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BIOCRUDE SUITABILITY FOR PETROLEUM REFINERIES

by

David K. Schmalzer,* Linda L. Gaines,
Caroline L. Herzenberg, and Mary A. Snider

Energy and Environmental Systems Division

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*Chemical Technology Division

CONTENTS

ABSTRACT 1

1 INTRODUCTION 1

2 BIOMASS PRODUCTION 3

- 2.1 Land Availability 3
  - 2.1.1 Sources of Land Data 4
  - 2.1.2 Land for Energy Biomass Production 5
- 2.2 Energy Crops and Their Yields 7
  - 2.2.1 Herbaceous Energy Crops 8
  - 2.2.2 Wood for Energy 10
  - 2.2.3 Arid-Land Biomass 13
- 2.3 Mapping of Potential Biomass Production 18
  - 2.3.1 Procedure 18
  - 2.3.2 Results 22

3 EXISTING PETROLEUM SYSTEMS 27

- 3.1 Transportation 27
  - 3.1.1 Modes of Transport 27
  - 3.1.2 Transportation Costs for Liquid Fuels 29
  - 3.1.3 Pipeline Transportation 30
- 3.2 Relevant Refinery Processes 31
  - 3.2.1 Hydrotreating and Hydrorefining 31
  - 3.2.2 Hydrocracking 32

4 BIOMASS CONVERSION AND UPGRADING 34

- 4.1 Properties of Biomass-Derived Oils 34
- 4.2 Biomass Conversion Processes 37
  - 4.2.1 PERC Process 37
  - 4.2.2 Rapid Pyrolysis Process 37
  - 4.2.3 Close-Coupled Rapid Pyrolysis and Upgrading 38
- 4.3 Biocrude Upgrading Processes 38
  - 4.3.1 Upgrading High-Pressure Oils by Hydrotreating 39
  - 4.3.2 Upgrading Pyrolysis Oils by Hydrotreating 40
- 4.4 Technical and Economic Advantages 43

5 MATCHING BIOFUELS TO EXISTING SYSTEMS 44

- 5.1 Interactions of Process Approaches and Transportation 44
- 5.2 Refinery Capacity Survey 45
  - 5.2.1 Existing Refineries 45
  - 5.2.2 New or Inactive Refineries 48
- 5.3 Technical Aspects of Biofuels Upgrading in Existing Refineries 49
  - 5.3.1 Hydroprocessing Suitability and Availability 49
  - 5.3.2 Hydrogen Requirements and Availability 51
  - 5.3.3 Research and Development Needs 53
- 5.4 Geographic and Capacity Matching 53

CONTENTS (Cont'd)

5.4.1 Approach 54
5.4.2 Results 56

6 ENVIRONMENTAL AND REGULATORY CONSIDERATIONS 64

6.1 Applicable Legislation 64
6.2 Regulation of Emissions from Petroleum Refineries 66
6.2.1 Gaseous Effluents 66
6.2.2 Liquid Effluents 68
6.2.3 Solid Wastes 70
6.3 Environmental Concerns for Biofuels Production 71

7 CONCLUSIONS 74

7.1 Summary 74
7.2 Areas for Further Research 75

APPENDIX A: Abbreviations 77

APPENDIX B: Land-Capability Classification of the Soil Conservation Service 79

APPENDIX C: Plant and Seed Oils 81

APPENDIX D: *Oil and Gas Journal* Refinery Data Base 83

REFERENCES 85

FIGURES

2.1 Southwest U.S. Regions Having 12 in. of Rainfall and 120 Frost-Free Days per Year 8

2.2 The 105 Producing Areas of the CARD Modeling System 10

2.3 Land Having High or Medium Potential for Conversion to Cropland 19

2.4 Land Suitable for Growing Woody or Herbaceous Energy Crops 19

2.5 Nonfederal Forest Land Needing to be Replanted 21

2.6 Nonfederal Forest Land Not Needing to be Replanted 22

2.7 Land Available for Conversion to Biomass Crops 24

2.8 Potential Harvest of Herbaceous Crops and Wood Grass 24

2.9 Potential Harvest of Excess Wood from Forests 26

FIGURES (Cont'd)

2.10 Total Potential Harvest of Biomass for Energy 26

3.1 Major U.S. Crude Oil Pipelines, 1984 27

3.2 Major U.S. Product Pipelines, 1983 28

3.3 U.S. Barge Routes 29

3.4 Petroleum Transportation Costs 30

3.5 Chemical Reactions of Hydrotreating 32

4.1 Hydrogen/Carbon Ratio of Various Fuels and Oils 35

4.2 Hydrodeoxygenation/Hydrocracking Process for PERC TR-12 Oil 41

4.3 Stabilization/Hydrodeoxygenation Process for Pyrolysis Oil 42

4.4 Process Yields from Upgrading High-Pressure and Pyrolysis Oils 43

5.1 Biofuels Processing and Transportation Operations 44

5.2 Yields from Upgrade Process Options for High-Pressure Oil 47

5.3 Potential Biomass Yields within 50 Miles of a Refinery 57

5.4 Potential Biomass Yields within 250 Miles of Crude Oil Pipelines 60

5.5 Potential Biomass Yields within 250 Miles of Waterways 60

5.6 Potential Biomass Yields within 250 Miles of Transportation or Refineries 62

6.1 Emissions and Emission Sources from Synthetic Fuel Facilities 72

TABLES

2.1 Estimated Land Use by State 3

2.2 Ownership of U.S. Forest and Range 4

2.3 Land Area Available for Conversion to Cropland 6

2.4 Herbaceous Energy Crop Characteristics 9

2.5 Herbaceous Crop Yields by Producing Area 11

2.6 Equivalence of CARD and SCS Land Classes 12

TABLES (Cont'd)

2.7 Tree Species for Short-Rotation Forestry 12

2.8 Wood Grass Yields by Producing Area 13

2.9 Average Current Net and Potential Net Forest Growth in the United States, 1976 14

2.10 Total Potential Yield of Forest Biomass for Energy, 1970 15

2.11 Plants for Growth on Arid Land 16

2.12 Crop Characteristics and Energy Analysis of Potential Biocrude Crops in the Southwest 16

2.13 Comparison of Energy Yields from Various Crops and Energy Products 17

2.14 Crop Assignments to Land Classes 20

2.15 Summary of Potential Biomass Harvest 23

2.16 Potential Biomass Harvest by State 25

4.1 Composition and Properties of Oils 36

4.2 Data on Biocrude Upgrading 39

4.3 Stream Flows and Compositions for Hydrodeoxygenation and Hydrocracking of PERC TR-12 Oil 41

4.4 Stream Flows and Compositions for Stabilization and Hydrodeoxygenation of Pyrolysis Oil 42

5.1 U.S. Refineries Having Both Hydrocracking and Hydrorefining Capacity 46

5.2 Summary of U.S. Refinery Hydrogen Generating Capacity 52

5.3 Dedicated Hydrogen Generating Capacity of Active U.S. Refineries 53

5.4 U.S. Refineries Having 25 x 10^6 scf/d or More of Hydrogen Production Capacity 54

5.5 Cost of Hydrogen Production by Various Processes 55

5.6 Total Biomass within a Given Radius of Refineries 56

5.7 Data for Refineries Having Good Potential for Conversion to Biocrude Upgrading 58

TABLES (Cont'd)

5.8 Potential Biomass Yields in Counties within a Given Radius of Crude Oil Pipelines 61

5.9 Potential Biomass Yields in Counties within a Given Radius of Waterways 61

5.10 Potential Biomass Yields in Counties within a Given Radius of Transportation or Refineries 63

6.1 Legislation Relevant to Biomass Production, Conversion, Upgrading, Transportation, and Refining 65

6.2 Major Airborne Emissions from a Gulf Coast Refinery, 1985 67

6.3 Characteristics of Raw and Treated Process Wastewater from a 200,000 bbl/d Gulf or East Coast Refinery 69

6.4 EPA Effluent Limitation Guidelines for Refineries Based on the Best Practicable Control Technology 70

6.5 Process Water Produced in Biocrude Upgrading 73

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ABSTRACT

Technologies are now being developed that could produce crude oil from biomass, making available an alternative fuel source as petroleum supplies dwindle and prices rise. If the existing infrastructure for transporting and refining petroleum could be used for biocrude, the transition from petroleum would be smoother and less costly. This report examines the suitability of the existing systems for transporting biocrude and processing it into gasoline. Available biomass production areas were identified and potential production was estimated. Production areas with the potential to supply conversion plants were then matched with transportation paths and refinery locations to minimize transportation costs. Technical requirements for treating biocrude were examined, based on its expected chemical composition and physical properties, and compared to existing refinery equipment and capacity. Environmental constraints were taken into account at each step. Although biomass-derived oils could be transported to refineries, the existing refinery equipment is not optimal for upgrading these oils to a gasoline-grade product. Furthermore, existing hydrogen production capacity is grossly inadequate for upgrading substantial volumes of biocrude. Partial or total upgrading at conversion facilities or regional upgrading facilities is discussed briefly, but in-depth evaluation of such options is beyond the scope of this study.

1 INTRODUCTION

Liquid fuels, especially for transportation, could be in short supply in the relatively near future. Although the United States has an extensive fossil fuel resource, the bulk of it is coal, and the economical production of liquid fuels from coal has not been fully demonstrated. In addition, any coal-based technology generates large quantities of carbon oxides and sulfur oxides, which could contribute to environmental concerns such as the greenhouse effect and acid rain.

Biomass is a renewable resource that could be used to produce liquid fuels and would not contribute to environmental damage. Oil from biomass (biocrude) can be produced by thermochemical processes or obtained from plant species that produce hydrocarbons directly. This report examines the technical feasibility of processing biocrude in the existing petroleum transportation and refinery systems. Results are based on geographic matching of potential biomass production areas with the conventional petroleum infrastructure and on the capability of the existing system to process oils having the chemical compositions and physical properties of biocrudes.

In Sec. 2, land suitable for biomass production is evaluated in terms of location, available area, and potential biomass growth rates. We identified land with a potential for conversion to cropland and assumed it was planted with high-yield energy crops. Yields were estimated by location and land class, with the best lands assumed to be capable of achieving the yield goals set for the energy crops under development by the U.S. Department of Energy (DOE). The amount of wood that could be harvested from forests without diminishing the standing stock of timber was examined, and the potential for arid land crop growth in the Southwest was considered but not quantified. In all cases, lands and crops were chosen to minimize the depletion of natural resources (land, water, trees, wilderness, animal habitats, etc.).

The existing infrastructure for transporting and refining petroleum is described in Sec. 3, including locations, capacities, and restrictions. In Sec. 4, we discuss the conversion and upgrading processes being developed to convert biomass to biocrude and the characteristics of the product. Chemical composition and physical properties are major factors in determining whether biocrude can be moved in existing transportation systems and processed with petroleum in conventional refineries.

In Sec. 5, potential biocrude production is matched to existing petroleum systems. We first matched the technical requirements for treating biocrude to the capabilities of the petroleum refineries. The suitability of biocrude for processing depends mainly on its chemical composition, which in turn depends on how it was produced. Then we matched locations and capacities to determine (1) how much biocrude could be produced in areas that allow economical transport to refineries and (2) whether there was sufficient capacity to treat the biocrude. Section 6 presents environmental concerns about the facilities, and Sec. 7 presents our conclusions and highlights areas for further study.

This report addresses classes of land, types of refinery units, and transportation modes. It does not address the suitability and availability of specific parcels of land for biomass production nor the suitability or availability of specific refinery units or pipelines. It should be viewed as providing estimated upper bounds rather than exact quantities.

2 BIOMASS PRODUCTION

2.1 LAND AVAILABILITY

The total land area of the contiguous United States is approximately 2×10^9 acres (a). About 30% of this land is forest and 22% is cropland. Most of the remainder is range or pasture; less than 3% of U.S. land is in urban areas. Table 2.1 shows how the major land types are distributed by state. Cropland is concentrated in the Corn Belt and forest in the Pacific Northwest and near the East Coast. Much of the land in the Rocky Mountain states is classified as range. The federal government owns over 20% of the total land area, but most of the federal land is located in the West. This land is predominantly forest and range. Western forest land is 72% federally owned and western range, 61% (see Table 2.2).

If the entire land area of the United States were planted with biomass yielding 5 dry tons per acre per year (dry ton/a-yr), the total annual production would have an energy content of about 150×10^{15} Btu (150 quad), or about twice the annual U.S. energy consumption. This represents a gross upper bound on total biomass production, but there are many reasons why actual production for energy uses can never approach this limit. First, much land is unsuited to high-yield crop production because of climate or terrain. Second, land with potentially high yields is generally used for food production. Third, land devoted to wood production for lumber and fiber is unlikely to be converted to energy biomass production. Finally, some land is reserved for parks, wilderness, wildlife preserves, etc., and is unavailable. Thus, the first task in estimating the potential biomass resource is to identify how much land could be used for energy biomass production.

TABLE 2.1 Estimated Land Use by State (%)

State	Forest	Cropland	Range	Pasture[a]
Northeast				
Connecticut	57	8	--	11
Delaware	31	40	--	12
Maine	83	5	--	3
Maryland	39	27	--	14
Massachusetts	58	6	--	10
New Hampshire	85	3	--	3
New Jersey	40	16	--	14
New York	60	19	--	9
Pennsylvania	59	20	--	10
Rhode Island	51	3	--	11
Vermont	73	11	--	9
West Virginia	77	7	--	12
North Central				
Illinois	12	69	--	10
Indiana	19	60	--	12
Iowa	4	73	--	16
Michigan	49	25	--	15
Minnesota	31	14	--	16
Missouri	28	34	3	29
Ohio	28	47	--	13
Wisconsin	43	32	--	16
Great Plains				
Kansas	3	55	31	7
Nebraska	2	41	49	5
North Dakota	1	60	28	4
South Dakota	3	34	48	10
Southeast				
Florida	45	10	6	22
Georgia	63	17	--	11
North Carolina	56	20	--	9
South Carolina	62	18	--	10
Virginia	61	13	--	16
South Central				
Alabama	66	14	--	14
Arkansas	50	24	--	20
Kentucky	47	23	--	22
Louisiana	45	21	2	18
Mississippi	55	24	--	15
Oklahoma	11	26	21	36
Tennessee	49	21	2	19
Texas	7	20	55	12
Pacific				
California	39	10	43	2
Oregon	45	7	36	9
Washington	50	18	19	7
Rocky Mountain				
Arizona	27	2	62	8
Colorado	32	16	42	8
Idaho	41	12	45	--
Montana	23	18	56	--
Nevada	13	1	79	5
New Mexico	24	3	63	9
Utah	30	4	52	10
Wyoming	16	4	76	1

[a] Pasture is overestimated because several minor uses are included.

Sources: Forest Service 1980; Bureau of the Census 1989.

TABLE 2.2 Ownership of U.S. Forest and Range

Region	Forest			Range		
	Federal (10^6 a)	Nonfederal (10^6 a)	Federal (%)	Federal (10^6 a)	Nonfederal (10^6 a)	Federal (%)
Northeast	3.3	79.9	4.0	0	0.1	0
North Central	10.4	68.8	13.1	0.3	1.4	17.2
Southeast	7.6	82.4	8.4	0.2	2.0	9.3
South Central	8.8	119.2	6.9	1.5	100.4	1.5
Rocky Mountain	94.0	42.4	68.9	167.4	164.7	50.4
Great Plains	1.2	3.3	26.7	3.7	72.5	4.9
Pacific Northwest	140.4	31.7	81.6	240.0	21.7	91.7
Pacific Southwest	18.8	23.3	44.7	25.6	18.4	58.2
Total[a]	285.6	451.0	38.8	438.8	381.2	53.5

[a] Columns may not sum to these figures due to rounding.

Source: Forest Service 1980.

2.1.1 Sources of Land Data

The major source of U.S. land data is the National Resources Inventory (NRI), produced by the Soil Conservation Service (SCS) of the U.S. Department of Agriculture in 1982. This data is updated at five-year intervals, and the 1987 version is in preparation. The NRI, available on magnetic tape, includes data for all nonfederal land in the U.S.A. (excluding Alaska) on current land use and vegetation, soil quality, slope, erosiveness, conservation practices in use and needed, and potential for conversion to cropland. The NRI contains over 800,000 data records, each describing a small area (typically 160 a, depending on the location and variability of the land).

Although the database is extensive, several types of data that would have been useful to this project are not included. The most important of these is the current use of forest land; for example, whether it has been harvested recently or if it is in a park. Also lacking is information on the productivity of cropland or forest, precipitation, and water availability. Finally, the NRI excludes federal lands, which an omission of considerable significance in the West; as a worst case, 85% of the land in Nevada is federally owned. However, this problem is partially mitigated by the fact that much of the federal land is unproductive, inaccessible, or unavailable for commercial use.

Of the sources used to supplement the NRI, the most important were Forest Service publications containing data on both federal and nonfederal U.S. forests (Forest Service 1980, 1982). Of particular interest were the data on net growth and removals, which are available at the state and regional level only. Forest Service publications also include some data on rangeland, including ownership and area by state, that were used to help characterize federal lands. A recent study at Oak Ridge National Laboratory (ORNL) identified the land areas in the Southwest (where little land is suitable for conventional crop growth) that have the most precipitation and a growing season most suitable for production of arid-land crops (Salk and Folger 1987). This study was used to identify land areas for further screening.

2.1.2 Land for Energy Biomass Production

Three types of land were considered for biomass production: (1) land that could be converted to cropland, (2) forests, and (3) arid lands. Each was evaluated based on a generic type of biomass (e.g., herbaceous energy crops). Energy crops are likely to be grown first on idle cropland; 70 x 10^6 a of cropland were not farmed in 1987 (Turhollow 1988). Including this land would raise the potential yield of biomass by about 30% over the base case in this report. However, existing cropland was assumed to remain in that use to minimize competition between food and fuel production. A recent study by Argonne National Laboratory and the Center for Agricultural and Rural Development (CARD) at Iowa State University showed that the production of 11 quad of energy from biomass grown on cropland would raise consumer food prices by almost 20% in the year 2000 (Turhollow et al. 1985).

Other land considered unavailable for growing biomass for energy included any land currently identified as a park, wilderness area, game reserve, or wildlife refuge; waste disposal, power transmission, R&D, and military sites; and steeply sloped land (considered unharvestable without risking excessive erosion). The first two categories of unavailable land total 22 x 10^6 a, and land too steep to be harvested includes 62 x 10^6 a. Most of the steep land is forest and would contribute little to the potential biomass harvest. The limit set on slope for cropland was 15% (9°) and that for forest was 30% (17°); sensitivity to more stringent slope limits should be examined in future work.

Conversion to Cropland

The NRI characterizes land not now used for crops in terms of its potential for conversion to cropland. Categories include high potential, medium potential, conversion unlikely in the foreseeable future, zero potential, and not suitable. Land in the last category includes current cropland, built-up areas, roads, waterways, and extremely low-quality land. The potential for converting land to cropland is summarized in Table 2.3 for each of the SCS land capability classes (see App. B for class descriptions). The land with high potential for conversion is mainly in land classes II and III, and that with medium potential is mainly in classes II to IV. Current pasture offers the most high-potential land. Only 3% of the medium-potential land and none of the high-potential land is too steep to harvest.

Judgments of the potential for conversion to cropland were made by thousands of SCS field employees and by contractors and employees of other agencies working under SCS direction. Some variability is therefore expected, but the basic criteria are clear. The primary criteria are the physical characteristics of the site, including soil quality, slope, potential for erosion, and availability of water for irrigation, if needed. Other criteria relate the site to its institutional situation. For example, small or isolated tracts were considered to have low potential because of the high cost to incorporate

TABLE 2.3 Land Area Available for Conversion to Cropland (10^6 a)

Conversion Potential and SCS Class	Pasture	Range	Forest	Other	Total[a]
High Potential					
I	1.11	0.16	0.39	0.06	1.73
II	9.61	2.96	3.99	0.48	17.04
III	5.73	3.55	2.06	0.26	11.59
IV	1.48	1.11	0.50	0.07	3.17
V	0.11	0.05	0.13	0.02	0.32
VI	0.30	0.64	0.12	0.05	1.18
VII	0.00	0.29	--	0.02	0.30
VIII	--	--	--	--	--
All classes[a]	18.35	8.76	7.26	0.96	35.33
Medium Potential					
I	0.75	0.14	0.49	0.12	1.51
II	12.66	6.66	11.23	0.98	31.57
III	16.44	14.57	12.11	0.77	43.89
IV	8.55	10.31	6.52	0.40	25.78
V	0.63	0.45	1.16	0.12	2.37
VI	2.16	6.43	2.28	0.21	11.07
VII	0.01	1.41	0.01	0.02	1.44
VIII	--	--	--	--	--
All classes[a]	41.21	40.01	33.80	2.62	117.64

[a] Columns and rows may not sum to these figures due to rounding.

Source: Adapted from the NRI (DOA 1982).

them into efficient farm units. Other land was considered to have low potential because it was committed to other uses by its owner.

We considered land with high or medium potential suitable for the production of dedicated energy crops. Current uses of this land include pasture, forest, and range. The costs for conversion of high-potential land would be lowest, and these would therefore be the first areas converted to biomass production. Medium-potential land would be converted later. The conversion of other land would presumably be too expensive to occur in the foreseeable future.

Forests

Biomass for energy could also be harvested from forests. This harvest could be in conjunction with conventional timber operations. Forest land having less than medium potential for conversion to cropland was considered to be a candidate for energy harvesting. The total amount of wood available for harvest was estimated based on actual growth and removals in the states. The use of state averages in this way almost certainly distorts local wood availability but accurately reflects state totals.

The NRI characterizes conservation treatment needs for nonfederal forest land. The largest category, over 43% of the forest, is land needing timber stand or crop improvement. About 9% of the forest, of particular interest for this project, is classified as needing timber establishment and reinforcement (replanting). This land could be densely planted and harvested on short rotation (1-10 yr rather than the 20-60 for conventional forestry) to produce high biomass yields. About 28% of the forest needing replanting was considered too steep to harvest. More aggressive strategies, such as planting short-rotation trees on the 43% of the forest needing improvement, were not considered but would further increase the potential for biomass.

Arid Land

The southwestern United States is generally unsuited to cultivation, and little of this arid land was identified by the NRI as suitable for conversion to cropland. The small area now used for crops requires irrigation. Because this is expensive, only high-value crops such as cotton can be grown economically. If energy crops are to be grown in the Southwest, they will need to be suited to the arid climate and take advantage of the best local conditions. Since lack of water is the major constraint, areas of maximum precipitation are desired. Many of these areas are at high elevations and therefore experience damaging freezes. Such data are not included in NRI but can be found elsewhere. A recent ORNL report identified the areas in the Southwest having at least 12 in. of rain annually and a frost-free period of at least 120 days (Salk and Folger 1987). Just over 40% of the land area in the region meets these minimal conditions (Fig. 2.1). Because the area is susceptible to serious erosion, only land with a slope of less than 10% (6°) was selected as potentially suitable for energy biomass. Even for growing specialized arid-land crops on this land, irrigation would likely be needed.

2.2 ENERGY CROPS AND THEIR YIELDS

The classes of materials considered in this report for energy biomass are dedicated energy crops (herbaceous and arid-land) and wood (including forest residues). Of the other possible sources of biomass, industrial wastes were eliminated because they are most economically used on-site. Municipal solid waste and wetland crops were not considered because they are most suited to producing methane or ethanol rather than petroleum-type products. Agricultural residues are suitable for conversion to refinery feedstocks, but the Office of Technology Assessment estimates that less than 1 quad of energy is available annually from them (OTA 1980). This potential resource is smaller

FIGURE 2.1 Southwest U.S. Regions Having 12 in. of Rainfall and 120 Frost-Free Days per Year

than the others included in this study, and its omission will not seriously affect our overall results, although the resource may be important locally.

Some oilseed crops, such as peanuts, sunflowers, safflowers, and rapeseed, are being studied as energy crops. The oils produced are most suitable for transesterification to a diesel fuel product that probably could be used locally without refinery processing. However, an economic source of methanol or ethanol would be required. Oilseed crops could generally be grown on the same land as other herbaceous crops and therefore do not represent additional biomass potential. A brief discussion is included in App. C.

2.2.1 Herbaceous Energy Crops

The major herbaceous energy crops being studied in DOE-sponsored programs are listed in Table 2.4. These species are grasses (Graminae) except for sericea lespedeza, which is a legume. All are suitable feedstocks for biochemical or thermochemical conversion to gaseous or liquid fuels. Many herbaceous crops will grow well in a variety of sites and climates (Cushman et al. 1985), and most regions of the U.S.A. will have a range of crop choices. Suitable species are available for almost any region where agriculture is possible. Both warm- and cool-season crops are available, so double cropping would be possible to increase the total biomass yield and to spread production more evenly over the year, minimizing storage costs.

TABLE 2.4 Herbaceous Energy Crop Characteristics

Species	Characteristics	Primary Growing Regions	Net Yield[a] (dry ton/a-yr)	Suitable Land Classes	Conditions Tolerated[b]
Napier grass (*Pennisetum purpurem*)	Perennial, warm-season	Subtropics	10	I-IV	E,W,S
Switchgrass (*Panicum virgatum*)	Perennial, warm-season	Corn Belt	5	I-IV	E
		Southeast	5		
		Piedmont	3		
Weeping lovegrass (*Erogostis curvula*)	Perennial, warm-season	Southeast	5	I-IV	E
		Piedmont	3	I-IV	
Sericea lespedeza (*Lespedeza cuneata*)	Perennial, warm-season	Piedmont	3	I-IV	E
Reed canarygrass (*Phalaris arundinacea*)	Perennial, cool-season	Lake States	4	I-V	E,W,S
Sweet sorghum (*Sorghum bicolor*)	Annual, warm-season	Corn Belt	8	I-II	W,E

[a] Current yield after harvest and storage losses.

[b] E = erosive, S = poor soil, W = wetness.

Source: Turhollow 1988.

Because of the range of growing conditions across the country, yields would vary by region and with local soil quality. For example, current hay yields average only 2 dry ton/a-yr in the U.S.A., but unirrigated hay yields of 5 dry ton/a-yr are achieved in some regions and irrigated yields may be as high as 10 dry ton/a-yr (Cost Goals Committee 1984). Management practices can be modified to maximize production of energy feedstocks. For example, less frequent cutting of forage crops increases yields and degrades feed quality, but nutritional value is not an important attribute for an energy crop.

Herbaceous energy crops will be harvested often enough to inhibit seed formation but infrequently enough to maximize biomass production (about 1-3 times per year). Extremely high yields of sorghum (15-18 dry ton/a-yr) and napier grass (25 dry ton/a-yr) have been obtained on small experimental plots in Florida and Texas, but such yields cannot be expected from large-scale energy crop production. The maximum yield goals for the DOE-sponsored production program operated by ORNL are 18 dry ton/a-yr for annual crops and 12 for perennials on the most favorable sites, the overall range being 6-18 dry ton/a-yr (Turhollow 1987). These yields are considerably higher than natural grassland productivity, which averages about 3,300 lb/a-yr (less than 1 dry ton/a-yr) on prairie, the most productive land (Forest Service 1980).

We did not assign a specific crop to each site available for production, but generic herbaceous crop yields were estimated for each site, depending on location and land quality. Agricultural practices consistent with maintaining the resource base of soil, water, and standing biomass were considered, and certain classes of land, in particular those with erosion and wetness limitations, were restricted to perennial crops to minimize erosion. Data were obtained from CARD on expected yields in those of the

105 producing areas (PAs) that are suitable for herbaceous crops (see Fig. 2.2). These yields, which assume removal of residues each spring, are shown in Table 2.5 for each of five CARD land classes. These classes differ from the SCS classes; the SCS equivalents to the CARD classes are listed in Table 2.6. In our later calculations for this report, the CARD yields were scaled up so that the maximum equaled the ORNL yield goal for either annual or perennial herbaceous energy crops.

