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MISSION ANALYSIS FOR THE FEDERAL FUELS FROM BIOMASS PROGRAM

Volume IV: Thermochemical Conversion of Biomass to Fuels and Chemicals

Final Report

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Fuels from Biomass Systems Branch

Contract EY-76-C-03-0115 PA-131

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PREFACE

Volume IV contains the detailed analysis of the thermochemical missions evaluated for this work for the Department of Energy, Solar Energy Division, Fuels from Biomass Systems Branch under Contract EY-76-C-03-0115 PA-131.

The other volumes in the project are:

- I General Summary and Conclusions
- II Mission Selection, Market Penetration Modeling, and Economic Analysis
- III Feedstock Availability
- V Biochemical Conversion of Biomass to Fuels and Chemicals
- VI Mission Addendum
- VII Program Recommendations

Dr. S. M. Kohan prepared this report, with assistance from P. M Barkhordar for the direct combustion missions. The assistance and guidance of Nello Del Gobbo, Project Technical Monitor, is gratefully acknowledged. Numerous other organizations and SRI staff members provided helpful information during this work.

The project was administered at SRI International by Dr. F. A Schooley, Project Leader, and Mr. R. L. Dickenson, Project Supervisor.

I INTRODUCTION

General

The thermochemical conversion of biomass feedstocks generally denotes technologies that use elevated temperatures to convert the fixed carbon content of biomass materials to produce other, more useful energy forms.[1] Examples are combustion to produce heat, steam, electricity, or combinations of these; pyrolysis to produce gas (low- or intermediate-Btu*), pyrolytic liquids and chemicals, and char; gasification to produce low or intermediate Btu gas (and, from IBG, additional products such as SNG, ammonia, methanol, or Fischer-Tropsch liquids); and liquefaction to produce heavy fuel oil or, with upgrading, lighter-boiling liquid products such as distillates, light fuel oils, or gasoline.

Widespread commercial applications of the renewable biomass resource to produce any or all of the above mentioned products offer domestic security of supply, potentially favorable environmental impacts when contrasted with fossil or nonfossil (e.g., nuclear) alternatives, and many positive secondary effects such as increased employment, decreased dependency on foreign oil, and the intergenerational transfer of nonrenewable resources (e.g., natural gas or petroleum). Direct combustion of wood is an example of a biomass thermochemical conversion technology which is commercial and is beginning to be used on a large scale in New England and other regions for electricity generation.

The remainder of this section discusses the selection of the feedstock used in the analysis of thermochemical conversion technologies. The following sections present detailed technical and economic evaluations of biomass conversion to:

- Electricity and steam by combustion
- SNG by gasification and methanation
- Methanol by gasification and synthesis
- Oil by catalytic liquefaction
- Oil and char by pyrolysis
- Ammonia by gasification and synthesis.

The conversion options were reviewed with DOE for approval at the start of the project.

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*Referred to throughout the report as IBG.

Feedstock Selection

While the generic biomass feedstocks considered to have high potential for thermochemical conversion are woody plants, low moisture plants, and miscellaneous collected residues, it is technically possible to thermochemically convert other generic biomass feedstocks (e.g., manures or high moisture content plants). However, for reasons of feedstock availability and potential conversion economics, only the three mentioned feedstocks were considered as candidates for detailed analysis.

When considering woody plants, low moisture plants, and miscellaneous collected residues, it became apparent that the feedstock with the highest potential availability was woody plants (both residues and crops). Therefore, woody plants were selected as the feedstock for the detailed thermochemical conversion analyses. This choice places certain restrictions on the generality of the analysis.

Wood is composed principally of cellulose $(C_6H_{10}O_5)_n$ and lignin. An examination of the ultimate analyses (dry basis) of several types of woods[2,3,4] reveals that sulfur and nitrogen components are low (generally each less than 0.1 wt%); the ash content varies from about 0.2 wt% to 2½-3 wt%; the carbon content is about 50 wt%; the hydrogen content varies from 5 to 6 wt%; and the oxygen content lies in the range of 35 to 40 wt%. Woods appearing to offer high potential for thermochemical conversion may have higher heating values in excess of 9,000 Btu per dry pound. Because of high resin content, barks generally have higher heating values than woods.[4] For this analysis, the following wood ultimate analysis was selected:

ULTIMATE ANALYSIS,	WEIGHT PERCENT
C	53.8
H	5.7
O	38.2
N	0.2
S	0.1
Ash	2.0
Total	100.0
Higher heating value (millions of Btu/dry ton)	19.1

The moisture content of wood is highly variable and may range from 50 to 60 wt% or more when green, down to 15 to 20 wt% when field dried. Site-specific considerations and economics, such as transportation costs, generally determine the advisability of field drying. To maintain a generality in the analysis, the wood feedstock was assumed to contain 50 wt% moisture as received at the thermochemical conversion plant.

The following generalizations are offered for other potential biomass feedstocks that have ultimate analyses (dry basis) resembling that used in the technical and economic evaluations that follow:

- For biomass feedstocks having a greater moisture content than that of the wood feedstock used in this analysis, the conversion economics are anticipated to be less favorable than those indicated.
- For biomass feedstocks having a lower moisture content than that of the wood feedstock used in this analysis, the conversion economics are anticipated to be more favorable than those indicated.

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II PRODUCTION OF ELECTRICITY AND STEAM BY DIRECT COMBUSTION OF WOOD

Included in the discussion of the production of electricity, steam, and both electricity and steam (cogeneration) from the direct combustion of wood, are current activities in the field; a conceptual technical and economic analysis of the technology, consisting of the technology description (including availability and reliability considerations); process economics, and environmental considerations. This same general pattern is followed for the other technologies analyzed.

Production of Electricity by the Direct Combustion of Wood

Rising energy prices and a growing national attention to energy independence have rekindled interest in wood as a source of energy. Wood fueled the industrial expansion in the United States in the mid-1800s until it was replaced by coal in the 1880-1900 period. Today, wood accounts for a small fraction of the national energy consumption in decentralized, small-scale applications such as wood waste and sawdust combustion at mills to provide on-site heat and power generation; in home heating; and in charcoal manufacturing.

Table 1 lists recent activities or announced plans of industry and electric utilities concerning wood-fired boilers. Products include electricity, steam, or both electricity and steam. Wood and wood residues can be combusted singly or cofired with conventional fuels (e.g., oil, coal). Because of wood's low sulfur, ash, and nitrogen contents, it may find increasing cofiring applications as a compliance fuel with certain types of existing equipment, although these applications are heavily site-specific. Additional applications for the combustion of wood are direct drying[11] and similar operations and are not discussed further.

Several examples are available for the commercial production of electricity from wood. In the Pacific Northwest, the Eugene Water and Electric Board operates a boiler of 34-MW generating capacity[12] fueled with inexpensive hogged wood and bark from nearby mills. The Burlington Electric Department, Burlington, VT, will soon begin design and construction of a new 50-MW wood fired power plant which is scheduled for completion in 1982 and will use about 1,200 to 1,500 tons per day of locally generated wood scrap from industrial or forest "weeding" sources.[10] The Burlington Electric Department converted its Moran Station No. 1 unit (10-MW) last October to wood chip firing. Unit tests using a mixture of 75 percent wood chips and 25 percent oil proved extremely successful, leading the Department to propose the bond financing of the

Table 1

SELECTED LIST OF WOOD-FIRED BOILERS IN NORTH AMERICA
(Recently Announced or Installed)

Industrial Company or Utility	Location	Capacity: Thousands of Pounds per Hour of Steam	Capacity: Electric Generation (MW)	Startup	Steam Conditions: Pressure (psig)	Steam Conditions: Temperature (°F)	Design Fuel Types	Reference
Olinkraft, Inc.	West Monroe, La	600	20	1978	1480	950	Oil, natural gas, bark	5
Champion International Corp.	Courtland, Ala	550		1978	450	550	Coal, bark	5
Federal Paperboard Co.	Riegelwood, NC	350		1978	850	825	Oil, bark	5
Owens-Illinois, Inc.	Tomahawk, Wis.	180		_	635	720	Coal, bark	5
Finch, Pryun & Co.	Glens Falls, NY	150		1977	850	825	Bark, waste liquor	5
Interstate Paper Co.	Riceboro, GA	60*		1978	650	750	Process gas, oil, bark	5
Idaho Veneer Co.	Post Falls, Idaho	40*		1977	250	406	Bark	5
Pacific Wood Treating Corp.	Ridgefield, Wash.	40*		1977	200	380	Wood, bark, sawdust, coal	5
Potlach Corp.	Lewiston, Idaho	550	(possible)	1980	_	_	Wood	6
Hammermill Paper Co.	Selma, Ala.	150		1979	600	_	Bark, wood	6
British Columbia Forest Products, Ltd.	Mackenzie, B.C.	_	20	_	_	_	Wood	6
Morbark Industries / Wolverine Electric Cooperative	Winn, Mich.	_	20	_	_	_	Wood	7
Louisiana-Pacific Corp.† / Pacific Gas and Electric	Oroville, CA	570	30-45	1980-85	_	_	Wood, bark, sawdust	8
Wheelabrator Cleanfuel Corporation (demonstration plant)	Lincoln, Maine	200	35	1980-82	_	_	Wood	9
Burlington Electric Co.	Burlington, Vt.	_	50	1982	_	_	Wood	10

*Package boiler.

†Proposed.

50-MW Intervale unit to Burlington's voters. Waste energy from the 50-MW unit may be used for heating an adjoining greenhouse and fish hatchery.[13]

The cost of the cull wood (low quality waste wood produced from forest "weeding") currently used in the Moran unit is reported to be \$12 to \$13.50 per ton. If this wet wood (40 percent moisture) has a heating value of 9.5 million Btu per short ton, the wood cost can be represented as \$1.25 to \$1.40 per million Btu. The cost of the electricity from the retrofitted Moran unit is stated as being 2.3 mills per kWh, which may exclude a large capital charge component.

DOE is sharing the cost of the Wheelabrator Cleanfuel Corporation program. It entails the design, construction, and operation of a 1,000 dry ton per day biomass (wood) energy conversion facility. Commercially available hardware will be used for wood handling and storage, combustion, and power generation. Phase I, demonstration systems selection and design, is in progress and is anticipated to take 16 to 20 months to complete. Phases II and III, through plant operation and evaluation, may continue an additional 40 to 45 months.[9]

The Wheelabrator project intends to use forestry and commercial wood residues to furnish a sustained supply of feedstock for the cogeneration facility. Mechanical harvesting equipment will selectively clean-cut the wood residues in a fashion that will be the most compatible with the surrounding environment, leaving a clean, healthy forest that will promote the growth of commercial timber.

A recent SRI report[14] describes the prospects for wood conversion in the state of Maine as follows:

> " ... several feasible alternatives for conversion include the generation of process steam and electricity from mill wood and bark. The low cost of fuel and relatively high cost of energy makes construction of conversion plants particularly advantageous in Maine."

It is likely that additional wood combustion projects with federal government incentives (e.g., Wheelabrator) or without federal government incentives (e.g., Burlington) may be forthcoming in the New England area.

Process Description

The technology for the production of electricity by the direct combustion of wood is commercial, and continued developments are anticipated principally in the optimization of the system as fuel prices continue to escalate.

General

The moisture content of the wood and the steam production rate desired generally influence the type of combustion equipment selected. Lower steam flow rates (e.g., below 100,000 pounds per hour) generally suggest using package boilers or even the older Dutch ovens.[15] Fluid bed combustion may also be used. If the wood contains low moisture (e.g., 10 to 20 wt%), then pulverized-feed vortex-type combustors may be more economical.[16,17] Above about 100,000 pounds per hour steam, field-erected boilers are generally used. References 15 and 16 present equipment arrangements. Feeding 2-inch or 3-inch wood chip requires a grate system, such as the endless traveling grates.

Wood preparation systems may entail handling drying, grinding, cleaning, storing, and metering. The complexity of these systems are indicated in discussions in References 16 through 20.

