) In addition, the evolving price of natural gas must be considered because that fuel provides critical heat input into oil sands conversion operations. All that said, the enormity of the potential contribution of oil sands to the Canadian energy system (with a significant portion destined for the U.S. market) seems indisputable, even if the cited NEB projections materialize at levels somewhat below their presently estimated endpoint.

Oil Shale: Economics

Were it only for the competitive risks posed by uncertainty over future crude oil prices, oil shale exploitation would be no more or less disadvantaged than that of other fuels whose development incentives must embody the perennial and inescapable prospect of oil market gyrations and surprises. In the case of shale, however, the outlook for economic viability seems especially daunting—so much so that, as noted already, EIA projects scarcely *any* shale oil production by 2030.

Some analysts have nonetheless addressed the economic issue, however speculatively. The 2005 RAND study (Bartis et al. 2005, p. x) cites estimated production costs from “first-of-a-kind commercial mining and surface retorting plants” at levels ranging between $75 and $100 per barrel (converted here to 2008 price levels).[11] But given the little research and development (R&D) support directed to surface retorting—with its manifold environmental implications—interest seems increasingly to have shifted to in situ retorting as the commercially more promising approach to oil shale exploitation, even if that route remains experimental for now. Shell Oil appears to be prominent among companies pursuing such in situ extraction and conversion. This is because of the presumably more manageable environmental problems and appreciably lower, though still murky, production costs. (The oil shale cost range depicted in Figure 1 surrounds a midpoint based on these contrasting possibilities.) A federal government fact sheet describes the Shell conversion process as one “currently unproven at a commercial scale but…regarded by the U.S. Department of Energy as a very promising technology” (Argonne National Laboratory 2008).

[11] More recently, EIA (2009, 38), contemplates an almost identical cost range.

Such economic and technological uncertainties are compounded by the thorny question—so far, largely unaddressed as to its likely economic implications—of measures to mitigate the significantly higher CO_2 releases associated with oil shale extraction relative to conventional crude oil production. (See further comments on oil shale environmental implications below.) Directionally, CO_2 emissions restrictions, whether imposed through taxes or a cap-and-trade regime, would clearly raise shale oil production costs disproportionately. But what matters overall is how that differential at the primary extraction stage plays out competitively in meeting the demand for and use of refined products, such as gasoline for the automotive market.

Strengthened federal R&D support, complemented by favorable leasing policies, could no doubt shorten the timeline for the operation of the earliest commercial plants, which, as noted, EIA analysts believe could begin to materialize in the course of the 2020s. But even under optimal circumstances, shale oil production poses little prospect of meaningful additions to U.S. oil supply—and, therefore, of slowing oil import requirements—in the course of the next several decades. Correspondingly, economic benefits to U.S. consumers would, within the time perspective of this study, probably be modest at best.

Oil Shale: Environment

As noted by Bartis et al. (2005, p. 40), "Heating oil shale for retorting, whether underground or in situ, requires significant energy inputs…. [T]he production of petroleum products derived from oil shale will [therefore] entail significantly higher emissions of carbon dioxide, compared with conventional crude oil production…."

At the extraction stage, that disproportionately high degree of CO_2 intensity has been estimated at up to five times higher than that associated with the production of conventional crude oil. On a lifecycle basis, from extraction of the resource to delivery and combustion of a refined liquid product, it translates into emissions ranging between roughly 20 percent and 50 percent above those based on conventional crude oil (Brandt 2008).

Exploitation of oil shale resources presents broad environmental and social challenges that go beyond heightened greenhouse gas implications. Unsurprisingly, one of the principal challenges is that of avoiding the degradation of water quality (e.g., increased salinity of the Colorado River drainage basin) given the location of the resource in an already water-stressed and ecologically sensitive region of the United States.

Perhaps more easily remediable, but nonetheless real, are the demographic and related impacts that a large shale oil development regime would pose. A presently sparsely settled area could face substantial fiscal, social, and community infrastructural and institutional needs. As oil sands development in the Athabasca region of Alberta has—somewhat analogously—shown, such ancillary accompaniments to, and consequences of, a major resource development complex portend significant challenges for planning and public policy.

And as noted in the preceding section, we are still some way from being able to do more than speculate on a wide range of likely shale oil production costs. No doubt, the costs that do exist (even if privately held) subsume some of these *external* costs—notably, the matter of water requirements. But *internalizing* in dollar terms the full spectrum of socioeconomic impacts, including such "disamenities" as foregone recreational opportunities, could well mean surprises affecting the prospects for this resource.[12]

Canadian Oil Sands: Economics

What with both the extraordinary volatility in the world oil pricein the last several years and EIA's most recent reference case projection to 2030 (pointing to a price of $130 per barrel expressed in 2008 dollars), the long-term competitive outlook for oil sands would seem at once reassuring and markedly cloudy. Yet, on balance, a 2008 RAND report (Toman et al. 2008) provides a cautiously favorable picture of the long-term ability of oil sands to be commercially attractive even at a lower oil price and even if obliged to bear the cost of significant CO_2 emissions restrictions. Encapsulating that key outcome in terms of several noteworthy conclusions, we find the following.