2.2.2 Wood for Energy

Wood is suitable for direct combustion or for biochemical or thermochemical conversion, although pretreatment (e.g., hydrolysis) may be required for some biochemical processes. Wood for energy could be obtained from forestry residues, pulp mill waste and sawdust (we assume this is already used), standing timber, or dedicated tree plantations. Our estimate of the total quantity of wood available for energy assumes that wood will be harvested for conventional uses at the existing rate and that the standing stock of timber should not be depleted. For this reason, we did not examine the total stock of standing timber in the U.S.A., which represents over 350 quad of energy. Instead, we examined the geographical distribution of net growth, potential net growth, and removals to estimate the sustainable biomass yield available from the forests. Conversion of other land to forest was not considered. Total potential excess

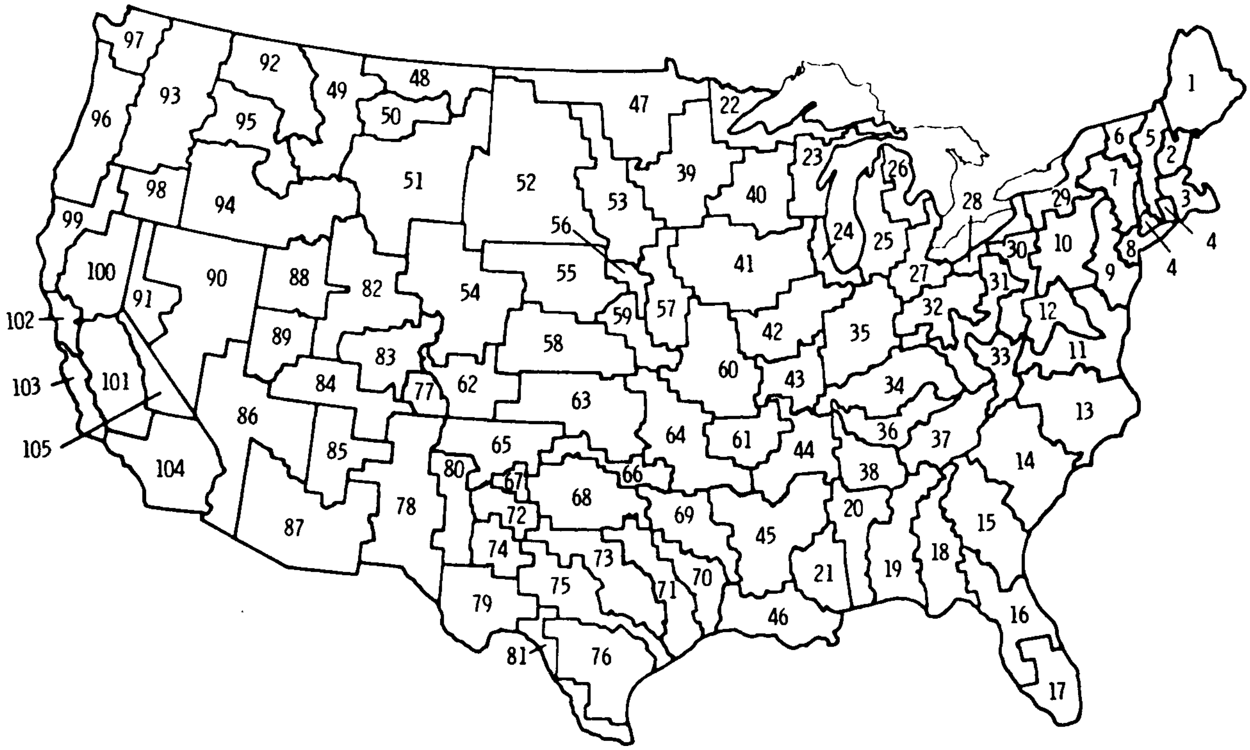


FIGURE 2.2 The 105 Producing Areas of the CARD Modeling System (Source: Huang, et al. 1980)

growth, based on Forest Service statistics, represents about 6 quad annually (American Forest Institute 1978).

Biomass available from the forests could be increased by replacing some conventional forests with intensively managed short-rotation plantations. Short-rotation forestry uses tree species able to coppice (sprout repeatedly from the same stump) to eliminate the cost of replanting; appropriate species are listed in Table 2.7. For the production of biomass to be used as feedstock, there are fewer constraints on the size and shape of the trees than for lumber or pulp use, so short-rotation forests generally have high planting densities, allowing more biomass to be harvested in a given time. The planting of cuttings at high density (typically 40,000/a) results in trees growing like tall grasses, hence the term "wood grass." Yields as high as 25 dry ton/a-yr have been reported for wood grass harvested annually (Shen et al. 1983). A conservative goal of 12 dry ton/a-yr, set by ORNL for the DOE-sponsored program, has been used in this report as the yield attainable without irrigation on the best class of forest land. Wood grass yields for other classes were estimated by scaling from the yields developed by CARD (Table 2.8).

After excluding forest having high or medium potential for conversion to cropland and forest needing replanting, the quantity of biomass that could be harvested from the remaining conventional forest was estimated by state. The Forest Service has published data on the net growth (total growth minus mortality) of the forests and has estimated the potential net growth with more intensive forest management (see Table 2.9 for regional averages). We assumed the potential net growth was the maximum sustainable harvest of biomass. (Current industry practice often depletes

TABLE 2.5 Herbaceous Crop Yields by Producing Area (dry ton/a)

Producing Area	CARD Land Group 1	2	3	4	5
1	2.09	1.97	2.20	2.06	1.80
2	2.18	2.07	2.30	2.16	1.89
3	2.16	2.04	2.27	2.13	1.86
4	2.22	2.10	2.35	2.20	1.92
5	2.63	2.46	2.70	2.55	2.21
6	1.99	2.11	2.35	2.21	2.32
7	2.20	1.88	1.72	1.45	1.22
8	2.37	2.02	1.87	1.60	1.37
9	2.34	2.02	1.91	1.65	1.44
11	2.32	1.97	1.81	1.56	1.23
12	2.09	1.75	1.67	1.44	1.18
13	4.77	3.77	2.15	1.66	1.11
14	4.06	3.20	1.83	1.42	1.24
15	5.92	4.89	3.20	2.70	2.58
16	4.97	3.90	2.25	1.67	1.55
17	4.91	3.88	2.03	1.64	1.43
18	3.25	2.35	2.35	2.08	1.67
19	3.24	2.24	2.23	1.88	1.47
20	2.98	1.95	1.95	1.60	1.14
21	2.83	1.81	1.89	1.45	0.98
22	5.66	4.23	3.40	2.81	1.82
23	5.17	3.86	3.11	2.57	1.66
24	7.06	5.63	4.70	4.07	3.21
25	5.29	3.99	3.25	2.73	1.82
26	2.46	2.26	2.13	1.86	1.66
27	2.22	2.02	1.90	1.63	1.44
28	2.39	2.20	2.08	1.82	1.63
29	2.40	2.21	2.07	1.80	1.61
30	2.94	2.53	2.38	2.15	1.84
31	2.96	2.54	2.34	2.08	1.76
32	3.11	2.61	2.29	1.92	1.55
33	3.26	2.75	2.50	2.14	1.62
34	3.33	2.82	2.56	2.23	1.84
35	3.50	2.97	2.64	2.26	1.87
36	2.55	2.04	1.65	1.16	1.17
37	2.52	1.92	1.72	1.45	1.00
38	2.39	1.82	1.63	1.42	0.91
39	5.79	4.41	4.42	3.81	2.77
40	5.37	4.12	4.09	3.51	2.58
41	4.79	3.58	3.60	3.05	2.15
42	3.99	2.84	2.86	2.34	1.49
43	3.27	2.13	2.15	1.62	0.78
44	2.19	1.67	1.49	1.34	1.23
45	2.44	1.87	1.69	1.49	1.38
46	2.27	1.73	1.57	1.46	1.28
47	3.35	2.72	1.41	1.40	1.89
48	3.50	2.00	1.55	1.21	1.21
49	3.51	2.00	1.55	1.21	1.21
50	4.07	2.57	2.12	1.78	1.77
51	3.44	1.96	1.52	1.19	1.18
53	2.77	1.59	1.23	0.96	0.93
56	4.10	2.56	3.46	2.90	2.90
57	5.00	3.10	2.40	2.00	2.64
59	4.10	2.53	3.20	2.72	0.65
60	5.00	2.94	3.51	2.89	1.52
61	3.91	2.76	2.24	1.53	0.46
64	4.25	3.00	2.31	1.86	0.73
66	4.29	3.13	2.43	2.00	1.06
68	4.47	3.25	2.45	2.00	1.11
69	6.12	4.85	3.88	3.51	2.45
70	4.99	2.90	3.02	2.72	2.37
71	4.99	2.91	3.01	2.68	2.41
82	5.37	3.13	3.25	2.92	2.65
83	5.37	3.13	3.24	2.91	2.65
97	4.42	3.07	3.22	2.78	2.15

Source: Shen et al. 1983.

local forest resources. In several areas of the West, removals far exceed net growth. For instance, removals in Alaska are 163% of net growth of growing stock in commercial forests and in California and Hawaii, 131%, compared with a range of 36-79% in other U.S. regions. Removals of Pacific Northwest Douglas fir and ponderosa pine are 165% and 103%, respectively [Clawson 1979].) Current removals, also tabulated by the Forest Service, were assumed to be committed to uses other than energy. For each state, we assumed potential net growth minus removals was available for energy. This assumption is somewhat optimistic, because much of the unused material is inaccessible and some is not concentrated enough geographically for economical collection, so the resulting numbers are only approximate. Table 2.10 shows the total forest biomass available for energy (potential net growth minus

TABLE 2.6 Equivalence of CARD and SCS Land Classes

CARD Land Class	SCS Classes and Subclasses[a]
1	I, II_{wa}, III_{wa}
2	II (except II_{wa}), III_c, III_w, III_s, IV (except IV_c), V
3	III_e
4	IV_c
5	VI, VII, VIII

[a] The subclasses are defined as follows:

c	Climatic limitations
e	Erosion limitations
s	Soil limitations
w	Wetness problems
wa	Wet soils that have been adequately treated so that wetness is not a problem.

Source: Turhollow et al. 1985.

TABLE 2.7 Tree Species for Short-Rotation Forestry

		Expected Yield[a] (dry ton/a-yr)			
Species	Suitable Region	First Rotation	Coppice	Suitable Land Classes[b]	Conditions Tolerated[c]
Eucalyptus (*Eucalyptus grandis*)	Subtropics	6.3	7.6	II	S,(E,W)
				III	W
Sycamore (*Platanus occidentalis*)	Piedmont	2.2	2.7	II-IV	E
Eastern cottonwood (*Populus deltoides*)	Mississippi River plain	4.5	5.4	II-III	W
Hybrid poplar (*Populus*)	Lake States	3.2	3.8	II	E,W
Black locust (*Robinia pseudoacacia*)	Midwest	5.1	6.2	II	E,W
				III-IV	E
Hybrid black cottonwood (*Populus deltoides* x *Populus trichocarpa*)	Pacific Northwest	7.1	8.7	II	W
				III	E,W

[a] With current technology.

[b] All species can also grow on Class I lands, which have few physical limitations that restrict their use.

[c] E = erosive, S = poor soil, W = wetness. Letters in parentheses indicate limitations that are less common but still significant.

Source: SERI 1986.

removals) by state, along with the average amount of biomass available per acre of forest. Some western states have sparse forests that will not be economical to harvest.

2.2.3 Arid-Land Biomass

Two types of energy biomass are proposed for growth in the southwest U.S.A.: land crops adapted to the arid conditions and microalgae grown in shallow ponds. Both require high insolation, a long frost-free period, and relatively flat land. Crops require fresh water from precipitation or irrigation, but because many algal species can be grown in saline groundwater, the water for microalgae growth in the Southwest would be expected to come from saline aquifers.

Crops

With irrigation, conventional agricultural crops can be grown in the Southwest. Yields are excellent because of the high insolation and long growing season. For example, alfalfa yields of 7 ton/a-yr have been reported in Arizona, compared with 3.7 ton/a-yr in Illinois (McLaughlin 1985). However, such high yields require 6-7 a-ft of water/a, at a cost of up to $400/a, which would be prohibitive for energy crops (McLaughlin 1985). The Arizona Water Commission (1977) has estimated that 2.4 x 10^6 a-ft of water will be available for irrigation in Arizona in 2020, which would be 2 a-ft/a for the existing cropland. This level of available water would require the growth of crops with low water requirements or a reduction of the acreage in production (McLaughlin 1985). Even if half of the available irrigation water were allocated to energy crops requiring 2 a-ft/a, less than 0.05 quad

TABLE 2.8 Wood Grass Yields by Producing Area (dry ton/a)

Producing Area	CARD Land Group				
	1	2	3	4	5
1	7.20	6.39	6.79	6.19	6.19
2	7.20	6.74	7.17	6.53	6.53
3	7.20	6.41	6.81	6.20	6.20
4	7.20	7.15	7.20	6.92	6.92
5	7.20	6.50	6.91	6.29	6.29
6	7.20	5.86	6.23	5.67	5.67
7	7.00	5.54	5.08	4.49	4.57
8	7.20	6.33	5.42	4.61	5.04
9	7.20	6.12	5.82	5.29	5.25
10	7.20	5.93	5.45	4.84	4.93
11	4.35	3.43	3.13	2.76	2.82
12	6.74	5.27	4.81	4.21	4.31
13	4.30	3.49	2.75	2.41	2.33
14	6.05	4.63	3.72	3.22	2.95
15	5.94	4.48	3.57	3.05	2.78
16	3.86	2.93	2.26	1.92	1.77
17	3.75	3.05	2.40	2.10	2.03
18	5.63	3.86	3.94	3.19	1.83
19	4.59	3.62	3.43	2.89	2.04
20	4.76	3.57	3.27	2.60	2.22
21	5.66	4.06	3.65	2.75	2.23
22	6.07	5.25	4.66	4.34	3.36
23	6.49	5.61	4.99	4.64	3.59
24	6.54	5.69	4.97	4.57	3.56
25	5.60	4.84	4.31	4.01	3.10
26	5.46	4.59	4.14	3.87	3.66
27	6.15	5.27	4.74	4.45	4.16
28	7.08	6.04	5.51	5.19	4.93
29	6.99	5.98	5.36	5.01	4.69
30	7.20	6.37	5.82	5.33	4.98
31	7.20	6.04	5.34	4.73	4.42
32	7.05	5.83	5.00	4.30	4.01
33	4.49	3.70	3.22	2.81	2.61
34	7.10	5.85	5.15	4.54	4.21
35	6.74	5.60	4.86	4.23	3.95
36	6.33	4.96	4.08	3.35	3.00
37	4.12	3.01	2.73	2.30	1.80
38	5.28	3.69	3.30	2.68	1.96
39	5.61	4.55	4.30	3.76	2.98
40	6.32	5.26	4.92	4.36	3.67
41	6.78	5.68	5.30	4.73	4.06
42	6.10	5.06	4.67	4.12	3.53
43	6.20	5.09	4.82	4.26	3.43
44	5.70	4.24	3.90	3.16	2.44
45	5.75	3.73	3.45	2.58	1.72
46	6.91	4.49	4.37	3.52	2.68
47	2.73	1.90	1.65	1.47	0.67
56	5.17	3.88	3.47	3.12	2.36
57	5.31	4.28	3.96	3.68	3.07
59	5.34	3.93	3.49	3.11	2.28
60	5.43	4.31	3.95	3.65	2.99
61	4.94	3.54	3.25	2.84	1.09
64	5.41	4.15	3.92	3.54	2.98
66	4.83	3.59	3.33	2.97	2.33
68	4.82	3.45	3.16	2.77	1.07
69	4.33	3.29	3.08	2.90	2.19
70	4.08	3.08	2.88	2.59	2.60
71	4.08	3.07	2.45	2.19	2.01
73	4.08	2.99	2.32	2.18	2.19
75	4.08	3.14	2.55	2.28	2.13
76	4.08	2.99	2.32	2.18	2.19
96	7.20	6.42	6.17	5.27	6.88
97	7.20	7.20	7.20	6.57	7.20
99	7.20	7.15	5.88	5.69	4.88

Source: Shen et al. 1983.

TABLE 2.9 Average Current Net and Potential Net Forest Growth[a] in the United States, 1976 (ft^3/a-yr)

Region	All Ownerships	National Forests	Other Public Forests	Forest Industry Forests	Farms and Private Forests
North					
Current	35.3	42.6	36.4	44.0	32.9
Potential	65.3	62.3	59.7	74.4	65.2
South					
Current	55.5	57.0	52.8	60.2	54.4
Potential	77.3	71.1	71.0	83.3	76.5
Rocky Mountain and Great Plains					
Current	28.7	30.4	24.5	49.9	23.4
Potential	59.5	63.7	54.5	74.1	49.7
Pacific Coast					
Current	49.3	30.3	53.1	79.3	62.0
Potential	97.0	90.8	88.0	119.5	98.9
Overall average					
Current	44.9	35.1	41.6	59.2	45.0
Potential	74.2	74.1	68.3	87.3	71.9

[a] Potential growth is defined as the average net growth attainable in fully stocked natural stands. Much higher growth rates can be attained in intensively managed stands.

Source: Forest Service 1980.

of energy could be produced. Growing higher-value crops (such as those yielding specialty chemicals, food, or fiber) on irrigated land makes better economic sense.

Thus, large-scale energy biomass production in the Southwest will have to rely on crops that need little or no irrigation. Examples of plants with such characteristics are listed in Table 2.11. The maximum yield expected is about 5 dry ton/a-yr, less than half of the goal for perennial herbaceous energy crops, but almost ten times the current yields of native species (OTA 1980). It is known that biomass yields depend directly on moisture received, but experts disagree on the minimum necessary for growth. McLaughlin (1987) doubts that anything can be grown in the Southwest without irrigation, whereas Johnson and Hinman (1980) estimate that 20-30 x 10^6 a could support *Euphorbia* growth with little or no irrigation. Net energy analysis of several promising crops reveals that agriculture in the Southwest is energy-intensive (see Table 2.12) and that irrigation, even at low levels, is a major contributor to energy costs.

Biomass crops for the Southwest differ by yield and by type of product. All produce carbohydrates similar to those in herbaceous or woody plants, but some also produce substantial quantities of oils or other hydrocarbons that have high value either as fuel or raw materials. The composition of the hydrocarbons differs among species, but it is believed that many are suitable for catalytic conversion to gasoline. For example, hydrocarbons can be extracted from *Euphorbia lathyris* to produce a sugar stream for fermentation to ethanol. The residue (solid fibrous carbohydrate, some of which is burned for process steam) is suitable for thermochemical conversion to liquid fuels. Species can be compared on the basis of total liquid fuel production per acre or, if water is the dominant expense, per unit water consumption. Calvin (1987) performed such a comparison but did not assume that the residue would be used (Table 2.13). Arid land crops can be seen to use water more efficiently than conventional crops.

No specific species are designated in this report as most appropriate for growth in the Southwest. Future work on the total potential biomass from the region could assume a species yielding 5 dry ton/a-yr with little or no irrigation.

TABLE 2.10 Total Potential Yield of Forest Biomass for Energy, 1970

State	Forest Area[a] (10^6 a)	Biomass Available for Energy[a] (10^6 ft^3/yr)	Average Potential Biomass Yield (dry ton/a-yr)
Alabama	21.8	1,055.6	0.73
Arizona	18.6	91.4	0.07
Arkansas	18.3	662.0	0.54
California	42.4	743.9	0.26
Colorado	22.5	337.6	0.22
Connecticut	2.2	164.4	1.13
Delaware	0.4	21.3	0.82
Florida	17.9	708.2	0.59
Georgia	25.5	1,238.8	0.73
Idaho	21.6	809.0	0.56
Illinois	3.8	199.2	0.79
Indiana	3.9	160.1	0.61
Iowa	2.5	92.1	0.56
Kansas	1.3	51.5	0.57
Kentucky	12.0	865.9	1.08
Louisiana	15.4	721.6	0.70
Maine	17.7	977.9	0.83
Maryland	3.0	169.8	0.86
Massachusetts	3.5	247.3	1.05
Michigan	19.3	797.3	0.62
Minnesota	19.0	746.2	0.59
Mississippi	16.9	730.1	0.65
Missouri	14.9	589.7	0.59
Montana	22.8	847.0	0.56
Nebraska	1.0	28.2	0.41
Nevada	7.7	6.3	0.01
New Hampshire	5.1	339.7	0.99
New Jersey	2.5	188.3	1.15
New Mexico	18.3	220.4	0.18
New York	17.4	796.9	0.69
North Carolina	20.6	759.7	0.55
North Dakota	0.4	13.7	0.49
Ohio	6.5	335.9	0.77
Oklahoma	9.3	183.7	0.29
Oregon	30.4	1,061.1	0.52
Pennsylvania	17.8	1,256.8	1.06
Rhode Island	0.4	31.8	1.10
South Carolina	12.5	404.4	0.49
South Dakota	1.7	36.3	0.62
Tennessee	13.1	674.4	0.77
Texas	24.1	618.8	0.39
Utah	15.3	132.1	0.13
Vermont	4.4	296.9	1.01
Virginia	16.4	567.7	0.52
Washington	23.1	444.0	0.29
West Virginia	12.2	874.6	1.08
Wisconsin	14.9	489.1	0.49
Wyoming	10.1	98.2	0.15

[a] Source: American Forest Institute 1978.

Microalgae

Microalgae are single-celled aquatic plants. Many species store lipids (oils), and the quantity produced increases as the organisms are subjected to stresses such as nitrogen deprivation. Screening of microalgae has yielded a variety of natural species that differ in size, growth rate, growing conditions, reaction to stress, and composition and production rate of lipids. In addition, genetic engineering is expected to produce species that combine the desirable characteristics found in the various naturally occurring species. Microalgal lipids are expected to be similar to vegetable oils. The lipids could be converted by transesterification into a substitute for diesel oil or by catalytic conversion into gasoline (Neenan et al. 1986). It is a goal of a DOE-sponsored program to produce species having 50-60% of their body weight as lipids.

TABLE 2.11 Plants for Growth on Arid Land

Species	Description	Primary Product	Water Use[a] (in./yr)	Expected Yield per Acre-Year (ton)[b]	Expected Yield per Acre-Year (10^6 Btu)[c]
Acacia (*Acacia* spp.)	Perennial shrub	Carbohydrate	16	1-3[d]	30
Big sagebrush (*Artemisia tridentata*)	Perennial shrub	Carbohydrate	15	3.5[d]	49
Creosote bush (*Larrea tridentata*)	Perennial shrub	Carbohydrate	6-16	1-5	80
Fourwing saltbush (*Atriplex canescans*)	Perennial shrub	Hydrocarbon	15	3.5[d]	49
Guayule (*Parthenium argentatum*)	Perennial shrub	Rubber	18-24	2.5	45
Milkweed (*Asclepias* spp.)	Perennial herb	Hydrocarbon	16	3.6	72
Russian thistle (*Salsola kali*)	Annual herb	Hydrocarbon	16	4.5	57

[a] Minimum water required for nonstressed plant growth that will produce biomass at expected or better rates.

[b] Field dry conditions, 8-10% moisture.

[c] Whole plant.

[d] Estimated.

Source: Adapted from Foster and Brooks 1981.

TABLE 2.12 Crop Characteristics and Energy Analysis of Potential Biocrude Crops in the Southwest[a]

Parameter	*Calotropis procera*	*Euphorbia lathyris*	*Grindelia camporum*	*Chrysothamnus paniculatus*
Crop characteristics				
Habit	perennial	annual	annual	perennial
Biomass yield (ton/a-yr)	9.9	6.9	5.4	3.5
Water required[b] (in./a)	27	17	14	8
Biocrude in plant (%)	5	8	15	20
Biocrude yield (bbl/a-yr)	3.5	3.9	5.7	4.9
Energy yield (10^6 Btu/a-yr)				
Biocrude	17.8	17.8	24.6	20.9
Residues	133.6	92.2	66.9	43.4
Land required (10^3 a)	33	48	61	95
Energy required (10^9 Btu/yr)				
Irrigation	615	650	686	772
Other agronomic	349	461	513	483
Processing	106	106	106	106
Total	1,070	1,217	1,305	1,361
Energy produced (10^9 Btu/yr)				
Biocrude	592	848	1,496	1,991
Electricity[c]	1,292	1,272	1,179	1,201
Total	1,884	2,120	2,675	3,192
Net	814	903	1,370	1,831

[a] For production of 330 x 10^3 dry ton/yr of biomass.

[b] Water requirements were estimated to be 800 ton/ton dry yield for all species. Four inches of annual rainfall is assumed.

[c] An efficiency of 29% was used for conversion of residues to electricity.

Source: McLaughlin et al. 1983.

TABLE 2.13 Comparison of Energy Yields from Various Crops and Energy Products

Crop/Product	Biomass per Acre-Year (dry ton)	Liquid Fuel Yield per Acre-Year		Water Required (in./yr)	Fuel Energy per Unit Water (10^6 Btu/ a-in. H_2O)	Cellulosic Residue per Acre-Year		Residue Energy per Unit Water (10^6 Btu/ a-in. H_2O)
		ton	10^6 Btu			ton	10^6 Btu	
Corn/ethanol	5	0.64	16	25	0.65	3.4	44.2	1.77
Sugar cane/ethanol	30	2.4	60	78	0.78	24	312	4
Energy cane/ethanol	35-50	--	65	48	1.35	--	400	8.2
Euphorbia lathyris/								
hydrocarbons	8.5	0.58	20	25	0.82	6.12	79.6	3.2
ethanol	--	0.68	17.3	--	--	--	--	--
Pittosporum resiniferum (fruits only)/hydrocarbons	7.8	1.5	50	~25	2.0	7.8	101	4.0
Jatopha curcas (seed only)/hydrocarbons	5.0	2.2	92	~25	3.6	2.8	36	1.45
Palm (fruit)/--	8.1	--	73	~25	2.9	~1	--	--

Source: Calvin 1987.

High per-acre yields are expected for the growth of microalgae in shallow ponds. The estimated yield with 1984 technology was 37 dry ton/a-yr, and the year-2000 goal is 45 dry ton/a-yr (Gaines and Flaim 1986). Water utilization is relatively efficient; evaporative losses are estimated to be 2.7-5.9 ft/yr, plus some additional consumption for blowdown (Neenan et al. 1986). This gives an average biomass production of 8-17 dry ton/a-ft of water, considerably better than the land-based plants. In addition, microalgae can tolerate saline water. Saline aquifers in regions with long frost-free periods could be used to grow microalgae without competing for fresh water. The ponds near such aquifers may be situated in areas too dry for land crops. However, these areas would likely have high evaporation rates that would increase water costs, and therefore they may not be desirable for microalgae either.

2.3 MAPPING OF POTENTIAL BIOMASS PRODUCTION

2.3.1 Procedure

The procedure for estimating potential energy biomass production is different for each of the three types of land: potential cropland, forest, and arid land. These differences arise because of the data available, but the goal in all cases is to estimate the maximum sustainable biomass production that could be achieved without depleting any resources (interpreted broadly to include land, water, recreation areas, animal habitats, and other irreplaceable natural resources). Slope and land use criteria were applied before any land was judged available for biomass production, and generic crops were chosen for each type and class of land with conservation in mind.

Potential Cropland

Land with high and medium potential for conversion to cropland was assumed to be planted with dedicated energy crops if its slope is less than 15%. Cultivation of more sloping land would result in erosion that would deplete its long-term productivity. In Fig. 2.3, nonfederal land in the contiguous 48 states having high or medium potential for conversion and less than 15% slope is shown by state. Large areas in the South Central states and the Southeast were judged suitable for conversion to cropland. Texas is of particular interest for this study because of the concentration of petroleum refining capacity there. A generic crop was assigned to each NRI plot area, depending on its land class and location. Yield was calculated by appropriately scaling for the type of crop, land class, and PA. Figure 2.4 shows areas we identified as suitable for the growth of herbaceous or woody crops. In areas where neither would be expected to grow, no crops were assigned; arid-land crops could later be assigned to some. Additional land in the North Central region, from Kansas to North Dakota, may be suitable for herbaceous crops, but the PAs in the Rockies may not be suitable (Turhollow 1988). The net result of these changes would be to increase the total biomass potential.

