Chapter 6

Synthetic Fuels

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INTRODUCTION

Synthetic fuels, or "synfuels," in the broadest sense can include any fuels made by breaking complex compounds into simpler forms or by building simple compounds into others more complex. Both of these types of processes are carried out extensively in many existing oil refineries. Current technical usage, however, tends to restrict the term to liquid and gaseous fuels produced from coal, oil shale, or biomass. This usage will be followed in this report.

Synfuels production is a logical extension of current trends in oil refining. As sources of the most easily refined crude oils are being depleted, refiners are turning to heavier oils and tar sands. Oil shale and coal, as starting materials for liquid hydrocarbon production, are extreme cases of this trend to heavier feedstocks.

Although synfuels production involves several processes not used in crude oil refining, many current oil refining techniques will be applied at various stages of synfuels processing. In order to indicate the range of currently used hydrocarbon processing techniques and to provide definitions of certain terms used later in describing some synfuels processes, a brief description of commonly used oil refining processes is given below. Following this are descriptions of coal, oil shale, and biomass synfuels processes; an evaluation of synfuel economics; and a presentation of two plausible development scenarios for a U.S. synfuels production capacity.

Petroleum Refining

A petroleum refinery is normally designed to process a specific crude oil (or a limited selection of crudes) and to produce a "slate" of products appropriate to the markets being supplied. Refineries vary greatly in size and complexity. At one extreme are small "topping" plants with product outputs essentially limited to the components of the crude being processed. At the other extreme are very large, complex refineries with extensive conversion and treating facilities and a corresponding ability to produce a range of products specifically tailored to changing market needs.

Refining processes include:

- Atmospheric Distillation. –The "crude unit" is the start of the refining process. Oil under slight pressure is heated in a furnace and boiled into a column containing trays or packing which serve to separate the various components of the crude oil according to their boiling temperatures. Distillation ("fractionation") is carried out continuously over the height of the column. At several points along the column hydrocarbon streams of specific boiling ranges are withdrawn for further processing.
- Vacuum Distillation. –Some crude oil components have boiling points that are too high, or they are too heat-sensitive, to permit distillation at atmospheric pressure. In such cases the so-called "topped crude" (bottoms from the atmospheric column) is further distilled in a column operating under a vacuum. This lowers the boiling temperature of the material and thereby allows distillation without excessive decomposition.
- Desulfurization. –Sulfur occurs in crude oil in various amounts, and in forms ranging from the simple compound hydrogen sulfide and mercaptans to complex ring compounds. The sulfur content of crude oil fractions increases with boiling point. Thus, although sulfur compounds in fractions with low boiling points can readily be removed or rendered unobjectionable, removal becomes progressively more difficult and expensive with fractions of higher boiling points. With these materials, sulfur is removed by processing with hydrogen in the presence of special catalysts at elevated temperatures and pressures. The "hydrofining," "hydrodesulfurization," "residuum hydrotreating, " and "hydrodemetallation" processes are examples. Nitrogen compounds

and other undesirable components are also removed in many of these hydrotreating processes.

- Therma/ Cracking Processes, –Prior to the development of fluid catalytic cracking (see below), the products of distillation that were heavier than gasoline were commonly "cracked" under high temperature and pressure to break down these large, heavy molecules into smaller, more volatile ones and thereby improve gasoline yields. Although the original process is no longer applied for this purpose, two other thermal cracking processes are being increasingly used. In visbreaking, highly viscous residues from crude oils are mildly cracked to produce fuel oils of lower viscosity. In delayed coking, crude unit residues are heated to high temperatures in large drums and severely cracked to drive off the remaining high-boiling materials for recovery and further processing; the porous mass of coke left in the drums is used as a solid fuel or to produce electric furnace electrodes.
- Fluid Catalytic Cracking.—This process in its various forms is one of the most widely used of all refinery conversion techniques. It is also undergoing constant development. Charge stocks (which can be a range of distillates and heavier petroleum fractions) are entrained in a hot, moving catalyst and converted to lighter products, including high-octane gasoline. The catalyst is separated and regenerated, while the reaction products are separated into their various components by distillation.
- Hydrocracking. —This process converts a wide range of hydrocarbons to lighter, cleaner, and more valuable products. By catalytically adding hydrogen under very high pressure, the process increases the ratio of hydrogen to carbon in the feed and produces low-boiling material. Under some conditions hydrocracking maybe competitive with fluid catalytic cracking.
- Catalytic Reforming. –Reforming is a catalytic process that takes low-octane "straight-run" materials and raises the octane number to approximately 100. Although several chemical reactions take place, the predominant reaction is the removal of hydrogen from naphthenes (hydrogen-saturated ring-like compounds) and their conversion to aromatics (benzene-ring compounds). In addition to markedly increasing octane number, the process produces hydrogen that can be used in desulfurization units.
- Isomerization, Catalytic Polymerization, and Alkylation. -These are specialized processes that increase refinery yields of high-octane gasoline blending components from selected straight-chain liquids and certain refinery gases.

Historically, the U.S. refining industry has dealt primarily with light, low-sulfur crudes. Using processes described above, the industry achieved a balance between refinery output and markets. Adjustments have been made to meet the increasing demand for lead-free gasolines and to the mandated reduction of lead in other gasolines. The heavy residual fuels, considerably higher in sulfur content than treated distillate fuels, have continued to find a market as ships' boilers and as fuels for utility plants that have not converted to coal. (In the latter market, it has sometimes been necessary to blend in desulfurized fuel oils to meet maximum fuel sulfur specifications.) In addition, large volumes of residual fuel oils have continued to be imported, largely from Venezuela and the Caribbean.

Now, however, the picture is changing. Due to the limited availability of light crude oils, refineries are being forced to run increasing volumes of heavy crudes that are higher in sulfur and other contaminants. With traditional processing methods, these crudes produce fewer light products and more heavy fuel oils of high sulfur content. On the other hand, fuel switching and conservation in stationary uses will shift market demand increasingly toward transportation fuels—gasoline, diesel, and jet–plus petrochemical feedstock.

Refiners are responding to this situation by making major additions to processing facilities. Although they differ in detail, the additions are intended to reduce greatly the production of heavy fuel oil and to maximize the conversion and recovery of light liquids. For a typical major refinery, the additions could include: 1) vacuum distillation facilities, 2) high-severity hydroprocessing, such as residuum desulfurization, together with hydrogen manufacturing capacity, 3) delayed coking, along with processes to recover and treat the high-boiling vapor fractions driven off, and 4) perhaps visbreaking, catalytic cracker expansions, and other modifications to accommodate the changed product slate. It should also be noted that none of these additions increases the crude-processing capacity of a refinery; they merely adapt it to changed supply and marketing conditions.

Purvin and Gurtz[1] have estimated the costs of upgrading domestic refining capacity to make such changes. Their results are shown in table 40. Although, as indicated in note d of the table, the investments shown do not include all applicable costs, upgrading existing refineries is, in most cases, less expensive than building synfuels plants to produce the same products; and there are regular reports that investments are being made in oil refineries to upgrade residual oil and change the product slate. *2

For a discussion of other issues related to oil refineries, the reader is referred to a Congressional Research Service report on "U.S. Refineries: A Background Study. "[3]

[1] Purvin & Gertz, Inc., "An Analysis of Potential for Upgrading Domestic Refining Capacity, " prepared for American Gas Association, Arlington, Va., undated.

*Another issue related to refining and oil consumption is the low yield of lubrication and specialty oils from certain types of crude oils (paraffinic crudes) and the redefining or reuse of these oils. There appears to be no technical problem with increasing the yield of lubrication and specialty oils from the paraffinic crudes (*Oil and Gas Journal,* "Gulf's Port Arthur Refinery Due More Upgrading," Sept. 8, 1980, p. 36.) or the redefining of lubrication oils. However, heat transfer, hydraulic, capacitor, and transformer fluids often become contaminated with PCBs (polychlorinated biphenyls) leached from certain plastics such as electrical insulating materials. Because of the health hazard, EPA regulations limit the allowable level of PCBs in enclosed systems to 50 ppm (parts per million). The contaminated oils pose a waste disposal problem and could damage refinery equipment (through the formation of corrosive hydrogen chloride and possible catalyst poisoning) if rerefined without treatment. Recently, however, two processes (*Chemical* and Engineering News, "Goodyear Develops PCB Removal Method, " Sept. 1, 1980, p. 9; Chemical and Engineering News, "More PCB Destruction Methods Developed, " Sept. 22, 1980, p. 6.) have been announced that enable the removal of most of the PCBs, thereby enabling reuse directly or redefining if necessary; and one of these processes has been demonstrated with a prototype commercial unit. Consequently, there do not appear to be significant technical problems with decontamination and reuse of PC B-contaminated oils. Due to the limits of this study, however, OTA was unable to perform an economic analysis of oil production from paraffinic crudes, redefining of lubrication oils, or decontamination of specialty oils.

[2] For example, *Oil* and Gas *Journal,* Aug. 25, 1980, p. 69; *Oil and Gas Journal,* Sept. 8, 1980, p. 36; *Oil* and Gas *Journal,* Nov. 10, 1980, p. 150; *Oil* and Gas *Journal,* Jan. 19, 1981, p. 85.

[3] Congressional Research Service, "U.S. Refineries: A Background Study, "prepared at the request of the Subcommittee on Energy and Power of the House Committee on Interstate and Foreign Commerce, U.S. House of Representatives, July 1980.

Table 40.—Analysis of Potential for Upgrading Domestic Refining Capacity

	Topping refineries		Total U.S. refineries
	Case 1a[a]	Case 1b[b]	Case 2[c]
Total investment[d]	$2.3 billion	$4.7 billion	$18.0 billion
Reduction in total U.S. residual fuel production, bbl/d	217,000-301,000	418,000-501,000	1,587,000-1,670,000
Percent total pool	13-18	25-30	95-1oo
Increase in motor gasoline production, bbl/d	134,000-200,000	167,000-234,000	467,000-534,000
Percent total pool	2-3	2.5-3.5	7-8
Increase in diesel/No. 2 fuel production, bbl/d	105,000-135,000	150,000-180,000	540,000-600,000
Percent total pool	3.5-4.5	5-6	18-20
Increase in low-Btu gas, MM Btu/D	—	233	1,320
Implementation period, years			4-1o
Investment per unit capacity	$6,800-9,600 per bbl/d	$11,300-14,000 per bbl/d	$15,800-17,900 per bbl/d

[a] Vacuum distillation, catalytic cradking, visbreaking.
[b] Vacuum distillation, catalytic cracking, coking plus gasification.
[c] Case 1 b plus coking and gasification and downstream upgrading at remaining U.S. refineries.
[d] First-quarter 19&3 investment, No provision for escalation, contingency or interest during construction.

SOURCE: Purvin & Gertz, Inc., "An Analysis of Potential for Upgrading Domestic Refining Capacity," prepared for American Gas Association, 19S0.

PROCESS DESCRIPTIONS

A variety of synthetic fuels processes are currently being planned or are under development. Those considered here involve the chemical synthesis of liquid or gaseous fuels from solid materials. As mentioned above, the impetus for synthesizing fluid fuels is to provide fuels that can easily be transported, stored, and handled so as to facilitate their substitution for imported oil and, to a lesser extent, imported natural gas.

The major products of various synfuels processes are summarized in table 41. Depending on the processes chosen, the products of synfuels from coal include methanol (a high-octane gasoline substitute) and most of the fuels derived from oil* and natural gas. The principal products from upgrading and refining shale oil are similar to those obtained from conventional crude-oil refining. The principal biomass synfuels are either methanol or a low- to medium-energy fuel gas. Smaller amounts of ethanol (an octane-boosting additive to gasoline or a high-octane substitute for gasoline) and biogas can also be produced. Each of these fuels can be synthesized further into any of the other products, but these are the most easily produced from each source and thus probably the most economic.

*As with natural crude oil, however, refining to produce large gasoline fractions usually requires more refining energy and expense than producing less refined products such as fuel oil.

In the following section, the technologies for producing synfuels from coal, oil shale, and biomass are briefly described. Indirect and direct coal liquefaction and coal gasification are presented first. Shale oil processes are described second, followed by various biomass synfuels. Hydrogen and acetylene production are not included because a preliminary analysis indicated they are likely to be more expensive and less convenient transportation fuels than are the synthetic liquids.[4]

[4]For a more detailed description of various processes, see: Engineering Societies Commission on Energy, Inc., "Coal Conversion Comparison, " July 1979, Washington, D. C.; An Assessment *of Oil Shale* Technologies (Washington, D, C.: U.S. Congress, Office of Technology Assessment, June 1980), OTA-M-118; Energy From *Biological* Processes (Washington, D, C.: U.S. Congress, Office of Technology Assessment, July 1980), vol. 1, OTA-E-124; and Energy From Biological Processes, Volume I/–Technical and *Environmental Analyses* (Washington, D. C.: U.S. Congress, Office of Technology Assessment, September 1980), OTA-E-128.

Table 41 .—Principal Synfuels Products

Process	Fuel production	Comments
Oil shale	Gasoline, diesel and jet fuel, fuel oil, liquefied petroleum gases (LPG)	Shale oil is the synfuel most nearly like natural crude.
Fischer-Tropsch	Gasoline, synthetic natural gas (SNG), diesel fuel, and LPG	Process details can be modified to produce principally gasoline, but at lower efficiency.
Coal to methanol, Mobil methanol to gasoline (MTG)	Gasoline and LPG	LPG can be further processed to gasoline. Some processes would also produced considerable SNG.
Coal to methanol	Methanol	Depending on gasifier, SNG may be a byproduct. Methanol most useful as high-octane gasoline substitute or gas turbine fuel, but can also be used as gasoline octane booster (with cosolvents), boiler fuel, process heat fuel, and diesel fuel supplement. Methanol can also be converted to gasoline via the Mobil MTG process.
Wood or plant herbage to methanol	Methanol	Product same as above.
Direct coal liquefaction	Gasoline blending stock, fuel oil or jet fuel, and LPG	Depending on extent of refining, product can be 90 volume percent gasoline.
Grain or sugar to ethanol	Ethanol	Product most useful as octane-boosting additive to gasoline, but can serve same uses as methanol.
SNG	SNG	Product is essentially indistinguishable from natural gas.
Coal to medium- or low-energy gas	Medium- or low-energy fuel gas	Most common product likely to be close to synthesis gas.
Wood or plant herbate gasification	Medium- or low-energy fuel gas	Fuel gas likely to be synthesized at place where it is used.
Anaerobic digestion	Biogas (carbon dioxide and methane] and SNG	Most products likely to be used onsite where produced.

SOURCE: Off Ice of Technology Assessment.

Synfuels From Coal

Liquid and gaseous fuels can be synthesized by chemically combining coal with varying amounts of hydrogen and oxygen, * as described below. The coal liquefaction processes are generally categorized according to whether liquids are produced from the products of coal gasification (indirect processes) or by reacting hydrogen with solid coal (direct processes). The fuel gases from coal considered here are medium-Btu gas and a synthetic natural gas (SNG or high-Btu gas). Each of these three categories is considered below and shown schematically in figure 13.

*Some liquid and gaseous fuel can be obtained simply by heating coal, due to coal's small natural hydrogen content, but the yield is low.

Indirect Liquefaction

The first step in the indirect liquefaction processes is to produce a synthesis gas consisting of carbon monoxide and hydrogen and smaller quantities of various other compounds by reacting coal with oxygen and steam in a reaction vessel called a gasifier. The liquid fuels are produced

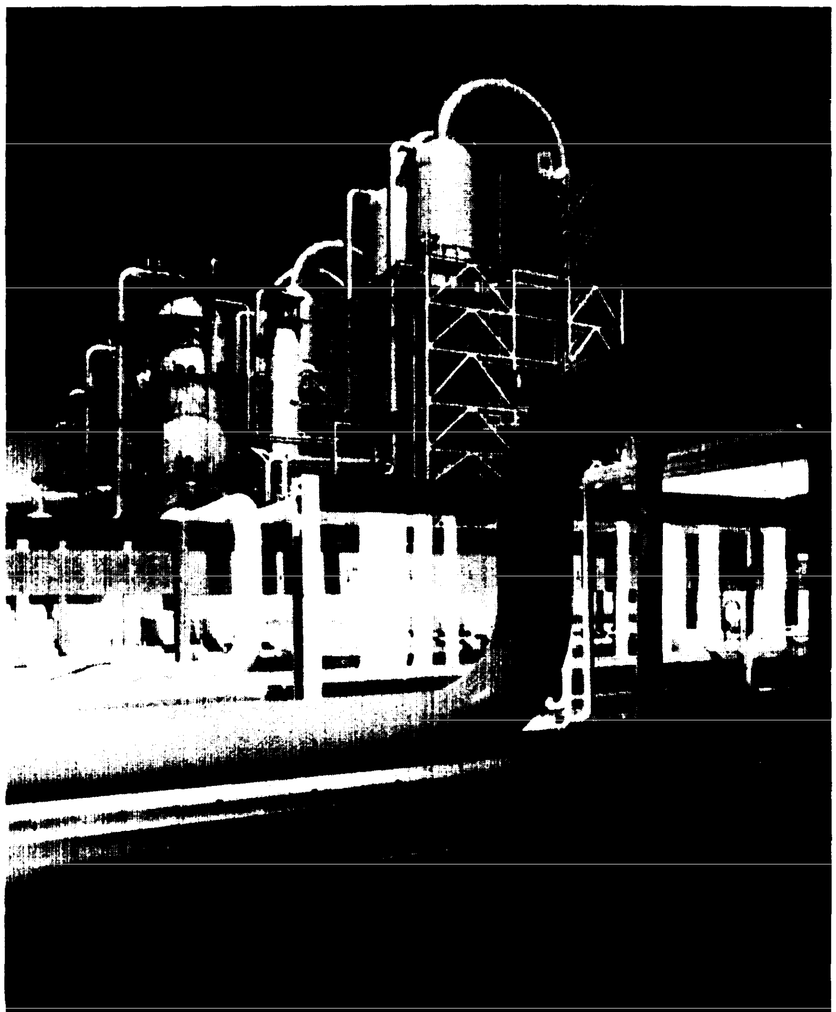
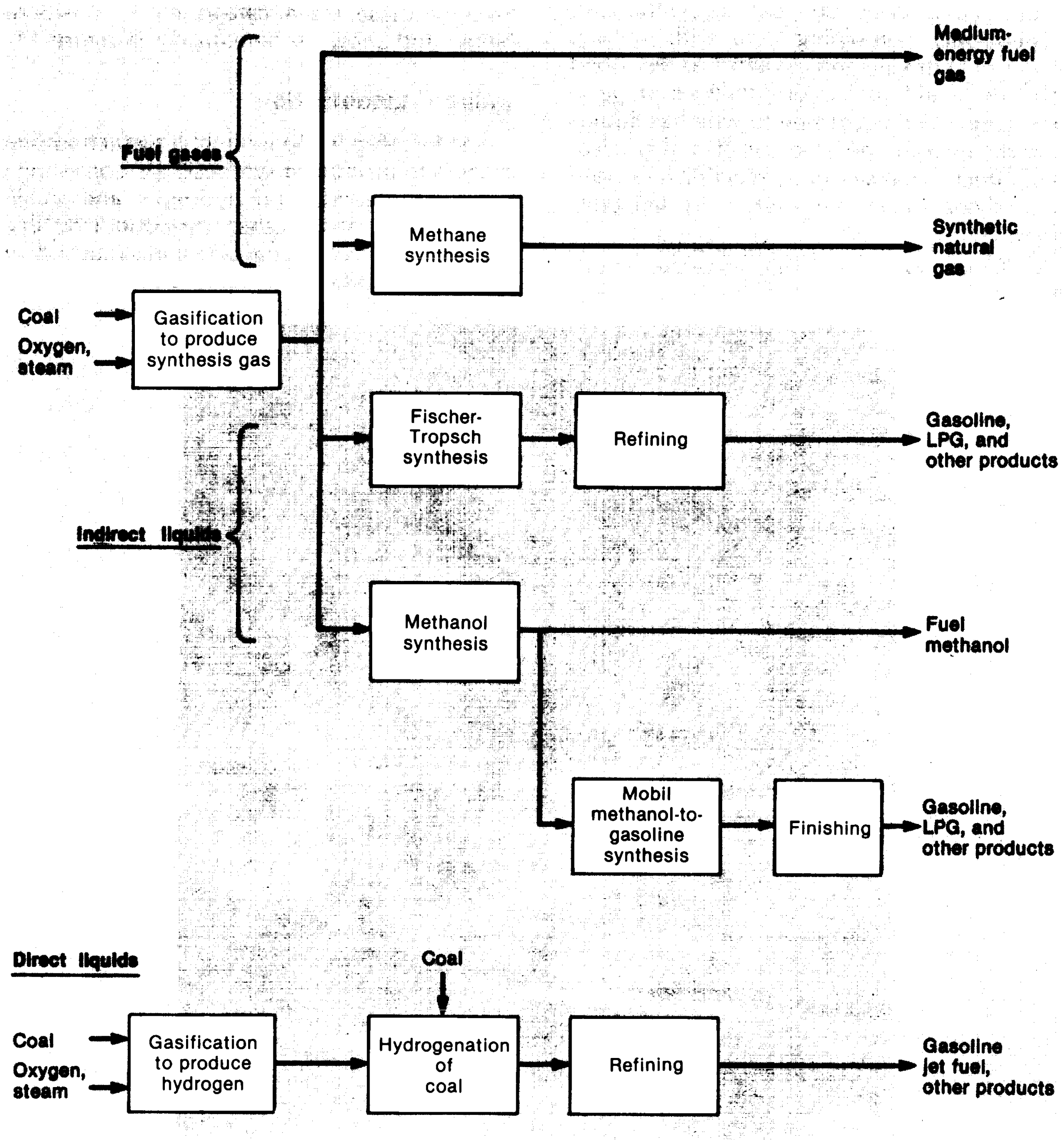


Photo credit: *Fluor Corp*

Synthesis gas is converted to liquid hydrocarbons in **Fischer-Tropsch** type reactors

Figure 13.—Schematic Diagrams of Processes for Producing Various Synfuels From Coal



SOURCE: Office of Technology Assessment.

by cleaning the gas, adjusting the ratio of carbon monoxide to hydrogen in the gas, and pressurizing it in the presence of a catalyst. Depending on the catalyst, the principal product can be gasoline (as in the Fischer-Tropsch process) or methanol. The methanol can be used as a fuel or further reacted in the Mobil methanol-to-gasoline (MTG) process (with a zeolite catalyst) to produce Mobil MTG gasoline. The composition of the gasoline and the quantities of other products produced in the Fischer-Tropsch process can also be adjusted by varying the temperature and pressure to which the synthesis gas is subjected when liquefied.

With commercially available gasifiers, part of the synthesis gas is methane, which can be purified and sold as a byproduct of the methanol or gasoline synthesis. * However, the presence of methane in the synthesis gas increases the energy needed to produce the liquid fuels, because it must be pressurized together with the synthesis gas but does not react to form liquid products. Alternatively, rather than recycling purge gas (containing increasing concentrations of methane) to the methanol synthesis unit, it can be sent to a methane synthesis unit and its carbon monoxide and hydrogen content converted to SNG. With "second generation" gasifiers (see below), little methane would be produced and the methanol or gasoline synthesis would result in relatively few byproducts.

There are three large-scale gasifiers with commercially proven operation: Lurgi, Koppers-Totzek, and Winkler. Contrary to some reports in the literature, all of these gasifiers can utilize a wide range of both Eastern and Western coals, * * although Lurgi has not been commercially proven with Eastern coals. In all cases, the physical properties of the feed coal will influence the exact design and operating conditions chosen * for a gasifier. For example, the coal swelling index, ease of pulverization (friability), and water content are particularly important parameters to the operation of Lurgi gasifiers, and the Koppers-Totzek gasifier requires that the ash in the coal melt for proper operation, as do the Shell and Texaco "second generation" designs.,

it is expected that the developing pressurized, entrained-flow Texaco and Shell gasifiers will be superior to existing commercial gasifiers in their ability to handle strongly caking Eastern coals with a rapid throughput. This is achieved by rapid reaction at high temperatures (above the ash melting point). These temperatures, however, are achieved at the cost of reduced thermal efficiency and increased carbon dioxide production.

The Fischer-Tropsch process is commercial in South Africa, using a Lurgi gasifier, but the United States lacks the operating experience of South Africa and it is unclear whether this will pose problems for commercial operation of this process in the United States. The methanol synthesis from synthesis gas is commercial in the United States, but a risk is involved with putting together a modern coal gasifier with the methanol synthesis, since these units have not previously been operated together. Somewhat more risk is involved with the Mobil MTG process, since it has only been demonstrated at a pilot plant level. Nevertheless, since the Mobil MTG process involves only fluid streams* * the process can probably be brought to commercial-scale operation with little technical difficulty.

Direct Liquefaction

The direct liquefaction processes produce a liquid hydrocarbon by reacting hydrogen directly with coal, rather than from a coal-derived synthesis gas. However, the hydrogen probably will be produced by reacting part of the coal with steam to produce a hydrogen-rich synthesis gas, so these processes do not eliminate the need for coal

*For example, the synthesis gas might typically contain 13 percent methane. Following methanol synthesis, the exiting gases might contain 60 percent methane, which is sufficiently concentrated for economic recovery.

* •For example, Sharman (R. B. Sharman, "The British Gas/Lurgi Slagging Gasifier—What It Can Do," presented at Coal Technology '80, Houston, Tex., Nov. 18-20, 1980) states: "It has been claimed that the fixed bed gasifiers do not work well with swelling coals. Statements such as this can still be seen in the literature and are not true. In postwar years Lurgi has given much attention to the problem of stirrer design which has much benefited the Westfield Slagging Gasifier. Substantial quantities of strongly caking and swelling coals such as Pittsburgh 8 and Ohio 9, as well as the equivalent strongly caking British coals have been gasified. No appreciable performance difference has been noted between weakly caking and strongly caking high volatile bituminous coals. "

*Including steam and oxygen requirements.

**The physical behavior of fluids is fairly well understood, and processes involving only fluid streams can be scaled up much more rapidly with minimum risk than processes involving solids.

gasification. The major differences between the processes are the methods used to transfer the hydrogen to the coal, while maximizing catalyst life and avoiding the flow problems associated with bringing solid coal into contact with a solid catalyst, but the hydrocarbon products are likely to be quite similar. The three major direct liquefaction processes are described briefly below, followed by a discussion of the liquid product and the state of the technologies' development.

The solvent-refined coal (SRC I) process was originally developed to convert high-sulfur, high-ash coals into low-sulfur and low-ash solid fuels. Modifications in the process resulted in SRC II, which produces primarily a liquid product. The coal is slurried with part of the liquid hydrocarbon product and reacted with hydrogen at about 850° F and a pressure of 2,000 per square inch (psi).[5] As it now stands, however, feed coal for this process is limited to coals containing pyritic minerals which act as catalysts for the chemical reactions.

The H-coal process involves slurrying the feed coal with part of the product hydrocarbon and reacting it with hydrogen at about 650° to 700° F and about 3,000 psi pressure in the presence of a cobalt molybdenum catalyst.[6] A novel aspect of this process is the so-called "ebullated" bed reactor, in which the slurry's upward flow through the reactor maintains the catalyst particles in a fluidized state. This enables contact between the coal, hydrogen, and catalyst with a relatively small risk of clogging.

The third major direct liquefaction method is the EXXON Donor Solvent (EDS) process. In this process, hydrogen is chemically added to a solvent in the presence of a catalyst. The solvent is then circulated to the coal at about 800° F and 1,500 to 2,000 psi pressure.[7] The solvent then, in chemical jargon, chemically donates the hydrogen atoms to the coal; and the solvent is recycled for further addition of hydrogen. This process circumvents the problems of rapid catalyst deactivation and excessive hydrogen consumption.

[5]Engineering Societies Commission on Energy, Inc., op. cit.

[6]Cameron Engineering, Inc., "Synthetic Fuels Data Handbook," 2d cd., compiled by G. L. Baughman, 1978.

[7]Ibid.

In all three processes, the product is removed by distilling it from the slurry, so there is no residual oil* fraction in these "syncrudes. " Because of the chemical structure of coal, the product is high in aromatic content. The initial product is unstable and requires further treatment to produce a stable fuel. Refining** the "syncrude" consists of further hydrogenation or coking (to increase hydrogen content and remove impurities), cracking, and reforming; and current indications are that the most economically attractive product slate consists of gasoline blending stock and fuel oil,[8] but it is possible, with somewhat higher processing costs, to produce products that vary from 27 percent gasoline and 61 percent jet fuel up to 91 percent gasoline and no jet fuel.[9]

The gasoline blending stock is high in aromatics, which makes it suitable for blending with lower octane gasoline to produce a high-octane gasoline. Indications are that the jet fuel can be made to meet all of the refinery specifications for petroleum-derived jet fuel.[10] However, since the methods used to characterize crude oils and the products of oil refining do not uniquely determine their chemical composition, the refined products from syncrudes will have to be tested in various end uses to determine their compatibility with existing uses. Because of the chemistry involved, these syncrudes appear economically less suitable for the production of diesel fuel.***

*Residual oil is the fraction that does not vaporize under distillation conditions. Since this syncrude is itself the byproduct of distillation, all of the fractions vaporize under distillation conditions.

● *At present, it is not clear whether existing refineries will be modified to accept coal syncrudes or refineries dedicated to this feedstock will be built. Local economics may dictate a combination of these two strategies. Refining difficulty is sometimes compared to that of refining sour Middle East crude when no high-sulfur residual fuel oil product is produced (i.e., refining completely to middle distillates and gasoline) (see footnote 8). This is moderately difficult but well within current technical capabilities. One of the principal differences between refining syncrudes and natural crude oil, however, is the need to deal with different types of metallic impurities in the feedstock.

[8]UOP, Inc., and System Development Corp., "Crude Oil vs. Coal Oil Processing Compassion Study," DOE/ET/031 17, TR-80/009-001, November 1979.

[9]Chevron, "Refining and Upgrading of Synfuels From Coal and Oil Shales by Advanced Catalytic Processes, Third Interim Report: Processing of SRC II Syncrude," FE-21 35-47, under DOE contract No. EF-76-C-01-2315, Apr. 30, 1981.

[10]Ibid.

* * *The product is hydrogenated and cracked to form saturated, single-ring compounds, and to saturated diolefins (which would tend to form char at high temperatures). The reforming step pro-

None of the direct liquefaction processes has been tested in a commercial-scale plant. All involve the handling of coal slurries, which are highly abrasive and have flow properties that cannot be predicted adequately with existing theories and experience. Consequently, engineers cannot predict accurately the design requirements of a commercial-scale plant and the scale-up must go through several steps with probable process design changes at each step. As a result, the direct liquefaction processes are not likely to make a significant contribution to synfuels production before the 1990's. At this stage there would be a substantial risk in attempting to commercialize the direct liquefaction processes without additional testing and demonstration.

Gasification

The same type of gasifiers used for the liquefaction processes can be used for the production of synthetic fuel gases. The first step is the production of a synthesis gas (300 to 350 Btu/SCF). * The synthesis gas can be used as a boiler fuel or for process heat with minor modifications in end-use equipment, and it also can be used as a chemical feedstock. Because of its relatively low energy density and consequent high transport costs, synthesis gas probably will not be transported (in pipelines) more than 100 to 200 miles. There is very little technical risk in this process, however, since commercial gasifiers could be used.

The synthesis gas can also be used to synthesize methane (the principal component of natural gas having a heat content of about 1,000 Btu/SCF). This substitute or synthetic natural gas (SNG) can be fed directly into existing natural gas pipelines and is essentially identical to natural gas. There is some technical risk with this process, since the methane synthesis has not been demonstrated at a commercial scale. However, since it only involves fluid streams, it probably can be scaled up to commercial-scale operations without serious technical difficulties.

As mentioned under "Indirect Liquefaction, " there are several commercial gasifiers capable of producing the synthesis gas. The principal technical problems in commercial SNG projects are likely to center around integration of the gasifier and methane synthesis process.

Shale Oil

Oil shale consists of a porous sandstone that is embedded with a heavy hydrocarbon (known as kerogen). Because the kerogen already contains hydrogen, a liquid shale oil can be produced from the oil shale simply by heating the shale to break (crack) the kerogen down into smaller molecules. This can be accomplished either with a surface reactor, a modified in situ process, or a so-called true in situ process.

In the surface retorting method, oil shale is mined and placed in a metal reactor where it is heated to produce the oil. In the "modified in situ" process, an underground cavern is excavated and an explosive charge detonated to fill the cavern with broken shale "rubble." Part of the shale is ignited to produce the heat needed to crack the kerogen. Liquid shale oil flows to the bottom of the cavern and is pumped to the surface. In the "true in situ" process, holes are bored into the shale and explosive charges ignited in a particular sequence to break up the shale. The "rubble" is then ignited underground, producing the heat needed to convert the kerogens to shale oil.

The surface retort method is best suited to thick shale seams near the surface. The modified in situ is used where there are thick shale seams deep underground. And the true in situ method is best suited to thin shale seams near the surface. The surface retorting method requires the mining and disposal of larger volumes of shale than the modified in situ method and the true in situ method requires only negligible mining. It is more difficult, using the latter two processes, however, to achieve high oil yields of a relatively uniform quality, primarily because of difficulties related to controlling the underground combustion and

duces aromatics from the saturated rings. The rings can also be broken to form paraffins, but the resultant molecules and other paraffins in the "oil" are too small to have a high cetane rating (the cetane rating of one such diesel was 39 (see footnote 9), while petroleum diesels generally have a centane of 45 or more (E. M. Shelton, "Diesel Fuel Oils, 1980, " DOE/BETC/PPS-80/5, 1980)). Polymerization of the short chains into longer ones to produce a high-cetane diesel fuel is probably too expensive.

**Assuming the gas consists primarily of carbon monoxide and hydrogen.

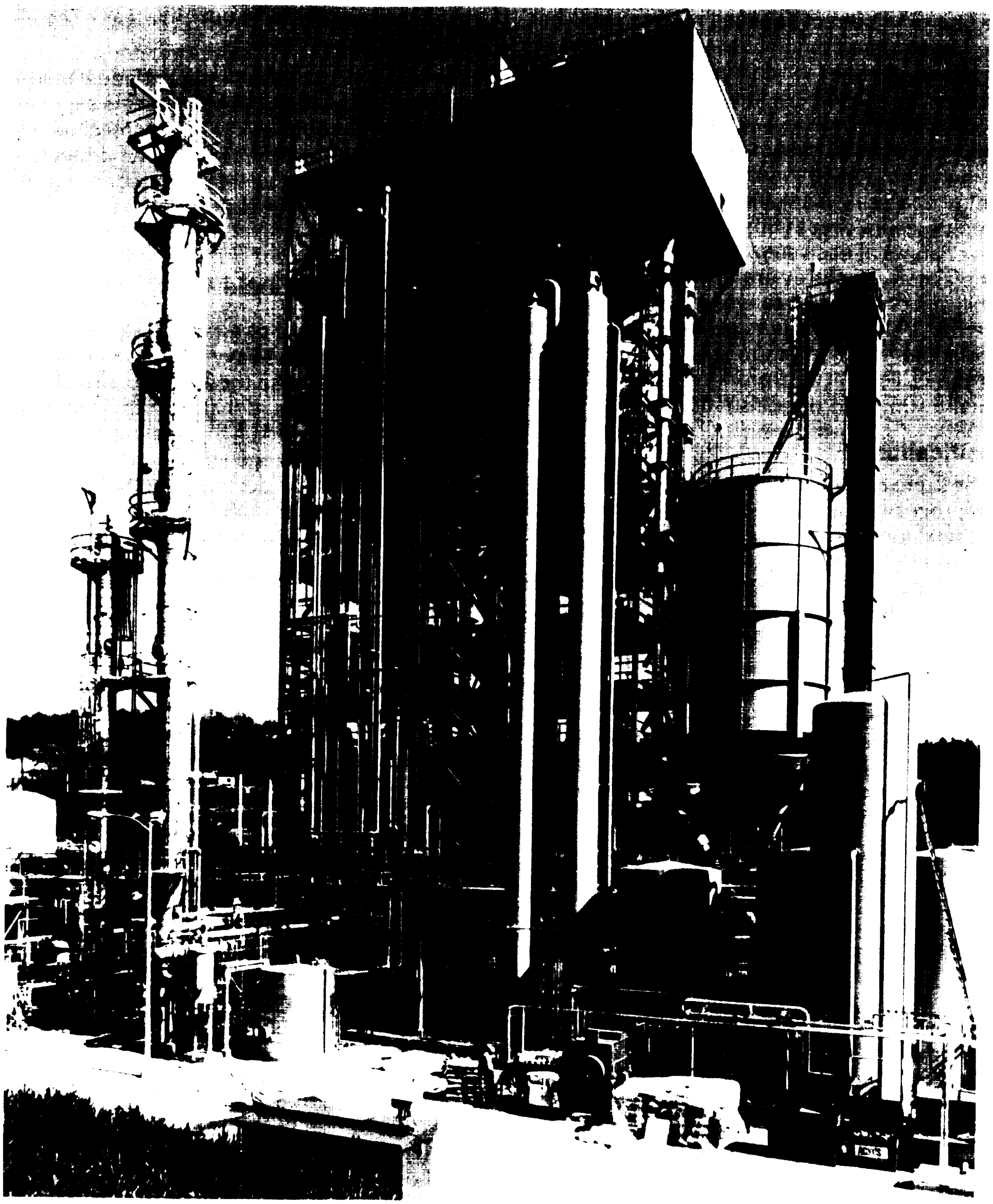


Photo *credit:* Department *of* Energy

Synthane pilot plant near Pittsburgh, Pa., converts coal to synthetic natural gas ensuring that the resultant heat is efficiently transferred to the shale. It is likely, however, that these problems can be overcome with further development work.

The shale oil must be hydrogenated under conditions similar to coal hydrogenation (800° F, 2,000 psi)[11] to remove its tightly bound nitrogen, which, if present, would poison refinery catalysts.

The resultant upgraded shale oil is often compared to Wyoming sweet crude oil in terms of its refining characteristics and is more easily refined than many types of higher sulfur crude oils currently being refined in the United States. Refining shale oil naturally produces a high fraction of diesel fuel, jet fuel, and other middle distillates. The products, however, are not identical to the fuels from conventional crude oil, so they must be tested for the various end uses.

Shale oil production is currently moving to commercial-scale operation, and commercial facilities are likely to be in operation by the mid to late 1980's. Because of completed and ongoing development work, the risks associated with moving to commercial-scale operation at this time are probably manageable, although risks are never negligible when commercializing processes for handling solid feedstocks.

Synthetic Fuels From Biomass

The major sources of biomass energy are wood and plant herbage, from which both liquid and gaseous fuels can be synthesized. These syntheses and the production of some other synfuels from less abundant biomass sources are described briefly below.

Liquid Fuels

The two liquid fuels from biomass considered here are methanol ("wood alcohol") and ethanol ("grain alcohol"). Other liquid fuels from biomass such as oil-bearing crops must be considered as speculative at this time.[12]

Methanol can be synthesized from wood and plant herbage in essentially the same way as it is produced from coal. One partially oxidizes or simply heats (pyrolyzes) the biomass to produce a synthesis gas. The gas is cleaned, the ratio of carbon monoxide to hydrogen adjusted, and the resultant gas pressurized in the presence of a catalyst to form methanol. As with the indirect coal processes, the synthesis gas could also be converted to a Fischer-Tropsch gasoline or the methanol converted to Mobil MTG gasoline.

Methanol probably can be produced from wood with existing technology, but methanol-from-grass processes need to be demonstrated. Several biomass gasifiers are currently under development to improve efficiency and reliability and reduce tar and oil formation. Particularly notable are pyrolysis gasifiers which could significantly increase the yield of methanol per ton of biomass feedstock. Also mass production of small (5 million to 10 million gal/y r), prefabricated methanol plants may reduce costs significantly. With adequate development support, advanced gasifiers and possibly prefabricated methanol plants could be commercially available by the mid to late 1980's.

Ethanol production from grains and sugar crops is commercial technology in the United States. The starch fractions of the grains are reduced to sugar or the sugar in sugar crops is used directly. The sugar is then fermented to ethanol and the ethanol removed from the fermentation broth by distillation.

The sugar used for ethanol fermentation can also be derived from the cellulosic fractions of wood and plant herbage. Commercial processes for doing this use acid hydrolysis technology, but are considerably more expensive than grain-based processes. Several processes using enzymatic hydrolysis and advanced pretreatments of wood and plant herbage are currently under development and could produce processes which synthesize ethanol at costs comparable to those of ethanol derived from grain, but there are still significant economic uncertainties.[13]

[11] 'Chevron, "Refining and Upgrading of Synfuels From Coal and Oil Shales by Advanced Catalytic Processes, First Interim Report: Paraho Shale Oil, "Report HCP/T23 15-25 UC90D, Department of Energy, July 1978,

[12] *Energy From Biological* processes, op. cit.

[13] Ibid

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Fuel Gases

By 2000, the principal fuel gases from biomass are likely to be a low-energy gas from airblown gasifiers and biogas from manure. Other sources may include methane (SNG) from the anaerobic digestion of municipal solid waste and possibly kelp.

A relatively low-energy fuel gas (about 200 Btu/SCF) can be produced by partially burning wood or plant herbage with air in an airblown gasifier. The resultant gas can be used to fuel retrofitted oil- or gas-fired boilers or for process heat needs. Because its low energy content economically prohibits long-distance transportation of the gas, most users will operate the gasifier at the place where the fuel gas is used. Several airblown biomass gasifiers are under development, and commercial units could be available within 5 years.

Biogas (a mixture of carbon dioxide and methane) is produced when animal manure or some types of plant matter are exposed to the appropriate bacteria in an anaerobic digester (a tank sealed from the air). Some of this gas (e.g., from the manure produced at large feedlots) may be purified, by removing the carbon dioxide, and introduced into natural gas pipelines, but most of it is likely to be used to generate electricity and provide heat at farms where manure is produced. The total quantity of electricity produced this way would be small and, to an increasing extent, would be used to displace nuclear- and coal-generated electricity. A part of the waste heat from the electric generation can be used for hot water and space heating in buildings on the farm, however.[14] A small part of the biogas (perhaps 15 percent corresponding to the amount occurring on large feedlots) could be purified to SNG and introduced into natural gas pipelines.

Biogas can also be produced by anaerobic digestion of municipal solid waste in landfills and kelps. Any gas so produced is likely to be purified and introduced into natural gas pipelines.

Manure digesters for cattle manure are commercially available. Digesters utilizing other manures require additional development, but could be commercially available within 5 years. The technology for anaerobic digestion of municipal solid waste was not analyzed, but one system is being demonstrated in Florida.[15] In addition, if ocean kelp farms prove to be technically and economically feasible, there may be a small contribution by 2000 from the anaerobic digestion of kelp to produce methane (SNG),[16] but this source should be considered speculative at present.

[14] TRW, "Achieving a production Goal of 1 Million B/D of Coal Liquids by 1990," March 1980.

[15] I. E., Associates, "Biological Production of Gas," contractor report to OTA, April 1979, available in Energy From *Biological Processes, Vol III:* Appendixes, Part C, September 1980,

[16] *Energy From* Biological *Processes,* op. cit.

COST OF SYNTHETIC FUELS

There is a great deal of uncertainty in estimating costs for synthetic fuels plants. A number of factors, which can be predicted with varying degrees of accuracy, contribute to this uncertainty. Some of the more important are considered below, followed by estimates for the costs of various synfuels.

Uncertainties

For most of the synfuels, fixed charges are a large part of the product costs. Depending on assumptions about financing, interest rates, and the required rate of return on investment, these charges can vary by more than a factor of 2. In many cases, differences in product cost estimates can be explained solely on the basis of these differences. For most of the biomass fuels, the cost of the biomass feedstock is also highly variable, and this has a strong influence on the product cost.

The cost of synfuels projects, and particularly the very large fossil fuel ones, is also affected by: 1) construction delays, 2) real construction cost increases (corrected for general inflation) during construction, and 3) delays in reaching full production capacity after construction is completed, due to technical difficulties. These factors are usually not included in cost estimates, but they are likely to affect the product cost.

Another factor that should be considered is the state of development of the technology on which the investment and operating cost estimates are based, As technology development proceeds, problems are discovered and solved at a cost, and the engineer's original concept of the plant is gradually replaced with a closer and closer approximation of how the plant actually will look. Consequently, calculations based on less developed technologies are less accurate. This usually means that early estimates understate the true costs by larger margins than those based on more developed and well-defined technologies. This is particularly true of processes using solid feedstocks because of the inherent difficulty with scaling-up process streams involving solids. Figure 14 illustrates cost escalations that can occur, by summarizing the increases in cost estimates for various energy projects as technology development proceeded. Table 42 also illustrates this point by showing average cost overruns that have occurred in various types of large construction projects.

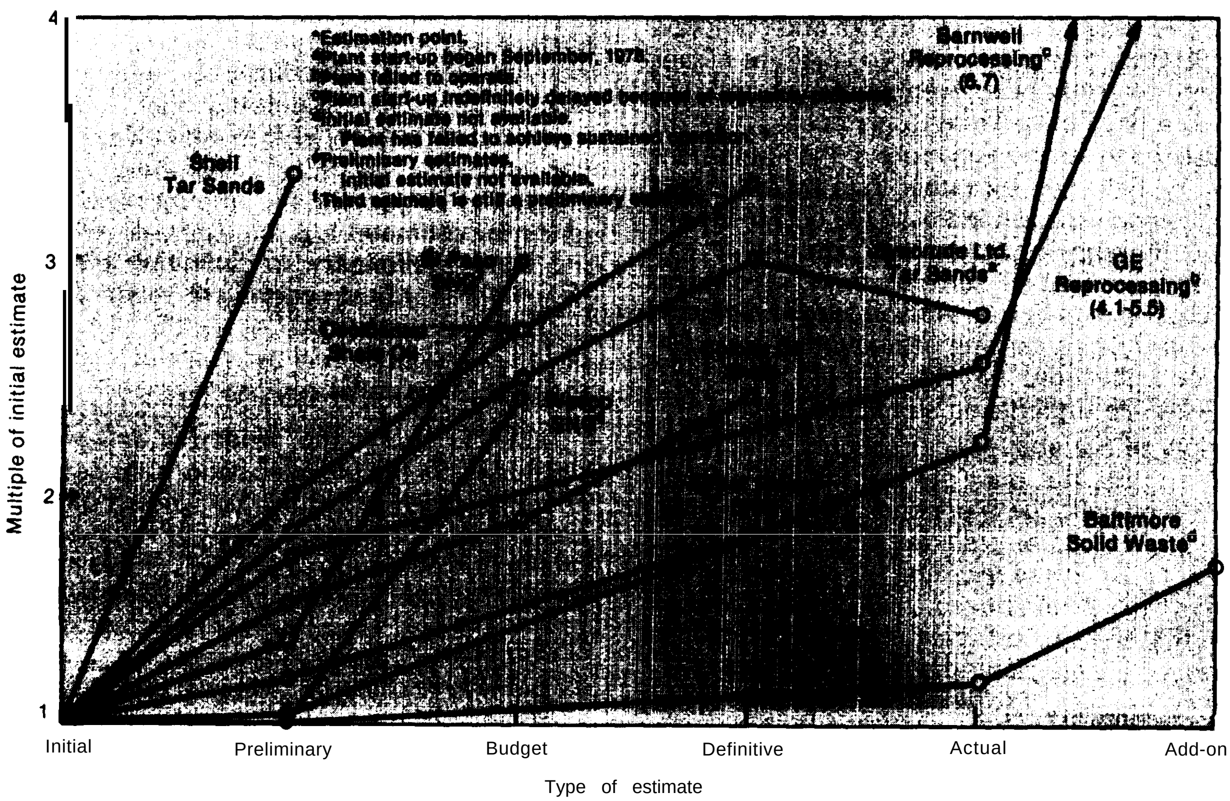
It should be noted, however, that the period of time in which most of the project evaluations

Table 42.-Average Cost Overruns for Various Types of Large Construction Projects

System type	Actual cost divided by estimated cost
Weapons systems.	1.40-1.89
Public works	1.26-2.14
Major construction	2.18
Energy process plants	2.53

SOURCES: Rand Corp., "A Review of Cost Estimates In New Technologies: Implications for Energy Process Plants," prepared for U.S. Department of Energy, July 1979; Hufschmidt and Gerin, "Systematic Errors In Cost Estimates for Public Investment Projects," in *The Analysis of Public Output*, Columbia University Press, 1970; and R. Perry, et al., "Systems Acquisition Strategies," Rand Corp., 1970.

Figure 14.—Cost Growth in Pioneer Energy Process Plants (constant dollars)



SOURCE: "A Review of Cost Estimation in New Technologies: Implications for Energy Process Plants," Rand Corp. R-2481- DOE, July 1979, in table 42 were made had high escalation rates for capital investment relative to general economic inflation. Historically this has not been the case; and if future inflation in plant construction more nearly follows general inflation, the expected synfuels investment increases from preliminary design to actual construction would be lower than is indicated in figure 14 and table 42.

When judging the future costs and economic competitiveness of synfuels, one must therefore also consider the long-term inflation in construction costs. To a very large extent, the ability to produce synfuels at costs below those of petroleum products will depend on the relative inflation rates of crude oil prices and construction costs.

Although economies of scale are important for synfuels plants, there are also certain diseconomies of scale—factors which tend to increase construction costs (per unit of plant capacity) for very large facilities as compared with small ones. First, the logistics of coordinating construction workers and the timely delivery of construction materials become increasingly difficult as the construction project increases in size and complexity. Second, construction labor costs are higher in large projects due to overtime, travel, and subsistence payments. Third, as synfuels plants increase in size, more and more of the equipment must be field-erected rather than prefabricated in a factory. This can increase the cost of equipment, although in some cases components may be "mass-produced" on site, thereby equaling the cost savings due to prefabrications. Some of these problems causing diseconomies of scale can be aggravated if a large number of synfuels projects are undertaken simultaneously.

Many of the above factors would tend to increase costs, but once several full-scale plants have been built, the experience gained may help reduce production costs for future generations of plants. Delays in reaching full production capacity can be minimized, and process innovations that reduce costs can be introduced. in addition, very large plants that fully utilize the available economies of scale can be built with confidence. Consequently, the first generation units produced are likely to be the most expensive, if adjustments are made for inflation in construction and operating costs.

An example of this can be found in the chemical industry, where capital productivity (output per unit capital investment) for the entire industry has increased by about 1.4 percent per year since 1949.[17] In some sectors, such as methanol synthesis, productivity has increased by more than 4 percent per year for over 20 years.[18] Much of this improvement is attributable to increased plant size and the resultant economies of scale: Because the proposed synfuels plants are already relatively large, cost decreases for synfuels plants may not be as large and consistent as those experienced in the chemical industry in recent years; however, because of the newness of the industry, some decreases are expected.