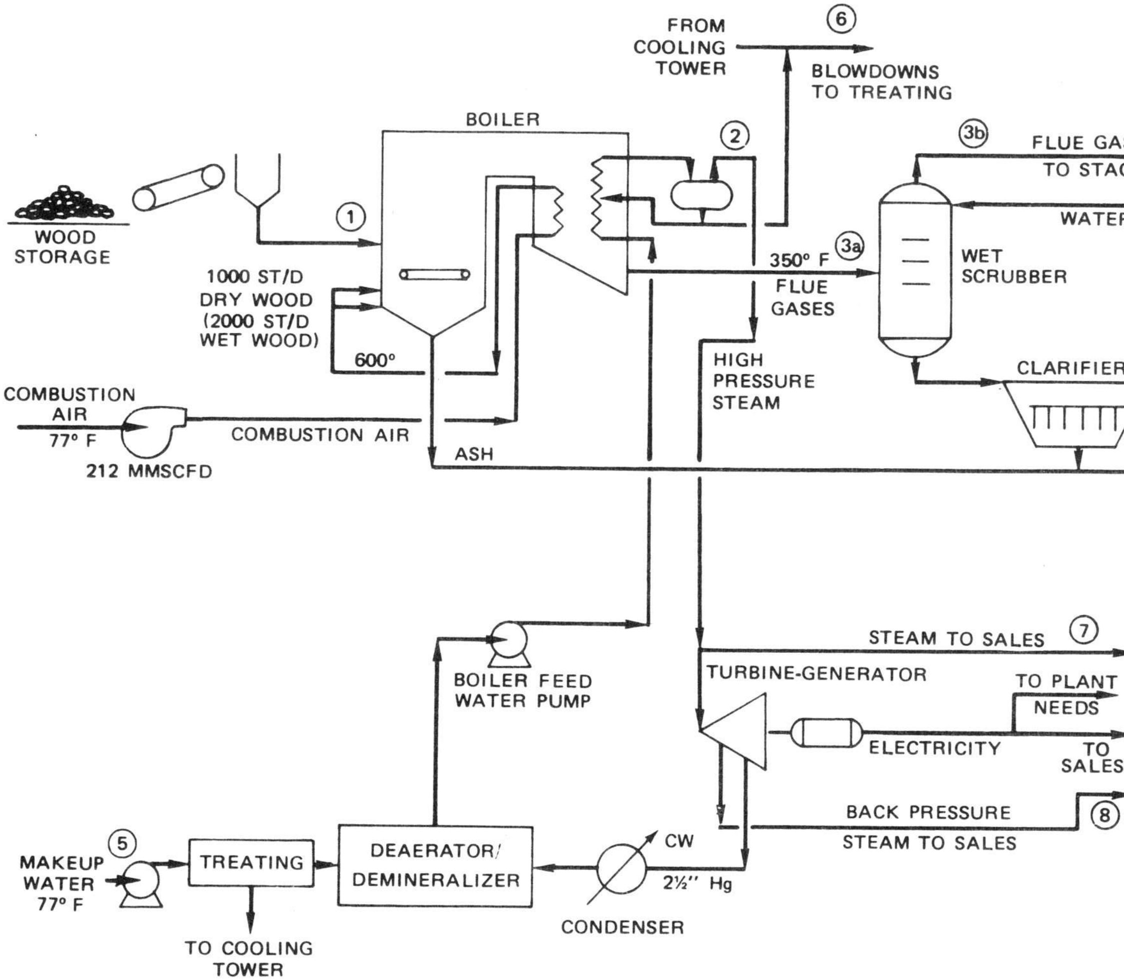
When chips are combusted, cyclone collectors are used to remove 80 to 90 percent of the solids entrained in the flue gas (cyclones are not effective for pulverized feeds because of the small particle sizes). Additional flue gas treatment technologies are wet or dry scrubbers (e.g., granular beds), precipitators, and baghouses.

Feedstock material containing above about 63 to 65 wt% moisture will not sustain combustion,[16,19] because the heat available from biomass combustion is below the heat required for moisture evaporation.[21]

Material and Energy Flows

Figure 1 is a schematic drawing for the production of electricity by the direct combustion of wood. Table 2 presents the stream flows. Tables 3 and 4 summarize the overall mass and energy balances. The basis for the calculations is 1,000 dry short tons per day of wood (2,000 wet short tons per day).

Wood chip (2-inch x 0) is assumed to be delivered to the plant by railcar. The chips are unloaded by a rotary dump mechanism and conveyed to the storage yard where a 30-day supply of wood chip is maintained. Wood chips are reclaimed from storage, cleaned of large rocks and grit, and routed to live feed hoppers which feed two spreader-stoker boilers. No wood drying or grinding is performed. Various investigators[22,23] have suggested the use of 600 to 800°F boiler stack gases to dry the incoming wood (if it is very wet). This alternative is certainly possible but derates the boiler steam generating capacity compared with a nominal 350°F stack temperature while permitting higher dry solids feed rates to the boiler. The choice among these alternatives would require an optimization study which was not attempted here.



PRODUCTION RATES OF ELECTRICITY AND STEAM		
CASE: ELECTRIC POWER	STEAM	COGENERATION
	478,100 lb/hr @450 PSIA, 560°F	
49,600 kW		7,300 kW
		420,300 lb/hr @450 PSIA, 810° F

FIGURE 1 PRODUCTION OF ELECTRIC POWER OR STEAM BY DIRECT COMBUSTION OF WOOD

Table 2

PRODUCTION OF ELECTRIC POWER
BY DIRECT COMBUSTION OF WOOD--STREAM FLOWS
(Thousands of Pounds per Hour)
Basis: 1,000 Dry Short Tons per Day Wood Feed Rate

	(1)	(2)	(3a)	(3b)	(4)	(5)	(6)	(9)
C	44.88							
H	4.74							
O	31.795							
N	0.165							
S	0.08							
Ash	1.67				1.7			
H_2O	83.33	429.8	125.7	16.9		1077.1	556.1	
CO_2			164.4	164.4				
SO_2			0.2	0.2				
O_2			31.4	31.4				156.9
N_2			516.8	516.8				516.6
Total	166.66	429.8	838.5	729.7	1.7	1077.1	556.1	673.5

Table 3

PRODUCTION OF ELECTRIC POWER BY DIRECT COMBUSTION OF WOOD--
OVERALL MATERIAL BALANCE
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	Thousands of Pounds Per Hour
Input	
Wet wood	166.7
Combustion air	673.5
Water	1,077.1
Total	1,917.3
Output	
Flue gas	729.7
Ash	1.7
Evaporation losses and treated wastewater	1,185.9
Total	1,917.3

Table 4

PRODUCTION OF ELECTRIC POWER BY DIRECT COMBUSTION OF WOOD--OVERALL ENERGY BALANCE
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	Millions of Btu Per Hour	Percent
Input		
Wet wood	796.7	100.0%
Total	796.7	100.0%
Output		
Electricity	169.4	21.3
Flue gases to scrubbing	169.4	21.3
Ash	1.0	0.1
Insulation losses	14.2	1.8
Heat rejected to cooling	419.0	52.5
Miscellaneous losses*	23.7	3.0
Total	796.7	100.0%

*Because of mechanical inefficiencies.

The wood is combusted with 25 percent excess air (preheated to 600°F) to minimize stack losses. Several investigators[16,23,24] suggest the use of a minimum of 40 percent excess air as following conventional practice. However, recent articles[25] suggest that lower excess air may be advisable from an energy conservation standpoint.

About 430,000 pounds per hour of steam is generated at 1200 psia and 1000°F. The steam conditions were selected based on discussions with a boiler manufacturer, the information in Table 1 and Reference 25. The high pressure steam is sent to a condensing turbine, generating electric power, and exhausted at 2-1/2-inch Hg absolute. The steam is condensed, deaerated, mixed with makeup boiler feedwater, and routed to the 1250 psia discharge boiler feedwater pump, completing the circuit.

The hot flue gases are directed to a cyclone separator and then to wet scrubbing for fine particle control.

Ash is collected from the boiler grate, quenched, and, together with the concentrated aqueous ash from the clarifier underflow, routed to ponds (or to silos for haulage to landfill).

After deducting the power requirements for the combustion air blower, cooling tower fans and pumps, wood receiving and handling, and other uses, the plant produces about 49.6 MW of electricity for sales. The thermal efficiency (electricity out/wood in) is about 21.3 percent, as shown in Table 4, which also shows that stack losses represent about 21 percent of the input energy (a larger value would be observed if the excess air were greater than 25 percent) and the heat rejected to cooling, about 52 percent.

The low thermal efficiency of 21.3 percent (heat rate = 16,000 Btu per kWh) may be explained in part by the high moisture level (50 wt%) assumed for the feed wood. The water in the feed leaves in the stack as unrecoverable latent heat. Lower feed moisture levels would result in higher overall plant thermal efficiencies.

Unpublished figures from TVA[26] suggest that the heat rate of a 20-MW wood-fueled power plant may be about 16,300 Btu per kWH (20.9 percent thermal efficiency) decreasing to about 15,200 Btu per kWh (22.4 percent thermal efficiency) at a 40-MW plant size. These numbers are in agreement with the plant thermal efficiencies calculated here.

MITRE[15] reports a plant heat rate of 10,950 Btu per kWh (31.1 percent thermal efficiency) for a 55-MW wood-fired power plant. The wood feed is reported to contain 50 wt% moisture, and the boiler efficiency is stated as 70.8 percent. Allowing 5 percent of the energy out for plant power requirements, the steam cycle thermal efficiency would appear to be:

$$\text{steam cycle thermal efficiency} = \frac{0.311}{0.708(1-.05)} = 46 \text{ percent}$$

which would appear to be too high for the reported steam conditions of 1,000 psig/1000°F.

Plant reliability is provided by multiple feeds, water pumps, combustion air blowers, and two boiler plants. No redundancy is provided in the steam-turbine generator set. The plant is constructed of commercially available equipment designed to meet current personnel safety standards.

Economics

Table 5 shows the breakdown of the plant facilities investment for the production of electric power by direct combustion of wood.

Receiving facilities include railcar unloading equipment, conveyor belts, and the like, for the transfer of wood chips from the railcar to the plant storage area; loading tractors; feed hoppers and feeding chutes. The dual train boiler plant includes conventional facilities such as the firebox, heat transfer surfaces, instrumentation, feed pumps,

Table 5

PRODUCTION OF ELECTRIC POWER BY DIRECT COMBUSTION OF WOOD--
ESTIMATED TOTAL CAPITAL INVESTMENT
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Millions of Dollars
Plant section investment	
Wood storage and handling	$ 2.9
Boiler plant	14.4
Turbine-generator	14.2
Utility facilities	12.9
General service facilities	6.7
Total plant facilities investment	$51.1
Land cost	0.5
Organization and start-up expenses	1.5
Interest during construction	3.5
Working capital	1.6
Total capital investment	$58.2
Depreciable investment	56.1
Debt capital	37.8
Equity capital	20.4

wet scrubber, stack, and boiler housing, and costs were based on information received from a boiler manufacturer. The turbine-generator facilities include one condensing turbogenerator, instruments, control panels, switch gear, and related facilities.

The utilities portion of the plant facilities investment includes the combustion air blower, condenser, water ponds (fresh and wastewater), fuel oil back-up equipment, and other items as discussed in the Appendix, Economic and Design Bases.

The general services facilities were assumed to cost about 15 percent of all other plant facilities investments. The estimated installed plant facilities investment of $51.1 million represents an investment of about $1,030 per kilowatt. This high value is attributed to the small plant size (about 50 MW) and in part to the estimated high plant heat rate of about 16,000 Btu per kWh. The 50-MW Burlington, VT, plant is reported to cost $80 million[10] and is scheduled for operation in 1982. Assuming an inflation rate of 8 percent per year, the constant (1977) dollars cost for the plant is $\$80 \text{ million}/(1.08)^5 =$ $54.4 million, presumably representing the total capital investment. This number is within 7 percent of the estimated $58.2 million total capital investment in Table 5, and the differences may be due to site-specific factors (e.g., the use of once-through cooling as opposed to a cooling tower; lower wood moisture content).

The assumed time schedule of cash flows for construction funds payout, operating costs, and revenue received during plant construction and start-up is shown below.

Start of year	Depreciable Investment	Operating Cash Expenses (% of maximum)	Revenue (% of maximum)
1	-25%		
2	-75%		
3		+100%	+100%

Start-up costs, including plant debugging and operator training costs, were assumed to be 3 percent of the plant facilities investment because of the advanced state of the technology.

Figure 2 shows the effect of plant size (capacity) on plant facilities investment. The curve appears to become linear for feedstock feed rates between 1,000 and 3,000 dry tons per day, reflecting the addition of more equipment trains of the same size as plant capacity increases. The investment falls from about $1,090 per kilowatt at a 25-MWe plant size (having a single train of equipment) to about $940 per kilowatt at a 150-MWe plant size (having multiple trains of equipment), reflecting economies of scale.

Table 6 presents the estimated major operating requirements. The operating labor requirement reflects the manpower needs for the solids handling equipment, boiler plant and rotating equipment, and pollution control equipment. The electric power for plant needs is furnished by the turbogenerator. Purchased water requirements are primarily for cooling tower makeup and reflect a 5 percent of circulation makeup rate (2 percent blowdown, 3 percent evaporation losses).