Annual herbaceous crops were assigned to good-quality, non-erosive land. These offered the highest yields of any of the energy crops available. Because annuals are

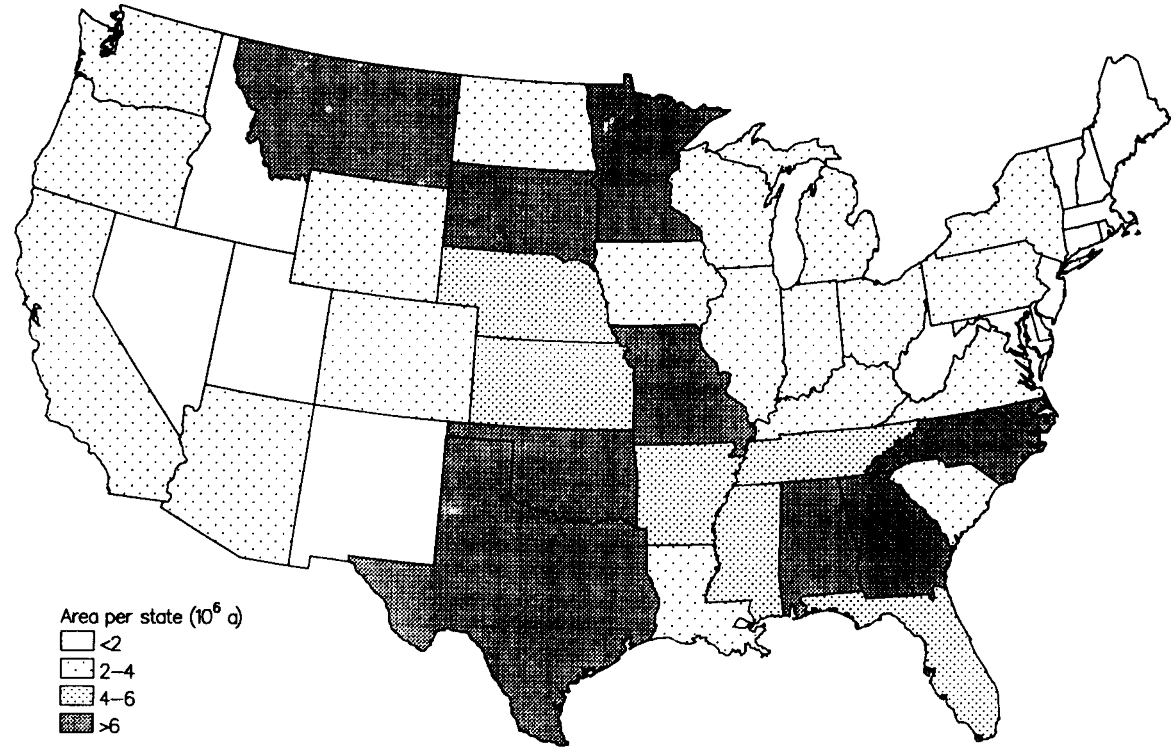


FIGURE 2.3 Land Having High or Medium Potential for Conversion to Cropland

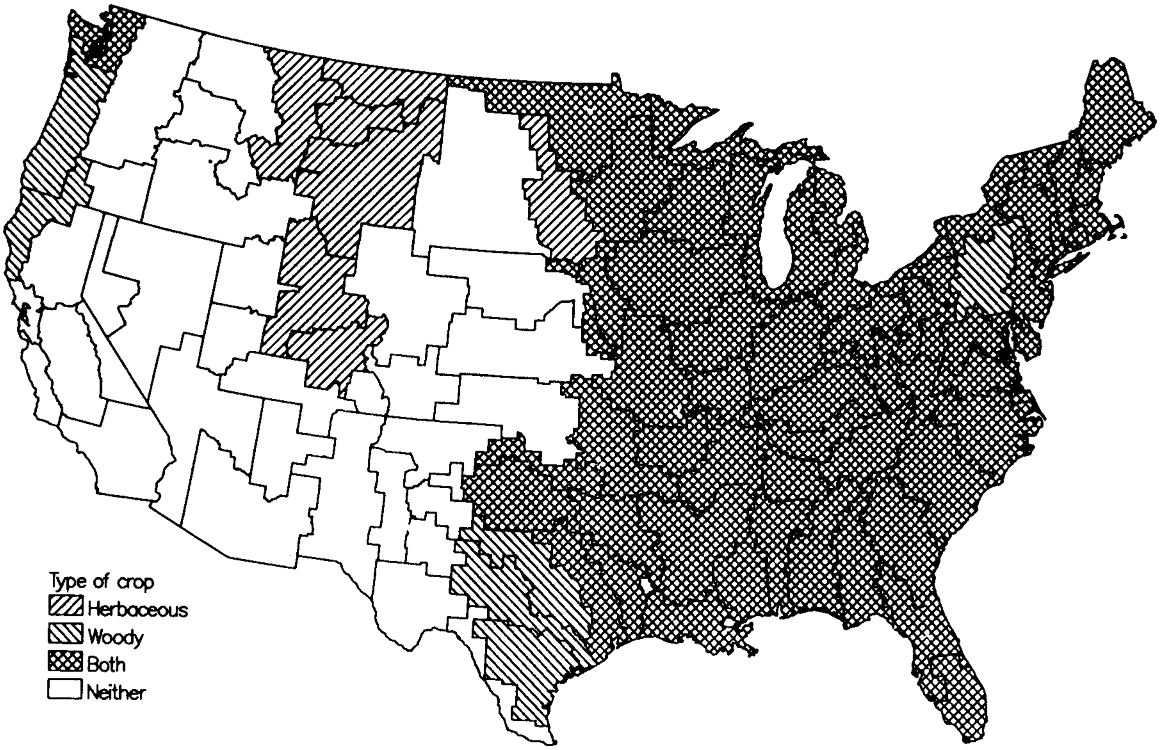


FIGURE 2.4 Land Suitable for Growing Woody or Herbaceous Energy Crops

more erosive than perennials, perennials were assigned to land vulnerable to erosion and to other lower-quality land. Wood grass was assigned to the poorest land and to land in the few PAs suitable for wood growth but not for herbaceous crops. The choice between perennials and wood grass was not important for this project because both have similar yields and produce suitable feedstocks for thermochemical conversion processes. A summary of the crop assignments is given in Table 2.14.

Yields were estimated based on CARD data scaled to the DOE production goals. Yields for each generic crop on the best land in the most productive regions were set equal to the DOE maximum goals: 18 dry ton/a-yr for herbaceous annuals and 12 dry ton/a-yr for perennial herbaceous crops and short-rotation trees. Then the current yields for other land were scaled up proportionately from the CARD data (Table 2.5). The total potential biomass yield was the area of land available times the scaled yield for that land.

Forest Land

Energy wood yields were estimated from forest land having less than a 30% slope. Forest land having high or medium potential for conversion to cropland was assigned a dedicated energy crop (see the previous section) and is not counted again here. We assumed that forest land identified in the NRI as needing replanting would be replanted for short-rotation intensive culture. The total area of nonfederal forest in this category having less than a 30% slope (24.5×10^6 a) is shown in Fig. 2.5. Yields were estimated as described in the previous section, but figures for wood grass yields (Table 2.8) were used.

TABLE 2.14 Crop Assignments to Land Classes

Crop	Maximum Yield (dry ton/a-yr)	SCS Land Classes[a]
Annual herbaceous	18	I, II_{ne}, III_{ne}
Perennial herbaceous	12	II_e, III_e, IV[b]
Wood grass	12	V, VI, VII[c]

[a] e = erosive subclasses, ne = nonerosive subclasses.

[b] Also classes V-VII in PAs 48-53 and 58, where wood will not grow.

[c] Also all classes in PAs 10, 73, 75, 76, 96, and 99, where nonirrigated herbaceous crops cannot be grown.

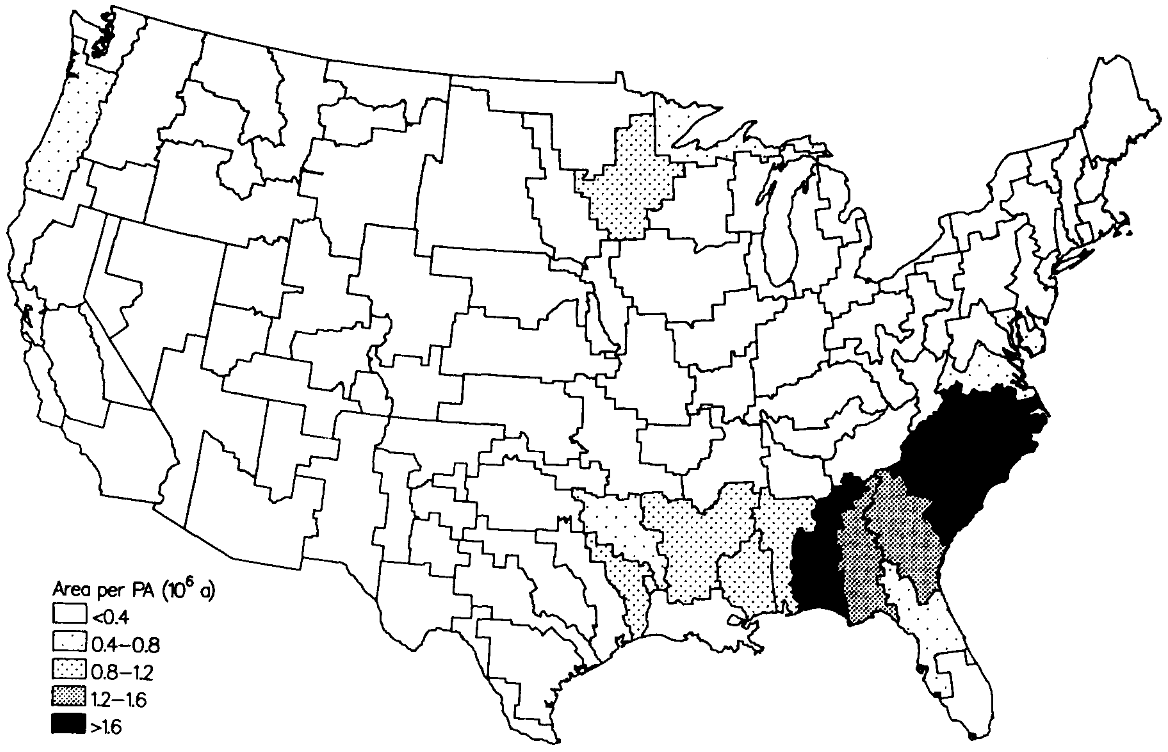


FIGURE 2.5 Nonfederal Forest Land Needing to be Replanted

The remaining forest land was assumed to be managed well enough to achieve the yield potentials estimated by the Forest Service (Table 2.9). The net quantity of wood available for energy would be the potential net growth (total growth minus mortality) minus the removals for all other purposes. This quantity would sustain the total standing stock of wood in each state and was used to estimate total biomass potentially available by state. Average per-acre wood availability for each state was calculated as the total acres divided by the total forested acres (see Table 2.10), because local production potential was not known. This potential yield was applied to all nonfederal forest land that does not need replanting, is not suitable as cropland, and meets the slope limit (Fig. 2.6). The largest such areas are in the Southeast; the Northwest has fewer because of federally owned land is not included.

Arid Land

The ecosystem of the arid Southwest is extremely fragile, and the land is very susceptible to erosion if the surface is disturbed. Therefore, a requirement of less than a 10% slope was applied to land in this region that met the criteria of rainfall over 12 in./yr and a frost-free period of over 120 days. Land meeting all of these criteria could be assigned a generic arid-land crop yielding 5 dry ton/a-yr. We expect that some areas would yield less than this estimate, which is viewed as an upper bound on productivity. No data were available that would allow estimation of yield as a function of land quality or location. No area could be assigned to microalgae culture because data on the location of saline water were not available.

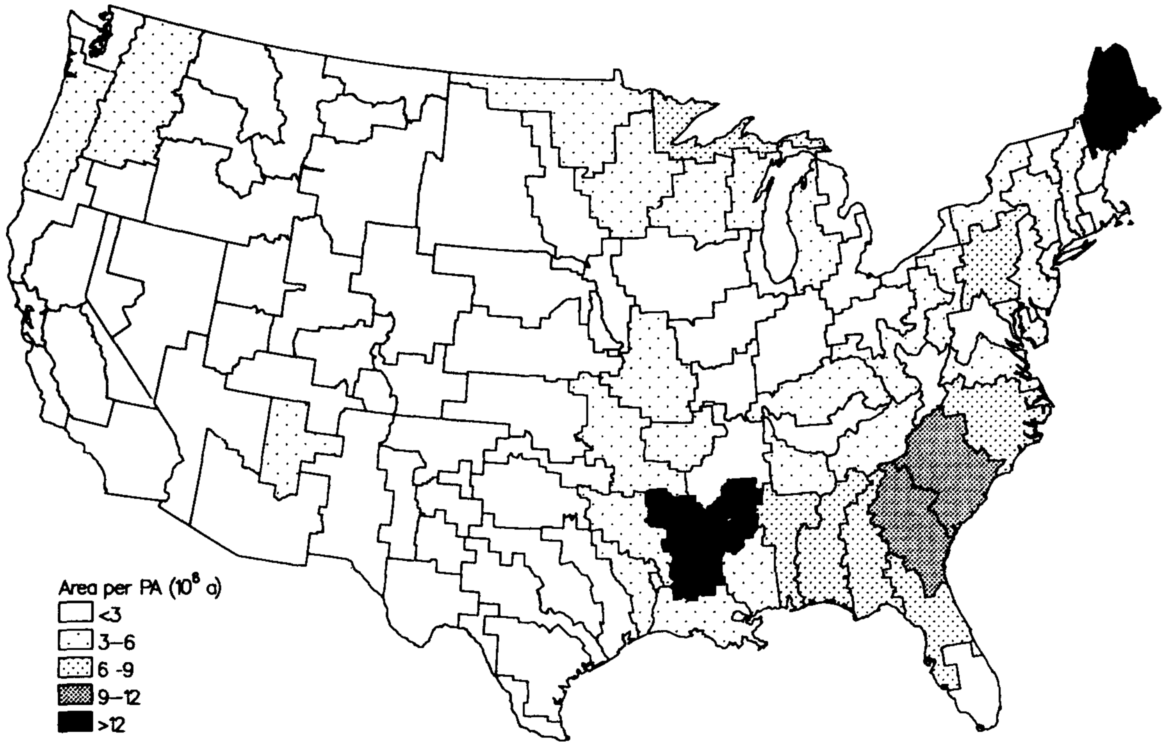


FIGURE 2.6 Nonfederal Forest Land Not Needing to be Replanted

2.3.2 Results

Area Available

The total area identified as suitable for planting dedicated energy crops (land with high and medium potential for conversion to cropland and forest needing replanting) was 174 x 10^6 a, equivalent to 42% of current cropland. Most of this land (66%) has medium potential, 20% has high potential, and 14% is forest needing replanting (Table 2.15). Existing forest that is neither suitable for conversion nor in need of replanting represents an area larger than the area needing replanting, but because biomass yields from this forest are lower than those from dedicated energy crops, this area will make a relatively small contribution to the total biomass harvest.

The distribution of land available for conversion to biomass crops is shown by PA in Fig. 2.7. The largest areas are in the Southeast along the Atlantic coast and in the central states north from Texas. Much of the land in the western U.S.A. is either unsuitable or is federal land excluded from the NRI. The inclusion of this federal land (see Table 2.2) could substantially increase the potential biomass available for energy.

Potential Biomass

The total annual potential for energy biomass production is estimated to be approximately 10^9 dry tons (Table 2.15). If this solid biomass were converted to liquid

TABLE 2.15 Summary of Potential Biomass Harvest[a]

Land Category	Area (10^6 a)	Average Yield (dry ton/ a-yr)	Biomass (10^6 dry ton/yr)	Energy Potential[b] (quad)
Medium potential for conversion	114.1	5.3	608.9	10.4
High potential for conversion	35.4	6.0	212.5	3.6
Forest needing replanting	24.5	6.4	156.4	2.7
Total energy cropland	174.0	--	--	--
Other nonfederal forest	265.1	0.62	164.8	2.8
Total harvestable[c]	439.2	2.6	1,142.6	19.5

[a] Excludes federal land, arid land, and land exceeding slope limits.

[b] Based on 17 x 10^6 Btu/dry ton.

[c] Columns may not sum to these figures due to rounding.

fuels at 50% efficiency, the energy content would be almost 10 quad, or 30% of the 1985 U.S. consumption of petroleum liquids (DOE 1985). Therefore, biofuels cannot be expected to completely replace petroleum, but they have the potential to make a substantial contribution.

More than half (53%) of the potential biomass comes from land with medium potential for conversion, and 14% from conventional forest excess growth. These sources are probably both relatively expensive, and so only about one-third of the potential biomass is likely to be available at the lowest cost. The potential biomass from replanting less than 10% of the forest land with wood grass is almost equal to that from the excess growth on all of the remaining forest because of the high yields of dedicated energy crops. However, the average yields expected on lands converted to biomass production are considerably below the herbaceous energy crop and short-rotation forestry production goals, because much of this land is not in the most productive regions or of the best quality.

The distribution by state of the potential biomass resource is given in Table 2.16. The quantity of dedicated energy crops that could be grown on nonfederal land by PA (Fig. 2.8) and the excess wood available from forests (Fig. 2.9) are totaled to give the total potential harvest of biomass (Fig. 2.10). The southern Atlantic coast looks especially promising, and an area of the South Central states looks fairly good. PA 96, on the Pacific coast, shows up even though federal land is excluded and it may therefore have significant potential. The Southwest shows low potential on these maps because arid land crops are not included.

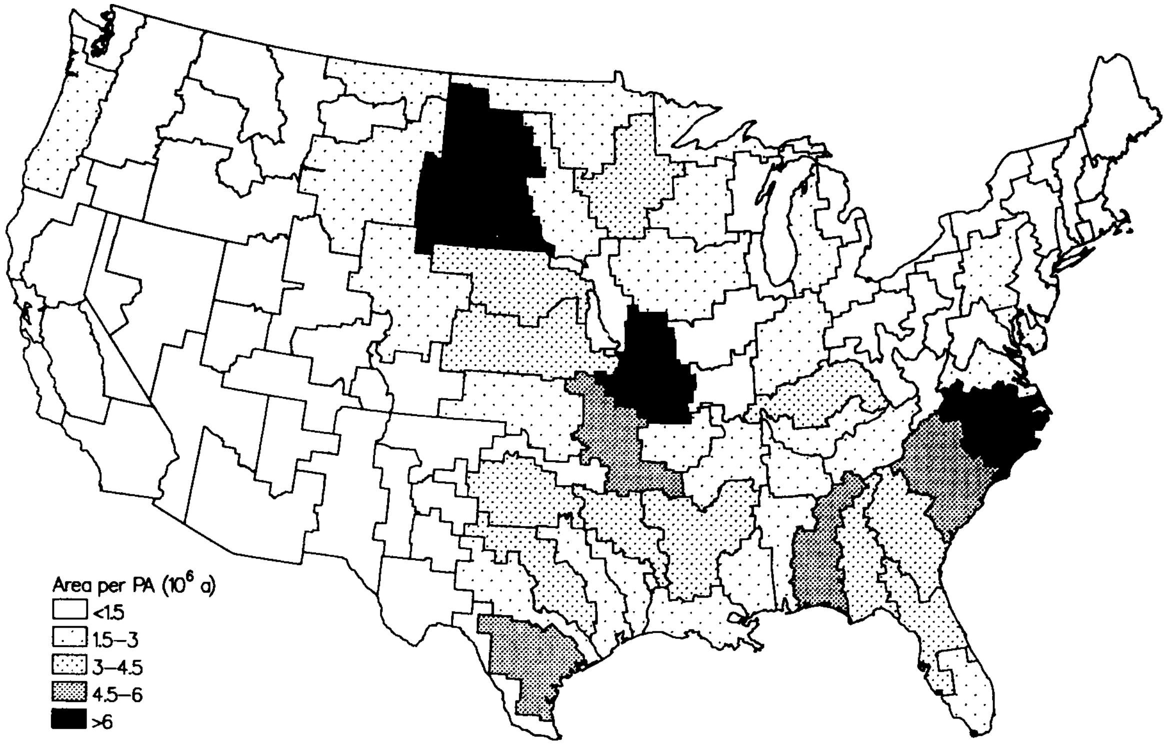


FIGURE 2.7 Land Available for Conversion to Biomass Crops

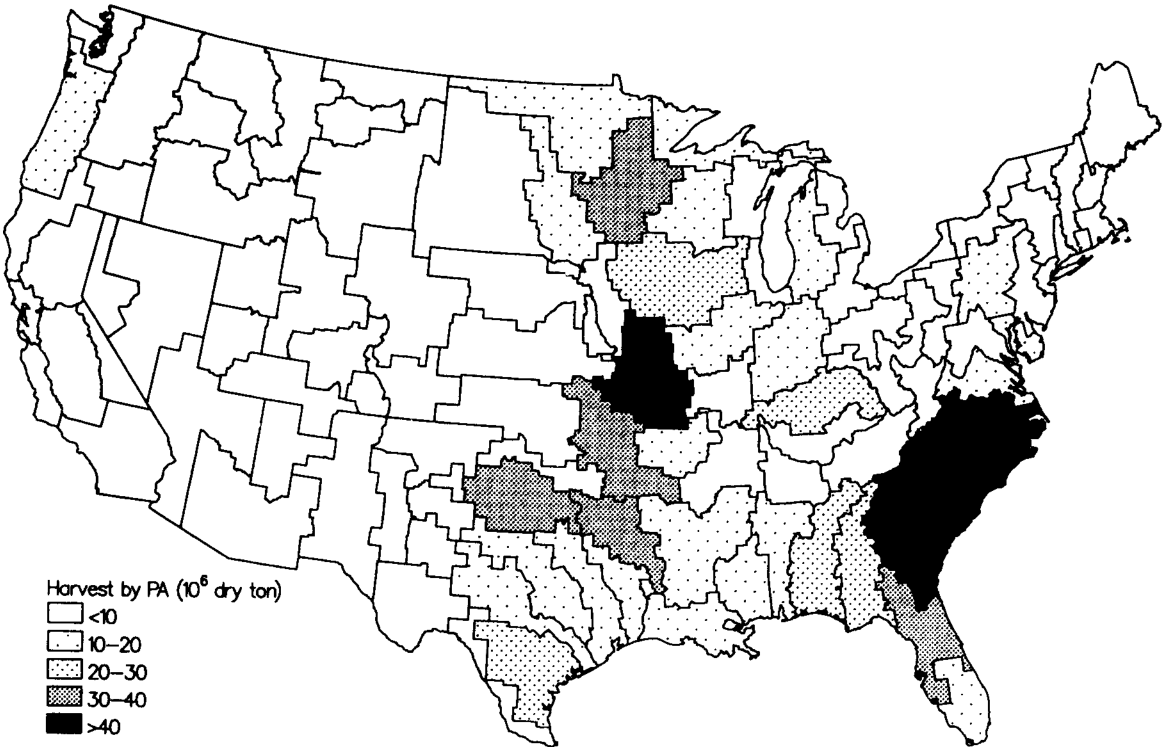


FIGURE 2.8 Potential Harvest of Herbaceous Crops and Wood Grass

TABLE 2.16 Potential Biomass Harvest by State (10^6 dry ton/yr)

State	Excess Wood	Biomass Crops	Total[a]
Alabama	10.2	39.7	49.9
Arizona	0.3	0	0.3
Arkansas	6.1	26.7	32.8
California	1.5	4.2	5.6
Colorado	0.6	0.8	1.3
Connecticut	1.7	2.3	4.0
Delaware	0.1	1.8	1.8
Florida	5.8	53.6	59.4
Georgia	11.9	58.5	70.4
Idaho	0.8	0	0.8
Illinois	1.7	17.0	18.6
Indiana	1.3	17.6	18.9
Iowa	0.6	23.0	23.6
Kansas	0.3	13.7	14.0
Kentucky	4.9	23.9	28.8
Louisiana	7.0	23.2	30.3
Maine	12.7	7.7	20.4
Maryland	1.4	4.1	5.5
Massachusetts	2.7	1.9	4.7
Michigan	7.7	32.0	39.6
Minnesota	5.3	60.3	65.7
Mississippi	7.6	23.7	31.3
Missouri	4.7	66.0	70.7
Montana	1.6	19.9	21.5
Nebraska	0.2	3.4	3.6
Nevada	0	0	0
New Hampshire	3.4	1.6	5.1
New Jersey	1.7	1.6	3.3
New Mexico	1.5	0	1.5
New York	7.9	17.0	24.9
North Carolina	3.8	72.3	76.1
North Dakota	0.1	6.3	6.5
Ohio	2.7	16.8	19.5
Oklahoma	1.7	42.9	44.6
Oregon	3.1	10.1	13.2
Pennsylvania	10.0	21.8	31.8
Rhode Island	0.4	0.3	0.7
South Carolina	3.8	31.5	35.3
South Dakota	0.1	11.8	11.9
Tennessee	5.2	19.2	24.4
Texas	2.8	114.8	117.6
Utah	0.3	0.4	0.7
Vermont	3.1	2.5	5.6
Virginia	4.3	23.2	27.5
Washington	1.8	18.3	20.0
West Virginia	3.4	5.1	8.5
Wisconsin	5.0	32.5	37.6
Wyoming	0.1	2.9	3.0
Total[a]	164.8	977.9	1,142.6

[a] Rows and columns may not sum to these figures due to rounding.

FIGURE 2.9 Potential Harvest of Excess Wood from Forests

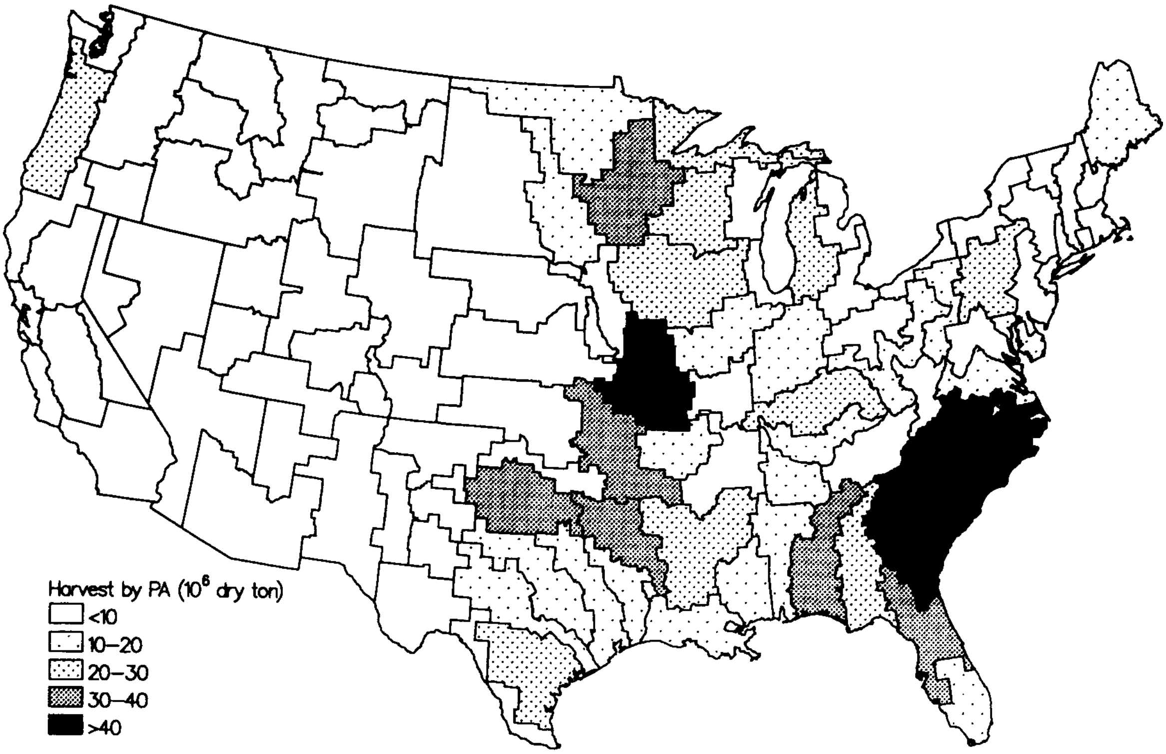


FIGURE 2.10 Total Potential Harvest of Biomass for Energy

3 EXISTING PETROLEUM SYSTEMS

3.1 TRANSPORTATION

3.1.1 Modes of Transport

Harvested biomass must be transported from its point of origin to conversion facilities, raw biocrude to upgrading facilities, upgraded biocrude to refineries, and ultimately, refined products to consumers. Our major concern is with the transportation of raw or upgraded biocrude to refineries or petroleum product distribution systems. The United States has an extensive system for transporting crude oil and refined products as a part of the national energy transportation system (CRS 1977), which includes crude oil pipelines, product pipelines, tankers, barges, railroads, and highway vehicles. Some parts of this system could be used for the large-scale transportation of biofuels.