Investment Cost

For purposes of cost calculations, previous OTA estimates[19,20] were used for oil shale and biomass synfuels (adjusted, in the case of oil shale, to 1980 dollars) and the best available cost estimates in the public literature were used for coal-derived synfuels. These latter estimates were compared[21] to the results of an earlier Engineering Societies' Commission on Energy (ESCOE) study[22] of coal-derived synfuels, which used preliminary engineering data. Since the best available cost estimates correspond roughly to definitive engineering estimates, the ESCOE numbers were increased by 50 percent, the amount by which engineering estimates typically increase when going from preliminary to definitive estimates. When these adjustments were made and the costs expressed in 1980 dollars, the two sources of cost estimates for coal-based synfuels produced roughly comparable results. *s

Table 43 shows the processes and product slates used for the cost calculations. As described above, a variety of alternative product slates are possible, but these were chosen to emphasize the production of transportation fuels. Table 44 gives the best available investment and operating costs

[17] E. J. Bentz & Associates, Inc., "Selected Technical and Economic Comparisons of Synfuel Options, " contractor report to OTA, 1981.
[18] Ibid.
[19] *An* Assessment of Oil *Shale* Technologies, op. cit.
[20] *Energy From Biological Processes,* op. cit.
[21] E. J. Bentz & Associates, Inc., op. cit.
[22] Engineering Societies Commission on Energy, Inc., OP. cit.
[23] E. J. Bentz & Associates, Inc., Op. cit.

Table 43.—Selected Synfuels Processes and Products and Their Efficiencies

Process	Fuel products (percent of output)	Energy efficiency (percent): Fuel products (percent of input coal and external power)	Energy efficiency (percent): Tranportation fuel products (percent of input coal and external power)
Oil shale	Gasoline (19)[b] Jet fuel (22) Diesel fuel (59)	N.A.[c]	N.A.[c]
Methanol/synthetic natural gas (SNG) from coal	Methanol (48)[d] SNG (49) Other (3)	65	33
Methanol from coal	Methanol (IOO)[e,f]	55[g]	55[g]
Coal to methanol/SNG, Mobil methanol to gasoline	Gasoline (40)[d] SNG (52) Other (8)	63	27
Coal to methanol, Mobil methanol to gasoline	Gasoline (87)[d] Other (13)	47	41
Fischer-Tropsch/SNG from coal	Gasoline (33)[d] SNG (65) Other (2)	56	17
Direct coal liquefaction	Gasoline (33)[f,h] Jet fuel (49) Other (18)	57	47
SNG from coal	SNG (IOO)[f]	59	0
Methanol from wood	Methanol (IOO)[i]	47[f]	47[h]
Ethanol from grain	Ethanol (IOO)[i]	N.A.[c]	N.A.[c]

[a]Higher heating value of products divided by higher heating value Of the coal plus imported energy.
[b]R. F. Sullivan, et al., "Refining and Upgrading of Synfuels From Coal and Oil Shales by Advanced Catalytic Processes," first interim report, prepared by Chevron for Department of Energy, April 1978, NTIS No FE-2315-25.
[c]Not applicable
[d]Max Schreiner, " Research Guidance Studies to Assess Gasoline From Coal to Methanol-to-Gasoline and Sasol-Type Fischer. Tropsch Technologies," prepared by Mobil R&D Co. for the Department of Energy, August 1978, NTIS No. FE-2447-13.
[e]DHR, Inc., "Phase I Methanol Use Options Study," prepared for the Department of Energy under contract No, DE-AC01-79PE-70027, Dec. 23, 1980,
[f]K. A. Rogers, "Coal Conversion Comparisons," Engineering Societies Commission on Energy, Washington, D.C., prepared for the Department of Energy, July 1979, No. FE-2488-51.
[g]Sullivant and Frumking (footnote h) give 57 percent, DHR (footnote e) gives 52 percent.
[h]R, F, Sullivan and H. A. Frumkin, "Refining and Upgrading of Synfuels by Advanced Catalytic Processes," third interim report, prepared by Chevron for the Department of Energy, Apr. 30, 1980, NTIS, No. FE-2315,47 Products shown are for H-Coal. It is assumed that same product slate results from refined EDS liquids.
[i]OTA, *Energy From Biological processes, Volume //*, September 1980, GPO stock No. 052-003-00782-7.

SOURCE: Office of Technology Assessment

(excluding coal costs) in 1980 dollars for the various processes, with all results normalized to the production of 50,000 barrels per day (bbl/d) oil equivalent of product to the end user (i.e., including refining losses). Only a generic direct liquefaction process is included because current estimation errors appear likely to be greater than any differences between the various direct liquefaction processes.

Based on the history of cost escalation in the construction of chemical plants, one can be nearly certain that final costs of the first generation of these synfuels plants will exceed those shown in table 44 (with the exception of ethanol which is already commercial), Using a methodology developed to estimate this cost escalation, Rand Corp. has examined several synfuels processes and derived cost growth factors, or estimates of how much the capital investment in the synfuels plant is likely to exceed the best available engineering estimates. Some of the results of the Rand study are shown in table 45. Also shown is the expected performance of each plant if it were built today, expressed as the percentage of designed fuel production that the plant is likely to achieve.

The figures reflect Rand's judgment that direct liquefaction processes require further development before construction of a commercial-scale plant should be attempted; but the calculations also indicate that even the first generation of near-commercial processes are likely to be more ex-

Table 44.—Best Available Capital and Operating Cost Estimates for Synfuels Plants Producing 50,000 bbl/d Oil Equivalent of Fuel to End Users

Process	Capital investment (billion 1980 dollars)	Annual operating costs (exclusive of coal costs) (million 1980 dollars)
Oil shale[a]	$2,2	$250
Methanol/SNG from coal[b]	2.1	150
Methanol from coal[c]	2.8	200
Coal to methanol/SNG, Mobil methanol to gasoline[b]	2.4	170
Coal to methanol, Mobil methanol to gasoline[b]	3.3	230
Fischer-Tropsch/SNG from coal[b]	2.5	190
Direct coal liquefaction[d]	3.0	250
SNG[e]	2..2	150
Methanol from wood[f]	2.9	610 (wood at $30/dry ton) (wood at $45/dry ton)
Ethanol[f]	1.8	860 ($3/bu. corn) 1,112 ($4.50/bu. corn)

[a]Office of Technology Assessment, An Assessment of 0// Shale Technologies, June 1980, $1.7 billion Investment in 1979 dollars becomes $1.9 billion In 1980 dollars for 50,000 bbl/d of shale oil. Assuming 88 percent refining efficiency, one needs 57,000 bbl/d of shale 011 to produce 50,000 bbl/d 011 equivalent of products, at an investment of $1.9 billion/0.88 -$2.2 billion.
[b]Derived from R. M. Wham, et al., "Liquefaction Technology Assessment-Phase 1: Indirect Liquefaction of Coal to Methanol and Gasoline Using Available Technology," Oak Ridge National Laboratory, ORNL-5664, February 1981.
[c]From DHR, Inc., "Phase I Methanol Use Options Study," prepared for the Department of Energy under contract No. DE-AC01-79PE-70027, Dec. 23, 1980, one finds that the ratio of investment cost of a methanol to a Mobil methanol-to-gasoline plant Is 0.85. Assuming this ratio and the value for a methanol-to-gasoline plant from footnote b, one arrives at the investment cost shown. The operating cost was increased in proportion to investment coat. Thia adjustment is necessary to put the costs on a common basis. These values are 50 percent more than the estimates given by DHR (reference above) and Badger (Badger Plants, Inc., "Conceptual Design of a Coal to Methanol Commercial Plant," prepared for the Department of Energy, February 1978, NTIS No. FE-2416-24). In order to compare Badger with this estimate, It was necessary to scale down the Badger plant (using a 0.7 scaling factor) and inflate the result to 1980 dollars (increase by 39 percent from 1977).
[d]Exxon Research and Engineering Co., "EDS Coal Liquefaction Process Development, Phase V," prepared for the Department of Energy under cooperative agreement DE-FCO1-77ETIOO89, March 1981. Investment and operating cost assumes an energy efficiency of 82.5 percent for the refining process. Refinery Investment of up to S700 million Is not included in the capital investment.
[e]Rand Corp., "Cost and Performance Expectations for Pioneer Synthetic Fuels Plants," report No. R-2571-DOE, 1981.
[f]Office of Technology Assessment, Energy From Biological Processes, Volume II, September 1980, GPO stock No. 052-003-00782-7; i.e., 40 million gallons per year methanol plant costing S88 million, 50 million gallons per year ethanol plant costing $75 million,

SOURCE: Office of Technology Assessment.

Table 45.—Estimates of Cost Escalation in First Generation Synfuels Plants

Process	Cost growth factor derived by Rand[a] for 90 percent confidence interval[b]	Revised investment cost (billion 1980 dollars)	Expected performance for 90 percent confidence interval[b] (percent of plant design)
Oil shale	1.04-1.39	2.3-3.1	57-85
Coal to methanol to gasoline (Mobil, no SNG byproduct)	1.06-1.43	3.5-4.7	65-93
Direct coal liquefaction (H-Coal)	1.52-2.38a	4.0-6 .3a	25-53
SNG	0.95-1.23	2.1-2.7	69-97

[a]Based on Rand @@ in which best estimate for H-Coal is $2.2 billion for 50,000 bbl/d of product syncrude. With 82.5 Percent refining efficiency, this becomes $2.7 billion for 50,000 bbl/d of product to end user.
[b]In other words, 90 percent probability that actual cost growth factor or Performance will fall in the interval.

SOURCE: Office of Technology Assessment; adapted from Rand Corp., "Cost and Performance Expectations for Pioneer Synthetic Fuels Plants," R-2571-DOE, 1981.

pensive and less reliable than the best conventional engineering estimates would indicate. This analysis indicates that it is quite reasonable to expect first generation coal liquefaction plants of this size to cost $3 billion to $5 billion or more each in 1980 dollars.

Consumer Cost

The consumer costs of the various synfuels are shown in table 46. These consumer costs are based on the estimates in table 44 and the economic assumptions listed in table 47. The effect on the calculated product cost of varying some of the economic assumptions is then shown in table 48.

With these economic assumptions, delivered liquid fossil synfuels costs (1980 dollars) range from $1.25 to $1.85 per gallon of gasoline equivalent (gge) for 100 percent equity financing and $0.80 to $1.25/gge with 75 percent debt financing at 5 percent real interest (i. e., relative to inflation), In 1981 dollars, these estimates become $1.40 to 2.10/gge and $0.90 to $1.40/gge, respectively. This compares with a reference cost of gasoline from $32/bbl crude oil of $1.20/gal (plus $0.1 7/gal taxes).

Extreme caution should be exercised when interpreting these figures, however. They represent the best current estimates of what fossil synfuels will cost after technical uncertainties have been resolved through commercial demonstration. They do not include any significant cost increases that may occur from design changes, hyperinflation in construction costs, or construction delays. They most likely represent a lower limit for the synfuels costs.

Table 46.—Consumer Cost of Various Synthetic Transportation Fuels

	1000/0 equity financing, IO% real return on investment			25°/0 equity/75% debt financing, 10% real return on investment		
	Plant or refinery gate product cost	Delivered consumer cost of fuel [a]		Plant or refinery gate product cost	Delivered consumer cost of fuel [a]	
Process	1960 dollars per barrel oil equivalent (5.9 MMBtu/B)	1960 dollars per gallon gasoline equivalent (125 k Btu/gal)	1980 $/MMBtu	1980 dollars per barrel oil equivalent (5.9 MMBtu/B)	1960 dollars per gallon gasoline equivalent (125 k Btu/gal)	1980 $/MMBtu
Reference cost of gasoline from $32/bbl crude oil . .	47	1.20	9.50		1.20	9.50
Oil shale.	52[b]	1.30	10.40	3 3[b]	0.90	7.20
Methanol/SNG from coal . .	43	1.30[c d]	10.60[c]	25	0.95[C d]	7.50[c]
Methanol from coal	58	1.60[d]	13.00	33	1.10[d]	8.60
Coal to methanol/SNG, Mobil methanol to gasoline	49[e]	1.25C [d]	10.00[c]	29[e]	0.80[C d]	6.40[C]
Coal to methanol, Mobil methanol to gasoline . . .	67[e]	1.60[d]	12.90	38[e]	1.00[d]	8.10
Fischer-Tropsch/SNG from coal	52[e]	1 .30[c]	10.40[C]	3o[e]	0.85[C]	6.70[C]
Direct coal liquefaction . . .	77[f]	1.85	14.60	5 1[f]	1.25	10.20
SNG from coal		1.15[g]	9.10[g]		0.75[g]	5.90[g]
Methanol from wood	68 (79)[h]	1.65 (2.05)[h]	14.70 **(16.60)**[h]	49 (60)[h]	1.45 (1.70)[h]	11.60 (13.40)[h]
Ethanol from grain	71 (87)'	1.60 (2.15)'	14.50 (17.10)'	60 (75)'	1.55 (1.90)'	12.60 (15.10)'

a**Assuming $0.20/physical gallon** delivery charge and **mark-up; fuel taxes** not **included.**
b**Includes $6/bbl refining cost.** Derived from **R. F. Sullivan,** et **al.,** "Refining and **Upgrading** of **Synfuels From Coal** and **Oil Shales** by Advanced **Catalytic** processes," first interim report by Chevron Research Corp. to the Department of Energy, April 1978, by increasing cost of **$4.50/bbl** by 22 percent to reflect 19S0 dollars and adjusting for **88** percent refinery efficiency.
c**Assumes coproduct SNG selling** for same **price** per **MMBtu** at the Plant **gate** ss the **liquid product.**
d**Although the plant or refinery gate cost of** methanol **is lower** than MTG gasoline, the **delivered** consumer **cost** Of **methanol is higher due to the higher cost** of **delivering** a given amount of energy in the form of methanol aa compared with gasoline, because of the lower energy content per gallon of the former.
eAii **necessary** refining is included in the **conversion** Plant.
f **Includes $14/bbl refining cost** from **R. F. Sullivan** and **H. A. Frumkin,** "Refining **and** Upgrading of **Synfuels** From **Coal** and Oil Shales by Advanced **Catalytic Processes,** Third Interim Report," report to the Department of Energy, Apr. 30, 19S0, NTIS No. **FE-2315-47.** Refining **costs** fOr EDS and H-Coal are assumed to be the same as **SRC** II. Note, however, that **refining** costs drop to **$10/bbl** for production **of** heating oil and **gasoline** and Increase to **$16.50/bbl** for production ***of gasoline only.***
g**$1.49/MMBtu delivery charge and markup, which** corresponds to **the 1980** difference between the **wellhead** and residential price of natural gas. Energy Information Administration, U.S. Department of Energy, "19S0 Annual Report to Congress," vol. 2, **DOE/EIA-0173** (S0)/2, pp. 117 and 119.
hAss ume s **$30/dry** ton **wood. Number** in parentheses corresponds to **$45/dry** ton **wood.**
i **Assumes $3/bu. corn. Number in** parentheses corresponds to **$4.50/bu.** corn.

SOURCE: Office of Technology Assessment.

Table 47.—Assumptions

1, Project life—25 years following 5-year construction period for fossil synfuels and 2-year construction period for biomass synfuels.
2.10 year straight-line depreciation.
3. Local taxes and property insurance as in K. K. Rogers, "coal Conversion Comparisons," ESCOE, prepared for U.S. Department of Energy under contract No. EF-77-C-01-2468, July 1979.
4.10 percent real rate of return on equity investment with: 1) 100 percent equity financing, and 2) 75 percent debt/25 percent equity financing with 5 percent real interest rate.
5.90 percent capacity or "onstream factor."
6. Coal costs $30/ton delivered to synfuels plant (1980 dollars).
7.46 percent Federal and 9 percent State tax.
8. Working capital = 10 percent of capital investment.

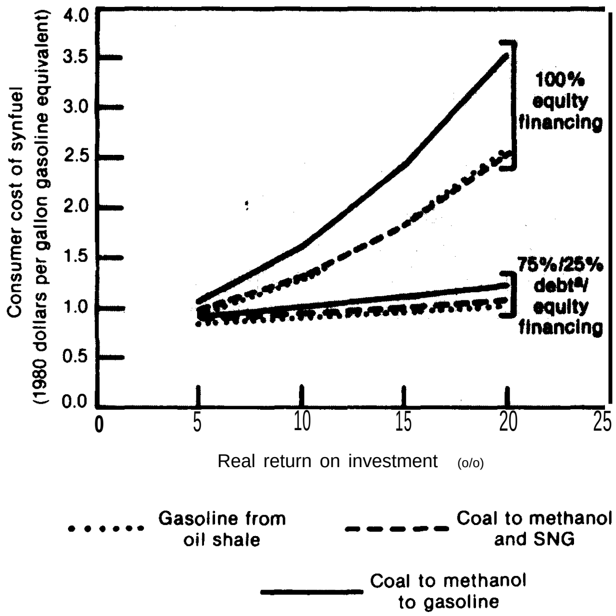
SOURCE: Office of Technology Assessment.

Table 48.—Effect of Varying Financial Parameters and Assumptions on Synfuels' Costs

Change	Effect on synfuels cost
Plant operates at a 50 percent on stream factor rather than 90 percent	Increase 60-70%
Increase capital investment by 50 percent	Increase 15-35%
8-year construction rather than 5-year	Increase 5-20%
Increase coal price by $15/ton . .	Increase $5-7/bbl

SOURCE: Office of Technology Assessment.

Figure 15.—Consumer Cost of Selected Synfuels With Various Aftertax Rates of Return on Investment



[a]5% real interest rate on debt.

SOURCE: Office of Technology Assessment

Because cost overruns and poor plant performance lower the return on investment, investors in the first round of synfuels plants are likely to require a high calculated rate of return on investment to ensure against these eventualities. Put another way, anticipated cost increases (table 45) would lead investors to require higher product prices than those in table 46 before investing in synfuels.

The effects on product costs of various rates of return on investment are shown in figure 15 for selected processes, and the effect of changes in various other economic parameters is shown in table 48. As can be seen, product costs could vary by more than a factor of 2 depending on the technical, economic, and financial conditions that pertain.

Nevertheless, it can be concluded that factors which reduce the equity investment and the required return on that investment and those which help to ensure reliable plant performance are the most significant in holding synfuels costs down. These factors do not always act unambiguously, however. Inflation during construction, for example, increases cost overruns, but inflation after construction increases the real (deflated) return on investment. The net effect is that the synfuels cost more than expected when plant production first starts, but continued inflation causes the prices of competing fuels to rise and consequently allows synfuels prices—and returns on investment —to rise as well. Similarly, easing of environmental control requirements can reduce the time and investment required to construct a plant, but inadequate controls or knowledge of the environmental impacts may lead to costly retrofits which may perform less reliably than alternative, less polluting plant designs.

Another important factor influencing the cost of some synthetic transportation fuels is the price of coproduct SNG. In table 46 it was assumed that any coproduct SNG would sell for the same price per million Btu (MMBtu) at the plant gate as the liquid fuel products, or from $4 to $9/

MMBtu, which compares with current well head prices of up to $9/MM Btu[24] for some decontrolled gas. (These prices are averaged with much larger quantities of cheaper gas, so average consumer prices are currently about $3 to $5/MMBtu.) However, the highest wellhead prices may not be sustainable in the future as their "cushion" of cheaper gas gets smaller, causing averge consumer prices to rise. This is because consumer prices are limited by competition between gas and competing fuels—e.g., residual oil—and probably cannot go much higher without causing many industrial gas users to switch fuels. Large quantities of unconventional natural gas might be produced at well head prices of about $10 to $1 l/MMBtu,[25] so SNG coproduct prices are unlikely to exceed this latter value in the next two decades. If the SNG coproduct can be sold for only $4/MMBtu or less, synfuels plants that do not produce significant quantities of SNG will likely be favored. However, for the single-product indirect liquefaction processes, advanced high-temperature gasifiers, rather than the commercially proven Lurgi gasifier assumed for these estimates, may be used. This adds some additional uncertainty to product costs.

Despite the inability to make reliable absolute cost estimates, some comparisons based on technical arguments are possible. First, oil shale probably will be one of the lower cost synfuels because of the relative technical simplicity of the process: one simply heats the shale to produce a liquid syncrude which is then hydrogenated to produce a high-quality substitute for natural crude oil. However, handling the large volumes of shale may be more difficult than anticipated; and, since the high-quality shale resources are located in a single region and there is only a limited ability to disperse plants as an environmental measure, large production volumes could necessitate particularly stringent and therefore expensive pollution control equipment or increase waste disposal costs.

Second, regarding the indirect transportation liquids from coal, the relative consumer cost (cost per miles driven) of methanol v. synthetic gasoline will depend critically on automotive technology. Although methanol plants are somewhat less complex than coal-to-gasoline plants, the cost difference is overcome by the higher cost of terminalling and transporting methanol to a service station, due to the latter's lower energy content per gallon. With specially designed engines, however, the methanol could be used with about 10 to 20 percent higher efficiency than gasoline. This would reduce the apparent cost of methanol, making it slightly less expensive (cost per mile) than synthetic gasoline. * Successful development of direct injected stratified-charge engines would eliminate this advantage, while successful development of advanced techniques for using methanol as an engine fuel could increase methanol's advantage. * *

This analysis shows that there is much uncertainty in these types of cost estimates, and they should be treated with due skepticism. The estimates are useful as a general indication of the likely cost of synfuels, but these and any other cost estimates available at this time are inadequate to serve as a principal basis for policy decisions that require accurate cost predictions with consequences 10 to 20 years in the future.

[24] Process Gas Consumer Group, Process Gas Consumers *Report,* Washington, D. C., June 1981.

[25] J. F. Bookout, Chairman, Committee on Unconventional Gas Sources, "Unconventional Gas Sources," National Petroleum Council, December 1980.

*If gasoline has a $0.10/gge advantage in delivered fuel price for synfuels costing $1 .50/gge, methanol would have an overall $0.20/gge advantage when used with a specially designed engine. This could pay for the added cost of a methanol engine in 2 to 4 years (assuming 250/gge consumed per year).

**For example, engine waste heat can be used to decompose the methanol into carbon monoxide and hydrogen before the fuel is burned. The carbon monoxide/hydrogen mixture contains 20 percent more energy than the methanol from which it came, with the energy difference coming from what would otherwise be waste heat.

DEVELOPING A SYNFUELS INDUSTRY

Development of a U.S. synfuels industry can be roughly divided into three general stages. During the first phase, processes will be developed and proven and commercial-scale operation established. The second phase consists of expanding the industrial capability to build synfuels plants. in the third stage, ynfuels production is brought to a level sufficient for domestic needs and possibly export. Current indications are that the first two stages could take 7 to 10 years each. Some of the constraints on this development are considered next, followed by a description of two synfuels development scenarios.

Constraints

A number of factors could constrain the rate at which a synfuels industry develops. Those mentioned most often include:

- Other Construction Projects. –Construction of, for example, a $20 billion to $25 billion Alaskan natural gas pipeline or a $335 billion Saudi Arabian refinery and petrochemical industry, if carried out, would use the same international construction companies, technically skilled labor, and internationally marketed equipment as will be required for U.S. synfuel plant construction.[26]
- Equipment. –Building enough plants to produce 3 million barrels per day (MMB/D) of fossil synfuels by 2000 will require significant fractions of the current U.S. capacity for producing pumps, heat exchangers, compressors and turbines, pressure vessels and reactors, alloy and stainless steel valves, draglines, air separation (oxygen) equipment, and distillation towers.[27 28 29 30]
- critical Materials. -Materials critical to the synfuels program include cobalt, nickel, molybdenum, and chromium. Two independent analyses concluded that only chromium is a potential constraint.[31 32] (Currently, 90 percent of the chromium used in the United States is imported.) However, development of 3 MMB/D of fossil synfuels production capacity by 2000 would require only 7 percent of current U.S. chromium consumption .[33]
- Technological Uncertainties. -The proposed synfuels processes must be demonstrated and shown to be economic on a commercial scale before large numbers of plants can be built.
- Transportation. — If large quantities of coal are to be transported, rail lines, docks, and other facilities will have to be upgraded.[34] New pipelines for syncrudes and products will have to be built.
- Manpower.–A significant increase in the number of chemical engineers and project managers will be needed. For example, achieving 3 MMB/D of fossil synfuels capacity by 2000 will require 1,300 new chemical engineers by 1986, representing a 35-percent increase in the process engineering work force in the United States.[35] More of other types of engineers, pipefitters, welders, electricians, carpenters, ironworkers, and others will also be needed.
- Environment, Health, and Safety. -Delays in issuing permits; uncertainty about standards, needed controls, and equipment performance; and court challenges can cause delays during planning and construction (see ch. 10). Conflicts over water availability could further delay projects, particularly in the West (see ch. 11).
- Siting. –Some synfuels plants will be built in remote areas that lack the needed technical and social infrastructure for plant construction. Such siting factors could, for example, increase construction time and cost.
- Financial Concerns. –Most large synfuels projects require capital investments that are large relative to the total capital stock of the company developing the project. Consequently, most investors will be extremely cautious with these large investments and banks may be reluctant to loan the capital without extensive guarantees.

[26] *Business* Week, Sept. 29, 1980, p. 83.
[27] Ibid.
[28] Bechtel International, Inc., "Production of Synthetic Liquids From Coal: 1980-2000, A Preliminary Study of Potential Impediments,'' final report, December 1979.
[29] TRW, op. cit.
[30] Mechanical Technology, Inc., "An Assessment of Commercial Coal Liquefaction Processes Equipment Performance and Supply," January 1980.
[31] Ibid.
[32] Bechtel International, Inc., op. cit.
[33] Ibid.
[34] *The Direct Use* of Coal: Prospects and Problems of Production and Combustion, OTA-E-86 (Washington, D. C.: U.S. Congress, Office of Technology Assessment, April 1979).
[35] Bechtel International, Inc., Op. cit.

None of these factors can be identified as an overriding constraint for coal-derived synfuels, although the need for commercial demonstration and the availability of experienced engineers and project managers appear to be the most important. There is still disagreement about how important individual factors like equipment availability actually will be in practice. However, the more rapidly a synfuels industry develops, the more likely development will cause significant inflation in secondary sectors, supply disruptions, and other externalities and controversies. But the exact response of each of the factors in synfuels development is not known. For oil shale, on the other hand, the factor (other than commercial demonstration) that is most likely to limit the rate of growth is the rate at which communities in the oil shale regions can develop the social infrastructure needed to accommodate the large influx of people to the region.[36]

The major impacts of developing a large synfuels industry are discussed in chapters 8 through 10, while two plausible synfuels development scenarios are described below.

Development Scenarios

Based on previous OTA reports[37] 38 estimates of the importance of the various constraints discussed above, and interviews with Government and industry officials, two development scenarios were constructed for synthetic fuels production. It should be emphasized that these are not projections, but rather plausible development scenarios under different sets of conditions. Fossil synthetics are considered first, followed by biomass synfuels; and the two are combined in the final section.

Fossil Synfuels

The two scenarios for fossil synthetics are shown in table 49 and compared with other estimates in figure 16. It can be seen that OTA scenarios are reasonably consistent with the other projections, given the rather speculative nature of this type of estimate.

Table 49.—Fossil Synthetic Fuels Development Scenarios (MMB/DOE)

Fuel	Year 1980	1985	1990	1995	2000
Low estimate					
Shale oil	—	O	0.2	0.4	0.5
Coal liquids	—	—	0.1	0.3	0.8
Coal gases	—	0.09	0.1	0.3	0,8
Total	—	0.1	0.4	1.0	2.1
High estimate					
Shale oil	—	O	0.4	0.9	0.9
Coal liquids	—	—	0.2	0.7	2.4
Coal gases	—	0.09	0.2	0.7	2.4
Total	—	0.1	0.8	2.3	5.7

SOURCE: Office of Technology Assessment

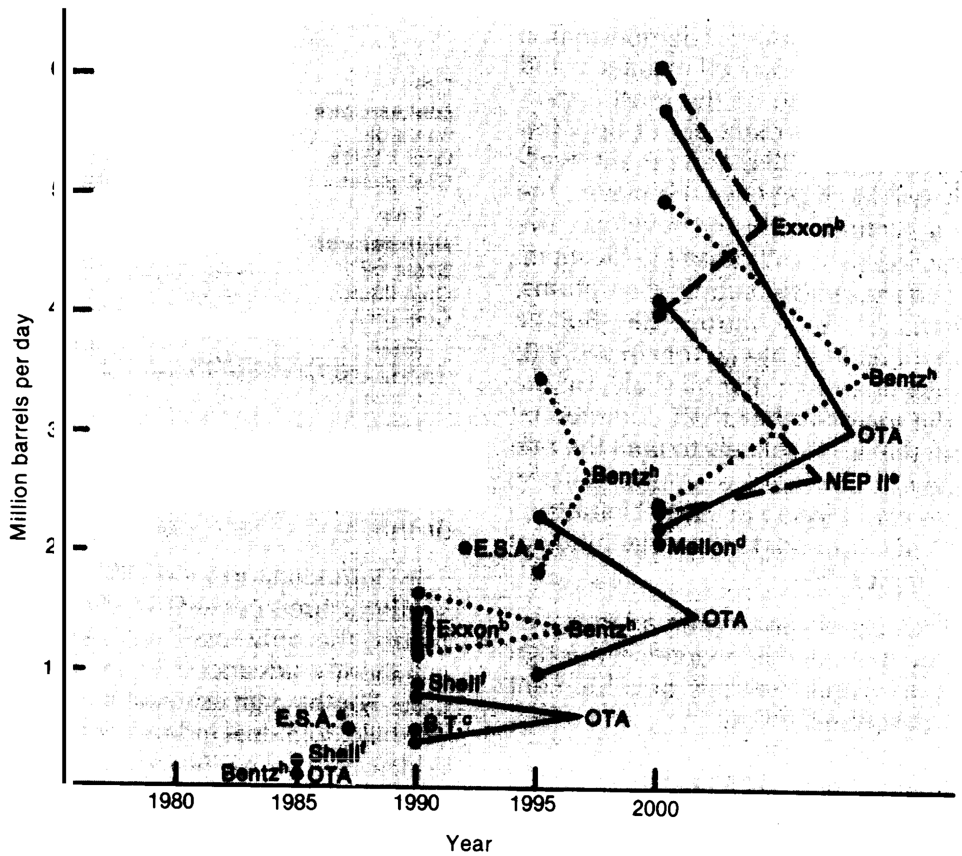
In both scenarios, the 1985 production of fossil synthetic fuels consists solely of coal gasification plants, the only fossil synfuels projects that are sufficiently advanced to be producing by that date. For the high estimate it is assumed that eight oil shale, four coal indirect liquefaction, and three additional coal gasification plants have been built and are operating by 1988-90. If no major technical problems have been uncovered, a second round of construction could proceed at this time.

Assuming that eight additional 50,000-bbl/d plants are under construction by 1988 and that construction starts on eight more plants in 1988 and the number of starts increases by 10 percent per year thereafter, one would obtain the quantities of synfuels shown for the high estimate. Ten-percent annual growth in construction starts was chosen as a high but probably manageable rate of increase once the processes are proven.

Oil shale is assumed to be limited to 0.9 MMB/D because of environmental constraints and, possibly, political decisions related to water availability. Some industry experts believe that neither of these constraints would materialize because, at this level of production, it would be feasible to build aqueducts to transport water to the region, and additional control technology could limit

[36] *An Assessment of Oil Shale Technologies*, op. cit.
[37] Ibid.
[38] *Energy From Biological Processes*, op. cit.

Figure 16.—Comparison of Fossil Synthetic Fuel Production Estimates



[a]Energy Security Act, Public Law 96-294 6/30/80, sec. 100 (a) (2).
[b]Exxon Energy Outlook, December 1979. These data are consistent with those in Exxon Energy Outlook, December 1980.
[c]Bankers Trust Forecast—as reported in *Synfuels*, Aug. 15, 1980.
[d]Mellon Institute Forecast—as reported in *Synfuels*, Aug. 22, 1980.
[e]National Energy Plan II, May 1979.
[f]National Transportation Policy Study Commission Report, July 1979.
[g]Shell National Energy Outlook, preliminary version, Feb. 19, 1980.
[h]E. J. Bentz and Associates, "Selected Technical and Economic Comparisons of Synfuel Options," contractor report to OTA, April 1981.

SOURCE: E. J. Bentz and Associates, "Selected Technical and Economic Comparisons of Synfuel Options," contractor report to OTA, 1981; modified by OTA.

plant emissions to an acceptable level. If this is done and salt leaching into the Colorado River does not materialize as a constraint, perhaps more of the available capital, equipment, and labor would go to oil shale and less to the alternatives.

The low estimate was derived by assuming that project delays and poor performance of the first round of plants limit the output by 1990 to about 0.4 MMB/D. These initial problems limit investment in new plants between 1988-95 to about the level assumed during the 1981-88 period, but the second round of plants performs satisfactorially. This would add 0.6 MMB/D, assuming that the first round operated at 60 percent of capacity, on the average, while the second round operated at 90 percent of capacity (i.e., at full capacity 90 percent of the time). Following the second round, new construction starts increase as in the high estimate.

In both estimates, it is assumed that about half of the coal synfuels are gases and half are liquids.

This could occur through a combination of plants that produce only liquids, only gases, or liquid/gas coproducts. Depending on markets for the fuels, the available resources (capital, engineering firms, equipment, etc.) could be used to construct facilities for producing more synthetic liquids and less synthetic gas without affecting the synfuels total significantly.

When interpreting the development scenarios, however, it should be emphasized that there is no guarantee that even the low estimate will be achieved. Actual development will depend critically on decisions made by potential investors within the next 2 years. I n addition to businesses' estimates of future oil prices, these decisions are likely to be strongly influenced by availability of Federal support for commercialization, in which commercial-scale process units are tested and proven. Unless several more commercial projects than industry has currently announced are initiated in the next year or two, it is unlikely that even the low estimate for 1990 can be achieved.

Biomass Synfuels

Estimating the quantities of synfuels from biomass is difficult because of the lack of data on the number of potential users, technical uncertainties, and uncertainties about future cropland needs for food production and the extent to which good forest management will actually be practiced. OTA has estimated that from 6 to 17 quadrillion Btu per year (Quads/yr) of biomass could be available to be used for energy by 2000, depending on these and other factors.[39] At the lower limit, most of the biomass would be used for direct combustion applications, but there would be small amounts of methanol, biogas, ethanol from grain, and gasification as well.

Assuming that 5 Quads/yr of wood and plant herbage, over and above the lower figure for bioenergy, is used for energy by 2000 and that 1 Quad/yr of this is used for direct combustion, then about 4 Quads/yr would be converted to synfuels. If half of this biomass is used in airblown gasifiers for a low-Btu gas and half for methanol synthesis (60 percent efficiency), this would result in 0.9 million barrels per day oil equivalent (MMB/DOE) of low-Btu gas and 0.6 MMB/DOE of methanol (19 billion gal/yr). *

The 0.9 MMB/DOE of synthetic gas is about 5 percent of the energy consumption in the residential/commercial and industrial sectors, or 9 percent of total industrial energy consumption. Depending on the actual number of small energy users located near biomass supplies, this figure may be conservative for the market penetration of airblown gasifiers. Furthermore, the estimated quantity of methanol is contingent on: 1) development of advanced gasifiers and, possibly, prefabricated methanol plants that reduce costs to the point of being competitive with coal-derived methanol and 2) market penetration of coal-derived methanol so that the supply infrastructure and end-use markets for methanol are readily available. OTA's analysis indicates that both assumptions are plausible.

In addition to these synfuels, about 0.08 to 0.16 MMB/DOE (2 billion to 4 billion gal/yr) of ethanol* * could be produced from grain and sugar

Box D.-Definitions of Demonstration and Commercial-Scale Plants

. After laboratory experiments and bench-scale testing show a process to be promising, a demonstration plant may be built to futher test and "demonstrate" the process, This plant is not intended to be **a** moneymaker and generally has a capacity of several hundred to a few thousand barrels per day. The next step may be various stages of scale up to commercial scale, in which commercial-scale process units are used and proven, **although the plant output** is less than would be the case for a commercial operation. For synfuels, the typical output of a commercial unit may be about **10,000** bbl/d. A commercial plant would then consist of several units operating in parallel with common coal or shale handling and product storage and terminal facilities.

[39] Ibid.

*If advanced biomass gasifiers methanol can be produced with an overall efficiency of 70 percent for converting biomass to methanol, this figure will be raised to 0.7 MMB/DOE or 22 billion gal/yr.

**Caution should be exercised when interpreting the ethanol levels, however, since achieving this level will depend on a complex balance of various forces, including Government subsidies, market demand for gasohol, and gasohol's inflationary impact on food prices.

crops, and perhaps 0.1 MMB/DOE of biogas and SNG from anaerobic digestion. * Taking these contributions together with the other contributions from biomass synfuels results in the high and low estimates given in table 50.

Summary

Combining the contributions from fossil and biomass synfuels results in the two development scenarios shown in figure 17. Coal-derived synfuels provide the largest potential. Ultimately, production of fossil synfuels is likely to be limited by the demand for the various synfuel products, the emissions from synfuels plants, and the cost of reducing these emissions to levels required by law. Beyond 2000, on the other hand, synfuels from biomass may be limited by the resource availability; however, development of energy crops capable of being grown on land unsuitable for food crops, ocean kelp farms, and other speculative sources of biomass could expand the resource base somewhat.

*The total potential from manure is about 0.14 MMB/DOE, but the net quantitity that may be used to replace oil and natural gas is probably no more than so percent of this amount. In addition, there may be small contributions from municipal solid waste and, possibly, kelp.

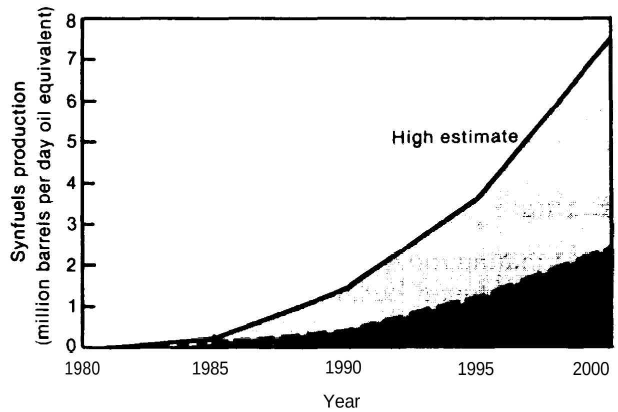
Table 50.—Biomass Synthetic Fuels Development Scenarios (MMB/DOE)

	Year				
Fuel	1980	1985	1990	1995	2000
Low estimate					
Methanol [ab]	–	(e)	(e)	(e)	0.1
Ethanol [c]	(e)	(e)	(e)	(e)	(e)
Low- and medium-energy fuel gas [a]	(e)	(e)	(e)	0.1	0.1
Biogas and methane [d]	(e)	(e)	(e)	(e)	
Total	(e)	(e)	(e)	0.2	0.3
High estimate					
Methanol [ab]	–	(e)	0.1	0.3	0.6
Ethanol [c]	(e)	(e)	0.1	.	.
Low- and medium-energy fuel gas	(e)	0.1	0.3	0.7	0.9
Biogas and methane [d]	(e)	(e)	0.1	0.2	0.2
Total	(e)	0.1	0.6	1.3	1.8

a From wood and plant herbage and possibly municipal solid waste.
b Ethanol could also be produced from wood and plant herbage, but methanol Is likely to be a less expensive liquid fuel from these sources.
c From grains and sugar croPs.
d From animal manure, municipal solid waste, and, possibly, kelp.
e Less than 0.1 MMB/DOE.

SOURCE: Office of Technology Assessment.

Figure 17.—Synthetic Fuel Development Scenarios



SOURCE: Office of Technology Assessment.

Chapter 7

Stationary Uses of Petroleum

Contents

TABLES

Stationary Uses of Petroleum

INTRODUCTION

Stationary users–buildings, industry, and electric utilities—consumed about 8.1 million barrels per day (MMB/D) of petroleum products in 1980. While the potential for reducing oil use by these sectors is well recognized, it has not received as much attention as oil reduction opportunities in transportation. Indeed, U.S. energy policies in the 1970's implicitly encouraged increased oil use for stationary purposes. Lately, however, policy objectives have been set to encourage reduction in oil use by fuel switching and conservation. These objectives include conservation goals and incentives to increase energy use efficiency by buildings and industry, and fuel-switching goals to convert utility and large industrial boilers from oil and natural gas to coal.

This section examines the current mix of petroleum products used in the stationary sector and recent trends. A Department of Energy forecast of stationary demand on petroleum products was selected to serve as a baseline. This will be used to provide estimates of the volume of fuel oil that can be saved by either conservation or conversion to new natural gas and electricity. Readers should note that these estimates only describe reductions in oil use that are technically and economically plausible. Whether the estimated reductions are actually realized depends on how numerous energy users and producers react to economic incentives and other factors affecting their choices. Some of these factors are discussed at the end of this section.

Photo credit: Department of Energy

Cracks and very narrow spaces, such as those around window framing are insulated to increase energy use efficiency

CURRENT SITUATION

Table 51 shows petroleum use by the stationary and transportation sectors since 1965.

Stationary sectors have accounted for 45 to 48 percent of total petroleum demand over this period. Demand growth has occurred in industry and electric utilities as a result of natural-gas curtailments during the 1970's, environmental restrictions on coal, and the rapid increase in electricity demand since about 1973. The type of petroleum product used is also important, since we are primarily concerned with products most readily converted to transportation fuels. Table 52 shows the distribution of major petroleum products for 1980 among the stationary and transportation sectors.

As fuel, the stationary sectors consume principally middle distillates and residual oil. The major components of the other category includes petrochemical feedstocks, asphalt, petroleum coke, and refinery still gas. These are unlikely

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Table 51 .–U.S. Petroleum Demand (MMB/D)

	Stationary				Transportation
Year	Industry	Buildings	Utilities	Total	Total
1965	2.2	3.0	0.3	5.5	6.0
1970	2.5	3.5	0.9	6.9	7.8
1975	2.8	3.2	1.4	7.4	8.9
1980	3.6	2.9	1.6	8.1	8.7

SOURCE: Department of Energy, Energy Information Administration, *1980 Annual Report* to Congress, vol. II.

candidates for conversion to transportation fuels because modifications to refineries would be required far beyond those needed to convert residual fuel oil.[1] Further, some of these products, such as the petrochemical feedstocks and asphalt, could only be replaced by synthetic liquids. The liquefied petroleum gases (LPGs) can be used directly as a transportation fuel, as is the case with cars and trucks that have been modified to run on propane. Widespread adoption will depend principally on the relative cost of propane compared with gasoline, diesel fuel, and methanol when the cost of motor vehicle conversion is included.

Since the current price of natural gas liquids–the major source of propane–is and is likely to remain as high as the price of domestic crude oil, a significant shift to propane-powered vehicles is not likely. Therefore, LPG was not considered in this analysis of stationary fuel use. The major target of fuel switching and conservation, then, is the 4.4 MMB/D of distillate and residual fuel oil in current use. They can be used as a transportation fuel, although it will be necessary to upgrade residual fuel to gasoline and middle distillates by modifying the refinery process. Such modification is under way but will require considerable time and investment.[2]

[1] Refining Flexibility (Washington, D. C.: National Petroleum Council, 1980).

[2] *Oil and Gas Journal*, Jan. 5, 1981, p. 43.

Table 52.—1980 Petroleum Demand (MMBD)[a]

	Stationary				Transportation
Product	Buildings	Industry	Electricity	Total	Total
Gasoline	0	0	0	0	6.3
Distillate	1.0	0.7	0.2	1.9	0.95
Residual	0.5	0.65	1.3	2.45	0.4
Jet	o	0	0	0	1.1
LPG	0.3	0.7	0	1.0	0
Other	0.7	2.0	0	2.7	0.2

[a] Given in terms of product equivalent–5.5 million Btu per Barrel.

SOURCE: Department of Energy, Energy Information Administration, *1980 Annual Report to Congress*, vol. II.

FUTURE DEMAND

Over the next decade some of this 4.4 MMB/D will be eliminated by fuel switching and conservation as the price of oil rises. Indeed, a decline of 1.1 MMB/D took place between 1979 and 1980.[3] How much more is possible by 1990 depends on future oil prices, the costs of alternatives, the ability to finance these alternatives, and environmental and regulatory factors. The 1980 Energy Information Administration (EIA) estimate of 1990 demand is shown in table 53. This fore-

[3] *1980 Annual Report* to Congress, *Vol.* 2, DOE/EIA-01 73(80)/2 (Washington, D. C.: U.S. Department of Energy, Energy Information Administration, 1980).

Table 53.—1990 EIA Petroleum[a] Demand Forecast for Stationary Fuel Uses (MMB/D)[b]

Product	Buildings	Industry	Electricity	Total
Distillate	0.9	0.1	0.15	1.4
Residual	0.3	0.2	0.9	1.15
Total	1.2	0.3	1.05	2.55

[a] The "other" and LPG category of stationary petroleum demand is forecast to remain at its 1980 level of 3.8 MMB/D. This category, however, would then increase from 48 percent of all stationary uses in 1980 to 60 percent In 1990. It has proven to be much less elastic to fuel price increases since 1973 than the distillate—residual fuel category.
[b] Barrel of product—5.5 MMBtu per barrel.

SOURCE: Department of Energy, Energy Information Administration, *Annual Report to Congress*, vol. III.

cast is based on a 1990 oil price of $45 per barrel (bbl) (in 1980 dollars).

The forecast reduction of 1.8 MM B/D over the next 10 years (from 4.4 MMB/D in 1980 to 2.6 MMB/D in 1990) would be accomplished by more efficient use, and by conversion to coal, electricity, and natural gas. Beyond 1990, continued reduction can be expected, particularly in the electric utility sector, if the economic advantages of alternate fuels and conservation continue.

For the purpose of this study, OTA determined the technology (alternate fuels, conservation) and investment necessary to eliminate this 2.6-MMB/D usage during the 1990's. This is about the same level of reduction that can be achieved by going from a new-car fleet average of 30 miles per gallon (mpg) in 1985 to an average of 65 mpg in 1995, * and is close to the target synthetic fuels production level by 1992 set forth in the Energy Security Act.[4] Therefore, it provides a good comparison for the remainder of the study. The rest of this chapter describes how this elimination might be achieved and what it might cost.

*See ch. 5, p. 127.

[4]42 USC 8701, Energy Security Act, June 30, 1980.

First, fuel switching alone is considered, and second, conservation. OTA did not attempt to estimate a timetable other than to assume that the reductions take place throughout the 1990's. This is consistent with the time needed to introduce similar savings from increased auto efficiency or from synthetic fuels production. * Where possible, serious time constraints that may appear are mentioned. The focus, however, is on investment costs and resource requirements. It is important to emphasize that because OTA's calculations were based on the EIA 1990 forecast, costs of fuel switching and conservation necessary to go from the 1980 to 1990 levels of fuel oil consumption were not counted. This somewhat arbitrary decision will bias against conservation and fuel switching, since the least costly steps are expected to be taken first, during the 1980's.

*See ch. 5, p. 127; ch. 6, p. 177.

FUEL SWITCHING

The prime candidates for eliminating this 2.6 MMB/D of fuel oil by fuel switching are natural gas, coal, and electricity from coal and natural gas. Indeed, a considerable amount of the oil now used by industry (about 20 percent) is a result of converting from natural gas to oil during the mid-l970's.[5] This was partially a result of the Federal curtailment policy for natural gas that gave low priority in many industrial applications (primarily boilers). Further, the uncertainty of supply that existed during that same period caused industry to switch other applications from natural gas to oil as well. In the buildings sector, "scarcity" of natural gas during the 1970's, combined with the rapid rise in its price, caused a temporary halt in the growth rate of natural gas use. There was no corresponding growth in petroleum use, however, unlike the case with industry, since electricity was the primary replacement energy.

[5]1980 Annual Report to Congress, Vol. 2, op. cit., pp. 65 and 107. This claim is inferred from these two tables which show a drop in natural gas consumption by industry between 1974 to 1979 of over 20 percent and a corresponding increase in industrial oil consumption.

Complete replacement of fuel oil in buildings by natural gas alone would require about 2.4 trillion cubic feet per year (TCF/yr), assuming current end-use efficiency. If only electricity were used, 425 billion kWh/yr of delivered electric energy would be needed assuming an end-use efficiency increase of 67 percent. * By 1990, most of the industrial processes that can use coal (primarily large boilers) will have been converted because of the large difference in coal and oil prices that currently exists.[6] If all the remaining fuel oil

*Assuming heat pumps (water and space) with a seasonal performance factor of 1.25 compared to oil furnaces with a seasonal performance factor of 0.75.

[6]*Cost and* Qua/@ of Fuels for Electric Utility Plants, *February 1981,* DOE/EIA-0075(81/02) (Washington, D. C.: U.S. Department of Energy, Energy Information Administration, 1981), p. 3.

used by industry were displaced by natural gas alone, 0.6 TCF/yr would be required, assuming no change in end-use efficiency. If electricity alone were used, about 120 billion kWh/yr of delivered electric energy would be needed, assuming a 50-percent increase in end-use efficiency. *

For electric utilities, residual fuel oil is primarily used in baseload steam plants, while distillate oil is used for peaking turbines. To replace the former by coal would require 135 million tons, and to replace the latter by natural gas would require 0.3 TCF/yr. ** Table 54 summarizes the amount of energy needed to replace oil in each sector, assuming that each substitute energy source is used exclusively.

The first question to ask is whether these substitute resources will be available. Forecasts for domestic natural gas production during the 1990's by Exxon and EIA are about 14 to 16 TCF/yr.[7] Of this, about 70 percent will come from existing reserves, while the remaining will come from new reserves including so-called unconventional gas; i.e., gas from tight sands, geopressured brine, coal seams, and Devonian shale. These latter resources are of particular interest since they are the likely source of any domestic natural gas, above that now forecast, that would be needed to replace stationary fuel oil during the 1990's.

*Assuming an end-use efficiency of 100 percent for electric heat, compared with 67 percent for oil-fired units. If combustion turbines are replaced by electric motors for mechanical drive a similar increase will occur.

**It was assumed that there would be no change in conversion efficiency upon replacing the residual and distillate oil generation by coal and natural gas generation.

[7] *Energy Outlook* 19802&X.1 (Houston, Tex.: Exxon Co., U. S. A., December 1980), p. 10; 1980 *Annual* Report to Congress, *Vol.* 3, DOE/EIA 01 73(80)/3 (Washington, D. C.: U.S. Department of Energy, Energy Information Administration, 1980), p. 87.

EIA currently forecasts unconventional gas production increasing from 1.3 TCF in 1990 to 4.4 TCF in 2000 at a production cost of about $5.50 to $6.50/MCF (in 1980 dollars).[8] EIA predicts, however, that additional volumes of unconventional gas will become available in the 1990's if natural gas reaches what would then be the world price of oil (about $56/bbl in 1980 dollars). The National Petroleum Council recently made a similar claim, predicting as much as an additional 10 TCF/yr becoming available by 2000.[9] Therefore, it appears that production of an additional 3.3 TCF/yr (relative to that now forecast by EIA and Exxon) could be possible by the mid-l990's at gas production prices equivalent to about $56/bbl of oil (1980 dollars).