- Even with carbon capture and sequestration (CCS) assumed inherent in the oil sands life cycle (extraction to end use), oil sands production costs in 2025 are competitive with conventional crude at a world oil price near $60 per barrel.
- A much higher assumed world oil price—say, close to EIA's reference case projection of $130 per barrel in 2030—cannot help but make the competitive advantage of oil sands still more robust. Still, in light of the volatility phenomenon just noted, alarm that prices may be headed downward and breaching the $60-per-barrel figure could inhibit capacity expansion investments. That, in fact, appears to have happened in the latter part of 2008

[12] Our focus on oil shale and other synfuels should not obscure the fact that environmental threats and damages are inherent in all mining operations. Consider the scars and wastes generated in an open-cast copper mine. But the energy and carbon intensity of synfuels give mining operations for these products an especially deserving amount of attention.

amid the precipitous and steep plunge in oil prices from the $140-to-150-per-barrel zone experienced not long before.

- In the RAND analysis, a competitive advantage would prevail at a shadow price of CO2 up to around $100 per tonne of CO2. (By way of context, the CO2 price hovered around $22 per tonne in the European Union carbon market in early September 2009.) Up to a shadow price of around $60 per tonne of CO2, the economics favor paying the shadow price rather than pursuing a CCS option. Beyond that point of "indifference," CCS becomes progressively more attractive.13
- Oil sands extraction and upgrading currently rely principally on the use of natural gas to meet large heat input requirements. Those energy costs are currently held in check as a result of natural gas having achieved significant exploratory success and declining prices. A number of analysts believe that that situation may prevail for the longer term. Still, variations in natural gas (or other energy prices), which can measurably lower or raise overall unit production costs, are a factor that firms are compelled to consider as an important part of their planning.

In short, and considering its wide-ranging scope, the RAND oil sands analysis lends considerable credibility to the findings highlighted above. Nonetheless, we are dealing here with a number of both technological and environmental challenges; ultimately, our success in addressing these challenges cannot simply be taken for granted because it will require a sustained commitment to research and reevaluation as experience dictates.

Consider just one elusive goal. CO_2 has, for decades, routinely been injected into operating oil reservoirs to achieve enhanced oil recovery (EOR). Such CO_2 disposition has, by all accounts, been carried out safely and with no significant CO_2 leakage into the atmosphere. (Such CO_2 as is necessarily emitted along with EOR-driven oil production is largely captured and reinjected.) But, because of the limited timeframe of EOR experience, an undisputed safe EOR–CO_2 record provides no assurance that the gas so injected and contained will remain locked in place and will not seep into the atmosphere over many more decades—indeed, centuries. Efforts underway in research facilities in Saskatchewan and elsewhere are therefore

[13] These observations apply only to the crude oil and oil sands extraction stages; that is, they exclude the downstream emissions (e.g., in refining) that a more exhaustive lifecycle assessment would include. In its highly stylized fashion, Figure 1 *does* reflect that broader perspective.

probing the prospect for truly long-term geologic containment (e.g., in saline aquifers) that removes that possibility.[14] In addition, a sustained commitment to oil sands development will need to contend with a host of environmental challenges. These are taken up next.

Canadian Oil Sands: Environment

At the scale at which production is increasing—from a recent level of about 1.2 million barrels per day—exploitation of Canadian oil sands poses an undeniably major environmental management challenge both for the industry and for policymakers charged with energy oversight responsibility. The environmental burden borne by oil sands development applies perhaps most conspicuously to the associated greenhouse gas emissions, but other environmental impacts are far from inconsequential.[15]

With respect to the greenhouse gas problem, by now a sufficient and well-documented number of estimates of the lifecycle *carbon footprint* allow us to delineate the magnitude of CO_2 emissions within a narrowing range of approximation. At the extraction stage, an emerging consensus centers on a figure indicating that, compared with conventional crude oil production, oil sands production generates CO_2 releases roughly twice as high (Farrell 2007; Argonne National Laboratory 2007)**,** although that reflects a degree of carbon intensity and emissions substantially below that associated with shale or coal liquefaction.