Crude Oil Pipelines

Pipelines transport crude oil from oil fields and import terminals to refineries. The major crude oil pipelines on land in the contiguous United States are shown in Fig. 3.1. Crude oil pipelines are largely concentrated in the Gulf Coast region.

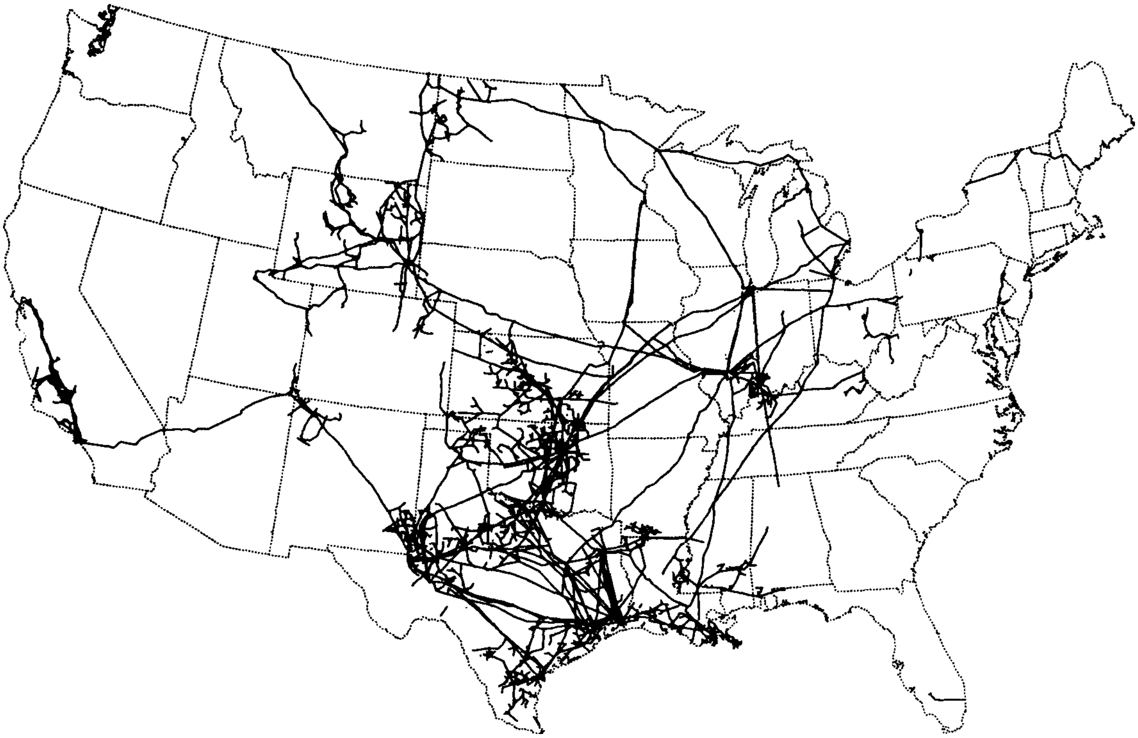


FIGURE 3.1 Major U.S. Crude Oil Pipelines, 1984

Product Pipelines

These pipelines carry refined products from refineries or tanker terminals to large consumers or local distribution depots. The major product pipelines in the United States are shown in Fig. 3.2. Product pipelines are generally used only in large, concentrated market areas where their high capital costs can be justified. The cost of pipeline transportation is typically about one-quarter the cost of movement by rail (which averaged $0.51/100 bbl-mi in 1979) and an even smaller fraction of the cost of road transport (which averaged $1.18/100 bbl-mi in 1979) (Riley 1987). Pipelines can also compete economically with inland barge movements.

Barges and Water Transport

Water transportation is comparatively cheap, and where available, it is widely used for distributing products. In coastal waters, small tankers (500- to 6,000-ton capacity) are used to supply ports that are inaccessible to larger tankers or to transport products in comparatively small lots. On inland waterways and estuaries, barges of 50- to 1,500-ton capacity are used. Some are self-propelled, and others are towed or pushed by a tug, often in trains of barges with total capacities of up to 25,000 tons. U.S. barge routes are shown in Fig. 3.3 (CRS 1977).

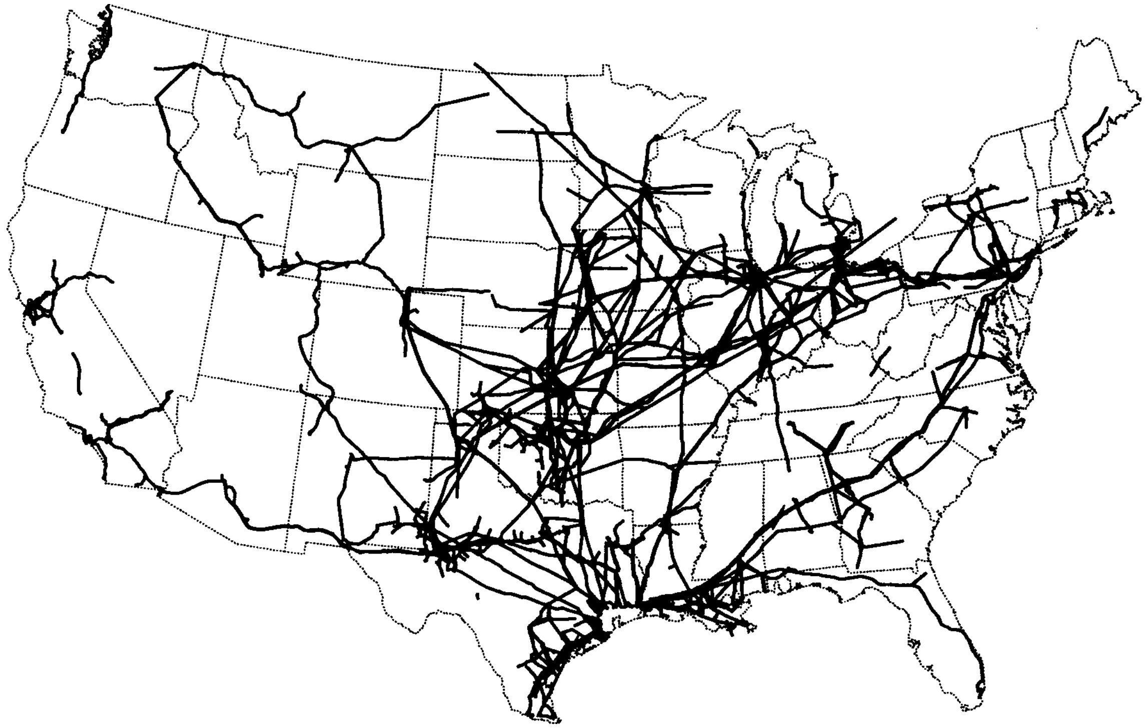


FIGURE 3.2 Major U.S. Product Pipelines, 1983

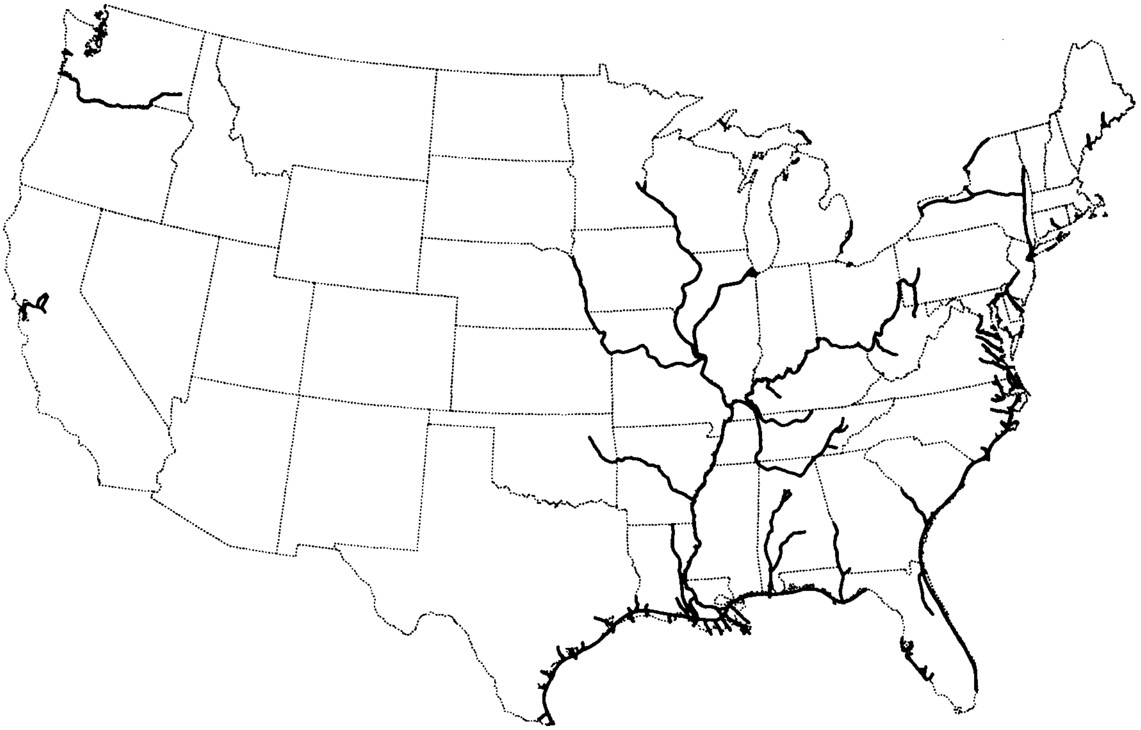


FIGURE 3.3 U.S. Barge Routes

Rail and Highway Transport

Harvested biomass will be trucked to a primary conversion facility. Rail and highway transport could be alternatives to short feeder pipelines for biocrude transport from conversion or upgrading facilities to major pipelines or to barge terminals. Costs will favor pipeline or water transport for long distances.

3.1.2 Transportation Costs for Liquid Fuels

The economic feasibility of biomass-derived fuels may depend to a significant extent on transportation costs. The cost of transporting biomass to a conversion facility depends upon many factors, including material density, distance, vehicle speed, and road class. A typical estimate for trucking baled woody biomass would be a loading/unloading cost of $1.88/ton plus $0.055/ton-mi, one way (Walsh, Aton, and Turner 1986).

Current pipeline costs per mile for onshore pipelines range from $60,000 to $1.6 million (O&GJ 1986); 4-10 in. onshore pipelines average $170,000/mi for lengths of 1.5-30 mi. Total investments of $300-540 million are reported for biomass liquefaction facilities (Elliott 1983). If spur pipeline costs were limited to 5% of the total installation costs, or roughly $20 million, spur pipeline length would be limited to about 100 mi or less. Conversion and upgrading facilities must therefore be located fairly close to trunk pipelines, barge terminals, or rail lines.

Petroleum transportation costs span a wide range. The costs shown in Fig. 3.4 are from the mid-1970s; current costs per 100 bbl-mi range from a few cents for water transportation to over a dollar for trucks (Riley 1987). Pipelines, barges, and coastal tankers are generally less expensive to use than rail or truck transportation. General information on transportation costs is available from Wolbert (1979) and Royal Dutch/Shell (1983). Detailed information on current transportation costs is available from the U.S. Federal Energy Regulatory Commission (FERC). Costs are expected to change significantly before biofuels production comes on line, but current costs help us assess the feasibility of biofuels production in different areas of the country and provide insight into preferred transportation modes.

3.1.3 Pipeline Transportation

American Society for Testing and Materials (ASTM) specifications govern pipeline contents. Interstate pipelines publish a tariff with FERC, including rules, regulations, and specifications for the materials to be carried. Such tariffs may require the shipper to furnish certified laboratory reports showing test results for the products to be transported and may also allow the carrier to make such tests as it deems desirable (Riley 1987; Colonial Pipeline Company 1986). The shipper may also be required to inform the carrier of the percentage and composition of any nonhydrocarbon blending components. As an example, we quote from a recent rules and regulations tariff (Colonial Pipeline Company 1986): "Carrier shall have no obligation to accept petroleum products for shipment if such products contain water or other impurities; have a color darker than No. 3 ASTM (except that gasolines to which artificial coloring has been added will be accepted for transportation regardless of color); have a vapor pressure of more than 15 pounds absolute at 100 degrees Fahrenheit; have an API gravity of less than 25 degrees or more than 80 degrees at 60 degrees Fahrenheit; a viscosity of more than 4.3 centistokes at 100 degrees Fahrenheit . . . "

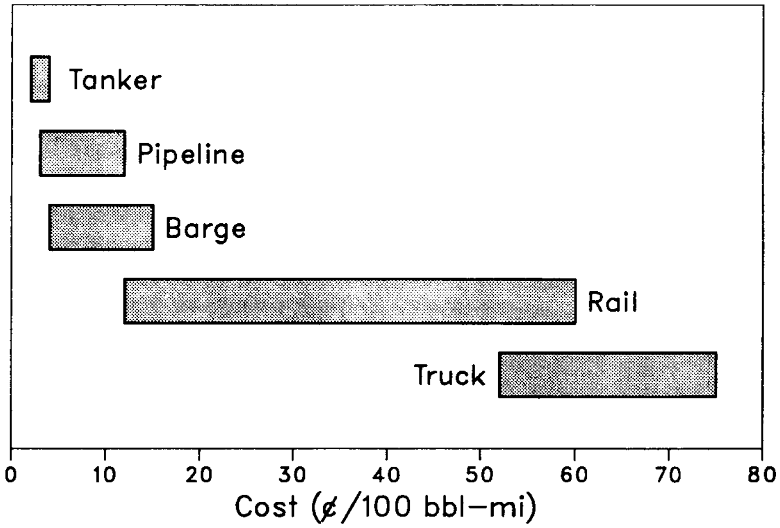


FIGURE 3.4 Petroleum Transportation Costs (mid-1970s)

Pipeline companies will decide, based on the properties of raw or upgraded biocrude and its compatibility with other materials being transported, whether to accept biocrude for pipeline transport; as a parallel example, a number of pipelines do not accept gasohol. Properties such as corrosiveness, high viscosity, instability, or high water content would make biocrude undesirable for transport by most pipelines. Biocrudes and partially upgraded oils vary widely in their composition and physical properties and, thus, in their suitability for pipeline transport. Biocrudes from different processes will not be equivalent and may pose differing demands on transportation systems. Biocrudes have substantial oxygen content. They also have an affinity for water and may thus have a substantial water content. Furthermore, some biocrude oils may be too viscous for ordinary pipeline transportation. Additional upgrading may be required before some types of biocrude will meet pipeline specifications.

3.2 RELEVANT REFINERY PROCESSES

The upgrading of biocrude oils will involve processes analogous to the conventional refinery processes known as hydrorefining, hydrotreating, and hydrocracking. Brief descriptions of these processes as implemented in U.S. petroleum refineries are given here. Flowcharts for these processes can be found in Gaines and Wolsky (1981). The technical potential for processing biocrudes in existing refinery units will be discussed in Sec. 5.3.

3.2.1 Hydrotreating and Hydrorefining

Catalytic hydrotreating was developed to remove from petroleum oils those compounds that have deleterious effects on process catalysts and vessels or produce harmful pollutants when burned. Sulfur compounds, for example, are corrosive and produce sulfur dioxide (SO_2) on combustion. Simple sulfur compounds can be removed with bauxite or with caustic or amine scrubbing, but catalytic hydrotreating is the only process that also removes sulfur from ring compounds. Nitrogen compounds, oxygen, heavy metals, and some olefins and diolefins may also be removed to improve color, odor, and stability.

Typical chemical reactions of hydrotreating (and of hydrorefining, which differs only slightly in conditions and products) are shown in Fig. 3.5. The process consumes hydrogen (H_2), and it came into use with the availability of hydrogen as a by-product of catalytic reforming of petroleum naphthas. Typical products from the hydrotreating of petroleum oils are saturated or aromatic hydrocarbons; by-products are hydrogen sulfide (H_2S), ammonia (NH_3), and water (H_2O). The hydrotreating process feeds range from light naphtha to reduced or whole crude but are usually naphthas, middle distillates, or catalytic reformer stock. Treating heavier feeds that have boiling points over 660°F (350°C) requires more severe conditions and more energy, resulting in higher costs (Hengstebeck 1959).

Hydrotreating catalysts are highly selective, minimizing the saturation of aromatics. Common catalysts are mixtures of cobalt and molybdenum oxides on alumina;

Desulfurization	$RSH + H_2 \longrightarrow RH + H_2S$ $R_2S + 2H_2 \longrightarrow 2RH + H_2S$ $(RS)_2 + 3H_2 \longrightarrow 2RH + 2H_2S$ $C_4H_4S + 4H_2 \longrightarrow C_4H_{10} + H_2S$
Denitrogenation	$C_4H_4NH + 4H_2 \longrightarrow C_4H_{10} + NH_3$ $C_5H_5N + 5H_2 \longrightarrow C_5H_{12} + NH_3$
Deoxidation	$C_6H_5OH + H_2 \longrightarrow C_6H_6 + H_2O$ $C_7H_{13}OOH + 3H_2 \longrightarrow C_7H_{16} + 2H_2O$
Dehalogenation	$RCl + H_2 \longrightarrow RH + HCl$
Hydrogenation	$C_5H_{10} + H_2 \longrightarrow C_5H_{12}$
Hydrocracking	$C_{10}H_{22} \longrightarrow C_4H_8 + C_6H_{14}$

FIGURE 3.5 Chemical Reactions of Hydrotreating

they may contain nickel if nitrogen is being removed along with sulfur (Gary and Handwerk 1975). The catalyst must be regenerated with air and steam or with an inert gas when its effectiveness is reduced by coke buildup. This occurs one to three times per year with normal feeds and as often as four times per day with residuum, which can deposit up to 2-6% of its mass as coke (Nelson 1958). Catalysts are generally presulfided before they are used and are maintained in a sulfided state by the H_2S in the circulating gas. Most petroleum stocks contain enough sulfur to maintain the catalyst system in the sulfided state, but this may not be the case for biocrudes. Catalyst makeup is from 0.001-0.007 lb/bbl of feed, depending on the feed and treatment conditions (Gary and Handwerk, 1975).

As of January 1, 1987, U.S. hydrotreating and hydrorefining charge capacity was 56.8% of crude distillation capacity (Cantrell 1987). Essentially all hydrotreating capacity for naphtha and middle distillates has fixed-bed downward-flow or radial-flow catalyst beds. A few heavy oil/residuum hydrotreaters are ebullated-bed designs. The catalyst bed configuration may play a role in determining the suitability of existing units for treating biofuels.

3.2.2 Hydrocracking

Hydrocracking uses hydrogen to convert gas oils and heavier fuels into gasoline, jet fuel, diesel fuel, butane, and liquified petroleum gas (LPG) fractions in an exothermic process, producing more middle distillates than can be obtained from crude oil by distillation. Hydrocracking consumes molecular hydrogen that has been obtained from the catalytic reformer or synthesized for this purpose. The gas oil feed may come from the catalytic cracker, the coker, or the crude distillation columns. The gasoline produced by hydrocracking contains more cycloalkanes than straight-run gasoline and is therefore a better feedstock for catalytic reforming. The jet and diesel fractions can be used directly in final products.

Besides converting olefins to paraffins, hydrocracking converts aromatics to cycloparaffins, which inhibits coke formation on the catalyst. Although the equilibrium concentrations of products and reactants are independent of pressure in cracking with subsequent hydrogenation, the conversion of aromatics to cycloparaffins is enhanced by high pressure. Hydrocracking is performed at pressures of 70-140 atm and 500°-800°F (260°-430°C); the reaction is exothermic.

The 1987 charge capacity of U.S. hydrocrackers was 7.3% of refining capacity (Cantrell 1987). Most hydrocracking units in the U.S.A. have fixed catalytic beds with downward flow of reactants; the exceptions are a few ebullated-bed units generally fed with heavy oils or residuum.

4 BIOMASS CONVERSION AND UPGRADING

The principal focus of this assessment is the production of liquid transportation fuels by thermochemical conversion of biomass and subsequent upgrading or refining. Biomass-derived oils are more oxygen-rich than petroleum-based materials; conversion and upgrading processes reduce the oxygen content in an attempt to produce oils that will be compatible with the existing transportation system (Chornet and Overend 1987). In this report, wood and herbaceous crops are considered to be the primary feedstocks for thermochemical conversion processes, which fall into two broad classes, high-pressure and low-pressure.

The high-pressure processes involve slurrying finely divided biomass in a recycle oil, water, or other liquid media and heating the mixture to about 660°F (350°C) in the presence of a reducing gas (typically a hydrogen/carbon monoxide mixture) at 2,500-6,000 lb/in.^{2} A catalytic agent, typically sodium carbonate, is often added to the slurry. High-pressure processes have been operated at both subcritical and supercritical pressures. Studies of these systems include those of Beckman and Elliott (1985) and ACS (1987). The Pittsburgh Energy Research Center (PERC) and Lawrence Berkeley Laboratory approaches were tested in a DOE pilot plant at Albany, Oregon, which provided substantial quantities of biocrude. Currently the University of Arizona is conducting research on an advanced-concept, direct-liquefaction process that uses a polymer extruder to handle more concentrated biomass slurries than those at the Albany pilot plant.

The low-pressure processes operate at from slightly above atmospheric pressure to moderate vacuum. They are pyrolytic, i.e., the biomass feed is heated in the absence of oxygen to temperatures at which it decomposes into gases, tars (liquids), and char. These processes have developed toward more rapid heating rates and relatively high peak temperatures, which tend to produce higher oil-to-gas ratios in the products. Reaction times of a few tenths of a second to a few seconds and maximum temperatures of 750°-1,025°F (400°-550°C) are typical of the rapid pyrolysis approaches. Georgia Tech Research Corporation and the University of Waterloo have been active in developing rapid pyrolysis (Knight et al. 1986; Scott et al. 1987). The Solar Energy Research Institute (SERI) has been developing an approach that closely couples rapid pyrolysis to catalytic upgrading with a zeolite catalyst at near atmospheric pressure, upgrading the products from the pyrolysis reactor without any intervening condensing, separating, or revaporizing steps (Diebold et al. 1986).

4.1 PROPERTIES OF BIOMASS-DERIVED OILS

Biomass-derived oils have chemical compositions and physical properties different from those of petroleum or shale- and coal-derived oils. The principal differences include

- Much higher oxygen content than petroleum or most synthetics,
- Low nitrogen and sulfur content,

- Low hydrogen-to-carbon ratios,
- High affinity for water,
- Viscosity more like that of petroleum residues than of crude oil or distillates, and strongly dependent on the dissolved water content,
- Low gravimetric heating values, and
- High density compared to petroleum and most synthetics.

Table 4.1 summarizes the composition and selected properties of several raw biomass-derived oils, crude oil, and synthetic oil from coal or shale. The raw high-pressure oils are physically similar to heavy fuel oils, having high viscosity and low volatility (Chornet and Overend 1987). The hydrogen-to-carbon mole ratios of raw biomass-derived oils are in the range of petroleum residuum and heavy coal-derived oils, well below the ratio for desirable petroleum crudes and transportation fuels (Fig. 4.1).

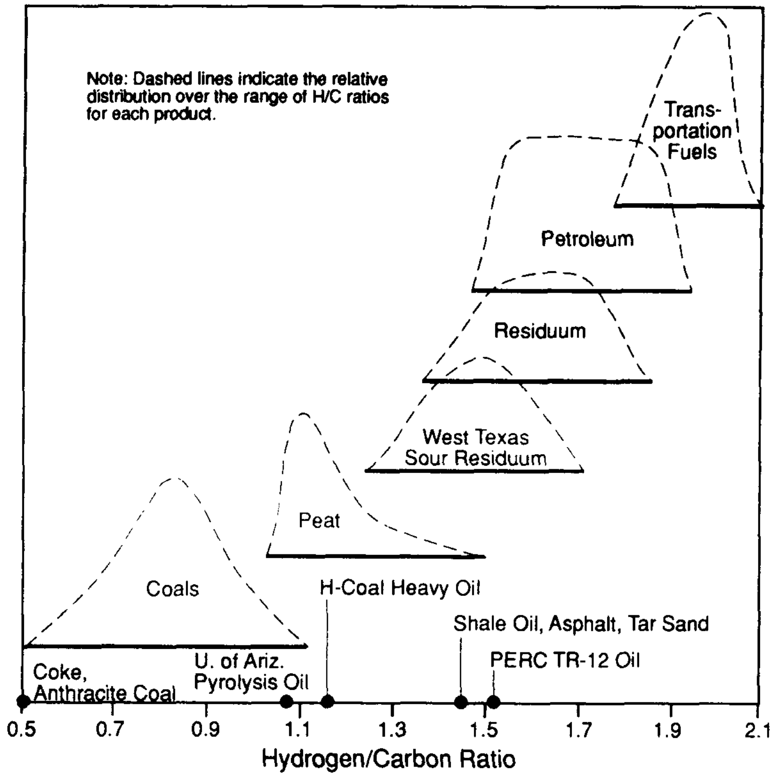


FIGURE 4.1 Hydrogen/Carbon Ratio of Various Fuels and Oils (adapted from Whitehurst 1978)

TABLE 4.1 Composition and Properties of Oils

	Biomass-Derived Oils							
	High-Pressure				Crude Petroleum Oils			
Characteristic	PERC TR-12[a]	U. of Arizona[a]	Georgia Tech Pyrolysis No. 11[a]	Rapeseed[b]	Typical Colo. 28[c]	West Texas Sour Residuum[c]	Shale Oil[c]	Direct Liquefaction Coal Oil[c]
Carbon content (wt%)[d]	81.0	83.4	59.2	80.3	86.5	84.8	84.6	88.8
Hydrogen content (wt%)[d]	10.2	7.9	7.0	10.7	12.3	10.1	11.2	7.9
Oxygen content (wt%)[d]	8.8	8.5	33.8	9.1	0.5	0.5	1.6	2.1
Nitrogen content (wt%)[d]	<0.1	0.1	<0.1	--	0.2	0.4	2.0	0.8
Sulfur content (wt%)[d]	<0.1	0.1	<0.1	--	1.0	4.2	0.6	0.4
Hydrogen/carbon ratio	1.51	1.14	1.42	1.59	1.71	1.43	1.59	1.07
Water content (wt%)	7.3	--	19.7	--	<0.5	<1.0	<0.5	<0.5
Higher heating value, raw (Btu/lb)	14,200	--	7,950	--	--	--	--	--
Higher heating value (Btu/lb)[d]	15,300	16,000	9,800	--	20,000[e]	18,700[e]	19,100[e]	17,700[e]
Density (g/mL at 23°C)	1.14	--	1.24	--	--	--	--	--
Specific gravity	1.14	--	1.24	--	--	--	--	--
Viscosity (cP at 40°C)	400,000	--	62	--	--	--	--	--
(cP at 61°C)	15,000	--	10[f]	--	--	--	--	--

[a] Data from Stevens (1987).

[b] Data from Kaufman (1982).

[c] Data from Energy Engineering Board (1980).

[d] Moisture- and ash-free.

[e] Estimated by Dulong formula.

[f] At 60°C.

4.2 BIOMASS CONVERSION PROCESSES

In this section, several conversion and upgrading processes are reviewed, because (1) at their present states of maturity, no single process has been recognized as technically or economically dominant; (2) the choice of conversion process is clearly interrelated with the extent of upgrading required; and (3) upgrading strategies will affect the transportation required for the raw, partially upgraded, or fully upgraded biocrude.

The oil produced by rapid pyrolysis contains much more oxygen than does the oil from high-pressure processes, so pyrolysis oil requires more extensive upgrading. To some extent, the savings from the low pressure and short contact time of the pyrolysis process are subsequently offset by the additional upgrading steps required and their inherently low potential yields. McKeough et al. (1985), in a study carried out as a part of the International Energy Agency Forest Energy Implementation Agreement, were unable to determine whether the PERC process or the flash pyrolysis process was more promising for the production of transportation fuels. With the modest levels of research in recent years, little has changed since that report.