These cost estimates are subject to a great deal of uncertainty, however, and the actual cost of this unconventional gas could be considerably higher. There is less uncertainty about the ability to produce this gas increment from unconventional sources—particularly tight sands–but other alternatives, including synthetic natural gas from coal, may be cheaper.

Next, consider electricity. Current generation capacity in the United States is 600,000 MW (including 100,000 MW using oil) operating at an overall capacity factor of 45 percent.[10] Although increasing the capacity factor to 65 percent while concurrently converting all oil units to coal would provide the quantity of electricity needed (see table 54), that path may not be practical. The pro-

[8] ‘i bid., p. 88.

[9] *Unconventional Gas Sources, Executive* Summary, (Washington, D. C.: National Petroleum Council, December 1980), p. 5.

[10] *Electric* Power *Supply and* Demand, 1981-*1990* (Princeton, N. J.: National Electric Reliability Council, July 1981).

Table 54.-Summary of Energy Requirements for Displacing 1990 Fuel Oil

		Replacement energy sources		
	1990 petroleum forecast (EIA) (MMB/D)	Natural gas (TCF)	Electricity (billion kWh)	Coal (million tons)
Buildings.	1.2	2.4	425	—
Industry.	0.3	0.6	120	—
Utilities	0.9 (residual)	—	—	135
	0.15 (distillate)	0.3	—	—
Total	2.55	3.3	545	135

SOURCE: Office of Technology Assessment.

file describing the fuel oil load of buildings for heating peaks rather sharply during the winter, and nearly all of the electric energy required to replace fuel oil would need to be generated during the 5 months of the heating season. Since the load profile is the primary determinant of the capacity factor, conversion to electric space and water heating will likely do little to increase the overall capacity factor. Therefore, as much as 120,000 MW of new capacity may be needed.*,

The ease with which this much capacity could be added depends on the growth rate for electricity for the remainder of the century in the absence of this oil-to-electricity conversion (underlying rate), and the financial health of the electric utility industry. These two points are obviously related because an industry which has difficulty raising capital, as is now the case,[11] will have difficulty meeting new generation requirements of any kind. Currently forecasts of the electric demand growth rate range from near zero (by the Solar Energy Research Institute (SERl))[12] to about 3.8 percent per year (by the National Electric Reliability Council).[13]

In the latter case, capacity additions become so great during the 1990's that the full increment of capacity needed for fuel oil replacement (120,000 MW) could be met if the underlying rate dropped to 3.2 percent per year but the utilities continued building at 3.8 percent per year. If growth of electricity demand in the absence of our hypothetical fuel switching dropped to 2 percent per year, a capacity addition rate of 3 percent per year would meet both underlying demand and the fuel-switching demand. Under these conditions, annual capital requirements would be approximately $25 billion to $35 billion (1980 dollars) and annual capacity addition would average about 27,000 MW. These are values below those attained by the utility industry during the early 1970's.[14] This is manageable provided the current financial problems are solved. If not, providing the replacement electricity from new capacity is unlikely.

Finally, there is the question of conversion of the electric powerplants that will still be burning oil in 1990 to other fuels (primarily coal). There should be little difficulty producing the extra coal for conversion of the plants burning residual fuel oil.[15] Further, as seen above, the natural gas could be available as a fuel in those plants burning distillate. There are barriers to converting existing plants including environmental problems of coal, the technical problems in actually converting many of these powerplants, and difficulties in financing the conversion projects. In many cases it may be less costly to build a new powerplant at a different site and retire the existing oil-fired plant.

Considering the physical requirements alone, however, there could be adequate supplies, during the 1990's, to replace 2.6 MMB/D of distillate and residual fuel oil by some combination of natural gas and electricity along with coal (or possibly nuclear) to replace the oil-fired electric utility boilers.

Although the cost of this process is difficult to calculate, it is possible to make an estimate by making several arbitrary, but plausible assumptions based on the above analysis and current operating conditions. First, it is assumed that natural gas replaces all of the fuel oil used by industry and utility combustion turbines, and half the heating oil used by buildings. Second, it is assumed that electricity is used to replace the other half of the heating oil used by buildings. Finally, all electric powerplants using residual fuel oil are replaced by coal conversions or new coal-fired powerplants. Table 55 summarizes the replacement energy requirements for this scenario.

To estimate the costs of eliminating this 2.6 MMB/D of fuel oil by fuel switching, the following costs (in 1980 dollars) for the replacement energy were used:

*This is the capacity required to produce 545 billion kWh operating at the current coal-fired average capacity factor of 52 percent.

[11] "The Current Financial Condition of the Investor-Owned Electric Utility Industry and Possible Federal Actions to Improve It," Edison Electric Institute before the Federal Energy Regulatory Commission, Mar. 6, 1981.

[12] *Building a Sustainable Future*, Vol. z, prepared by the Solar Energy Research Institute, Committee on Energy and Commerce, U.S. House of Representatives, Washington, D. C., April 1981, p. 837.

[13] *Electric Power Supply and Demand, 1981-1990*, op. cit.

[14] *Electrical World*, Sept. 15, 1980, p. 69.

[15] *The Direct Use of Coal*, OTA-E-86 (Washington, D. C.: U.S. congress, Office of Technology Assessment, April 1979).

Table 55.—Annual Replacement Energy Requirements [a]

	Buildings	Industry	Electric utilities	Total
Natural gas (TCF) . . .	1.2	0.6	0.3	2.1
Electricity (billion kWh)	225	[b] –	—	225
Coal (million tons) . .	–	–	135[c]	135

[a] Assumes an increase in end-use efficiency of 67 percent when switching from fuel oil to electricity for space or water heating and no change when switching from fuel oil to natural gee in any of the three sectors.
[b] Requires 50,000 MW operating at a 50 percent capacity factor.
[c] Assumes the 1990 oil-fired capacity, which is now forecast to operate at a 35 percent capacity factor (N ERC), can be replaced by 55,000 MW of coal-fired capacity operating at 57.5 percent capacity factor.

SOURCE: Off Ice of Technology Assessment.

1. New coal-fired electric powerplants cost $900/kW, including all necessary environmental controls.[16]
2. Investment costs for natural gas from unconventional sources (tight sands) are approximately $16,500/MCF per day. " Operating costs, including transmission and distribution, are about $1.30/MCF.[18]
3. The investment cost for new coal surface mines is approximately $9,000/ton of coal per day. Operating costs are about $6.50/ton.[19]
4. The cost to convert oil fired capacity to coal is estimated at $600/kW.[20]

All of these costs are in 1980 dollars. Therefore, they will underestimate the actual costs of conversion in the 1990's to the extent there are real increases in these costs between new and the mid-1990's. Cost estimates are also needed for the end-use equipment. This was simplified by assuming no change is needed for industry and combustion turbines in converting from distillate to natural gas. For buildings, heat pumps are used when electricity is the new energy source, and new gas furnaces are used for natural gas. Based on current retail estimates these costs are $2,000 and $1,200, respectively (1980 dollars), for units capable of delivering 100 million Btu of heat per heating season, and having the capacity to meet the peak-hour heating load.[21] Table 56 summarizes the investment costs per barrel per day replaced for each sector.

The total investment, obtained by multiplying the per unit investment (table 56) by the amount of oil replaced (table 55), is about $230 billion (1980 dollars). These estimates include production of the energy resource (electric generating plants, natural gas, and coal mines) and end-use equipment when needed. They do not include costs to construct new transmission and distribution facilities that might be needed. This omission will be discussed below.

[16] *Technical Assessment Guide,* EPRI PS-1 201 -SR (Palo Alto, Calif.: Electric Power Research Institute, July 1979), pp. 8-11.

[17] *Unconventional Gas* Sources, Tight Gas Reservoirs, Part 1, op. cit., pp. E-1 15.

[18] " Natural Gas Issues" (Arlington, Va.: American Gas Association, May 1981), p. 8.

[19] "Comparative Analysis of Mining Synfuels" (Los Angeles, Calif.: Fluor Corp., 1981).

[20] "The Regional Economic Impacts on Electricity Supply of the Powerplant and Industrial Fuel Use Act and Proposed Amendments" (Washington, D. C.: Edison Electric Institute, April 1980), p. 37.

[21] Academy Airconditioning Co., Rockville, Md., private communication.

Table 56.—investment Costs For Fuel Oil Replacement Energy [a b]

	Buildings	Industry	Utilities
Natural gas	121,000	100,000	90,000
Electricity.	110,000	–	–
Coal.	–	–	54,000

[a] Dollars per barrel of oil replaced per day.
[b] Includes investment cost necessary to upgrade the replaced residual fuel oil to gasoline and diesel where applicable. Cost is $14,000/bbl of residual per day on the average, Purvin and Gertz, Inc., An Analysis *of Potential* for *Upgrading Domestic Refining* Capacity, prepared for the American Gas Association, Arlington, Va., March 1960.

SOURCE: Office of Technology Assessment.

CONSERVATION

The other major alternative for reducing oil use in the stationary sectors is conservation. Conservation cannot completely eliminate fuel oil use by itself–but it can reduce it, and possibly free enough natural gas and electricity to substitute for the remaining fuel oil. There have been numerous estimates of conservation potential for buildings and industry in the past several years.

The most detailed analysis is that recently completed by SERI.[22]

The SERI estimates are used to examine the possibility of and potential costs for eliminating stationary uses of fuel oil over the period 1990-2000. OTA has used the SERI analysis of conservation measures in the buildings sector to obtain an approximation of the costs of eliminating the remaining stationary uses of fuel oil in all sectors in the 1990-2000 period. These conservation measures reduce the use of fuel oil, electricity, and natural gas. The electricity and natural gas saved is used to replace the fuel oil remaining after the conservation. In table 57, the SERI projection for 2000 is given, by fuel, along with the savings obtained relative to the 1990 baseline demand (EIA forecast). The savings are the difference between the SERI 2000 projection and the EIA 1990 forecast. * As shown in table 57, conservation could eliminate 67 percent of the fuel oil used by buildings and provide more than enough natural gas to eliminate the remaining fuel oil used in both buildings and industry, as well as distillate used by electric utilities. Finally, enough electricity would be saved to replace the electricity produced by oil-fired generation (see table 54). The amount of natural gas and electricity needed to do this are given in the last column of table 57. About 65 percent of the SERI estimated savings for the buildings sector alone will achieve the goal.

The SERI study estimated an investment cost of $335 billion (in 1980 dollars) to achieve their savings goals for 2000. *[23] If we arbitrarily allocate these costs to the portion of the savings needed solely for fuel oil elimination, the cost investment for the scenario is about $215 billion (65 percent of total). In addition, investment is needed in converting end-use equipment from fuel oil to natural gas in buildings for oil not eliminated by conservation. Using the procedure described in the previous section, this amounts to about $10 billion. The total investment for these measures is $225 billion–equivalent to $88,000/bbl of oil replaced per day.

[22] *Building a* Sustainable Future, op. cit., pp. 5 and 6.

*By using the 1990 EIA forecast rather than the 1990 SERI projection as the starting point, we have compressed some of the savings calculated by SE RI. They assumed that much of the savings would occur between 1980 and 1990 with a result that their 1990 projection of fuel oil use is considerably below the EIA forecast. Our calculation does not change the net savings but only the period in which they could occur.

*Adjusted to reflect savings not accounted for by OTA's choice of base case.

[23] Ibid.

Table 57.—Energy Made Available by Conservation

Energy source	SERI demand estimate (2000)	EIA demand estimate (1990)	Savings by 2000	Savings used for oil substitution
Fuel oil (MMB/D)	0.4	1.2	0.8	—
Natural gas (TCF/yr).	4.5	7.8	3.3	1.7
Electricity (billion kWh/yr). .	1140	1580	440	250

SOURCE" Office of Technology Assessment.

DISCUSSION

The analysis described gives a plausible estimate of the technical and investment requirements of eliminating stationary uses of oil between 1990 and 2000. These requirements are not forecasts, as mentioned above, but only describe what is technically and economically within reason. There are several items, however, that were not considered in the calculation that will affect these costs somewhat. In this section some of the more important points are briefly discussed.

In calculating the costs of conversion to natural gas and electricity the possibility was ignored that new transmission and distribution equipment would be needed. This also holds for the conservation case, since natural gas freed by conservation would need to be delivered to sites formerly using fuel oil, and it is likely that new transmission and distribution facilities would be needed for some of those locations. A transmission and distribution operating cost for all the natural gas conversions was included but this is not likely to cover new construction where it is needed.

Similarly, the electricity made available by conservation may not be able to substitute for oil-fired capacity without the construction of new transmission lines. In a previous OTA study on solar energy,[24] the construction and operation costs of both electric and natural gas transmission and distribution systems were calculated. Using those values updated to 1980,[25] it was found in the worst case–electricity used to replace oil for heat in buildings—that the cost of oil replaced should be increased by about 20 percent. In all other cases the adjustment is less than 10 percent under the unlikely assumption that all the replacement energy requires new transmission and distribution facilities.

Another point concerns the choice of conservation estimates. The SERI study is the most optimistic of several analyses which attempt to calculate the potential for conservation under least cost conditions. The calculations in the SERI study, particularly for buildings, are based on the most complete analysis to date of the thermal characteristics of buildings, and include extensive experimental data. Therefore, these engineering and cost estimates can be considered as attainable.

Though the SERI calculations were used, it is not explicitly or implicitly claimed that SERI conservation targets will be reached. In an OTA study on building energy conservation recently completed it is estimated that only about 40 percent of the targets will be reached under current conditions.[26] A number of economic constraints and choices—including restrictive financial conditions, uncertainty of results, and high owner discount rates—will reduce the probability that these goals can be met. Even though it was not necessary to use the entire SERI estimate of savings to achieve OTA's hypothetical goal of eliminating stationary fuel oil use, more than two-thirds was still required. Therefore, while it is technically possible to eliminate all stationary fuel oil use through conservation, this is not likely to happen under current conditions.

The final point concerns conversion of oil-fired electric generation capacity to coal. Although the high end of the range of estimates for conversion costs was used, in some instances even this will be insufficient. There will be sites where conversion is impossible because of lack of coal storage facilities or inadequate coal transportation, or where excessive derating of the boiler would be necessary. In such cases, it will make more sense to retire the plant and replace it with new capacity built elsewhere. For these cases, the replacement cost will equal the cost of new capacity, including any needed transmission costs. It should be expected, however, that new coal or nuclear generation will have a much higher capacity factor than current oil generation because of the former's lower cost of producing energy.

it should be remembered, however, that the load profile will dictate the capacity factor to a great extent. With the large amount of capacity under discussion, it can be expected that there will be sufficient load diversity so that power transfers between regions will allow for an increase in capacity factor to a level that now exists for coal-fired powerplants (about 57 percent).

The possibility of power transfers was assumed and accounted for in the calculation by assuming the 57-percent capacity factor. The result is that less capacity is needed to replace the electricity produced by the oil-fired generation that is expected to be on-line in 1990. To some degree this capacity reduction will take care of some of the site-specific problems described above.

Another point to be considered is whether coal-fired electricity will be less expensive than that generated from residual fuel oil in the 1990's. Because of the continuing decline in crude oil quality[27]—i.e., lower gravity—it will be increasingly

[24] *Application* of solar Technology to Today's *Energy* Needs, *Vol.* 1, OTA-E-66 (Washington, D. C.: U.S. Congress, Office of Technology Assessment, June 1978), p. 140.

[25] *Oil and* Gas *Journal,* Aug. 10, 1981, p. 76.

[26] *The Energy Efficiency* of Buildings in Cities, OTA-E-168 (Washington, D. C.: U.S. Congress, Office of Technology Assessment, March 1982).

[27] *Oil and Gas Journal,* Apr. 20, 1981, p. 27.

more costly to refine this oil up to the point where no residual oil remains. Currently, the average cost of converting residual fuel oil to middle distillates and gasoline is about $10,000 to $14,000/bbl/d.[28] The marginal cost, however, is much higher and will grow as more and more residual oil is transformed and as the crude oil feed becomes heavier.

[28] *An Analysis of Potential* for Upgrading Domestic Refining Capacity, op. cit.

Consequently, it is possible that it would be cheaper to use the residual oil directly in boilers, as it is used now, and produce the lighter fuels from oil shale or by way of methanol from coal. To reach that point, residual fuel oil would have to be priced below coal as a boiler fuel because the residual oil would have no other market. No attempt was made to determine when or to what extent this may occur.

SUMMARY

Elimination of fuel oil use in the stationary sectors (buildings, industry, electric utilities) appears to be technically plausible by 2000. The cost for either the conservation or fuel-switching scenario would be high. As shown, the total cost for the 1990-2000 period would be about $225 billion to $230 billion to eliminate the 2.6 MM B/D forecast still to be in use by 1990. These costs are consistent with estimates for synthetic fuels production and automobile efficiency improvement that would produce about the same amount of oil. * In addition, reduction from current use of 4.4 MMB/D to the 1990 level will also require several tens of billions of dollars. As noted earlier, the 1980-90 costs were not taken into account in the calculations.

Uncertainties about these estimates for stationary fuel oil elimination by conversion arise from changes in powerplant construction costs, in coal prices, in the cost of producing natural gas from tight sands, and in the discovery rate of new natural gas. All or any of these could cause significant swings in the cost of displacing oil, most likely upward. In the absence of information about these uncertainties, the estimates given here, which represent the best analyses to date, can be considered as reasonable. Similarly, for conservation, uncertainties about the conservation potential of buildings exist which can only be cleared up as more and more buildings are actually retrofit. Preliminary audits of buildings already retrofitted have indicated a range of energy savings from 80 percent less than predicted to 50 percent more.[29] The sample for this measurement was small, but it does indicate the level of uncertainty.

The estimates that were derived are plausible targets. They are not forecasts or even necessarily desirable goals. That will have to be decided within the context of all the economic choices possible and within the country's policy objectives about oil imports.

*See ch. 5, p. 139; ch. 6, p. 172.

[29] *Energy Efficiency* of Buildings in Cities, op. cit.

Chapter 8

Regional and National Economic Impacts

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Regional and National Ecomomic Impacts

INTRODUCTION

This chapter examines the types, timing, and distribution of economic impacts associated with both development of a synthetic fuels industry using national coal and oil shale resources, and improved automobile fuel efficiency. identifying and assessing these impacts are difficult because: impacts are not distributed evenly in time or across regions, so that people may not receive benefits in proportion to the adverse consequences they experience; impacts are not translatable into directly comparable terms (e.g., dollars); the evaluation of impacts is subjective, based on perceptions of the uncertain benefits and costs of new technologies; and impacts are cumulative and may be difficult to monitor or attribute solely to a particular technology choice.

This chapter assesses the broad economic impacts of synfuels and changes in auto technology. Chapter 9 further analyzes employment effects and discusses other social impacts of these technological developments. Decisions about synfuels and making cars more efficient will require tradeoffs in terms of energy use, economic growth, and social welfare and equity. There will be both beneficial and adverse social consequences for the Nation as it moves towards energy independence.

ECONOMIC IMPACTS OF AUTOMOTIVE CHANGE

Overview

The economic impacts of improving automotive technology result primarily from two factors: the large investments that will be required for associated capacity, and changes in the goods and services purchased by the auto manufacturers. Large investments increase financial risk, exhaust profits, and influence the ability of firms to raise outside capital. Changes in goods and services used by manufacturers affect suppliers and, in turn, local economies. As automotive fuel economy increases, the structure and conduct of the auto industry and the relationship of the domestic auto industry to the general economy change. Radical increases in demand for fuel economy, induced either by changes in consumer preferences or by Government mandates, would lead to greater industry change, most likely in the form of acceleration or exacerbation of current trends.

Changes in the auto industry stem from both technological developments and new market trends, including strong competition from foreign manufacturers. Large increases in demand for fuel economy, and for small cars relative to large cars, encourage the industry to improve the fuel economy of all car classes and to invest in the production of small cars. These activities help domestic manufacturers to satisfy relatively new demands, but at the cost of diminished profits during at least the short term. Profits can fall when manufacturers prematurely write off large-car and other capacity investments and change their pricing strategies to replace large-car profits with small-car profits.

Meanwhile, manufacturers lose money when sales of their least efficient models decline. High fixed costs and scale economies make their profitability vulnerable to sales declines of even a few percent. Profits would therefore also fall if domestic manufacturers lost market share to foreign firms. Future opportunities to gain market share and profits will be limited by slowing market growth. *

*The U.S. auto market is nearly saturated (there were 0.73 cars for every licensed driver in 1979, according to the Motor Vehicle Manufacturers Association) and the U.S. population is growing slowly. Therefore, auto sales will grow at lower rates than in past decades, probably averaging 1 to 1.5 percent per year.

Manufacturing Structure

The U.S. automotive industry includes three major manufacturers—General Motors (GM), Ford, and Chrysler-plus a smaller manufacturer, AMC (now almost half-owned by Renault, a French firm) and some very small specialty car manufacturers. The three major manufacturers have historically been characterized by moderate levels of vertical integration and broad product lines that include trucks and other vehicles as well as automobiles. During the past few decades, GM's operations have been the most extensive both vertically and horizontally; Chrysler's have been the least extensive.

Because of the high costs of production change, U.S. auto manufacturers are becoming less vertically integrated, relying increasingly on suppliers to. make components and other vehicle parts. For example, the Department of Transportation (DOT) reported that in late 1980 alone, domestic manufacturers announced purchasing agreements with foreign suppliers for over 4 million 4-cylinder gasoline engines plus several hundred thousand units of other engines and parts. Reliance on outside suppliers, referred to as "outsourcing," relieves short-term spending pressures on manufacturers. By spending less initially to buy parts rather than new plants and equipment (in which to make parts), manufacturers can afford to make more production changes while exposing less cash to the risk of financial loss due to limited or volatile consumer demands.

On the other hand, outsourcing may cause manufacturers to lose control over product quality. Also, manufacturers may incur higher vehicle manufacturing costs in the longer term because the price of purchased items includes supplier profits as well as production costs. Because of more severe financial constraints, Ford and Chrysler tend to rely on suppliers more than GM. In the future, all domestic manufacturers may outsource more from domestic suppliers, foreign firms, or foreign facilities owned by domestic manufacturers as a means of reducing capital investments and thus short-term costs.

Manufacturers are consolidating their operations across product lines and engaging in joint ventures, primarily with foreign manufacturers. While there appears to be no up-to-date source of data aggregating these changes, trade journals and the business press report that American firms are sharing production and research activities with foreign subsidiaries, with foreign firms in which they have equity (Ford with Toyo Kogyo, GM with Isuzu and Suzuki, Chrysler with Mitsubishi and Peugeot, AMC with Renault), and with other foreign firms. Joint ventures are also increasingly common between non-American firms, which have historically been highly interconnected.

Cooperative activity among auto firms worldwide is likely to grow. Many firms will be unable to remain competitive alone, because of the growing costs and risks of improving automotive technology and increasing competition in markets around the world. The quickest way for U.S. manufacturers to respond to a mandated or demand-induced fuel economy increase would be to use foreign automotive concepts directly, by licensing designs, assembling foreign-made automobile kits, or marketing imported cars under their own names. GM and Ford, for example, assemble Japanese-designed cars in Australia and AMC sells Renaults in the United States.

Domestic companies can make profits by merely selling foreign-designed cars. They can gain additional manufacturing profits without risking additional capital if they sell cars made by companies in which they have equity. Cooperative activity (and, in the extreme, mergers and acquisitions) allows firms to pool resources, afford large investments in research and development (R&D) or in plant and equipment, gain scale economies, and spread large financial risks. It is consistent with the reduction in the number of autonomous auto producers widely predicted by industry analysts.

Although the number of automotive manufacturing entities is declining worldwide, there may be continued growth in the number of firms producing and selling in the United States. Already, Volkswagen produces cars in Pennsylvania and is building a plant in Michigan; Honda is planning to build cars in Ohio; and Nissan is building a light truck plant in Tennessee. There are now about 23 different makes of foreign cars sold in the United States, excluding "captive imports" sold under domestic manufacturers' nameplates (e.g., the Plymouth Colt, which is made by Mitsubishi).[1] Manufacturers of captive imports, including Isuzu and Mitsubishi, are already preparing to enter the U.S. market directly.

Manufacturer Conduct

U.S. auto manufacturers are fundamentally altering their product, production, and sales strategies as automobile technology and consumer demand change. Several changes in product policy include the following.

First, the number and variety of models is falling. The highest number of models offered by domestic manufacturers was 375 in 1970; 255 were offered in 1980.[2] Manufacturers might sharply reduce the number of available models to increase fuel economy quickly, by producing relatively efficient models on overtime and ceasing production of relatively inefficient models.

Second, while cars of all size classes are shrinking in number, small cars are becoming more prominent in number, share of capacity, and contribution to revenues relative to large cars. Recent changes in price strategy have led to smaller profit differentials by vehicle size and higher absolute and relative small-car prices. As individual models become more alike in size, manufacturers will differentiate models by visible options and design.

Third, manufacturers may introduce new, oil-conserving products such as very small "mini" cars (e.g., GM's P-car and Ford's Optim projects) and vehicles powered by electricity as well as alternating fuels.

Cost-reducing alterations to the physical and financial characteristics of individual firms–widely reported in trade journals, the business press, and company publications—help manufacturers adjust to declines in sales and profits and growing investment requirements. Cost-cutting efforts include reductions in white-collar employment and elimination of relatively inefficient or unneeded capacity. During the last couple of years GM, Ford, and Chrysler have sold or announced plans to sell several manufacturing and office facilities. One investment analyst estimates that sales of assets may have provided over $600 million to GM and Ford during 1981.[3]

Efforts to reduce long-term costs focus on measures to improve productivity and reduce labor costs per unit. To improve productivity, manufacturers (and suppliers) are already investigating and beginning to use new types of equipment, plant designs, and systems for materials handling, quality control, and inventory management. Industry analysts and firms also expect that improved coordination between management and labor, vendors, and Government will be important means for improving productivity and competitiveness. Finally, manufacturers maintain that reductions in hourly labor costs (wages and/or benefits) are essential for making U.S. cars competitive with Japanese cars. Whether, when, and how much labor costs are lowered depends on negotiations between manufacturers and the United Auto Workers union.

Another cost-cutting measure is reduction in planned capital spending, Spending cutbacks affect firms differently, depending on their context. For example, Chrysler reduced 1980 planned capital spendings by $2 billion, halting a diesel engine project and others.[4] GM has announced cutbacks that take the form of spending deferrals and cancellations of planned projects (with little effect on immediate cash flow, however).

Another factor which complicates the evaluation of cutbacks is that U.S. projects abroad are, and could be, used to supply the U.S. market. Foreign projects are relatively cheap where foreign partners or foreign governments share in or subsidize investments. Cost-cutting efforts are consistent with growth in the share of U.S. auto investment and production abroad, because facilities in Central and South America, Asia, and in parts of Europe generally produce at lower costs

[1] Automotive News, *1981* Market Data nook (Detroit, Crain Communications, Inc., Apr. 29, 1981).

[2] Maryann N. Keller, "Status Report: Automobile Monthly Vehicle Market Review" (New York: Paine, Webber, Mitchell, Hutchins, Inc., February 1981).

[3] Maryann N. Keller, personal communication, 1981.

[4] *Ward's* Automotive Reports, June 15, 1981.

and sell in home markets that are more profitable than the U.S. market.

Some analysts believe that if extreme pressures were placed on U.S. manufacturers to make sizable investment in brief periods of time, Ford and GM (at least) would reduce U.S. production in favor of foreign production (Chrysler has divested foreign facilities to obtain cash). U.S. manufacturers and suppliers are already operating with high fixed costs, large investment requirements, weak demand, and labor costs higher than foreign competitors. If there are sharp increases in fuel economy demand, or if there are other sources of growth in perceived investment requirements–without offsetting changes in manufacturing and demand/market share–these developments might give auto firms additional incentives to curb, if not abandon, auto production in the United States. If U.S. production were curtailed, it would affect production of new, very efficient small cars while U.S. production of larger and specialty cars would probably continue. Large and specialty cars are characterized by consumer demand that is relatively insensitive to price and in many cases limited to U.S. car buyers.

Other Firms

Suppliers

Automobile suppliers manufacture a wide variety of products, including textiles, paints, tires, glass, plastics, castings and other metal products, machinery, electrical/electronic items, and others. Changes in the volumes of different materials used to produce cars and the ways in which cars are produced are changing the demands on suppliers. In the near term, for example, GM predicts that the average curb weight of its cars will fall 21 percent, from 3,300 lb in 1980 to about 2,600 lb in 1985, with up to 67 percent more aluminum, 48 percent more plastics, and 30 percent less iron and steel, by weight. Rubber use will also fall. GM predicts that steel will comprise a relatively constant proportion of car weight, while the proportion of iron will fall and aluminum and plastics proportions may even double by 1985[5] (see table 58).

Changes in demands for materials and other supplies create pressures on traditional suppliers to close excess capacity and invest to develop or expand capacity for new or increasingly important products. They also create new business opportunities for firms whose products become newly important to auto manufacturers, such as semiconductor and silicone producers. The degree of hardship on individual traditional suppliers depends on how much of their business is automotive and on their resources for change. Like the auto manufacturers, suppliers operate in the context of a cyclical market which can cause their cash flow to be unstable. Table 59 indicates the dependence of different supplier groups on automotive business as of 1980.

The steel and rubber industries have already been adversely affected by changing auto demands together with stronger import competition. Tire manufacturers have suffered with the rise in popularity of radial tires (which are replaced less frequently than bias ply tires and require different production techniques) and the fall in rubber use per vehicle. Between 1975 and 1980, over 20 tire plants (about one-third of the domestic total) were closed, one major tire manu-

[5]"GM Sees Big Gain for Aluminum, Plastics in 'Typical' 1985," Ward's Automotive Reports, Apr. 27, 1981.

Table 58.—GM's Major Materials Usage
(per typical car, 1980 v. 1985)

	1980		1965	
Materials	Pounds	Percent total	Pounds	Percent total
Iron	500	15%0	250-300	10-12%
Steel	1,900	58	1,450	58
Aluminum	120	4	145-200	6-8
Glass	92	3	60	
Plastics	203	6	220-300	8-12
Rubber	86	3	88[a]	3[a]
Other	377	11	277	11
Total	3,300	100%	2,600	100%

[a]GM projects actual rubber use to be less than SS lb in 19S5.

SOURCE: General Motors Corp., reported in *Wards Automotive* Reports, Apr. 27, 1981.

Table 59.—1980 Motor Vehicles (MVs) and Parts Supplier Trade

Industry	Percent of industry output for MVs and parts	Value of output for MVs and parts
Textiles	7 +	$4 billion+
Wood products	2 +	618 million +
Nonhousehold furniture	2.4	260 million
Paper and allied products	3	2.5 billion +
Chemical	4 –	15 billion+
Plastics, synthetic rubber, and synthetics	6 –	4 billion+
Paints and allied products	8 +	900 million +
Tire and rubber products (OEM)	13	4 billion+
Glass	11–	1.3 billion
Steel furnaces, foundries, and forgings	21–	24.6 billion
Aluminum and aluminum products	14.6	4 billion+
Copper and other nonferrous metal products	11–	6 billion+
Metal products and machine shop products	13–	22 billion
Metalworkings and industrial machinery	5.6	8 billion+
Service industry machinery	12	3 billion
Electrical and electronic equipment	5.2	8 billion
Scientific and controlling instrument	7.5	900 million

NOTES: "+" means "greater than" and "–" means "less than." "OEM" stands for "original equipment manufacturer."

SOURCE: The Automotive Materials Industry Council of the United States.

facturer (Mansfield) declared bankruptcy, and another (Uniroyal) suffered severe financial problems (see fig. 18). Several steel plants were closed during the same period. In both industries, additional plant closings and continued import competition are likely in the 1980's, although the elimination of excess and inefficient capacity is expected by Government and private analysts to leave these industries financially healthier.[6]

Machinery and parts suppliers also face import competition and product demand changes. A recent Delphi survey of auto suppliers conducted by Arthur Andersen & Co. and the Michigan Manufacturers Association (hereafter referred to as A&M) predicted that these suppliers will be investing together at least $2 billion per year in the 1980's, especially for new equipment (about 60 percent of total investment). z Machinery investments are needed both to make new types of supplied products and to help suppliers adapt to a shortage of skilled machinists. A recent study prepared for DOT by Booz-Allen & Hamilton describes the types and levels of investments associated with different types of auto activities on a new-plant basis (see table 60).[8]

Analyses by A&M, Government agencies, and industry analysts suggest that both appreciation of the types of supplier changes needed and ability to make those changes are greater among larger supplier firms than among smaller ones. Most supplier firms are small- and medium-sized, although a few large firms have large shares of the auto supply business. Among GM's total 32,000 suppliers in the United States, for example, only 4 percent have at least 500 employees while 52 percent have at most 25.[9]

Auto product change and market volatility are leading large suppliers, in particular, to diversify into nonautomotive products. For example, between 1978 and mid-1981 Eaton Corp., a major supplier, spent about $470 million to buy companies producing electronics, machinery, electrical parts, hydraulic systems, and other high-technology goods.[10] Large suppliers are also

W .S. Department of Commerce, *1981* U.S. *Industrial Outlook* (Washington, D.C: U.S. Government Printing Office, 1981).

[7]Arthur Andersen & Co. and the Michigan Manufacturers' Association, "Worldwide Competitiveness of the U.S. Automotive Industry and Its Parts Suppliers During the 1980s" (Detroit: February 1981).

[8]Booz-Allen & Hamilton, Inc., Automotive Manufacturing *Processes* (Washington, D.C: U.S. Department of Transportation, National Highway Traffic Safety Administration, February 1981).

[9]"Supplier Conference, Ford/Europe Interview Underscore Threat, " Ward's Automotive *Reports,* June 15, 1981.

[10]"Eaton: Poised for Profits From Its Shift to High Technology," Business Week, June 8, 1981.

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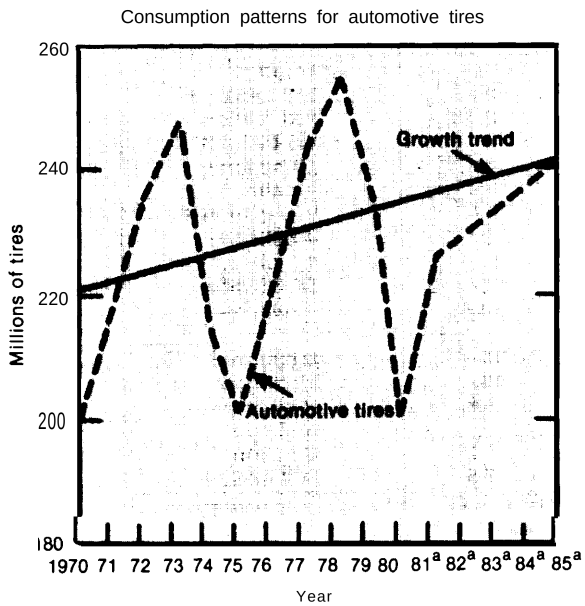
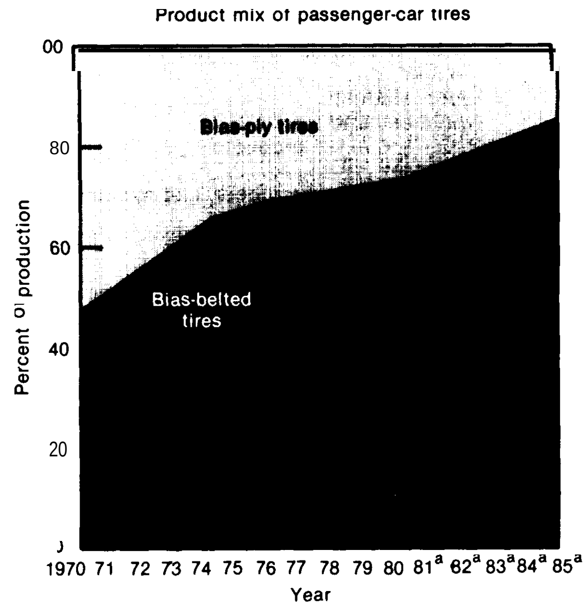
Figure 18.—Tire Industry Trends



[a]Estimated by Bureau of Industrial Economics.
SOURCE: Trade Association data.



[a]Estimated by Bureau of Industrial Economics.
SOURCE: Trade Association data.

Major tire manufacturer earnings fall,
July 1979 to June 1980, as the table below shows:

Company	Change in earnings
Armstrong. . . .	+ 12.1%
Cooper	negative (loss)
Dunlop	negative (loss)
Firestone	negative (loss)
General	negative (loss)
Goodrich	+ 11.2%
Goodyear	– 40.8%
Mohawk	negative (loss)
Uniroyal	negative (loss)

SOURCE: U.S. Department of Commerce, Bureau of Industrial Economics *1981 U.S* Industrial Outlook January 1981.

strengthening their international operations, diversifying away from the U.S. market. Small- and medium-size firms are likely to follow auto manufacturers in undertaking joint R&D and production ventures, while mergers and acquisitions and even closings or bankruptcies are likely. * The A&M survey predicted that decline in the numbers of suppliers will lead to increased vertical integration among suppliers, while strong import competition and other market changes will motivate increases in supplier productivity.

Sales and Service

Other segments of the auto industry include dealers and replacement part and service firms. The latter group, which serves consumers after they buy their cars, is called the automotive aftermarket.

Dealer sales activities are not necessarily affected by changing auto technology per se. Sales depend on consumer income and general eco-

*According to Dun & Bradstreet, transportation equipment firms, primarily including auto suppliers, suffered financial failure at a rate of 101 per 10,000 in 1980, as compared with a rate of 42 per 10,000 for all manufacturers.

Table 60.—Examples of Supplier Changes and Associated New Capacity Investment [a]

Characteristics	Approximate capital requirements for property, plant, and equipment
Foundries	
90 percent of auto castings use iron, 92 percent of which are sand cast, and auto manufacturers operate about 20 percent of U.S. sand casting capacity	$21 million (typical independent die cast foundry producing 15,000 tons/year)
Downsizing and production of smaller parts generates excess capacity	
Materials substitution reduces sand casting with iron and increases die casting with aluminum	
Metal stamping	
Autos have had up to 3,000 stampings and auto manufacturers produce about 60 percent of all stampings by weight	$67 million (typical captive plant producing stampings for 175,000 cars/year; independent plants are smaller and cheaper)
Materials substitution decreases carbon steel, increases high-strength steel and aluminum for stampings	
Plastics processing	
Injection molding	$31 million (typical plant producing 65 million lb parts/year)
Compression molding	$43 million (typical plant producing 60 million lb compound/year
Reaction injection molding	$19 million (typical plant producing 30 million lb parts/year)

[a] Figures for completely new facilities.

SOURCE: Booz-Allen & Hamilton, Inc.. Automotive *Manufacturing* Processes, prepared for the Department of Transportation, National Highway Traffic Safety Administration, February 1961.

nomic conditions (including the availability of credit), demographic conditions (including household size), the price of fuel, and vehicle price and quality attributes. Although consumers have responded to recent gasoline price increases by demanding relatively fuel-efficient cars, the experience of the recent recession illustrates that overall sales levels in a given year are primarily determined by consumer finances and not by vehicular technology.

There are about 300,000 automobile repair facilities in the United States[11] (see table 61). New automobile technology affects them because automobile design and content are changing. For example, problems in new, computer-controlled components will be diagnosed with computerized equipment, and plastic parts will be repaired with adhesives rather than welding. Components are more likely to be replaced than repaired on the vehicle or even at the repair shop. While automobile service firms will have to invest in new equipment and skills to service new cars, continued service needs of older cars may ease the transition,

Table 61 .—1980 Auto Repair Facilities

Type of facility	Quantity
Dealers	26,000
Auto repair shops (independent and franchised)	170,000
Tire—battery-accessory outlets	18,850
Other auto and home supply stores	1,860
Gasoline stations	70,000
General merchandise stores	3,500
All others	1,430
Total	292,240
Total including facilities selling only parts, accessories	331,090

SOURCE: *Wards Automotive* Reports, Apr. 6, 1981.

However, the concurrent operation of very different types of cars requires firms to double their parts inventories to service both types. The dollar value of parts and the frequency of repairs are also likely to differ between new and old car types. Manufacturers are attempting to curb service cost growth by designing cars for easy servicing. For example, the Ford Escort and Lynx and the Chrysler K and Omni/Horizon cars were designed so that servicing during the first 50,000 miles would cost less than $150.[12]

[11] "Auto Repair Facilities Total 300,000, " *Ward's* Automotive Reports, Apr. 6, 1981.

[12] Francis J. Gaveronski, "Ford's New Escort, Lynx Designed for Easy Service," Automotive News, May 19, 1980, and "Chrysler K-car to Stress Ease of Diagnosis, Repair, " Automotive News, June 16, 1980.

The effects of new repair and service practices on the structure of the aftermarket are uncertain. During the past decade, repair and service activity shifted from dealers to service centers run by general retailers (e.g., Sears) and tire retailers (e.g., Firestone) and to specialized franchised centers for tune-ups, body work, or component service (e.g., AAMCO Transmissions and Midas Muffler). Both of these trends help to moderate service cost increases because of scale economies in planning and management. However, the intimate and advance knowledge of new technologies held by manufacturers is likely to help dealers regain repair and service business. While dealers now perform about 20 percent of auto repairs, they are expected to gain a greater share by the mid-1980's. Meanwhile, scale economies in advertising and inventory management may promote consolidation among parts firms.[13]

Prospects

Further financial strain on the domestic auto industry is not likely to lead to financial failure of major manufacturer and supplier firms (except perhaps Chrysler, but Government intervention makes its future hard to predict). However, the continued viability of many smaller auto suppliers is becoming especially uncertain because automotive technology changes make products and capacity obsolete. While the industry may continue to contract, "collapse" of its leading firms is not likely because major and even intermediate-sized firms can make at least partial adjustments to automotive market changes; adjustments are already under way. Reduction in the U.S. activities of domestic firms and failure or contraction of smaller firms would, nevertheless, severely affect employment and local economies.

In contemplating the future of the industry it is important to appreciate what financial failure means. In a technical sense, businesses fail when they are unable to make scheduled payments. If this inability is temporary, firms can usually negotiate with creditors or seek protection from bankruptcy courts to relieve immediate creditor demands. In many cases, bankrupt firms are successfully reorganized, structurally as well as financially. However, some firms find that the stigma of bankruptcy makes producing and selling especially difficult. * If selling a firm's assets generates more value than using them for production by the firm, the firm is fundamentally unviable, and there are financial and economic grounds for liquidating it.

Barring Government support or merger, Chrysler is the large automotive firm most likely to fail if viability in the U.S. market entails large investments that it cannot afford. AMC has been at least temporarily rescued by the French Government-backed Renault. Because Chrysler's financial weakness has been known for years, the magnitude of the potential social and economic effects of its failure has been diminishing as Chrysler has cut back its operations and suppliers have reduced their dependence on Chrysler as a customer.

In mid-1979, when Data Resources, Inc., prepared for the U.S. Department of the Treasury a simulation of the macroeconomic effects of a Chrysler bankruptcy and liquidation, it found that only temporary macroeconomic instability was likely to result, although 200,000 people might be permanently unemployed. Dependence of workers and businesses on Chrysler has diminished since that simulation was done, although small firms for which Chrysler is a primary customer remain vulnerable. If Chrysler were to liquidate, its exit from the U.S. market would provide opportunities to domestic and foreign manufacturers to expand market share and purchase plant and equipment at relatively low cost. This could relieve financial pressures on Ford and GM.

While contraction of the U.S. auto industry may result in fewer, healthier firms, employment and local economies will suffer.** Loss of jobs will re-

[13] Maryann N. Keller, "Status Report: Auto Parts Industry Automotive Aftermarket Quarterly Review" (New York: Paine, Webber, Mitchell, Hutchins, Inc., July 29, 1980).

*When Lockheed and Chrysler appealed for Government aid, they both argued that their customers would not buy from firms in bankruptcy. This is more likely to be a problem for automobile (or aircraft) manufacturers than for their suppliers, given the difference in size of customer purchase and producer liability.

**Also, change in the amount of U.S manufacturer operations in Canada (not considered "foreign") could imply violation of our obligations under the Automotive Products Trade Act agreements with Canada.

suit predominantly from supplier-firm difficulties. Unemployment of auto industry workers may also affect the performance of the national economy. Unemployment causes a more than proportionate decline in aggregate production, because slack demand reduces average hours per worker, output per worker, and entry into the labor force, The reduction in disposable personal income (DPI) because of unemployment reduces personal consumption spending. Reduced personal consumption (and business fixed investment) spending reduces gross national product (GNP), causing DPI to fall, and so forth. Both personal and corporate tax revenues decline, while transfer payments to unemployed workers and economically depressed communities rise.

The national economy can better adjust to auto industry trauma than local and regional economies because the national economy is more diversified, and because, over time, national economic sensitivity to auto industry problems has been diminishing. Since World War II, manufacturing employment in the Midwest (and Northeast) has been declining as a percent of national manufacturing employment; it has declined in absolute volume since 1970 because job opportunities have not been growing, foreign and domestic firms have located facilities in other regions, and other industries primarily located elsewhere have been growing in their importance to the economy. * In this context of structural change, the 1975 recession seems to have been a turning point for traditional Midwest manufacturing, accelerating a trend of decline that was further aggravated by the 1979-80 oil crisis and recession.

*Electronics, computing equipment, chemicals and plastics, aerospace equipment, and scientific instruments have been the leading growth industries in the postwar period. These industries are both outlets for diversification by auto-related firms and competitors to traditional auto-related firms in automotive supply.

ECONOMIC IMPACTS OF SYNFUELS

Because large blocks of capital are required for synfuels projects, they will be visible centers of economic activity even from a national viewpoint and, in fact, for' people outside of the synfuels industry, the economic costs and benefits of synfuels may be more easily understood in terms of regional and national impacts.

Despite the absence of commercial experience, an outline of the synfuels industry emerges with comparisons to coal mining, conventional oil and gas production, chemicals processing, and electric power generation. By itself, this new industrial organization is an important economic impact, as it changes the way economic decisions are made regarding the supply of premium fuels. Furthermore, along with the technologically determined menu of resource requirements, industrial organization determines the major regional and national economic impacts of synfuels deployment.

potential regional and national economic impacts are then explored through comparisons of aggregate resource demands and supplies. Since plans call for very large mines and processing plants, and perhaps many construction projects in progress at once, the emphasis is on potential bottlenecks which could delay deployment schedules and drive up project costs. If severe resource bottlenecks do occur, the resulting inflation in the prices of these resources will spread through the economy, driving up prices and costs for a broad range of goods and services.

These resource costs add up in the next section of this chapter to financial requirements for projects and for the industry as a whole. To the extent that the Federal Government does not intervene, individual firms must compete in financial markets with all other products and all other firms for limited supplies of debt and equity capital. With the important exception of methanol and ethanol from biomass, * the large scale and long leadtimes of synfuels projects may make it difficult to raise capital, especially during the next

*Ethanol from biomass is not included in this discussion because with current technology its potential production is limited by the availability and price of feed-grain feedstocks. However, if economic processes for converting ligno-cellulose into ethanol are developed, ethanol could compete with methanol as a premium fuel from biomass.

decade, when important technological uncertainties are likely to remain. Federal subsidies or loan guarantees will speed synfuels deployment–but only by reducing capital available to other types of investments, by reducing other Federal programs, by increasing taxes, or by increasing the Federal deficit. Depending on general economic conditions, each of these different market interventions may be inflationary.

Each of these areas of regional and national economic impacts—industrial structure, potential resource bottlenecks, finance capital, and inflation as related to synfuels development–is discussed below.

The Emerging Industrial Structure of Synfuels

Synfuels are fundamentally different from conventional oil and gas because they are manufactured from solid feedstocks and because synfuels economics may lead to the replacement of conventional fuels by methanol and low- or medium-Btu gas in the future. Liquids from coal and oil shale, the feedstocks with a natural resource base sufficient to fully displace petroleum in the long run, involve economies of scale which encourage ownership concentration. The methanol option, however, provides offsetting opportunities for large chemical firms to enter the liquid fuel business and, based on biomass feedstocks, it may also allow many small producers to supply local markets throughout the Nation.

The following discussion is broken down into the four stages of synfuels production. While this breakdown is convenient, it should be understood that several stages of production may be performed on the same site in order to minimize handling, transportation, and management costs.

Mining Coal and Shale

Mining for synfuels will closely resemble mining for any other purpose except that the mines dedicated to synfuels production will be relatively large .[14] It takes approximately 2.4 million tons of coal per year to fire an 800 MWe generator and about three times that much to feed a 50,000 barrels of oil equivalent per day (BOE/D) coal synfuels plant, and about four to eight times as much oil shale (by weight) for the same output of liquid fuel produced by surface retorting. *

Capital costs for development of a coal mine depend primarily on the depth and thickness of the coal seam. Average investment cost data can be misleading, since each mine is unique, but it takes about $60 of investment per annual ton of coal mined underground (1981 dollars). With coal preparation and loading facilities, investments at the mine site may approach $100 per annual ton, or about $750 million for capacity sufficient to supply a 50,000 bbl/d synfuels plant. Western surface mining may in certain cases be substantially less expensive. * * Furthermore, substantial synfuels production may be achieved on the basis of existing excess mining capacity.***

In the absence of commercial experience, investment cost estimates are unavailable for shale mining. It is clear, however, that they can be either larger or smaller than for coal, depending on two opposing factors. First, investments costs could be much higher because of the low energy density of shale. Hence, much more material must be mined per barrel of oil equivalent. Second, shale investment costs could be lower because major shale resources lie in very thick

[14]For an extensive discussion of mining techniques and costs, see The Direct Use of Coal: Prospects and Problems of Production and Combustion, OTA-E-86, (Washington, D. C.: U.S. Congress, Office of Technology Assessment, June 1979), chs. Ill and IV.

*This range is determined by the Btu content of coal and shale and by the efficiencies of converting a Btu of solids into a Btu of finished liquid fuels. If we just compare shale oil and methanol (the two liquid synfuel options which are best understood and probably of least cost), conversion efficiencies are comparable, so the difference in feedstock rates is entirely a matter of the energy density of the feedstock. Coal has 16 to 30 MMBtu/T with Western coal typically on the lower end of the range. Shale, which is presently considered suitable for retorting, has 3.6 to 5.2 MM Btu/T. Hence, the ratio of shale to coal inputs can be as low as 4.2 and as high as 8.3.

**Investment cost data were obtained from National Coal Association. Federal surface mine regulations have increased investment requirements in increasing the equipment required to operate a mine and to reclaim land after coal has been removed, by increasing the amount of premining construction and equipment required to establish baseline data, and by extending the required development period.