However, although that disproportionately large volume of emissions is dramatic (and, frequently, public awareness is directed primarily to *extraction*), when one follows successive stages of the production chain all the way to the delivery of liquid fuels to, and tailpipe emissions from, end users, the CO_2 penalty drops from a multiple of 2-to-1 to something like 1.25-to-1. The reason is that, between the extremes of extraction and end-use consumption, CO_2 emissions across intermediate stages (such as refining, pipelining, distribution, and final combustion) are unlikely to differ appreciably between a conventional crude oil or oil sands pathway. On the basis of various estimates, I judge that, very roughly, an end-use barrel of crude-based liquids

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[14] A detailed discussion of policy strategies governing EOR and longer-term sequestration appears in Bandza and Vajjhala (2008). See also the box below.

[15] Our discussion sidesteps the very much unsettled issue of CO_2 emissions constraints, whether within Canada or in concert with U.S. policy. An item in the *Toronto Star* (Woods and Talaga 2009) reports that the Canadian government is thought to be designing a greenhouse warming policy in which oil sands emissions would be dealt with more favorably than the country's industrial emitters.

signifies cumulative CO_2 releases of 1 tonne, whereas a barrel of oil sands-derived feedstocks signifies a magnitude of around 1.2 tonnes. With crude oil, extraction accounts for 10 percent, and the ensuing stages for 90 percent of emissions; with oil sands, the respective numbers are 25 percent and 75 percent.

But one also must acknowledge the lack of a standard definition of the exhaustiveness of the elements comprising a lifecycle calculation. If, say, methane leakages occur in natural gas piped to an oil sands complex, such releases ought, in principle, to be counted as a lifecycle emissions component. Similarly, the clearing of forest cover to make way for an oil sands project may, along with releases resulting from disturbed soil conditions, diminish photosynthetic absorption of $CO_{2.}$ But such tangential—and less certain—cases of CO_2 or other greenhouse gas implications are not considered here nor, to my knowledge widely addressed in specialized analyses. But it does seem reasonable to suppose that the quantitative significance of such releases is substantially dwarfed by the more direct activities discussed above.

When it comes to perceived or substantiated environmental threats separate from those related to greenhouse gases, oil sands development entails a series of significant issues that appear, at best, to be only partially internalized in the cost of production. Three items of particular concern are (a) the impact of boreal forest cover and the challenge of land reclamation; (b) the substantially greater water requirements comparison with those of conventional crude oil production; and (c) the management of wastes—in the form of *tailing ponds*—in which toxic liquids, separated out during oil sands processing, must be isolated and monitored for at least a decade to ensure the integrity of surrounding soils and groundwater.

Although a significant amount of oil sands production has been underway for well over a decade, that time span has not been long enough to gauge the long-term ecosystem threat in any of these three cases. With respect to land use, not only has reclamation been limited to a relatively low fraction of the area disturbed, but the ultimate success of such efforts remains to be validated. Notably, that judgement is not seriously contested by the governments of Canada or Alberta or by producing firms themselves—parties that do not always see eye-to-eye in assessing environmental impacts.

The water problem is complicated by the fact that the Athabasca River is virtually the sole source of water for oil sands operations which, in turn, represent the single largest claim on the river's flow. To be sure, the Alberta government has imposed maximum limits on withdrawals from the Athabasca but, as noted in the 2008 RAND study (Toman et al. 2008), without a more thorough impact analysis, how such limits would affect the river basin remains unclear.

Long-term management of tailings may be an even greater environmental dilemma. The land area required for their containment is huge. A few years ago, when oil sands production had not yet reached a million barrels per day, the ponds already exceeded an area of more than 30 square miles. Questions about the efficacy of controlling the migration of hazardous pollutants, the effect on migratory bird flyways, and possible releases of methane—a potent greenhouse gas—cloud the picture.[16]

For the present study, I echo precisely what is stated in the 2008 RAND study (Toman et al. 2008, p. 24): "Quantifying the importance of these issues to oil-sand production either in terms of the extent of the environmental impact or in terms of the additional cost that might be associated with [synfuels] production is beyond the scope of this report."

CTL: Economics

Commercial-scale CTL production has, like Canadian oil sands, been underway for decades in South Africa. Even so, the implications of ongoing South African CTL production for the economics and competitive standing of an American CTL industry can only be cautiously drawn. Too little is known, for example, about the role of subsidies and other possible distortions in the South African cost structure to gauge their relevance to American circumstances. In the United States, the prospects for an economically viable CTL industry face challenges over lingering technological aspects, locational factors, and environmental management—both greenhouse and nongreenhouse related, with the former driven especially by the outlook for CO_2 sequestration.[17]

Fortuitously, recently released and comprehensive studies, one by the RAND Corporation and the other by NRC, take up a range of the technological, economic, environmental, and public policy questions that are key to the emergence of a successful U.S. CTL industry (Bartis et al. 2008; NRC 2009). What may give the RAND report particular salience is its commissioning by

[16] This is not to question whether the cost of tailings management is internalized in the cited cost figures. The issue revolves around what is, at this point, virtually unknowable *long-term* soil and groundwater degradation that will very likely need to be more fully addressed in both its physical and economic dimensions.