4.2.1 PERC Process

This high-pressure, direct-liquefaction process is technically the most mature of the thermochemical conversion routes, having been tested at pilot-plant scale at Albany, Oregon. McKeough et al. (1985) identified the following areas in need of additional research:

- Feed preparation, particularly the fine grinding of wood,
- Process slurry concentration and viscosity, and the trade-offs between slurry concentration and heat exchanger costs and operability,
- Wastewater treatment and the capability to recycle condensate, and
- Process variable optimization.

4.2.2 Rapid Pyrolysis Process

Rapid pyrolysis has been developed at bench-scale and process-development-unit-scale at Georgia Tech Research Institute (Knight et al. 1986) and the University of Waterloo (Radlein et al. 1987). Based on the University of Waterloo work, McKeough et al. (1985) identified the following areas for additional research:

- Scale-up of the pyrolysis reactor and cooler/absorber,
- Heat requirements and heat balance for the pyrolysis reactor,

- Feed preparation (including wood grinding), and
- Process variable optimization.

4.2.3 Close-Coupled Rapid Pyrolysis and Upgrading

SERI has a rapid pyrolysis process in the preliminary development stage. It is a closely coupled process in which initial upgrading (deoxygenation) of the pyrolysis oil vapors occurs by direct passage of the vapors over a zeolite catalyst, without intervening condensation and revaporization steps (Diebold et al. 1986; Diebold and Scahill 1982, 1987a, 1987b). The vapors must flow directly from the rapid pyrolysis chamber (vortex reactor) to the catalyst bed, and the residence times in the transfer line, and pyrolysis reactor transfer bed must all be short. This approach requires that the conversion and at least the initial upgrading be done at a single plant, and it may require that each pyrolysis reactor have a directly associated catalytic reactor. The advantages of this approach include the production of an oil that contains much less oxygen than raw pyrolysis oil and the avoidance of some processing difficulties in hydrotreating the raw pyrolysis oils and in treating the wastewater from the hydrocatalytic stabilization of the oils. Some major uncertainties and research needs include:

- Demonstration of adequate and attractive oil yields,
- Demonstration of the process elements of the vapor-upgrading step, including catalyst circulation, regeneration, and stability, and the energy balances of the upgrading step and the overall process,
- Composition, physical properties, and suitability of the product oil for transport, further treatment, and end use, and
- Scale-up of the process elements and their integration into an overall process.

4.3 BIOCRUDE UPGRADING PROCESSES

Table 4.2 provides information on upgrading thermochemical biocrude by catalytic hydrotreating, including the composition and properties of the upgraded oils; the most notable fact is the very high hydrogen requirement for upgrading the biocrude. Upon severe hydrotreating, the high-pressure oils yield products that have oxygen contents, hydrogen-to-carbon ratios, and densities similar to gasoline components derived from petroleum or synthetic crudes. These products have not received the extended engine tests, stability tests, or miscibility and corrosion tests required to demonstrate their suitability for incorporation into transportation fuels. Less extensive testing may be adequate to indicate the level of deoxygenation necessary for using the products in such fuels. The hydrotreated pyrolyzate from Georgia Tech is clearly not sufficiently

TABLE 4.2 Data on Biocrude Upgrading

Parameter	PERC TR-7 Oil[a]				PERC TR-12 Oil[b]		Georgia Tech Pyrolyzate[a]
	Run A	Run B	Run C	Run D	Run A	Run B	
Process Conditions[c]							
Catalyst	NiMo	CoMo	CoMo[d]	CoMo	CoMo[e]	CoMo[e]	Ni
Pressure (lb/in.^{2} gage)	2,007	2,019	2,021	1,195	2,020	2,030	2,050
Temperature (°C)	388	397	394	341	397	403	280
Hydrogen feed rate (L/L feed oil)	3,270	2,705	666	4,107	--	--	550
Hydrogen consumption							
L/L feed oil	938	670	435	947	548	212	161
scf/bbl feed oil	5,550	3,910	2,580	5,620	3,250	1,260	953
Liquid hourly space velocity (vol. oil/h-vol. catalyst)	0.05	0.08	0.30	--	0.11	0.44	0.44
Products							
Liquid product yield (L/L feed)	1.10	1.01	1.01	1.0	0.92	0.94	0.42
Gasoline range fraction (liquid vol%)	--	--	60	--	37	11	--
Oxygen (wt%)	0.6	0.03	1.1	0.4	0.8	3.8	25.0
Hydrogen/carbon ratio	1.97	1.61	1.41	1.90	1.50	1.30	1.42
Density (g/mL)	0.798	0.832	0.913	--	0.91	1.03	--

[a] Data from Elliott and Baker (1986).

[b] Data from Baker and Elliott (1987).

[c] All runs used upward flow of oil through the catalyst bed.

[d] Additional data from Baker and Elliott (1987).

[e] Composite.

upgraded; in fact, the raw pyrolysis oil coked rapidly when it was processed at 350°C or above, the temperature range necessary to obtain adequate deoxygenation (Elliott and Baker 1986). Baker and Elliott (1987) have proposed an upgrading process with an initial stabilizing stage, operated at conditions like those shown for Georgia Tech pyrolyzate, followed by one or two stages operating at conditions similar to those shown for the high-pressure oils.

4.3.1 Upgrading High-Pressure Oils by Hydrotreating

Based on their own work and the extrapolation of hydrotreating studies on other synthetic oils, Elliott and Baker (1987) developed preliminary flow sheets and material balances for the PNL process, which involves hydrodeoxygenation and subsequent hydrocracking of PERC-type high-pressure oils. Figure 4.2 is a block flow diagram of an integrated hydrodeoxygenation/hydrocracking process for producing gasoline blending stock. Table 4.3 provides the stream flows and compositions for a nominal 1,000-L/h oil charge rate. The process flow scheme, stream flows, and compositions are based on limited bench-scale experimental work and reasonable extrapolations from the literature; they do not represent a mature, tested process. Overall hydrogen consumption is estimated to be 4,500 scf/bbl biocrude feed. The maximum catalyst test run length has been 48 hours, well short of commercial run requirements for fixed-bed catalytic reactors.

Further research is needed to:

- Improve the reaction rate and catalyst aging (the liquid hourly space velocity in hydrodeoxygenation is quite low, and catalyst activity degrades markedly within hours);
- Demonstrate catalyst stability in operation and in regeneration, particularly with the high H_2O partial pressure in the reactor and the significant residual sodium in the charge oil;
- Reduce hydrogen consumption substantially to improve economics and reduce the severity of exothermic reactions;
- Demonstrate the hydrocracking step and identify the resulting mix of products;
- Scale-up the reaction steps, including flow orientation over the catalyst beds and the necessity for and placement of quench inlets in large-scale reactors;
- Optimize the process variables; and
- Develop wastewater characterization and treatment design.

4.3.2 Upgrading Pyrolysis Oils by Hydrotreating

Early attempts to hydrotreat pyrolysis oil under conditions similar to those effective for hydrotreating high-pressure oils led to rapid coking and reactor plugging (Elliott and Baker 1986). Subsequent work indicated that a stabilization treatment at milder conditions yielded an oil similar to the raw high-pressure oil and similarly upgradable (Baker and Elliott 1987). The stabilization reaction produces a by-product wastewater stream containing high levels of dissolved organic carbon.

Figure 4.3 is a diagram of one scheme for upgrading pyrolysis oil by stabilization and partial hydrodeoxygenation. Additional deoxygenation and hydrocracking would be required to produce gasoline components. Table 4.4 provides the stream flows and compositions. Gasoline yield is only about 31 vol% on charge for the steps illustrated, compared to about 92 vol% for upgrading high-pressure oil by hydrocracking. Further hydrodeoxygenation and hydrocracking of the residuum from the hydrodeoxygenation step

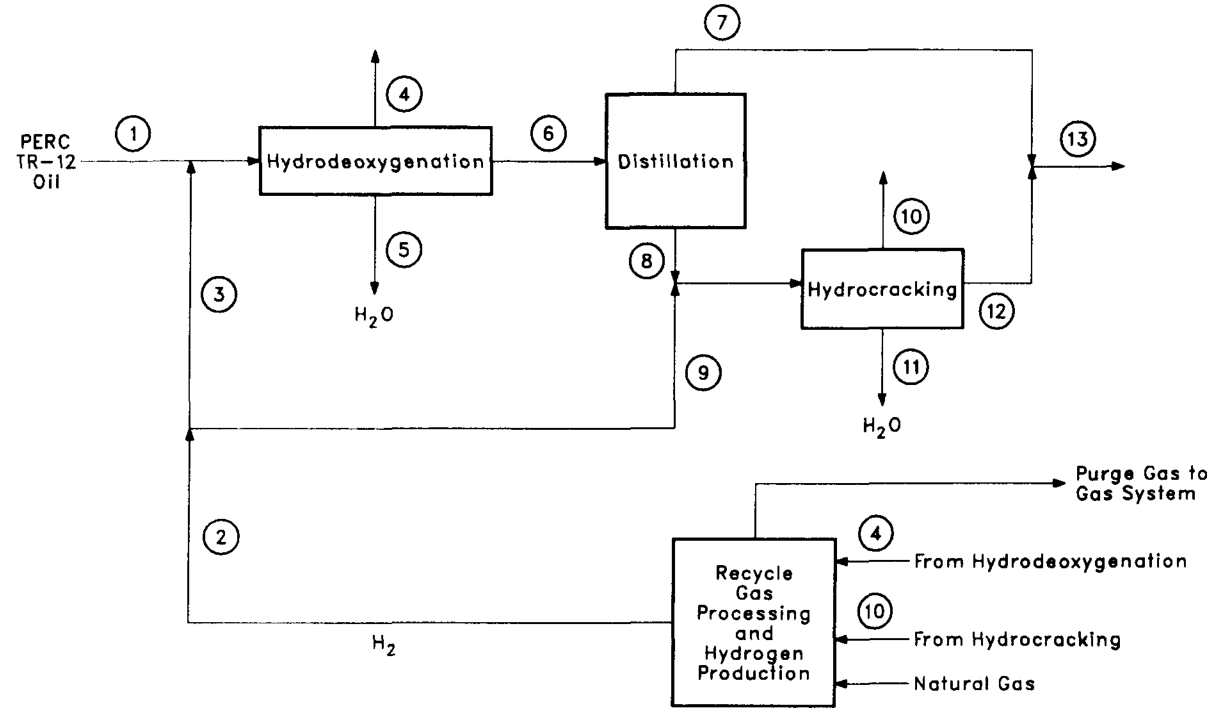


FIGURE 4.2 Hydrodeoxygenation/Hydrocracking Process for PERC TR-12 Oil

TABLE 4.3 Stream Flows and Compositions for Hydrodeoxygenation and Hydrocracking of PERC TR-12 Oil

	Liquid Streams							Gaseous Streams				
	Flow Rate		Composition (wt%)				Gasoline Range Fraction (vol%)	Flow Rate		Composition (vol%)		
Stream[a]	L/h	kg/h	C	H	O	Ash		10^3 L/h at 60°F	kg/h	H_2	CO_2	C_1-C_4 Hydrocarbons
1. TR-12 oil	1,000	1,100	72.6	8.0	16.3	3.0	--					
2. Hydrogen								1,266	105.5	100	--	--
3. Hydrogen								732	61	100	--	--
4. HDO gas								367	124	78.0	3.1	18.8
5. HDO water	179	179	1.8	10.9	87.3	--	--					
6. HDO product	907	826	88.0	11.0	1.0	--	40					
7. HDO gasoline	363	305	87.9	11.8	0.3	--	100					
8. HC feed	544	521	88.0	10.6	1.3	--	--					
9. Hydrogen								534	44.5	100	--	--
10. HC gas								262	109	85.0	--	14.9
11. HC water	9	9	--	11.1	88.9	--	--					
12. HC gasoline	556	445	86.3	13.7	--	--	100					
13. Total gasoline	919	750	87.0	12.9	0.1	--	100					

[a] HDO = hydrodeoxygenation; HC = hydrocracking. Streams are shown by number in Fig. 4.2.

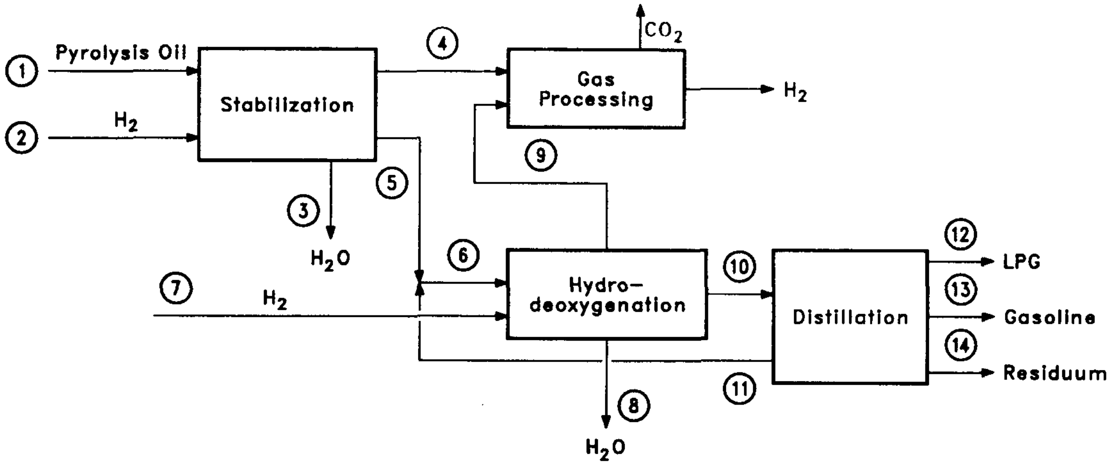


FIGURE 4.3 Stabilization/Hydrodeoxygenation Process for Pyrolysis Oil

TABLE 4.4 Stream Flows and Compositions for Stabilization and Hydrodeoxygenation of Pyrolysis Oil

	Liquid Streams								Gaseous Streams				
	FLow Rate		Composition (wt%)						Flow Rate		Composition (vol%)		
Stream[a]	L/h	kg/h	C	H	O	Ash	H_2O (wt%)	Gasoline Range Fraction (vol%)	10^3 L/h at 60°F	kg/h	H_2	CO_2	C_1-C_4 Hydro-carbons
1. Pyrolysis oil	1,000	1,220	43.6	7.8	48.4	0.2	21.1	--					
2. Hydrogen									100	8.5	100	--	--
3. Water	377	377	11.1	9.9	79.1	--	--	--					
4. Gas									151	96.8	66.4	30.0	3.6
5. Oil	666	753	61.6	7.6	30.8	--	14.8	--					
6. HDO feed	1,177	1,254	71.7	8.5	19.9	--	8.4	--					
7. Hydrogen									646	54.3	100	--	--
8. HDO water	222	222	1.4	10.9	87.8	--	--	--					
9. HDO gas									350	94.6	82.8	5.5	11.6
10. HDO product	1,023	972	86.8	10.2	3.0	--	--	30	12	24.66	--	--	100
11. Recycle oil	511	501	87.0	9.7	3.3	--	--	--					
12. LPG									12	24.66	--	--	100
13. Gasoline	307	258	87.0	12.5	0.5	--	--	100					
14. Residuum	205	213	86.4	8.7	5.0	--	--	--					

[a] HDO = hydrodexoygenation.
Streams are shown by number in Fig. 4.3.

would be needed to maximize gasoline production. The overall gasoline yield from upgrading pyrolysis oil would remain lower than that from high-pressure oils because of the large amount of water formed in the stabilization reactor from the high oxygen content of the raw pyrolysis oil. The gasoline yield on biomass is comparable, however, as can be seen from Fig. 4.4. As in the previous section, this scheme and the flow and product data are based on experimental work, not on a tested, mature process.

Recent work indicates that it may be possible to integrate the stabilization and initial hydrodeoxygenation steps into a single, non-isothermal reactor operated with

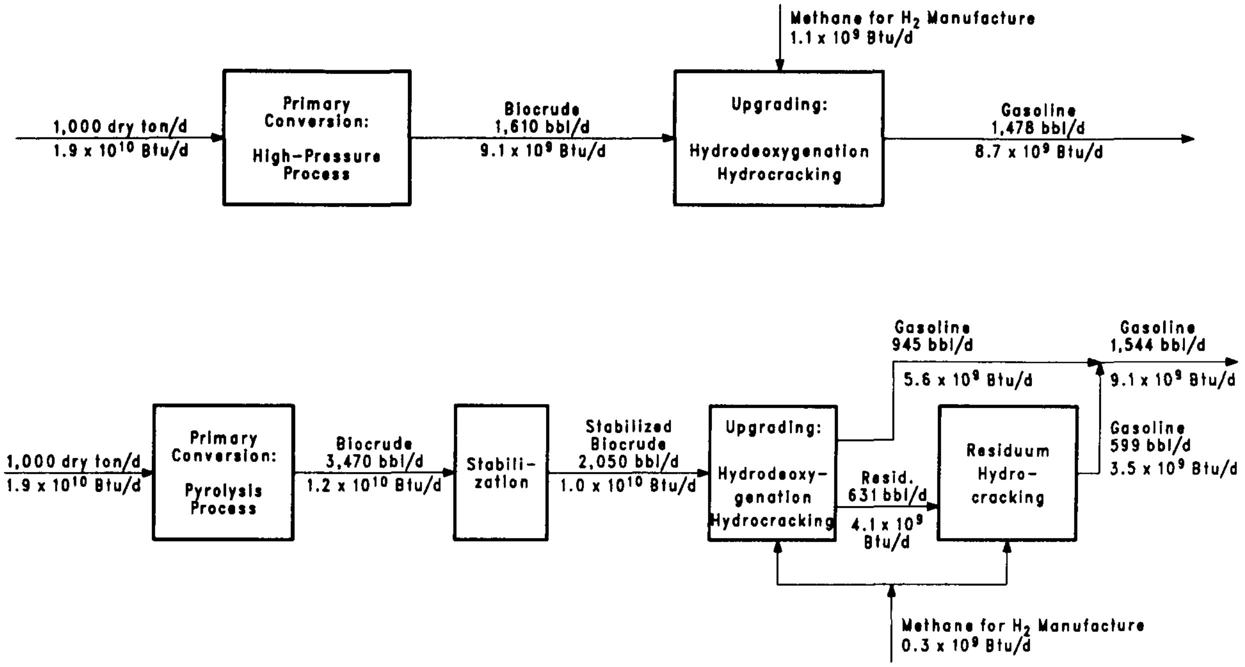


FIGURE 4.4 Process Yields from Upgrading High-Pressure and Pyrolysis Oils

increasing temperatures (Elliott and Baker 1987). This may markedly reduce the dissolved organic carbon in the by-product water, which would significantly reduce the difficulty of wastewater treatment.

Process uncertainties and areas for further research are largely the same as those for upgrading the high-pressure oil. Catalyst fouling and degradation from ash would likely be less of a problem, but the problem of the hydrothermal stability of the catalysts could be more serious due to the high water production in the stabilization and hydrodeoxygenation reactors. The fouling and corrosive properties of pyrolysis oil could also require substantial study.

4.4 TECHNICAL AND ECONOMIC ADVANTAGES

At present level of technical maturity, little can be said about the technical and economic advantages of the various thermochemical conversion and upgrading approaches. As experience is gained with operations closer to potential commercial practice, clear advantages may emerge.

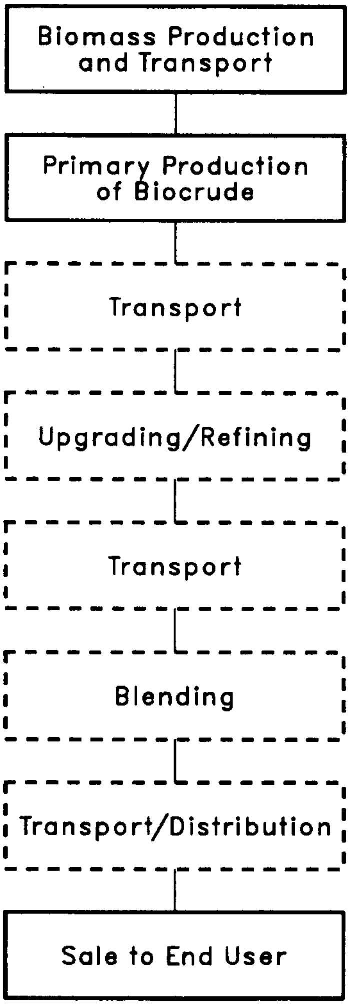
5 MATCHING BIOFUELS TO EXISTING SYSTEMS

5.1 INTERACTIONS OF PROCESS APPROACHES AND TRANSPORTATION

Unlike coal, shale, oil, and gas, which often appear in massive localized deposits, biomass is a distributed resource. Hence, the economics of producing biomass-derived fuels will depend strongly on the costs of transporting the biomass to a conversion facility. Conversion facilities will probably process about 1,000 dry ton/d of raw biomass and produce about 2,000 bbl/d of raw oil (Elliott 1983). This is much smaller than the economic scale of new petroleum refineries (80,000-200,000 bbl/d), coal-liquefaction plants (40,000-100,000 bbl/d), or shale-retorting plants (10,000-100,000 bbl/d).

Figure 5.1 illustrates the sequence of processing and transport operations for biofuels. The simplest case would be the direct sale of raw biocrude at the point of production. Transportation-grade fuel production could involve transporting raw biocrude from conversion facilities to a central upgrading facility, processing at that facility, and subsequent transportation (perhaps by existing pipelines) to a petroleum refinery, where the oil would be processed into gasoline blending stock.

The suitability of biocrudes to the normal petroleum transportation system is questionable because they differ from petroleum in chemical composition, water content, and physical properties. Raw PERC oil is too viscous to pump through unheated conventional crude oil pipelines. Raw pyrolysis oil, while not excessively viscous, differs so much in composition from petroleum oils that is unlikely to be accepted for transport in crude oil pipelines. The SERI process produces an oil that is more like petroleum than is raw pyrolysis oil, and this oil could be suitable for transport in product or crude pipelines (although it probably would require additional upgrading to be suitable for direct blending with gasoline). A plant using the SERI process might produce 1,000-4,000 bbl/d of "near gasoline-quality" oil, assuming a 50-mi transport radius for raw biomass.



Note: Steps in dashed boxes are not always required

FIGURE 5.1 Biofuels Processing and Transportation Operations

The economic scale of a greenfield biocrude-upgrading facility has been estimated to be about 20,000 bbl/d of raw biocrude (Elliott 1983), which could treat the output of 10 conversion plants each consuming 1,000 dry ton/d of biomass. The maximum economic distance from conversion plant to upgrading plant is estimated to be 100 mi. The product from an upgrading plant is likely to be similar enough to conventional gasoline components to be transported in product or crude oil pipelines, although it might be blended locally if local markets and blending stocks exist. It is beyond the scope of this study to estimate local or regional transportation fuel needs and to attempt to match those needs with the corresponding potentials for biofuel production.

5.2 REFINERY CAPACITY SURVEY

5.2.1 Existing Refineries

The refinery processes of hydrorefining, hydrotreating, and hydrocracking could be used to upgrade the oxygen-rich biocrudes from thermochemical conversion. Upgrading of biocrudes will require severe conditions to achieve adequate deoxygenation and molecular-weight reduction. In our review of existing U.S. refinery units, naphtha and middle-distillate hydrotreating and hydrorefining capacity has been excluded, based on the assumption that such units are designed for lower pressures, lower gas circulation and hydrogen consumption, and higher catalyst space velocities than would be required to treat biocrudes. This is a reasonable assumption, but it could not be rigorously tested within the scope of this study. This should be studied further if upgrading process conditions are developed that are closer to those used for petroleum middle distillates.

We reviewed information from a data base on U.S. refineries that is available from the *Oil & Gas Journal* (Cantrell 1987; O&GJ 1987). (See App. D for further information on the data base.) Of the 187 U.S. refineries active on January 1, 1987, 41 can hydrorefine residuum, heavy gas oil, or catalytic cracker and cycle stock feeds. Those units have 1.8×10^6 barrels per stream day (bbl/sd) of hydrorefining capacity. Eighteen of the refineries have residuum or heavy gas oil hydrorefining capacities totaling 778,000 bbl/sd, about 24% of their crude charge capacity. These are predominantly large refineries (averaging 180,000-bbl/sd capacity) and they are almost all on the Gulf Coast or in California. Forty-two refineries have hydrocracking units with a total feed capacity of 1.2×10^6 bbl/sd, much of which is for distillate upgrading. If only residuum and "other" hydrocracking is included, the total capacity is just 327,000 bbl/sd at 10 refineries. The geographic distribution of these refineries is more uniform than that of the hydrorefining plants, but they also tend to be large, averaging 211,000 bbl/sd of crude charge capacity and 32,700 bbl/sd of hydrocracker charge capacity.

If refineries having both hydrocracking and hydrorefining capacity are the most promising for upgrading thermochemical biocrudes, there are only 18 candidates when all types of hydrocracking and hydrorefining are considered (Table 5.1). Such a combination of units would approximate the hydrodeoxygenation and hydrocracking needed for upgrading. Of these 18 refineries, none have both hydrorefining and hydrocracking capacity for heavy oils or residuum.

TABLE 5.1 U.S. Refineries Having Both Hydrocracking and Hydrorefining Capacity (in order of hydrocracking capacity, by type)

Location	Company	Crude Capacity (10^3 bbl/sd)	Hydro-cracking (10^3 bbl/sd)	Hydro-refining (10^3 bbl/sd)	Hydro-treating (10^3 bbl/sd)	Hydrogen Production (10^6 scf/sd)
Richmond, Calif.	Chevron	383	76^a	60^e	82^i	135^l
			30^b	65^g	18^k	--
Pascagoula, Miss.	Chevron	310	68^a	96^d	48^i	215^l
Texas City, Texas	Amoco	425	56^a	118^f	126^i	180^l
Ferndale, Wash.	ARCO	170	50^a	17^g	32^i	80^l
El Segundo, Calif.	Chevron	435	43^a	24^d	56^i	112^m
Lake Charles, La.	Citgo	330	37^a	40^f	91^i	--
Norco, La.	Shell	220	35^a	70^f	29^j	70^l
Wood River, Ill.	Shell	296	34^a	29^f	64^j	28.3^l
Benicia, Calif.	Exxon	124	30^a	37^e	23^i	104^l
Martinez, Calif.	Shell	148	27^a	50^f	17^j	110^l
Martinez, Calif.	Tosco	133	23^a	50^f	139^i	80^l
Robinson, Ill.	Marathon	215	22^a	6^h	22^i	25^l
Baytown, Texas	Exxon	527	19^a	85^e	14^i	85^l
Chalmette, La.	Tenneco	147	15^a	40^f	38^i	24^l
Bakersfield, Calif.	Texaco	42	14^a	15^e	12^i	20^l
Wynnewood, Okla.	Kerr-McGee	45	5^a	6^e	9^i	10^l
Deer Park, Texas	Shell	235	65^c	45^f	65^j	65^l
Marcus Hook, Penn.	BP Oil	180	21^c	50^f	64^i	--
Total		4,285	670	903	948	1,343.3

Process key:

Hydrocracking

a. Distillate upgrading
b. Residuum upgrading
c. Other

Hydrorefining

d. Residuum desulfurizing
e. Heavy gas oil desulfurizing
f. Cat-cracker and cycle-stock feed pretreatment
g. Middle distillate
h. Other

Hydrotreating

i. Pretreating cat-reformer feeds
j. Naphtha desulfurizing
k. Other distillate

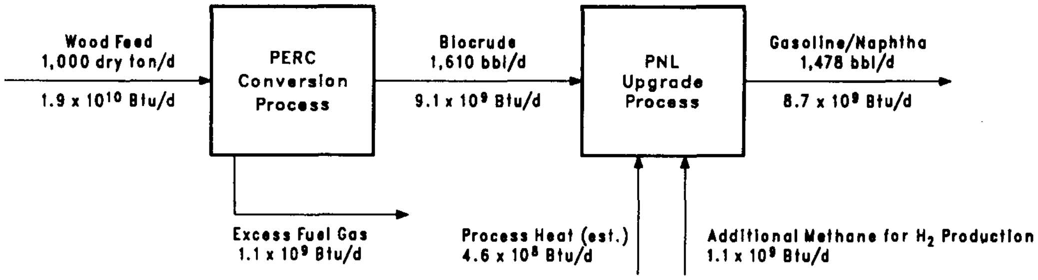
Hydrogen production

l. Steam methane reforming
m. Steam naphtha reforming

Large amounts of hydrogen would be required for upgrading thermochemical biocrudes. The research discussed in Sec. 4.3 indicates hydrogen requirements of 4,000-5,000 scf/bbl for upgrading high-pressure oils and 2,000 scf/bbl for pyrolysis oils, but the gasoline yields from raw pyrolysis oils would be much lower, offsetting the apparent greater efficiency of hydrogen utilization. If methane (natural gas) were the source of the hydrogen, 1.64-2.05 x 10^6 Btu (1,600-2,000 scf) of methane would be required per barrel of high-pressure biocrude; this is equivalent to 29-36% of the heating value of a barrel of biocrude. For pyrolysis biocrude, about 0.82 x 10^6 Btu/bbl (800 scf/bbl), or about 24% of the heating value of the biocrude would be needed. If the hydrogen were from coal gasification, the energy cost would be 1.15-2.87 x 10^6 Btu/bbl, about 40% greater than if the hydrogen were produced from methane.