* * *The National Coal Association estimates excess capacity at 100 million to 150 million tons per year. The low end of the range is calculated on the basis of the number of mines closed and the number of workers working short weeks. The high end of the range is calculated by comparing peak weekly production to average annual output per week.

seams (in some areas over 1,000 ft thick) and often relatively near the surface. Estimates for the first commercial shale project indicate that mining investments for a 50,000 bbl/d project may be substantially below $750 million. * Furthermore, if in situ retorting techniques fulfill optimistic expectations, shale mining could become relatively inexpensive as mining and retorting operations are accomplished together underground.

Mine investment is important in project planning, but its share in total investment is still usually less than a third. (Notice that in the estimated investment costs for coal-based synthetics in ch. 8, the cost of the mine was not included. It is included in ch. 4 in the discussion of total investment costs.) Beyond actual costs, the activity of mining itself is important in the synthetic fuel cycle because of its previous absence in the U.S. oil and gas industry. In fact, the entire sequence of economic events associated with extraction of coal and shale contrasts sharply with the extraction of conventional petroleum and natural gas. The key difference is that oil and gas reserves must be discovered, with potentially large rewards for the discoverer, while the location and morphology of coal and shale resources have been known for a long time.

A wildcat driller, looking for an oil or gas deposit, can rent and operate a drilling rig with a relatively small initial investment. Since the most promising prospects have already been drilled in this country, exploration typically is a high-risk gamble and, although investment is small compared with development of resources, it can still require large sums of money in frontier areas such as deep water or the Arctic. The uncertainty is a deterrent to investment, but potentially large payoffs and special Federal tax incentives continue to attract large numbers of investors and large sums of capital.[15] Furthermore, the wildcatted can induce cooperation from landowners, local government officials, and any other powerful local interests by promising royalty payments, or at least a rapid expansion of local business activity, without serious environmental impacts. Only after a substantial reservoir has been discovered is it necessary to make relatively large investments in development wells, processing equipment, and pipelines.

In mining, there is nothing comparable to the opportunity and uncertainty of discovery wells. Most of the business parameters of a potential mine site are evident to the landowner and to all potential mining companies, which means that profit margins are generally limited by competitive bidding.

As discussed below, mines also typically employ more labor per million Btu of premium fuel produced than oil and gasfields[16] and they have many more adverse environmental impacts (e.g., acid drainage, subsidence, etc). For both reasons, interests external to the firm are more likely to oppose and perhaps interrupt mining operations. Investors realize such contingencies and see them as risks for which they expect compensation.

This discussion of relative payoffs and risks is by no means complete or conclusive, but it does suggest that private investors may exploit min-

*The Denver office of Tosco Corp. estimates that mine costs for the Colony project, which is the first shale project to proceed with commercial development, could be as low as $250 million. That particular site has the advantage that large-scale open pit mining equipment can be used in an underground mine, since the seam is horizontal and the mine can be entered via portals opened in a canyon wall. This means that the reclamation costs of a surface mine can be avoided as well as the costly mine shaft of a conventional underground mine. Furthermore, the site is propitious because there is virtually no methane trapped in the shale, so safety measures are minimal. In the future, mine costs as well as conversion costs may be held down by in situ liquefaction, but this technology remains unproven.

[15] In 1979, approximately $12.5 billion was invested in exploration for oil and gas in the United States. That includes (in billions), $5.4 for lease acquisition, $4.5 for drilling, $2.3 for geological and geophysical activity, and $0.3 for lease rentals. (See *Capital Investments of the World Petroleum Industry*, 1979, Chase Manhatten Bank, p. 20, and Basic *Petroleum* Data Book, American Petroleum Institute, vol. 1, No. 2, sec. Ill, table 8a). $12.5 billion is about 3 percent of total gross domestic investment ($387 billion). (See 1980 Statistical Abstract, p. 449.)

The oil and gas industry receives special tax treatment mainly in terms of expensing intangible expenditures of exploration, even though they are surely treated as capital expenses in corporate accounts.

[16] Although oil and gas has been closing steadily, in 1979 it took approximately 14,500 workers (miners and associated workers) to produce a Quad of coal and about 11,500 workers to produce a Quad of oil and gas. However, the labor intensity of mining for synfuels is actually 160 to 200 percent greater than for coal alone, since only about 50 to 60 percent of the energy in coal feedstock remains in the finished synfuel product. See 1980 Statistical Abstract, p. 415, for employment data and 1980 Annual Report to Congress, Energy Information Administration, p. 5, for production data. See note 2, ch. 9 for further discussion of labor productivity.

ing prospects for synfuels much more slowly than prospects for conventional oil and gas, or that investors will accept much greater risks with conventional oil and gas prospects because of the offsetting chances of striking it rich. Synfuels capacity could still expand rapidly, but probably not without very high profit incentives to reorient investors who have traditionally been in oil and gas exploration.

Conversion Into Liquids and Gases

During the second stage of production, solid feedstocks are converted into various liquids and gases. Current synfuels project plans indicate that coal or shale conversion plants will resemble coal-fired electric power stations in the sense that both convert a large volume of solid feedstock into a premium form of energy. They will resemble chemical processing (in products such as ammonia, ethylene, and methanol from residual oil or natural gas) and petroleum refining facilities in their use of equipment for chemical conversions at high temperatures and pressures. *

Of the $2 billion to $3 billion (1981 dollars) required overall for a 50,000 BOE/D shale project, between one-third and one-half goes into surface retorts which decompose and boil liquid kerogen out of the shale rock. A larger fraction of total project costs is required to obtain methanol from coal, but with subsequent avoidance of the upgrading and refining costs.** In general (but with the exception of in situ mining shale), the conversion step alone requires investments comparable to a nuclear or coal power station of 1 GWe capacity or to outlays for a 200 to 400,000 bbl/d petroleum refinery.[17]

Factors other than economy of scale dominate the economics of syngas production, as demonstrated by the existence of many small gasification plants across the country.[18] Two factors account for this. First, gasification is only the first stage in the production of either methane or methanol, so costs of the second stage can be avoided and system engineering problems are less complex and more within the technical capabilities of smaller users. Airblown gasifiers involve the least engineering, since they do not require the production of oxygen, but only certain onsite end users such as brick kilns can use the low-Btu gas. The second reason involves transportation and end-use economics.

In many industrial applications, natural gas (methane) has been the preferred fuel or feedstock, but medium-Btu gas is an effective substitute in existing installations because it requires relatively minor equipment changes. Either low- or medium-Btu gas may be used in new installations, depending on the industrial process and site-specific variables. However, since these methane substitutes cannot be transported over long distances economically, conversion facilities must be located near the end users.

The size of the conversion facility is therefore determined by the number and size of gas consumers within a given area, and this often dictates conversion plants that are small in comparison with a 50,000 bbl/d liquid synfuels plant. Consequently, industrial gas users may choose to locate near coalfields in order to produce and transport their own gas or to contract from dedicated sources. Either approach assures security of supply and availability over many years.

Upgrading and Refining of Liquids

As discussed in chapter 6, raw syncrudes from oil shale and direct liquefaction must be upgraded and refined to produce useful products. Technically, these activities are quite similar to petroleum refining, and this affords a competitive advantage to large firms already operating major, integrated refineries. This bias toward large, established firms is reinforced in the case of direct

*Refineries typically use lower pressures than chemical plants and lower than what is expected for synfuels conversion.

** For a breakdown of methanol costs, see ch. 8.

[17]As discussed in ch. 8, all synfuels capital cost estimates are very uncertain because none of these technologies has been used commercially. Furthermore, engineering cost estimates available to OTA typically do not clearly differentiate costs by stages of production. Nevertheless, the conversion step, going from a solid feedstock to a gas or a liquid product, is undoubtedly the most expensive single step in synfuels production. For presentation of costs for electric power stations see *Technical Assessment Guide,* Electric Power Research Institute, July 1979.

[18]See National Coal Association, "Coal Synfuel Facility Survey," August 1980, for a listing and discussion of between 15 to 20 low-Btu gas facilities coupled with kilns, small boilers, and chemical furnaces.

coal liquids by the apparent cost reduction if upgrading and refining are fully integrated with conversion, thus making it difficult for smaller firms to specialize in refining as some do today. Upgraded shale oil, on the other hand, is a high-grade refinery feedstock that can be used by most refineries.

Downstream Activities: Transportation, Wholesaling, and Retailing

As long as synthetic products closely resemble conventional fuels, downstream activities will be relatively unaffected. However, medium- or low-Btu gas and methanol are sufficiently different to require equipment modifications, and they may be sufficiently attractive as alternative fuels to induce changes in location of business and structure of competition.

Depending.on the market penetration strategy, methanol may be mixed with gasoline or handled and used as a stand-alone motor fuel. As a mixture, equipment modifications will involve installation of corrosion-resistant materials in the fuel storage and delivery system. As a stand-alone fuel, methanol may have its own dedicated pipeline and trucking capacity and its own pump at retail outlets, and auto engines may eventually be redesigned to obtain as much as 20 percent added fuel economy, primarily by increasing compression ratios and by using leaner air-fuel mixtures when less power is required. *

If firms currently producing methanol for chemical feedstocks should enter fuel markets,[19] drivers stand to gain from the increased competition among the resulting larger number of major fuel-producing companies and by competition between methanol and conventional fuel. Furthermore, with coal-based methanol providing a critical mass of potential supply, drivers across the Nation may be able to purchase fuel from small local producers (using biomass feedstocks), a situation which has not obtained since the demise of the steam engine.

*See ch. 9 for further information about methanol vehicles.

[19]At the present time, approximately 1.2 x 109 gal barrels of methanol (1 1 x 1 0[6] BOE) are produced domestically, primarily from natural gas, and used almost exclusively as a chemical feedstock. See Chemical and Engineering News, Jan. 26, 1981.

Medium- or low-Btu gases are effective substitutes for high-Btu gas (methane) but, as discussed above, their relatively low energy density prohibits mixing in existing pipelines and generally restricts the economical distance between producer and consumer (the lower the Btu content the shorter the distance). Hence, deployment of these unconventional gases will require dedicated pipelines, relocation of industrial users closer to coalfields, or coal transport to industrial gas-users.

Conclusion and Final Comment

Massive financial and technical requirements for synthetic liquids from oil shale and coal encourage ownership that is more concentrated than has been typical in conventional oil and gas production. Large firms, already established in petroleum or chemicals, have three major advantages.

First, they can support a large in-house technical staff capable of developing superior technology and capable of planning and managing very large projects. Second, they can generate large amounts of investment capital internally, which is especially important during the current period of high inflation (inflation drives up interest on borrowed capital, making it much more expensive for smaller firms who must supplement their more limited internal funds).

Third, such firms already have powerful product-market positions where synthetic liquids must compete, so entry by new firms involves a greater risk that synthetic products cannot be sold at a profit. * The second and third advantages may be

*Predicting investment behavior is always difficult, but barring Federal policy to the contrary, the most likely group of potential investors are the 26 petroleum and chemical firms, each with 1981 assets of $5 billion or more (see list below). Seven chemical firms were included in this list primarily because they may be in a strong position to produce and market fuel methanol, based on their experience with methanol as a chemical feedstock.

Fortune, May 4, 1981, presents a listing of the 26 largest (in terms of total assets) petroleum and chemical firms: Exxon, Mobil, Texaco, Standard Oil of California, Gulf Oil, Standard Oil of Indiana, Atlantic Richfield, Shell Oil, Conoco, E. 1. du Pent de Nemours, * Phillips Petroleum, Tenneco, * Sun, Occidental Petroleum, Standard Oil of Ohio, Dow Chemical, * Getty Oil, Union Carbide, * Union Oil of California, Marathon Oil, Ashland Oil, Amerado Hess, Cities Service, Monsanto, * W. R. Grace, * and Allied Chemical. * Asterisk indicates firm primarily in the chemicals industry.

This conclusion about the dominance of larger companies holds despite the fact that current synfuels projects planned or under study

(continued on next page)

nullified if several smaller firms can effectively band together into consortia, but it maybe much more difficult for a consortium to build a technical staff which can develop superior technology and manage large projects during the next decade, when there will be many technical risks.

Ownership concentration is an important aspect of industrial organization in an economy organized on classical economic principles of anonymous competition, market discipline, and consumer sovereignty. Very large synfuels projects owned by very large energy corporations and consortia of smaller firms would not be anonymous, even from the viewpoint of the national economy, and they would have leverage to dictate terms in their input and output markets.

Conversely, once companies have made very large investments in new synfuels projects, they become visible targets for political action which might significantly raise costs or reduce output. Visible producers may not in fact allocate resources much differently than if there were only anonymous competitors, but at least the opportunity to manipulate markets exists where it would not otherwise—and just the appearance of doubt about the existence of consumer sovereignty can raise serious political questions.

The capital intensity of synfuels will also change the financial structure of the domestic liquid and gaseous fuel industry. Compared with investments in conventional oil and gas during the last 20 years, investment in synfuels per barrel of oil equivalent of productive capacity (barrels of oil per day) will increase by a factor of 3 to 5.[20] While all such calculations are of necessity very imprecise, the order of magnitude is confirmed by data contained in the 1980 Annual Report of Exxon Corp. As of 1980, Exxon's capitalized assets in U.S. production of oil and gas totaled $11.5 billion, and its average daily production rate (of crude oil and natural gas) was about 1.4 million BOE; so its ratio of capital investment to daily output was $8,200.[21] A 50,000 BOE/D synfuels plant at $2.2 billion implies a ratio more than five times larger ($44,000/BOE/D).

In other words, switching from conventional to synthetic liquids and gases amounts to a substitution of financial capital (and the labor and durable goods it buys) for a depleting stock of superior natural resources. A parallel substitution of investment capital for natural resources is occurring as conventional resources are increasingly hard or expensive to find and develop because of the depletion of the finite stockpile of natural resources.

As long as the United States could keep discovering and producing new oil and gas at relatively low cost, energy supplies did not impose serious inflexibilities on our economy. When we needed more we could get it without making much of a sacrifice. With synfuels, it is necessary to plan ahead, making sure that capital resources are indeed available to supply synfuels projects, and that product demand is also going to be available at least a decade into the future so that large synfuels investments can be amortized.

The current financial situation of many electric utilities in the United States illustrates the risks entailed when plans depend on long-term price and quantity predictions which may prove to be wrong. It was not long ago that utility investments were considered almost risk-free, and the industry had for decades raised all the debt it wished at low rates. Needless to say, the utility situation has now dramatically reversed as the result of sharply rising costs embodied in new, long-lived gener-

involve many relatively small firms. For example, three of the four major parties in the Great Plains Gasification Project are primarily involved with either gas-distribution or transmission: American Natural Resources Co., Peoples Energy Corp., and Transco Cos. Inc. American Natural Resources is associated with gas-distribution firms operating in Michigan and Wisconsin; Peoples Energy Corp. is associated with Northern Natural Gas, a major distributor in the Midwest; and Transco is the parent company of Transcontinental Gas Pipeline Co., a major operator of transmission lines. The fourth partner, Tenneco, is also a major transmission company, but it was included in the group of top 26 firms listed above because of its chemical processing business. Undoubtedly, all four firms' participation is predicated upon the existence of Government subsidies and loan guarantees, but that is especially true for the three smaller firms.

[20] Comparison based on data for total costs of oil and gas wells, plus estimated costs for predrilling activities over the period from 1959-80. Capital outlays per barrel oil equivalent of reserves over the past 20 years averaged about $1.60. Depending on the synfuels option, a synfuels plant would have a comparable ratio of $5.40 to $7.00/BOE of "reserves." Well-drilling and other exploration costs were obtained from Society of Exploration Geophysicists, Annual Reports and from Joint Association Survey of the U.S. Oil and Gas Producing Industry.

[21] See 1980 *Annual* Report of Exxon *Corporation,* pp. 34, 44, 51.

ating capacity. while it may be premature to draw an analogy with synfuels, it is clear that synfuels will tie up capital in considerably larger blocks and for considerably longer periods than was true for conventional oil and gas reserves over the last 30 years.

Compared with synthetic petroleum, methanol presents two opportunities to partially offset the tendency toward industrial concentration. First, as indicated above, its present use as a major chemical feedstock provides an opportunity for large chemical firms to enter the liquid fuel business. Second, since methanol can be produced from wood and other solid biomass, small-scale conversion plants (approximately $1 O-million investments) operated by relatively small entrepreneurs may be able to take advantage of local conditions across the country. * Assuming cost competitiveness, having a mixture of small- and large-scale methanol producers may reinforce the attractiveness of downstream equipment investments (e. g., retail pumps and engine improvements), thus making it more likely that drivers will indeed have an attractive methanol opt ion.

Besides methanol, synthetic gases may attract additional large and small firms from outside the petroleum and chemical industries. Depending on the deregulated "well head" price of natural gas (relative to fuel liquids) and depending on regulatory policy regarding utility pricing, synthetic natural gas and synthetic medium-Btu gas may become profitable investments for gas utilities. Indeed, the first synthetic gas project to reach the final planning stage has substantial gas utility ownership, * * Syngas may become attractive as a methanol coproduct or as a primary product, in either case taking advantage of capital savings and higher conversion efficiencies than if methanol or gasoline is the sole product of indirect liquefaction.

*One domestic company, International Harvester, is presently developing technology to mass-produce this equipment and transport it to the purchaser's location in easily assembled modules.

* *This compares with total private domestic investment in 1980 of about $395 billion, and out of that total about $294 billion went for nonfarm investments in new plant and equipment. Also in 1980, two large blocs of energy investments were $34 billion for oil and gas exploration and production and $35 billion for gas and electric utilities.

A final comment can be made about the location of the synfuels industry. Shale oil production will be concentrated in Colorado and Utah, since that is where superior shale resources exist and since unprocessed shale cannot be shipped as a crushed rock without driving up costs prohibitively, Coal-based synfuels offer the possibility of spreading liquid fuel production over a wider cross section of the Nation. This is especially important for the Northeast and North Central section of the United States, where there remain substantial coal deposits in Pennsylvania, Ohio, and Illinois, States which have by this time depleted most of their original petroleum reserves.

Unlike their shale counterparts, coal-conversion facilities and subsequent upgrading and refining plants need not be immediately adjacent to the mine mouth, since coal's shipping costs per Btu are less than for shale. Location of facilities and, hence, their regional impacts will depend on site-specific factors and the available modes of transportation. Location of facilities to convert biomass into methanol will be determined primarily by local availability and cost of biomass feedstocks. This restriction is imposed by the dispersed location of plant material, rather than by differences in energy density (biomass feedstocks such as wood have an energy density only marginally lower than some Western coals).

Potential Resource Bottlenecks and Inflation

Technology, ownership concentration, and (in certain important cases) regional concentration, all combine to impose heavy demands on labor, material, and financial resources relative to current and potential new supplies of the same resources. If deployment plans fail to account for supply limitations, long project delays and large cost overruns can occur.

Anytime a capital-intensive industry attempts to start up quickly, temporary factor input shortages can be expected—if not more extreme "bottlenecks" or chronic shortages which generally disrupt construction schedules. Ideally, shortages and, certainly, bottlenecks can be avoided by advanced planning and giving suppliers purchase contracts years in advance if necessary to ensure availability. However, while such planning and long-term commitments minimize shortage risks, they also increase risks of loss should plans be technically ill-conceived and commitments are made to projects with actual costs much larger than planned. These two sets of risks must be weighed against each other, but at the present time technical risks clearly are more significant.

In order to predict resource bottlenecks and their impacts, the full array of supplier market dynamics must be understood. In this limited discussion, one can only begin to compare potential demands and supplies for key synfuels resources.

As a final introductory remark, it should be clear that factor price inflation drives up costs in many industries, not just for builders of synfuels plants. Industries that appear most vulnerable to inflation resulting from synfuels deployment will be identified. However, in general, a much larger study would be necessary to trace inflationary pressures through complex interindustry transactions.

Experienced Project Planners, Engineers, and Managers

As planned, the construction of oil shale and coal liquids projects requires the mobilization of thousands of skilled workers and massive quantities of equipment and materials. Of all these synfuels investment resources, the supplies of skilled engineers and project managers are the most difficult to measure, and in the final analysis, it is left up to the large investing firms to decide for each project when a critical mass of talent has been assembled. While individual firms may have excellent engineering departments, the possibility of supply bottlenecks for chemical engineering services, across the full spectrum of chemical processing industries, must be of concern because of the potential financial risks due to design errors and because of the length of time required to educate and train new people. *

t the present time, only one of the country's 10 major architectural and engineering (A&E) firms[22] has actually built a synfuels plant. * No commercial-scale plant has been built. Given this general inexperience, and making the reasonable assumption that A&E firms will not be short of work worldwide, it seems highly unlikely that synfuels construction contracts for the first round of a rapid deployment scheme will be able to hold builders to binding cost targets and completion dates. Consequently, those who would actually take investment risks may be extremely skeptical of builders' qualifications and judgment, and this may severely limit the apparent supply of qualified engineers and engineering firms.

Furthermore, if synfuels projects proceed ahead at a rapid pace despite the technical uncertainties and commercial inexperience, it could drive up the A&E costs for other large, new processing facilities which rely on the same limited group of A&E firms and the same pool of skilled workers. Of all synfuels resource markets, the possibilities

● Well-trained engineers and project planners can still make major mistakes, but risks due to miscalculations and design errors are controlled by careful training and building up experience incrementally. Commonly accepted periods for obtaining a bachelor's degree and subsequent on-the-job training range from 6 to 10 years.

Several recent examples illustrate that errors in the design of large mining and chemical processing plants do occur and can cause severe cost overruns and project delays. Perhaps the most extreme case was the Midwest (nuclear) Fuel Reprocessing Plant built for General Electric. Construction started in 1968, with completion planned for 1970 at an estimated cost of $36 million. Unfortunately, expected time for major technical component failure in the new plant was less than the time required to achieve stable operating conditions. The project was abandoned and the company estimated that an additional expenditure of between $9o million and $130 million would have been required to redesign and rebuild.

Additional examples include a municipal solid waste gasifier in Baltimore begun in 1973 which never achieved its major goal of commercial steam production, an oil sands project in Canada which underwent extensive retrofit when the teeth of its large mining shovels were worn away in a matter of weeks by frozen oil sands, and so on. Clearly, major design errors have happened in the past and are likely in the future, with the number and severity of such errors increasing if a shortage of experienced design engineers develops,

For further information about these and other examples of design errors, see Edward Merrow, Stephen Chapel, and Christopher Worthing, A Review of Cost Estimation in New Technologies: *Implication for Energy Process Plants and Corporations*, July 1979.

[22]According to Business *Week*, Sept. 29, 1980, p. 84, the 10 major A&E firms, in order of their largest projects to date, are: Fluor, Parsons, Bechtel, Foster Wheeler, C-E Lummus, Brown and Root, Pullman Kellog, Stone and Webster, CF Braun, and Badger.

*The Fluor Corp. built Sasol I and II in South Africa and will undoubtedly sell this technology and its unique experience in the United States. However, different resource endowments can cause very different engineering economics in different countries, and thus this existing technical base may have to be adapted to the United States by investing in significant additional engineering.

for propagation of inflation from synfuels into the rest of the economy is greatest here. Petrochemicals, oil refining, and electric power generation are all industries which depend on the same engineering resources in order to build new facilities. in 1979, these three industries accounted for more than 25 percent of the total investment in new plant and equipment.[23]

Mining and Processing Equipment, Including Critical Metals for Steel Alloys

The construction of massive and complex synfuels plants will require equally massive and diverse supplies of processing equipment and construction materials. Some of this equipment must meet high performance standards for engineering, metals fabrication, component casting, and final product assembly because it must withstand corrosive and abrasive materials under high pressure and temperature.

Potential supply problems can be identified first by comparing projected peak annual equipment demand (for each deployment scenario) to current annual domestic production. While projections were not done specifically for OTA's low and high scenarios, useful information can be extrapolated from an earlier projection for the deployment of coal liquids.[24] In that analysis, which postulated 3 million barrels per day (MMB/D) of synfuels by 2000, 7 of 18 input categories were identified as questionable because projected synfuels demands account for a significant fraction of domestic production. * Supply problems for chromium, the one item in this group of seven which is not a manufactured piece of equipment, would not be caused by synfuels deployment, since synfuels requirements would amount to less than 3 percent of domestic consumption, but supplies may nevertheless be difficult to obtain because U.S. supply is imported, much of it from politically unstable southern Africa.[25]

For the six types of equipment identified, the actual occurrence of bottlenecks will depend on the ability of domestic industry to expand with synfuels demand. In all cases, including draglines and heat exchangers—where coal synfuels requirements exceed 75 percent of current domestic production even in the low scenario—there appear to be no technical or institutional reasons why, if given notice during the required project planning period, supplies should not expand to meet demand with relatively small price incentives.

In general, this optimistic conclusion is based on the fact that leadtimes for expanding capacity to produce synfuels equipment are shorter than the leadtimes required to definitely plan and then build a synfuels plant.[26] The fact that many plants would be built at the same time does not nullify this basic comparison as long as all synfuels construction projects are visible to supplier industries, as they should be. Furthermore, foreign equipment suppliers can be expected to make up for deficiencies in domestic supply if not actually displace domestic competitors.

For example, consider the case of heat exchangers. As indicated in table 62, coal synfuels

[23]For data see Statistical Abstract, 1980, p. 652.

[24]Data obtained from "A Preliminary Study of Potential Impediments," by Bechtel National, Inc., which is one part of a three-part compendium, Achieving a Production Goal of 1 Million B/D of Coal Liquids by 1990, TRW, March 1980. We can extrapolate from coal liquids to all other synfuels because subsequent research (by E. J. Bentz & Associates, OTA contractor) indicates that shale oil, coal liquids, and coal gases are all quite similar in their total use of processing equipment per unit output (measured in dollars) and in their mix of processing equipment. Furthermore, the Bechtel study remains useful, despite its age, since subsequent increments in synfuels plant costs do not add items to this list or significantly increase demand requirements for the group of seven critical items. In other words, recent escalations in plant costs are primarily related to increases in the expected prices of components and to increasing demands for certain components which are insignificant when compared with productive capacity nationwide.

*Significance in this case means that projected synfuels demand exceeds 1 to 2 percent of domestic production. Since this is a relatively low threshold, this list should stay about the same for both scenarios.

[25]The chief use of chromium is to form alloys with iron, nickel or cobalt. In the United States, deposits of chromite ore are found on the west coast and in Montana. However, domestic production costs are much higher than in certain key foreign countries. In 1977, South Africa produced about 34 percent of total world production, with the U.S.S.R. and Albania producing another 34 percent. Other major producers are Turkey, the Phillipines, and Zimbabwe. See Minerals in the U.S. Economy: Ten-Year Supply-Demand Profiles for Nonfuel Mineral Commodities (1968-77), Bureau of Mines, U.S. Department of Interior, 1979.

[26]One can never be certain about how well industrial systems will adapt to rapidly expanding demand for a limited number of highly engineered types of equipment which must be produced with stringent quality control, However, informal surveys of equipment manufacturers have not revealed substantial reasons why equipment supplies should not be responsive to moderate price incentives. See Frost and Sullivan, Coal Liquefaction and Gasification: Plant and Equipment Markets 1980 2000, August 1979.

Table 62.—Potentially Critical Materials and Equipment for Coal Liquids Development

Category	Units	(A) Peak annual requirements	(B) U.S. production capacity	(A)/(B) (percent)
1. Chromium	tons	10,400	0	—
2. Valves, alloys, and stainless	tons	5,900	70,000	8
3. Draglines	yd	2,200	2,500	88
4. Pumps and drivers (less than 1,000 hp)	hp	830,000	20,000,000	4
5. Centrifugal compressors (less than 10,000 hp	hp	1,990,000	11,000,000	18
6. Heat exchangers	ft^2	36,800,000	50,000,000	74
7. Pressure vessels (1.5 to 4 inch walls)	tons	82,500	671,000	12
8. Pressure vessels (greater than 4 inch walls)	tons	30,800	240,000	13

SOURCE: Achieving a Production Goal of *1* Million *B/D* of Coal Liquids by *1990,* draft prepared for the Department of Energy **by** TRW, Inc. and **Bechtel** National, Inc., March 1980, pp. 4-28. Although these projections apply to the achievement of 3 MM B/D of coal liquids, and not specifically to the low and high production scenarios Postulated in this **report, they** nevertheless Indicate **rough** orders of **magnitude** for **equipment** demand. See footnote 16 of this **chapter** for further discussion of alternative **synfuels projections.**

requirements for the low scenario could account for about 75 percent of current domestic U.S. production. Extrapolation from table 62 indicates that requirements for the high scenario could amount to 150 percent of current production and, as data in table 63 indicate, even in the low scenario, synfuels demand could exceed current U.S. production for "fin type" heat exchangers. However, productive capacity can expand as rapidly as machine operators and welders can be trained, which for an individual worker is measured in terms of weeks and months. Additional heat-treated steel and aluminum inputs will also be required, as well as manufacturing equipment, but in all cases supplies of these inputs should expand with demand .27

This generally optimistic assessment does not mean that temporary shortages could not occur and temporarily drive up equipment prices if prospects for synfuels deployment should improve dramatically.[28] However, as orders for new equipment skyrocket, new capacity should become available in time so that extremely high equipment prices can be avoided if project managers are willing to accept relatively brief (measured in months) delays in delivery.

Skilled Mining and Construction Labor

Construction workers and their families can move with employment opportunities, but moving is costly and especially burdensome if jobs in an area last for only a period of months. In order to induce essential migration, synfuels projects must incur high labor costs in the form of travel and subsistence payments as well as

[27]Compared with the full range of heat exchangers used in industrial and utility applications, those likely to be used in synfuels plants will operate at relatively low temperatures. Low-temperature units are made primarily out of carbon steel, low-alloy steel, and enamel steel, all of which are readily available in commodity markets where demand for heat exchangers is a small fraction of the total. Hence, material inputs are unlikely to restrain expansion of heat exchanger supplies.

It is also unlikely that skilled labor or manufacturing plant and equipment will limit supplies, because the required welding and machine operator skills can be learned in a period of weeks if necessary, and manufacturing facilities are not highly specialized. Background information about the heat exchanger industry, and synfuels technology in particular, was obtained by private communication with James Cronin, Manager of Projects, Air Preheater Division, Combustion Engineering, Wellsville, N.Y.

[28]A commonly cited example of a temporary inflationary spurt, caused by a construction boom, occurred in the U.S. petrochemicals industry in 1973-75. Over the period from the mid-1 960's to mid-1 970's, the following three price indices show a distinctive pattern for chemical process equipment:

Year	Chemical process equipment[a]	Producer goods[b]	All machinery and Equipment
1967	100	100	100
1970	81	110	111
1971	86	119	118
1972	74	135	122
1973	91	160	139
1974	139	175	161
1975	167	183	171
1976	188	194	182
1977	154	209	206

[a]Data obtained from Annual Survey of Manufacturers, Bureau of Census, U S. Department of Commerce, SIC No. 35591 005, as reported in ASM-2.
[b]Data obtained from U.S. Statistical Abstract, 1979, PP 477-79.

In words, chemical process equipment prices reversed a decline in 1973, increased by more than 150 percent through 1976, and then tapered off again in 1977. This compares with a steady upward trend from both producer goods and all machinery and equipment.

Table 63.—Peak Requirements and Present Manufacturing Capacity for Heat Exchangers (Million Square Feet)

	Peak requirements for 3 MMB/D of coal liquids (1985)"	U.S. manufacturing capacity
1. Process shells and tubes.	22.0	27
2. Fin type	9.2	8
3. Condensers	4.4	15
	36.8	50

apeak requirements indicate maximum capacity requirements if synfuels Projects are to maintain production schedules.

SOURCE: Achieving a Production Goal of 1 Million B/Do f Coal Liquids by 1990, draft prepared for the Department of Energy by TRW, Inc. and Bechtel National, Inc., March 1980, pp. 4-28.

"scheduled overtime. " * However, while the influx of people and the relatively high payments to workers may cause severe local inflation, regional and national impacts should not be significant. Confidence in this conclusion is based primarily on the fact that training in construction skills can be obtained in the period of weeks and months and that, if anything, there is an oversupply of people willing to enter these trades.[29]

Miners will be expected to move into a new area and stay permanently. Although it would seem reasonable to suppose that workers would be reluctant to mine underground, where working conditions can be unpleasant and hazardous, historical experience suggests otherwise. In the Eastern mines, with present wages about 140 percent of the national average in manufacturing, labor shortages have not been a serious problem.[30]

Basic Construction Materials

Among all synfuels resources, basic construction materials (primarily steel and concrete) are least likely to cause serious bottlenecks. The more rapid the pace of deployment, the more likely a premium price must be paid for steel and cement, but supplies of both should be highly responsive to price incentives.

Mineral resources for the manufacture of Portland cement (the class of hydrolic cement used for construction) are widely distributed across all regions of the Nation. The same is true for the sand and gravel that are mixed with cement and water to make concrete. The only constraint on supplies of cement or concrete is the time required to construct new capacity, which takes at most 3 years for a new cement plant and much less than that for a concrete mixing facility.[31] Since these times are short relative to the construction period for a synfuels project, cement shortages should not be a serious problem.

Steel supplies, on the other hand, may be insufficient in certain regions because required resources such as iron ore, scrap, and coking coal are not widely distributed. However, steel can be shipped long distances without dramatically raising costs. For example, unfabricated structural shapes and plates (e.g., 1 beams) are valued today at approximately $25 per hundred pounds FOB

*Apparently, it is important for major employers to emphasize that they do not pay premium wages and salaries for large construction projects, but instead there are various special considerations. Whatever it is called, total worker remuneration appears to provide an abnormally large incentive.

29Bechtel's experience at nuclear powerplant sites in Michigan, Pennsylvania, and Arizona has demonstrated that a person with limited welding experience can be upgraded to "nuclear quality" in 6 to 12 weeks of intensive training. See Bechtel, "Production of Synthetic Liquids, " pp. 4-23. Actual training periods are influenced by various institutional factors. For further discussion of labor productivity see K. C. Kusterer, Labor Productivity in Heavy Construction: Impact on *Synfuels* Program Employment, Argonne National Laboratory, ANL/AA-24, U.S. Department of Energy.

The supply of people willing to work on large construction projects seems to be very price-elastic. In other words, large numbers of skilled or "able-and-willing-to-learn" workers will migrate to even remote construction sites if wage incentives exceed going rates elsewhere in the Nation by 20-30 percent. Although it is difficult to confirm this conclusion in published literature, it appears to be commonly held among university-based experts as well as in the construction industry, Information was obtained from private communications with J. D. Borcherding, Department of Civil Engineering, University of Texas in Austin; Richard Larew, Department of Civil Engineering, Ohio State University; John Racz, Synfuels Project Manager, Exxon USA in Houston; and Dan Mundy, Building Construction Trades Department, AFL-CIO, in Washington, D.C.

30As prescribed in the new United Mine Workers/Bituminous Operators Association contract, dated June 6, 1981, underground miners presently earn $10 to $11.76 per hour and surface miners $11.15 to $12.53. This compares with the national average wage in manufacturing of $7.80 and the average wage in construction of $9.90, both calculated for March 1981. See Monthly Labor Review, May 1981, p. 84, for additional wage data. The generalization, that labor supply has not been a serious problem, is a conclusion reached but stated only implicitly in an OTA report, *The* Direct Use of *Coal,* op. cit.

31 Information about the resource base and construction leadtimes obtained by private communication with Richard Whitaker, Director of Marketing and Economic Research, Portland Cement Association, Skokie, III,

(freight on board at the factory) and they are commonly shipped from Bethlehem, Pa., to Salt Lake City, Utah, for another $4 per hundred pounds. In other words, even if local production is insufficient to meet the needs of synfuels deployment, vast additional supplies from a national network of suppliers can be shipped into the area without driving up costs excessively .32

Final Comments

Despite OTA's conclusions that resource shortages other than engineering skills need not obstruct synfuels deployment, it does not follow that rapid synfuels deployment would not be inflationary for a broad range of resource inputs. Disregarding the prospect of Federal intervention to speed up deployment or to alleviate impacts, rapid deployment could cause bursts of inflation in an economy where certain suppliers have dominant market positions at least within regions, where skilled workers are reasonably well organized, and where people have grown accustomed to inflation. In such circumstances, it would be surprising if those with power to negotiate their revenues and incomes did not exercise it to their advantage when demand for their product and services is rapidly expanding.

Another caveat should also be made concerning the importation of processing equipment. If foreign suppliers compete successfully and become major suppliers of synfuels equipment, as they have already demonstrated in the Great Plains Gasification Project, rapid deployment could result in substantial foreign payments.[33] Depending on the general balance of payments picture, this could devalue the dollar in foreign exchange markets and thus increase the price of all imports into the United States. Perhaps offsetting this concern about balance of payments, the success of equipment imports may have a salutary effect on domestic producers by inducing them to improve their products and lower their costs.

Finance Capital and Inflation

In addition to potential shortages among resource inputs, the deployment of synfuels capacity may be restrained by the limited availability of financial capital. Such a limit has already been mentioned for small companies which cannot raise $2 billion to $3 billion and for any company trying to borrow at presently inflated interest rates.

Limits may also be imposed by financial markets that compare synfuels against all other types of investments. If synfuels projects are indeed unprofitable, the number of projects funded may be small or, if they are profitable, the number may be large. In this sense, a market-based synfuels deployment scenario should be self-correcting, with the lure of profits attracting new investment when expansion is warranted and the pain of losses driving investors away and thus curtailing deployment. Any of the previously discussed shortage possibilities, should they arise, will be perceived sooner or later by investors and the number of projects reduced as a result.

Whether or not deployment is by market incentives or Government policy, the adjustment and possible disruption of financial markets required by synfuels deployment can be discussed in terms of gross investment data. Assume that on the average, during its 5-year construction period, a $2.5-billion synfuels project requires $500 million in outlays annually. This compares with total private domestic investment in 1980 of about $395 billion, of which total about $294 billion went for nonfarm investments in new plant and equipment. Also in 1980, two large blocs of energy investments were $34 bilion for oil and gas exploration and production and $35 billion for gas and electric utilities.[34]

[32]Data obtained from American *Metal Market*, June 16, 1981, and from Bethlehem Steel, Washington Office. It should be noted that fabricated steel or steel which has been tailored to specific applications can cost as much as $75 per hundred pounds and hence ship ping costs may add much less to delivered costs (on a percentage basis).

[33]In this first major synfuels project, the Japanese low bid was substantially below apparent costs. Among other things, this indicates the competitive determination of at least one foreign supplier to capitalize on synfuels deployment. For related comments by U.S. Steel firms, see *Metals Daily*, Sept. 4, 1980; and the Chicago Tribune, Aug. 30, 1980. For a general analysis of the U.S. steel industry and its competition from abroad, see Technology *and Steel Industry* Competitiveness, OTA-M-122 (Washington, D. C.: U.S. Congress, Office of Technology Assessment, June 1980).

[34]All investment data except for oil and gas were obtained from the Survey of Current Business, Bureau of Economic Analysis, U.S. Department of Commerce, September 1981, pp. 9, S1. Oil and gas

In other words, 12 fossil synfuels plants under construction at the same time would account for about 18 percent of the 1980 investments for the production of petroleum and natural gas, about 17 percent of 1980 investments by electric utilities, or about 5 percent of the total investment in manufacturing. At this pace, assuming 5-year construction periods, approximately 2 MMB/D capacity could be installed over the next 20 years (the low scenario). Almost three times this many plants on the average must be under construction at one time, and about three times as much capital must be committed to achieve the goal of just under 6 MM B/D by 2000 (high scenario). In either case, this average would be achieved by means of a relatively gradual startup, as technologies are proven and experience is gained in construction, followed by a rapid buildup as all systems become routine.

The question remains: Can funding be reasonably expected for scenarios presented in this report? The answer depends on the future growth of GN P and the future value of liquid fuels relative to other fuels and to all other commodities. Without trying to predict the future, the question may be partially answered by showing that such a diversion of funds to energy applications has precedents in recent history.

From 1970 to 1978, investments in oil and gas grew at a rate of about 7.5 percent per year and investments in electric utilities grew at about 5 percent per year, both in constant dollars.[35] A glance back at synfuels requirements as fractions of existing energy investments shows that it would take only about 2.5 years of 7.5 percent growth in oil and gas investments or about 3.5 years of 5 percent growth in electric utility investments to provide sufficient incremental funds to support the low scenario, and about three times as many years of growth in each case to fund the high scenario.

In other words, another 5-year period of expansion in energy investments, similar to their growth in 1970-78 with oil and gas and electricity added together, could provide more than enough funds annually to reach the goal of about 6 MMB/D of synfuels by 2000 (high scenario), assuming that this higher level of investment were sustained for the next 20 years. Furthermore, if such rapid deployment were economically justified (i.e., other costs were rising sufficiently to make synfuels relatively low-cost options) there would be an economic incentive to divert funds to synfuels which had been devoted to conventional fuels.

Final Comments About Inflation and Synfuels

In an inflating economy, all price increments tend to be viewed as inflationary. However, this appearance obscures the fact that some price increases are necessary adjustments in relative prices in order to reduce consumption and to increase production. The latter will be true if synfuels place large, long-term, new demands on scarce human and material resources.

On the other hand, construction costs have grown faster than the general rate of inflation since the mid-1960's.[36] (See fig. 19.) Recently, the reverse has been true but there is reason to be concerned that rapid synfuels deployment could exacerbate what has been a serious inflationary problem. In any case, rising real costs of construction has been one of the major reasons why "current" estimates of synfuels costs have more or less kept pace with rising oil prices. (See ch. 6 for more detailed discussion.)

Finally, although most of this discussion has explored how synfuels deployment may aggravate inflation, the cause and effect could be reversed if deployment of first generation plants is too slow. That is, if the promise of synfuels remains

investment data were obtained from *Petroleum Industry Investments in* the 80's, Chase Manhatten Bank, October 1981. The total of $34 billion is broken down into $22 billion for service equipment, $6.3 billion for lease bonuses, and $3.1 billion for geological and geophysical data gathering.

35 Energy investment growth data obtained from *1978 Annual Report to Congress*, Energy Information Administration, p. 128.

36 Consumer Price Index obtained from 1980 U.S. Statistic/ Abstract, p. 476. Construction Cost Index obtained from Engineering News Record, McGraw Hill, Dec. 4, 1981, Market Trends Section. The actual data series published in this journal has been converted from a base year of 1916 to a base year of 1977. There are several construction cost indices published by reputable sources, but only the ENR was reproduced here because the data available to OTA suggest that all such series reflect more or less the same trends.

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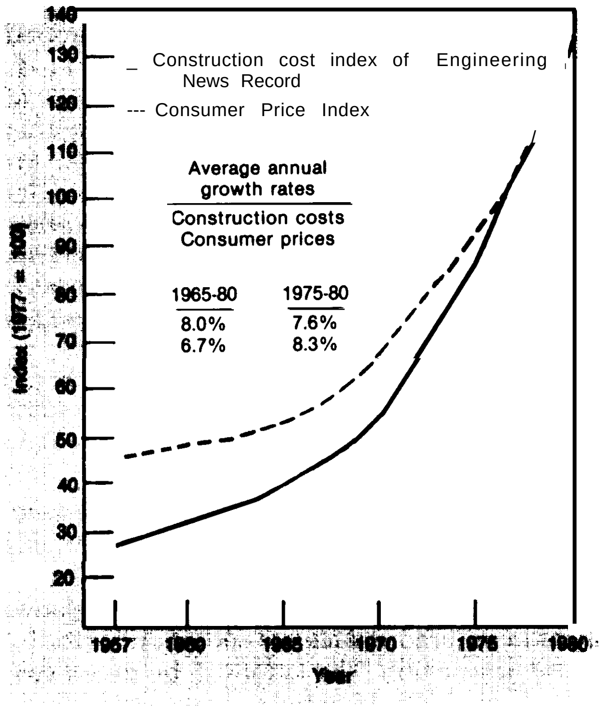
Figure 19.—Time Series Comparison: Construction Costs and Consumer Prices



SOURCE: U.S. Bureau of Labor Statistics, "Monthly Labor Review and Handbook of Labor Statistics," annual, and **"BM** and ID Investment Manual," ***Investment Engineering,*** sec. 1, part 6, item 614, pg. 1, Apr. 16, 1961.

in the distant future and conservation attempts are clearly insufficient to balance oil supply and demand worldwide, there will be no market-imposed lid on the price of oil and no reason to expect that sharp oil import price increases will not continue to destabilize domestic prices. In that case, the inflationary impacts of rapid deployment may appear to be much more acceptable.

Chapter 9

Social Effects and Impacts

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Social Effects and Impacts

INTRODUCTION

Increased automotive fuel efficiency and production of synthetic fuels will both give rise to a variety of social impacts. The impacts of increasing fuel efficiency will occur primarily as changes in employment conditions, while the impacts of producing synthetic fuels will be felt primarily in communities which experience rapid surges and declines in population as plants are built and begin to operate.

SOCIAL IMPACTS OF CHANGING AUTOMOTIVE TECHNOLOGY

Overview

The characteristics and uses of automobiles sold in the United States indicate that historically Americans have valued automobiles not only for personal transportation but also as objects of style, comfort, convenience, and power. Substantial increases in the costs of owning and operating automobiles that occurred during the 1970's, and that are expected in the future, are motivating consumers to change their attitudes and behavior in order to reduce spending on personal transportation. Some have purchased smaller, more fuel-efficient vehicles. Others have chosen to keep their present vehicles longer. Large numbers are simply driving less. Since January 1979, the combined subcompact and compact share of total sales has climbed from 44 to 61 percent, and gasoline consumption has declined 12 percent. About one-half to three-quarters of these fuel savings can be attributed to increased fuel efficiency of the automobile fleet.

Although about 12 percent of personal consumption expenditures has historically gone to automobile ownership and operation, rising costs may ultimately induce consumers to spend a smaller share of their budgets on automobiles or —at least—not to let that share increase. Recent increases in the small-car proportion of new-car sales suggest that consumers are prepared to trade cargo space and towing capability for high fuel economy and the prospect of relatively low operating costs. in the future, instead of buying vehicles designed for their most demanding transportation needs, people may buy small vehicles for daily use and rent larger vehicles for infrequent trips with several passengers, bulky or heavy cargo, or towing. The movement toward small cars is slowed by the tendency for people to retain cars longer than before. * Purchases of fuel-efficient vehicles and ownership of several vehicles, each suited for different transportation needs, would be facilitated by improved economic conditions.

Ridesharing and mass transit use have become more common and could increase further. Since the 1973-74 oil embargo public transit ridership has increased 25 percent.[1] Ridesharing and transit use are limited by the dispersion of residences and jobs, and, for transit, by the adequacy and availability of facilities. Mass transit capacity is limited during peak commuting periods and often is unavailable or scheduled infrequently in areas outside of central cities.

It should be noted that low-income people are likely to have the fewest options for adjusting to rising automobile costs. People with low incomes already tend to own fewer vehicles, have relatively old vehicles (which were typically bought used), travel less, and share rides or use public transit more than the affluent.

Consumers are likely to respond differently to electric vehicles (EVs) and small conventionally

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*Thirty-five percent of private vehicles were over 5 years old in 1969, 51 percent were over 5 years old in 1978.

‘American Public Transit Association.

powered cars (using internal combustion engines) because of different cost, range, and refueling attributes (see table 64). The conventionally powered car would have two significant advantages over an EV: unlimited range (with refueling) and substantially lower first cost. The EV, on the other hand, would offer the advantage of being powered by a secure source of energy (electricity) and therefore assure mobility in the event of disruption of gasoline supplies. It is not clear how the consumer would weigh these two options, although the degree to which EV manufacturers can reduce the cost differential is certain to be very important.

Employment

In 1980, the Bureau of Labor Statistics estimated that there were fewer than 800,000 people employed in primary automobile manufacturing and automotive parts and accessories manufacturing. This compares with employment levels over 900,000 during the peak automobile production period, 1978-79.[2] These figures, however, present an incomplete picture of employment. Although the Bureau of the Census counts employees in industries producing various primary products, it does not identify how many workers contribute to intermediate products used in automobiles or other finished goods. Thousands of automotive people perform work in support of automobile manufacturing within industries otherwise classified—producing, for example, glass vehicular lighting, ignition systems, storage batteries, and valves. Thus, the Department of Transportation estimated that during 1978 to 1979 about 1.4 million people were employed by auto suppliers overall.[3]

Historically, the growing but cyclical nature of the auto market resulted in a pattern of periodic growth and decline in auto-related employment (see table 65). Current and projected trends for strong import sales, decline in the growth rate of the U.S. auto market, increased use of foreign suppliers and production facilities, and adoption of more capital-intensive production processes and more efficient management by auto manufacturers and suppliers will contribute to a general decline in auto industry employment.

Specific changes in employment will depend on the number of plants closed or operating un-

[2] Bureau of Labor Statistics, Current Employment Statistics Program data.

[3] U. S. Department of Transportation, *The U.S. Automobile Industry*, 1980: *Report* to the President from the Secretary of Transportation (Washington, D.C: Department of Transportation, January 1981).

Table 64.—initial and Lifecycle Costs of Representative Four-Passenger Electric Cars

	Near term					Advanced		
	Pb-Acid	Ni-Fe	Ni-Zn	Zn-CL_2	(ICE)	Zn-CL_2	Li-MS	(ICE)
Initial cost, dollars	8,520	8,400	8,130	8,120	4,740	7,050	6,810	5,140
Vehicle	6,660	5,950	5,720	5,540	4,740	5,410	5,180	5,140
Battery	1,860	2,450	2,410	2,580	—	1,640	1,630	—
Lifecycle cost, cents per mile	23.9	24.9	26.6	22.0	21.4	19.4	20.1	21.8
Vehicle	5.0	4.5	4.3	4.2	4.3	4.1	3.9	4.7
Battery	3.0	4.8	7.0	2.3	—	1.4	2.6	—
Repairs and maintenance	1.5	1.5	1.5	1.5	3.9	1.5	1.5	3.9
Replacement tires	0.6	0.5	0.5	0.5	0.4	0.4	0.4	0.4
Insurance	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Garaging, parking, tolls, etc.	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Title, license, registration, etc.	0.7	0.6	0.6	0.6	0.6	0.5	0.5	0.5
Electricity	2.3	2.2	2.0	2.2	—	1.7	1.5	—
Fuel and oil	—	—	—	—	4.0	—	—	3.7
Cost of capital	5.5	5.5	5.4	5.4	3.0	4.5	4.4	3.3

NOTE: All costs are In mid-1980 dollars.

Assumptions:

Electricity price	S0.03 per kilowatt-hour
Gasoline price	$1.25 per gallon
Electric vehicle life	12 years
Internal combustion engines vehicle life	10 years
Annual travel	10,000 miles
Car end battery salvage value	10 percent
Cost of capital	10 percent per year

Car and battery purchases are 100 percent financed over their useful lives.
Electricity cost includes a road use tax equal to that paid by typical gasoline vehicles of equal weight via State and Federal gasoline taxes.

SOURCE: General Research Corp. Cost categories and many entries, such as tires, Insurance, garaging, etc., are based on periodic cost analyses by the Department of Transportation (see footnote 13). All costs shown were computed by the Electric Vehicle Weight and Cost Model (EVWAC) (see footnote 14).