The use of dry cooling towers is an alternative for reducing fresh water requirements, at additional expenses of initial capital and operating energy requirements.[27] Reference 28 discusses selected examples of European power plants using steam turbines with dry cooling towers.

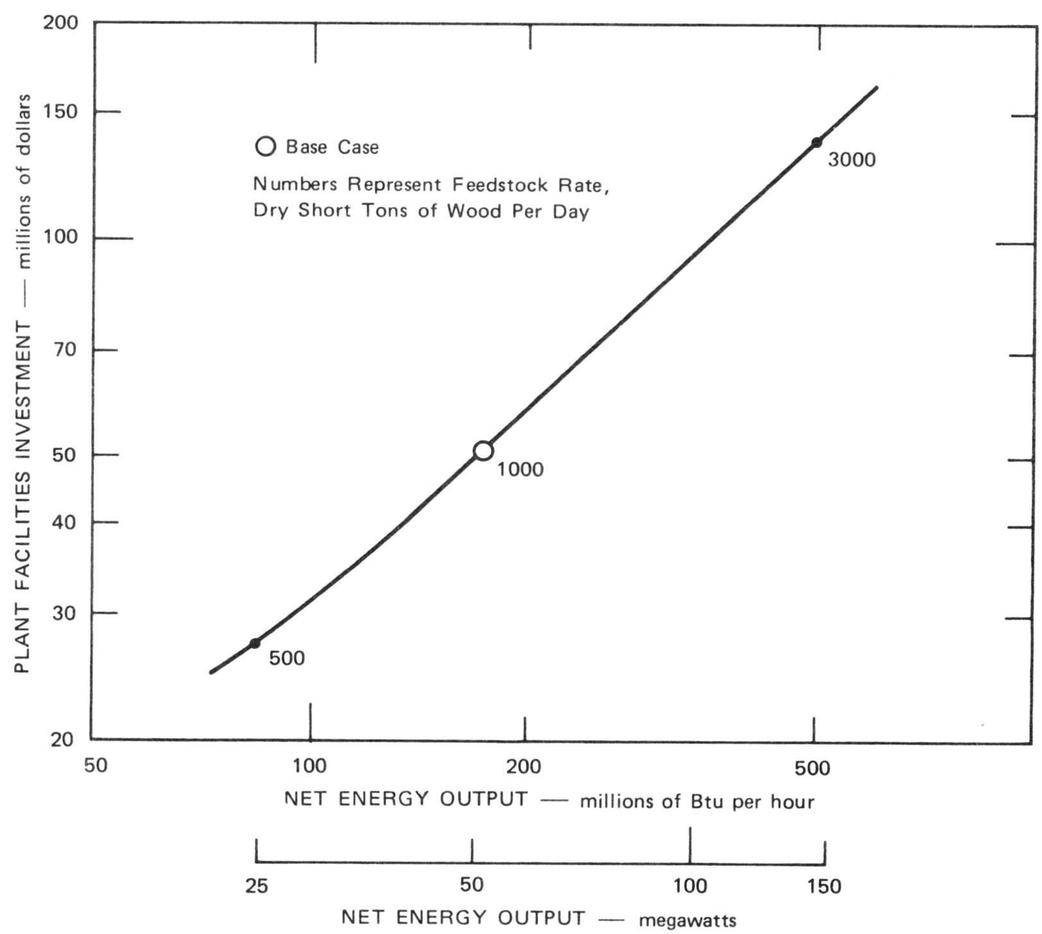


FIGURE 2 PRODUCTION OF ELECTRIC POWER BY DIRECT COMBUSTION OF WOOD — EFFECT OF PLANT SIZE ON PLANT FACILITIES INVESTMENT

Table 6

PRODUCTION OF ELECTRIC POWER BY DIRECT COMBUSTION OF WOOD--
ESTIMATED MAJOR OPERATING REQUIREMENTS
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

Operating labor (men per shift)	10.5
Electric power (kWh/hr)	
Plant needs	3,600
Purchased (if any)	0
Cooling tower circulation--ΔT = 20°F (gpm)	42,000
Purchased water (gpm)	2,150

Table 7 shows annual operating costs and revenue requirements for generating electricity by direct combustion of wood. The base case assumes a wood cost of $1.00 per million Btu ($19.12 per dry ton), and a capacity factor of 80 percent as may be typical of new base load power plants. Depreciation extends for the 20-year project life. The resulting 20-year average required revenue for the sale of electricity is 60.5 mills per kWh. Feedstock costs represent 35 percent of total annual operating costs and labor related costs, about 19 percent.

Figure 3 shows the effect of plant size on revenue requirements. Three feedstock costs of $2.00, $1.00, and $0 per million Btu are shown. As plant sizes increase from 25 to 150 MWe, the revenue requirements are seen to decrease by about 10 to 20 percent.

Directionally, using feedstocks with lower moisture content would result in improved plant heat rates and lower electricity costs, compared with the values presented here.

Figure 4 shows the effect of feedstock cost, annual load factor, and uncertainty in plant facilities investment on revenue requirements. A base feedstock rate of 1,000 dry short tons per day is used. As the capacity factor falls from 80 percent (base load) to 40 percent (intermediate load), revenue requirements increase by a factor of about 1.7, reflecting a more expensive electricity cost should the facility be dedicated to intermediate load operation. For every 10 cents per million Btu change in wood cost, revenue requirements change by about 1.6 to 1.7 mills per kWh, reflecting the high plant heat rate of 16,000 Btu per kWh. For every 10 percent change in plant facilities investment, revenue requirements are seen to change by about 4 mills per kWh.

Table 7

PRODUCTION OF ELECTRIC POWER BY DIRECT COMBUSTION OF WOOD--
ESTIMATED ANNUAL OPERATING COSTS AND REVENUE REQUIRED
FOR A REGULATED PRODUCER
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Millions of Dollars per Year	Mills per Killowatt-Hour
Materials and supplies		
Wood at $9.56/short ton (wet)	$ 5.58	16.0
Catalysts and chemicals	0.72	2.1
Maintenance materials	1.02	2.9
Total materials and supplies	7.32	21.0
Labor		
Operating labor	0.74	2.1
Supervision	0.12	0.3
Maintenance labor	1.02	2.9
Administrative and support labor	0.37	1.1
Payroll burden	0.78	2.2
Total labor costs	$ 3.03	8.7
Purchased utilities		
Water	0.56	1.6
Total purchased utilities	0.56	1.6
Fixed costs		
G&A expenses	1.02	2.9
Property taxes and insurance	1.28	3.7
Plant depreciation, 20-year	2.81	8.1
Total fixed costs	$ 5.11	14.7
Total annual operating costs	16.02	46.0
Return on rate base and income tax*	5.04	14.5
Total revenue required*	21.06	60.5
Sources of required revenue		
Electric power	21.06	60.5
Total revenue*	21.06	60.5

*20-year average values.

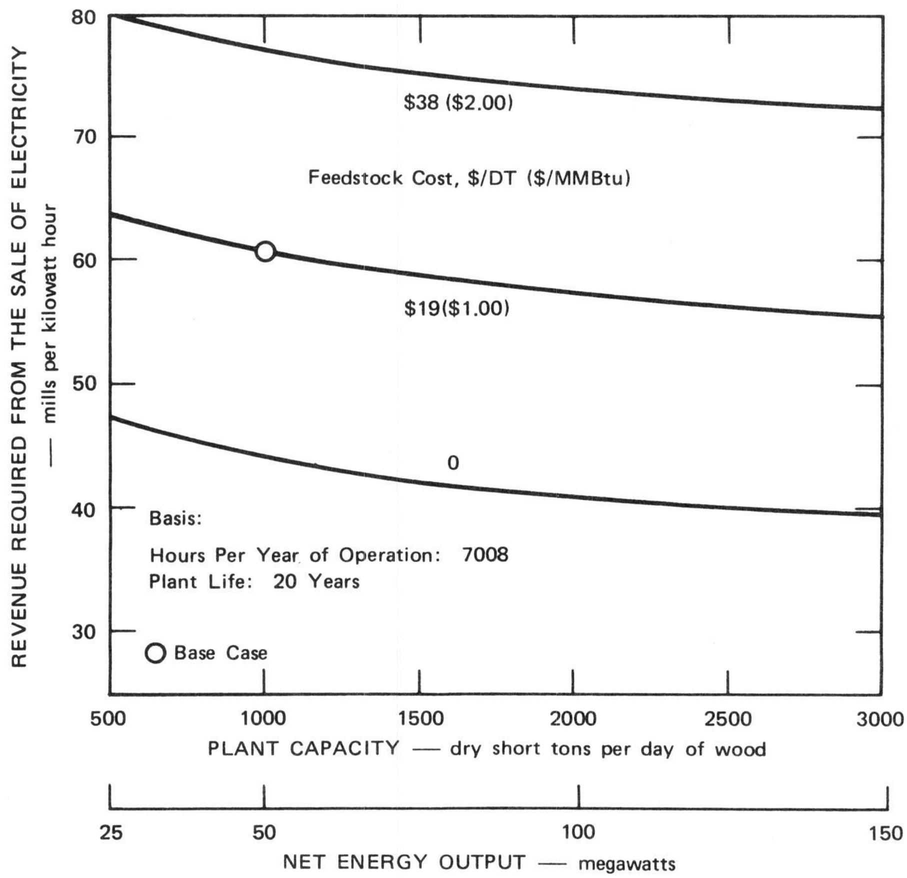


FIGURE 3 PRODUCTION OF ELECTRIC POWER BY DIRECT COMBUSTION OF WOOD — EFFECT OF PLANT SIZE ON REVENUE REQUIRED FROM THE SALE OF ELECTRICITY BY A REGULATED PRODUCER

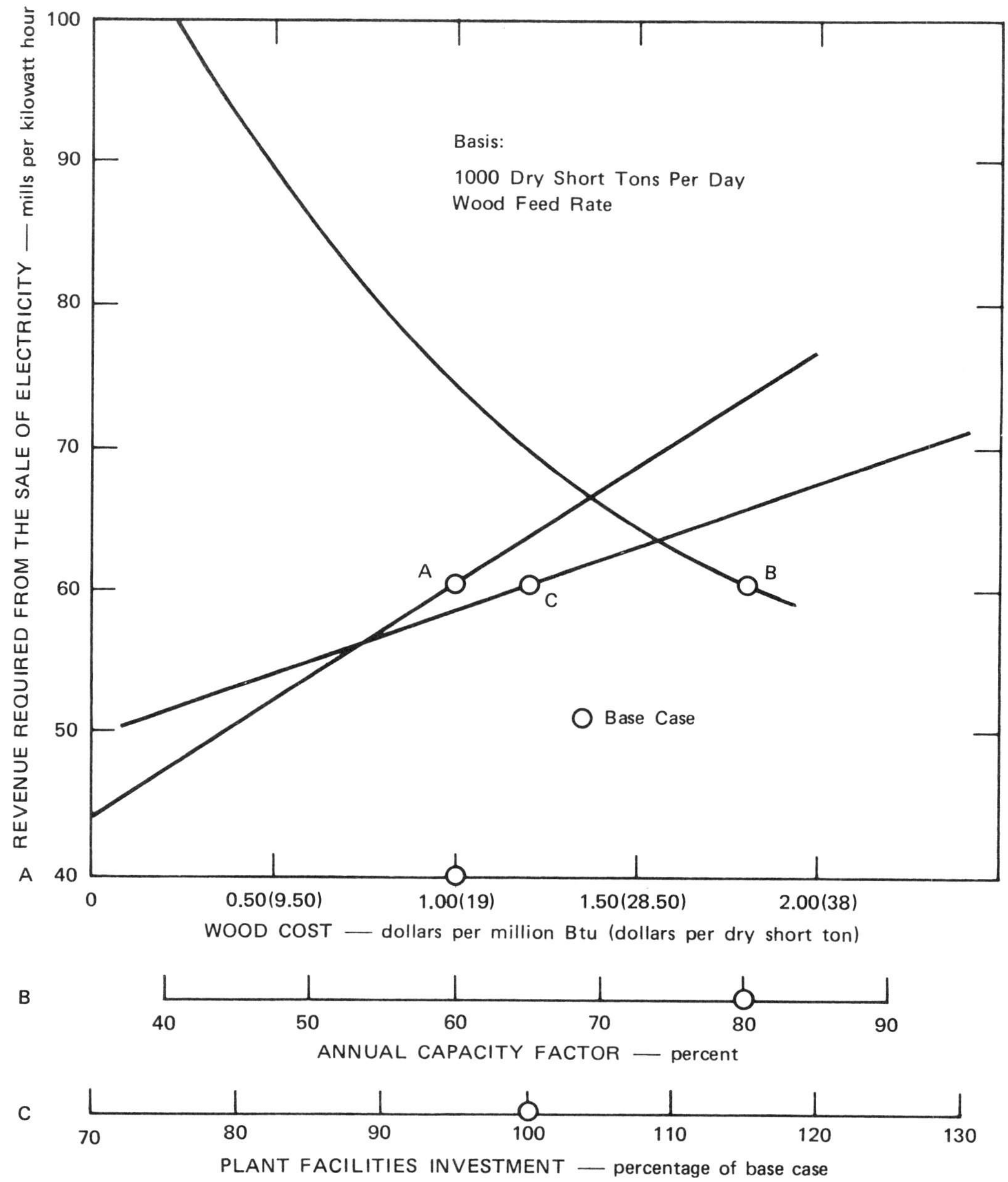


FIGURE 4 PRODUCTION OF ELECTRIC POWER BY DIRECT COMBUSTION OF WOOD — EFFECT OF VARIATION OF SELECTED PARAMETERS ON REVENUE REQUIRED FROM THE SALE OF ELECTRICITY BY A REGULATED PRODUCER