Figure 5.2 illustrates the overall gasoline yields from two upgrading options for high-pressure oil, one using externally supplied methane for process heat and hydrogen, and the other using biocrude as process fuel and product naphtha as a supplemental feed for hydrogen manufacture. In both cases, primary conversion by the PERC process would be followed by the PNL upgrading scheme of Elliott and Baker (1987). For both cases, we assumed that 90% of reactor off-gas hydrogen would be recovered as a stream of 97% H_2 and 3% methane for recycle and that the balance of the off-gas hydrogen and C_1-C_4 hydrocarbons would go to steam reforming to produce hydrogen for process needs.

Case 1: Natural gas used for hydrogen production and process fuel



Case 2: Biocrude used as process fuel and product naphtha used as supplemental feed for hydrogen production

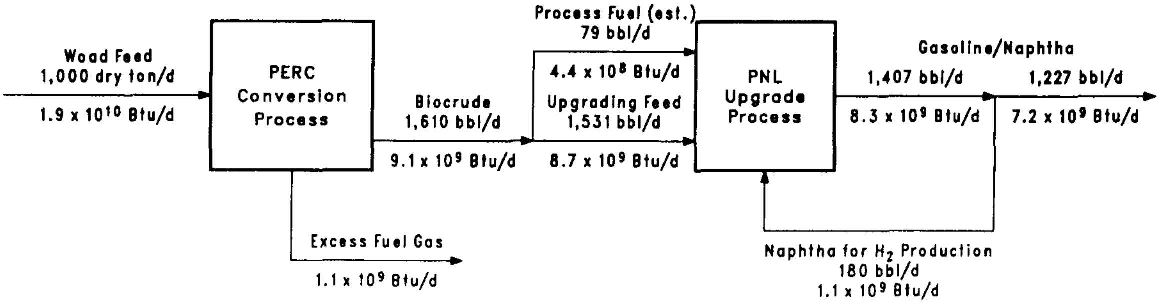


FIGURE 5.2 Yields from Upgrade Process Options for High-Pressure Oil

Several observations can be made from this figure.

- Use of process materials for process fuel and hydrogen production lowers the transportation fuel (gasoline) production per 1,000 dry tons of biomass about 17%.
- Absolute quantities of external energy required could be very large, about 19.5 x 10^9 Btu/d (20 x 10^6 scf natural gas/d) for a 20,000-bbl/d upgrading facility.
- If conversion facilities and upgrading facilities can be located close enough together, the hydrogen-rich excess fuel gas could be sent by pipeline from the conversion facility to the upgrading plant. This potential synergism should be studied further, particularly for regions of the U.S.A. where there is potential for substantial biomass production in relatively small areas.

In Case 2, biocrude was chosen for fuel and naphtha for hydrogen feed for situations in which natural gas is unavailable or unduly expensive. PERC biocrude appears to be suitable as fuel for process heaters and boilers, but not as a feedstock for steam reforming due to its high molecular weight and tendency to coke. The upgraded naphtha would be a suitable, though not optimal, feedstock. Biocrude could probably be used to produce synthesis gas by partial oxidation; however, about 62% of the feed necessary for hydrogen production is available as residue gas (slip hydrogen plus C_1-C_4 from off-gas processing) that is a suitable feed for steam reforming. We assumed that it would be preferable to use naphtha rather than to incur the investment necessary for the partial oxidation of the biocrude or of both the residue gas and the biocrude. It is not within the scope of this study to resolve the relative attractiveness of the possible configurations.

Similar analyses could be made for other process configurations (including fast pyrolysis followed by hydrocatalytic upgrading) if detailed material and energy balances to the point of production of gasoline-quality liquids were available. We would expect to see the same general features as seen in the PERC cases, except that the potential synergism between PERC excess fuel gas and upgrading hydrogen needs would not be expected from a fast pyrolysis conversion process.

5.2.2 New or Inactive Refineries

Two additional sources of potential biocrude upgrading capacity exist: (1) new construction and (2) the reactivation of units in currently inactive refineries. As of October 1, 1986, six hydroprocessing units were under construction with total capacity of 124,500 bbl/sd. One of these was a 20,000-bbl/sd hydrocracking unit, and another was a gas oil and cycle stock hydrorefiner of 68,000-bbl/sd capacity. The remaining four were hydrotreating units.

We reviewed the inactive U.S. refineries as of January 1, 1987, that have some type of hydroprocessing capacity. Hydrocracking capacity in those refineries is all middle-distillate type and probably is not suitable for biocrudes. Three of the five inactive hydrorefining units are suitable for treating heavy gas oil, and one has significant hydrogen production capacity as well. All of these refineries are located in California. A number of inactive refineries have hydrotreating capacity.

Reactivation of currently inactive U.S. refineries is unlikely to provide any significant upgrading capacity for biocrude. The inventory of inactive refineries will vary over time, and this potential capacity should be reviewed when upgrading needs, timing, and locations are more defined.

5.3 TECHNICAL ASPECTS OF BIOFUELS UPGRADING IN EXISTING REFINERIES

5.3.1 Hydroprocessing Suitability and Availability

Existing hydroprocessing capacity must be both suitable and available for upgrading biocrude. Availability will depend on refinery operating rates, crude slates, retirements, construction, and dismantling. Advances in hydroprocessing technology or in biomass conversion technology could improve the suitability of existing refinery units for biocrude feeds.

In our survey, no active refineries were found that had the ideal combination of residuum and gas oil hydrorefining and hydrocracking capacities. Eighteen refineries have residuum or heavy gas oil hydrotreating capacity totaling 778,000 bbl/sd. Ten refineries have residuum or "other" hydrocracking capacity totaling 327,000 bbl/sd. Without more detailed work, it is not known whether these units could be used for biocrude upgrading or what effective capacity they would have. Some specific technical issues that require study include:

- Velocities and heat loads in fired heaters;
- Velocities, fluid viscosities, and sensible and latent heat loads in process exchangers and coolers;
- Configuration, heat release, heat balance, quench flows, and flow directions and rates in catalytic reactors;
- Range of hydrogen sulfide partial pressure in a catalytic reactor needed to maintain catalyst metals at the necessary levels of sulfidation;
- Capacity of fresh hydrogen and recycle hydrogen compressors; and
- Capacity and sizing of liquid/vapor and liquid/liquid separators, particularly oil/water separators.

Detailed discussion of process design and suitability is not within the scope of this study. We assume that the high oxygen content of thermochemical biocrudes will preclude coprocessing significant amounts of these oils with petroleum. Hence hydroprocessing units would have to be modified to charge biocrude. Existing units would require a detailed evaluation before processing specific biocrudes. The following discussion illustrates process- and unit-specific concerns to be addressed when evaluating the feasibility and cost of modifying an existing refinery unit for biocrude upgrading.

Fired Heaters

Biocrude may have significant amounts of dissolved water and therefore could begin to vaporize at lower temperatures than would gas oil or residuum. The heat load per pound of charge could be higher due to the high sensible and latent heats of water, but the total heat load might be close to the design value if the lower volumetric charge rate offsets the higher heat load values. The altered temperature and vaporization characteristics will change the vapor fractions in the heater tubes, which in turn will change the process side velocities and possibly the flow regimes. The stability, operability, and rate of coking of fired heaters depend strongly on flow velocities, flow regimes, heat fluxes, and maximum tube-wall temperatures.

Process Exchangers and Coolers

The behavior of exchangers typically depends on the viscosities, sensible and latent heat capacities, and volumetric flow rates (tube-side and shell-side velocities). Refinery heat-exchanger trains are typically designed for a range of flows, compositions, and loads. Only a unit-specific analysis is likely to provide reliable information about the suitability of a set of exchangers and whether retubing, repiping, or replacement would be required.

Catalytic Reactors

Because catalytic reactors operate at specific temperatures, total pressures, and hydrogen/hydrogen sulfide partial pressures, units designed for hydroprocessing of naphthas and middle distillates cannot be used for biocrude oils. Vessel compatibility, the configuration of flows, catalyst beds, quench nozzles and other internals, heat release, heat balance, and reactor stability and controllability all must be considered. Elliott and Baker (1986) found upflow of oil through the catalyst bed helpful in avoiding coking in bench-scale hydroprocessing of thermochemical biocrudes. Should such a need exist in large-scale reactors, the work required to convert existing fixed-bed reactor systems might render such retrofits uneconomical.

Hydrogen Sulfide Partial Pressure and Catalyst Sulfidation

Hydrotreating and hydrocracking catalysts generally use one or more transition metals (commonly cobalt, molybdenum, nickel, and tungsten) on an alumina or silica-alumina base. Sulfided or partially sulfided metal crystals are believed to be the catalytically active sites. In processing petroleum or synthetic oils (e.g., shale oil), it is normal to sulfide the catalyst prior to use to avoid rapid coking and catalyst deactivation. Petroleum stocks and most synthetics contain enough sulfur to maintain the catalyst in a sulfided state. Biocrudes tend to be low in sulfur, and sulfur addition may be needed in hydrotreating and hydrocracking. The high amounts of water formed and the high partial pressure of water in stabilization and hydrodeoxygenation reactors may increase this need because of the solubility of sulfide in the water and because of the potential effect of the water on the sulfur/metal equilibrium. These issues have not been studied at a process-development level, so little can be said about the magnitude of this potential problem.

Hydrogen Compressors

Fresh- and recycle-hydrogen compressors are typically expensive items in hydroprocessing units and thus are not generally designed with large excess capacity. The capacities of these machines might therefore limit the unit's capacity for biocrude upgrading. If this capacity limit were severe, it could encourage the addition of more compressors.

Separators

Vapor/liquid and oil/water separators will be affected by biocrude processing temperatures and pressures, the volatility of biocrude, volumetric flow rates, and properties of biocrude such as the tendency to form oil/water emulsions.

5.3.2 Hydrogen Requirements and Availability

Hydrocatalytic upgrading of thermochemical biocrudes would require large amounts of hydrogen: 4,000-5,000 scf/bbl for high-pressure oils and 2,000-3,000 scf/bbl for raw pyrolysis oils. The difference is more apparent than real, because the product yields from pyrolysis oil are only about half those from the high-pressure oils. The economic scale of new biocrude-upgrading facilities has been estimated to be about 20,000 bbl/d (Elliott 1983), which would require between 40×10^6 and 100×10^6 scf/d hydrogen for a stand-alone upgrading facility. Retrofit of smaller upgrading units could be economical if they matched the existing hydrogen production capacity at the site.

Hydrogen availability in petroleum refineries is a complex function of the operating rates, conditions, and feedstocks. Some refineries have dedicated units to generate more hydrogen than that produced in naphtha reforming. By-product hydrogen is not expected to be available for biocrude upgrading. Less will be produced as biocrude displaces petroleum, and the remainder will be needed to upgrade petroleum streams. Table 5.2 summarizes information on the capacity of existing U.S. hydrogen generation units at petroleum refineries; the table does not include by-product hydrogen. The dedicated hydrogen generation capacity per barrel of charge at U.S. refineries is much

TABLE 5.2 Summary of U.S. Refinery Hydrogen Generating Capacity

Hydrogen Unit Size (10^6 scf/d)	Summed Capacity (10^6 scf/sd)	Percent of U.S. Capacity	Number of Refineries	Percent of Refineries	Summed Crude Capacity (10^3 bbl/sd)	Percent of U.S. Crude Capacity
≥ 25	2,110	89	27	14	5,598	35
≥ 50	1,796	76	19	10	4,391	28
≥ 100	911	38	6	3	1,795	11

Source: *Oil & Gas Journal* data base.

lower than would be required for biocrude upgrading (see Table 5.3). Hydrogen capacities at individual refineries vary widely; some refineries could provide large volumes of hydrogen to hydrotreating or hydrocracking units, but such capability is not common.

Active U.S. refineries having at least 25 x 10^6 scf/d of dedicated hydrogen production are listed in Table 5.4. It is apparent that (1) only a small fraction of U.S. refineries have large dedicated hydrogen generation capacity, (2) refineries having such capacity tend to be in California or on the Gulf Coast, and (3) this geographic bias increases with increasing hydrogen capacity. Of the refineries having 25 x 10^6 scf/d of capacity, 74% are on the Gulf Coast or in California; at 50 x 10^6 scf/d, 90% are in these two regions. All refineries having 100 x 10^6 scf/d or more of hydrogen capacity are in California or on the Gulf Coast.

Dedicated hydrogen production could be augmented at existing refineries. This might be economically attractive at refineries with appropriate hydroprocessing units and a diminishing demand to treat conventional petroleum. Another option would be to build the hydrogen production units at new, dedicated biocrude-processing plants. These plants could perform both biocrude upgrading and final refining, could be better matched to the biomass production areas than are existing refineries, and could send the product directly to gasoline blending terminals.

At current fossil fuel prices, the production of hydrogen from methane would probably be the least expensive route. Table 5.5 provides estimated costs for hydrogen production from fossil fuels and by water electrolysis. Hydrogen from methane reforming costs less than 60% as much as the next closest competitor, partial oxidation of residual oil. If only 2,000 scf of hydrogen were required to upgrade a barrel of biocrude, the cost from methane would be about $3/bbl. Electrolysis is not likely to be economical for large-scale hydrogen production in the U.S.A. in the foreseeable future. Hydrogen production from biomass would likely cost about the same as that from coal, with slightly higher biomass feedstock costs offset by lower costs for environmental controls. Supplying 2,000 scf of hydrogen from coal or biomass would cost at least $5.60/bbl. Thus, hydrogen for upgrading is likely to significantly contribute to both the capital and energy costs of upgraded oil from biomass.

TABLE 5.3 Dedicated Hydrogen Generating Capacity of Active U.S. Refineries (scf H_2)

Type	Per bbl Crude Charge	Per bbl Hydrocracking Charge	Per bbl Hydrorefining Charge
All U.S. refineries	150	2,041	1,022
Refineries with heavy gas oil and residuum hydrorefining	208	2,678	840
Refineries with hydrocracking	254	1,722	2,218
Refineries with hydrocracking and hydrorefining	313	2,004	1,487

5.3.3 Research and Development Needs

The following aspects of biocrude upgrading require further research and development. Many of these areas apply both to the design of retrofits in existing refineries and to new construction.

- Physical, thermodynamic, and transport properties of biocrudes over broad temperature, pressure, and composition ranges.
- Reaction rates, pathways, and kinetics for upgrading steps.
- Composition and properties of products.
- Process and material compatibility with existing process equipment.
- Maintenance of catalysts at appropriate level of sulfidation when processing low-sulfur, high-water-content feeds.
- Composition and treatability of process wastewaters.

5.4 GEOGRAPHIC AND CAPACITY MATCHING

The key question this report is attempting to answer is, "Could a significant quantity of biocrude be sent to petroleum refineries for processing?" The answer depends on the answers to three other questions:

- How much biomass could be grown for energy?
- How much potential biocrude would be located close enough to a refinery or oil transportation system for economical shipment?

TABLE 5.4 U.S. Refineries Having 25 x 10^6 scf/d or More of Hydrogen Production Capacity

		Daily Capacity				
Location	Company	Hydrogen Production (10^6 scf)	Crude Oil (10^3 bbl)	Hydro- cracking (10^3 bbl)	Hydro- refining (10^3 bbl)	Hydro- treating (10^3 bbl)
Pascagoula, Miss.	Chevron	215	310	68	96	48
Texas City, Texas	Amoco	180	415	56	118	126
El Segundo, Calif.	Chevron	167	425	43	84	74
Richmond, Calif.	Chevron	135	383	78	60	82
Martinez, Calif.	Shell	110	138	27	50	17
Benicia, Calif.	Exxon	104	124	30	37	23
Baytown, Texas	Exxon	85	517	19	85	139
Martinez, Calif.	Tosco	80	133	23	50	14
Sweeny, Texas	Phillips	80	195	0	75	53
Ferndale, Wash.	ARCO	80	170	50	17	32
Carson, Calif.	ARCO	70	225	22	0	40
Rodeo, Calif.	Unocal	70	125	33	0	23
Norco, La.	Shell	70	220	35	70	29
Deer Park, Texas	Shell	65	225	65	45	65
Convent, La.	Texaco	63	240	35	0	40
Torrance, Calif.	Mobil	62	130	22	0	21
Beaumont, Texas	Mobil	60	285	32	0	92
Borge, Texas	Phillips	50	110	0	50	27
Corpus Christi, Texas	Valero	50	21	0	54	8
Los Angeles, Calif.	Unocal	49	111	22	0	54
Wilmington, Calif.	Texaco	48	78	20	0	18
Toledo, Ohio	Sun CI	48	124	28	0	28
Delaware City, Del.	Texaco	40	150	19	0	55
Philadelphia, Penn.	Atlantic	40	130	30	0	50
Wilmington, Calif.	Shell	36	122	0	0	25
Wood River, Ill.	Shell	28	286	34	29	64
Robinson, Ill.	Marathon	25	205	22	6	22

Source: *Oil & Gas Journal* data base.

- Is the capacity of suitable refinery equipment adequate for processing the biocrude?

5.4.1 Approach

We established several technical and economic conditions in order to estimate the quantity of biocrude that might be processed at existing petroleum refineries. One condition was that sufficient biomass be available within a distance to economically supply an upgrading facility. The minimum density for economical harvest was specified as 0.1 dry ton/a-yr of biomass. This minimum, about 20% of the conventional minimum forest harvest density, eliminated energy wood collection from forests in several western states where vegetation is very sparse.

TABLE 5.5 Cost of Hydrogen Production by Various Processes[a]

Costs	Methane Reforming	Partial Oxidation of Residual Oil	Coal Gasification	Water Electrolysis
Input energy (Btu/scf H_2)	410 ± 50	410 ± 50	575 ± 100	380 ± 30
Energy cost ($/$10^6$ Btu)	2.24[b]	3.03[b]	1.52[b]	13.89[c]
Energy cost ($/$10^3$ scf H_2)	0.92	1.24	0.87	5.28
Capital and other costs ($/$10^3$ scf H_2)	0.62	1.46	1.94	0.86
Total cost ($/$10^3$ scf H_2)	1.54	2.70	2.81	6.14
Energy (% of total cost)	60	46	30	86

[a] Based on 10^8 scf/d; costs in 1987 dollars.

[b] Delivered cost to steam utility plants.

[c] Industrial price.

Sources: Gaines and Wolsky 1984; DOE 1987.

We assumed that solid biomass (1,000 dry ton/d) would be shipped by truck from the growing site to a conversion facility, where raw biocrude would be produced. The maximum distance for economical truck transport of low-value materials is about 50 mi. Raw biocrude would be upgraded either at the conversion plant or at a separate upgrading facility. A separate facility would likely be within 100 mi of the conversion plant, because raw biocrude has about twice the energy density of raw biomass and so can be economically transported twice as far. Sufficient biomass must therefore be available within a 150-mi radius of an upgrading plant.

An upgrading facility of minimum economic size would serve 10 conversion plants and require annual biomass conversion of about 3.3 x 10^6 dry ton/yr. Such a facility would produce about 20,000 bbl/d of upgraded biocrude. This quantity might be large enough to warrant construction of a small pipeline up to 100 mi long (see Sec. 3.1.2) for transporting the upgraded biocrude to a refinery, petroleum pipeline, or port for barge transport. Biomass must therefore be grown within 250 mi of a refinery or a major petroleum transportation network.

Petroleum refineries were assumed to have only current processing capacity available to upgrade biocrude. The quantity of biocrude that can be treated is limited by the refinery's hydrotreating capacity and by the quantity of hydrogen that can be produced. We assumed that at least 2,000 scf of hydrogen will be required to treat each barrel of biocrude.

Only potential production that met all the constraints was included in the total. For ease of display, the detailed mapping of the matches between biomass production areas, transportation, and refineries uses states and counties rather than the CARD producing areas.

5.4.2 Results

Matching of Refineries and Locally Produced Biocrude

Table 5.6 gives the potential quantities of biomass available within 50, 150, and 250 mi of refineries; biomass within a given county was assigned to the closest refinery to avoid double counting. About 70% of the potential biomass we identified (1.1×10^9 dry ton/yr) is within 250 mi of a refinery; 16% is within 50 mi (see Fig. 5.3), which would allow direct transport of biomass to a conversion plant at the refinery site.

TABLE 5.6 Total Biomass within a Given Radius of Refineries[a] (10^6 dry ton/yr)

State	Refinery Location	250 mi	150 mi	50 mi
Alabama	Tuscaloosa	28.8	28.5	5.6
Alabama	Saraland	22.6	16.4	5.6
Arkansas	Stevens	28.9	24.0	5.9
Arkansas	Smackover	4.4	4.4	1.8
Delaware	Delaware City	5.3	5.3	1.0
Georgia	Savannah	94.4	51.3	7.9
Georgia	Douglasville	40.5	34.2	3.5
Illinois	Hartford	29.3	19.5	1.2
Illinois	Wood River	7.1	2.2	0.4
Illinois	Lemont	6.6	3.0	0
Indiana	Mt. Vernon	11.0	9.9	3.2
Kansas	Coffeyville	27.8	24.8	5.9
Kansas	El Dorado	12.8	4.8	1.1
Kentucky	Catlettsburg	11.1	2.5	0.4
Kentucky	Somerset	10.9	10.2	2.3
Louisiana	Shreveport	9.9	9.9	6.9
Louisiana	Lake Charles	5.6	5.6	4.0
Louisiana	Krotz Springs	4.3	4.3	3.0
Louisiana	Cotton Valley	4.2	4.2	2.6
Louisiana	Princeton	4.0	4.0	1.1
Michigan	Alma	14.2	9.6	2.8
Michigan	Carson City	8.3	6.8	2.0
Michigan	Kalamazoo	5.5	5.5	4.5
Minnesota	St. Paul Park	27.7	22.5	2.0
Minnesota	Rosemount	8.1	3.2	0.8
Mississippi	Vicksburg	9.8	9.8	5.0
Mississippi	Sandersville	6.5	6.5	4.4
Montana	Billings	5.2	3.9	1.1
Montana	Great Falls	4.3	3.9	1.0
New Jersey	Linden	19.6	10.3	0
North Dakota	Mandan	9.3	3.9	0
Ohio	Canton	4.3	4.3	1.6
Oklahoma	Ardmore	14.8	14.8	5.9
Oklahoma	Wynnewood	9.0	9.0	7.1
Oklahoma	Tulsa	7.7	7.7	4.5
Oklahoma	Thomas	6.5	6.5	2.8
Oregon	Portland	13.5	9.6	5.6
Pennsylvania	Rouseville	11.7	11.3	5.4
Pennsylvania	Smethport	11.0	11.0	2.1
Pennsylvania	Bradford	5.3	4.4	1.4
Tennessee	Memphis	5.3	5.3	0.4
Texas	Tyler	23.1	23.1	9.2
Texas	Bridgeport	15.5	15.5	7.6
Texas	Abilene	10.9	10.9	2.5
Texas	Sweeny	10.3	10.3	6.1
Texas	San Antonio	8.6	8.6	3.2
Texas	Three Rivers	6.3	6.3	5.5
Texas	Corpus Christi	4.0	4.0	2.8
Texas	Big Spring	3.4	3.4	1.4
Virginia	Yorktown	68.7	40.8	0.4
Washington	Tacoma	10.5	10.5	5.2
Wisconsin	Superior	52.1	42.5	3.9
Total[b]		790.6	615.0	171.6

[a] Includes only counties having more than 330×10^3 dry ton/yr of biomass and refineries having more than 3.3×10^6 dry ton/yr within 250 miles.

[b] Columns may not sum to these figures due to rounding.

However, many of the refineries are not suited to processing biocrude. Refineries were ranked in terms at the potential for converting their process units to biocrude upgrading, nominally at 20,000 bbl/sd. A refinery with good potential has at least two heavy oil or residuum hydrorefining, hydrocracking, or hydrotreating units of substantial size and a substantial hydrogen generation capacity; one with medium potential has at least one heavy oil or residuum hydroprocessing unit of substantial size and either a substantial hydrogen generation capacity or a second hydroprocessing unit. Table 5.7 lists the hydrogen capacities and the potential biocrude available within 50 mi of the refineries ranked as good. Conversion and upgrading could both be considered at these sites. Hydrogen generated at the refinery was deemed to be available for biocrude processing. By-product hydrogen was not counted, because even if biocrude is

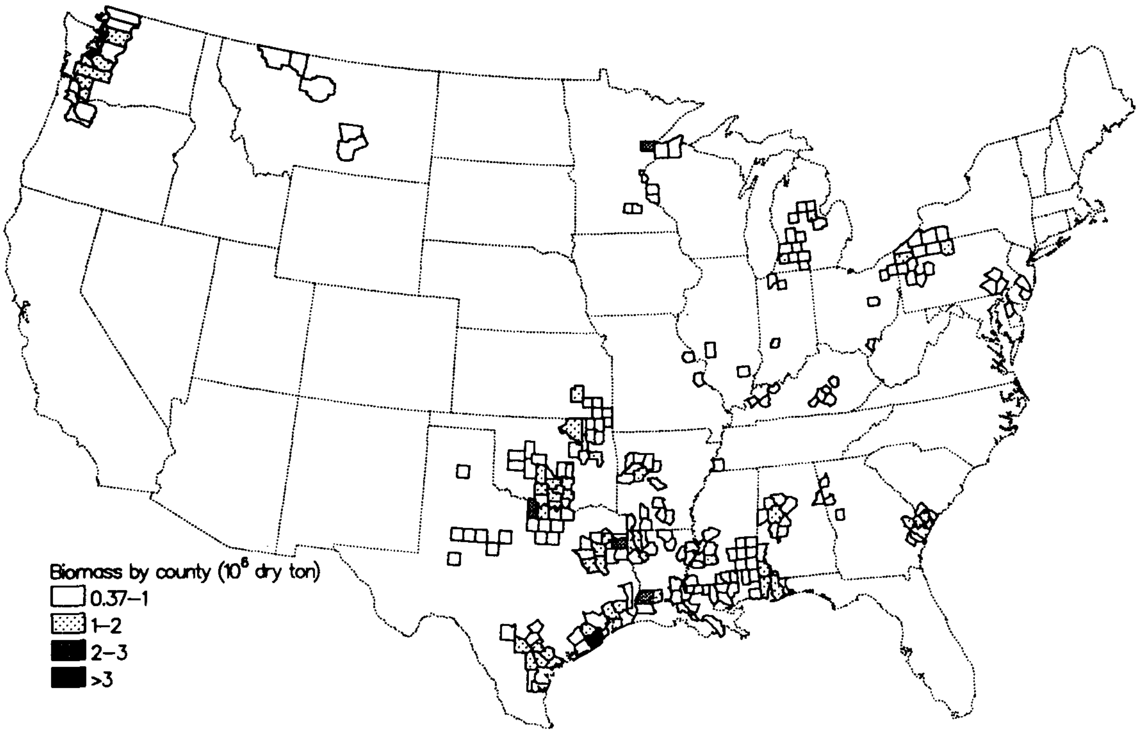


FIGURE 5.3 Potential Biomass Yields within 50 Miles of a Refinery

processed in units that provide by-product hydrogen, the amount will likely be lower from biocrude than from petroleum.