Table 65.—Auto Industry Employment Data

Year	(1) Average annual unemployment rate in the motor vehicle industry SIC 371 (percent)	(2) Average annual employment in primary auto manufacturing and parts and accessories manufacturing, SIC 3711 and SIC 3714 (000)
1970. . . .	7.0	733.4
1971	5.1	781.3
1972	4.4	798.2
1973. . . .	2.4	891.5
1974	9.3	818.9
1975. . . .	16.0	727.8
1976. . . .	6.0	814.9
1977	3.9	869.5
1978. . . .	4.1	921.7
1979. . . .	7.4	908.6
1980	20.3	775.6

SOURCE Column 1 data are from the Bureau of Labor Statistics, household sample survey Column 2 data are from the Bureau of Labor Statistics establishment survey, Data in the two columns are not directly comparable. "SIC" refers to "Standard Industrial Classification."

der capacity, the capacity of the plants, and the degree to which production at affected plants is labor-intensive. The long-term effects on workers depend on personal characteristics such as skills (many production workers have few transferable skills), the levels of local and national unemployment, information about job opportunities, and personal mobility (greatest for the young, the skilled, and those with some money).

The Department of Transportation estimates that each unemployed autoworker costs Federal and State Governments almost $15,000 per year in transfer payments and lost tax revenues. This estimate implies, for example, that if 100,000 to 500,000 manufacturer and supplier workers are unemployed for a year their cost to government is about $1.5 billion to $7.5 billion. During 1980, payments to unemployed workers of General Motors (GM), Ford, and Chrysler in Michigan included about $380 million in unemployment insurance, $100 million in extended benefits, and $800 million in "trade adjustment assistance" (provided by a program established in the Trade Expansion Act of 1962 and modified by the Trade Act of 1974).[4]

Growing use of labor-saving machinery by auto manufacturers and major suppliers to implement complex technologies, cut costs, and improve product quality is reducing job opportunities in the auto industry. GM, for example, expects to invest almost $1 billion by 1990 for 13,000 new robots for automobile assembly and painting and parts handling. A new robotic clamping and welding system developed by GM and Robogate Systems, Inc., will enable GM to reduce labor costs for welding by about 70 percent, improve welding consistency, and reduce vibration and rattling in finished automobiles. s

MacLennan and O'Donnell, analysts at DOT, have calculated that today's new and refurbished plants can assemble 70 cars/hour with an average employment level of 4,500, while older plants typically produce 45 to 60 cars/hour using about 5,400 workers. Such plant modernization implies that three fewer assembly plants and 23,000 fewer workers are needed to assemble 2 million cars annually.[6] The United Auto Workers estimates that labor requirements in auto assembly, which has been a relatively labor-intensive aspect of auto manufacture, will be reduced by up to 50 percent by 1990 through the use of robots and other forms of automation. '

Foreign-designed automobiles manufactured in the United States also provide jobs. Current and anticipated local production by foreign firms (only Volkswagen (VW) to date) largely involves vehicle assembly, using primarily imported components and parts. VW's Pennsylvania plant employs 7,500 workers to assemble over 200,000 cars and contributes to about 15,000 domestic supplier jobs;[8] a comparably sized domestic--owned plant would support a total of about 35,000 domestic jobs. New U.S. manufacturing and supplier jobs will grow with local production and purchasing from U.S. suppliers by foreign firms in proportion to the amount of local production content in the automobiles. The planned increase in local content for Rabbits made here by VW—from 70 percent in model

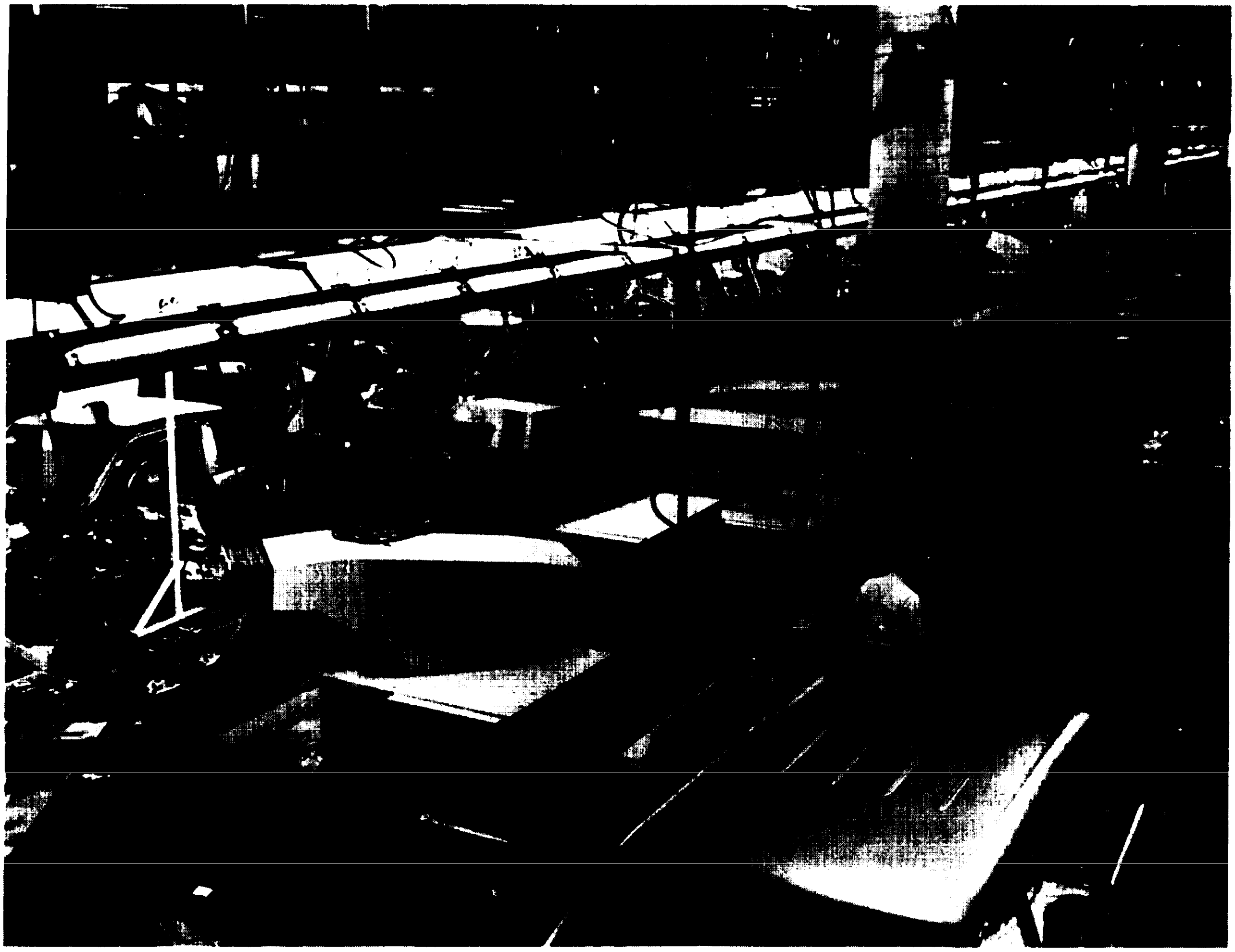
[4]Michigan Employment Security Commission, personal communication.

[5]"GM's Ambitious Plans to Employ Robots, " Business Week, Mar. 16, 1981.

[6]Carol MacLennan and John O' Donnell, "The Effects of the Automotive Transition on Employment: A Plant and Community Study" (Washington, D.C: U.S. Department of Transportation, December 1980).

[7]*Business* Week, op. cit.

[8]Department of Transportation, op. cit.



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year 1981 to 74 percent in model year 1983–implies more work in the United States.[9]

The Departments of Labor and Transportation estimate that there are between one and two supplier jobs overall for each primary auto manufacturing job.[10] Change in supplier employment associated with declining manufacturing employment is uncertain, and will depend on the nature of the supplied product, how it is made, and the amount that auto manufacturers buy. While some supplier jobs, like auto manufacturing jobs, depenal on production volume, other supplier jobs (e.g., in machine tool manufacture and plastics processing) are tied to the implementation of new technology. Trends toward foreign sourcing and vehicle production and automation among suppliers suggest that supplier employment overall will decline.

Steel and rubber industry jobs are especially vulnerable to automotive weight and volume reductions. Many of these supplier jobs have already been lost with automotive weight reductions during the 1970's. For example, MacLennan and O' Donnell estimate that reduced automotive use of iron and steel in 1975 to 1980 led to a permanent loss of 20,000 jobs, a loss only

[9] "VW Projects Increases in U.S. Content," *Ward's* Automotive Reports, May 27, 1981.

[10] MacLennan and O'Donnell, Op. cit.

partially offset by a gain of 8,000 jobs in processing plastics and aluminum for automotive use.[11] During the same period, employment in the tire and rubber industry declined at a compound annual rate of 4.1 percent.[12]

Jobs with parts and component manufacturers are also relatively vulnerable, although, again, many have already been lost. Mac Lennan and O'Donnell estimate that the closing of almost 100 materials, parts, and component plants in 1979 to 1980 eliminated over 80,000 supplier jobs.[13] Because of the predominance of small firms among auto suppliers, near-term supplier job losses may occur incrementally.

Automobile importation supports some domestic jobs and results in the loss of others. There are over 125,000 people employed by importers, primarily in dealerships.[14] Growth in import-related employment stems from increases in the number and market shares of importers, in the number of dealerships per importer, and in employment per dealership. On the other hand, imports cause loss of industrial jobs. DOT estimates that loss of 100,000 vehicle sales to imports results in the loss of about 8,500 primary manufacturing and 13,000 to 16,000 supplier jobs.[15] This implies, for example, that the almost 400,000-unit increase in import sales in 1978 to 1980 caused a loss of 34,000 jobs in automobile manufacturing and up to 64,000 supplier jobs.

Employment in automotive services, including repair, parking, renting and leasing, washing, and other services (Standard Industrial Classification 75) grew at a compound annual rate of 5.7 percent in 1975 to 1980 to a total level of almost 540,000 people, according to the Department of Commerce.[16] Employment in these areas is expected to continue to grow.

Occupational and Regional Issues

Improvements in automotive technology cause changes in the skills required for production jobs. Major design and technology changes increase demands for engineers, who have been in short supply, while cost-cutting strategies eliminate other white-collar positions. GM, for example, eliminated about 10,000 white-collar jobs beginning in 1980 to save about $300 million, and may eliminate up to 20,000 more.[17] Automation reduces the number of routine and hazardous tasks, while increasing equipment maintenance and service tasks. GM, for example, plans to have equal numbers of skilled and unskilled workers by the 1990's, although it presently has one skilled worker for each five to six unskilled workers.[18]

Auto production jobs are concentrated in Michigan, Ohio, Indiana, New York, and Illinois (see fig. 20). The geographic distribution of auto-related jobs is likely to change somewhat for several reasons. First, some nontraditional auto suppliers are located away from traditional areas of auto production. Major plastics-producing States, for example, include California, New Jersey, and Texas as well as Ohio and Illinois. Furthermore, many of today's suppliers are located abroad and many U.S. suppliers are opening plants abroad. Second, foreign or domestic firms may establish production facilities outside of the East-North Central area to gain lower labor and utility costs, For example, Nissan chose to build a plant in Tennessee. Third, domestic firms are closing inefficient and unneeded plants. Table 66 summarizes the factors considered in locating parts-supplier plants.

Automotive plant closings primarily affect employment in the East-North Central region, because automobile production is concentrated there. Ongoing and future losses of automobile-related employment in this region are largely a reflection of the structural changes in the auto industry described earlier in this chapter, although there will continue to be cyclical changes

11 Ibid.

12 U.S. Department of commerce, *1981 U.S. Industrial Outlook* (Washington, D.C: Department of Commerce, 1981).

13 Mac Len nan and O' Donnell, Op. cit.

14 Patricia Hinsberg, "Study Finds Imports Create U.S. Jobs," *Automotive News*, Aug. 20, 1979.

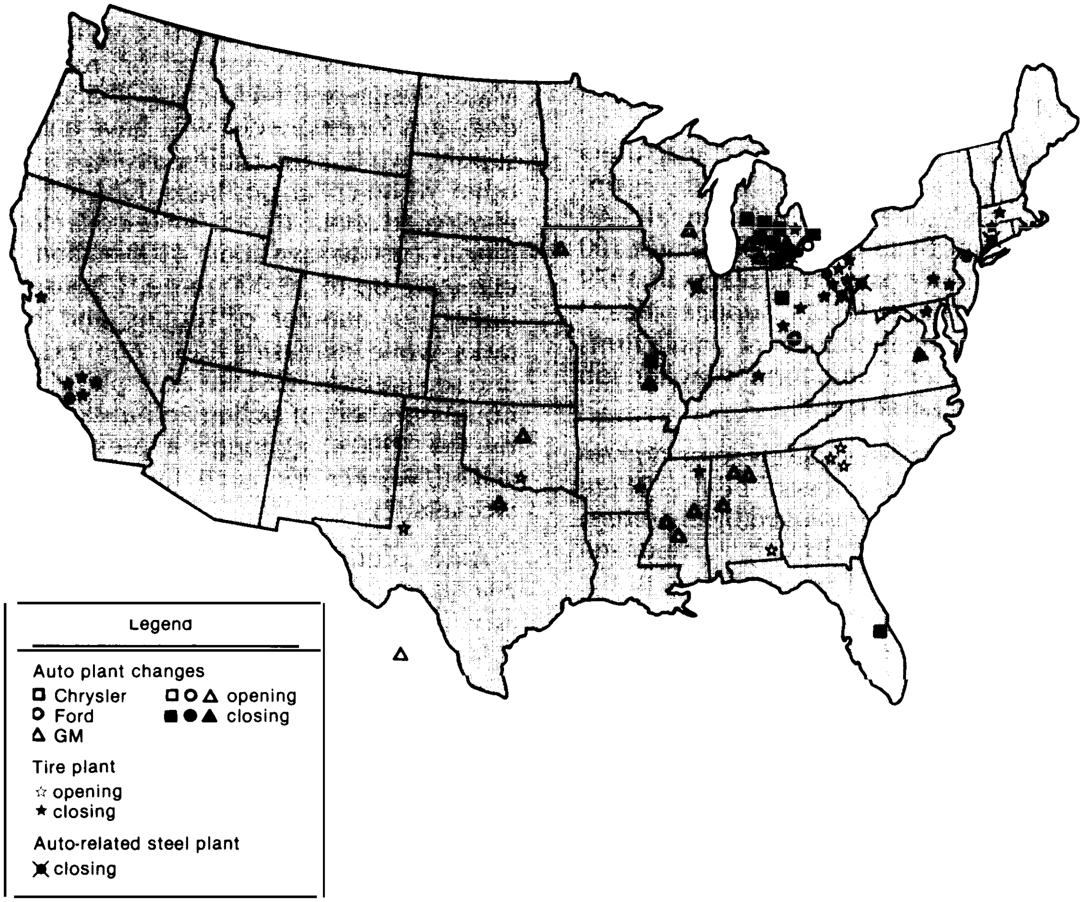
15 Department of Transportation, op. cit.

16 Department of Commerce, op. cit.

17 "GM May Chop Another 19,000 Salaried jobs," Automotive News, Mar. 2, 1981.

18 *Wall Street Journal*, January 1981.

Figure 20.–Auto, Steel, and Tire Plant Changes, 1975=80



SOURCE: U.S. Department of Transportation, "The U.S. Automobile industry, 1980," DOT-P-1 O-81-O2, p. xviii, January 1981.

Table 66.—Factors to Consider in Locating Parts-Supplier Plants

Factor	Relative ranking 1970's	1980's
Availability and cost of skilled labor		1
Availability and cost of energy	2;	2
State and local taxes, incentives	3	3
Availability and cost of raw materials . . .	2	4
Work ethic of area	4	5
State and local permits, regulations	5	6
Worker's compensation insurance	7	7
Availability and cost of capital	7	8
Right-to-work state (union relations)	6	9
Freight costs	10	10
Quality of living environment	8	11
Community attitude ., ...	9	11
Customer service	12	11
Available land	11	12

SOURCE: Arthur Andersen & Co. and the Michigan Manufacturer Association, ***Worldwide Competitiveness of the*** U.S. ***Automotive*** Industry ***and Its*** Parts Suppliers ***During*** the ***1980s,*** **February** 1981.

in automobile-related employment. Because of local and regional employment dependence on one industry—motor vehicles—other businesses (such as retail and service establishments) and their employment also suffer as employment in the local population declines.

Unemployment and out-migration will jeopardize other businesses and strain local tax bases, and Michigan will be especially vulnerable. Loss of employment, population, and business recently induced Moody's Investers Service, Inc., to lower bond ratings for Akron, Ohio, which has depended on the tire and rubber industry for its economic vitality; bond ratings for other auto-dependent cities have also been lowered.

Photo credit: Michigan Employment Security Commission

Shifts in plant location associated with investments in fuel efficiency may create unemployment problems in traditional manufacturing centers

SOCIAL IMPACTS OF SYNFUELS DEVELOPMENT

Overview

The principal social consequences of developing a synthetic fuels industry arise from large and rapid population increases and fluctuations caused by the changing needs of industry for employees during a facility's useful life. Such population changes disproportionately affect small, rural communities that have limited capacity to absorb and manage the scale of growth involved; these types of communities characterize the locations where oil shale and many coal deposits are found.

In general, whether the consequences of growth from synfuels development will be beneficial or adverse will depend on the ability of communities to manage the stresses which accompany rapid change. Although impacts can be generally characterized, the extent and nature of their occurrence will be site-specific depending on both community factors (size, location, tax base) and technology-related factors (the location, size, number, and type of synfuels facilities; the rate and timing of development; and associated labor requirements).

Growth will tend to concentrate in established communities where services are already available, if they are within commuting distance to synfuels facilities. New towns may be established to accommodate growth in some areas. Large towns will serve as regional service centers. Isolated communities will more likely experience greater impacts than areas where well-linked communities can share the population influx. Energy conversion facilities which are sited near mines will result in the greatest concentration of local impacts.

Most synfuels production from oil shale in the Nation will be concentrated in four Western counties, affecting about a dozen communities in sparsely populated areas of northwestern Colorado and northeastern Utah, and eventually southwestern Wyoming. These communities are widely separated, are connected by a skeletal transportation network, and have had historically small populations. Oil shale cannot be economically transported offsite because of the large quantities of shale involved per barrel of product.

Coal presents a more flexible set of options than oil shale with respect to the location of conversion facilities in relation to mines. The coal used for synfuels production will most likely be dispersed among all the Nation's major coal regions.

In the West, coal sites will be in the oil shale States (Colorado, Utah, and Wyoming) as well as in Montana, North Dakota, and New Mexico. Most of the increase in Western coal production for synfuels will be in Wyoming and Montana.[19] Midwestern sites will most likely be in Illinois, western Kentucky, and Indiana. The coal counties to be most severely affected in Appalachia will be in rural parts of southwestern Pennsylvania, southern West Virginia, and eastern Kentucky. Parts of Illinois will also be affected. In central Appalachia, communities are typically small, congested, and in rural mountain valleys.

The major differences between the Eastern and Western coalfields, in general, are that in the West, counties are larger, towns are smaller and more scattered, the economic base is more diversified, more land is under Federal jurisdiction, water is relatively more scarce, and the terrain is less rugged and variable. To the extent that coal is transported, there could be additional environmental and safety hazards, noise, and disruption or fragmentation of communities, farms, and ranch lands.

The social consequences of producing synthetic fuels from biomass are discussed in detail in a previous OTA report, *Energy From Biological Processes*. Unlike the social consequences associated with fossil fuels, the social impacts of biomass arise from production rather than processing. For example, 90 percent of the employment impacts from biomass are expected from cultivation and harvesting (mostly forestry).

Manpower Requirements

Manpower requirements for synfuels production are generally of two types: 1) labor is required for the construction of energy facilities and supporting service infrastructures, and 2) workers are needed for the operation and maintenance of facilities. As discussed in chapter 8, the ability to attract and retain an adequate labor force—particularly experienced chemical engineers and skilled craftsmen, who are already in short supply—could become a constraint on synfuels development.

Construction manpower requirements for single projects lead to large, rapid, yet temporary, increases in the local population. The construction phase usually lasts 4 to 6 years, peaking over a 2- to 4-year period as construction activities near completion.[20] The shorter the scheduled construction period, the higher the peak labor force.[21] Labor requirements will change significantly during the construction phase, in terms of both size and occupational mix. Labor requirements for the daily, routine operation and maintenance of a plant are relatively stable during the useful life of the facility; scheduled yearly and major maintenance work would cause only brief increases in the operations labor force.

Estimates of manpower requirements for generic 50,000 barrel per day (bbl/d) synthetic fuel

[19] E. J. Bentz & Associates, Inc., "Selected Technical and Economic Comparisons of Synfuel Options," contractor report to OTA, April 1981.

[20] Ibid.

[21] peter D. Miller, "stability, Diversity, and Equity: A Comparison of Coal, Oil Shale, and Synfuels," in Supporting Paper *5:* Socio-political Effects of Energy Use and Policy, CONAES, Washington, D. C., 1979.

plants are shown in table 67. They are highly uncertain, in large part because of the lack of experience with commercial-size plants. In addition, major components of uncertainty in the construction manpower estimates include such unpredictable situations as regulatory delays, lawsuits, delays in the receipt of materials, labor unrest, and the weather; and major components of uncertainty in the estimates of operations manpower relate to the age of the plant, maturity of the technology, and novelty of the plant design.

Even for well-known technologies such as coal-fueled electric powerplants, initial estimates of the peak construction labor force required for selected rural-sited plants have varied from about 50 to 270 percent of the actual peak levels.[22] This range of uncertainty may be applicable to the estimates of construction manpower requirements for synfuels plants in general, but should prove to be overly broad when considering a specific technology. The uncertainty surrounding requirements for operational manpower is expected to be narrower, perhaps on the order of + 25 percent.[23]

The estimates shown in table 67 are plant-gate employment requirements; other synfuels-related activities such as mining, beneficiation, and transportation are not included unless indicated. The manpower requirements for these additional activities will be site-specific and could alter the relative ordering of alternative technologies. For example, on the national average, production per miner per day is approximately three times greater in surface mines than in underground mines. This ratio can be expected to vary, depending on many factors including types of methods and equipment used and geology for underground mining, and geology and environmental considerations for surface mining.[24]

Population Growth

Local population will grow where synfuels are produced because workers directly employed at the synfuels plants, employees in secondary industries and services, and accompanying families will move into these areas. Population growth rates will depend on the nature of the area where the plant is located and on the phase of plant development.

Estimates of population growth due to synfuels development usually assume that for each new worker entering an area, the population increases between three and five persons.[25] The demand

[22] John S. Gilmore, "Socioeconomic Impact Management: Are Impact Assessments Good Enough to Help?" paper presented at the Conference on Computer Models and Forecasting Impacts of Growth and Development, University of Alberta, Jasper Park Lodge, Alberta, Apr. 21, 1980 (revised June 1980).

[23] George Wang, Bechtel Group, Inc., personal communication.

[24] The average national production per miner per day was 8.38 tons in underground mines and 25.78 tons in surface mines for bituminous and lignite in 1978. Nationwide, productivity varied: for underground mining, from approximately 2 to 15 average tons per miner per day and, for surface mining, from approximately 7 to 98 average tons per miner per day. (Department of Energy, Energy Information Administration, Bituminous *Coal* and Lignite Production and Mine Operations— 1978, Energy Data Report, June 16, 1980.)

[25] As an example, White, et al., use a population/employment multiplier of 3.0 for the construction phase and 4.0 for the operation phase (Energy From *the West,* Science and Public Policy Program, University of Oklahoma, prepared for the Environmental Protection Agency, March 1979). Miller uses a uniform "conservative" population/employ merit multiplier of 5.o (see footnote 21 above).

Table 67.—Manpower Requirements for a 50,000 bbl/d Generic Synfuels Plant

	Liquefaction			
	Direct	Indirect	Coal gases	Oil shale
Total construction (person-years)	11,000	20,000	11,000	11,000 [a]
Peak construction (persons)	3,500	6,800 [b]	3,800	3,500 [a]
Operations and maintenance (persons)	360 [c]	360 [c]	360 [c]	2,000 [e]
	2,300 [d]	3,800 [d]	1 ,200 [d]	

[a] Surface retorting will generally have higher construction manpower requirements than modified in-Situ Processes.
[b] Manpower requirements of 17,000 persons have been projected by Fluor Corp. based on a SASOL tYPe coal conversion plant ("A Fluor Perspective on Synthetic Liquids: Their Potential and Problems").
[c] Daily, routine O&M requirments (E. J. Bentz & Associates, Inc., "Selected Technical and Economic Comparisons of Synfuels Options," April 1981).
[d] Annual aggregation of scheduled yearly and major maintenance work. Technology specific (Bechtel National, Inc., "production of Synthetic Liquids From Coal: 19S0-2000," December 1979).
[e] coil shale requirements include mining. Modified in-situ (MIS) processes will generally have higher O&M requirements than surface retorting (e.g., MIS Involves an ongoing mining process).

SOURCE: Office of Technology Assessment

for support services in nearby communities increases with the absolute size of the work force during the peak construction period. The larger the work force required during peak construction relative to that required for operations and maintenance, the greater the likelihood that nearby communities will experience large population fluctuations.

In general, if several facilities are located in the same area, the impacts from population growth and fluctuation could be disproportionately large unless construction and operation activities are coordinated; on the other hand, population growth associated with construction can be stabilized if an indigenous construction work force develops. *

Estimates of population increases associated with the fossil synfuels development scenarios presented in chapter 6 are shown in table 68. On a regional basis, population growth associated with oil shale will be concentrated in only several counties in the Mountain Region (see fig. 21). population increases associated with coal-based synfuels will be dispersed throughout the Nation, with the East North Central experiencing the biggest population increases and the West South Central experiencing the smallest population increases.

Table 69 shows energy-related population growth during the last decade in selected communities. In small communities, and in sparsely populated counties and States, energy-related population growth could represent a significant proportion of future population growth. For example, official population projections by the Colorado West Area Council of Governments (CWACOG) show increases by 1985, relative to 1977, of up to 400 percent in Rio Blanco County (1977 special census population was 5,100) and 300 percent in Garfield County (1 977 special census population was 18,800), assuming the industry develops according to the 1979 plans of companies active in the area.

*A succession of projects in an area should lead to an indigenous and more stable construction manpower work force, depending on whether workers perceive a permanence of industrial expansion in the area. Some proportion of the construction work force may also be employed in operations and maintenance activities once construction is completed.

Table 68.—Estimates of Regional Population Growth Associated With Fossil Synfuels Development [a] (thousands)

	1990	1995	2000
Low estimate:			
South Atlantic	4-6	12-20	30-51
East North Central	14-24	46-76	115-192
East South Central	5-9	17-28	42-71
West North Central	5-9	17-28	42-71
West South Central	2-3	6-10	15-25
Mountain:			
Coal	7-12	23-38	58-96
Shale	66-110	90-150	81-135
Total	103-173	211-350	383-641
High estimate:			
South Atlantic	11-18	33-55	86-144
East North Central	33-56	105-174	275-458
East South Central	11-18	33-55	86-144
West North Central	17-29	54-90	141-235
West South Central	5-8	15-25	39-65
Mountain:			
Coal	19-32	60-100	122-203
Shale	132-220	213-355	108-180
Total	228-381	513-854	857-1,429

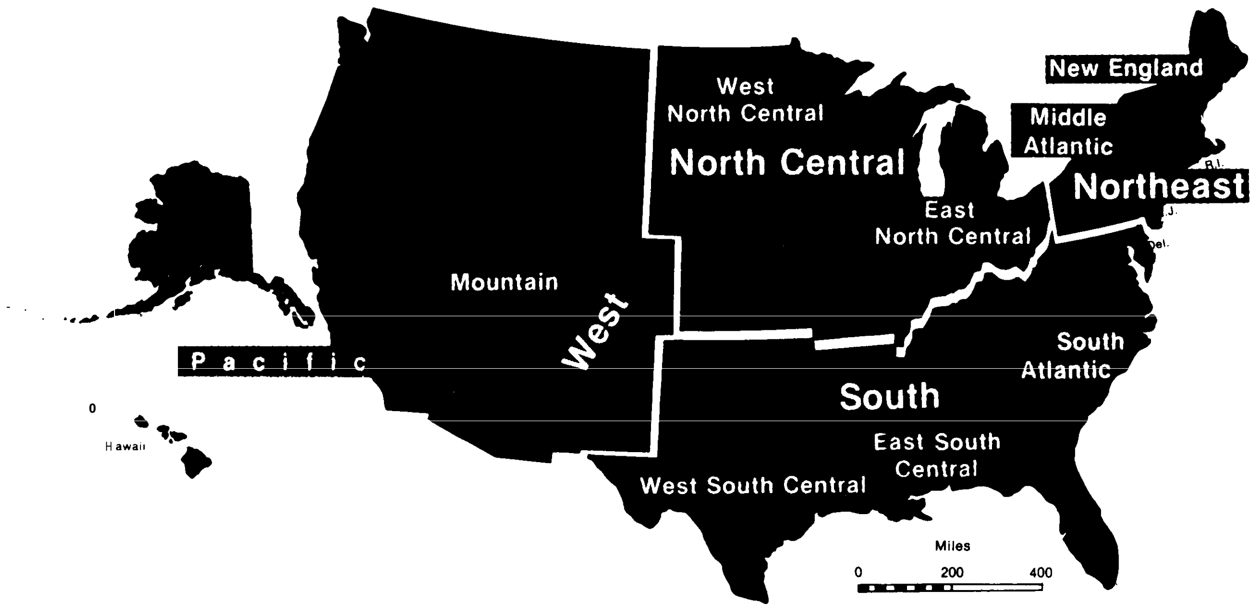
[a]Estimate are relative to 1985 (for plants coming online in the Year shown) and are based on OTA's development scenarios presented in ch. 8. Population multipliers of 3 and 5 were applied to develop the ranges shown. Aggregated estimates should not be extrapolated to determine the ability of any State or localitv. to absorb this population.
[b]Production is distributed among the regions, according to the low and high scenario distributions used In the Bechtel report for, respectively, the low and high scenarios developed herein (Bechtel National, Inc., December 1979). It is further assumed that direct and indirect liquids will be representad equally. Only dally, routine O&M requirements are included.
Regional estimates are for coal processes unless other wise indicated.

SOURCE: Office of Technology Assessment.

Under CWACOG's high-growth scenario (500,000 bbl/d in 1990 and 750,000 bbl/d in 1995 and 2000), increases of up to 800 percent in Rio Blanco County and 350 percent in Garfield County are projected.[26] In three counties in Kentucky where the construction of four major synfuels plants had recently been planned to commence (H-Coal, SRC-1, W. R. Grace, and Texas Eastern), the expected maximum number of synfuels workers (excluding accompanying family members) was projected to increase 1980 population levels by about 3 percent in Daviess County (1 980 census population was 86,000) to over 30 percent in Breckinridge County (1980 census population was 17,000) and over 50 percent in Henderson County (1980 census population was 41 ,000); population increases during the operation phase

[26]*An Assessment of Oil Shale Technologies*, OTA-M-118 (Washington, D. C.: U.S. Congress, Office of Technology Assessment, June 1980).

Figure 21 .—Census Regions and Geographic Divisions of the United States



SOURCE: U.S. Department of Commerce, Bureau of the Census.

Table 69.–Population Growth in Selected Communities, 1970-80

State	City	Energy resource impact [a]	Population [b] 1970	Population [b] 1980	Percent increase Total	Percent increase Average annual (compounded)
West Virginia	Buckhannon, Upshur County (Union District)	coal	248	587	136.7	9.0
Kentucky	Caseyville, Union County	coal			87.0	6.5
Utah	Huntington, Emergy County	coal, powerplant	857	2,316	170.2	10.5
	Orangeville, Emery County	coal, powerplant	511	1,309	156.2	9.9
	Helper, Carbon County	coal	1,964	2,724	38.7	3.3
Wyoming	Douglas, Converse County	coal, uranium, oil, gas	2,677	6,030	125.3	8.5
	Gillette, Campbell County	coal	7,194	12,134	68.7	5.4
	Rocksprings, Sweetwater County	coal, oil, gas, trona, powerplant, uranium	11,657	19,458	66.9	5.3
North Dakota	Washburn, McLean County	coal, powerplant	804	1,767	119.8	8.2
	Beulah, Mercer County	coal, powerplant	1,344	2,878	114.1	7.9
Montana	Forsyth, Rosebud County	coal, powerplant	1,873	2,553	36.3	3.2
	Hardin, Big Horn County	coal	2,733	3,300	20.7	1.9
	Colstrip, Rosebud County [c]	coal, powerplant	<200	3,500	1,650.0	33.1
Colorado	Craig, Moffat County	coal, powerplant	4,205	8,133	93.4	6.8
	Rifle, Garfield County	oil shale, minerals, coal	2,150	3,215	49.5	4.1
	Hayden, Routt County	coal, powerplant	763	1,720	125.4	8.5

[a] Identified by the Department of community Development within the respective States.
[b] Bureau of the Census, *1980 Census* of Population and Housing, *Advance Reports*.
[c] Estimates by Sunlight Development, Inc.

SOURCE: Office of Technology Assessment.

were projected to be respectively 0.4, 4, and 15 percent (excluding accompanying family members).[27] Table 70 shows statewide population estimates, based on an extrapolation of only demographic trends, for some of the States that are most likely to experience population increases from synfuels development.

Small rural communities (under 10,000 residents) that experience high population growth rates are vulnerable to institutional breakdowns. Such breakdowns could occur in the labor market, housing market, local business activities, public services, and systems for planning and financing public facilities. Symptoms of social stress (such as crime, divorce, child abuse, alcoholism, and suicide) can be expected to increase.

The term "modern boomtown" has been used to describe communities that experience strains on their social and institutional structure from sudden increases and fluctuations in the population. Communities are also concerned about the possibility of a subsequent "bust." Large fluctuations in population size could lead to a situation where a community expands services at one point in time only to have such services underutilized in the future if demands fail to materialize or be sustained.

[27] C. Gilmore Dutton, "Synfuel Plants and Local Government Fiscal Issues, " memorandum to the Interim Joint Committee on Appropriations and Revenue, Frankfort, Ky., Dec. 18, 1980.

Private Sector Impacts

The principal social gains from synfuels development in the private sector are increased wages and profits; direct and secondary employment opportunities will be created and expanded; disposable income will increase; profits from energy investments should be realized; and local trade and service sectors will be stimulated. The ability of the private sector to absorb growth will depend, in large part, on the degree of economic diversification already present. Western communities, in general, have more diversified economies and broader service bases than those in the East, where many communities (as in central Appalachia) have historically been economically dependent on coal.

Many private sector benefits, however, will not be distributed to local communities, at least during the early periods of rapid growth. For example, synfuels development would be located in areas where the required manpower skills are already scarce; unemployment in local communities may thus not be significantly lowered unless local populations can be suitably trained. Where synfuels development competes with other sectors for scarce labor, fuel and material inputs, and capital resources, traditional activities may be curtailed and the price of the scarce resources inflated. Local retail trade and service industries may experience difficulties in providing and expanding services to keep pace with demands, re-

Table 70.—Statewide Population Estimates

State	Total State population 1980[a] (millions)	Statewide population percent increase 1970-80		Projected State population 2000[b]	
		Total	Annual compounded	1990	2000
Kentucky	3.66	13.7	1.3	4.08	4.43
West Virginia.	1.95	11.8	1.1	2.08	2.20
Colorado	2.89	30.7	2.7	3.50	4.00
Montana.	0.79	13.3	1.3	0.90	0.98
North Dakota.	0.65	5.6	0.5	0.70	0.73
Wyoming	0.47	41.6	3.5	0.54	0.60
Utah	1.46	37.9	3.3	1,73	1.95

[a] Bureau of the Census, *1980 Census* of Population and Housing, Advanced *Reports.*
[b] Bureau of the census, *Illustrative* Projections of State Populations by Age, Race, and Sex: *1975 to 2000.* Projected estimates are from Series II-B which assumes a continuation from 1975 through 2000 of the civilian non-college interstate migration patterns by age, race, and sex observed for the 1970-75 period. Has been corrected by the percent difference between the 1980 projections and the 19S0 census. Note that these projections are extensions of recent trends with respect to demographic factors only.

SOURCE: Office of Technology Assessment.

cruiting and retaining employees, and competing with out-of-State concerns. Both the Eastern and western sites for synfuels development have generally depended on imported capital, and profits to and reinvestments of the energy companies are likely to be distributed to locations remote from plant sites.

High local inflation rates often accompany rapid growth, due to both excess demand for goods and services and high industrial wage rates. Local inflation penalizes those whose wages are independent of energy development and those on fixed incomes.[28]

Housing can be a major problem for the private sector in areas that grow rapidly from synfuels development: the existing housing stock is usually already in short supply and often of poor quality; local builders often lack the experience and capability to undertake projects of the large scale required; shortages of construction financing and mortgage money are common; and land may not be available for new construction because of terrain, land prices, or overall patterns of ownership. Housing shortages have already led to dramatic price increases in the Western oil shale areas. The need for temporary housing for construction workers aggravates housing supply problems, and mobile homes are often used by both temporary and permanent workers.

Public Sector Impacts

Communities experiencing rapid growth are vulnerable to the overloading of public facilities and services, due both to large front-end capital costs and to constraints which limit a community's ability to make the necessary investments in a timely fashion. * Ability of a community to absorb and provide for a growing population will be community-specific and depend on many factors—such as the size of the predevelopment tax base, availability of developable land, existing social and institutional structure, extent and rate of growth of demand for public services, local planning capabilities and management skills, and political attitudes.

In the long run, local governments should benefit from expanded tax bases arising from the capital intensity of energy facilities and the establishment of associated economic activity. In the aggregate, sufficient additional tax revenue should be produced to pay for the upgrading and expansion of public facilities and services as required for the growing population.[29] In the short run, however, raising local revenues under conditions of rapid growth is often made difficult because of the unequal distribution of incurred costs and revenue-generating capacity among different levels of government.

For example, energy development activities are typically sited outside municipal boundaries, with the result that revenues go to the county, school district, and/or State. However, the population growth accompanying this energy development, and hence the need for services, typically occurs within cities and towns that do not receive additional revenues from the new industry. The separation between taxing authority and public service responsibility can also occur across State lines. In addition, the availability of local tax revenues can lag behind the need for services, because industrial taxes are often based on assessed property values and are not received until full plant operation. * Note also that the total tax burden on the mineral industry and the proportion of State taxes distributed to localities vary from State to State.

There is no clear consensus on the cost of providing additional new public facilities and services in communities affected by energy development. The economics of the decision to expand from an existing service base, or to build a new town, will depend on such factors as the availability of land, accessibility to employment, extent and

[28] *An* Assessment of *Oil* Shale Technologies, Op. cit.

*investments in the public sector can be constrained by, as examples, existing tax bases, debt limitations, bonding capacity, and the 2- to 5-year leadtime typically required for planning and implementing services. In addition, ceilings are often established on the rate of expansion of local government budgets, and there is a tendency either not to tax or to undervalue undeveloped mineral wealth.

[29] *Management* of *Fuel* and *Nonfuel* Minerals in Federal Lands, OTA-M-88 (Washington, D. C.: U.S. Congress, Office of *Technology* Assessment, April 1979).

*Note that mobile homes generate little, if any, property taxes; and local governments have had difficulty in providing services to such sites.

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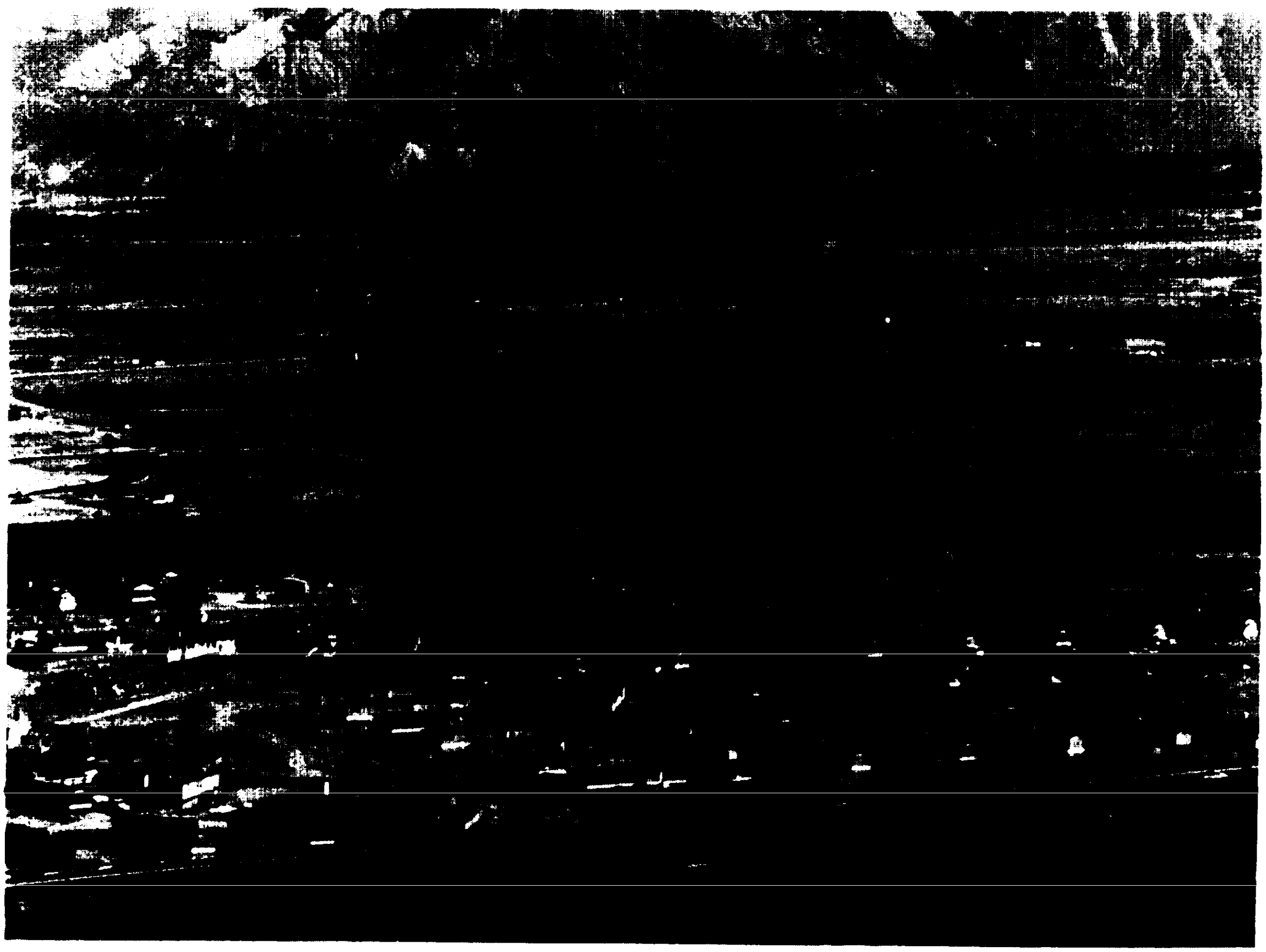

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Synfuels development will require the creation of new communities in sparsely populated areas recovery or other funding/revenue mechanisms have been applied.

Health care is particularly vulnerable to overloading from rapid growth because rural communities often have inadequate health services prior to development and experience difficulties in attracting and retaining physicians. Synfuels development will change the health care needs of local communities because of the influx of young families, the increase in sources of social stress, and new occupational environments that will give rise to special health care needs. Hospital facilities as well as health, mental health, and social services will be required. Educational facilities are also likely to be overloaded. Both Eastern coal communities and Western oil shale communities are presently having difficulty in attracting and retaining personnel and in funding the provision and expansion of facilities and programs,

Public sector dislocations caused by synfuels development on Indian lands could be more severe than on other rural areas. Tribes have limited ability to generate revenues, there will be large cultural differences between tribal members and workers who immigrate to an area to work on a project, and land has religious significance to some tribes and individual landownership is commonly prohibited (so that, for example, conventional patterns of housing development may not be possible).

Most reservations are also sparsely populated, with few towns, and public services and facilities are severely inadequate and overburdened. Significant amounts of coal are owned by Indians in New Mexico and Arizona, lesser amounts in Montana, North and South Dakota, and Colorado. Although in the aggregate current coal leases represent only a fraction of the total coal under lease, Indian leases are important because of their size and coherence. About 8 percent of the oil-shale mineral rights in the Uinta Basin are owned by Indians, but most of the associated deposits are of low grade.[32]

Managing Growth

Unmanaged growth, although not well understood, appears nevertheless to be a leading source of conflict and stress associated with energy development. All involved parties-the Federal, State, and local governments; industry; and the public—have an interest in and are contributing in varying degrees to growth management by providing planning, technical, and financial assistance to communities experiencing the effects of synfuels development. These mechanisms, which vary among States in terms of their scope, detail, and development, are discussed in detail in previous OTA reports.[33,34,35] In general, the effectiveness of existing mechanisms has yet to be tested in the face of rapid and sustained industrial expansion. Major issues to be resolved include who will bear the costs of and responsibilities for both anticipating and managing social impacts, and how up-front capital will be made available when needed to finance public services.

[32] U.S. Geological Survey, Synthetic Fuels Development, Earth-Science Considerations, 1979.

[33] *An* Assessment of *Oil* Shale Technologies, op. cit.

[34] *Management* of *Fuel* and *Nonfuel* Minerals *in* Federal Lands, op. cit.

[35] The *Direct Use* of *Coal:* Prospects and Problems of Production and Combustion, OTA-E-86 (Washington, D. C.: U.S. Congress, Office of Technology Assessment, April 1979).

Chapter 10

Environment, Health, and Safety Effects and Impacts

Contents

Chapter 10

Environment, Health, and Safety Effects and Impacts

INTRODUCTION

There are major differences in the risks to public health and the environment associated with the alternative approaches to reducing the dependence of the U.S. transportation sector on foreign oil. Depending on the level of development, the production and use of synthetic fuels imply massive increases in mining (and agriculture and forestry for biomass), construction and operation of large conversion plants producing substantial quantities of waste products (some of which are toxic), and fuel products that may be different from the fuels now in commerce and that may thus represent different risks in handling and use.

Electrification of autos would require large increases in electric power production, which in turn imply major increases in powerplant fuel use and emissions. Also, the use of electric cars would decrease the use of conventional vehicles and thus yield reductions in vehicular emissions as well as changes in vehicle materials and operating characteristics.

Increased automotive fuel efficiency would involve changes in vehicle size, materials, operating characteristics, and emissions. All the strategies would reduce the use of petroleum that would otherwise have been imported, and adverse effects associated with the strategies should be partially offset by the resulting environmental benefit of reductions of oil spills and other hazards.

This section identifies potential effects on the environment and human health of these three alternative (or complementary) approaches to reducing or eliminating oil imports. Because of significant uncertainties in the precise characteristics of the technologies to be deployed, their potential emissions and the control levels possible, and future environmental regulations and other important predictive factors, the approach of this evaluation is relatively informal and qualitative. We attempt to put the alternatives into reasonable perspective by identifying both a range of potential effects and, given the availability of controls and incentives to use them, the most likely environmental problems of deployment. The major emphasis in the discussion of synthetic fuels is on coal-based technologies. OTA has recently published reports on biomass energy[1] and oil shale,[2] both of which contain environmental assessments.

[1] *Energy* From Biological Processes, OTA-E-124 (Washington, D. C.: U.S. Congress, Office of Technology Assessment, July 1980).

[2] An Assessment of Oil Shale Technologies, OTA-M- 118 (Washington, D. C.: U.S. Congress, Office of Technology Assessment, June 1980).

AUTO FUEL CONSERVATION

Some measures taken to improve the fuel economy of light-duty vehicles might have significant effects on automobile safety and the environment. Major potential effects include changes in vehicle crashworthiness due to downsizing and weight reduction, environmental effects from changes in materials and consequent changes in mining and processing, and possible air-quality effects from the use of substitutes for the spark-ignition engine,

Motor Vehicle Safety

The shift to smaller, lighter, more fuel-efficient cars has led to heightened concern about a possible increase in traffic injuries and fatalities. Part of this concern stems from evidence that occupants of smaller cars have been injured and killed at rates considerably higher than the rates associated with larger cars. The National Highway Traffic Safety Administration (N HTSA) has recently estimated that a continuing shift to smaller vehicles could result in an additional 10,000 traffic deaths per year (with total annual road fatalities of 70,000) by 1990 unless compensating measures are taken.

In light of these concerns, OTA examined available evidence on the relationship between vehicle size and occupant safety in today's auto fleet, and reviewed some attempts—including the NHTSA estimate—to extrapolate this evidence to a future, downsized fleet.

Occupant Safety and Vehicle Size in Today% Fleet

Much of the current concern about the safety of small cars is based on statistical analysis of national data from the Fatal Accident Reporting System (FARS), which contains information on fatal motor vehicle accidents occurring in the United States. For example, an analysis of FARS data on automobile occupant deaths conducted by the Insurance Institute for Highway Safety (IIHS) (fig. 22) shows that deaths per registered vehicle increase substantially as vehicle size (measured by length of wheelbase) decreases.[4] Furthermore, this trend occurs for both single- and multiple-vehicle crashes. The trend is so strong that the annual occupant deaths per registered small subcompact are more than twice as high as the rate for full-size cars–3.5 per 10,000 cars compared with 1.6 per 10,000.

The relationships illustrated in figure 22 tempt one to conclude that small cars are much less safe than large cars in virtually all situations. For a variety of reasons, however, the information in the figure must be interpreted with care. First, the recent crash tests sponsored by NHTSA[5] (new cars were crashed head-on into a fixed barrier at 35 miles per hour) seemed to indicate that the differ-

[3]National Highway Traffic Safety Administration, *Traffic Safety Trends and Forecasts*, DOT-HS-805-998, October 1981.
[4]Insurance Institute for Highway Safety, *Status Report*, vol. 17, No. 1, Jan. 5, 1982.

[5]The crash tests are described in several references. A useful, clear reference is "Which Cars Do Best in Crashes?" in the April 1981 issue of Consumer Reports. Also see M. Brownlee, et al., "Implications of the New Car Assessment Program for Small Car Safety, " in proceedings of the Eighth International Technical Conference on Experimental Safety Vehicles, Wolfsburg, Germany, Oct. 21-24, 1980, NHTSA report.