Environmental Considerations

Table 8 shows the estimated emissions and environmental parameters based on the plant net energy output expressed in millions of Btu. The values (with the exception of the land value) are easily converted to an input energy basis by multiplying by 0.213 (the plant thermal efficiency expressed as a fraction). Sulfur oxide emissions are based on a sulfur balance. Other values are based on information previously presented. Particulates are removed by wet scrubbing. Nitrogen oxides were calculated on the basis of 10 pounds NO_2 per ton input as presented in Reference 29. The NO_x emissions resulting from this calculation are high and may be lowered by such techniques as burner modifications[30] (if applicable), flue gas recirculation, or staged combustion. The SO_x and particulate emissions are well within the requirements established by EPA for new stationary sources. Additional discussions of potential emissions from the direct combustion of wood may be found in Gikis.[23]

Table 8

PRODUCTION OF ELECTRIC POWER BY DIRECT COMBUSTION OF WOOD--
ESTIMATED EMISSIONS AND ENVIRONMENTAL PARAMETERS
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

Parameter	Units*	Value†
Sulfur (SO_x)	Lb SO_2/MMBtu	1
Nitrogen (NO_x)	Lb NO_x/MMBtu	5
Particulates	Lb/MMBtu	Tr
Solid waste	Lb/MMBtu	9.8
Aqueous waste	Gal/MMBtu	390
Fresh water	Gal/MMBtu	770
Land	Acre/billion Btu/day	45

*Millions of Btu of total energy output.

†Tr = trace.

Production of Steam by the Direct Combustion of Wood

Table 1 lists several current applications for the production of steam from firing wood or wood waste singly or in combination with other fuels. Other applications can be found in the literature.[9,31]

An examination of this information suggests a wide variability in steam pressure and temperature levels, reflecting different industrial process requirements. For this work, steam conditions of 450 psia, 560°F (100°F superheat) were selected as representing perhaps the midrange of these applications. The ultimate use of the steam is not specified here, and the steam is suited for only across-the-fence sales.

Process Description

Table 9 presents the stream flows shown in Figure 1, the schematic flow diagram for this case. Tables 10 and 11 present overall material and energy balances, respectively.

Table 9

PRODUCTION OF STEAM BY DIRECT COMBUSTION OF WOOD--STREAM FLOWS
(Thousands of Pounds per Hour)
Basis: 1,000 Dry Short Tons per Day Wood Feed Rate

	(1)	(2)	(3a)	(3b)	(4)	(5)	(6)	(7)	(9)
C	44.88								
H	4.74								
O	31.795								
N	0.165								
S	0.08								
Ash	1.67				1.7				
H_2O	83.33	478.1	125.7	16.9		506.7	137.4	478.1	
CO_2			164.4	164.4					
SO_2			0.2	0.2					
O_2			31.4	31.4					156.9
N_2			516.8	516.8					516.6
Total	166.66	478.1	838.5	729.7	1.7	506.7	137.4	478.1	673.5

The process description is much the same as that for the production of electricity from wood combustion. Since steam is the desired product, the steam turbine-generator set and cooling tower are eliminated, and piping is added to convey the live steam to the plant gate. About 478,100 pounds per hour of 450 psia steam may be produced from the combustion of 2,000 short tons per day of wet wood. The overall energy balance in Table 11 shows that the plant thermal efficiency is about 76.1 percent [steam out/(wood and electricity in)]. This high value occurs because no steam is condensed (with resulting cooling losses).

Table 10

PRODUCTION OF STEAM BY DIRECT COMBUSTION OF WOOD--
OVERALL MATERIAL BALANCE
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Thousands of Pounds per Hour
Input	
Wet wood	166.7
Combustion air	673.5
Water	506.7
Total	1,346.9
Output	
Steam	478.1
Flue gas	729.7
Ash	1.7
Treated wastewater	137.4
Total	1,346.9

Table 11

PRODUCTION OF STEAM BY DIRECT COMBUSTION OF WOOD--
OVERALL ENERGY BALANCE
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Millions of Btu per Hour	Percent
Input		
Wet wood	796.7	99.3%
Electricity	6.0	0.7
Total	802.7	100.0%
Output		
Steam	611.2	76.1
Ash	1.0	0.1
Flue gases to scrubbing	169.4	21.1
Insulation losses	14.2	1.8
Miscellaneous losses*	6.9	0.9
Total	802.7	100.0%

*Because of mechanical inefficiencies.

The plant is not energy self-sufficient and must purchase about 1,750 kW of electric power to run the wood receiving and handling equipment, the combustion air blower, and the like. An alternative would be the generation of this electricity on-site, with the addition of a steam turbine, generator, and a cooling tower, and a reduction in the amount of steam available for sale. However, this alternative was not evaluated because it was felt that purchased electricity at 25 mills per kWh would be a less expensive option.

Plant reliability is provided by multiple feed water pumps, combustion air blowers, and two boiler plants. The plant is constructed of existing equipment, designed to meet current personnel safety standards.

Economics

Table 12 shows the plant facilities investment (PFI). The elements in Table 12 correspond in many instances to those shown in Table 5 for the generation of electricity. Differences occur in the elimination of the steam turbine-generator facilities and the cooling tower facilities and in the addition of steam transfer piping. The PFI is estimated to be $27.9 million ($45 per 1,000 Btu per hour of steam).

Table 12

PRODUCTION OF STEAM BY DIRECT COMBUSTION OF WOOD--
ESTIMATED TOTAL CAPITAL INVESTMENT
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Millions of Dollars
Plant section investment	
Wood storage and handling	$ 2.9
Boiler plant	14.4
Utility facilities	7.0
General service facilities	3.6
Total plant facilities investment	$27.9
Land cost	0.5
Organization and start-up expenses	0.8
Working capital	1.2
Total capital investment	$30.4

This case is analyzed from the point of view of a nonregulated producer (100 percent equity financing) selling steam to adjacent industrial installations. In certain instances (e.g., the across-the-fence sale of steam to an adjacent steam electric power plant), it is possible that the plant may be operated from a regulated producer standpoint. However, this latter case was not analyzed here. The total capital investment is estimated to be about $30.4 million.

Figure 5 shows the effect of plant size on plant facilities investment. The curve becomes linear for feedstock rates between 1,000 and 3,000 dry tons per day, reflecting the addition of more equipment trains of the same size as the plant capacity increases. The plant facilities investment falls from about $49 per 1,000 Btu per hour of steam at 500 dry tons per day wood feed rate to about $42 per 1,000 Btu per hour of steam at 3,000 dry tons per day wood feed rate, reflecting economies of scale.

Table 13 presents the estimated major operating requirements. Compared with the case of electricity production from wood combustion, this case requires fewer operators per shift (because of the lack of the turbogenerator set, cooling tower, and other equipment) and requires 1,750 kW of purchased power.

Table 14 shows the estimated operating costs and revenue requirements.

A feedstock cost of $1.00 per million Btu ($19 per dry ton) is used. Fifteen-year accelerated depreciation and a 90 percent annual stream factor are typical of an industrial venture. Revenue requirements (15-year average) are $3.99 per million Btu of steam. Wood costs represent 58 percent of annual operating costs and labor related costs, 17 percent.

Figure 6 shows the effect of plant size on revenue requirements. A wood cost of $1.00 per million Btu is used. As the plant size increases from about 400,000 pounds per hour of steam to about 1 million pounds per hour of steam, revenue requirements fall by about 10 percent, reflecting economies of scale.

Figure 7 shows the effect of feedstock cost, annual load factor, and uncertainty in plant facilities investment on revenue requirements. A base feedstock rate of 1,000 dry short tons per day is used. As the plant capacity factor falls from 90 to 50 percent, revenue requirements increase by about 50 percent. For every 10 cents per million Btu change in wood cost, revenue requirements change by about 13 cents per million Btu. For every 10 percent change in plant facilities investment, revenue requirements change by about 24 cents per million Btu.

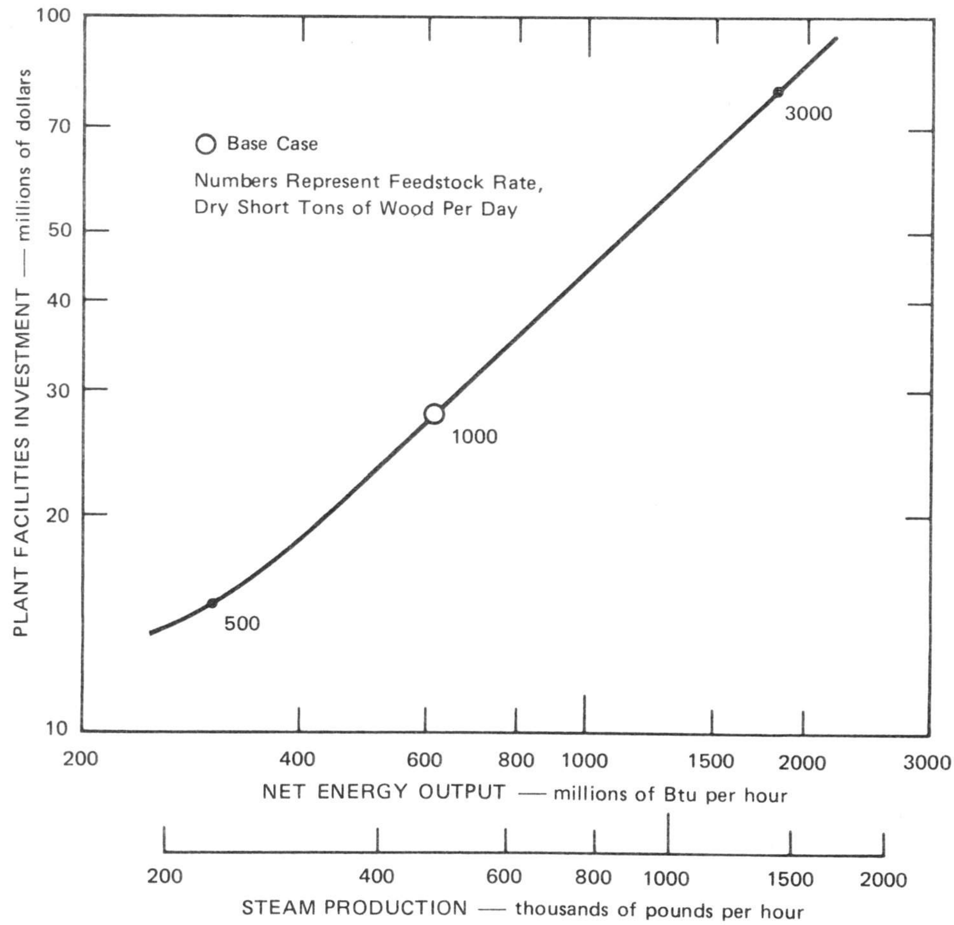


FIGURE 5 PRODUCTION OF STEAM BY DIRECT COMBUSTION OF WOOD — EFFECT OF PLANT SIZE ON PLANT FACILITIES INVESTMENT

Table 13

PRODUCTION OF STEAM BY DIRECT COMBUSTION OF WOOD--
ESTIMATED MAJOR OPERATING REQUIREMENTS
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

Operating labor (men per shift)	7.0
Electric power (kWh/hr)	
Plant needs	1,750
Purchased (if any)	1,750
Cooling tower circulation--$\Delta T = 20°F$ (gpm)	0
Purchased water (gpm)	1,000

Environmental Considerations

Table 15 shows estimated emissions and environmental parameters based on the plant net steam output expressed in millions of Btu. Compared with the case of electricity production from wood combustion, the parameter values are all lower, reflecting the much higher thermal efficiency of the plant when producing steam.