For the refineries ranked good, the upgrading capacity would be 166,500 bbl/d based on potential biomass production within a 50-mile radius. Based on these refineries' dedicated hydrogen capacity, consumption of 2,000 scf H_2/bbl, and disregarding biomass availability, the total capacity would be 648,000 bbl/d. Assuming a PERC-type crude and natural gas as supplemental feed, gasoline yield would be 153,000-595,000 bbl/d. This would be 2.2-8.7% of the 1985 average daily gasoline consumption and 1.4-5.3% of the average daily total distillate product consumption (EIA 1987). It would be 7-27% of the 1985 daily product imports (which were about 2 million bbl/d).

The following observations can be drawn from the matching process:

- Potential biomass availability is generally more than adequate within a 250-mi radius to support refineries ranked good or medium. Major exceptions are the California refineries.

- Four to six refineries (see Table 5.7) appear to have enough potential biomass within a 50-mi radius to support upgrading of 20,000 bbl/d. At those locations, integrated primary conversion and upgrading may be feasible at an existing refinery and many existing refinery utility units might be shared.

TABLE 5.7 Data for Refineries Having Good Potential for Conversion to Biocrude Upgrading

Location	Company	Hydrogen Production Capacity (10^6 scf/sd)	Biocrude Capacity[a] (10^3 bbl/sd)	Potential Biocrude within 50 mi (10^3 bbl/d)
Deer Park, Texas	Shell	65	33	40.4
Baytown, Texas	Exxon	85	42	38.7
Texas City, Texas	Amoco	180	90	22.0
Wood River, Ill.	Shell	28	14	18.3
Convent, La.	Exxon	63[b]	31	17.6
Pascagoula, Miss.	Chevron	215	107	15.6
Ferndale, Wash.	ARCO	80	40	9.0
Benson, Texas	Phillips	50	25	4.9
Richmond, Calif.	Chevron	135	68	Negl.[c]
El Segundo, Calif.	Chevron	112	56	Negl.
Martinez, Calif.	Shell	110	55	Negl.
Benicia, Calif.	Exxon	104	52	Negl.
Carson, Calif.	ARCO	70	35	Negl.
Total			648	

[a] Based on 2,000 scf H_2/bbl.

[b] Hydrogen by partial oxidation.

[c] Negligible.

- Unless additional production capacity is built, hydrogen availability is likely to be a major constraint on the ability of refineries to process biocrudes. The average hydrogen availability at refineries ranked as having good potential would be sufficient to process 50,000 bbl/d of raw biocrude. The average amount of hydrogen available at other refineries is significantly less.

- Many refineries in areas that could produce substantial quantities of biomass either do not have process units compatible with biocrude upgrading or do not have the hydrogen-generation capacity to support significant upgrading. There may be potential for adding units to such refineries to take advantage of the existing sites, permits, utilities, and other infrastructure.

Matching of Biomass to Transportation Systems

Biomass that is not produced near an appropriate refinery must be converted locally, and the product biocrude must be transported. Almost 60% of the potential biomass that is economically harvestable is within 50 mi of crude oil pipelines, and about 90% is within 250 mi (Fig. 5.4). However, there is significant variation by state (see Table 5.8). All of the potential biomass in Gulf Coast states like Texas and Louisiana is within 50 mi of crude oil pipelines, but practically none of the biomass in the Southeast is within 150 mi. Figure 5.5 and Table 5.9 show similar information for barge routes. Almost 95% of the potential biomass is within 250 mi of barge routes, and almost 50% within 50 mi. Eastern states have good access to barge transportation, while much of the West has none. Considering both barge routes and pipelines, there is excellent coverage of the country.

Summary

The distribution of potential biomass relative to pipelines, waterways, and refineries is provided by state in Table 5.10 and shown by county in Fig. 5.6. Essentially all of the biomass that could be harvested for energy is within 150 mi of a pipeline, barge, or refinery, and 83% is within 50 mi. We therefore conclude that biocrude could be produced in locations with sufficient access to transport. The distances are short enough that transportation costs are not expected to be a major economic constraint. Obstacles such as mountains have not been considered and may reduce the total biomass that can be economically collected. The only remaining caveat on transportation is that the biocrude must meet the carriers' specifications regarding physical and chemical properties.

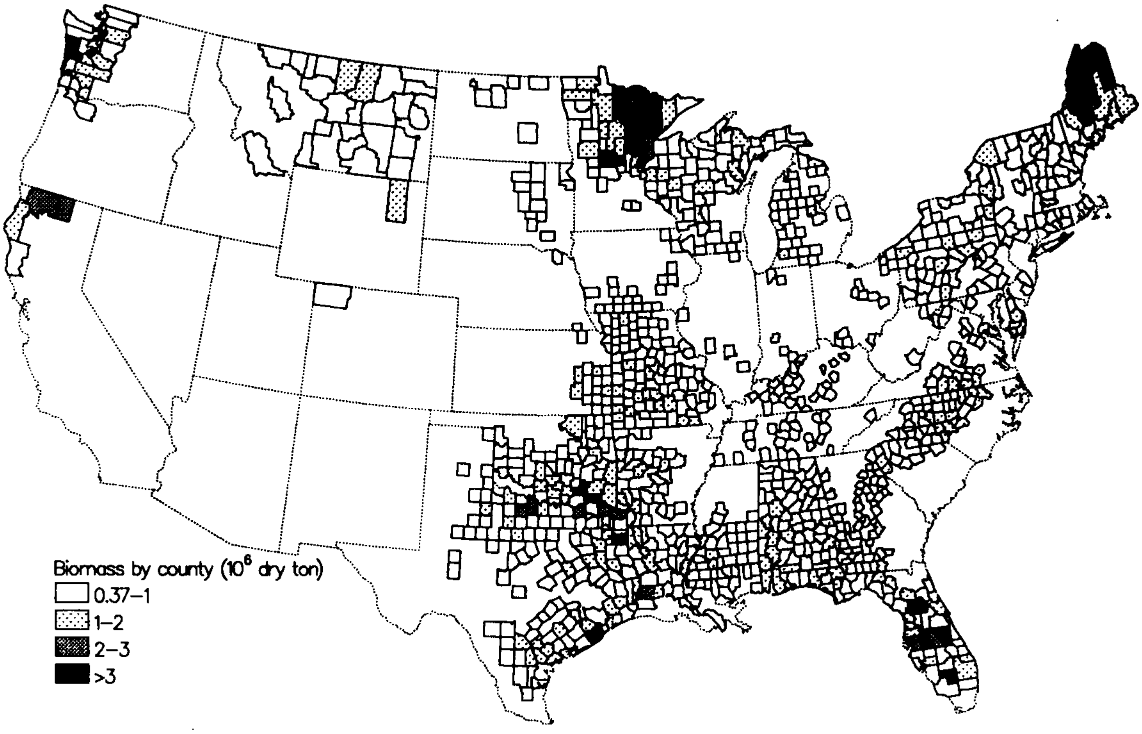


FIGURE 5.4 Potential Biomass Yields within 250 Miles of Crude Oil Pipelines

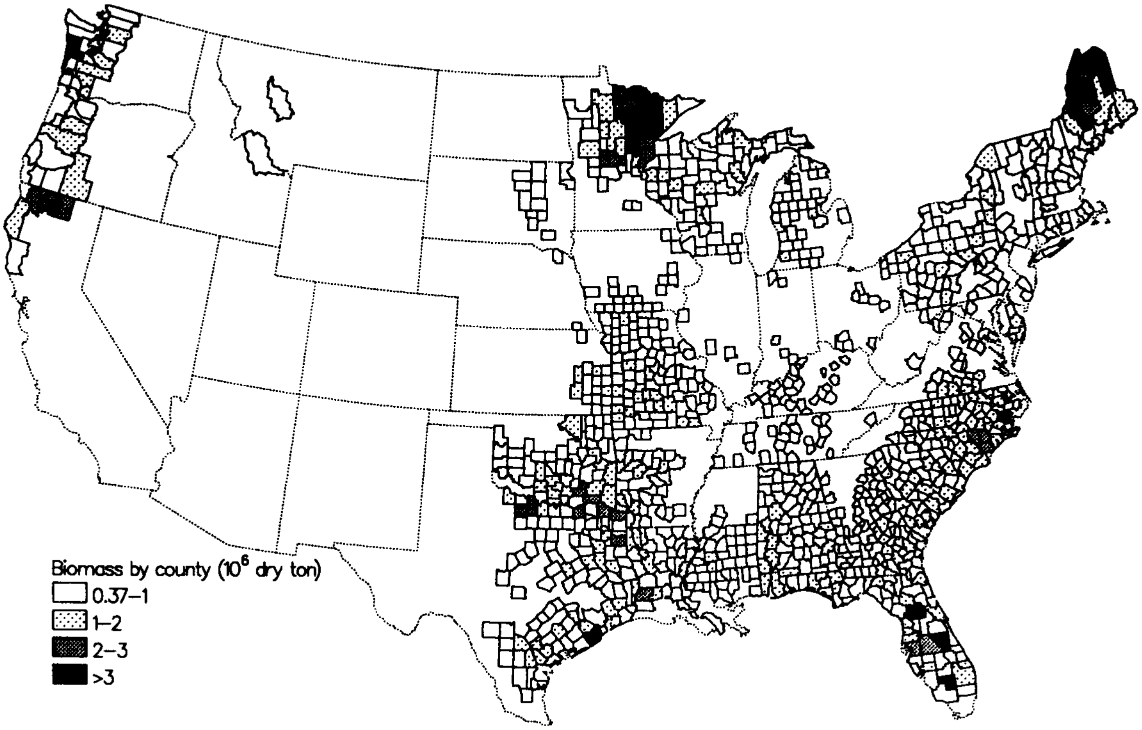


FIGURE 5.5 Potential Biomass Yields within 250 Miles of Waterways

TABLE 5.8 Potential Biomass Yields in Counties within a Given Radius of Crude Oil Pipelines[a] (10^6 dry ton/yr)

State	Total	250 mi	150 mi	50 mi
Alabama	48.8	48.8	48.8	24.9
Arizona	0	0	0	0
Arkansas	26.2	26.2	26.2	21.4
California	4.2	4.2	0.6	0
Colorado	0.5	0.5	0.5	0.5
Connecticut	3.5	3.5	1.3	0
Delaware	1.7	1.7	1.7	0
Florida	57.0	53.7	35.8	11.7
Georgia	57.4	32.5	5.5	0
Idaho	0	0	0	0
Illinois	3.2	3.2	3.2	3.2
Indiana	5.0	5.0	5.0	5.0
Iowa	10.8	10.8	10.8	7.5
Kansas	12.0	12.0	12.0	12.0
Kentucky	12.3	12.3	12.3	12.3
Louisiana	26.9	26.9	26.9	26.9
Maine	20.2	20.2	14.8	4.1
Maryland	2.9	2.9	2.9	0
Massachusetts	3.7	2.5	2.5	0
Michigan	32.2	32.2	32.2	31.7
Minnesota	58.3	58.3	58.3	52.6
Mississippi	23.6	23.6	23.6	22.5
Missouri	65.0	65.0	65.0	63.0
Montana	16.6	16.6	16.5	11.1
Nebraska	1.1	1.1	0.5	0.5
Nevada	0	0	0	0
New Hampshire	4.2	4.2	4.2	2.4
New Jersey	0.9	0.9	0.9	0.9
New Mexico	0	0	0	0
New York	19.8	19.8	19.8	10.2
North Carolina	71.4	31.4	2.6	0
North Dakota	2.9	2.9	2.9	1.8
Ohio	7.7	7.7	7.7	7.3
Oklahoma	42.6	42.6	42.6	41.3
Oregon	10.8	3.2	0	0
Pennsylvania	26.4	26.4	26.4	11.1
Rhode Island	0.3	0.3	0.3	0
South Carolina	33.8	9.0	0	0
South Dakota	8.1	8.1	2.1	0
Tennessee	12.8	12.8	12.8	8.6
Texas	105.1	105.1	105.1	105.1
Utah	0	0	0	0
Vermont	4.4	4.4	4.4	2.9
Virginia	17.5	17.0	5.2	0
Washington	18.0	18.0	14.7	3.2
West Virginia	2.6	2.6	2.6	0.6
Wisconsin	31.9	31.9	31.9	28.5
Wyoming	1.6	1.6	1.6	1.6
Total[b]	916.1	813.7	694.6	536.3

[a] Includes only counties with more than 330 x 10^3 dry ton/yr of biomass.

[b] Columns may not sum to these figures due to rounding.

TABLE 5.9 Potential Biomass Yields in Counties within a Given Radius of Waterways[a] (10^6 dry ton/yr)

State	Total	250 mi	150 mi	50 mi
Alabama	48.8	48.8	48.8	46.6
Arizona	0	0	0	0
Arkansas	26.2	26.2	26.2	16.3
California	4.2	4.2	0.6	0
Colorado	0.5	0	0	0
Connecticut	3.5	3.5	3.5	3.5
Delaware	1.7	1.7	1.7	1.7
Florida	57.0	57.0	57.0	51.9
Georgia	57.4	57.4	57.4	29.2
Idaho	0	0	0	0
Illinois	3.2	3.2	3.2	3.2
Indiana	5.0	5.0	5.0	4.0
Iowa	10.8	10.8	10.8	4.0
Kansas	12.0	12.0	12.0	2.3
Kentucky	12.3	12.3	12.3	10.4
Louisiana	26.9	26.9	26.9	18.7
Maine	20.2	20.2	20.2	11.8
Maryland	2.9	2.9	2.9	2.5
Massachusetts	3.7	2.5	2.5	0.9
Michigan	32.2	32.2	32.2	11.1
Minnesota	58.3	54.6	28.0	3.1
Mississippi	23.6	23.6	23.6	11.8
Missouri	65.0	65.0	65.0	35.1
Montana	16.9	0.9	0	0
Nebraska	1.1	1.1	1.1	1.1
Nevada	0	0	0	0
New Hampshire	4.2	4.2	4.2	0
New Jersey	0.9	0.9	0.9	0.9
New Mexico	0	0	0	0
New York	19.8	19.8	19.8	16.4
North Carolina	71.4	71.4	70.7	39.6
North Dakota	2.9	0.4	0	0
Ohio	7.7	7.7	7.7	3.0
Oklahoma	42.6	42.6	33.8	13.9
Oregon	10.8	10.8	6.8	3.7
Pennsylvania	26.4	26.4	26.4	9.8
Rhode Island	0.3	0.3	0.3	0
South Carolina	33.8	33.8	33.8	19.6
South Dakota	8.1	8.1	1.8	0
Tennessee	12.8	12.8	12.8	12.4
Texas	105.1	89.8	66.5	23.6
Utah	0	0	0	0
Vermont	4.4	4.4	4.4	2.0
Virginia	17.5	17.0	17.0	7.6
Washington	18.0	18.0	18.0	10.5
West Virginia	2.6	2.6	2.6	1.8
Wisconsin	31.9	31.9	31.9	9.0
Wyoming	1.6	0	0	0
Total[b]	916.1	874.8	800.2	443.2

[a] Includes only counties with more than 330 x 10^3 dry ton/yr of biomass.

[b] Columns may not sum to these figures due to rounding.

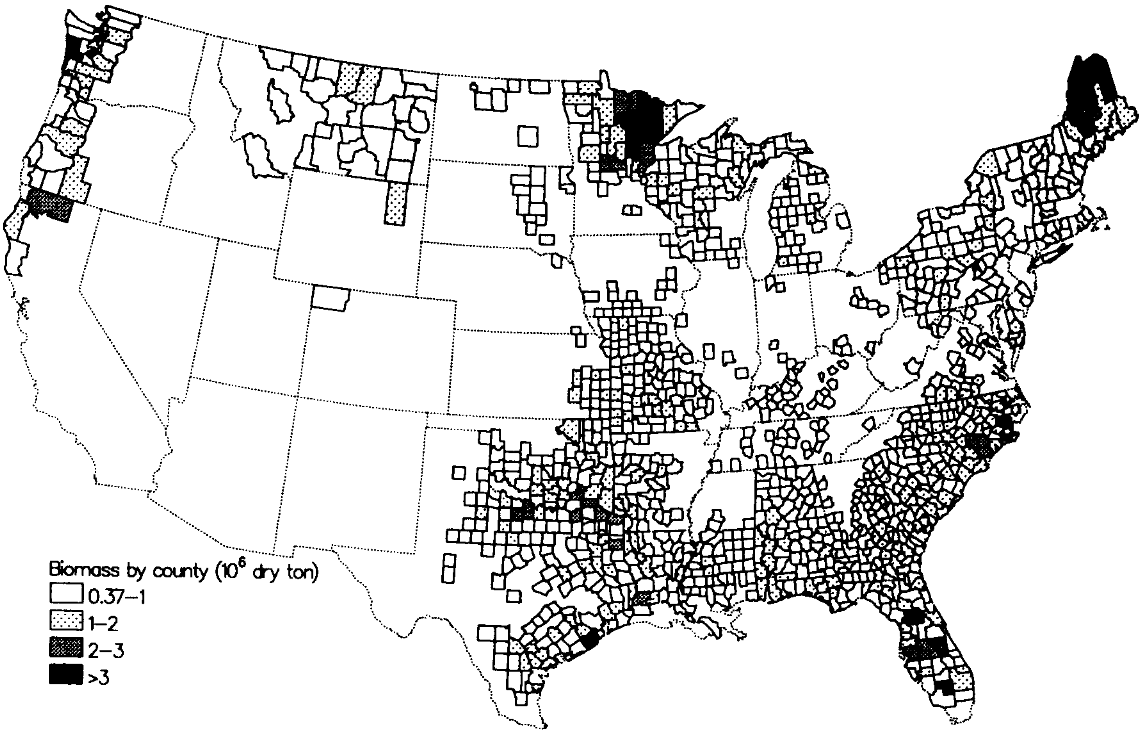


FIGURE 5.6 Potential Biomass Yields within 250 Miles of Transportation or Refineries

TABLE 5.10 Potential Biomass Yields in Counties within a Given Radius of Transportation or Refineries[a]

		Within 250 mi		Within 150 mi		Within 50 mi	
State	Total	10^6 dry ton/yr	%	10^6 dry ton/yr	%	10^6 dry ton/yr	%
Alabama	48.8	48.8	100	48.8	100	47.9	98
Arizona	0	0	--	0	--	0	--
Arkansas	26.2	26.2	100	26.2	100	24.4	93
California	4.2	4.2	100	0.6	16	0	0
Colorado	0.5	0.5	100	0.5	100	0.5	100
Connecticut	3.5	3.5	100	3.5	100	3.5	100
Delaware	1.7	1.7	100	1.7	100	1.7	100
Florida	57.0	57.0	100	57.0	100	52.5	92
Georgia	57.4	57.4	100	57.4	100	30.8	54
Idaho	0	0	--	0	--	0	--
Illinois	3.2	3.2	100	3.2	100	3.2	100
Indiana	5.0	5.0	100	5.0	100	5.0	100
Iowa	10.8	10.8	100	10.8	100	10.0	93
Kansas	12.0	12.0	100	12.0	100	12.0	100
Kentucky	12.3	12.3	100	12.3	100	12.3	00
Louisiana	26.9	26.9	100	26.9	100	26.9	100
Maine	20.2	20.2	100	20.2	100	13.4	66
Maryland	2.9	2.9	100	2.9	100	2.5	85
Massachusetts	3.7	2.5	67	2.5	67	0.9	25
Michigan	32.2	32.2	100	32.2	100	31.7	98
Minnesota	58.3	58.3	100	58.3	100	53.3	92
Mississippi	23.6	23.6	100	23.6	100	22.5	95
Missouri	65.0	65.0	100	65.0	100	63.0	97
Montana	16.9	16.5	100	16.5	98	11.1	65
Nebraska	1.1	1.1	100	1.1	100	1.1	100
Nevada	0	0	--	0	--	0	--
New Hampshire	4.2	4.2	100	4.2	100	2.4	57
New Jersey	0.9	0.9	100	0.9	100	0.9	100
New Mexico	0	0	--	0	--	0	--
New York	19.8	19.8	100	19.8	100	18.5	93
North Carolina	71.4	71.4	100	70.7	99	39.6	55
North Dakota	2.9	2.9	100	2.9	100	1.8	63
Ohio	7.7	7.7	100	7.7	100	7.7	100
Oklahoma	42.6	42.6	100	42.6	100	42.6	100
Oregon	10.8	10.8	100	6.8	64	3.7	35
Pennsylvania	26.4	26.4	100	26.4	100	15.3	58
Rhode Island	0.3	0.3	100	0.3	100	0	0
South Carolina	33.8	33.8	100	33.8	100	19.6	58
South Dakota	8.1	8.1	100	5.5	67	0	0
Tennessee	12.8	12.8	100	12.8	100	12.4	97
Texas	105.1	105.1	100	105.1	100	105.1	100
Utah	0	0	--	0	--	0	--
Vermont	4.4	4.4	100	4.4	100	4.4	100
Virginia	17.5	17.0	98	17.0	98	7.6	44
Washington	18.0	18.0	100	18.0	100	17.6	98
West Virginia	2.6	2.6	100	2.6	100	1.8	71
Wisconsin	31.9	31.9	100	31.9	100	31.1	97
Wyoming	1.6	1.6	100	1.6	100	1.6	100
Total[b]	916.1	914.4	100	903.3	99	764.0	83

[a] Includes only counties with more than 330 × 10^3 dry ton/yr of biomass.

[b] Columns may not sum to these figures due to rounding.

6 ENVIRONMENTAL AND REGULATORY CONSIDERATIONS

6.1 APPLICABLE LEGISLATION

The major federal laws that may apply to various aspects of biomass production, conversion, upgrading, transport, and refining are summarized here. These and additional laws are listed in Table 6.1. State and local regulations and ordinances may also apply.

The Clean Air Act of 1970

The Clean Air Act, as amended in 1977, provides the basic legal authority for the nation's air pollution control programs and is designed to enhance the quality of air resources. It establishes air emissions limitations and air quality standards, and it requires each state to develop an implementation plan for attaining and maintaining air quality standards (42 U.S.C. 7401-7462; DOE 1987; Arbuckle et al. 1983). Partial authority for regulating sources of air emissions has been delegated to the states by the EPA. The major pollutants regulated by the Clean Air Act include sulfur oxides, nitrogen oxides, and particulates. New sources must meet more stringent standards than existing sources, especially in areas where air quality does not meet the minimum standards.

Resource Conservation and Recovery Act of 1976 (RCRA)

The Resource Conservation and Recovery Act authorizes the U.S. Environmental Protection Agency (EPA) to establish regulations and programs to ensure safe waste treatment and disposal. It has two objectives: to protect human health and the environment and to conserve valuable material and energy resources by providing technical and financial assistance for resource recovery (42 U.S.C. 6901-6987; EPA 1985a; Arbuckle et al. 1983; BNA 1984; Cheremisinoff et al. 1979; Oakes and Kelly 1980). Since its enactment, the RCRA has been amended by several public laws, including the Used Oil Recycling Act of 1980 and the Hazardous and Solid Waste Amendment Act of 1984. RCRA now regulates underground tank storage of all petroleum products (including gasoline and crude oil) and any substance defined as hazardous under CERCLA (EPA 1985a).

Toxic Substances Control Act of 1976 (TOSCA or TSCA)

The Toxic Substances Control Act provides authority to regulate the manufacture, distribution, and use of chemical substances. The EPA has the authority to require testing of chemical substances entering the environment and to regulate them as necessary (EPA 1985b; DOE 1986; Oakes and Kelly 1980). Major materials which this act covers include PCBs, asbestos, and fully halogenated chlorofluoroalkanes.

TABLE 6.1 Legislation Relevant to Biomass Production, Conversion, Upgrading, Transportation, and Refining

---

- General
  - National Environmental Policy Act of 1969
- Land use
  - Materials Act of 1947
  - Coastal Barrier Resources Act
  - Coastal Zone Management Act of 1972
  - Marine Protection, Research and Sanctuaries Act of 1972
  - Wild and Scenic Rivers Act
  - Wilderness Act
  - Objects Affecting Navigable Airspace
  - Taylor Grazing Act
  - National Trails System Act
  - National Forest Organic Legislation
  - Organic Act of the National Park Service
  - Farmland Protection Policy Act
  - Floodplain/Wetlands Executive Orders
  - Department of Transportation Acts
- Waste disposal
  - Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (see text)
  - Hazardous Materials Transportation Act
  - Solid Waste Disposal Act
  - Resource Conservation and Recovery Act of 1976 (see text)
  - Hazardous and Solid Waste Amendments of 1984
  - Toxic Substances Control Act of 1976 (see text)
- Ecology and wildlife protection
  - Migratory Bird Treaty Act
  - Fish and Wildlife Coordination Act
  - National Wildlife Refuge System Administration Act of 1966
  - Endangered Species Act of 1973
  - Wild Free-Roaming Horses and Burros Act
  - Sikes Act
- Air quality and noise
  - Noise Control Act of 1972
  - Clean Air Act of 1970 (see text)
- Cultural resources
  - Archaeological Resources Protection Act of 1979
  - National Historic Preservation Act of 1966
  - American Antiquities Act
  - American Indian Religious Freedom Act
- Hydrology and water quality
  - Federal Water Pollution Control Act
  - Clean Water Act of 1977 (see text)
  - Rivers and Harbors Appropriations Act of 1899
  - Safe Drinking Water Act

The Clean Water Act of 1977

The Clean Water Act, as amended, is the basic authority for water pollution control programs. It regulates the discharge of effluents into navigable waters, which includes essentially all lakes, rivers, and streams (DOE 1986; Arbuckle et al. 1983). The injection of wastes into underground aquifers is regulated under the Clean Water Act and the Safe Drinking Water Act. A permit from the EPA is required for all discharges, including thermal effluents. Discharges of dredged or fill materials require a permit from the U.S. Army Corps of Engineers.

Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA)

This act establishes a program to deal with release of hazardous substances in spills and from inactive and abandoned disposal sites. The main purpose of CERCLA, also known as the Superfund law, is to provide a means to reclaim inactive disposal areas polluted by hazardous substances and to assist with cleanup of accidental spills (42 U.S.C. 9601-9657; DOE 1986). The Act requires reporting of "reportable quantities" of spilled hazardous substances to the National Response Center. The original Superfund Act expired, but the reauthorization (the Superfund Amendments and Reauthorization Act) was passed by Congress early in 1987.

6.2 REGULATION OF EMISSIONS FROM PETROLEUM REFINERIES

Refineries have invested in air and water pollution controls to comply with the Clean Air, Clean Water, Safe Drinking Water, and Resource Conservation and Recovery Acts (BNA 1985). The Clean Air Act amendments of 1977 also indirectly affect refineries by requiring that petroleum products have low sulfur contents (0.7% for residual fuel oil, 0.5% for distillates, and 0.04% for gasoline) and that lead be phased out of gasoline (Phung 1981). The production of high-octane unleaded gasoline alters emissions because it requires either running reforming equipment under severe conditions and at high capacity factors or building new equipment. The sulfur and lead standards of states such as California are even stricter than the federal standards.

The Clean Water and Safe Drinking Water Acts affect refineries mainly in terms of the control of condensates, storm water collection and discharge, ballast water discharge, wastewater discharge, and oil spills. The measurement and control of trace elements such as cadmium and contaminants such as benzene and cyanide are also involved (Phung 1981). The Resource Conservation and Recovery Act lists a number of refinery wastes as hazardous, requiring a specified series of tests, manifests, and proper disposal.

6.2.1 Gaseous Effluents

The principal gaseous effluents from a petroleum refinery are combustion gases, tail gases from sulfur recovery units, fugitive hydrocarbon emissions, and combustion gases from flares (Danielson 1967; Royal Dutch/Shell 1983). Except for the fugitive hydrocarbon emissions, which emanate from valves, pump seals, flanges, tanks, or drainage systems, the gaseous effluents are generally vented to the atmosphere through stacks high enough to ensure adequate dispersion. Table 6.2 gives the major airborne emissions from various refinery processes.