[17] CTL shares with oil shale development a major, but largely unsuccessful, past effort through SFC to jump from a promising technology to a large and rapidly growing synfuels industry in the United States.

NETL and the U.S. Air Force. Interestingly, the latter has for several years shown active interest in CTL as a potential contributor to meeting its future jet fuel requirements.[18]

Notwithstanding wide understanding of the application of F–T technology to CTL production, the economics that will govern its competitive prospects are still beset with a host of uncertainties. The market prospects of CTL will be sensitive to five factors in particular.[19] First, an overriding go–no go determinant is the assumed level of the world oil price. Second, there is the possibility that unexpectedly large capital investments may be required to generate a given level of output at various stages of the learning curve that normally characterizes the emergence of any innovative technology. That issue, in turn, points up a third dilemma: the perceived need for government support to overcome reluctance by the private sector to invest in such an unconventional energy system. Fourth, constraints on going ahead may exist because an agreement on steps to manage the CO_2 emissions problem is still lacking. And finally, one faces the all-important matter of the extent to which assumptions and estimates for each of these factors combine to benefit the national economy.

The RAND study Batis et al., 2008) systematically addresses each of these economic considerations to arrive at an approximate bottom line for CTL's viability in a liquid fuels marketplace in which the world oil price is reckoned to range between $60 and $100 per barrel (2008 prices) in the year 2030. (As shown in Table 2, NRC adopts a comparable assumption.) Two other assumptions relate, first, to the effects on world oil markets of a supply elasticity under which each million barrels per day of CTL lowers the world oil price by around 1 percent and, second, to capital investment requirements for early and modest-sized plants of between $100,000 and $125,000 per barrel of CTL capacity. On a more qualitative level, the study emphasizes the critical importance of cost-lowering learning curve benefits as the industry progresses from a modest startup scale (of, say, no more than a level of 500,000 barrels per day) to the million-per-day dimension needed to play a meaningful role in the U.S., much less global, energy scene.

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18 Interestingly, and notwithstanding national security concerns over oil dependence, a group of high-ranking retired U.S. military officials has strongly questioned serious pursuit of a CTL strategy without effective management of its global warming implications (CNA 2009). CNA is a nonprofit and federally funded research organization that comprises the Center for Naval Analyses and the Institute for Public Research.

19 These factors apply as well to the use of a mix of coal-biomass feedstocks, discussed in more detail below.

Table 2. Per-Barrel Gasoline and Crude Oil Equivalent Costs under Different Assumptions

	Without CO_2 price ($)	With CO_2 emissions priced at $50/tonne ($)
Conventional gasoline		
at $60/barrel crude	75/60	95/75
at $100/barrel crude	115/100	135/110
CBTL without CCS	95/75	120/95
CBTL with CCS	110/90	100/80
CTL without CCS	65/50	110/90
CTL with CCS	70/55	90/70

Notes: CO_2 emissions refer to the entire fuel cycle, but CCS refers only to the CTL or CBTL synfuels production facility. As in NRC (2009), costs are expressed in 2007 dollars. The 2008 price deflator was 2 percent higher than 2007. The dollar figure before the slash refers to per-barrel gasoline costs as shown in NRC (2009); the figure after the slash is an estimate of the corresponding crude oil equivalent cost.
Source: NRC 2009 (p. 27 of prepublication copy).

In addition to the foregoing elements, the RAND analysis allows for onsite *capture* of 90 percent of CO_2 emissions but—in the face of too great a degree of uncertainty—makes no attempt to account for *sequestration* costs. CO_2 capture, an inherent feature of F–T technology, is estimated to cost a modest $5 or less per barrel. The resultant overall findings: CTL production costs could nudge this unconventional liquid fuel source into competitive territory at a conventional crude oil benchmark price of between $55 and $65 per barrel and an assumed coal price of $30 per short ton—in other words, only slightly higher than recent levels. Given the complementary decline in the world oil price, the net national economic benefits could be significant, though the realization of these benefits would depend on a level of CTL output not presently judged realistic. The RAND authors estimate that such benefits might average around $5 billion for every million barrels of unconventional fuels production. That corresponds to an average per-barrel benefit of around $15 which, in turn, could justify an equivalent amount of government subsidy to promote CTL development along environmentally sound lines.