Production of Electricity and Steam by the Direct Combustion of Wood

Cogeneration of electricity and steam may find extensive application in industry and therefore was included in the anlysis. Electrical generation is typical of regulated industries, and steam production may be conducted by a nonregulated industry. In the cogeneration case, the analysis is considered from both points of view, and the selling prices of electricity are presented as a function of the selling price of steam.

Table 1 lists several examples of wood or wood waste fueled plants that will produce both steam and electricity. Steam turbines of the back pressure or extraction type are widely used in industry. In these applications, the high pressure steam from the boiler is expanded to the pressure level(s) required by the process. Mechanical work is available from the expansion and may be used to drive compressors or converted to electricity for plant needs. It is difficult to generalize about the back pressure or extraction pressure steam conditions, since these vary widely throughout industry.[32] A steam back pressure of 450 psia was selected for analysis, to be consistent with the pressure selected in the steam generation case.

Table 14

PRODUCTION OF STEAM BY DIRECT COMBUSTION OF WOOD--
ESTIMATED ANNUAL OPERATING COSTS AND
REVENUE REQUIRED FOR A NONREGULATED PRODUCER
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Millions of Dollars per Year	Dollars per Million Btu of Steam
Materials and supplies		
Wood at $9.56/short ton (wet)	$ 6.28	$1.30
Catalysts and chemicals	0.26	0.05
Maintenance materials	0.56	0.12
Total materials and supplies	$ 7.10	$1.47
Labor		
Operating labor	0.49	0.10
Supervision	0.08	0.02
Maintenance labor	0.56	0.12
Administrative and support labor	0.22	0.04
Payroll burden	0.47	0.10
Total labor costs	$ 1.82	$0.38
Purchased utilities		
Electric power	0.34	0.07
Fresh water	0.30	0.06
Total purchased utilities	$ 0.64	$0.13
Fixed costs		
G&A expenses	0.56	0.12
Property taxes and insurance	0.70	0.14
Total fixed costs	$ 1.26	$0.26
Total annual operating costs	10.82	2.24
Capital charges for a 15% DCF return	8.43	1.75
Total revenue required	$19.25	$3.99
Sources of revenue required		
Steam at $3.99/MMBtu	19.25	3.99
Total revenue	$19.25	$3.99
(Revenue required--regulated* producer, 20-year average values)	(15.19)	(3.15)

*See economic bases (the Appendix) for definition of terms.

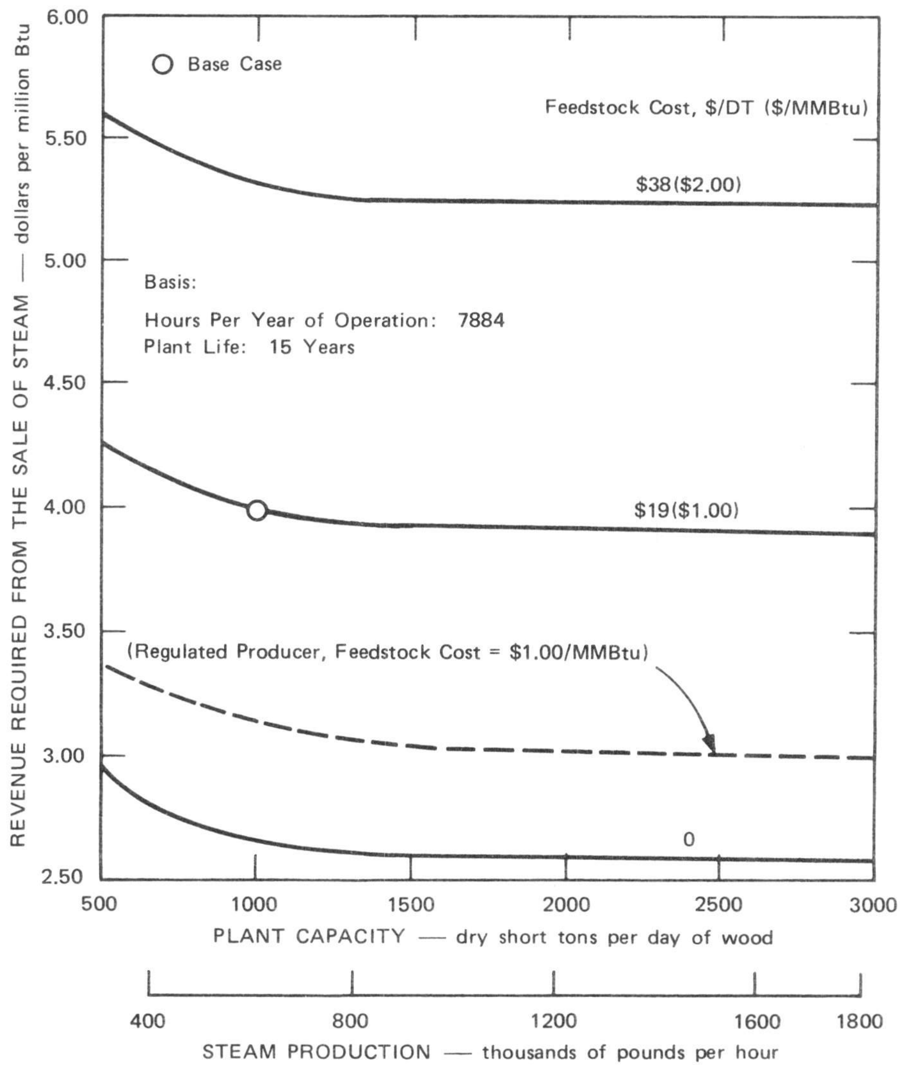


FIGURE 6 PRODUCTION OF STEAM BY DIRECT COMBUSTION OF WOOD — EFFECT OF PLANT SIZE ON REVENUE REQUIRED FROM THE SALE OF STEAM BY A NONREGULATED PRODUCER

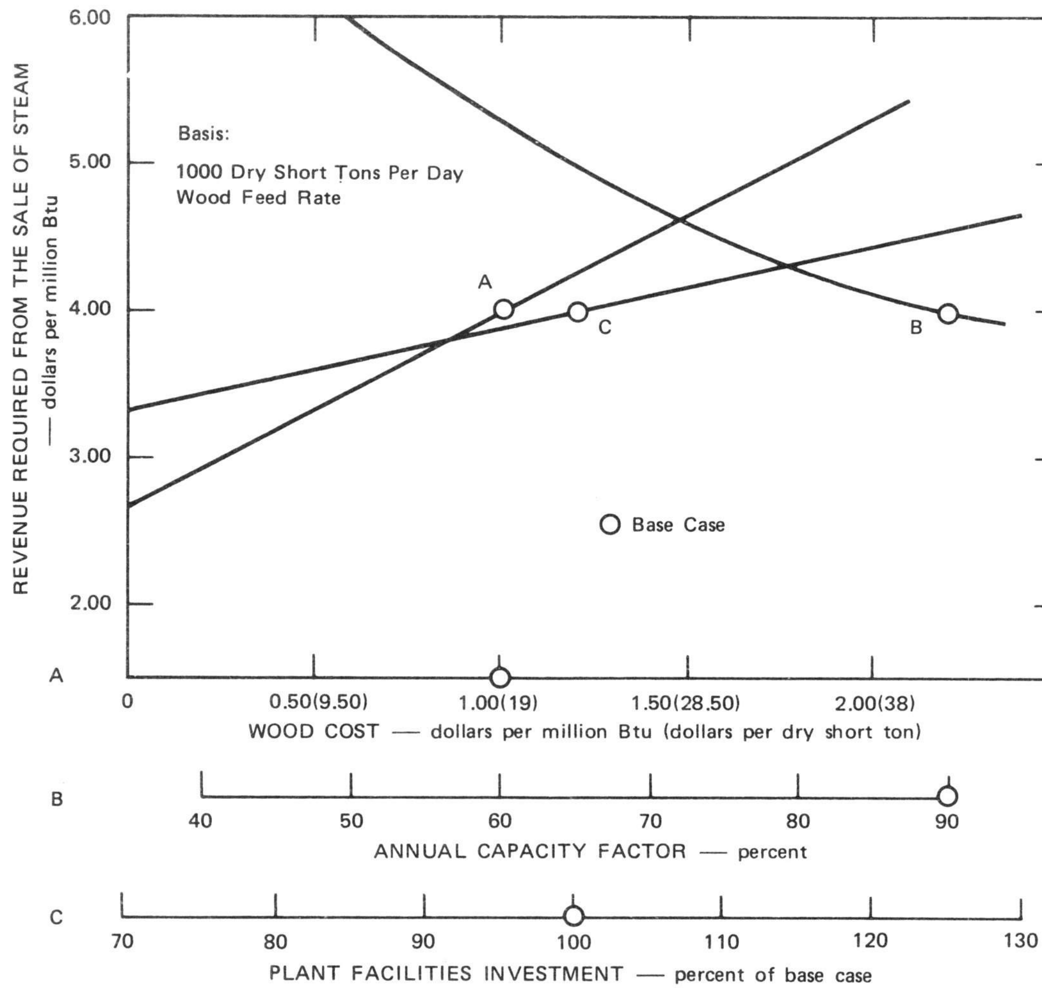


FIGURE 7 PRODUCTION OF STEAM BY DIRECT COMBUSTION OF WOOD — EFFECT OF VARIATION OF SELECTED PARAMETERS ON REVENUE REQUIRED FROM THE SALE OF STEAM BY A NONREGULATED PRODUCER

Table 15

PRODUCTION OF STEAM BY DIRECT COMBUSTION OF WOOD--
ESTIMATED EMISSIONS AND ENVIRONMENTAL PARAMETERS
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

Parameter	Units*	Value†
Sulfur (SO_x)	Lb SO_2/MMBtu	0.27
Nitrogen (NO_x)	Lb NO_x/MMBtu	1.4
Particulates	Lb/MMBtu	Tr
Solid waste	Lb/MMBtu	2.7
Aqueous waste	Gal/MMBtu	27
Fresh water	Gal/MMBtu	100
Land	Acre/billion Btu/day	12

*Millions of Btu of total energy output.

†Tr = trace.

Table 16 presents a recent estimate of the cogeneration potential of six industries.

Process Description

Table 17 gives the stream flows shown in the schematic flow diagram (Figure 1) for this case. Tables 18 and 19 present overall material and energy balances, respectively.

The process description is much the same as for the electric power generation case, generating boiler steam at 1,200 psia and 1000°F. Variations are the substitution of a back pressure turbine for the condensing turbine and the elimination of the cooling tower and condenser. Plant electricity needs are furnished by the turbogenerator set. As shown in Figure 1 and Table 17, a wood feed rate of 2,000 wet short tons per day is estimated to produce about 7.3 MW of electricity and 420,000 pounds per hour of superheated, 450 psia steam.

Table 16

ESTIMATED OUTPUTS AND POTENTIAL COGENERATION CAPACITIES OF SIX INDUSTRIES

Industry	1985 Output: Process Steam (10^{12} Btu/year)	1985 Output: 10^9 kWh/Year	1985 Output: Percent Electricity	Total Cogeneration Capacity (MW): 1976	Total Cogeneration Capacity (MW): 1985
Food	49	2.1	13	189	343
Textiles	13	0.6	13	114	98
Pulp and paper	891	38.3	13	1,286	4,861
Chemicals	408	21.1	15	1,451	2,677
Petroleum refining	107	6.0	16	118	763
Steel	247	11.2	13	887	1,423
Total	1,715	79.3	14	4,045	10,165

Source: Reference 8.