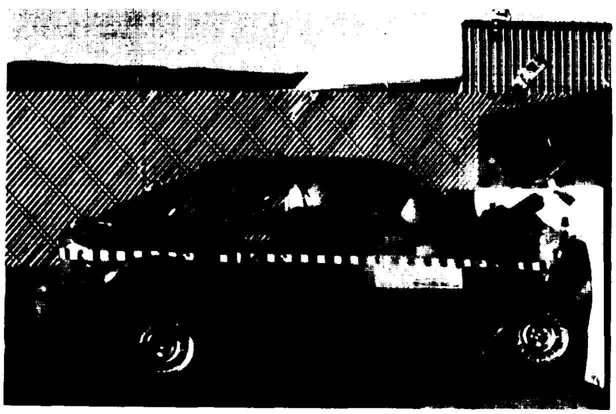
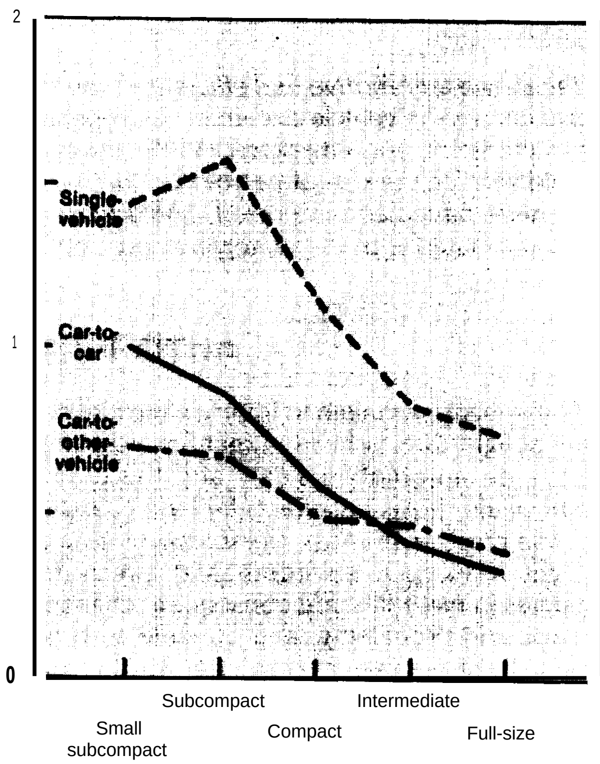


Photo credit: National Highway Traffic Safety Administration

Crash tests sponsored by the National Highway Traffic Safety Administration are an important source of information for understanding the mechanics of crashes and evaluating auto safety features

Figure 22.—Passenger-Car Occupant Death per 10,000 Registered Cars by Car Size and Crash Type: Cars 1 to 5 Years Old in Calendar Year 1980-



SOURCE: Insurance Institute for Highway Safety.

ences in expected occupant injuries between vehicles in the same size class–i.e., differences caused by factors other than size—can be greater than any differences between the size classes. importantly, the results imply that relatively minor changes in engineering and design, such as inexpensive improvements in the steering column and changes in the seatbelt mechanisms, can produce improvements in vehicle crashworthiness that may overwhelm some of the differences caused by size alone. The results of the tests can be applied only to occupants wearing seatbelts (11 percent of total occupants), however, and only to new cars in collisions with fixed objects.

Another reason to be cautious is that the IIHS analysis may be overlooking the effect of variables other than car size. For example, the age of drivers and occupants is a critical determinant of fatality rates. Younger drivers tend to get into more serious accidents,[7] and younger occupants are less likely than older ones to be killed or seriously injured in otherwise identical crashes.[8] Because the average age of drivers and occupants is not uniform across car size classes—it is believed that smaller cars tend to have younger drivers and occupants—the observed differences in fatality rates may be functions not only of the physical characteristics of the cars but also of differences in the people in those cars.

Other variables that should be considered in interpreting injury and fatality statistics include safety belt usage (drivers of subcompact cars have been reported to use seatbelts at a significantly higher rate than drivers of intermediate and large cars[9]), the average number of occupants per car, and differences in maneuverability and braking capacity (i. e., crash avoidance capability) between big and small cars. *

Several analyses have tried to account for the effect of some of these variables.[10] However, these analyses use different data bases (e.g., State data such as that available from North Carolina, and other national data bases such as the National Accident Sampling System and the National Crash Severity Study), different measures of vehicle size (wheelbase, the Environmental Protection Agency (EPA) interior volume, weight, etc.), different formulations of safety (e.g., deaths per 100,000 registered vehicles, deaths per vehicle-mile driven, deaths per crash), and in addition their data reflect different time frames. Few analyses correct for the same variables. Consequently, it is extremely difficult to compare these analyses and draw general conclusions.

Also, credible data on total accident rates for all classes of cars, and more detailed data on accident severity, are not widely available. This type of data would allow researchers to distinguish between the effects of differences in crashworthiness and differences in accident avoidance capability in causing the variations in fatalities measured in the FARS data base. For example, studies of accident rates in North Carolina indicate that subcompacts are involved in many more accidents than large cars.[11] Consequently, the relationship between fatalities per registered vehicle and car size, and that between fatalities per crash and car size could be significantly different for this data set, with the latter relationship indicating less dependence between safety and vehicle size than appears to be the case in the former. Unfortunately, such data are available only in a few jurisdictions and cannot be used to draw nationwide conclusions.

Finally, the existing data base reflects only current experience with small cars. In particular, the data reflect no experience with the class of extremely small sub-subcompacts that currently are sold in Japan and Europe but not in the United States. it is conceivable that widespread introduction of such cars into the U.S. fleet, triggered by

6R. H. Stephenson and M. M. Finkelstein, "U.S. Government Status Report," in proceedings of the Eighth International Technical Conference on Experimental Safety Vehicles, op. cit.

7H. M. Bunch, "Smaller Cars and Safety: The Effect of Downsizing on Crash Fatalities in 1995, " HSRI Research Review (University of Michigan), vol. 9, No. 3, November-December 1978.

8Ibid.

9Stephenson and Finkelstein, op. cit.

*The effect of improved crash avoidance capability and other safety factors may be perverse. To the extent that drivers may take more chances in reaction to their perception of increased safety, they can negate the effectiveness of safety improvements. The tendency of drivers of large cars to use seatbelts at a lower rate than drivers of small cars may be an indicator of such a reaction.

10A variety of these are described in J. R. Stewart and J. C. Stutts, "A Categorical Analysis of the Relationship Between Vehicle Weight and Driver Injury in Automobile Accidents, " NHTSA report DOT-HS-4-O0897, May 1978.

11J. R. Stewart and C. L. Carroll, "Annual Mileage Comparisons and Accident and Injury Rates by Make, Model, " University of North Carolina Highway Safety Research Center.

their lower sales prices or by renewed oil price increases, could have severe safety consequences. NHTSA engineers are concerned that occupants of sub-subcompacts might be endangered not only by the increased deceleration forces that are the inevitable danger to the smaller vehicle in multicar crashes, but also by problems of managing crash forces and maintaining passenger-compartment integrity that are encountered in designing and building cars this small.[12]

Despite these problems, some conclusions about the relationship between vehicle size and safety can be drawn. For example, the strong positive relationship between vehicle size and safety in *all accidents combined* and in *car-to-car collisions* has been confirmed in virtually all analyses.[13] However, the size/safety relationship does not appear to be as "robust" for single-car collisions, which accounted for about half of all passenger-car occupant fatalities in 1980. Although several studies conclude that there is a strong positive relationship between car size and safety in this class of accidents,[14] I Q and the IIHS analyses show a very strong relationship,[15] some studies have concluded that this positive relationship disappears among some size classes when the data are corrected for driver age and other variables.[16] However, even these studies show that subcompacts fare worse than all other size classes in single-vehicle accidents. "

Forecasting Future Trends in Auto Safety

Attempts to forecast the effects on traffic safety of a smaller, more fuel-efficient fleet—a result of further downsizing within each size class as well as a continued market shift to smaller size classes—are confronted with severe analytical difficulties. First, if the forecast is to account for the effects of important vehicle and driver-related variables, the forecasters must predict how these variables will change in the future—e.g., for each size class, forecasters must predict future values of average driver age, vehicle miles driven, occupancy rates, seatbelt usage, etc. And they must either estimate future size dimensions in each car class and the number of vehicles in each class in the fleet, or else postulate these values. Second, forecasters must construct a credible model that describes the relationship between traffic safety (e.g., injury and fatality rates) and key vehicle and driver-related variables in such a way that the model will remain valid over the time period of the forecast.

The models used by NHTSA[18] and others[19] to project future safety trends generally use simple statistical representations of the relative risk of accidents or injuries and fatalities. The traffic fatality projections examined by OTA all relied on accident data that included older design automobiles even though few such vehicles are likely to remain in the fleet when the date of the projection arrives.

In particular, NHTSA's widely disseminated estimate of 10,000 additional annual traffic deaths by 1990[20] assumed that exposure to fatality risk is a function only of vehicle weight and the number of registered vehicles in each weight class. No account is taken of the effect of recent vehicle design changes, age and behavior of drivers, differences in crash avoidance capabilities, differences in annual vehicle-miles driven and vehicle occupancy rate between various automobile size classes, and other variables. Similar shortcomings exist in the other projections. The resulting projections of future changes in traffic injuries and fatalities should be considered as only rough, first-order estimates.

[12] J. Kanianthra, Integrated Vehicle Research Division, NHTSA, personal communication, March 1982.

[13] Stewart and Stutts, op. cit.

[14] For example, several studies cited in Stewart and Stutts, op. cit.; also, J. H. Engel, Chief, Math Analysis Division, NHTSA, "An Investigation of Possible Incompatibility Between Highway and Vehicle Safety Standards Using Accident Data," staff report, April 1981; also, J. O'Day, University of Michigan Highway Safety Research Institute, personal communication, March 1982.

[15] IIHS, op. cit.

[16] Stewart and Stutts, Op. cit.

[17] I bid.

[18] NHTSA, op. cit. The model briefly described in this report appears to be similar to the forecasting model used in J. N. Kanianthra and W. A. Boehly, "Safety Consequences of the Current Trends in the U.S. Vehicle Population, " in proceedings of the Eighth International Technical Conference on Experimental Safety Vehicles, op.cit.

[19] W. Dreyer, et al., "Handling, Braking, and Crash Compatibility Aspects of Small Front-Wheel Drive Vehicles, " Society of Automotive Engineers Technical Paper Series 810792, June 1981. Also, Bunch, op. cit. Also, J. Hedlund, "Small Cars and Fatalities—Comments on Volkswagen's SAE Paper, " internal NHTSA memorandum, Feb. 4, 1982.

[20] NHTSA, op. cit.

Because of the weaknesses in available quantitative projections of future fatality rates, OTA examined current injury/fatality data and other sources for further evidence of whether or r-tot downsizing and a mix shift to smaller size classes would have a significant effect on safety. In particular, the following observations are important to answering this question:

1. A safety differential between occupants of small and large cars in multiple-car collisions does not necessarily imply that reducing the size of all cars will result in more deaths in this class of accidents. Although available data clearly imply that reducing a vehicle's size will tend to increase the vulnerability of that vehicle's occupants in a car-to-car collision, the size reduction also will make the vehicle less dangerous to the vehicle it collides with. Under some formulations of accident exposure and fatality risk, these two factors may cancel each other out. For example, Volkswagen has calculated the effect of increasing the proportion of subcompacts in today's fleet. Using FARS data and forecasting assumptions that are well within the plausible range, Volkswagen concluded that an increase in subcompacts would actually lead to a decrease in traffic fatalities in car-to-car collisions.[21] Other models using different formulations and data bases might come to different conclusions. For example, models using traffic safety data from North Carolina probably would arrive at a different result. In this historical data set, subcompacts colliding with subcompacts have been found to have a considerably greater probability of causing a fatality than collisions between two full-size cars.[22] Presumably, models using this data set would be likely to forecast that a trend toward more subcompacts would lead to an increase in car-to-car crash fatalities.
2. If small cars are less safe than large cars in single-car accidents, then a decrease in the average size of cars in the fleet with no compensatory improvements in crashworthiness clearly should imply an increase in injuries and fatalities in this class of accidents. As just discussed, some studies suggest that a consistent relationship between size and safety does not exist for compact, midsize, and full-size cars in single-car accidents.[23] On the other hand, subcompacts do fare worse than the other classes in these studies.[24] Consequently, if these studies are correct, a general downsizing of the fleet might have only a small effect on fatalities in single-car accidents, while a drastic shift to very small cars could cause a large increase in such fatalities.

The results of these studies may not be widely applicable. Other studies observe a definite size/safety relationship across all size classes.[25] And some factors tend to favor this alternative conclusion. For example, the higher seatbelt usage in smaller cars should tend to make small cars appear safer in the raw injury data, and thus tend to hide or weaken a positive size/safety relationship. Taking differences in seatbelt usage into account might expose or strengthen such a relationship.[26] Also, analysis of FARS data that includes only vehicles up to 5 years old produces a stronger size/safety relationship than analysis of the whole fleet.[27] Most studies use the whole fleet, but the more limited data set might prove to be better for a projection of the future because it reflects only newer-design automobiles. Finally, as discussed in chapter 5, the larger crush space and passenger compartment volume available to the larger cars should give them, at least theoretically, a strong advantage in the great majority of accidents. On the other hand, an opposing factor favoring those studies showing less dependence between vehicle size and crashworthiness is the limited evidence of increasing accident rates with decreasing car sizes.[28] This offers a reason other than

21 Dreyer, et al., Op. cit.

22 K. Digges, "Panel Member Statement," Panel on ESV/RSV Program, in proceedings of the Eighth International Technical Conference on Experimental Safety Vehicles, op. cit.

23 Stewart and Stutts, op. cit.

24 Ibid.

25 Supra 14,

26 Stephenson arid Finkelstein, op. cit.

27 Based on a comparison of II HS's analysis, op. cit., and Engel's analysis, op. cit.

28 Stewart and Carroll, op. `cit.

(or in addition to) differences in crashworthiness for the differences in fatalities among the various auto size classes.

3. Although most arguments about downsizing and traffic safety have focused on vehicle occupants, the inclusion of pedestrian fatalities will affect the overall argument. About 8,000 pedestrians were killed by motor vehicles in 1980,[29] and analysis of FARS data indicates that pedestrian fatalities per 100,000 registered cars increase as car size increases[30]—i.e., reducing the average size of cars in the fleet might decrease pedestrian fatalities because of the reduced "aggressiveness" of smaller cars towards pedestrians. If policy concern is for total fatalities, this effect should lessen any overall adverse safety effect of downsizing the fleet.
4. Much of the available data implies that traffic fatalities will rise if the number of collisions between vehicles of greatly different weights increases. This points to three dangers from a downsized fleet. First, for a limited period of time, the number of collisions of this sort might increase because of the large number of older, full-size cars left in the fleet. This problem should disappear within a decade or two when the great majority of these older cars will have been scrapped. Second, a more permanent increase in fatalities could occur if large numbers of very small sub-subcompacts–cars not currently sold in the U.S. market—were added to the passenger vehicles fleet. The potential for successful large-scale sales of such vehicles will depend on their prices—they may be significantly less expensive than current subcompacts—as well as future oil prices and public perceptions of gasoline availability. Third, car-truck collisions, which today represent a significant fraction of occupant fatalities (car-to-other-vehicle accidents account for about 25 percent of total occupant fatalities[31]), may cause more fatalities unless the truck fleet is downsized as well. Subcompacts fare particularly poorly in car-truck collisions, and a large increase in the number of vehicles in this size class could create substantial problems.

The available statistical and physical evidence on auto safety suggest that a marked decrease in the average vehicle size in the automobile fleet may have as a plausible outcome an increase in vehicle-occupant fatalities of a few thousand per year or more. This outcome seems especially likely during the period when many older, heavier vehicles are still on the road. Also, such an outcome seems more likely if the reduction in average size comes mainly from a large increase in the number of very small cars in the fleet, rather than from a more general downsizing across the various size categories in the fleet.

The evidence is sufficiently ambiguous, however, to leave open the possibility that only a minor effect might occur. And, as discussed in the next section, improvements in the safety design of new small vehicles (possibly excluding very small sub-subcompacts) probably could compensate for some or all of the adverse safety effect associated with smaller size alone. Some automobile analysts feel that significant safety improvements are virtually inevitable, even without additional Government pressures. For example, representatives of Japanese automobile companies have stated[32] that the present poor record of Japanese cars in comparison with American small cars is unacceptable and will not be allowed to continue. Major improvements in Japanese auto safety would seem likely to force a response from the American companies. Also, General Motors has begun to advertise the safety differentials between its cars and Japanese models, an indication that American manufacturers may have decided that safety can sell. On the other hand, because of its severe financial difficulties, the industry may be reluctant to pursue safety improvements that involve considerable capital expenditures.

Safer Design

Increases in traffic injuries and fatalities need not occur as the vehicle fleet is made smaller in

29 NHTSA, *Fatal* Accident Reporting System *1980.*
30 Based on an analysis of data presented in Engel, op. cit.
31 NHTSA, op. cit.
32 Reported in the April 1981 Consumer *Reports,* op. cit.
33 Ibid., and IIHS, op. cit.

size. Numerous design opportunities exist to improve vehicle safety, and some relatively simple measures could go a long way towards compensating for adverse effects of downsizing and shifts to smaller size classes.

Increased use of occupant restraint systems would substantially reduce injuries and fatalities. NHTSA analysis indicates that the use of air bags and automatic belts could reduce the risk of moderate and serious injuries and fatalities by about 30 to 50 percent.[34]

Simple design changes in vehicles may substantially improve occupant protection. As noted in evaluations of NHTSA crash tests, design changes that are essentially cost-free (changing the location of restraint system attachment) or extremely low cost (steering column improvements to facilitate collapse, seatbelt retractor modifications to prevent excessive forward movement)[35] appear to be capable of radically decreasing the crash forces on passenger-car occupants.

A variety of further design modifications to improve vehicle safety are available. As demonstrated in the NHTSA tests,[36] there are substantial safety differences among existing cars of equal weight. One important feature of the safer cars, for example, is above-average length of exterior structure to provide crush space. Also, the Research Safety Vehicle Program sponsored by the Department of Transportation shows that small vehicles with safety features such as air bags, special energy-absorbing structural members, anti laceration windshields, improved bumpers, doors designed to stay shut in accidents, and other features can provide crash protection considerably superior to that provided by much larger cars.

Two forms of new automotive technology introduced for reasons of fuel economy could also have important effects on vehicle safety. First, the incorporation of new lightweight, high-strength materials may offer the automobile designer new possibilities for increasing the crashworthiness of the vehicle. Because some of the plastics and composite materials currently have problems resisting certain kinds of transient stresses, however, their use conceivably could degrade vehicle safety unless safety remains a primary consideration in the design process. Second, the use of electronic microprocessors and sensors, which is expected to become universal by 1985 to 1990 to control engine operation and related drivetrain functions, could eventually lead to safety devices designed to avoid collisions or to augment driver performance in hazardous situations.

Modifications to roadways can also play a significant role in improving the safety of smaller vehicles. For example, concrete barriers and roadway posts and lamps designed to protect larger vehicles have proven to be hazards to subcompacts[37] in single-vehicle crashes, and redesign and replacement of this equipment could lower future injury and fatality rates.

Mining and Processing New Materials

Aside from the beneficial effects of downsizing on the environmental impacts of mining—by reducing the volume of material required–vehicle designers will use new materials to reduce weight or to increase vehicle safety. Table 71 shows four candidates for increased structural use in automobiles and the amount of weight saved for every 100 lb of steel being replaced.

It appears unlikely that widespread use of these materials would lead to severe adverse impacts. Magnesium, for example, is obtained mostly from seawater, and the process probably has fewer pollution problems than an equivalent amount of iron and steel processing, Most new aluminum

Table 71 .—Material Substitutions for Vehicle Weight Reductions

Structural material	Weight saved/100 lb steel replaced
Magnesium	75
Fiberglass-reinforced composites. . .	35-50
Aluminum	50-60
High-strength low-alloy steel	15-30

SOURCE: M. C. Flemming and G. B. Kenney, "Materials Substitution and Development for the Light-Weight, Energy-Efficient Automobile," OTA contractor report, February 1980

MR. J. Hitchcock and C. E. Nash, "Protection of Children and Adults in Crashes of Cars With Automatic Restraints, " in Eighth International Technical Conference on Experimental Safety Vehicles, op. cit.

35 Brownlee, et al., Op. cit.

36 Ibid.

37 IIHS, op. cit.

probably would be obtained by importing bauxite ore or even processed aluminum, rather than expanding domestic production. if kaolin-type clays are used for domestic production, waste disposal problems could be significant; however, the cost of producing aluminum from this source currently is too high to make it economically worthwhile.

Use of high-strength low-alloy steel will likely lead to slightly lowered iron and steel production because of the higher strength of this material, with a positive environmental benefit. Finally, the use of plastics and reinforced composites would substitute petrochemical-type processing for iron and steel manufacture, with an uncertain environmental tradeoff.

Air Quality

Regulation of automobile emissions under the Clean Air Act of 1970 (Public Law 91-614) and subsequent amendments has sharply reduced the amount of pollutants from automobile exhaust in the atmosphere. Assuming that present standards and proposed reductions in permissible levels of hydrocarbons (HC), carbon monoxide (CO), and nitrogen oxides (NO_x are met, the aggregate of automobile emissions by 1985 will be roughly half of what they were in 1975 despite an increase of 25 percent in the number of cars on the road and a corresponding rise in total miles of vehicle travel. * By 2000, if the 1985 standards have been maintained and complied with, the aggregate of automobile emissions of HC, CO, and NO_x will be 33, 32, and 63 percent of today's levels, respectively. Particulate emissions would be about one-half of today's levels—and possibly much lower, depending on the progress in control of particulate emissions from diesels.

The reductions expected by 1985 will have been brought about by a combination of two basic forms of emission control technology—methods of limiting the formation of pollutants through control of fuel-air mixture, spark timing, and other conditions of combustion in the engine, and systems to remove pollutants from the exhaust before it is discharged into the atmosphere. The effectiveness of both techniques has been greatly enhanced by the advent of electronic engine controls in recent years.

By 1985, when electronic engine controls will be virtually universal in passenger cars, the mandated levels of 3.4 grams per mile (gpm) CO, 0.41 gpm HC, and 1.0 gpm NO_x can probably be met by spark-ignition engines with little or no penalty in fuel economy beyond that associated with the lower engine compression ratios dictated by (low-octane) lead-free gasoline. * And although this fuel penalty may be charged to the control of CO, HC, and NO_x emissions because lead-free gasoline is required to protect catalytic converters, the reduction in lead additives to gasoline may also be justified on the basis of its beneficial effect in reducing lead emissions and, consequently, the level of lead in human tissue. Assuming that reducing lead in gasoline is desirable even without the catalytic converter requirement, the much-argued tradeoff between fuel economy and emissions that seemed so compelling in the 1970's is unlikely to remain a major issue with the spark-ignition engine by the last half of the 1980's.

A shift to still smaller vehicles and the introduction of new engines (and substantial increases in the use of current diesel technology) may affect the tradeoff between air quality and control costs. Because lower vehicle weights and lesser performance requirements will allow substantially smaller engines, the grams per mile emission standards should be easier to meet for most engine types. And, although manufacturers can be expected to respond to this opportunity by cutting back on emission controls, there will be an enhanced potential for eventually lowering emissions still further. On the other hand, some of the engines—e.g., the gas turbines and diesels —may pose some control problems, with NO_x and particulate especially.

*These projections, based on an earlier study by OTA[38] have been adjusted to account for more recent data on automobile use and the lower projected growth rates used in this study.

[38] *Changes in the Future Use* and Characteristics of the Automobile *Transportation* System, OTA-T-83 (Washington, D. C.: U.S. Congress, Office of Technology Assessment, February 1979).

*Although high-octane lead-free gasoline can be, and is, manufactured, the fuel savings it might allow from higher compression engines may be counterbalanced by additional energy required for refining. The exact energy required to produce higher octane lead-free gasoline will be very specific to the refinery, feedstock, and refinery volumes.

Table 72 briefly describes some of the emissions characteristic of current and new engines for light-duty vehicles. The potential emission problem with diesels appears to be the major short-term problem facing auto manufacturers today in meeting vehicle emission standards. There appears to be substantial doubt that diesels can comply with both NO_x and particulates standards without some technological breakthrough, because NO_x control, already a problem in diesels, conflicts with particulate control. This problem is especially significant because diesel particulate are small enough to be inhaled into the lungs and contain quantities of potentially harmful organic compounds.

The effect on human health of a substantial increase in diesel particulate emissions is uncertain, because clear epidemiologic evidence of adverse effects does not exist and because there is doubt about the extent to which the harmful organics in the emissions will become biologically available—i.e., free to act on human tissue *—after inhalation.[39] However, a sharp increase in the number of diesel automobiles to perhaps 25 percent of the market share, which appears possible by the mid-1990's, probably should be considered to represent a significant risk of adverse health effects unless improved particulate controls are incorporated or unless further research provides firmer evidence that diesel particulate produce no special hazard to human health.

Table 72.—Emissions Characteristics of Alternative Engines

Current spark ignition. —Meets currently defined 1983 standards.
Current (indirect injection) diesel.—Can meet CO and HC standards, but NO_x remains a problem. NO_x control conflicts with HC and particulate control. Future particulate standards could be a severe problem.
Direct-injection diesel. —Meets strictest standards proposed for HC and CO. NO_x limit 1 to 2 g/mile depending on vehicle and engine size. Possible future problems with particulates, odor, and perhaps other currently unregulated emissions.
Direct-injection stratified-charge.— Needs conventional spark-ignition engine emission control technology to meet strict HC/CO/NO_x standards. Better NO_x control than diesel. In some versions particulate likely to be problem.
Gas turbine-free shaft.—Attainment of 0.4 g/mile NO_x limit a continuing problem, appears solvable, maybe with variable geometry. Other emissions (HC, CO) no problem,
Sing/e shaft. —Same basic characteristics as comparable free shaft. Better fuel economy may help lower NO_x emissions.
Sing/e shaft (advanced). – NO_x emissions aggravated because of higher operating temperatures.
Stirling engine (first generation).—Early designs have had some NO_x problems, but should meet tightest proposed standards on gasoline, durability probably no problem, emissions when run on other fuels not known.

SOURCE: Adapted from: J. B. Heywood, "Alternative Automotive Engines and Fuels: A Status Review and Discussion of R&D Issues," contractor report to OTA, November 1979.

*Initially, the organics adhere to particulate matter in the exhaust. In order for them to be harmful, they must first be freed from this matter. In tissue tests outside the human body ("in vitro" tests), they were not freed, i.e., they did not become biologically active. This may be a poor indicator of their activity inside the body, however.

[39] Health Effects Panel of the Diesel Impacts Study Committee (H. E. Griffin, et al.), National Research Council, *Health Effects of Exposure to Diesel Exhaust*, National Academy of Sciences, Washington, D. C., 1980.

ELECTRIC VEHICLES

The substitution of electric vehicles (EVs) for a high percentage of U.S. automobiles and light trucks may have a number of environmental effects. The reduction in vehicle-miles traveled by conventional gasoline- and diesel-powered vehicles will reduce automotive air pollution, whereas the additional requirements for electricity will increase emissions and other impacts of power generation. Changes in materials use may have environmental consequences in both the extractive and vehicle manufacturing industries. The use of large numbers of batteries containing toxic chemicals may affect driver and public health and safety. The different noise characteristics of electric and internal combustion engines imply a reduction in urban noise levels, while differences in size and performance may adversely affect driving safety. Finally, there may be a variety of lesser effects, for example, safety hazards caused by installation and use of large numbers of charging outlets.

Power Generation

As discussed in chapter S, utilities should have adequate reserve capacitv to accommodate high levels of vehicle electrification without adding new powerplants. For example, if the utilities could use load control and reduced offpeak prices to confine battery recharging to offpeak hours, half of all light-duty vehicular traffic could be electrified today without adding new capacity. Given the probable constraints on EVs, however, a 20-percent share probably is a more reasonable target for analysis. *

The effects on emissions of a 20-percent electrification of vehicular travel are mixed but generally positive. If present schedules for automotive pollution control are met and utilities successfully restrict most recharging to offpeak hours, this level of electrification would, by the year 2010, lead to the following changes in emissions** compared with a future based on a conventional fossil fuel-powered transportation system:

- less than a l-percent increase in sulfur dioxides (SO_2),
- about a 2-percent decrease in NO_x,
- about a 2-percent decrease in HC,
- about a 6-percent decrease in CO, and
- little change in particulates.[40]

The positive effects on air quality may in reality be more important than these emission figures imply. The addition of emissions due to electricity production occurs outside of urban areas, and the pollution is widely dispersed, while the vehicle emissions that are eliminated occur at ground level and are quite likely to take place in dense urban areas. Thus, the reduction in vehicular emissions should have a considerably greater effect on human exposure to pollution than the small increase in generation-related emissions. Also, any relaxation of auto emissions standards will increase the emissions reductions and air quality benefits associated with "replacement" of the (more polluting) conventional autos. On the other hand, future improvements in automobile emission controls–certainly plausible given progress during the past decade–might decrease the air quality benefits of electrification. *

*As noted elsewhere, however, this is still an extremely optimistic market share even for the long term, unless battery costs are sharply reduced and longevity increased, or gasoline availability decreases.

**Assuming existing emission regulations for powerplants.

[40]W. M. Carriere, et al., The Future *Potential of Electric* and Hybrid *Vehicles,* contractor report by General Research Corp. to OTA, forthcoming.

Other effects of increased electricity demand must also be considered. Most importantly, a 20-percent electrification of cars will lead to substantial increases in utility fuel use, especially for coal. Although the extent of increased coal use will depend on the distribution of EVs, if the vehicles were distributed uniformly according to population, coal would supply about two-thirds of the additional power necessary in 2010,41 requiring the mining of about 38 million additional tons per year. ** If the EVs replaced gasoline-powered cars getting 55 mpg, the gasoline savings obtained by the coal-fired electricity—about 36 billion gal/yr–could also have been obtained by turning the same amount of coal into synthetic gasoline.***

Resource Requirements

EVs will use many of the same materials, in similar quantities, as conventionally powered vehicles, but there will be some differences which may create environmental effects. EVs, for exam pie, will require more structural material than their conventional counterparts because of the substantial weight of the batteries (at least with existing technology). More importantly, the batteries themselves will require some materials in quantities that may strain present supply. Table 73 shows the increase in U.S. demand for battery materials for 20-percent electrification of light-duty vehicular travel by 2000.

The effect on the environment of increases in materials demand is difficult to project because the increased demand can be accommodated in a number of ways. In several cases, although U.S.

"It is equally reasonable to speculate about future improvements in powerplant emission controls. For example, more stringent controls on new plants as well as efforts to decrease SO_2 emissions from existing plants in order to control acid rain damages could increase the benefits of electrification.

[41] Ibid.

**Assumptions: 12,000 Btu/lb coal; vehicle energy required = 0.4 kWh/mile at the outlet; total 2010 vehicle miles = 1.55 trillion miles, 20 percent electric; electrical distribution efficiency = 90 percent; generation efficiency = 34 percent.

***Assuming a synfuels conversion efficiency of coal into gasoline of 50 percent.

Table 73.—increase in U.S. Use of Key Materials for 20 Percent Electrification of Light-Duty Travel (year 2000)

Battery type	Material	Percent increase [a]
Lead-acid	Lead	31.2
Nickel-iron	Cobalt	18.2
	Lithium	14.3
	Nickel	21.3
Nickel-zinc	Cobalt	31.8
	Nickel	34.3
Zinc-chloride	Graphite	50.0
Lithium metal sulfide	Lithium	103.6

[a]Assuming 100 percent of the batteries are of the category shown ... the percent increases thus are *not* additive for the same materials.

SOURCE: W. M. Carrier, et al., *The Future* Potential of Electric and Hybrid Vehicles, contractor report to OTA by General Research Corp., forthcoming.

and world identified reserves currently are insufficient, increased demand probably will be met by identifying and exploiting new reserves. The environmental effects would then be those of expanding mining and processing in the United States or abroad. In other cases, mining of seabed mineral nodules or exploitation of lower quality or alternative ores (e.g., kaolin-type clays instead of bauxite to produce aluminum) could occur. Supplies of some materials may be made available for cars by substituting other materials for nonautomotive demands.

In general, the potential for finding additional resources and the long-range potential for recycling indicate that major strains on resources—and, consequently, environmental impacts of unusual concern—appear to be unlikely with levels of electrification around 20 or 30 percent. Local areas subject to substantially increased mining activity could, however, experience significant impacts.

Noise

EVs are generally expected to be quieter than combustion-engine vehicles, and electrification should lower urban noise. The effect may not, however, be large. Although automobiles account for more than 90 percent of all urban traffic, they contribute only a little more than half of total urban traffic noise and a lesser percentage of total urban noise. A recent calculation of the effect on noise levels of 100-percent conversion of the automobile fleet to electric vehicles predicts a reduction in total traffic noise of only 13 to 17 percent.[42]

Safety

EVs will affect automotive safety because of their lower performance capabilities and different structural and material configuration. Lower acceleration and cruising speed, for example, could pose a safety problem because it could increase the average velocity differential among highway vehicles and make merging more difficult. Many EVs will be quite small and, as discussed in the section on auto fuel conservation, this may degrade safety. On the other hand, compensating changes in driver behavior or redesign of roads in response to EVs could yield a net positive effect.

Similarly, the net effect of materials differences is uncertain. The strong positive effect of removing a gas tank containing highly flammable gasoline or diesel fuel will be somewhat offset by the addition of the battery packs, which contain acids, chlorine, and other potentially hazardous chemicals. Collisions involving EVs may result in the generation of toxic or explosive gases or the spillage of toxic liquids (e.g., release of nickel carbonyl from nickel-based batteries). Finally, the necessity to charge many of the vehicles in locations that are exposed to the weather creates a strong concern about consumer safety from electrical shock.

Occupational and Public Health Concerns

In addition to the potential danger to drivers (and bystanders) from release of battery chemicals after collisions, there are some concerns about the effects of routine manufacture, use, and disposal of the batteries. Manufacture of nickel-based batteries, for example, may pose problems for women workers because several nickel compounds that may be encountered in the manufacturing process are teratogens (producers of birth defects). Also, because many potential battery materials (lead, nickel, zinc, antimony) are per-

[42]W.M. Carriere, General Research Corp., personal communication, June 19, 1981.

sistent, cumulative environmental poisons, the prevention of significant discharges during manufacture as well as proper disposal (preferably by recycling) must be assured. Finally, routine venting of gases during normal vehicle operations may cause air-quality problems in congested areas.

These risks do not appear to pose difficult technological problems (most have been rated as "low risk" in the Department of Energy's (DOE) Environmental Readiness Document for EVs[43]) and existing regulations such as the Resource Conservation and Recovery Act provide an opportunity for strict controls, but institutional problems such as resistance to further Government controls on industry obviously could increase the level of risk. Recycling could pose a particular problem unless regulations or scale incentives restrict small-scale operations, which are often difficult to monitor and regulate.

[43]U.S. Department of Energy, *Environmental* Readiness *Document,* Electric and Hybrid Vehicles, Commercialization Phase III P/arming DOE/ERD-0004, September 1978.

SYNTHETIC FUELS FROM COAL

Development of a synthetic fuels industry will inevitably create the possibility of substantial effects on human health and the environment from a variety of causes. A 2 million barrels per day (MMB/D) coal-based synthetic liquid fuels industry will consume roughly 400 million tons of coal each year, * an amount equal to roughly half of the coal mined in the United States in 1980. The several dozen liquefaction plants required to produce this amount of fuel will operate like large chemical factories and refineries, handling multiple process and waste streams containing highly toxic materials and requiring major inputs of water and other valuable materials and labor. Transportation and distribution of the manufactured fuels not only require major new infrastructure but are complicated by possible new dangers in handling and using the fuels. Table 74 lists some of the major environmental concerns associated with coal-based synfuels. Note that the severity of these concerns is sharp/y dependent on the level of environmental control and management exerted by Government and industry.

*This corresponds to an average process efficiency of about 55 percent and coal heat content of about 20 x 10^6 Btu/ton. The actual tonnage depends on the energy content of the coals, the conversion processes used and the product mixes chosen. Process efficiencies will vary over a range of 45 to 65 percent (higher if large quantities of synthetic natural gas are acceptable in the product stream), and coal heat contents may vary from 12 million to 28 million Btu/ton.

The health and environmental effects of the synfuels fuel cycle can be better understood by dividing the impacts into two kinds. Some of the impacts are essentially identical in kind (though not in extent) to those associated with more conventional combustion-related fuel cycles such as coal-fired electric power generation. These "conventional" impacts include the mining impacts, most of the conversion plant construction impacts, the effects associated with population increases, the water consumption, and any impacts associated with the emissions of environmental residuals such as SO_2 and NO_x that are normally associated with conventional combustion of fossil fuels.

Another set of impacts more closely resembles some of the impacts of chemical plants and oil refineries. These include the effects of fugitive HC emissions and the large number of waste and process streams containing quantities of trace metals, dangerous aromatic HCs, and other toxic compounds. These are referred to as "nonconventional" impacts in this section.

This distinction between "conventional" and "nonconventional" impacts is continued throughout this discussion. In particular, for the conventional impacts, synfuels plants are explicitly compared with coal-fired powerplants. A further understanding of the scale of coal-fired powerplants should allow this comparison to better

Table 74.—Major Environmental Issues for Coal Synfuels

Land use and water quality	Air quality	Ecosystems	Safety and health	Other
Mining				
Short- and long-term land use changes, erosion, and uncertainty of reclamation in arid West Aquifer disturbance and pollution Nonpoint source water pollution (acid mine drainage—East; sedimentation—West) Subsidence	Fugitive dust (especially in the West)	Disruption of wildlife habitat and changed productivity of the land Siltation of streams Habitat fragmentation from primary and secondary population growth	Mining accidents Occupational diseases in underground mining (e.g., black lung)	Increased water use for reclamation Coal transportation impacts on road traffic and noise
Liquefaction and refining				
Potential surface and ground water pollution from holding ponds Wastewater discharges (East) Disposal of large amounts of solid wastes Local land use changes Construction on flood plains	Emission of "criteria pollutants" (i.e., NO_x, SO_2, particulate, etc. Fugitive emission of carcinogenic substances Possible release of trace elements Releases during "upset" conditions Possible localized odor problems	Air pollution damage to plants Contributions to acid rain Wildlife habitat fragmentation from population increases Contribution to the "greenhouse" effect	Occupational safety and health risks from accidents and toxic chemicals Carcinogens in direct process intermediates and fuel products	Water availability issues (especially in the West)
Product transport and end-use				
Product spills from trains, pipelines, and storage	Changed automotive exhaust emissions (increase in some pollutants, decrease in others) Increased evaporative emissions from methanol fuels Toxic product vaporization	Acute and chronic damages from spills	Exposure to spills Uncertain effects of trace elements and HCs	Potential change in fuel economy Methanol corrosion and reduction of existing engine longevity

SOURCE: M. A. Chartock, et al., Environmental Issues of Synthetic Transportation Fuels From Coal, OTA contractor report, forthcoming

serve the reader. A 1,000-MWe plant, for example, serves all the electrical needs (including requirements for industry) of about 400,000 people. A plant of this size would be large but not excessively so for a new facility, because many currently planned coal-fired plants are larger than 600 MWe, and the nationwide average capacity of planned units is 433 MWe.[44] Existing plants are, on the whole, much smaller than these new plants, with an average capacity of only 57 MWe.[45] Some existing plants, however, are very large: Arizona Public Service Co.'s Four Corners plant in New Mexico, for example, has a capacity of 2,212 MWe.[46]

This comparison is intended to place the environmental and health impacts of a synfuels plant side by side with the impacts of a technology that may be more familiar to readers. We stress, however, that this comparison is not relevant to a comparison of coal liquids and coal-based electricity as competing alternatives.

[44] R. W. Gilmer, et al., "Rethinking the Scale of Coal-Fired Electric Generation: Technological and Institutional Considerations," in Office of Technology Assessment, *The Direct Use of Coal, Volume II*, Part A, 1979.

[45] Ibid.

[46] Federal Energy Regulatory commission, *Steam-Electric Plant Air and Water Quality Control Data, Summary Report*, October 1979.

Such a comparison can be made only by carefully considering the end uses for the competing energy forms, which we have not done. For use in automobile travel, however, a synthetic fuel may prove to be as efficient in its utilization of coal energy as a powerplant producing electricity for EVs (see "Electric Vehicles, Power Generation" in this chapter), In this case, to the extent that a synfuels production facility produces fewer (or more) impacts than a powerplant processing the same amount of coal, the impact of the energy-production stage of the "synfuels to motor fuel" fuel cycle may be considered to be environmentally superior (or inferior) to the same stage of the "electric auto" fuel cycle.

It is also stressed that the "nonconventional" effects associated with the toxic waste streams produced by synfuels plants are essentially impossible to quantify at this time, because of significant uncertainties associated with the type and quantity of toxic chemicals produced, the rate at which these chemicals might escape, the effectiveness of control systems, the fate of any escaping chemicals in the environment, and finally, the health and ecological impacts of various exposures to the chemicals.

Because of these uncertainties, there may be a temptation to judge synfuels production mainly on the basis of its "conventional," and more quantifiable, impacts. In OTA's opinion, this is a mistake, because the toxic wastes pose difficult environmental questions and also because the magnitudes of several of the more conventional impacts are themselves quite uncertain.

Mining

A large coal-based synfuels industry will consume a significant portion of U.S. coal output. Although actual coal-production growth during the remainder of this century is uncertain, several sources agree that total production on the order of 2 billion tons per year is possible by 2000.[47] At this level a 2 MMB/D coal synfuels capacity would require roughly 20 percent of total U.S. production in 2000.

The impacts of a mine dedicated to synfuels production should be essentially the same as those from other large mines dedicated to power production and other uses, and thus these impacts fit into the "conventional" category. Although the coal requirement for a unit plant with a 50,000 barrel per day (bbl/d) output capacity—at least 5 million tons per year*—is high by today's standards, mines are already tending towards this size range where it is feasible (e.g., eight mines in the Powder River Basin produced more than 5 million tons of coal each in 1980[48]). On the other hand, it is not clear that the geographic distribution (and thus the distribution of impacts) of synfuels coal production and production for other uses will be similar. Because it is difficult to predict where a future synfuels industry will be located, the nature of any differences between mining for synfuels and mining for other uses is uncertain.

As discussed in another OTA report,[49] although many of coal mining's adverse impacts have been mitigated under State and Federal laws, important environmental and health concerns remain. The major concerns are likely to be /and reclamation failure, acid mine drainage, subsidence of the land above underground mines, aquifer disruption, and occupational disease and injury. Mining for synfuels conversion will experience all of these impacts, although not at all sites.

The following discussion of mining impacts relies primarily on the OTA report:

Reclamation.– The use of new mining methods that integrate reclamation into the mining process and enforcement of the Surface Mine Control and Reclamation Act (SMCRA) should reduce the importance of reclamation as a critical national issue. However, concern remains that a combination of development pressures and inadequate knowledge may lead to damage in particularly

[47] *The Direct Use of Coal:* Prospects and Problems of Production and Combustion, OTA-E-86 (Washington, D. C.: U.S. Congress, Office of Technology Assessment, April 1979). Also available from Ballinger Publishers in a March 1981 edition.

*The potential range is about 5 million to 18 million tons per year. The 5-million-ton extreme represents a 65-percent efficient process (not truly a lique faction process because half of its output is syngas; the upper limit of efficiency for processes producing primarily liquids is about 60 percent) using very-high-value (28 million Btu/ton) Appalachian coal. The 18-million-ton extreme represents a 45-percent efficient process using low-energy (12 million Btu/ton) lignite.

[48] *An Assessment* of the Development Potential and Production Prospects of *Federal Coal* Leases, OTA-M-150 (Washington, D. C.: U.S. Congress, Office of Technology Assessment, December 1981).

@The *Direct Use* of *Coal,* op. cit.

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vulnerable areas—arid lands and alluvial valley floors in the West, prime farmland in the Midwest, and hardwood forests, steep slope areas, and flood-prone basins in Appalachia. Although most of these areas are afforded special protection under SMCRA, the extent of any damage will depend on the adequacy of the regulations and the stringency of their enforcement. Recent attempts in the Congress to change SMCRA and administration actions to reduce the Office of Surface Mining's field staff and to transfer enforcement responsibilities to State agencies have raised concerns about the future effectiveness of this legislation.

Acid Mine Drainage.Acid mine drainage, if not controlled, is a particularly severe byproduct of mining in those regions—Appalachia and parts of the interior mining region (indiana, Illinois, Western Kentucky) —where the coal seams are rich in pyrite. The acid, and heavy metals leached into the drainage water by the acid, are directly toxic to aquatic life and can render water unfit for domestic and industrial use. Zinc, nickel, and other metals found in the drainage can become concentrated in the food chain and cause chronic damage to higher animals. An additional impact in severe cases is the smothering of stream bottom-dwelling organisms by precipitated iron salts.

Acid drainage is likely to be a significant problem only with underground mines, and only after these mines cease operating. Assuming strong enforcement of SMCRA, acid drainage from active surface and underground mines should be collected and neutralized with few problems. only a very small percentage of inactive surface mines may suffer from acid seepage. Underground mines, however, are extremely difficult to seal off from air and water, the causal agents of acid drainage. Some mining situations do not allow adequate permanent control once active mining and water treatment cease. A significant percentage of the mines that are active at present or that will be opened in this century will present acid drainage problems on closure.

In a balancing of costs and benefits, it may not be appropriate to assign to synfuels development the full acid damage associated with synfuels mines, even though these mines will have acid drainage problems. This is because drainage problems may taper off as shallower reserves are exhausted and new mines begin to exploit coal seams that are deeper than the water table. Many of these later mines will be flooded, reducing the oxidation that creates the acid drainage. It is possible that many or most acid drainage-prone mines dedicated to a synfuels plant would have been exploited with or without synfuels development.

Subsidence.–Another impact of underground mining that will not be fully controlled is subsidence of the land above the mine workings. Subsidence can severely damage roads, water and gas lines, and buildings; change natural drainage patterns and river flows; and disrupt aquifers. Unfortunately, there are no credible estimates of potential subsidence damage from future underground mining. However, a 2 MMB/D industry could undermine about a hundred square miles of land area (about one-tenth the area of Rhode Island) each year, * most of which would be a potential victim of eventual subsidence.

Subsidence, like acid drainage, is a long-term problem. However, SMCRA does not hold developers responsible for sufficient time periods to ensure elimination of the problem, nor does it specifically hold the developer responsible to the surface owner for subsidence damage. The major "control" for subsidence is to leave a large part of the coal resources—up to 50 percent or more —in place to act as a roof support. There is obviously a conflict between subsidence prevention and removal of the maximum amount of coal. Moreover, the supports can erode and the roof collapse over a long period of time. The resulting intermittent subsidence can destroy the value of the land for development. An alternative mining technique called longwall mining deals with some of these problems by actually promoting subsidence, but in a swifter and more uniform fashion. Longwall mining is widely practiced in Europe but is in limited use in the United States. It is not suitable for all situations.

Aquifer Disruption.–Although all types of mining have the potential to severely affect ground water quantity and quality by physical disruption of aquifers and by leaching or seepage into them, this problem is imperfectly understood. The shift of production to the West, where ground water is a particularly critical resource, will focus increased attention on this impact. As with other sensitive areas, SMCRA affords special protection to ground water resources, but the adequacy of this protection is uncertain because of difficulties in monitoring damages and enforcing regulations and by gaps in the knowledge of aquifer/mining interactions,

Occupational Hazards.–Occupational hazards associated with mining are a very visible concern of synfuels production, because coal workers are likely to continue to suffer from occupational disease, injury, and death at a rate well above other occupations (see table 75), and the total magnitude of these impacts will grow along with the growth in coal production.

The mineworker health issue that has received the most attention is black lung disease, the non-

*Assuming half of the coal is produced by eastern and central underground mining, 18,000 acres undermined per 10^{15} Btu of coal.

Table 75.—Fatality and Injury Occurrence for Selected Industries, 1979

	Fatalities		Nonfatal injuries	
	Number	Rate[a]	Number	Rate[a]
Underground bituminous.	105	0.09	14,131	12.30
Surface bituminous .	15	0.02	2,333	3.47
All bituminous coal[c] (and lignite)	137	0.064	16,464	10,20
Other surface mining[b] (metal, nonmetal, stone, etc.).	97	0.07	8,121	5.82
Petroleum refining[c]. .	20	0.0011	8,799	5.30
Chemical and allied products[c].	55	0.0025	78,700	7.20
All industries	4,950	0.0086	5,956,000	9.20

[a]Rate per 200,000 worker-hours (100 worker-years).
[b]For all companies.
[c]For companies with 11 or more workers; fatality data Include deaths due to job-related accident and Illness.

SOURCE: Bureau of Labor Statistics, personal communication, 1981; and Staff, Mine Safety end Health Administration, personal communication, 1981.

clinical name for a variety of respiratory illnesses affecting underground miners of which coal workers' pneumoconiosis (CWP) is the most prominent. Ten percent or more of working coal miners today show X-ray evidence of CWP, and perhaps twice that number show other black lung illnesses—including bronchitis, emphysema, and other impairments. so

To prevent CWP from disabling miners in the future, Congress mandated a 2-mg/m^3 standard for respirable dust (the small particles that cause pneumoconiosis). However, critics now question the inherent safeness of this standard and the soundness of the research on which it is based. Furthermore, other coal mine dust constituents—the large dust particles (that affect the upper respiratory tract) and trace elements–as well as fumes from diesel equipment also represent continued potential hazards to miners.

Mine safety–as distinct from mine health–has shown a mixed record of improvement since the 1969 Federal Coal Mine Health and Safety Act establishing the Mining Enforcement and Safety Administration was passed. The frequency of mining fatalities has decreased for both surface and underground mines, but no consistent improvement has been seen in the frequency of disabling injuries, Coal worker fatalities numbered 139 in 1977, and disabling injuries approached 15,000.[51] Each disabling injury resulted in an average of 2 months or more of lost time. The number of disabling injuries has been increasing as more workers are drawn to mining and accident frequency remains constant.

As shown in table 75, surface mining is several times safer than underground mining. But some underground mines show safety records equal to or better than some surface mines. Generally, western surface mines are safer than eastern surface mines. As western surface-mine production assumes increasing prominence, accident frequency industrywide is likely to decline when expressed as accidents per ton of output. But this statistical trend may conceal a lack of improvement in safety in deep mines.

Liquefaction

Coal liquefaction plants transform a solid fuel, high in polluting compounds and mineral matter, into liquid fuels containing low levels of sulfur, nitrogen, trace elements, and other pollutants. In these processes, large volumes of gaseous, liquid, and solid process streams must be continuously and reliably handled and separated into end-products and waste streams. Simultaneously, large quantities of fuel must be burned to provide necessary heat and steam to the process, and large amounts of water are consumed for cooling and, in direct liquefaction processes, as raw material for hydrogen production. These processes, coupled with the general physical presence of the plants and their use of a large construction (up to 7,000 men at the peak for a single 50,000 bbl/d plant) and operating force (up to 1,000 workers per plant), lead to a variety of potential pathways for environmental damage.

As noted previously, the following discussion divides impacts into "conventional" and "nonconventional" according to the extent to which the effects resemble those of conventional combustion systems. The discussion does not consider the various waste streams in detail because of their complexity. Appendix 10-A lists the gaseous, liquid, and solid waste streams, the residuals of concern, and the proposed control systems for generic indirect and direct liquefaction systems. DOE's Energy Technologies and the Environment handbook,[52] from which appendix 1O-A is derived, describes these streams in more detail.