As noted, the above cost calculations stop short of internalizing CO_2 sequestration. They also stop short of bracketing the life cycle over which the synthetic fuel products would need to compete with the conventionally produced product. One NRC study, more recent than the RAND effort, pursues the implications of that more extended lifecycle analysis (NRC 2009). The chastening message signaled by NRC's more tempered CTL production cost estimate is that CTL's competitive advantage over crude oil shrinks significantly once a CO_2 penalty ($50 per tonne in the case considered by NRC) is imposed over the entire fuel cycle, from initial production or extraction to final combustion. But exploration of these issues is still so tentative that it would be prudent not to view even the more expansive treatment of the topic by NRC as definitive. A robust sense of CTL's economic prospects within a broad analytical and empirical framework remains a work in progress.

CTL: Environment

Even with the use of conventional fuels, the long-term management of greenhouse gas emissions poses significant technological and policy issues. It is no longer uncommon—on grounds of climate change concerns—for public debate to swirl around the desirability of, for example, just building a standard pulverized-coal electricity-generating plant. (An ongoing controversy about such a plant in Kansas illustrates the point.) Although the problem is inherently no different from oil sands and oil shale operations, prospective recourse to an energy system whose associated CO_2 emissions are still larger (per unit of end-use energy) raises such concerns to a particularly pressing level—none more so than in the case of CO_2 releases associated with coal liquefaction and the outlook for a CCS solution (see Box 2).

Box 2: The Dilemma of CO_2 Containment

Discourse about CO_2 management often reminds us of the fact that the gas has long been routinely injected into depleting oil reservoirs to restore heightened recovery rates. But that has only temporizing relevance to a situation seeking, if not "indefinite" containment, then centuries-long sequestration in geologic strata, such as saline aquifers. CO_2 injected for purposes of EOR, in contrast, ensures only transitional retention before its venting to the atmosphere poses a renewed management challenge.

The scientific community is mindful of these problems and is increasingly and actively engaged in research to find solutions both technically sound and economically defensible. In the Weyburn (Saskatchewan) oil field, for example, CO_2-induced EOR has been under way for decades. But major research—with multicountry funding, both public and private—into the prospects for long-term geologic storage has more recently been grafted onto the Weyburn EOR operations.

Still, uncertainty about CCS achievability and the time frame over which its success can reasonably be assumed remains elusive. An effort to diminish that uncertainty was reflected in several CCS provisions of H.R. 2454 (the American Clean Energy and Security Act of 2009), passed by the House of Representatives on June 26, 2009. Although those provisions are largely directed to CO_2 emissions from coal-burning power plants, a broader legislative intent may be inferred from their application to other "appropriate industrial operations." The bill, strongly emphasized the need to pursue geologic sequestration and, toward that end, proposed consideration of establishment of a "Carbon Storage Research Corporation." But both that specific provision, along with the broader legislation of which it would be a part, remains stalled in the legislative impasse on energy and climate.

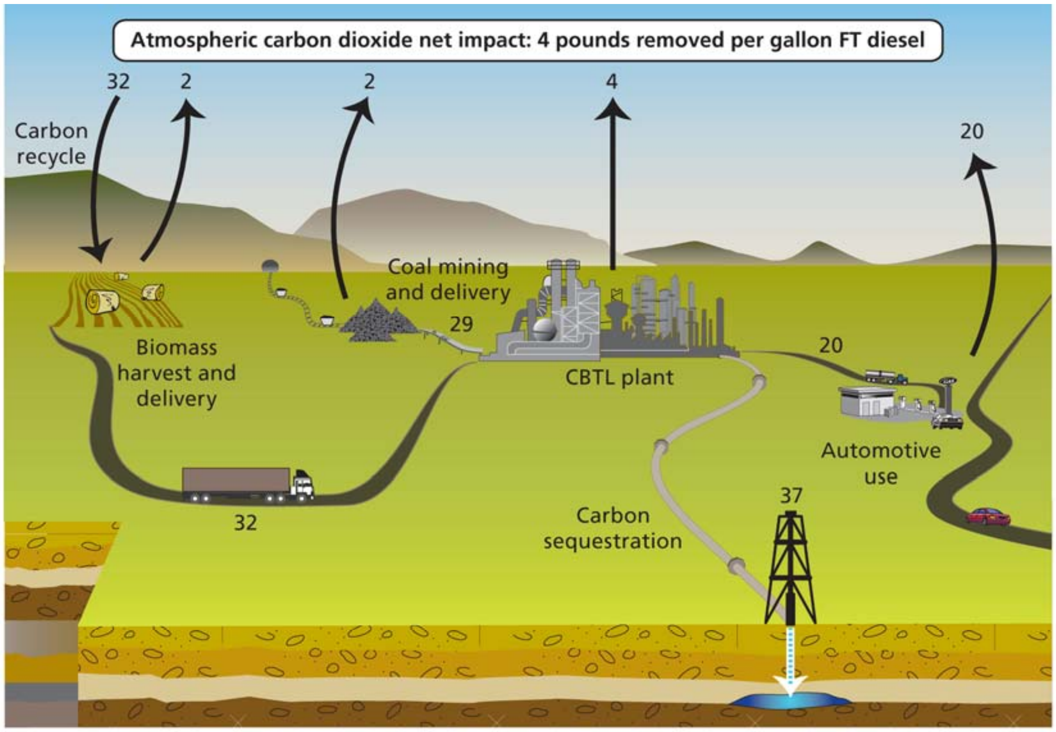
The production of coal-based liquids not only poses greenhouse gas–related problems, but also raises some other serious environmental concerns. The development of a major CTL industry in the United States presupposes, at the very least, a significant expansion of coal mining. The RAND analysts figure that a CTL output rising to three million barrels per day over the next 20 years translates into additional annual coal requirements of around 550 million tons on top of the recent roughly 1.3-billion-ton level (Bartis et al. 2008). Such expansion need not, of course, signify a correspondingly large prospect of further (nongreenhouse) environmental damage. After all, existing laws, regulations, and technologies keep numerous environmental threats to land, air, and water under control.