Table 17

PRODUCTION OF ELECTRICITY AND STEAM BY DIRECT COMBUSTION OF WOOD--STREAM FLOWS
(Thousands of Pounds per Hour)
Basis: 1,000 Dry Short Tons per Day Wood Feed Rate

	(1)	(2)	(3a)	(3b)	(4)	(5)	(6)	(8)	(9)
C	44.88								
H	4.74								
O	31.795								
N	0.165								
S	0.08								
Ash	1.67				1.7				
H_2O	83.33	420.3	125.7	16.9		444.9	133.4	420.3	
CO_2			164.4	164.4					
SO_2			0.2	0.2					
O_2			31.4	31.4					156.9
N_2			516.8	516.8					516.6
Total	166.66	420.3	838.5	729.7	1.7	444.9	133.4	420.3	673.5

Table 18

PRODUCTION OF ELECTRICITY AND STEAM BY DIRECT COMBUSTION OF WOOD--
OVERALL MATERIAL BALANCE
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Thousands of Pounds per Hour
Input	
Wet wood	166.7
Combustion air	673.5
Water	444.9
Total	1,285.1
Output	
Steam	420.3
Flue gases	729.7
Ash	1.7
Treated wastewater	133.4
Total	1,285.1

Table 19

PRODUCTION OF ELECTRICITY AND STEAM BY DIRECT COMBUSTION OF WOOD--
OVERALL ENERGY BALANCE
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Millions of Btu per Hour	Percent
Input		
Wet wood	796.7	100.0%
Total	796.7	100.0%
Output		
Electricity	25.0	3.1
Steam	578.6	72.6
Flue gases to scrubbing	169.4	21.3
Ash	1.0	0.1
Insulation losses	14.2	1.8
Miscellaneous losses*	8.5	1.1
Total	796.7	100.0%

*Because of mechanical inefficiencies.

Table 19, the overall energy balance, suggests that the plant thermal efficiency (steam and electricity out/wood in) is 75.7 percent. This high value reflects the absence of any steam condensation and cooling requirements. It is slightly lower than the steam-only case because of assumed inefficiencies in the turbogenerator set.

Electricity represents only about 4 percent of the net plant energy output, and reflects the 450 psi steam back pressure level. The ratio of steam to electricity (on an energy basis) may be varied by varying the back pressure level.

Plant reliability is provided by multiple feed water pumps, combustion air blowers, and two boiler plants. A single back pressure turbine is used. The plant is constructed of existing equipment, designed to meet current personnel safety standards.

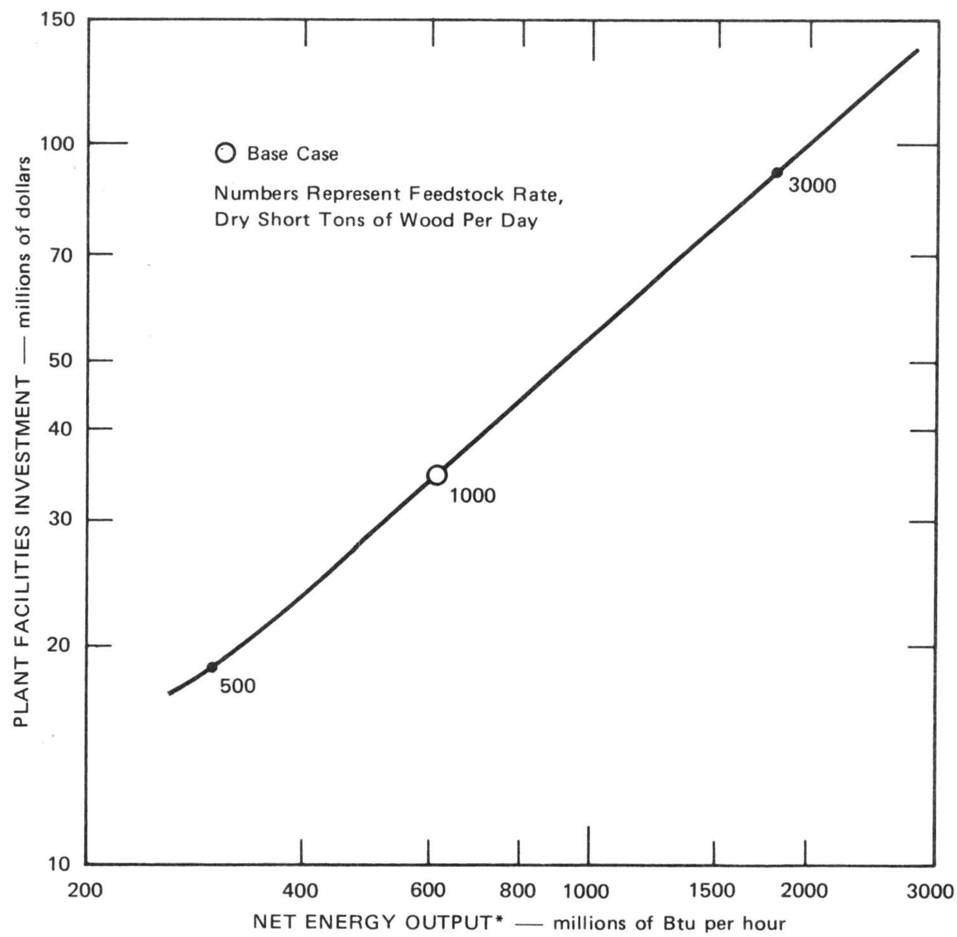
Economics

The PFI is analogous in many respects to the PFI for the electrical production case. Differences occur in the costs of the turbine-generator set (here, a back-pressure turbine is used), in the elimination of the steam condensing and cooling tower facilities, and in the addition of steam transfer piping. Table 20 shows the breakdown of the plant facilities investment for both regulated (debt financed) and nonregulated (equity financed) operations. The PFI is estimated to be \$35.1 million, falling between the PFIs for the electric power generation and steam generation cases. Total capital investments are estimated to be \$40.3 and \$37.9 million for regulated and nonregulated producers, respectively.

Figure 8 shows the effect of plant size on plant facilities investment. For feedstock rates ranging between 1,000 and 3,000 ODT per day, the curve is seen to become linear, reflecting the addition of more equipment trains of the same sizes as plant size increases.

Table 21 presents the estimated major operating requirements. Operating labor requirements are estimated to lie between the electric power production and the steam production cases. Tables 22 and 23 show the annual operating costs and revenue requirements for the production of electricity and steam by direct combustion of wood for a nonregulated and a regulated producer, respectively. The base cases assume a feed cost of \$1.00 per million Btu and an annual operating load factor of 80 percent.* Twenty-year straight line depreciation is used for the regulated case, while the nonregulated case uses 15-year accelerated (sum-of-the-years digits) depreciation. Revenue requirements (based on the sale of both electricity and steam) are \$3.80 and \$5.00 per million

*An 80 percent annual load factor was selected because it was assumed that the sale of electricity would be to the base load market.



*Steam and electricity

FIGURE 8 PRODUCTION OF ELECTRICITY AND STEAM BY DIRECT COMBUSTION OF WOOD — EFFECT OF PLANT SIZE ON PLANT FACILITIES INVESTMENT

Table 20

PRODUCTION OF ELECTRICITY AND STEAM BY DIRECT COMBUSTION OF WOOD--ESTIMATED TOTAL CAPITAL INVESTMENT
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Millions of Dollars Regulated Producer	Millions of Dollars Nonregulated Producer
Plant section investment		
Wood storage and handling	$ 2.9	
Boiler plant	14.4	
Turbine-generator	6.4	
Utility facilities	6.8	
General service facilities	4.6	
Total plant facilities investment	$35.1	$35.1
Land cost	0.5	0.5
Organization and start-up expenses	1.1	1.1
Interest during construction	2.4	—
Working capital	1.2	1.2
Total capital investment	$40.3	$37.9
Depreciable investment	38.6	
Debt capital	26.2	
Equity capital	14.1	

Table 21

PRODUCTION OF ELECTRICITY AND STEAM BY DIRECT COMBUSTION OF WOOD--ESTIMATED MAJOR OPERATING REQUIREMENTS
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

Operating labor (men per shift)	9.0
Electric power (kWh/hr)	
Plant needs	1,750
Purchased (if any)	0
Cooling tower circulation--ΔT = 20°F (gpm)	0
Purchased water (gpm)	880

Table 22

PRODUCTION OF ELECTRICITY AND STEAM BY DIRECT COMBUSTION OF WOOD--ESTIMATED ANNUAL OPERATING COSTS AND REVENUE REQUIRED FOR A NONREGULATED PRODUCER
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	Millions of Dollars per Year	Dollars per Million Btu of Electricity and Steam
Materials and supplies		
Wood at $9.56/short ton (wet)	$ 5.58	$1.32
Catalysts and chemicals	0.23	0.05
Maintenance materials	0.70	0.17
Total materials and supplies	$ 6.51	$1.54
Labor		
Operating labor	0.63	0.15
Supervision	0.09	0.02
Maintenance labor	0.70	0.17
Administrative and support labor	0.29	0.07
Payroll burden	0.60	0.14
Total labor costs	$ 2.31	$0.55
Purchased utilities		
Electric power	—	—
Fresh water	0.22	0.05
Total purchased utilities	$ 0.22	$0.05
Fixed costs		
G&A expenses	0.70	0.17
Property taxes and insurance	0.88	0.20
Total fixed costs	$ 1.58	$0.37
Total annual operating costs	10.62	2.51
Capital charges for a 15% DCF return	10.51	2.49
Total revenue required	$21.13	$5.00
Sources of revenue required		
Electricity and steam	21.13	5.00
Total revenue	$21.13	$5.00

Table 23

PRODUCTION OF ELECTRICITY AND STEAM BY DIRECT COMBUSTION OF WOOD--
ESTIMATED ANNUAL OPERATING COSTS AND REVENUE
REQUIRED FOR A REGULATED PRODUCER
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Millions of Dollars per Year	Dollars per Million Btu of Electricity and Steam
Materials and supplies		
Wood at $9.56/short ton (wet)	$ 5.58	$1.32
Catalysts and chemicals	0.23	0.05
Maintenance materials	0.70	0.17
Total materials and supplies	$ 6.51	$1.54
Labor		
Operating labor	0.63	0.15
Supervision	0.09	0.02
Maintenance labor	0.70	0.17
Administrative and support labor	0.29	0.07
Payroll burden	0.60	0.14
Total labor costs	$ 2.31	$0.55
Purchased utilities		
Water	0.22	0.05
Electric power	—	—
Total purchased utilities	$ 0.22	$0.05
Fixed costs		
G&A expenses	0.70	0.17
Property taxes and insurance	0.88	0.20
Plant depreciation, 20-year	1.93	0.46
Total fixed costs	$ 3.51	$0.83
Total annual operating costs	12.55	2.97
Return on rate base and income tax*	3.53	0.83
Total revenue required	$16.08	$3.80
Sources of required revenue		
Electricity and steam	16.08	3.80
Total revenue*	$16.08	$3.80

*20-year average values.

Btu for regulated and nonregulated producers, respectively. This difference is caused by the higher capital charge rates for the nonregulated compared with the regulated producer. Excluding depreciation, wood costs represent 52 percent of annual operating costs and labor related costs, 22 percent.

Figure 9 shows the effect of plant size on revenue requirements. Revenue requirements are those from the sale of both steam and electricity. The base feedstock cost of $1.00 per million Btu is used. As plant sizes increase from about 300 million Btu per hour energy output to about 1,800 million Btu per hour energy output, the revenue requirements (from the sale of both steam and electricity) are seen to decrease by about 13 to 20 percent, reflecting economies of scale.

Figures 10 and 11 show the effects of feedstock cost, annual load factor, and uncertainty in plant facilities investment on revenue requirements for regulated and nonregulated producers, respectively. Revenue requirements represent the requirements for the sale of both steam and electric power and are expressed in dollars per million Btu of combined steam and electricity energy output.

Referring to Figure 10, as the annual load factor drops from 80 to 40 percent, the revenue requirements increase by over 50 percent. For every 10 cents per million Btu change in wood costs, revenue requirements change by about 13 cents per million Btu. For every 10 percent change in plant facilities investment, revenue requirements change by about 22 cents per million Btu.

Figure 12 presents the selling price of electricity as a function of the selling price for steam for both a regulated and a nonregulated producer. For the regulated producer, if the steam is sold across the fence for about $3.15 to $3.20 per million Btu, the selling price of electricity would be about 60-61 mills per kWh, the same as found in the case of electricity production from the direct combustion of wood. Thus the cogeneration case would appear to produce two energy products that, for the conditions studied, may be sold for prices not exceeding the revenue requirements for the energy products produced separately.

Environmental Considerations

Table 24 shows estimated emissions and environmental parameters based on the plant net energy output expressed in millions of Btu of steam and electricity. The values are almost the same as those for the steam production case because of very similar plant thermal efficiencies.