Conventional Impacts

An examination of the expected "conventional" impacts reveals that, with a few exceptions, they are significant mainly because the individual plants are very large and national synfuels development conceivably could grow very rapidly—

[50] National Institute for Occupational Safety and Health, *National Study of Coal Workers' Pneumoconiosis,* unpublished reports on second round of examinations, 1975. Cited in *The* Direct Use of *Coal,* op. cit.

[51] Mine Safety and Health Administration, "1 njury Experience at All coal Mines in the United States, by General Work Location, 1977, " 1978. Cited in The Direct Use of *Coal,* op. cit.

[52] U.S. Department of Energy, Energy Technologies and *the* Environment, *Environmental* Information *Handbook,* DOE/EV/74010-1, December 1980.

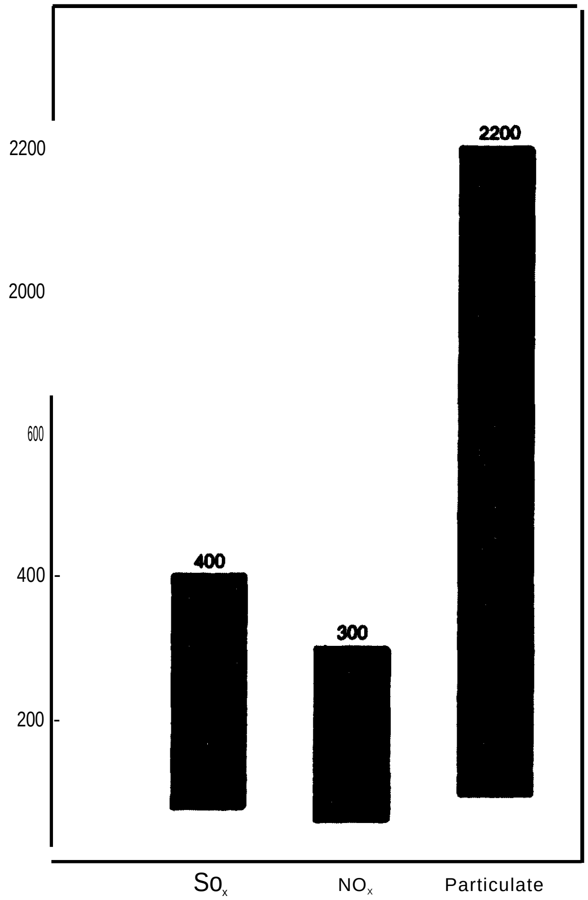
not because the impacts per unit of production are particularly large.

Air Quality.– Emissions of criteria air pollutants* from synfuels generally are expected to be lower than similar emissions from a new coal-fired powerplant processing the same amount of coal.[53] A 50,000 bbl/d synfuels plant processes about as much coal as a 3,000 MWe powerplant,** but (as shown in fig. 23) emits SO_2 and NO_x in quantities similar to those of a plant of only a few hundred megawatts or less. For particulate, synfuels plant emissions may range as high as those from a 2,200-MWe plant, but emissions for most synfuels plants should be much lower.

In any case, particulate standards for new plants are quite stringent, so even a 2,200-MWe plant (or a "worst case" synfuels plant) will not have high particulate emissions. CO emissions from synfuels plants are expected to be extremely low, and are likely to be overwhelmed by a variety of other sources such as urban concentrations of automobiles. HC emissions, on the other hand, conceivably could create a problem if fugitive emissions—from valves, gaskets, and sources other than smokestacks—are not carefully controlled. Although the level of fugitive HC emissions is highly uncertain, emissions from a 50,000 bbl/d SRC II plant could be as high as 14 tons/day–equivalent to the emissions from several large coal-fired plants–if the plant's valves and other equipment leaked at the same rate as equipment in existing refineries.[54]

The broad emission ranges shown in figure 23 reflect very substantial differences in emission projections from developers of the various processes. OTA's examination of the basis for these projections leads us to believe that the differences are due less to any inherent differences among the technologies and more to differences in developer control decisions, assumptions about the effectiveness of controls, and coal characteristics. The current absence of definitive environmental standards for synfuels plants will tend to aggravate these differences in emission projections, because developers have no emissions targets or approved control devices to aim at. EPA has been working on a series of Pollution Control Guidance Documents (PCGDs) for the several synfuels technologies in order to alleviate this problem. The proposed PCGDs will describe the control systems available for each waste stream and the level

Figure 23.-Size Ranges of New Coal-Fired Powerplants With Hourly Emissions Equal to 50,000 bbl/day Synfuels Plants



SOURCE: M. A. Chartock, et al., "Environment Issues of Synthetic Tranportation Fuels From Coal," contractor report to OTA, table revised by OTA.

*"Criteria air pollutants" are pollutants that are explicitly regulated by National Ambient Air Quality Standards under the Clean Air Act. Currently, there are seven criteria pollutants: SO_2, CO, NO_x, photochemical oxidants measured as ozone (O_3), nonmethane HC, and lead.

[53] M. A. Chartock, et al., *Environmental Issues of Synthetic Transportation Fuels From Coal*, Background Report, University of Oklahoma Science and Public Policy Program, report to OTA, forthcoming.

**The actual range is about 2,500 to 3,600 MW for synfuels process efficiencies of 45 to 65 percent, powerplant efficiency of 35 percent, synfuels load factor of 0.9, powerplant load factor of 0.7.

[54] Oak Estimate of Fugitive *Hydrocarbon Emissions for SRC II Demonstration Plant*, for U.S. Department of Energy, September 1980. Based on "unmitigated" fugitive emissions.

of control judged to be attainable. However, the PCGDs became embroiled in internal and interagency arguments and apparently may not be completed and published in the foreseeable future.

The air quality effects of synfuels plants on their surrounding terrain vary because of differences in local conditions—terrain and meteorology—as well as the considerable range of possible emission rates. Some tentative generalizations can, however, be drawn from the variety of site-specific analyses available in the literature. One important conclusion from these analyses is that individual plants generally should be able to meet prevention of significant deterioration (PSD) Class II limits* for particulate and SO_2 with planned emission controls, although in some cases (e.g., the SRC II commercial-scale facility once planned for West Virginia) a major portion of the limit could be used up.[55] In addition, NO_x and CO emissions are unlikely to be a problem for individual plants in most areas, while regulated HC emissions should remain within ambient air quality guidelines if fugitive HC emissions are minimized.[56]

Restrictions will exist, however, near PSD Class I areas in the Rocky Mountain States and nonattainment areas in the eastern and interior coal regions. Several of the major coal-producing areas of Kentucky and Tennessee are currently in nonattainment status, and siting of synfuels plants in those areas is virtually impossible without changes in current regulations or future air quality improvement.[57] Finally, failure to control fugitive HC emissions conceivably could lead to violations of the Federal shot-t-term ambient standards near the plant because, as noted above, the potential emission rate is quite high and because the emissions are released near ground level and will have a disproportionately large effect on local air quality .58

Some potential restrictions on siting maybe obscured in current analyses by the failure to consider the short-term air quality effects of upsets in the conversion processes. For example, under extreme upset conditions, the proposed (but now canceled) Morgantown SRC II plant would have emitted as much $S0_2$ in 2 hours as it would have emitted during 4 to 10 days of normal operation.[59] Unfortunately, most environmental analyses of synfuels development have tacitly assumed that control devices always work properly and plant operating conditions always are normal. These assumptions may be inappropriate, especially for the first generation of plants and particularly for the first few years of operating experience.

On a wider geographic scale, most analyses show that the emissions impact of a synfuels industry will be moderate compared with total emissions from all sources. For example, DOE has estimated 1995 emissions from all major sources for particulate, SO_2, and NO_x. Its calculations show that a 1.3 MM B/D synfuels industry (combining gasification, liquefaction, and oil shale) would represent less than 1 percent of national emissions for all three pollutants.[60] A more intensive development—a 1 MM B/D liquefaction industry concentrated in Wyoming, Montana, and North Dakota—would represent a 7.7 percent (particulate), 9.8 percent (SO_2), 32 percent (No_x), and 1,7 percent (HC) increase over 1975 emissions in a region where existing development—and thus the existing level of emissions—is quite low.[61] These additional emissions are not insignificant, and there has been speculation that high levels of development could cause some acid rain problems in the West, especially from

*PSD regulations limit the increases in pollution concentrations allowed in areas whose air quality exceeds national ambient standards. Class I areas, generally national parks and other areas where pristine air quality is valued very highly, are allowed only minimal increases. Class III areas are areas designated for industrial development and allowed substantial increases. Most parts of the country presently are designated Class II areas and allowed moderate increases in concentrations. PSD limits are under intense scrutiny by Congress and appear to be primary candidates for change under the Clean Air Act reauthorization.

[55] Chartock, et al., op. cit.

[56] Ibid.

[57] 1 bid.

[58] I. L. White, et al., Energy From the West, Impact Analysis *Report Volume I*, /introduction *and* Summary, U.S. Environmental Protection Agency report EPA-600/7-79-082a, March 1979.

[59] U.S. Department of Energy, *Draft* Appendix C *of Final Environ*mental Impact Statement: *SRC-II* Demonstration Plant, Plant Design and Characterization of Effluents, 1980.

[60] U.S. Department of Energy, Synthetic Fuels and the *Environment,* An *Environmental and* Regulatory Impacts Analysis, DOE/EV-0087, June 1980.

[61] Chartock, et al., op. Cit.

NO_x. * Nevertheless, if control systems work as planned and facility siting is done intelligently, coal-based synfuels plants do not appear to represent a severe threat to air quality.

Water Use. -Water consumption has also been singled out as a significant impact of a large-scale synfuels industry, especially in the arid West. Synfuels plants are, however, less intensive consumers of water than powerplants consuming similar amounts of coal. A 3,000-MWe plant—which processes about as much coal annually as a 50,000 bbl/d facility–will consume about 25,000 acre-feet of water per year (AFY), whereas the synfuels facility is unlikely to consume more than 10,000 AFY and may consume considerably less than this if designed with water conservation in mind. According to current industry estimates, a standard 50,000 bbl/d facility will consume about as much water as a 640 to 1,300-MWe plant. Using stricter water conservation designs, the facility may consume as much water as a 400- to 700-MWe plant.[62] Achieving an annual synfuels production of 2 MMB/D might require 0.3 million AFY, or only about 0.2 percent of the projected national freshwater consumptive use of 151 million AFY in 2000.[63]

Environmental impacts associated with synfuels water requirements are caused by the water consumption itself and by the wells, pipelines, dams, and other facilities required to divert, store, and transport the necessary water.

The impacts associated with consumption depend on whether that consumption displaces other offstream uses for the water (e.g., the developer may buy a farmer's water rights) or is additive to existing uses. In the former case, the impact is caused by eliminating the offstream use; in displacing farming, for example, the impact may be a reduction in soil salinization that was being caused by irrigation as well as a reduction in water contamination caused by runoff of fertilizers and pesticides. Any calculation of impacts is complicated, however, by the probability that large reductions in economic activities (such as farming) in one area will result in compensating increases elsewhere as the market reacts to decreases in production.

if the water consumption is additive to existing uses, it will reduce downstream flows. In surface streams or tributary ground waters connected to these streams, the consumption may have adverse effects on the ability of the stream to dilute wastes and to support recreation, fishing, and other instream uses downstream of the withdrawal. Also, consumption of ground water, if excessive, may lead to land subsidence and saltwater intrusion into aquifers.

The impacts associated with wells, dams, and other infrastructure may also be significant. improperly drilled wells, for example, can lead to contamination of drinking water aquifers. Dams and other storage facilities will increase evaporative and other losses (e.g., Lake Powell is underlaid with porous rock and "loses" large amounts of water to deep aquifers). In many cases, the lands submerged by reservoirs have been valuable recreational or scenic areas. In addition, in some circumstances dams can have substantial impacts, including drastic changes in the nature of the stream, destruction of fish species, etc. On the other hand, the ability of dams to regulate downstream flow may help avoid both flooding and extreme low-flow conditions and thus improve instream uses such as recreation and fishing.

Although consumptive water use by synfuels will be small on a national basis, local and even regional effects may be significant. Prediction of these effects is made difficult, however, by a number of factors, including substantial uncertainties in water availability assessments, levels of disaggregation in many assessments that are insufficient to allow a prediction of local and subregional effects, and the variety of alternative supply options available to developers. Water availability

*Current understanding of the transformation of NO_x emissions into nitrates and into acid rain is not sufficient to allow a firm judgment to be made about the likelihood of encountering an acid rain problem under these conditions.

[62] H. Gold, et al., *Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States*, U.S. Environmental Protection Agency report EPA-600/7-77-037, April 1977. Assumes powerplant load factor of 70 percent, synfuels load factor 90 percent. Synthoil is used as a baseline liquid fuels plant.

[63] U.S. Water Resources Council, *Second National Water Assessment, The Nation's Water Resources 1975-2000, Volume II*, December 1978.

considerations for the five major river basins where synfuels development is most likely to occur are discussed in chapter 11.

Work Force and Population Impacts.-The size of the synfuels work force will be large compared with power generation; for a 50,000 bbl/d plant, it is equivalent to the work force that would be needed for powerplants totaling 4,000 to 8,000 Mw (during peak construction) and to plants totaling at least 2,500 MW (during operation)[64] (see ch. 8 for detailed discussion). These high work force values are particularly important for western locations, because significant population increases caused by energy development place considerable stress on semiarid ecosystems through hunting and recreational pressures, inadequate municipal wastewater treatment systems, and limited land use planning.

[64] I. L. White, et al., *Energy From the* West, *Energy Resource Development* Systems *Report, Volume II: Coal,* U.S. EPA report EPA-600/7-79 -060b, March 1979. Used for powerplant work force only (for a 3,000-MWe plant, construction peak is 2,545, operating force is 436),

Summary of Conventional Impact Parameters. –Table 76 provides a capsule comparison of the conventional environmental impacts of synfuels plants and coal-fired plants.

Nonconventional Impacts

The remaining, "nonconventional" impacts of synthetic fuel plants represent substantially different environmental and health risks than do coal-fired plants and other combustion facilities. The conversion of coal to liquid fuels differs from coal combustion in several environmentally important ways. Most importantly, the chemistries of the two processes are considerably different. Liquefaction is accomplished in a reducing (oxygen poor) environment, whereas combustion occurs in an oxidizing environment. Furthermore, the liquefaction reactions generally occur at lower temperatures and usually higher pressures than conventional combustion.

One major result of these chemical and physical differences is that the heavier HCs originally

Table 76.—Two Comparisons of the Environmental Impacts of Coal-Based Synfuels Production and Coal-Fired Electric Generation [a]

Type of impact	A. Coal-fired generating capacity that would produce the same impact as a 50,000 bbl/d coal-based synfuels plant, MWe	B. Side-by-side Comparison of environmental impact parameters		
		3,000 MWe generator	50,000 bbl/d synfuels	Units
Annual coal use	2,500-3,600 [b]	6.4-15.0	5.3-17.9	million tons/yr
Annual solid waste	(2,500-3,600)± [c]	0.9-2.0+	0.6-1 .8+	million tons/yr
Annual water use:				acre feet/yr
Current industry estimates	640-1,300	25,000	5,400-10,800	
Conservation case	400-700		3,400-5,900	
Annual emissions:				tons/yr
Particulate	120-2,800	2,700	100-2,500	
Sulfur oxides	90-500	27,000-108,000	1,600-9,900	
Nitrogen oxides	70-400	63,000	1,600-7,800	
Hourly emissions:				lb/hr
Particulate	90-2,200	880	30-800	
Sulfur oxides	70-40	8,800-35,200	500-3,200	
Nitrogen oxides	60-300	20,500	500-2,500	
Peak labor	4,100-8,000	2,550	3,500-6,800	persons
Operating labor	2,500	440	360	persons

[a] In example A, the powerplant uses the same coal as the synfuels plant, New Source Performance Standards (NSPS) apply, SO_x emissions assumed to be 0.6 lb/10[6] Btu. In B, NSPS also apply but SO_x emissions can range from 0.3 to 1.2 lb/10[6] Btu. In both cases, the synfuels plant Parameters rePresent a range of technologies, with a capacity factor of 90 percent and an efficiency range of 45 to 65 percent; the powerplant is a baseload plant, with a capacity factor of 70 percent, efficiency of 35 percent.

[b] In other words, the amount of coal—and thus the amount of mining—needed to fuel a 50,000 bbl/d synfuels plant is the same as that required for a 2,500 to 3,600 MWe powerplant.

[c] A synfuels plant will have about as much ash to dispose of as a coal-fired powerplant using the same amount of coal. It may have less scrubber sludge, but it may have to dispose of spent catalyst material that has no analog in the powerplant . . . thus the ±.

SOURCE: M. A. Chartock, et al., *Environmental Issues* of Synthetic Transportation *Fuels* From *Coal,* Background Report, University of Oklahoma Science and Public Policy Program, contractor report to OTA, July 1981, in the coal or formed during the reactions are not broken down as effectively in the liquefaction process as in combustion processes, and thus they appear in the process and waste streams. The direct processes (see ch. 6 for a brief description of the various coal liquefaction processes) and those indirect processes using the lower temperature Lurgi gasifier are the major producers of these HCs; indirect processes using high-temperature gasifiers (e.g., Koppers-Totzek, Shell, Texaco) are relatively free of them.

The liquefaction conditions also favor the formation of metal carbonyls and hydrogen cyanide, which are hazardous and difficult to remove. Trace elements are less likely to totally volatilize and may be more likely to combine with or dissolve in the ash. The solids formed under these conditions will have different mineralogical and chemical form than coal combustion ash, and the volubility of the trace elements, which generally is low in combustion ash, is likely to be different. Consequently, solid waste disposal is complicated by the possibility that the wastes may be more hazardous than those associated with conventional combustion.

Finally, the high pressure of the processes, their multiplicity of valves and other vulnerable components, and, for the direct processes, their need to handle liquid streams containing large amounts of abrasive solids all increase the risk of accidents and fugitive emissions.

The major concerns from the "nonconventional" waste streams are occupational hazards from leaks of toxic materials, accidents, and handling of process intermediates, and ground and surface water contamination (and subsequent health and ecological damage) from inadequate solid waste disposal, effluent discharges, and leaks and spills.

Occupational Hazards.–Coal synthetic fuel plants pose a range of occupational hazards from both normal operations and upset conditions. Aside from risks associated with most heavy industry, including exposure to noise, dusts, and heat, and falls from elevated areas, synfuels workers will be exposed to gaseous and liquid fugitive emissions of carcinogenic and other toxic materials. During upset conditions, contact with hot gas and liquid streams and exposure to fire and explosion is possible. Table 77 lists some of the potential exposures from coal gasification plants documented by the National Institute for Occupational Safety and Health. Table 78 lists the potential occupational health effects associated with the constituents of indirect liquefaction process streams. Similar exposure and health-effect potentials would exist for any coal liquefaction process.

Although the precise design and operation of the individual plant is a critical factor in determining occupational hazards, there are certain generic differences in direct and indirect technologies that appear to give indirect technologies some advantages in controlling health and safety risks.

The advantages of indirect technologies include the need to separate only gases and liquids (the solids are eliminated in the very first gasification step) in contrast with the gas/liquid/solid phase separation requirements of direct processes; fewer sites for fugitive emissions than the direct processes; lower processing requirements for the process liquids produced (direct process liquids require additional hydrogenation); the abrasive

Table 77.—Potential Occupational Exposures in Coal Gasification

Coal handling, feeding, and preparation.—Coal dust, noise, gaseous toxicants, asphyxia, and fire

Gasifier/reactor operation. —Coal dust, high-pressure hot gas, high-pressure oxygen, high-pressure steam and liquids, fire, and noise

Ash removal, —Heat stress, high-pressure steam, hot ash, and dust

Catalytic conversion. —High-pressure hot gases and liquids, fire, catalyst, and heat stress

Gas/liquids cooling. —High-pressure hot raw gas and liquid hot tar, hot tar oil, hot gas-liquor, fire, heat stress, and noise

Gas purification. —Sulfur-containing gases, methanol, naphtha, cryogenic temperature, high-pressure steam, and noise

Methanol formation.—Catalyst dust, fire, and noise

Sulfur removal — Hydrogen sulfide, molten sulfur, and sulfur oxides

Gas-liquor separation. —Tar oil, tar, gas-liquor with high concentrations of phenols, ammonia, hydrogen cyanide, hydrogen sulfide, carbon dioxide, trace elements, and noise

Phenol and ammonia recovery. -Phenols, ammonia, acid gases, ammonia recovery solvent, and fire

Byproduct storage. —Tar, oils, phenols, ammonia, methanol, phenol recovery solvent and fire

SOURCE: Adapted from U.S. Department of Health, Education and Welfare, "Criteria for a Recommended Standard . . . Occupational Exposures In Coal Gasification Plants" (Cincinnati: National Institute of Occupational Safety and Health, Center for Disease Control, 19S43).

Table 78.—Occupational Health Effects of Constituents of Indirect Liquefaction Process Streams

Constituents	Toxic effects	Stream or area
Inorganic		
Ammonia	Acute: respiratory edema, asphyxia, death Chronic: no evidence of harm from chronic subirritant levels	Gas liquor
Carbon disulfide	Acute: nausea, vomiting, convulsions Chronic: psychological disturbances, mania with hallucinations	Concentrated acid gas
Carbon monoxide	Acute: headache, dizziness, weakness, vomiting, collapse, death Chronic: low-level chronic effects not established	Coal-lockhopper vent gas Raw gas from gasifier
Carbonyl sulfide	Little data on human toxicity	Concentrated acid gas
Hydrogen sulfide	Acute: collapse, coma, and death may occur within a few seconds. Insidious, may not be detected by smell Chronic: possible cocarcinogen	Coal-lockhopper vent gas Raw gas from gasifier Concentrated acid gas Catalyst regeneration off-gas
Hydrogen cyanide	Acute: headache, vertigo, nausea, paralysis, coma, convulsions, death Chronic: fatigue, weakness	Concentrated acid gas Coal-lockhopper vent gas
Mineral dust and ash	Chronic: possible vehicle for polycyclic aromatic hydrocarbons and cocarcinogens	Ash or slag
Nickel carbonyl	Acute: highly toxic, irritation, lung edema Chronic: carcinogen to lungs and sinuses	Catalyst regeneration off-gas
Trace elements: arsenic, beryllium, cadmium, lead, manganese, mercury, selenium, vanadium	(Complex)	Bottom ash Fly ash Gasifier ash Solid waste disposal
Sulfur oxides	Acute: intense irritation of respiratory tract Chronic: possible cocarcinogen	Combustion flue gases
Organic		
Aliphatic hydrocarbons	Most not toxic. N-Dodecane potentates skin tumors	Evaporative emissions from product storage
Aromatic amines	Acute: cyanosis, methemoglobinemia, vertigo, headache, confusion Chronic: anemia, skin lesions (aniline) Benzidine and beta-naphthylamine are powerful carcinogens	Coal-lockhopper vent gas Gas liquor
Single-ring aromatics	Acute: irritation, vomiting, convulsions Chronic: bone-marrow depression, aplasia	Coal-lockhopper vent gas Gas liquor
Aromatic nitrogen heterocyclics	Acute: skin and lung irritants Chronic: possible cocarcinogens	Gas liquor Coal-lockhopper vent gas
Phenols	Chronic: possible carcinogens, skin and lungs	Gas liquor
Polycyclic aromatic hydrocarbons (PAH)	Chronic: skin carcinogens, possible respiratory carcinogens	Gas liquor Coal-lockhopper vent gas Raw gas

SOURCE: US. Department of Energy, Energy Technologies and the Environment. Environmental Information Handbook DOE/EV/74O1O-1, December 1980.

nature of the direct process stream (which contains entrained solids); and fewer dangerous aromatic compounds, including polynuclear aromatics and aromatic amines, than in direct process streams. Lurgi gasifiers, however, produce a wider range of organic compounds than the higher temperature gasifiers and as a result are more comparable in health risk to direct processes.

In sum, however, the indirect processes appear to have a lower potential for occupational health and safety problems than the direct processes. In actual practice other factors—such as differences in the selection of control equipment and in plant design, maintenance procedures, and worker training—conceivably could outweigh these differences. In fact, developers of liquefaction processes appear to be aware of the potential hazards and are taking preventive action such as providing special clothing and providing frequent medical checkups. Nevertheless, the occupational health risk associated with synthetic fuel plants must be considered a major concern.

Ground and Surface Water Contamination.– A portion of the solid waste produced by liquefaction plants is ash-bottoms, fly ash, and scrubber sludge from the coal-fired boilers—materials that are routinely handled in all coal-fired powerplants today. Much of the waste, however, is ash or slag from the gasifiers producing synthesis gas or hydrogen and chars or "bottoms" from the direct processes (although much of the latter material is expected to be recycled to the gasifies), As noted previously, this material is produced in a reducing atmosphere and thus contains organic compounds as well as trace elements whose solubility may be different from that produced in the boiler.

Other solid wastes that may create disposal problems more severe than those of powerplant waste include spent catalysts and sludges from water treatment. Total solid wastes from a 50,000 bbl/d plant range from 1,800 to 5,000 or more tons per day.[65] At these rates, a 2 MM B/D industry would have to dispose of between 26 million and 72 million tons of wastes per year. The major concern from these materials is that water percolating through landfill disposal areas may leach the toxic organic compounds and trace elements out of the wastes and into the ground water. Currently, the extent of this risk is uncertain, although tests of EDS[66] and SRC-II[67] liquefaction reactor wastes and gasifier ash from several gasifiers[68] yielded leachates that would not have been rated as "hazardous" under Resources Conservation and Recovery Act criteria. *

One major problem with permanent landfill disposal, however, is that damage to ground water may occur at any future time when the landfill liner may be breached–many of the toxic materials in the wastes are either not degradable or will degrade very slowly, and may last longer than the design life of the liner.

Liquid effluent streams from liquefaction plants also pose potential water pollution problems. Although there are a number of wastewater sources that are essentially conventional in character—cooling tower and boiler blowdown, coal storage pile runoff, etc.—the major effluent streams, from the scrubbing of the gases from the gasifiers and from the water separation streams in the direct processes, contain a variety of organics and trace metals that will pose difficult removal problems. The direct processes are expected to have the dirtiest effluent streams, the indirect systems based on Lurgi gasifiers will also pose some problems because of their high production of organics, and the systems based on high-temperature gasifiers should have only moderate treatment requirements.[69]

Although total recycle of water is theoretically possible, in practice this is unlikely and "zero discharge" will only be achieved by using evaporation ponds. Aside from the obvious danger of breakdown of the pond liner and subsequent ground water contamination (or overflows from flooding), evaporation ponds may pose environmental problems through the formation of toxic gases or evaporation of volatile liquids. The complex mixture of active compounds in such a pond creates a particular hazard of unforeseen reactions occurring.

[65] Chartock, et al., op. Cit.

[66] R. C. Green, "Environmental Controls for the Exxon Donor Solvent Liquefaction Process," Second DOE Environmental Control Symposium, Reston, Va., Mar. 19, 1981.

[67] Supra 59.

[68] *Inside* EPA, Sept. 26, 1980. As reported, researchers from TRW and Radian Corps. have tested ash from Lurgi, Wellman-Galusha, and Texaco gasifiers.

*Wastes are rated as "hazardous" and will require more secure (and more expensive) disposal if concentrations of pollutants in the leachates are greater than 100 times the drinking water standard.

[69] H. Gold, et al., "Fuel Conversion and Its Environmental Effects," Chemical Engineering Progress, August 1979.

Although the use of ponds to achieve zero discharge is practical in the West because of the low rainfall and rapid evaporation rates, zero discharge may be impractical at eastern sites without artificial evaporation, which is expensive and energy-intensive. Consequently, it appears probable that continuous or intermittent effluent discharges will occur at eastern plants, with added risks from control system failures as one result.

Environmental Management

The likelihood of these very serious potential environmental and health risks turning into actual impacts depends on a variety of factors, and particularly on the effectiveness and reliability of the proposed environmental controls for the plants, the effectiveness of environmental regulations and scientists' ability to detect damages and ascertain their cause.

In general, synfuels promoters appear to be confident that the control systems proposed for their processes will work effectively and reliably. They tend to view synfuels processes as variations of current chemical and refinery operations, albeit variations that will require careful design and handling. Consequently, the environmental controls planned for synthetic fuels plants are largely based on present engineering practices in the petroleum refining, petrochemical, coal-tar processing, and power generation industries.

There are reasons to be concerned about control system effectiveness and reliability, however, especially for the first generation of commercial plants. First, few of the wastewater effluents from either direct or indirect processes have been sent through a complete environmental control system such as those designed for commercial units. Process waste streams from several U.S. pilot plants have been subjected only to laboratory and bench-scale cleanup tests or else have been combined with waste streams from neighboring refineries and treated, with a poorly understood level of success, in the refinery control systems.

Second, scaling up from small-scale operations is particularly difficult for the direct processes, because of the entrainment of solids in the liquid process streams. Engineering theory for the scale up of solids and mixed solids/liquids processes is not well advanced. For the most part, the problem of handling liquid streams containing large amounts of entrained solids under high-temperature and pressure conditions is outside of current industrial experience.

Third, currently available refinery and petrochemical controls are not designed to capture the full range of pollutants that will be present in synfuels process and waste streams. Several of the trace elements as well as the polycyclic aromatic hydrocarbons (PAHs) are included in this group, although techniques such as hydrocracking are expected to help eliminate PAHs when they appear in process streams. (As noted previously, problems with the trace organics generally are focused on the direct and on low-temperature indirect processes, because high-temperature gasifiers should effectively destroy most of these compounds.)

Fourth, in some cases, compounds that generally are readily controlled when separately encountered appear in synfuels process and waste streams in combinations that complicate control. For example, current processes for removing hydrogen sulfide, carbonyl sulfide, and combustibles tend to work against each other when these compounds appear in the same gas stream,[70] as they do in synfuels plants. Also, the high level of toxics that appear in the waste streams may create reliability problems for the biological control systems.

Fifth, as noted earlier, the high pressures, multiplicity of valves and gaskets, and (for the direct processes) the erosive process streams appear to create high risks of fugitive emissions. plans for control of these emissions generally depend on "directed maintenance" programs that stress frequent monitoring and inspection of vulnerable components. Although it appears reasonable to expect that a directed maintenance program can significantly reduce fugitive emissions, rigorous specifications for such a program have not been published,[71] and some doubts have been raised

[70] Congressional Research Service, *Synfuels From Coal and the National Synfuels Production Program: Technical,* Environmental and Economic Aspects, December 1980 (Committee Print 11-74 No. 97-3, January 1981, U.S. Congress).

[71] U.S. Department of Energy, *Final Environmental Impact Statement:* Solvent Refined Coal-n Demonstration Project, Fort Martin, Monongalia County, W, Va., 2 vols., 1981.

about the adequacy of proposed monitoring for pioneer plants.

The significance of these technological concerns is uncertain. As noted previously, industry representatives generally have dismissed the concerns as unimportant, at least with regard to the extent to which pollution control needs might be compromised. Government researchers at EPA and DOE[72] have expressed some important reservations, however. On the one hand, they are confident that each of the synfuels waste streams is amenable to control, usually with approaches that are not far different from existing approaches to control of refinery and chemical process wastes. On the other hand, they have reservations about whether or not the industry's control program, as it is currently constituted, will achieve the high levels of control possible. Potential problem areas (some of which are related) include wastewater treatment, ’J control system reliability, and pollution control during process upsets.

Virtually all of the Government researchers OTA contacted were concerned that the industry programs were not addressing currently unregulated pollutants but instead were focusing almost exclusively on meeting immediate regulatory requirements. Several expressed special concern about the failure of some developers to exploit all available opportunities to test integrated control systems; they expected these integrated systems to behave differently from the way the individual devices behave in tests.

The above concerns, if well founded, imply that environmental control problems could have serious impacts on the operational schedules of the first generation of commercial plants. These impacts could range from extentions in the normal plant shakedown periods to extensive delays for redesign and retrofit of pollution controls.[74] Because of the large capital costs of the plants, there will likely be severe pressure on regulators to minimize delays and allow full-scale production to proceed. The outcome of any future conflicts between regulatory requirements and plant schedules will depend strongly on the public pressures exerted on the industry and Federal and State Governments.

[72] Personal Communications with headquarters and field personnel, EPA and DOE.

[73] The draft of EPA's Pollution Control Guidance Document on indirect liquefaction also expressed strong concerns about wastewater treatment. *Inside* EPA, Sept. 12, 1980, "Indirect Liquids Draft Sees Zero Wastewater Discharge, Laments Data Gap."

[74] Some of the architectural and engineering firms submitting synfuels plant designs have incorporated certain control system flexibilities as well as extra physical space in their control systems designs. These features presumably would reduce schedule problems. Frederick Witmer, Department of Energy, Washington, D. C., personal communication.

There are reasons to believe that a great deal of public interest will be focused on the synfuels industry and its potential effects. For one, when plant upsets do occur, the results can be visually spectacular–for example, purging an SRC-II reactor vessel and flaring its contents can produce a flame up to 100 ft wide and 600 ft long.[75] It also seems likely that odor problems will accompany these first plants, and in fact the sensitivity of human smell may render it impossible to ever completely eliminate this problem. Malodorous compounds such as hydrogen sulfide, phenols, organic nitrogen compounds, mercaptans, and other substances that are present in the process and waste streams can be perceived at very low concentrations, sometimes below 1 part per billion.[76]

In addition, the presence of highly carcinogenic materials in the process and waste streams appears likely to sensitize the public to any problems with these plants. This combination of potential hazards and perceptual problems, coupled with the industry strategy of locating at least some of these plants quite close to populated areas (e.g., SRC-II near Morgantown, W. Va., now canceled, and the Tri-State Synthetic Fuels Project near Henderson, Ky.), appears likely to guarantee lively public interest.

The nature of the industry's response to unexpected environmental problems as well as its general environmental performance also will depend on the degree of regulatory surveillance and control exerted by Federal and State environmental agencies. Although the degree of surveillance and control will in turn depend largely on the environmental philosophy of the Federal and State Governments at various stages in the lifetime of the industry-a factor that is unpredictable-it will also depend on the legal framework of environ-

[75] Supra 59.

[76] Supra 58.

mental regulations, the scientific groundwork that is now being laid by the environmental agencies, and the nature of the scientific problems facing the regulatory system.

Existing Federal environmental legislation gives the Occupational Safety and Health Administration (OSHA) and EPA a powerful set of tools for dealing with the potential impacts of synfuels development. OSHA has the power to set occupational exposure standards and define safety procedures for all identified hazardous chemicals in the workplace environment. EPA has a wide variety of legal powers to deal with synfuels impacts, including:

- setting National Emission Standards for Hazardous Air Pollutants (N ES HAPS) under the Clean Air Act;
- setting New Source Performance Standards, also under the Clean Air Act;
- setting effluent standards for toxic pollutants (which, when ingested, cause "death, disease, cancer, genetic mutations, physiological malfunctions or physical deformations") under the Clean Water Act;
- setting water quality standards, also under the Clean Water Act;
- defining acceptable disposal methods for hazardous wastes under the Resource Conservation and Recovery Act;
- defining underground injection guidelines under the Safe Drinking Water Act; and
- a variety of other powers under the mentioned acts and several others.[77]

The regulatory machinery gives the Federal environmental agencies a strong potential means of controlling synfuels plants' hazardous emissions and effluents. In general, however, the machinery is immature. Because there are no operating commercial-scale synthetic fuels plants in the United States, EPA has not had the opportunity to collect the data necessary to set any technology-specific emission and effluent limitations for synfuels plants. Aside from this inevitable problem, the environmental agencies have not fully utilized some of their existing opportunities for environmental protection. For example, EPA has allowed its authority to define standards for hazardous air pollutants to go virtually unused. In addition, in some areas, such as setting effluent guidelines and New Source Performance Standards for air emissions, EPA has a substantial backlog of existing industries yet to be dealt with.

The environmental research programs conducted by various Federal agencies will lay the groundwork for EPA's and OSHA's regulation of the synfuels industry. The key programs are those of EPA and OSHA themselves and those of DOE. DOE's programs appear likely to be essentially eliminated if current plans to dismantle DOE are successful. EPA and OSHA research budgets have both been reduced. In particular, EPA has essentially eliminated research activities aimed at developing control systems for synfuels waste streams, on the basis that such development is the appropriate responsibility of industry. As mentioned before, Federal researchers familiar with the industry's current environmental research programs perceive that the industry has little interest in developing control measures for potential impacts that are not currently regulated, and they believe that industry is unlikely to expand its programs to compensate for EPA's reductions.[78]

With or without budget cuts, EPA and OSHA face substantial scientific problems in setting appropriate standards for hazardous materials from synfuels technologies. Probably the worst of these problems is that current air pollution and occupational exposure regulations focus on a relatively small number of compounds and treat each one individually or in well-defined groups, whereas synfuels plants may emit dozens or even hundreds of dangerous compounds with an extremely wide range of toxicity (i.e., the threshhold of harm may range from a few parts per billion to several parts per thousand or higher) and a variety of effects.

The problem is further complicated by the expected wide variations in the amounts and types

[77]See table 4.1, *Synthetic Fuels and the Environment: An Environmental and Regulatory Impacts Analysis,* Office of Technology Impacts, U.S. Department of Energy, DOE/EV-0087, June 1980. Also, see ch. 5, The *Impacts of* Synthetic *Fuels* Development, D. C. Masselli, and N. L. Dean, jr., National Wildlife Federation, September 1981.

[78]Supra 72,

of pollutants produced. The synfuels waste streams are dependent on the type of technology, the control systems used, the product mix chosen by the operator (which determines the operating conditions), and the coal characteristics. The implication is that uniform emission and worker exposure standards, such as a "pounds per hour" emission limit on total fugitive HC emissions or a "milligrams per cubic meter" limit on HC exposures, are unlikely to be practical because they would have to be extraordinarily stringent to provide adequate protection against all components of the emission streams. Consequently, EPA and OSHA may not be able to avoid the extremely difficult task of setting multiple separate standards for toxic substances.

The regulatory problem represented by the toxic discharges is compounded by difficulties in detecting damages and tracing their cause. Because low-level fugitive emissions from process streams and discharges or leaks from waste disposal operations probably are inevitable, regulatory requirements on the stringency of mitigation measures will depend on our knowledge of the effects of low-level chronic exposures to the chemical components of these effluents. Aside from the problems of monitoring for the actual presence of pollution, problems may arise both from the long lag times associated with some critical potential damages (e.g., 5 to 10 years for some skin cancers, longer for many soft-tissue cancers) and from the complex mixture of pollutants that would be present in any emission.

Transport and Use

As synthetic liquids are distributed and used throughout the economy, careful control of exposure to hazardous constituents becomes less and less feasible. This is especially true for liquid fuels because of the multitude of small users and the general lack of careful handling that is endemic to the petroleum distribution system. Consequently, the toxicity of synfuels final products may be critical to the environmental acceptability of the entire synfuel "fuel cycle."

The pathways of exposure to hazardous substances associated with synfuels distribution and use include accidental spills and fugitive emissions from pipelines, trucks, and other transport modes and storage tanks; skin contact and fume inhalation by motorists and distributors; and public worker exposure to waste products associated with combustion (including direct emissions and collected wastes from control systems).

Evaluation of the relative danger of these exposure pathways and comparisons of synfuels to their petroleum analogs are extremely difficult at this time. Most environmental and health effects data on synfuels apply to process intermediates–"syncrudes"- rather than finished fuels. Combustion tests have generally been limited to fuel oils in boilers rather than gasolines in automobiles. 'g The tests that have been conducted focus more on general combustion characteristics than on emissions, and those emission characterizations that have been done measure mainly particulate and SO_x and NO_x rather than the more dangerous organics.[80] Adding to the difficulty of determining the relative dangers of synfuels use is a series of surprising gaps in health effects data on analogous petroleum products. Apparently, many of these widely distributed products are assumed to be benign, and monitoring of their effects has been limited.[81]

Table 79 presents a summary of the known differences in chemical, combustion, and health effects characteristics of various synfuels products and their petroleum analogs. The major characteristics of coal-derived liquid fuels are:

- The major concern about synthetic fuels products is their potential to cause cancer, mutations, or birth defects in exposed persons or wildlife. (Petroleum-based products also are hazardous, but usually to a lesser extent than their synfuels counterparts.)[82] In general, the heavier (high boiling point) liquids—especially heavy fuel oils—are the most dangerous, whereas most of the lighter products are expected to be relatively free of these effects. This distribution of effects may be considered fortunate because the lighter

[79] M. Ghassemi and R. Iyer, Environmental Aspects *of Synfuel* Utilization, U.S. Environmental Protection Agency report EPA-600/7-81-025, March 1981.
[80] Ibid.
[81] Ibid.
[82] Ibid.

Table 79.—Reported Known Differences in Chemical, Combustion, and Health Effects Characteristics of Synfuels Products and Their Petroleum Analogs

Product	Chemical characteristics	Combustion characteristics	Health effects characteristics
Shale 011			
Crude	Higher aromatics, FBN, As, Hg, Mn	Higher emissions of NO_x particulate and (possibly) certain trace elements	More mutagenic, tumorigenic, cytotoxic
Gasoline	Higher aromatics	Slightly higher NO_x and smoke emissions	
Jet fuels	Higher aromatics	Slightly higher NO_x and smoke emissions	Eye/skin irritation, skin sensitization same as for petroleum fuel
DFM	Higher aromatics	Slightly higher NO_x and smoke emissions	Eye/skin irritation, skin sensitization same as for petroleum fuel
Residuals	Higher aromatics		—
Direct Iiquefaction			
Syncrude (H-Coal, SRC ll, EDS)	Higher aromatics and nitrogen		
SRC II fuel oil	Higher aromatics and nitrogen	Higher NO_x emissions	Middle distillates: nonmutagenic; cytotoxicity similar to but toxicity greater than No. 2 diesel fuel; burns skin. Heavy distillate: considerable skin carcinogenicity, cytotoxicity, mutagenicity, and cell transformation
H-Coal fuel oil	Higher nitrogen content	Higher NO_x emissions	Severely hydrotreated: nonmutagenic, nontumorigenic; low cytotoxicity
EDS fuel oil		Higher NO_x emissions	—
SRC II naphtha	Higher nitrogen, aromatics	—	Nonmutagenic, extremely low tumorigenicity cytotoxicity and fetotoxicity
H-Coal naphtha	Higher nitrogen, aromatics		Non mutagenic
EDS naphtha	Higher nitrogen, aromatics		
SRC II gasoline	Higher aromatics		
H-Coal gasoline	Higher aromatics		
EDS gasoline	Higher aromatics		
Indirect liquefact/on			
FT gasoline	Lower aromatics; N and S nil		Noncarcinogenic
FT byproduct chemical	—	N/A	—
Mobil-M gasoline	(Gross characteristics similar to petroleum gasoline)		
Methanol	—	Higher aldehyde emissions	Affects optic nerve
Gasification			
SNG	Traces of metal carbonyls and higher CO		
Low/medium-Btu gas	(Composition varies with coal type and gasifier design/operation)	(Emissions of a wide range of trace and minor elements and heterocyclic organics)	Nonmutagenic, moderately cytotoxic
Gasifier tars, oils, phenols	(Composition varies with coal and gasifier types; highly aromatic materials)	—	

SOURCE: M. Ghasseml and R. Iyer, Environmental Aspects of Synfuel Utilization, EPA-600/7-81-025, March 1981.

products–such as gasoline–are more likely to be widely distributed.

- Products from direct liquefaction processes appear more likely to be cancer hazards than do indirect process products, because of the higher levels of dangerous organic compounds produced in the direct processes.
- Coal-derived methanol fuel appears to be similar to the methanol currently being used, although there are potentials for contamination that must be carefully examined. Methanol is rated as a "moderate hazard" ("may involve both irreversible and reversible changes not severe enough to cause death or permanent injury'')[83] under chronic –long-term, low-level–exposure, although the effects of multi-year exposures to very low levels (as might occur to the public with widespread use as a fuel) are not known. Methanol has been assigned a hazard rating for acute exposures similar to that for gasoline,[84] but no comparison can be made for chronic exposures because data for gasoline exposure is inadequate.[85 86] In automobiles, methanol use increases emissions of formaldehyde sufficiently to cause concern, but lowers emissions of nitrogen oxides and polynuclear aromatics.[87] Depending on the potential health effects of low levels of formaldehyde, which are not now sufficiently understood, and the emission controls on automobiles, methanol use in automobiles conceivably may provide a significant net pollution benefit to areas suffering from auto-related air pollution problems.
- Many of the dangerous organics that are the source of carcinogenic/mutagenic/teratogenic properties in synfuels should be controllable by appropriate hydrotreating. Tradeoffs between environmental/health concerns and hydrotreating cost, energy consumption, and effects on other product characteristics currently are not known.

[83] N. I. Sax, *Dangerous* properties of Industrial Materials, Fourth Edition, Van Nostrand Reinhold Co., 1975.
[84] Ibid.
[85] Ibid,
[86] Ghassemi and Iyer, Op. Cit.
[87] *Energy From* Biological processes, op.cit.

OIL SHALE

Production and use of synthetic oil from shale raises many of the same concerns about limited water resources, toxic waste streams and massive population impacts as coal-derived liquid fuels, but there are sufficient differences to demand separate analysis and discussion, OTA has recently published an extensive evaluation of oil shale;[88] the discussion here primarily summarizes the key environmental findings of that study.

U.S. deposits of high-quality oil shale (greater than 25 gal of oil yield per ton) generally are concentrated in the Green River formation in northwestern Colorado (Piceance Basin) and northeastern Utah (Uinta Basin), The geographic concentration of these economically viable reserves to an arid, sparsely populated area with complex terrain and relatively pristine air quality, and the impossibility of transporting the shale (because of its extremely low energy density) lead to a potential concentration of impacts that is (at least in theory) easier to avoid with coal-derived synfuels. Thus, compliance with prevention of significant deterioration regulations for SO_2 and particulates may constrain total oil shale development to a million barrels per day or less unless current standards are changed or better control technologies are developed.

Also, the lack of existing socioeconomic infrastructure implies that environmental impacts associated with general development pressures could be significant without massive mitigation programs. Although coal development shares these concerns (especially in the West) and has water and labor requirements as well as air emissions that are not dissimilar on a per-plant basis, it is unlikely to be necessary to concentrate coal development to the same extent as with oil shale. Thus, coal development should have fewer se-

[88] *An* Assessment of Oil Shale Technologies, Op. cit.

vere physical limitations on its total level of development.

The geographic concentration of oil shale development should not automatically be interpreted as environmentally inferior to a more dispersed pattern of development, however. Although impacts will certainly be more severe in the developed areas as a result of this concentration, these impacts must be balanced against the smaller area affected, the resulting pressure on the developers to improve environmental controls to allow higher levels of development, and the possibility of being able to focus a major monitoring and enforcement effort on this development. Also, the major oil shale areas generally are not near large population centers, whereas several proposed coal conversion plants are within a few miles of such centers and may consequently pose higher risks to the public.

The volume of the material processed and discarded by an oil shale plant is a significant factor in comparing oil shale with coal-derived fuels. A 50,000 bbl/d oil shale plant using aboveground retorting (AGR) requires about 30 million tons per year of raw shale* versus about 6 million to 18 million tons of coal (the higher values apply only to low-quality lignites converted in a relatively inefficient process) for a similarly sized coal liquefaction plant. A modified in-situ (MIS) plant requires about the same tonnage of feedstock as does the coal plant, Consequently, although the underground mining of shale thus far has had a much better worker safety record than coal mining, underground mining of coal may be safer than shale mining for an AGR plant on a "fuel output" basis, especially when full-scale shale mining begins. Mining for an MIS plant, on the other hand, will be safer than that for the coal plant unless previous shale experience proves to be misleading.

The very large amount of spent shale represents a difficult disposal problem. An AGR plant must dispose of about 27 million tons/yr of spent shale, at least five times as much solid waste as that produced by a similarly sized coal synfuels plant (MIS plants may dispose of about 6 million tons/yr of spent shale, one to three times the disposal requirements of a coal plant). At this rate, a 1 MMB/D industry using AGRs will have to dispose of approximately 10 billion cubic feet of compacted shale each year.

This material cannot be fully returned to the mines because it has expanded during processing, and it is a difficult material to stabilize and secure from leaching dangerous compounds—cadmium, arsenic, and lead, as well as organics from some retorts (for example TOSCO II and Parajo Indirect)—into surface and ground waters. It also may cause a serious fugitive dust problem, especially with processes like TOSCO II that produce a very fine waste. Even with secure disposal, it will fill scenic canyons and represents an esthetic and ecosystem loss. Current research on small plots indicates that short-term (a few decades) stability of spent shale piles appears likely if sufficient topsoil is applied, but the long-term stability and the self-sustaining character of the vegetation is unknown. For these reasons, solid waste disposal may be oil shale's major environmental concern.

As with coal liquefaction processes, the "reducing environment" in the retorts produces both reduced sulfur compounds and dangerous organics that represent a potential occupational hazard for workers from fugitive emissions and fuel handling. Crude shale oil appears to be more mutagenic, carcinogenic, and teratogenic than natural crude.

On the other hand, the refined products are less likely to be significantly different in effect from their counterparts produced from natural crude, and shale syncrude is less carcinogenic or mutagenic than syncrudes from direct coal liquefaction. Although comparisons of relative risk must necessarily be tentative at this early stage of development, it appears that the risks from these toxic substances–excluding problems with spent shale—probably are somewhat comparable to those of the cleanest coal-based liquefaction processes (indirect liquefaction with high-temperature gasifies).

Other oil shale environmental effects of particular concern include:

- The mining of oil shale generates large amounts of silica dust that is implicated in various disabling lung diseases in miners.

*assuming 25 gal of oil per ton of shale.

- Aside from the reduced sulfur compounds and organics, the crude shale oil contains relatively high levels of arsenic, and somewhat higher levels of fuel bound nitrogen than most natural crude does. These pollutants as well as the organics can be reduced in the refining operation.
- In-situ production leaves large quantities of spent shale underground and thus creates a substantial potential for leaching out toxic materials into valuable aquifers. Control of such leaching has not been demonstrated.
- Although oil shale developers are proposing to use zero discharge of point-source water effluents, it may be desirable in the future to treat water and discharge it. The state of water pollution control in oil shale development is essentially the same as in coal-derived synfuels, however. Many of the controls proposed have not been tested with actual oil shale wastewaters, and none have been tested in complete wastewater control systems.
- MIS production—whereby a moderate amount of mining is done to provide space with which to blast the shale into rubble and then retort it underground—may present a special occupational hazard to workers from explosions, fire, and toxic gases as well as a potential danger to the public if toxic fumes escape from the mine to the surface.

To summarize, the environmental concerns of oil shale production appear to be quite similar to those of coal-based synfuels production, but with two important differences. First, the geographic concentration of oil shale production will tend to concentrate and intensify its environmental and socioeconomic impacts to a greater extent than is likely to be experienced by coal development. Second, the problems of disposing of the huge quantities of spent shale associated with the AGR system appear to be substantially greater than those of coal wastes.