That said, it is also the case that, where existing statutes and policies keep a precariously balanced environment and fragile ecosystem from tipping over into the danger zone, a massive CTL industry could make that crossover a reality. Consider, for example, that year after year, incremental coal production gravitates relentlessly to the (low-sulfur, high-productivity) surface-mining states of the Rocky Mountain region. An already water-stressed area would find itself burdened with the water-intensive demands both of coal mining and of coal's conversion to a liquid fuel. Revegetation of mined lands could add further impediments. One should keep in mind the circumstances surrounding efforts to begin developing the Western oil shale industry in the 1980s. This experience, even apart from overcoming technological hurdles, laid bare the challenge of supporting an expanding and large industrial presence in a sparsely settled region with the community infrastructure and institutions to ensure that the integrity of the physical environment is complemented as well by a stable socioeconomic environment.

Liquids Production from a Coal–Biomass Mixture

F–T technology does not require coal as the sole energy feedstock. Use of a blend of coal and biomass is a topic of growing interest and attention in energy–environment discussions. A coal-and-biomass-to-liquids (CBTL) configuration is not only a promising complement to an exclusively coal-based operation, it also can confer decided environmental benefits given that the biomass component offsets, through photosynthetic regrowth, the CO_2 it emits in the conversion process (see Figure 2). (The biomass resources of particular interest include switchgrass, poplar trees, and corn stover—all amenable inputs in the gasification stage of the F–T process.) Of course, even a CBTL operation will not obviate the need for CCS because its practical feasible biomass input share appears, for now, to be not much more than 10 percent.

Figure 2. Estimated Carbon Balances for a Fischer–Tropsch Dual-Feed Coal- and Biomass-to-Liquids Plant



NOTE: Plant-energy input is 50/50 coal and biomass. Carbon flows are expressed as equivalent pounds of CO_2 per gallon of FT diesel produced (see Appendix B). The 2 pounds of CO_2 equivalents (CDEs) shown entering the atmosphere from biomass harvesting and delivery are associated with fuel and chemicals used in those operations. For coal mining and delivery, the 2 pounds of CDE emissions include methane released during mining operations. For each gallon of FT diesel produced and used, 28 pounds of CDE emissions enter the atmosphere and 32 pounds are removed from the atmosphere by biomass growth, yielding a net reduction of 4 pounds.
RAND *MG754-3.4*

Source: Bartis et al. (2008, 40). Reprinted with permission from RAND Corporation.

Although research into CBTL economics and technological potentials clearly needs to be strengthened, the combined insights from many research studies over the past several years point to encouraging possibilities. The most recent efforts comprise one conducted by NETL (2009). A more cautionary assessment than NETL's rather optimistic judgement emerges from the second study, cited in the CTL discussion above, prepared by NRC (2009).

Turning first to the NETL study, we find that, like other efforts probing the viability of unconventional sources of liquid fuels, its findings—apart from a number of other uncertainties—are extremely sensitive to assumptions about the course of the world oil price. With the long-term price assumed to equal or exceed around $93 per barrel (in 2008 dollars), a CBTL operation is judged to be a commercially successful prospect, even with an allowance for CCS.