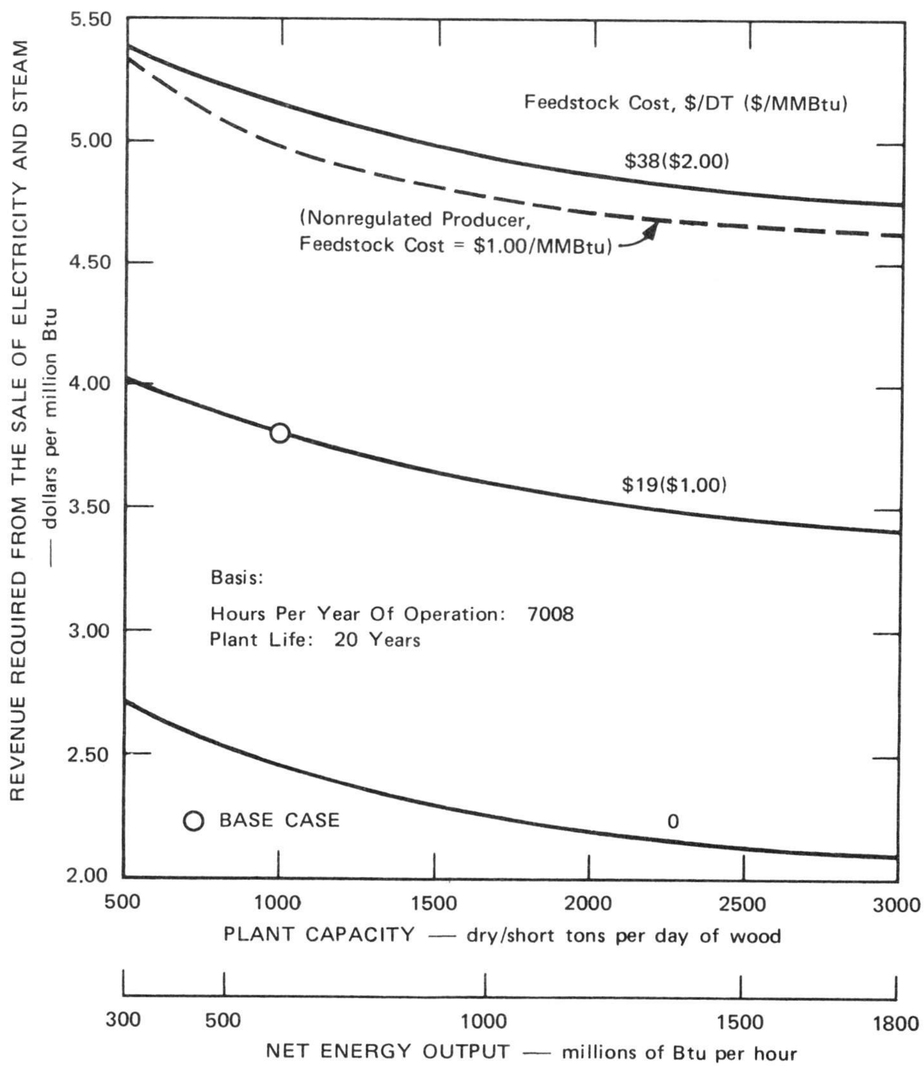


FIGURE 9 PRODUCTION OF ELECTRICITY AND STEAM BY DIRECT COMBUSTION OF WOOD — EFFECT OF PLANT SIZE ON REVENUE REQUIRED FROM THE SALE OF ELECTRICITY AND STEAM BY A REGULATED PRODUCER

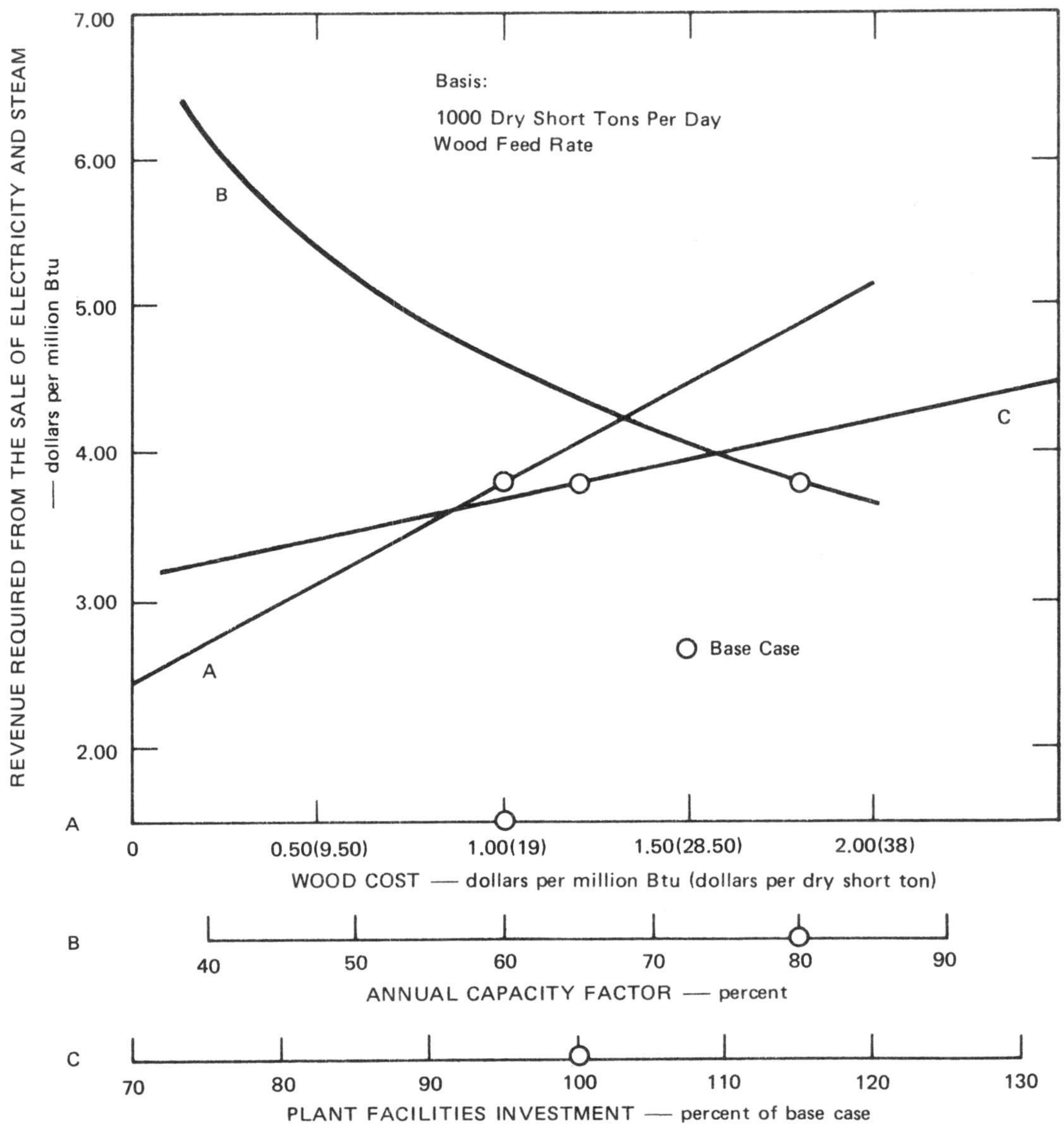


FIGURE 10 PRODUCTION OF ELECTRICITY AND STEAM BY DIRECT COMBUSTION OF WOOD — EFFECT OF VARIATION OF SELECTED PARAMETERS ON REVENUE REQUIRED FROM THE SALE OF ELECTRICITY AND STEAM BY A REGULATED PRODUCER

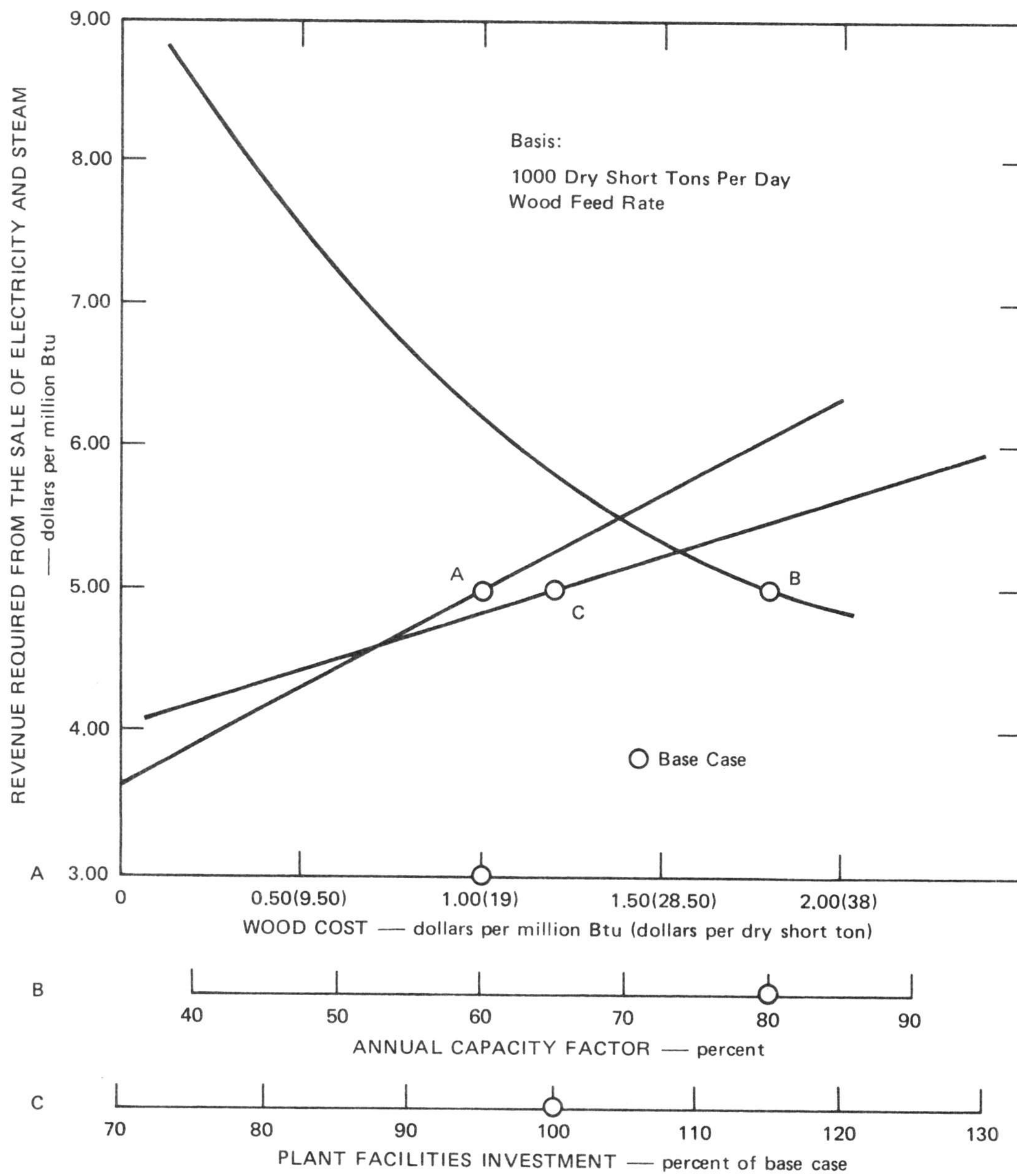


FIGURE 11 PRODUCTION OF ELECTRICITY AND STEAM BY DIRECT COMBUSTION OF WOOD — EFFECT OF VARIATION OF SELECTED PARAMETERS ON THE REVENUE REQUIRED FROM THE SALE OF ELECTRICITY AND STEAM BY A NONREGULATED PRODUCER