Air emissions requiring control in petroleum refining are typically carbon monoxide, nonmethane hydrocarbons, particulates, and sulfur in various forms. Carbon monoxide and particulates are usually point-source emissions from fluid catalytic cracking regenerator exhausts. Sulfur is emitted from point sources (heaters and boilers, regenerator exhausts, and sulfur recovery units) and as fugitive emissions from process equipment that handles sour gases. Nonmethane hydrocarbons are emitted as process fugitive emissions and from storage tank air exchange.

The major contribution to atmospheric emissions from a refinery is from the combustion of fuel. Sulfur oxides (SO_x), nitrogen oxides (NO_x), and particulates are the main pollutants in combustion gases. The quantity of SO_x, typically about 2 ton/1,000 ton of crude oil throughput (Royal Dutch/Shell 1983), depends not only on the sulfur content of the refinery fuel, but also on the capacity and the efficiency of the sulfur recovery unit. Refinery fuel may consist of gas (which may be desulfurized) or liquid fuel (mostly residuum). If the refinery has a catalytic cracker, coke burned off the catalyst may contribute a small amount to combustion gases. Flue gas scrubbing can reduce the SO_x emission but reportedly is seldom economical (Royal Dutch/Shell 1983). The sulfur content of a refinery's residuum is determined by its crude oil input and its processing scheme. Desulfurizing a refinery's residual fuel is reportedly also uneconomical, and replacement of high-sulfur residuum by desulfurized distillate would result in a heavy economic penalty and a higher sulfur content in the refinery's product slate (Royal Dutch/Shell 1983).

TABLE 6.2 Major Airborne Emissions From a Gulf Coast Refinery, 1985 (10^3 lb/d)

Source	Particulate	SO_x	Hydrocarbons	NO_x	Aldehydes	Ammonia
Gas-fired equipment	0.9	--	1.3	10.0	0.1	Negl.[a]
Oil-fired equipment	9.0	--	1.5	31.0	0.3	Negl.
Combustion total	9.9	27.6	2.8	41.0	0.4	Negl.
Fluid catalytic cracking	3.6	8.4	17.6	5.7	1.5	4.3
Vacuum distillation	Negl.	Negl.	9.9	Negl.	Negl.	Negl.
Claus plant	--	0.7	--	--	--	--
Total emissions[b]	13.4	36.7	30.3	46.7	1.9	4.3

[a] Negl. = negligible.

[b] Columns may not sum to these figures due to rounding.

Source: EPA 1976.

A typical NO_x emission from a refinery is 8 kg/ton of fuel burned, expressed as NO_2 (Royal Dutch/Shell 1983). The nitrogen originates in part from chemically bound nitrogen in the fuel and in part from atmospheric nitrogen; the extent to which atmospheric nitrogen is converted to NO_x during combustion depends on burner and furnace/boiler design.

Airborne particulate emissions originate from the burning of liquid fuel and from the operation of the catalytic cracker. Irregular emissions of soot or black smoke can occur from stacks and flares during abnormal operating conditions. The continuous particulate emission typically amounts to a few tons per day (Royal Dutch/Shell 1983).

Hydrocarbon emissions are generally from many small sources. The literature suggests that hydrocarbon emissions range from 0.04-0.4 wt% of the crude oil input (Royal Dutch/Shell 1983). Such emissions frequently contain compounds such as hydrogen sulfide and thiols that may have objectionable odors or toxic properties. Emissions from the storage of volatile products and crudes can be controlled by using floating-roof storage tanks. Hydrocarbon vapor relief streams from refinery equipment are usually collected in closed systems, and the vapor either is recompressed and used as refinery fuel gas or is burned in flares.

6.2.2 Liquid Effluents

Most major refining operations produce water streams containing pollutants from direct contact with process streams. The most contaminated streams are typically the condensates from processing units and the water drained from the storage tanks; these contain volatile and malodorous compounds, hydrocarbons, dissolved organics, and suspended solids (Royal Dutch/Shell 1983). Other streams are contaminated with oil and suspended solids (for example, rainwater runoff and ballast water), and still others are normally oil-free. In modern refineries, the various streams of wastewater are collected in separate sewer systems and the most contaminated streams are given the most thorough treatment. For example, water containing volatile, malodorous impurities (such as phenols, hydrogen sulfide, thiols, ammonia, or light hydrocarbons) is collected in a closed sewer system and countercurrently stripped with steam before joining other contaminated streams. Frequently the stripped condensates are reused as wash water in crude oil desalters (Royal Dutch/Shell 1983).

Raw refinery wastewater contains significant amounts of oil (free and emulsified), water-soluble hydrocarbons such as phenolics, a variety of sulfur compounds (the most objectionable of which are sulfides), and nitrogen compounds (chiefly ammonia, and to a lesser extent cyanides). The wastewater may also contain heavy metals (such as mercury, cadmium, chromium, or lead in trace amounts) and carbonaceous and inorganic particulates. Many of the contaminants are oxidizable, leading to chemical oxygen demand (COD), and some are biodegradable, leading to biochemical oxygen demand (BOD_5).

Since the free oil in the wastewater is readily removable, the first unit in any refinery wastewater treatment facility is an oil/water separator (Royal Dutch/Shell 1983; EPA 1976). Raw wastewater characteristics are almost always measured after the separator (EPA 1976). Table 6.3 provides information on the amount and composition of typical raw and treated refinery wastewater.

Effluent guidelines for the petroleum refining industry limit total suspended solids, COD, BOD_5, oil and grease, phenolics, ammonia, sulfide, total chromium, hexavalent chromium, and pH (BNA 1985). Table 6.4 lists the EPA guidelines for these pollutants, based on the degree of effluent reduction attainable with the best practicable control technology. These are adjustable by size factor and process factors; additional limitations apply to ballast water, contaminated runoff, and other wastewater streams.

TABLE 6.3 Characteristics of Raw and Treated Process Wastewater from a 200,000 bbl/d Gulf or East Coast Refinery[a] (lb/d)

Wastewater Component	Raw Wastewater[b]	Treated Effluent[c]
BOD_5	5,000	260
Total suspended solids	1,920	260
COD	14,000	1,420
Oil and grease	1,920	50
Phenolic compounds	200	1.0
Ammonia[d]	700	316
Sulfide	700	4.4
Chromium (total)	Varies	13
Chromium (hexavalent)	Varies	0.22

[a] Flow rate, 6,600,000 gal/d; includes stormwater runoff from process areas but not from offsite facilities such as tank farms.

[b] Downstream of API oil separator.

[c] Based on the Best Available Technology Economically Achievable (BATEA) treatment level for 1983, as defined in "Effluent Guidelines and Standards - Petroleum Refining," 40 CFR 417 FR, May 9, 1974.

[d] As nitrogen.

Source: EPA 1976.

TABLE 6.4 EPA Effluent Limitation Guidelines for Refineries Based on the Best Practicable Control Technology ($lb/10^3$ bbl feed)

Variable	Maximum for Any 1 Day	Average of Daily Values for 30 Consecutive Days Shall Not Exceed
BOD_5	8.0	4.25
Total suspended solids	5.6	3.6
COD[a]	41.2	21.3
Oil and grease	2.5	1.3
Phenolic compounds	0.060	0.027
Ammonia[b]	0.99	0.45
Sulfide	0.063	0.024
Chromium (total)	0.122	0.071
Chromium (hexavalent)	0.01	0.0044
pH	Note c	Note c

[a] If chloride exceeds 1,000 ppm, TOC may be used in place of COD.

[b] As nitrogen.

[c] Within the range of 6-9.

Source: BNA 1985.

6.2.3 Solid Wastes

A petroleum refinery also generates solid waste streams, many of which contain materials on the EPA toxic substances list (EPA 1976). Sludges (bottom sludges in the oil/water separators, waste biological sludges from the activated sludge units, and scum and sludge from the flocculation unit) have high water contents and low calorific values. After collection, homogenization, and primary dewatering in a sludge thickener, they can be mechanically dewatered with vacuum filters or centrifuges and then incinerated or disposed of on land. Heavy metals are usually present in the sludges in low concentrations, and these can affect the level of control required.

Continuously produced solid wastes include spent catalysts and catalyst fines from the fluid catalytic cracking units, coker wastes (such as coke fines from fluidized cokers and spilled coke from unloading facilities), and spent or spilled grease and wax wastes from lube oil processing plants. Intermittently generated wastes result from cleaning within the process areas and off-site facilities of the refinery (EPA 1976) and from accidental oil spills.

6.3 ENVIRONMENTAL CONCERNS FOR BIOFUELS PRODUCTION

Little research directly addresses the potential environmental effects of biomass technologies, and little literature deals with the environmental limitations and consequences of using of biomass for energy (Smith 1987). Biomass recycles CO_2, and biomass-derived fuels therefore do not contribute to CO_2 enrichment of the atmosphere or the consequent greenhouse effect. However, large-scale production of biomass might lead to some climatic change, because such change has been attributed to large-scale changes in land use (Smith 1987). Biofuel use does not contribute to the acid rain problem.

Many of the environmental risks from biomass production are similar to those from conventional agriculture and forestry and depend on the crop and the management practices. The problems associated with annual herbaceous energy crops (for example, sweet sorghum) are essentially the same as those for conventional food crops (SERI 1986). In particular, soil erosion can be a significant problem. For perennial crops, the environmental risks are generally lower, because both soil erosion and pesticide use are typically low relative to annual crops. In fact, the soil-conserving features of perennial herbaceous energy crops make them particularly appropriate for land with erosion problems. For short-rotation woody biomass production, erosion will be most severe during the initial two or three years after plantation establishment (SERI 1986). However, infrequent harvests and regeneration without annual plantings mean less traffic and reduced soil disturbance -- both potentially environmentally degrading activities (Smith 1987). The potential risks of short-rotation forestry include dust emissions, soil disturbance, nutrient depletion, impacts of the use of fertilizers and pesticides, and altered habitats (SERI 1986; Holdren, Morris, and Mintzer 1980). The magnitude of the impact depends upon site characteristics and management strategy.

The new facilities required for converting biomass to biocrude will be similar to facilities for producing other synthetic fuels (notably coal conversion), so many of the same environmental considerations will apply (Probstein and Hicks 1982). Generic emission sources and major air pollutant emissions are shown in Fig. 6.1. Actual emissions will vary with the conversion process. Since the chemistries of biocrude production are just now being explored, it is difficult to predict the emissions from conversion facilities. However, biomass is generally low in sulfur, arsenic, selenium, and heavy metals, which create serious problems in other industries, so compliance with emission requirements for these elements is unlikely to be a severe problem. Questions will arise concerning the application to biomass-derived oils of regulations such as the "new material" requirements under the Toxic Substances Control Act.

Pyrolysis produces a liquid fraction that is a complex mix of hydrocarbons, many of which are known to be carcinogens or otherwise serious pollutants (Smith 1987). However, flash pyrolysis oils have been tested for mutagenicity by the Ames test and for tumorgenicity by painting the skin of mice, and they appear to be inactive; no acute toxicity studies have been made (Elliott and Baker 1987). Emissions problems analogous to some of those connected with coal conversion may still occur.

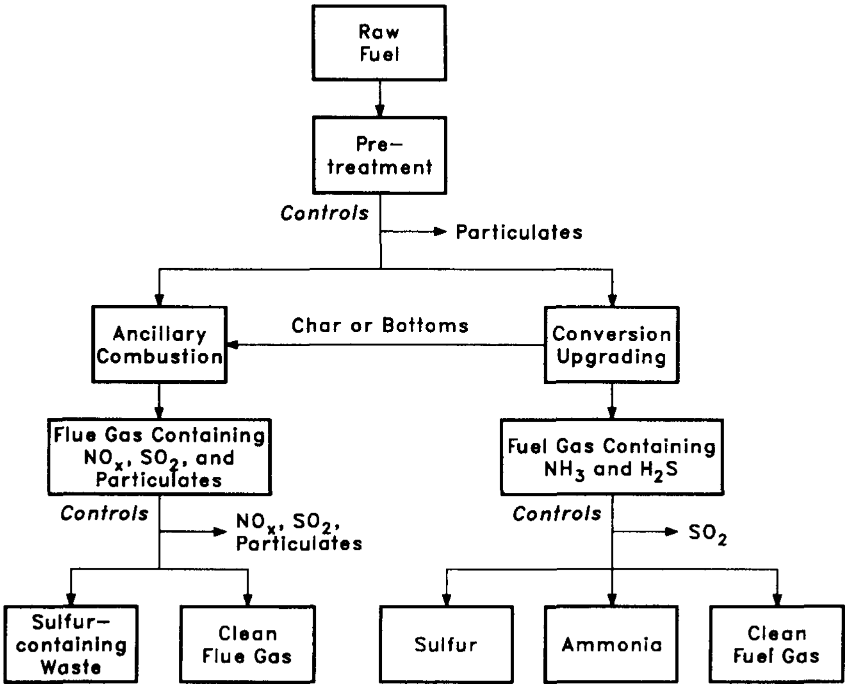


FIGURE 6.1 Emissions and Emission Sources from Synthetic Fuel Facilities

Environmental considerations for refineries that process raw or upgraded biocrudes will be similar to those of current refineries. Depending upon the extent of upgrading required, the properties of biocrudes will affect the refinery operation and effluents, and consequently, the detailed nature of the environmental problems. For example, biocrudes will require generally severe hydrotreating to produce acceptable gasoline, and these conditions may increase effluent production. The detailed composition of the effluents will depend upon the chemistry of biocrude feedstocks. In general, air emissions are likely to be easier to deal with and wastewater treatment requirements could be more demanding, possibly much more so, than those in conventional petroleum refineries.

Airborne sulfur emissions would be reduced in a refinery upgrading biocrude if the biocrude (which typically contains less than 0.1 wt% sulfur) displaces crude oil (1-3 wt% sulfur). The reduction in emissions will not be linear if process heaters and boilers continue to be fired with fossil fuel. The substitution of biocrude for conventional petroleum feeds is expected to have little effect on emissions of carbon monoxide, particulates, and nonmethane hydrocarbons.

The processing of biocrude in an existing refinery could have a major effect on wastewater treatment facilities. The hydrogenative upgrading of biocrudes would produce a considerable volume of wastewater containing high levels of dissolved organic carbon (as much as 10% carbon by weight) and phenols (Table 6.5). Such a volume of wastewater (10-100 times that from petroleum crude processing) might be difficult to treat in existing refinery wastewater facilities. Integration of the stabilization and hydrodeoxygenation steps into a single non-isothermal reactor could reduce the organic carbon contamination of the wastewater.

The production of biomass and its conversion to biocrude should pose environmental problems no more difficult than those of conventional agriculture and the chemical processing industries. However, environmental effects and the associated regulatory requirements should be major considerations in planning the production, conversion, upgrading, and refining activities.

TABLE 6.5 Process Water Produced in Biocrude Upgrading[a]

	High-Pressure Oil		Pyrolysis Oil		
Parameters	Hydro-deoxygenation	Hydro-cracking	Stabilization	Hydro-deoxygenation	Hydro-cracking[b]
Yield[c]					
wt%	16.3	0.8	30.9	18.2	0.5
vol%	17.9	0.9	37.7	22.2	0.6
Elemental analysis (wt%)					
C	1.8	--	11.1	1.4	--
H	10.9	11.1	9.9	10.29	11.1
O	87.3	88.9	79.0	87.7	88.9
Water-soluble organic carbon[c]					
wt%	0.29	--	3.43	0.25	--
lb/bbl	1.07	--	14.1	1.02	--
lb/sd	2.14×10^4		3.02×10^5		
Volume[c]					
gal/bbl	7.5	0.4	15.8	9.3	0.3
gal/sd	1.58×10^5		5.08×10^5		

[a] Based on 20,000 bbl/sd.

[b] Estimated.

[c] On biocrude charge.

7 CONCLUSIONS

7.1 SUMMARY

We estimate that 10^9 dry ton/yr of biomass could be grown on nonfederal lands and harvested, enough to satisfy about 25% of the U.S. energy requirement without displacing conventional agricultural crops or causing substantial soil loss. This amount of biomass, representing 19.5 quad of energy, could be produced annually by growing herbaceous energy crops or short-rotation trees on land identified as having high or medium potential for conversion to cropland, by planting short-rotation trees in forest areas needing replanting, and by harvesting excess forest growth. Additional biomass could be produced on federal lands and in arid regions, but no estimates of these quantities are available. Not all of this biomass could be economically produced. It was beyond the scope of this study to estimate costs, but constraints on production and transportation methods eliminated those known to be too expensive. Further work would be required to determine how sensitive the potential quantity of biomass is to our assumptions.

If all of the biomass were converted to oil, the total quantity would be about 6×10^6 bbl/d, which is equivalent to about 40% of the U.S. refinery crude capacity and 45% of the actual quantity of crude processed in recent years. The total energy content of the biocrude would be about 35% of that of petroleum crude because of biocrude's lower energy density (high oxygen content). In theory, then, biocrude could supply as much as one-third of the U.S. liquid fuel requirements. However, the realistic potential is lower, and the probability of biocrude displacing petroleum crude in existing refineries is severely limited by process requirements and hydrogen availability.

Much of the biomass would be concentrated in a few growing areas in the eastern half of the U.S.A. The southern Atlantic and South Central states have the highest potential. To be considered usable, biomass must be dense enough to harvest, available in sufficient quantity to supply a local conversion plant, and close to a refinery or to affordable transportation. A surprisingly high percentage of the potential biomass met these constraints (83% for a 50-mi transport distance). This high percentage is largely the result of having an easily transportable oil product after the initial conversion of solid biomass, which is more difficult to transport over large distances.

However, most refineries are not well suited to producing a gasoline-quality product from biocrude, even if it has been partially upgraded. Few refineries have sufficient hydroprocessing capacity to treat even partially upgraded biocrude, and several of those having such capacity are in California, where there would be insufficient biomass to supply them. For the refineries ranked as good prospects for biocrude upgrading, the total available capacity based on hydrogen availability would be 648,000 bbl/d; based on potential biomass production within 50 miles, the capacity would be 166,500 bbl/d.

As with other synthetic fuels, the hydrogen needed for biocrude processing represents a significant energy cost in the final product, and the generating units represent a substantial fraction of plant capital and operating costs. The hydrogen required for all of the biocrude that could be produced would be over 12×10^9 scf/d, or five times the current dedicated hydrogen production at refineries. The hydrogen might be supplied by steam reforming of natural gas, which would allow the use of all the carbon in the biomass feedstock. Alternatively, some of the biomass could be partially oxidized to hydrogen, or upgrading schemes could be used that increase the H/C ratio by eliminating carbon rather than by adding hydrogen. In either case, the total liquid yield would be lower than if hydrogen were added from another source, but the total energy input would also be lower. The choice of hydrogen source will depend on the relative prices and availabilities of biomass, natural gas, and other potential sources. The energy efficiencies of the two options are believed to be similar. In an integrated conversion and upgrading process, by-product gases could be reformed to produce hydrogen.

Wan, Fraser, and Kwarteng (1987) recently reported on the economics of greenfield conversion and upgrading facilities for various yields, processes, and economic assumptions. Their results indicate that greatly increased gasoline yields and very inexpensive feedstock are required to produce a competitive product. It was not within the scope of this study to evaluate greenfield facilities or mixes of greenfield and retrofit construction.

In conclusion, we find that sufficient biomass could be grown to supply a significant fraction of U.S. liquid fuel needs and that most of the biocrude produced from this biomass could be transported to petroleum refineries. However, the capacity of equipment required to produce a gasoline-grade product from biocrude is generally inadequate at existing petroleum refineries, and few compelling advantages are seen to constructing new capacity at these refineries. Rather, new biomass-processing facilities could be located in or near areas of high potential biomass production. A more detailed analysis of the economic tradeoffs between using existing infrastructure and siting new plants closer to biomass-producing areas would be needed to determine if there is an advantage either way.

7.2 AREAS FOR FURTHER RESEARCH

One major area of interest is the potential for growing biomass on federal land, especially in the Pacific Northwest. Federal land represents a considerable resource, but we assumed no energy biomass from this land because data on the soil quality and terrain were unavailable in the NRI. Another resource not included in the potential biomass is arid land crops, because insufficient data were available in the NRI to identify areas suitable for unirrigated crop growth, and the saline water maps needed to identify areas for microalgae growth were not available.

This study assumed that energy crop yields on the best land would equal the DOE production goals. Actual yields could be greater (with very successful developments in crops and management practices) or less (because of slower progress, diseases, or pest problems). Therefore, it would be prudent to examine the sensitivity of our results to assumed yields. In addition, sensitivity to other factors, including slope cutoffs and land classes suitable for different crops, should be studied.

In the transportation area, further work is required to determine if biocrude produced in the Pacific Northwest could be transported by coastal tanker to California refineries, which might otherwise be unable to obtain biocrude. In addition, it must be demonstrated that upgraded biocrude has low enough viscosity and corrosivity to allow transport in common carrier pipelines.

Major technological advances are needed in both the primary conversion and the upgrading processes before these technologies are ready for commercialization or even large-scale, proof-of-concept demonstrations. These advances generally involve improvements in catalyst and process performance, including conversion rates, efficiency of hydrogen utilization, and stability and longevity of catalysts. Much of the upgrading work and some of the promising recent conversion work has been on a small scale with nonintegrated processes over short run times. Improved performance must be achieved and demonstrated at larger scales to allow the confident design of commercial-scale facilities.

When a better understanding of the process requirements of upgrading has been developed, additional analysis of the merits of greenfield upgrading facilities versus the modification of existing refinery units or the addition of new units to existing refineries would be warranted.

APPENDIX A:

ABBREVIATIONS

a	acre
ASTM	American Society for Testing and Materials
bbl	barrel
BOD_5	biochemical oxygen demand (5-day)
Btu	British thermal unit
CARD	Center for Agricultural and Rural Development
CO_2	carbon dioxide
COD	chemical oxygen demand
cP	centipoise
d	day
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ft	foot
gal	gallon
h	hour
H_2	hydrogen
H_2O	water
in.	inch
kg	kilogram
L	liter
lb	pound
LPG	liquified petroleum gas
mi	mile
mL	milliliter
NH_3	ammonia
NO_x	nitrogen oxides
NRI	National Resources Inventory
ORNL	Oak Ridge National Laboratory
PA	producing area
PERC	Pittsburgh Energy Research Center
quad	10^{15} Btu
scf	standard cubic feet
SCS	Soil Conservation Service
sd	stream day
SERI	Solar Energy Research Institute
SO_x	sulfur oxides
vol%	percent by volume
wt%	percent by weight
yr	year

APPENDIX B:

LAND-CAPABILITY CLASSIFICATION OF THE SOIL CONSERVATION SERVICE

Class	Description	Primary Uses	Secondary Uses
	Suitable for Cultivation		
I	Excellent land, flat, well-drained; suited to agriculture with good farming practices and no special precautions.	Agriculture	Recreation Wildlife Pasture
II	Good land with minor limitations such as slight slope, sandy soils, or poor drainage; suited to agriculture with precautions such as contour farming, strip-cropping, and drainage.	Agriculture Pasture	Recreation Wildlife
III	Moderately good land with important limitations caused by soil, slope, or drainage; requires long rotation with soil-building crops, contouring or terracing, strip-cropping, drainage, etc.	Agriculture Pasture Watershed	Recreation Wildlife Urban/industrial
IV	Fair land with severe limitations caused by soil, slope, or drainage; requires long rotation with soil, slope, or drainage; suited only to occasional or limited cultivation.	Pasture Tree crops Agriculture Urban/industrial	Recreation Wildlife
	Unsuitable for Cultivation		
V	Land suited to grazing or forestry with normal good management.	Forestry Range Watershed	Recreation Wildlife Urban/industrial
VI	Land suited to grazing or forestry with minor limitations such as erosion, shallow soils, etc.; requires careful management.	Forestry Range Watershed Urban/industrial	Recreation Wildlife
VII	Land suited to grazing or forestry with major limitations caused by slope, low rainfall, soil, etc; use must be limited and extreme care taken.	Forestry Range Watershed Urban/industrial	Recreation Wildlife
VIII	Land unsuited to grazing or forestry because of soil limitations, steep slopes, or extreme dryness or wetness.	Recreation Wildlife Watershed Urban/industrial	

Source: Shen et al. 1982.

APPENDIX C:

PLANT AND SEED OILS

The oils from plants, seeds, or algae are largely triglycerides. These typically contain three long-chain primary fatty acids, each bound to one of the carbons of a glycerin molecule via an ester linkage. The viscosity and other properties of these oils vary with the degree of saturation of the fatty acid, the more paraffinic (saturated) oils having higher viscosities and higher melting points. The elemental composition of a typical seed-derived oil is similar to the TR-12 high-pressure oil from the Albany pilot plant.

The recovery of these oils has not received the same intensity of development as thermochemical conversion. Mechanical expression and solvent extraction, both widely practiced for food oil recovery from oil seeds, are the most probable methods.

Triglyceride oils such as those from oilseeds and algae can be upgraded to diesel fuels or to gasoline plus diesel fuels by transesterification (Kaufman 1982) or by catalytic cracking or hydrocracking (Weisz and Marshall 1979; Prasad and Bakhshi 1985; Prasad et al. 1986a, 1986b). Work in this area has been largely at the proof-of-principle level. Transesterification with methanol or ethanol yields monoesters in the C_{15}-C_{20} range, depending on the source oil. These monoesters have viscosity and volatility characteristics similar to conventional diesel fuels (Kaufman 1982). Carbon build-up and crankcase oil contamination in diesel engines vary with iodine number (a measure of the unsaturation of the oil) and with the nature and service characteristics of the diesel engine. Catalytic cracking of these oils over shape-selective zeolites gives substantial yields of aromatic-rich gasoline-range liquids; coke yields are 3-5 wt% of feed (Weisz and Marshall 1979).

Hillen et al. (1982) hydrocracked the algal oil from *Botryococcus braunii*, producing good yields of gasoline and middle distillates. Their results are illustrative rather than definitive because of the small scale and short duration of their experiments, which did not address issues like potential fouling of the heat exchange surface or the catalyst bed by mineral salts.

Biocrudes from algae or oilseed plants might be suitable for upgrading by catalytic cracking. Existing studies have been at a small scale and little information is available on coke formation, catalyst stability, or heat balances. U.S refineries have a large amount of catalytic cracking capacity (5.3×10^6 bbl/sd or, about 33% of crude charge capacity), and it is widely distributed. The 39 refineries with catalytic cracking capacities of 50,000 bbl/sd or more have a total charge volume of 3.3×10^6 bbl/sd; those units could process 33,000 bbl/sd of plant-derived oils (150% of the output from one upgrading plant) by blending only 1% biocrude to petroleum. These oils may be most readily be processed in the existing petroleum facilities. If the potential volumes of lipid-like oils and their cost of production become attractive, extensive work on cracking and upgrading should become a priority R&D objective.

APPENDIX D:

OIL AND GAS JOURNAL REFINERY DATA BASE

The *Oil and Gas Journal* (O&GJ) has available in computer-readable form the results of their annual U.S. Refinery Survey. O&GJ solicited information on all operating refineries in the U.S.A. as of January 1, 1987, and published that data in the March 30, 1987, edition. Argonne obtained the Lotus 1-2-3™ version of this data base. For this study the data base was converted to Reflex™ files using a utility supplied with the Reflex software, which simplified the manipulation of the data base.

Two files that were not included in the March 30, 1987, edition were included on the diskette. The first contained information on planned refinery construction in the U.S.A., taken from an O&GJ construction report of October 6, 1986. The second contained a list of inactive refineries that last operated between the years 1983 and 1986. Capacities and other data on inactive refineries were taken from the survey from the last year of operation.

One significant error was noted in the active refinery file. Entry AA287 (record No. 279) contained 3,500.0 and entry AB287 was blank. Column AA contains refinery hydrogen generation capacity column and column AB contains coking capacity. Since 3,500.0 x 10^6 scf/sd substantially exceeds the total U.S. refinery hydrogen generation capacity (2,374 x 10^6 scf/sd), there clearly was an error. Inspection of the printed refinery survey showed that the entries between AA287 and AB287 had been transposed. This was corrected in the working copy of the diskette. This error would affect sums such as the state totals for Texas if one were to manipulate the data base without being aware of the entry error.

The refinery data base did not always have entries for refinery capacity in both barrels per stream day and barrels per calendar day. Where such omissions existed, the missing quantity was estimated assuming a 95% service factor, as in the published O&GJ survey. These adjustments are not expected to have any material impact on the conclusions reached in this study.

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