Although the NETL study examines a wide range of alternative economic and technological cases, its central findings are illuminating. With respect to CO_2 emissions, and even without an allowance for biomass input, a scenario where CCS is incorporated into the CTL F–T process brings the lifecycle carbon footprint effectively down to the level associated with the extraction of conventional crude oil and its refining into transportation fuels. Beyond that, a mixture composed of 8 percent biomass (by weight, in the form of switchgrass) and 92 percent coal can bring the lifecycle carbon footprint to a level some 20 percent below the comparable conventional crude oil extraction–final use sequence.[20] In short, other challenges to deploying CTL technology aside, the NETL analysis points to the photosynthetic role of the biomass component as a welcome element in carbon management, even if its hypothesized possibility of achieving an output capacity of as much three million barrels per day seems remarkably optimistic, at least when judged by EIA's vastly lower AEO 2009 projection.

For its part, the NRC (2009) study, a part of NRC's broader "America's Energy Future" effort, also takes an encouraging position on both CTL and CBTL but, like NETL, underscores the need for cost-reducing developments—with plant-site CO_2 containment a key objective—if it is to succeed in the commercially competitive arena. Its tone is therefore quite guarded, with both CTL and CBTL characterized in a "could" rather than "likely" perspective and with possibilities for significant output volumes over the next two decades dependent on the achievement of a "commercially deployable" system by around 2020. Deep geologic sequestration of CO_2 is just one required milestone. More generally—once again, unsurprisingly—a "substantial investment" by both public and private entities is deemed one vital incentive for spurring an alternative liquid fuels industry.[21] In addition, hurdles unique to biomass require attention—not least, the prospect of sufficient idle agricultural land to sustain production along with an assurance that major land-use changes will not lead to erosion or other harm. Yet, notwithstanding hurdles that remain to be overcome, the NRC report sounds guardedly upbeat about the prospect for major CBTL cost reduction, if not by 2020, then within a reasonable period thereafter. And don't forget the "C" in CBTL. The sheer expansion of CBTL

[20] An 8 percent–92 percent biomass–coal mixture in weight equates to proportions of around 4 percent and 96 percent, respectively, in energy terms. NETL (2009) explores the lifecycle CO_2 implications of several much higher shares in biomass content. But for now, the benefits of further increases in the biomass share should perhaps be viewed as problematic because of scale diseconomies and upward price pressures on biomass feedstocks.

[21] Evidently, whatever such public support would involve, NRC does not appear to view it as subsidization; the latter is explicitly absent from its cost estimates, as discussed below.

plants—conceivably two to three new plants per year over the next several decades, necessitating an increase in coal mine output by, say, 50 percent above current levels—will itself present undoubted challenges of environmental integrity and social acceptance.

The NRC nonetheless conjectures that, like NETL, CBTL could, within its (not always sharply defined) time horizon, achieve a fuel output of several million barrels per day. Needless to say, CBTL output of that magnitude, if forthcoming, could meet a sizable portion of U.S. transportation fuel requirements, which are projected by EIA to reach a level well over 10 million barrels per day by 2030. In consequence, oil imports could be appreciably lower.

NRC's cost calculations—based on much more analytical detail than cited here—suggest the ranges of world crude oil prices (and corresponding crude oil–equivalent gasoline prices) within which CTL or a coal–biomass blend would need to compete as soon as 2020. (Unfortunately, NRC did not extend its detailed economic analysis beyond that date; presumably CBTL could only improve its relative market standing in the years thereafter.) Key results are shown in Table 2.

Judged against NRC's conjecture of a world oil price ranging between $60 and $100 per barrel, it would appear that, broadly consistent with the RAND analysis cited earlier, even the lower part of that range—never mind the $100 level—could signal CTL's entry as a competitive contender in the liquid fuels market. CBTL would find market penetration much more difficult under those circumstances, notwithstanding the benefits of atmospheric removal of CO_2 during biomass growth and a high-biomass feedstock cushioning coal's CCS burden The lower part of the world oil price range appears inimical to CBTL's prospects.

Importantly, the NRC (2009) report is somewhat murky on the shares of a plant's resource input apportioned between coal and biomass. It appears, however, that biomass is assigned a significant multiple of the (maximum 10 percent or so) portion assumed by NETL. The extent to which a more modest quantity of biomass input, with attendant production cost reduction, might make CBTL look competitively more attractive in the NRC analysis would depend on forgone CO_2 benefits as a result of greater fossil energy use.

Concluding Comments

Clearly, understanding and insights regarding the future potentials and roles of alternative, fossil-based transportation fuels are continually evolving. All the same, the preceding review permits six germane observations.

1. Although each of the three synfuels technologies examined is supported by an abundant resource base (a situation that could conceivably apply to natural gas as well in the years ahead), the synfuel most likely to shore up U.S. energy availability over the next several decades is that derived from Canadian oil sands. EIA projects U.S. oil imports from Canada—and that means almost exclusively Alberta oil sands—at around four million barrels per day by 2030. A world oil price of no less than $60 per barrel (in 2008 prices) appears to be required to sustain oil sands investment and production, including the cost of CCS (or a carbon-cost proxy). Allowance for other environmental externalities could raise that figure.