BIOMASS FUELS

Production of liquid fuels from biomass will have substantially different impacts from those of coal liquefaction and oil shale production. These are described in detail in OTA's Energy From Biological Processes [89] and summarized briefly here.

The liquid fuel that appears to have the most potential for large-scale production is methanol produced from wood, perennial grasses and legumes, and crop residues. Ethanol from grains has been vigorously promoted in the United States, but appears likely to be limited by problems of food/fuel competition to moderate production levels (a few billion gallons per year).

Obtaining the Resource

Environmental concerns associated with alcohol fuel production focus on feedstock acquisition to a greater extent than with coal liquefaction. All of the credible alcohol fuel cycles require various degrees of ecological alteration, replacement, or disruption on vast land areas. Taking into account the expenditure of premium fuels needed to obtain and convert the biomass into usable fuels, replacing about 10 billion gal/yr of gasoline with biomass substitutes would require adding intensive cropping to a minimum of about 25 million acres with a combination of sugar/starch crops (for ethanol) and grasses (for methanol).

If this savings were attempted strictly by the use of ethanol made from corn, the land requirement probably would be at least 40 million acres. If methanol from wood were the major source, much of the gasoline displacement theoretically could be obtained by collecting the logging residues that are now left in the forest or burned. To replace 10 billion gal over and above the amount available from residues would involve increasing the scale and intensity of management (more acreage under intensive management,

[89] *Energy* From Biological processes, OP. cit.

shorter times between thinnings, more complete removal of biomass, more conversion of low-quality stands) on upwards of so million acres of commercial forest. It might involve an increased harvest of forestland with lower productive potential—so-called "marginal lands''—and it will almost certainly mean that lands not now subject to logging will be logged. Despite these difficulties, however, wood is the most likely source of large-scale biomass production.

If handled with care, a "wood-for-methanol" strategy could have a number of benefits. These include upgrading of poorly managed forests, better forest fire and pest control through slash removal, and reduced pressure on the few remaining unprotected stands of scenic, old-growth timber because of the added yields of high-quality timber that are expected in the long run from increased management.

Nevertheless, there is substantial potential for damage to the forests if they are mismanaged. High rates of biomass removal coupled with short rotations could cause a depletion of nutrients and organic matter from the more vulnerable forest soils. The impacts of poor logging practices—erosion, degraded water quality, esthetic damage, and damage to valuable ecosystems—may be aggravated by the lessening of recovery time (because of the shorter rotations) and any lingering effects of soil depletion on the forests' ability to rebound. The intensified management may further degrade ecological values if it incorporates widespread use of mechanical and chemical brush controls, very large area clearcuts and elimination of "undesirable" tree species, and if it neglects to spare large pockets of forest to maintain diversity.

Finally, the incentive to "mine" wood from marginal lands with nutrient deficiencies, thin soils, and poor climatic conditions risks the destruction of forests that, although "poor" from the standpoint of commercial productivity, are rich in esthetic, recreational, and ecological values. Because the economic and regulatory incentives for good management are powerful in some circumstances but weak in others, a strong increase in wood energy use is likely to yield a very mixed pattern of benefits and damages unless the existing incentives are strengthened.

The potential effects of obtaining other feedstocks for methanol or ethanol production may also be significant. Obtaining crop residues, for example, must be handled with extreme care to avoid removing those residues that are critical to soil erosion protection. Large-scale production of corn or other grains for ethanol is likely to occur on land that is, on the average, 20 percent more erosive than present cropland. Aside from creating substantial increases in erosion, corn production will require large amounts of agricultural chemicals, which along with sediment from erosion can pollute the water, and will displace present ecosystems.

Equivalent production levels of perennial grasses and legumes, on the other hand, could be relatively benign because of these crops' resistance to erosion as well as their potential to be obtained by improving the productivity of present grasslands rather than displacing other ecosystems. Although large quantities of agricultural chemicals would be used, the potential for damage will be reduced by the low levels of runoff from grasslands.

Conversion

Production of alcohol fuels will pose a variety of air and water pollution problems. Methanol synthesis plants, for example, are small indirect liquefaction plants that may have problems similar to those of coal plants discussed previously. The gasification process will generate a variety of toxic compounds including hydrogen sulfide and cyanide, carbonyl sulfide, a multitude of oxygenated organic compounds (organic acids, aldehydes, ketones, etc.), phenols, and particulate matter. As with coal plants, raw gas leakage or improper handling of tars and oils would pose a significant hazard to plant personnel, and good plant housekeeping will be essential. Because of low levels of sulfur and other pollutants in biomass, however, these problems may be somewhat less severe than in an equivalent-size coal plant.

Ethanol distilleries use substantial amounts of fuel–and therefore can create air pollution problems. An efficient 50-million-gal/yr distillery will consume slightly more fuel than a 30-Mw powerplant. There are no Federal emissions standards for these plants, and the prevailing local standards may be weak in some cases, especially for small onfarm operations.

The plants also produce large amounts of sludge wastes, called stillage, that are high in biological and chemical oxygen demand and must be kept out of surface waters. Although the stillage from grains is a valuable animal feed product and will presumably be recovered without the need for any further incentives, the stillage from sugar crops is less valuable and will require strict regulation to avoid damage to aquatic ecosystems, EPA has had a history of pollution control problems with rum and other distilleries, and ethanol plants will be similar to these.

APPENDIX 10A.– DETAILED DESCRIPTIONS OF WASTE STREAMS, RESIDUALS OF CONCERN, AND PROPOSED CONTROL SYSTEMS FOR GENERIC INDIRECT AND DIRECT COAL LIQUEFACTION SYSTEMS

Table 10A-1 .-Gaseous Emissions and Controls (indirect liquefaction)

Gaseous stream	Source	Stream components of concern	Controls	Comments
Fugitive emissions				
Vent gases				
Coal-lockhopper vent gas	Coal gasification	Carbon monoxide, hydrogen sulfide, tars, oils, naphtha, cyanide, carbon disulfide	Compression and recycle of pressurization gas, incineration of waste gas	
Ash-lockhopper vent gas	Coal gasification	Particulate, trace elements	Scrubber	The need for and the effectiveness of incineration/particulate control have not been defined
Concentrated acid gas	Gas purification	Hydrogen sulfide, carbonyl sulfide, carbon disulfide, hydrogen cyanide, carbon monoxide, carbon dioxide, light hydrocarbons, mercaptans	Stretford or ADIP/Claus processes followed by a sulfur recovery tail gas process, e.g., Beavon, and incineration of the Beavon off-gas in a boiler	The acid gases will be concentrated by the gas purification process. The control choice is dependent on the sulfur content of the gases; a combination of Stretford and ADIP/ Claus may have the lowest overall costs.
Off-gases from catalyst regeneration	Catalytic synthesis	Nickel and other metal carbonyls, carbon monoxide, sulfur compounds, organics	Incineration in a flare, incinerator, or controlled combustion	Other control technology requirements not established
Evaporative emissions from stored products	Product storage	Aromatic hydrocarbons, C_5-C_{12} aliphatic hydrocarbons, ammonia	Vapor recovery systems, use of floating roof storage tanks, conservation vents. Incinerate	Control technologies used in petroleum refinery and other industries should be applicable to Lurgi plants; standards promulgated for the petroleum refining industry would probably be extended to cover the synthetic fuel industry.
Auxillary plant emissions				
Flue gases	Power/steam generation	Sulfur and nitrogen oxides, particulate trace elements, coal fines	Electrostatic precipitators, fabric filters, flue-gas desulfurization systems, combustion modification	Controls applicable to utility and industrial boilers would generally be applicable. Established emissions regulations would cover boilers at Lurgi plants
Cooling-tower drift and evaporation	Power/steam generation, process cooling	Ammonia, sodium, calcium, sulfides/sulfates, chlorine, phenols, fluorine, trace elements, water treatment chemicals	Proper design and siting can mitigate impacts	Recycled process water is used for cooling-tower makeup. If cooling-tower drift becomes a problem then the recycled water will receive additional treatment or makeup water will come from another source.
Treated waste gases	Gaseous emission controls (e.g., sulfur recovery	Hydrogen sulfide, carbonyl sulfide, carbon disulfide, hydrogen cyanide, carbon monoxide, carbon dioxide, light hydrocarbons	Essentially the same as for the concentrated acid gas	—

SOURCE' U.S. Department of Energy, Energy Technologies and the Environment, *Environmental* Information Handbook, DOEIEVI74O1O-1, December 1980

Table 10A-2.—Liquid Waste Stream Sources, Components, and Controls (indirect liquefaction)

Liquid waste stream	Source	Stream components of concern	Controls	Comments
Ash quench water	Gasification	Dissolved and suspended solids, trace elements, sulfides, thiocyanate, ammonia, dissolved organics, phenols, cyanides	Gravity settling of solids: the overflow from the settling basin is recycled back to the ash quenching operation	See table 10A-3 Streams, for final disposition of ash solids. Capabilities of technology in terms of clarified ash slurry water not known
Gas liquor	Gas purification	Sulfides, thiocyanate, ammonia, cyanides, mono- and polycyclic organics, trace metals, mercaptans	Lurgi tar/oil separator	Capabilities of tar/oil separation, Phenosolvan, and ammonia recovery well established in terms of removal of major constituents. Capabilities for removal of minor constituents not established. Limited cost data available on processes.
			Phenosolvan process	Removes dissolved phenols from water
			Phosam W or Chemi-Linz	Removes dissolved ammonia, produces saleable anhydrous ammonia.
			Bio-oxidation and reverse osmosis	Removes dissolved organics and inorganic.
Boiler blowdown	Power/steam generation	Dissolved and suspended solids	Use as cooling-tower makeup or as ash quench water makeup	Impacts on the quench system and subsequent treatment of clarified water not established.
Spent reagents and sorbents	Gaseous emission controls, wastewater treatment	Sulfides, sulfates, trace elements, dissolved and suspended solids, ammonia, phenols, tar oils, hydrogen sulfide, carbon dioxide	Recovery of reagents from air pollution control processes, addition to ash quench slurry	Applicable controls (e.g., resource recovery disposal in lined pond, dissolved solids removal, etc. are waste- and site-specific; cost and performance data should be developed on a case-by-case basis.
Acid wastewater	Product separation and purification	Dissolved organics, thiocyanate, trace elements	Oxidation, use as cooling-tower or quench water makeup	—
Leachates	Gasifier ash, boiler ash, FGD sludge, biosludge, spent catalysts	Trace elements, organics	Landfill should have impervious clay liner and a leachate collection system. If buried in the mine, the mine should be dry and of impervious rock or clay.	—
Treated aqueous wastes	Wastewater treatment	Dissolved and suspended solids, trace elements	Forced or natural evaporation	The effectiveness and costs of various applicable controls (e.g., solar or forced evaporation, physical-chemical treatment for water reuse, etc.) not determined.

SOURCE: U.S. Department of Energy, Energy Technologies and the Environment, *Environmental* Information Handbook, DCN2EVI7401O-1, December 1980.

Table 10A-3.—Solid Waste Stream Sources, Components, and Controls (Indirect liquefaction)

Solid waste stream	Source	Stream components of major concern	Controls	Comments
Ash or slag	Gasification	Trace elements, sulfides, thiocyanate, ammonia, organics, phenols, cyanides, minerals	Combined with boiler ash and flue gas desulfurization sludge and disposed of in a lined landfill or pond, or buried in the mine	Ash is more than 90 percent of the solid wastes generated at a Lurgi plant. The choice and design of disposal system depend on the ash content of coal and plant/mine site characteristics.
Scrubber sludge	Power/steam generation	Calcium sulfate, calcium sulfite, trace metals, limestone, alkali metal carbonates/sulfates	Disposed of with the gasifier ash	—
Boiler ash	Power/steam generation	Trace elements, minerals	Disposed of with the gasifier ash	
Sludge	Waste treatment	Trace elements, polycyclic aromatic hydrocarbons	Combined with gasifier ash, boiler ash and flue gas desulfurization sludge and disposed of in a lined landfiii or buried in the mine. May also be incinerated	Because of lack of data on waste quantities and characteristics, optimum control(s) cannot be established.
Spent catalysts	Gas shift conversion, catalytic synthesis, sulfur recovery (gaseous emission centrol)	Metalic compounds, organics, sulfur compounds	Process for material recovery, or fixation/ encapsulation and disposal in landiil or mine	The technical and economic feasibility of resource recovery have not been established
Tarry and oily sludges	Product/byproduct separation	Mono- and polycyclic aromatic hydrocarbons, trace elements	injection into the gasifier, disposal in a secure landfiil, return to the mine for burial, incineration	Because of lack of data on waste quantities and characteristics, optimum control(s) cannot be established

SOURCE: U.S. Department of Energy, Energy Technologies and the ***Environment,Environmental*** Information Handbook, DOI3EVI74O1O1, December 19S0.

Table 10A-4.—Gaseous Streams, Components, and Controls (direct liquefaction)

Operation/auxiliary process	Air emissions discharged	Components of concern	Control methods
Coal storage and pretreatment	Coal dust	Respirable dust, particulate, trace elements	Spray storage piles with water or polymer. cyclones and baghouse filters for control of dust due to coal sizing.
	Particulate-laden flue gas from coal dryers	Respirable dust, particulate, trace metals, sulfur and nitrogen oxides	Cyclones and baghouse filters. Wet scrubbers such as venturi.
Liquefaction	Preheater flue gas	Particulate, sulfur and nitrogen oxides	If other than clean gas, scrub for sulfur, nitrogen, and particulate components.
	Pressure letdown releases	Hydrocarbons, hydrogen sulfide, hydrogen cyanide, ammonia, PAH, hydrogen, phenols, cresylics	Flaring[a]
Separation:			
Gas separation	Pressure letdown releases	Same as for liquefaction letdown releases	Flaring[a]
Solids/liquids separation	Preheater flue gas	Same as the liquefaction preheater	If other than clean gas, scrub for sulfur, nitrogen, and particulate components.
	Particulate-laden vapors from residue cooling (SRC-II)	Particulate, hydrocarbons, trace elements	Cyclone and baghouse filter. Wet scrubbers.
	Pressure letdown releases	Same as for liquefaction letdown releases	Flaring[a]
Purification and upgrading:			
Fractionation	Preheater flue gas	Same as for liquefaction preheater	If other than clean gas, scrub for sulfur, nitrogen, and particulate components.
	Particulate-laden vapors from product cooling (SRC-I)	Same as for SRCII residue cooling	Cyclone and baghouse filter. Wet scrubbers
	Pressure letdown releases	Same as for liquefaction letdown releases	Flaring[a]
Hydrotreating	Preheater flue gas	Same as for liquefaction preheater	If other than clean gas, scrub for sulfur, nitrogen and particulate components.
	Pressure letdown releases	Same as for liquefaction letdown releases	Flaring[a]
Water cooling	Drift and evaporation	Ammonia, sodium, calcium sulfides/sulfates, chlorine, phenols, fluorine, trace elements, water treatment chemicals	No controls available—good design of water management system can minimize losses.
Steam and power generation	Boiler flue gas	Sulfur and nitrogen oxides, particulate	Sulfur dioxide scrubbing, combustion modifications.
Hydrogen generation	Preheater flue gas	Same as for liquefaction preheater	If other than clean gas, scrub for sulfur, nitrogen, and particulate components.
Acid gas removal	Pressure letdown releases	Hydrogen sulfide, hydrogen cyanide, carbon oxides, light hydrocarbons	Flaring[a]
Sulfur recovery	Flue gas	Same as for liquefaction preheater	If other than clean gas, scrub for sulfur, nitrogen, and particulate components.
	Low-sulfur effluent gas[b]	Hydrogen sulfide, hydrogen cyanide, sulfur dioxide	Carbon absorption. Direct-flame incineration. Secondary sulfur recovery (Beavon).
Hydrogen/hydrocarbon recovery	Pressure letdown releases	Hydrogen, hydrocarbons	Direct-fired afterburner
Product/byproduct storage	SRC dust (SRC-I)	Respirable dust, particulate	Spray storage piles with water.
	Sulfur dust	Elemental sulfur	Store in enclosed area.
	Hydrocarbon vapors	Phenols, cresylics, hydrocarbons, PAH	Spills/leaks prevention.

[a]Collection, recovery of useful products and incineration may be more appropriate.
[b]A secondary sulfur recovery process may be necessary to meet specified air emission standards.

SOURCE: U.S. Department of Energy, Energy Technologies and the Environment, Environmental Information Handbook, DOE/EV/74010-1, December 1980.

Table 10A-5.—Liquid Stream Sources, Components, and Controls (direct liquefaction)

Operation/auxiliary process	Wake effluents discharged	Components of concern	Control methods
Coal pretreatment	Coal pile runoff	Particulate, trace metals	Route to sedimentation pond.
	Thickener underflow	Same as above	Route to sedimentation pond.
Water cooling	Cooling tower blowdown	Dissolved and suspended solids	Sidestream treatment (electrodialysis, ion exchange or reverse osmosis) permits discharge to receiving waters.
Hydrogen generation	Process wastewater	Sour and foul wastewater; spent amine scrubbing solution	Route to wastewater treatment facility.
Acid gas removal	Process wastewater	Dissolved hydrogen sulfides, hydrogen cyanide, phenols, cresylics	Route to wastewater treatment facility.
Ammonia recovery	Process wastewater	Dissolved ammonia	Route to wastewater treatment facility.
Phenol recovery	Process wastewater	Dissolved phenols, cresylics	Route to wastewater treatment facility.

SOURCE: U.S. Department of Energy, Energy Technologies and the Environment, Environmental Information Handbook, DOE/EV/74010-1, December 1980.

Table 10A.6.—Soiid Waste Sources, Components, and Controls (direct liquefaction)

Operation/auxiliary process	Solid waste discharged	Components of concern	Control methods
Coal pretreatment	Refuse	Mineral matter, trace elements	Landfill, minefill
Solids/liquids separation	Excess residue (SRC-II) or filter cake (SRC-I)	Mineral matter, trace elements, absorbed heavy hydrocarbons	Gasification to recover energy content followed by disposal (landfill or minefill
Hydrotreating	Spent catalyst	Metallic compounds, absorbed heavy organics, sulfur compounds	Return to manufacturer for regeneration
Steam and power generation	Ash	Trace elements, mineral matter	Landfill, minefill
Hydrogen generation	Ash or slag	Trace elements, sulfides, ammonia, organics, phenols, mineral matter	Landfill, minefill

SOURCE: U.S. Department of Energy, Energy Technologies and the *Environment,* Environmental Information Handbook, DOEIEVI74O1O-1, December 1980

Chapter 11

Water Availability for Synthetic Fuels Development

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Water Availability for Synthetic Fuels Development

INTRODUCTION

Operation of a synthetic fuels plant requires a steady supply of water throughout the year for both plant and site activities. Availability of water will be determined not only by hydrology and physical development potential, but also by institutional, legal, political, and economic factors which govern and/or constrain water allocations and use among all sectors. This chapter expands the environmental discussion of the role of water in synfuels development and examines the major issues that will determine both water availability for synfuels and the impacts of procuring water supplies for synfuels on other water users. There are five river basin areas where oil shale and coal resources are principally located: in the eastern basins of the Ohio, Tennessee and the Upper Mississippi, and in the western basins of the Upper Colorado and the Missouri (see fig. 24).

Figure 24.—Water Resources Regions

SOURCE: U.S. Water Resources Council, *The Nation's Water Resources* 197S2000, vol. 2, pt. 1, p. 3,

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WATER REQUIREMENTS FOR SYNFUELS PLANTS

Estimates of the consumptive use requirements of generic synthetic fuels plants producing 50,000 barrels per day oil equivalent (B/DOE) of product are shown in table 80. In general, the actual amount of water consumed will vary according to the nature of the products produced, process methods, plant design, and site conditions. In coal conversion, the largest single component of total water consumption is typically for cooling, * with other major components being for hydrogen production, waste disposal, and revegetation. In producing synfuels from oil shale, retorting and upgrading require the most water; other major uses are for the handling and disposal of spent shale, and for revegetation.

*The amount of water consumed in cooling will depend on many factors, including the degree to which evaporative or "wet" cooling, or dry cooling, are used. Air or "dry" cooling is an alternative to wet cooling but is less efficient and generally more expensive.

Table 80.—Estimates of Net Consumptive Use Requirements of Generic Synfuels Plants (50,000 B/DOE)[a]

	Acre-feet/year	Barrels wate/ barrel product
Gasification	4,500-8,000	1.9-3.4
Liquefaction	5,500-12,000	2.3-5.1
Oil shale	5,000-12,000	2.1-5.1

[a]Available estimates are based on theoretical calculations, conceptual designs, small-scale experimental facilities, etc. A range is shown for each generic process In order to reflect differences among process technologies (e.g., Indirect liquefaction will generally consume more water than direct liquefaction; modified-in-situ will generally consume less water than aboveground 011 shale processes), plant design options (e.g., alternative methods of water reuse, conservation, and cooling), and sites. Estimates also vary with the level of detail and state of development of the engineering designs. There are also at least two major elements of uncertainty surrounding these estimates. Firat, both the refinement and optimization of operational requirements are limited by the lack of commercial experience. Secondly, estimates commonly assume zero wastewater discharge, which Is to be achieved via the treatment and reuse of plant wastewater for cooling water makeup and boiler feed; however, the treatment processes to be used generally have yet to be demonstrated on a commercial scale. Although the estimates shown In table 80 may thus not be representative of actual consumptive use requirements In specific cases, the magnitude of the other uncertainties concerning water availability in general, as discussed In this chapter, will likely overshadow the question of how much water will be required for expected synfuels development. The following references provide additional details:

1. Office of Technology Assessment, An Assessment of Oil Shale Technologies, June 1980, ch. 9.
2. Ronald F. Probstein and Harris Gold, Water In Synthetic Fuel Production, MIT Press, Cambridge, Mess., 1978.
3. R. M. Wham, et al., Liquefaction Technology Assessment—Phase 1: Indirect Liquefaction of Coal to Methanol and Gasoline Using Available Technology, Oak Ridge National Laboratory, Oak Ridge, Term., February 1981.
4. Exxon Research and Engineering Co., EDS Coal Liquefaction Process Development, phase V, vols. 1, II, and Ill, March 1881.
5. Harris Gold and David J. Goldstein, "Water Requirements for Synthetic Fuel Plants;" and Harris Gold, J. A. Nardella, and C. A. Vogel (ads.), "Fuel Conversion and Its Environmental Effects," Chemical Engineering Progress, August 1979, pp. 58-84.

SOURCE: Office of Technology Assessment.

Synfuels plants will also generally require water for other process-related activities such as environmental control (e.g., dust control) and for associated growth in population, commerce, and industry (e.g., for water supply and sewerage). Plant activities will not all require water of similar qualities. As examples, high-quality water is required for processing; intermediate-quality water is required for cooling; mining, materials preparation, and disposal activities are the least sensitive to water quality characteristics.

Procuring water supplies for synfuels plants will represent a small fraction of total plant investment and operations costs (typically less than 1 percent). * * Thus, assuming that the overall economic feasibility of the plant has been established, the more critical industrial considerations in selecting a water source will be the ease of acquiring water of appropriate quality and the certainty of the yield. Major water sources for synfuels would include the direct diversion of surface water, the purchase or transferring of existing water rights, the use of existing or the construction of new storage, the use of tributary and nontributary ground water,*** savings from improved efficiency, reuse, and conservation by all users, and interbasin diversions.

The feasibility and attractiveness of sources will vary among sites according to environmental, social, legal, political, and economic criteria, and

**Obtaining reliable and comparable cost data on the procurement of water to the synfuels industry is difficult because of variation in the conditions surrounding each sale (e.g. water rights vary according to their seniority, historic use, point of diversion, etc.). As examples, annual costs per acre-foot of consumption vary between $50 to $300; water rights have sold for as high as $2,000/acre-foot (in perpetuity). Assuming a cost of $2,000/acre-foot, water rights costs would still represent a maximum of only 0.8 percent of the cost of a $2 billion plant with an average annual consumption of 8,000 acre-feet. Note that what is bought is the right to use water, not the water per se.

Costs are, nevertheless, important industrial criteria for evaluating alternative sources of water supply. Costs will also be important for water resources planning efforts, as they will help to determine the nature and extent of impacts on other water users from synfuels development.

***The development of deep, nontributary ground water, which is hydrologically unconnected to the surface flow, can be considered as an "additional" source of water. Development of tributary ground water, which is hydrologically connected to streamflow, does not represent an increase in supply and may alter the surface flow regime, it is therefore difficult a priori to predict how and which water "packages" will be assembled. Evidence suggests that the industry is conservative in planning for a plant's water resource needs in order to ensure (both hydrologically and legally) that the plant obtains its minimum operating requirements. As examples, developers can secure several different sources of supplies; estimates of resource needs will include a margin of safety; and sources can be "guaranteed" by obtaining agreements not only with rights holders but also with upstream appropriators and/or potential downstream claimants. Synfuels technology modifications should also be forthcoming from the industry, if needed to reduce water needs.

IMPACTS OF SYNFUELS DEVELOPMENT ON WATER AVAILABILITY

In the aggregate, water consumption requirements for synfuels development are small. Achieving a synfuels production capability of 2 MMB/DOE would require on the order of 0.3 million acre-feet/year (AFY), which will be distributed among all of the Nation's major oil shale and coal regions. This compares with an estimated (1975) total national freshwater consumptive use of119 million AFY, of which about 83 percent is for agriculture. [1] Table 81 shows the general hydrologic characteristics of the principal river basins to be affected.

Although in the aggregate synfuels water requirements are small, each synfuels plant, nevertheless, is individually a relatively large water consumer. Depending on both the water supply sources chosen for a synfuels plant and the size and timing of water demands from other users, synfuels development could create conflicts among users for an increasingly scarce water supply or exacerbate conflicts in areas where water is already limited or fully allocated. Sectors that will be competing for water will vary among the regions and will include both offstream uses (e.g., agriculture, industry, municipalities) and instream uses (e.g., navigation, recreation, water quality control, fish and wildlife, hydropower). Because energy developers can afford to pay a relatively high price for water, nonenergy sectors are not likely to be able to compete economically against synfuels for water. However, it is speculative to identify which sectors may be the most vulnerable to synfuels development.

Public reactions to proposed water use change and nonmarket mechanisms can be used to allocate and protect water for use by certain sectors depending on the region and State. Examples of nonmarket mechanisms include the assertion of Federal reserved water rights, water quality legislation, and State water allocation laws. While such mechanisms may prevent developers from always obtaining all the water they need, the synfuels industry is expected to obtain the major portion of its water requirements.

[1] U.S. Water Resources Council, The Nation Water *Resources*—1975-2000, December 1978. The assessment projects a total national freshwater consumption of 151 million AFY in 2000, of which about 70 percent would be for agriculture.

Table 81 .—Regional Streamflow Characteristics 1975 [a] (millions acre-feet/year)

	Mean annual streamflow [b]	Consumption [c] 1975	Consumption [c] 2000	Low flow ratio [d]	Low flow month
Ohio	199	2.0	4.9	0.15	September
Tennessee	46	0.5	1.2	0.38	September
Upper Mississippi	136	1.3	3.0	0.23	January
Upper Colorado	11	2.7	3.6	0.12	July
Missouri	49	17.3	22.3	0.19	January

[a] U.S. Water Resources Council (WRC), The *Nation's Water Resources—1975-2000*.
[b] WRC, table IV-1. Note that all these outflows are inflows to a downstream river basin.
[c] WRC, table III-3.
[d] Ratio of the annual flow of a very dry year (that flow which will be exceeded with a 95-percent probability in any Year) to the mean annual flow. WRC, table IV-2.

SOURCE: US. Water Resources Council as tabulated by OTA.

Photo credit: Office of Technology Assessment

Competing uses will increase pressures on the Nation's water resources, especially in the arid West

The nature and extent of the impacts of synfuels development on water availability in general, and on competing water users, are controversial. The controversy arises in large part because of the many hydrologic, institutional, legal, and political constraints and uncertainties that will ultimately determine when, how, and if users will be able to obtain the water they need. Furthermore, analyzing these constraints and uncertainties is difficult because of many additional complex factors: the lack of dependable and consistent data, limitations of demand-forecasting methods, time and budget constraints, and the unpredictability of future administrative decisions and legal interpretations. In some cases, the uncertainties about water availability in general appear to be so large that they overshadow the question of how much water will be required for synfuels development.

OTA's study[2] found that there was considerable variation in the quality, detail, and scope of the water availability assessments that have been completed related to synfuels development. Few studies take into account all of the issues that will determine resource allocations and use; and studies rarely try to address the likely, cumulative water resource impacts of alternative decisions on reducing uncertainties and resolving conflict among competing water users. Decision makers need to be better informed about the assump-

[2]Wright Water Engineers, Inc., "Water Availability for Synthetic Fuels," prepared for the Office of Technology Assessment, June 1981.

tions and uncertainties upon which reports are predicated, so that estimates can be properly interpreted and tradeoffs can be evaluated.

Some of the major uncertainties about water availability for synfuels are discussed below. More informed decisions on water availability questions, however, can only partially be achieved by "improving" studies themselves; more informed decisions also depend on greatly improved water planning practices in general in the Nation. The present fragmentation of responsibilities for water policy, planning, and management effectively prevents an assessment of the cumulative impacts of water resource use on an ongoing and comprehensive basis. *

*The fragmentation of water-related responsibilities among agencies, States, and levels of governments arises in large part because river system boundaries rarely coincide with political boundaries. As a result, there can be major inconsistencies in water management practices across the country (e. g., inconsistent criteria for evaluation; the lack of integrated planning—including data management—for ground and surface waters, water quality and quantity, and instream and offstream uses).

WATER AVAILABILITY AT THE REGIONAL LEVEL

Eastern River Basins

In the principal eastern basins where energy resources are located (i.e. Ohio, Tennessee, and the Upper Mississippi), water should be adequate on the mainstems and larger tributaries, without new storage, to support planned synfuel development.[3] However, localized water scarcity problems could arise during abnormally dry periods or due to conflicts in use on smaller tributaries. The severity and extent of local problems cannot be fully ascertained from existing data and have not yet been examined comprehensively, * but, with appropriate water planning and management, these problems should be reduced if not eliminated.

There are, nevertheless, various uncertainties in the eastern basins that will influence water availability for synfuels development, and difficult local situations could arise.[4] For example, 7-day, 10-year minimum low flows are used to estimate water availability. * * These estimates are essentially based on recorded streamflow data which can be of varying quality. Furthermore, by using historical streamflow records directly, reports on water availability in the eastern basins characteristically underestimate the frequency of future critical low flows; i.e., as flow depletions increase in the future, the critical flow associated with the 7-day, 10-year frequency will actually occur more often in the future than the historical data would indicate.

The political, institutional, and legal factors that will determine water availability for synfuels in the eastern basins differ in type and complexity from those in the western basins. For example, the East and West have different regional hydrologic characteristics, with the East being relatively humid. There are also varying legal and administrative structures as shown in figures 25 and 26: riparian water law is generally applied in the East whereby riparian landowners are entitled to an equal, "reasonable" use of adjacent streamflow; the prior appropriation doctrine is generally applied in the West whereby water rights are based on "beneficial" use with priorities assigned according to "first in time, first in right. " Furthermore, in the East there is a general lack of treaties and compacts, and there are no major Federal (including Indian) reserved water rights questions.

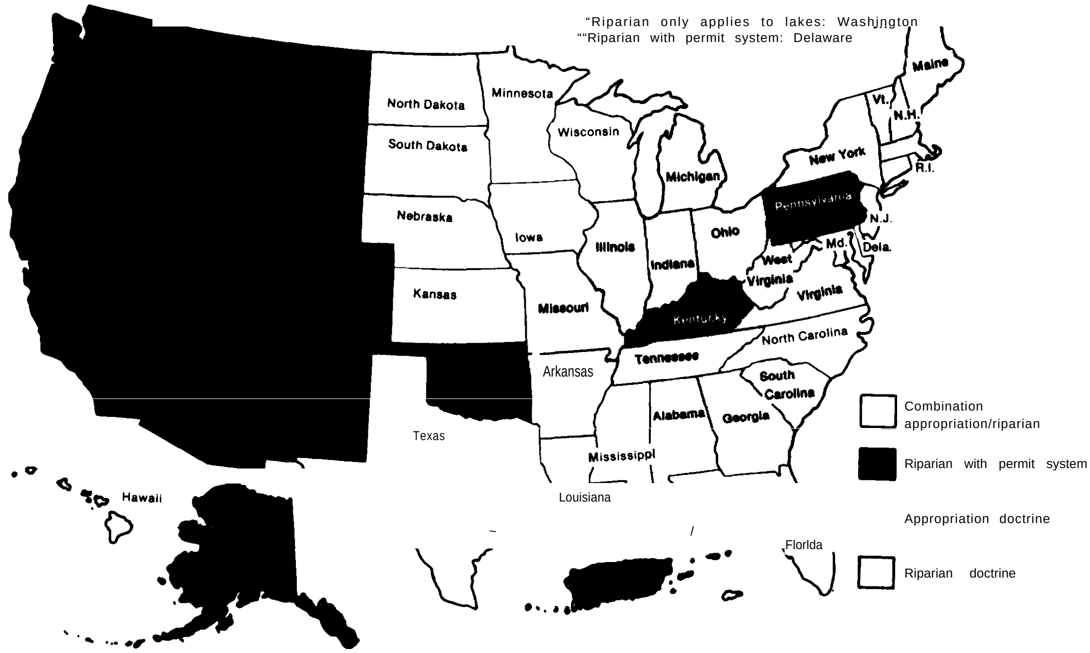
Although water may thus appear to be more readily available for synfuels development in the East (e.g., through the transfer of ownership of riparian land), eastern water law can result in significant uncertainty concerning the dependability of the supply: because all users have equal

[3]1 bid.

"For example, available reports related to ynfuels for the Tennessee River Basin generally deal with specific project sites; the sparsity of comprehensive information with respect to cumulative impacts and possible water use conflicts is presumably because of the large quantities of water available at the regional level. The Ohio River Basin Commission study focuses on water availability for plants located on the mainstem, even though there are facilities being proposed for tributaries.

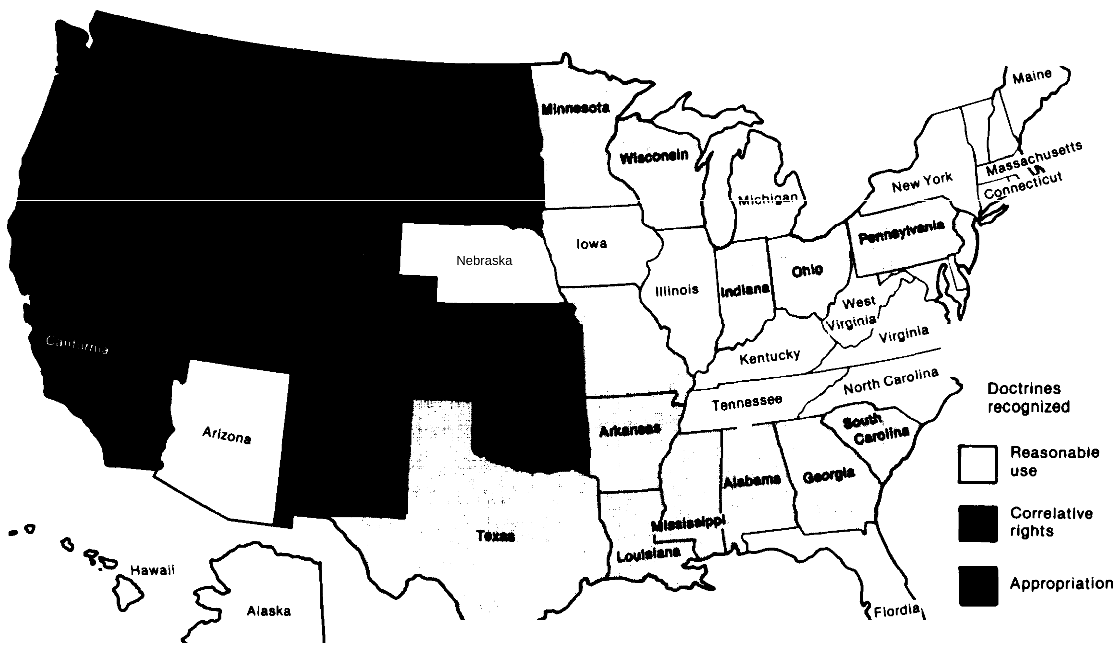
* *The use of the 7-day, 10-year minimum flow in the East is also the basis for water quality regulations and for estimating critical conditions for navigation in rivers with limited storage.

Figure 25.– The Nation's Surface Water Laws



SOURCE: U.S. Water Resources Council, (The *Nation's Water* Resources 7975-2000, vol. 2, **pt.** iv, P. 118).

Figure 26.— The Nation's Ground Water Laws



SOURCE: U.S. Water Resources Council, (The *Nation's* Water Resources 197%?000, vol. 2, pt. iv, p. 118).

rights under riparian law, the law does not protect given users against upstream diversions or against pumping by adjacent wells. * Uncertainty also arises because eastern water law has not been as well advanced through court tests as in the West. There are also questions in the East concerning the availability of water from Federal storage (i.e., in the Ohio River Basin) because of uncertainties regarding who has responsibility for marketing and reservoir operation.

The Western River Basins

Competition for water in the West already exists and is expected to intensify with or without synfuels development. There are potential sources of supply in both the Upper Colorado and the Missouri River basins that could support synfuels development. However, the issues determining whether and the extent to which these sources will be available for use differ between the two basins. These issues concern complex State water allocation laws, compacts and treaties, Federal including Indian reserved water rights claims, and the use of Federal storage. In addition, the use of "mean annual virgin flows" in both regions to characterize the hydrology results in the masking of important elements of hydrologic uncertainty.** However, and in contrast with the situation in the East, although the complex water setting in the West will probably make obtaining water difficult, the user will be more assured of a certain supply once a right is obtained.[5]

Missouri River Basin

The magnitude of the institutional, legal, political, and economic uncertainties in the Missouri River Basin, together with the need for major new water storage projects to average-out seasonal and yearly streamflow variations, preclude an unqualified conclusion as to the availability of surface water resources for synfuels development.[6] Ground water resources are not well understood in the basin, but are not likely to be a primary source of water for synfuels.

Major coal deposits for synfuels development in the Missouri River Basin lie within and adjacent to the Yellowstone River subbasin. The availability of water for synfuels from the Yellowstone subbasin, however, could be constrained by the provisions of interstate compacts, i.e., the Yellowstone River Compact. For example, at present all signatory States must approve any water exports from the basin (e.g., to the coal-rich Belle Fourche/Gillette area where water is scarce). Although export approval procedures are now being challenged in court and States have begun to modify approval procedures, such approvals are likely to take some time. Furthermore, additional storage would likely be required to develop fully the compact allocations.

Federal reserved water rights are often senior rights and have the potential of preempting current and future uses. These rights, however, have yet to be quantified and are a major source of uncertainty for water planning. The largest single component of Federal reserved rights are Indian water rights. There is a general lack of quantitative data concerning Indian water rights because of political controversy over which jurisdictions should be adjudicating the claims, varying interpretations of the purposes for which water rights reservations can be applied, and ongoing litigation.[7]

*For example, Federal storage has not yet been utilized in Illinois because delivery of the water from the reservoirs (e.g., to the synfuels plants) cannot be guaranteed along the river; riparian landowners along the way could intercept the released water. Energy companies are thus faced with having to build private pipelines.

**The accuracy of mean annual virgin flows is uncertain due to possible inaccuracies in the underlying data both on streamflows and on depletions. (Depletions are usually not measured directly for practical reasons.) Furthermore, virgin flow estimates are treated as both deterministic and stationary, rather than as time-varying, which prevents the variability of streamflows from being addressed accurately in areas lacking sufficient storage. Estimates of the mean annual virgin flow for the Colorado River at Lees Ferry vary from 12.5 million to 15.2 million acre-feet depending on the assumptions (in this case, the period of the historical record) used.

In general, the use of aggregated data, in the form of regional and basinwide averages, will mask the local and cumulative downstream effects of development on water availability. Such data do not provide information about either the seasonal variability of streamflows and demands or the relative positioning and hence interrelationships among users. These factors are important for identifying potential competition for water, especially in areas where water is scarce and subject to development pressures, as will often characterize locations for synfuels development.

'Ibid.

[6]Ibid.

[7]The only "official" Government estimates of Indian reserved water rights project depletions (i.e. requirements) of 1.9 million acre-

(continued on next page)

Other major uncertainties that could effect the availability of water for synfuels concern State water allocation laws. For example, Montana has established instream flow reservations in the lower-Yellowstone River of 5.5 million AFY to protect future water quality and wildlife. Over 500,000 AFY have also been reserved in the basin for future municipal and irrigation use. Additional storage would be required to meet these reservations during years of low flow, but Montana State officials generally do not advocate the construction of new mainstem storage, even if instream flow shortages were to occur otherwise, as this would interfere with the free-flowing nature of the river.[8 9] No determination has yet been made as to how these instream flow reservations would be accommodated under the Yellowstone Compact.

The transferring of water rights from existing (e.g., agricultural) to new (e.g., synfuels) uses in Montana is subject to administrative restrictions under primarily the 1973 Water Use Act, and State environmental and facility siting acts.[10] Because of these restrictions, water rights are not freely transferable from existing users, and, in effect, there is presently no economic market for rights transfers.

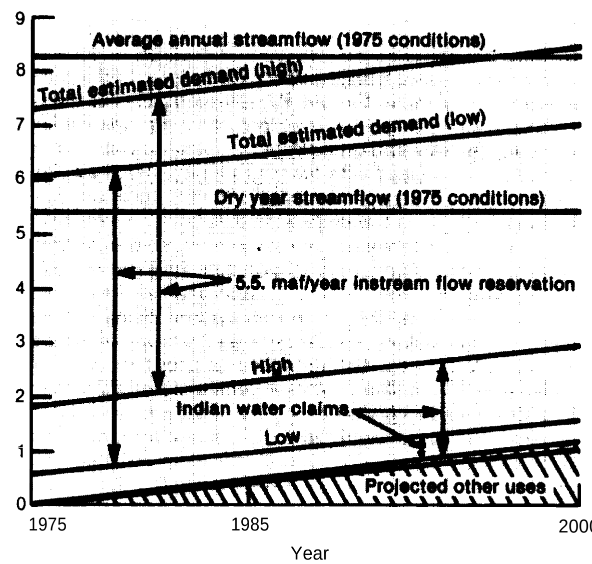
State water laws and statutory provisions in other Upper Basin States similarly could constrain water rights transfers to synfuels.11 As examples, water for irrigation takes precedence in these States over water for energy development, and the "public interest" is to be explicitly considered in approving water allocations. Alternatively, other laws could work to the disadvantage of nonenergy sectors, such as navigation in the Missouri region under the Federal Flood Control Act of 1944 (33 USC 701 -(b)).

Many of the water availability issues in the Missouri River Basin cannot be adequately evaluated because of a lack of supporting data and case law interpretations. Figure 27 illustrates the possible magnitude of uncertainty by superimposing the major projected consumptive uses (excluding synfuels) onto the availability of water in the Yellowstone River. As can be seen, assuming a low total estimated demand growth scenario, demands would not be met in a dry year without additional storage. Assuming a high-growth scenario, not only would demands not be met in a dry year without storage, but they would also exceed the average annual flow with additional storage.

Upper Colorado River Basin

Although water may not be available in certain tributaries and at specific sites, sources of water

Figure 27.–Streamflows and Projected Increased Incremental Water Depletions, Yellowstone River at Sidney, Mont.



SOURCE: "WaterAvailability for Synthetic Fuels," Wright Water Engineers, Inc., contractor report to OTA, June 5, 1981.

feet for the year 2020 in the Yellowstone. (U.S. Department of Interior, Water for Energy Management Team, Report *on* Water *for* Energy *in* the Northern Great Plains With Emphasis on the *Yellowstone* River Basin, January 1975.) A lower estimated value of 0.5 million acre-feet appeared in a 1960 background paper (for a larger framework study of the Missouri River Basin) by the Bureau of Reclamation. For a detailed discussion of Indian reserved water rights, the reader is referred to Constance M. Boris and John V. Krutilla, Water Rights and Energy Development in the *Yellowstone* River Basin, Resources for the Future, 1980.

[8]Wright Water Engineers, Inc., op. cit.

[9]Personal communications, Department of Natural Resources and Conservation, State of Montana.

[10]For a detailed discussion of State water allocation laws see Grant Gould, State Water Law in the West: *Implications* for Energy *Development,* Los Alamos Scientific Laboratory, Los Alamos, N. Mex., January 1979.

[11] Ibid.

generally exist in the Upper Colorado River Basin that could be made available to support OTA's low and high estimates of oil shale development through at least 1990. * However, the institutional, political, and legal uncertainties **in the basin make it difficult to determine which sources would be used, the actual amount of water that would in fact be made available from** any source to support synfuels development, and thus the water resource impacts of using any source for synfuels on other water users. Until major components of these uncertainties are analyzed quantitatively and start to become resolved, the extent to which synfuels production can be expanded beyond a level of several hundred thousand barrels/day (i. e., about 125,000 AFY) cannot be estimated with confidence.[12]

One potential source of water supply for synfuels is storage from Federal reservoirs. For example, approximately 100,000 AFY could be made available for synfuels from two Federal reservoirs on the western slope of Colorado (Ruedi and Green Mountain). However, the amount of water available is uncertain because of questions regarding firm yields, contract terms for water sales, which purposes are to be served by the reservoirs, competing demands, the marketing agent, and operating policy.

Under State water laws, water rights throughout the basin—in Colorado, Utah, and Wyoming—can generally be transferred (e. g., from agriculture) via the marketplace (i. e., sold) to synfuels developers who can afford to pay a relatively high price for water.[13] The degree to which developers rely on such transfers will determine the subsequent economic and social impacts on the users being displaced and, in turn, on the region. * The transfer process, however, is time-consuming and legally cumbersome, is constrained under State water law by the nature of the original right, and is subject to political and legal challenge.

Some provisions of the laws and compacts governing water availability to the States within the basin will not be tested and interpreted until water rights in the basin are fully developed. For example, procedures and priorities have not yet been developed for limiting diversions among the Upper Basin States when downstream commitments to the Lower Basin, under the Colorado River Basin Compact, cannot otherwise be met. There is also controversy about whether the Upper Basin States as a whole will be responsible for providing any of the 1.5 million AFY commitment to Mexico under the Mexican Water Treaty of 1944-45. Individual States within the basin, such as Colorado, have generally not yet developed procedures and priorities for internally administering their downstream delivery commitments for when the basin becomes fully developed; thus, the impacts of a State's allocation of available water to individual subbasins and users within that State, such as synfuels, cannot yet be determined. State water law also generally evolves through individual court cases, so that the cumulative effects of development are not known.

There are generally no institutional or financial mechanisms for obtaining water **for synfuels, either through conservation or through increased efficiency in water use in other sectors, as in other parts of the country.** In Colorado, for example, changes in agricultural practices to increase water efficiency are likely to be challenged legally, since downstream water rights appropriators are entitled to return flows resulting from existing albeit inefficient practices. It has been reported that basin exports for municipal uses could be reduced by as much as 200,000 to 300,000 AFY with improved water use efficiency .14

Other uncertainties that affect water availability for synfuels in the area include: Federal reserved water rights (e. g., for the Naval Oil Shale Reserve

*The low estimate for shale oil production in 1990 (see ch. 6) implies a range of annual water use of 20,000 to 48,000 acre-feet; the high estimate implies a range of 40,000 to 96,000 acre-feet. By 2000, annual water requirements would be, respectively, 50,000 to 120,000 acre-feet, and 90,000 to 216,000 acre-feet.

[12]Wright Water Engineers, Inc., op. cit.

[13]Gould, op. cit.

"irrigation requirements are determined by many factors, including climate, crop, irrigation methods, etc. Assuming that agriculture consumes 1.5 to 2.5 acre-feet/acre in the Rocky Mountain area, an average oil shale plant consuming 8,500 AFY would need to acquire water rights applicable to about 3,4oo to 5,7oo irrigated areas.

[14]Office of the Executive Director, Colorado Department of Natural Resources, The Availability of Water for Oil Shale and Coal Gasification Development in the Upper Colorado River Basin, Upper Colorado River Basin 13(a) Assessment, October 1979.

at Anvil Points, Colo.) have not yet been quantified; storage would have to be provided in the White River Basin (where the Uinta and Piceance Creek oil shale reserves are located) but prime reservoir sites are located in designated wilderness areas; there is as yet no compact between Colorado and Utah apportioning the flows of the White River; and in Colorado, in order to develop much of the deep ground water in the Piceance Basin, oil shale developers must prove that the ground water is nontributary, for which data are often lacking and difficult to obtain. The resolution of the uncertainties in the Upper Colorado could limit large-scale synfuels growth as illustrated in table 82, but "even at these highly aggregated levels for the entire Upper Colorado River Basin, the confidence limits or ranges that are placed on estimates of water availability are so broad that they tend to (overshadow) the amount of water needed for synfuels development."[15]

[15] Wright Water Engineers, Inc., op. cit., p. IV-38.

Table 82.—Preliminary Quantification of Uncertainties With Respect to Water Availability in the Upper Colorado River Basin

Annual amount available for consumption (millIons of acre-feet)[a]		
	12.5 -15.2	Estimates of mean annual flow of the Colorado River at Lees Ferry
Subtract	7.5	Required delivery to the Lower Basin
	5.0 -7.7	
Subtract	0.75	Estimate of the Upper Basin's Mexican Treaty obligation
	4,25-6.95	
Subtract	.65	Estimated annual reservoir evaporation from Flaming Gorge, Lake Powell, and the Curecanti Unit Reservoirs
Total	3.60-6.30	
Annual projected consumptive demands (millions of acre-feet) In 2000[b]		
Total	4.10-4.78	(excluding synfuels)
Total	4.15-4.90	(including OTA low estimates for oil shale[c])
Total	4.19-5.00	(including OTA high estimates for oil shale[c])

[a]Does not make allowances for the quantification of Federal reserved water rights claims (the Naval Oil Shale Reserve at Anvil Points has claimed, for example, 200,000 AFY), the effect of potential environmental constraints (e.g., salinity control, protection of endangered species), or the availability of Federal storage.
[b]Estimates are for 2000 and exclude synfuels development (Colorado Department of Natural Resources, Section 13(a) Assessment of the Upper Colorado River Basin; 1975 estimate = 3.12 maf). Instream uses are not included.
[c]The low estimate for shale oil production in 1990 (see ch. 6) implies a range of annual water use of 20,000 to 48,000 acre-feet; the high estimate implies a range of 40,000 to 96,000 acre-feet. By 2000, annual water requirements would be, respectively, 50,000 to 120,000 acre-feet, and 90,000 to 216,000 acre-feet.

SOURCE: OTA based on Wright Water Engineers, Inc.

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