   When one considers the economic, security, and CO_2 aspects of that scenario a paradox presents itself. Depending on the magnitude of oil sands expansion, the world oil price will be lower—*for consumers in the United States and everywhere else*—than it would otherwise have been. Typically, that would mean increased oil demand, which, in the case of the United States, signifies expanded imports, not just from Canada but from other exporting countries as well.[22] From the standpoint of U.S. energy security, two closely interrelated questions arise. First, should increased Canadian imports be considered "insecure?" Second, might those imports at least attenuate rising imports from insecure suppliers? Political discourse frequently treats *all* oil import dependence as undesirable, irrespective of the supplying country or economic benefits to the United States. However, security and purely economic issues aside for the present, Canadian greenhouse gas policy is undefined. That could mean an early test of the cross-border provisions of the Waxman–Markey cap-and-trade bill, approved by the House of Representatives in May 2009. Moreover, oil sands exploitation results in unresolved nongreenhouse environmental impacts. Dealing with these could impede development and/or raise costs.

2. Of the other two unconventional resources considered—coal- or shale-derived synfuels—CTL conversion has to be judged the more promising. It rests on largely well-established technology which, even when incorporating carbon containment, might meet the $60-per-barrel world oil price test cited above. The introduction of a coal–biomass blend would entail higher costs but signify a reduced carbon footprint.

[22] For detailed treatment of security issues, see the RFF/NEPI monographs by Deutch and by Brown and Huntington.

Costs aside, the big unknown is technical uncertainty over the integrity of geologic sequestration, without which its carbon-intensive characteristic would make coal liquefaction problematic. In contrast to coal, oil shale offers a poorer outlook of significant market penetration over the next 20 years. Despite some cautiously optimistic assessments of the technological and economic progress of in situ retorting (which, if realized, would reduce CO_2 emissions), commercial exploitation faces some daunting environmental hurdles.

3. If the foregoing reflections are reasonably well grounded, U.S.-based synfuels ought not to be looked to as promising relief to the nation's burden of oil import dependency, driven in large measure by the underlying demands of the country's transportation fuels sector. To the extent that such relief was forthcoming from the exploitation of domestic initiatives and resources, some combination of greatly enhanced fuel efficiency and the use of biofuels is likely to play a much more measurable role.

4. I have, at various points in this paper, referenced a range of future synfuels output projections by different groups. For example, AEO 2009 posits shale and CTL numbers for the year 2030 scarcely exceeding a million barrels per day. NRC, for its part, discusses the underpinnings for a vastly greater production capacity from coal alone. Such differences do not primarily spell differences in judgement about economics or technology; rather, they reflect "what if" assumptions explained by the institutional or policy terms of reference imposed on, or driven by, the respective research entity. At one end, EIA is compelled to operate within the narrow boundaries of existing statutes and policies, whereas NRC has the discretion to entertain the possibility of policy changes that result in what otherwise would be unrealistically large and unrealistically early output prospects. Thus, governed not by methodological or predictable differences but, rather, circumscribed by assigned tasks and institutional constraints, such differences are not susceptible to yielding a "best guess" median outcome. My own best guess veers more in the direction of EIA's conservative synfuels projection estimate, notwithstanding its assumptions based on existing policy.

5. Closely related to the last point is the decisive importance of what is assumed about the trajectory of world oil prices and their effect on synfuels cost competitiveness. For example, as AEO 2009 hypothesizes a 2030 world oil price as low as $50 per barrel (in 2008 prices) rather than its reference case assumption of $130 per barrel, U.S.

CTL output declines from 260,000 barrels per day to 40,000 barrels per day. World oil prices in the $60-per-barrel range (the approximate level at the time of writing, in late 2009), probably represent the minimum level needed to spur meaningful synfuels development. Even apart from the assumed *secular trend* in crude oil prices, if the upheavals of the last one to two years lead to the expectation of chronic *volatility* in global oil markets, that, too, could spook investors in a risk-averse direction.

6. This paper has spotlighted the extent to which various synfuels would pose both economic and environmental problems, with greenhouse gas management chief among the latter. However, even without considering the extent to which oil shale, CTL, and oil sands aggravate the challenge of carbon management, *conventional* liquid fuel use in itself requires effective carbon control policies. Although one or another unconventional resource generates disproportionate emissions in its "upstream" extractive or retorting stage, one still must address the well-to-wheel matter of emissions from distribution, refining, and combustion. In other words, handling shale, sands, and coal liquefaction to make them more like conventional crude oil is a necessary, but scarcely sufficient, way to come to grips with a major energy–environment dilemma of our time.

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