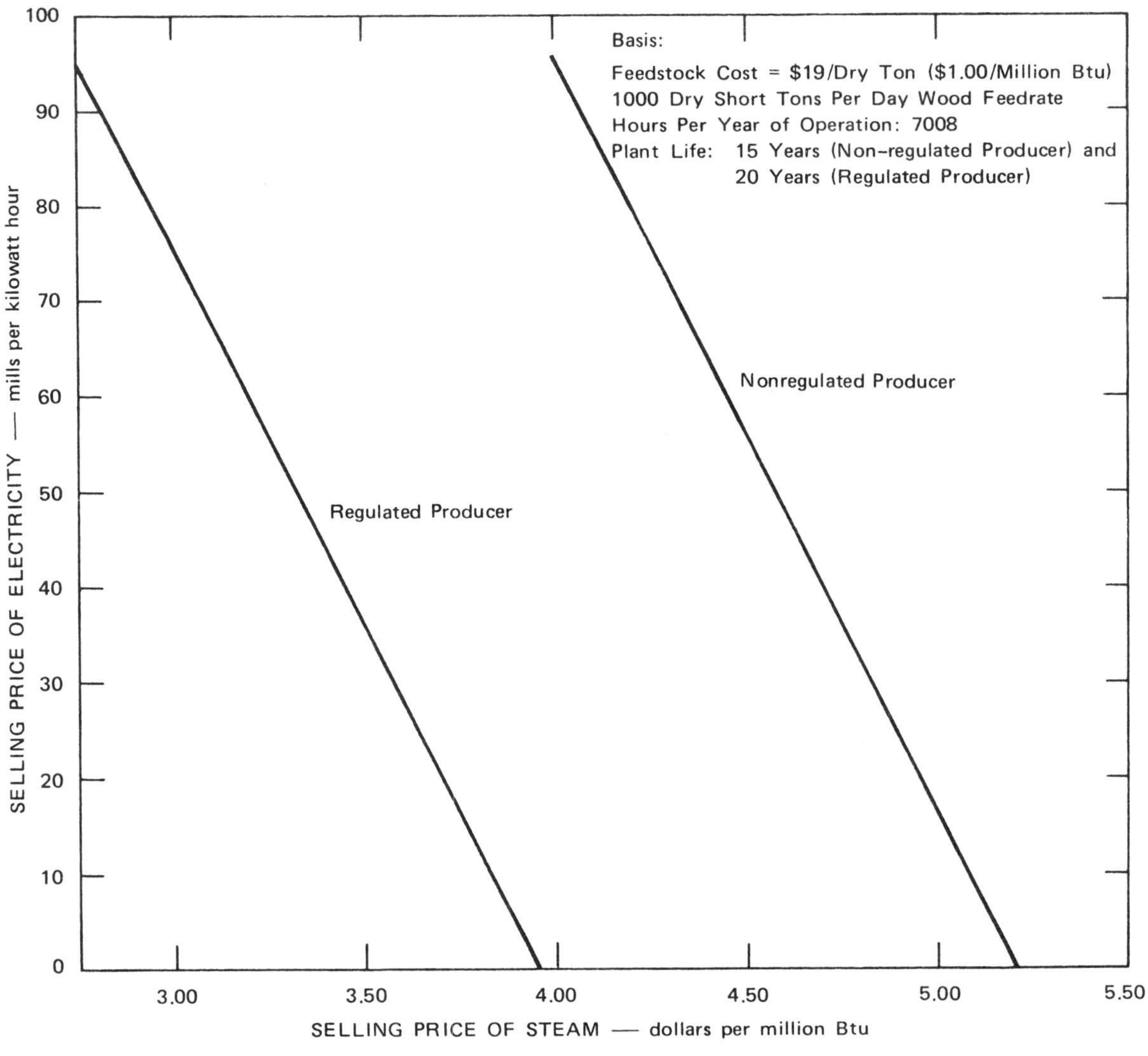


FIGURE 12 PRODUCTION OF ELECTRICITY AND STEAM BY DIRECT COMBUSTION OF WOOD — SELLING PRICE OF ELECTRICITY AS A FUNCTION OF SELLING PRICE OF STEAM

Table 24

PRODUCTION OF ELECTRICITY AND STEAM BY DIRECT COMBUSTION OF WOOD--
ESTIMATED EMISSIONS AND ENVIRONMENTAL PARAMETERS
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

Parameter	Units*	Value†
Sulfur (SO_x)	Lb SO_2/MMBtu	0.28
Nitrogen (NO_x)	Lb NO_x/MMBtu	1.4
Particulates	Lb/MMBtu	Tr
Solid waste	Lb/MMBtu	2.7
Aqueous waste	Gal/MMBtu	27
Fresh water	Gal/MMBtu	88
Land	Acre/billion Btu/day	12.4

*Millions of Btu of total energy output.

†Tr = trace.

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III PRODUCTION OF SNG FROM WOOD BY DIRECT GASIFICATION AND COMBINED SHIFT/METHANATION

Research and development activities to further the efficient use of environmentally acceptable fuels have attracted national interest. The DOE, the Gas Research Institute, and others are making significant expenditures to develop technologies designed to augment the dwindling supply of natural gas. The principal focus of these R&D activities has been the production of substitue natural gas (SNG) from the nation's most abundant resource, coal; several advanced technologies (e.g., COGAS and the British Gas Corporation's slagging fixed bed gasifier) have reached the demonstration phase.

Alternative feedstocks may be used to produce SNG, including biomass, solid waste, peat, shale, and in situ coal. Biomass conversion technologies tend to be feedstock-limited, resulting in smaller capacity SNG facilities (e.g., 6 to 36 billion Btu per day of SNG, as is developed later) compared with the 250 to 280 billion Btu per day SNG plants proposed for SNG from coal. Consequently, the cost of SNG produced from wood or other biomass materials may tend to be more expensive than coal-derived SNG because extreme economies of scale may not be achievable.

In describing the technology and economics of converting woody feedstocks to SNG, conceptual gasification and combined shift/methanation steps are considered, and the cost of SNG is presented as a function of plant size, feedstock cost, investment uncertainty, and other factors.

Activities in Wood Gasification

Wood gasification for the production of low-Btu gas* for gas engine fuel, power generation or for industrial uses (firing ceramic kilns or metallurgical furnaces)[33] is not a new concept. During World War II, and between the wars, many vehicles (e.g., cars, trucks, buses) in Europe were powered with gas derived from wood, charcoal, or coal.[33,34] The capacity of the older, stationary producers (nonslagging) was generally limited to about 50 dry tons per day, with a 10 to 12 foot diameter grate[33] and low length-to-diameter ratios (1-1.5). The gas outputs of these units may have fallen between 20 and 40 million Btu per hour.†

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*Low-Btu gas is defined as gas with a higher heating value of 100 to 200 Btu per standard cubic foot.

†Based on 40 to 50 oven dried tons (ODT) per day of 18 million Btu ODT feedstock and a cold gas efficiency of 70 to 80 percent.

Tables 25, 26, and 27 summarize commercial and advanced technologies for recovering liquid and gaseous fuels from solid wastes and residues.[35] PTGL denotes pyrolysis, thermal gasification, or liquefaction processes. When considering the direct gasification of wood with steam and air or

Table 25

PTGL PROCESS CATEGORIES*

VERTICAL FLOW REACTORS	
Direct heat transfer • Moving packed bed† (shaft furnaces) • Moving, staged, stirred bed (multiple hearth furnaces) • Entrained bed (transport reactors)	Indirect heat transfer • Moving packed bed (shaft furnaces) • Entrained bed (recirculating heat carrier)
FLUIDIZED BED REACTORS	
Direct heat transfer	Indirect heat transfer (recirculating heat carrier)
HORIZONTAL OR INCLINED FLOW REACTORS	
Direct heat transfer • Tumbling solids bed (rotary kilns) • Agitated solids bed (on conveyor)	Indirect heat transfer • Tumbling solids bed - Rotary calciners - Rotary vessels (recirculating heat carrier) • Agitated solids bed (on conveyor) • Static solids bed (on conveyor)
MOLTEN METAL OR SALT BATH REACTORS	
Numerous flow and mixing options	
MULTIPLE REACTOR SYSTEMS	
Numerous flow and mixing options	
BACK-MIX FLOW REACTORS	
For slurries and melts	

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*Some reactors may be designed with numerous solids and gas flow regimes (e.g., countercurrent, cocurrent, split flow, crossflow).

†Also known as fixed bed reactors.

Table 26

SUMMARY OF SELECTED NORTH AMERICAN PTGL PROCESSES
(Not all active)

Solids Flow & Bed Conditions	Typical Types of Reactor Vessels	Heat Transfer	Relative Direction of Gas Flow	Examples of Processes, Developers, R&D Programs	Status§	Feedstock	Main Products: Fuels or Char Materials	Main Products: Steam*
I VERTICAL FLOW REACTORS								
A. Moving packed beds (gravity solids flow; also called fixed beds)	Refractory lined shaft furnaces	Direct	Countercurrent	Forest Fuels Manufacturing, Inc. (Antrim, NH)	C	FAR**		X
				Battelle Northwest (Richland, WA)	I	Refuse,FAR	X	X
				American Thermogen (location unknown)	I	Refuse		X
				Andco, Inc./Torrax Process (Buffalo, NY)	C	Refuse		X
				H. F. Funk Process† (Murray Hill, NJ)	A	Refuse	X	
				Tech-Air Corp/Georgia Inst. Tech. (Atlanta, GA)	C	FAR, refuse, sludge	X	
				Union Carbide Purox Process (Tonawanda, NY)	C	Refuse, FAR	X	
				Westwood Polygas, Ltd. (Vancouver, BC, Canada)	A	FAR	X	
				Urban Research & Development (E. Granby, CN)	I	Refuse	X	
				Wilwardco, Inc. (San Jose, CA)	A	FAR, sludge	X	
				Worcester and Hunt (Eugene, OR)	A	FAR	X	
				Pyrotechnic Industries, Ltd.(Calgary, AL, Canada)	C	FAR, tires	X	
				Chevron Research Co. (Richmond, CA)	I	Refuse	X	
		Direct	Cocurrent	University of California (Davis, CA)	A	FAR	X	
	Metal retort	Indirect--wall	Crossflow	Koppelman Process (Encino, CA)	I	FAR	X	
B. Moving, staged, stirred beds (gravity solids flow)	Refractory lined multiple hearth furnaces	Direct	Countercurrent, or Crossflow, or Splitflow	BSP/Envirotech (Belmont, CA)	C	Sludge, refuse	X	X
				Nichols Research & Engr. (Belle Mead, NJ)	C	Sludge, FAR, refuse	X	X
				Zimpro (Rothschild, WI)	C	Sludge	X	X
				Garrett Energy Research & Engr. (Claremont, CA)	A	Manure	X	
				Hercules/Black, Crow & Eidsness (Gainsville, FL)	I	Refuse	X	
C. Moving entrained beds (may include mechanical bed transport)	Refractory lined tubular reactor	Indirect by RHC*	Cocurrent	Occidental Research Co. (La Verne, CA) } Flash Pyrolysis Process	C	Refuse	X	
II FLUIDIZED REACTORS	Refractory lined or metal walled vessels	Direct	--	Copeland Systems, Inc. (Oak Brook, IL)	A	Sludges		X
				Adolph Coors Co./U. of Missouri (Rolla, MO)	A	Refuse, FAR	X	
				Energy Resources Co. (ERCO) (Cambridge, MA)	A	Refuse, FAR	X	
				Hercules/Black Crow & Eidsness (Gainsville, FL)	I	Refuse	X	
				BC Research (Vancouver, BC)	A	Wood	X	
				Industrial Developments, Ltd. (Edmonton, AL)	C	Wood	X	
				Texas Tech University (Lubbock, TX)	A	Manure		
		Indirect by RHC*		Wheelabrator Incin.Inc.(Bailie Proc.)(Pittsburgh,PA)	A	FAR, refuse		
				A. D. Little Inc./Combustion Equipment Assoc. (Cambridge, MA/New York, NY)	I	Refuse	X	
III HORIZONTAL AND INCLINED FLOW REACTORS (Rotary kilns and calciners)								
A. Tumbling solids bed	Refractory lined kilns	Direct	Countercurrent	Devco Inc. (New York, NY)	C	Refuse		X
				Monsanto Landgard/City of Baltimore (MD)	C	Refuse	X	X
				Watson Energy Systems (Los Angeles, CA)	A	Refuse		X
	Metal retort	Direct	--	A&P Coop Inc. (Jonesboro, AK)	A	FAR	X	X
	Metal retort in firebox (calciners)	Indirect--wall	Countercurrent or cocurrent	Ecology Recycling Unlimited, Inc. (Santa Fe Springs, CA)	I	Refuse	X	
				JPL/Orange County, CA (Fountain Valley, CA)	A	Sludge	X	
				Pan American Resources, Inc. (West Covina, CA)	I	Refuse, FAR	X	
				Rust Engineering (Birmingham, AL)	I	Refuse, sludge	X	
	Metal retort	Indirect by RHC*	Cocurrent	Tosco Corp./Goodyear Tire and Rubber (Los Angeles, CA/Akron, OH)	A	Tires	X	

Source: J.L. Jones, R.C. Phillips, S. Takaoka, and F.M. Lewis, "Pyrolysis, Thermal Gasification, and Liquefaction of Solid Wastes and Residues Worldwide Status of Processes (as of Fall 1977)," Proceeding of the ASME 8th Biennial National Waste Processing Conference (American Society of Mechanical Engineers, New York, May 1978).

Table 26 (concluded)

Solids Flow & Bed Conditions	Typical Types of Reactor Vessels	Heat Transfer	Relative Direction of Gas Flow	Examples of Processes, Developers, R&D Programs	Status§	Feedstock	Main Products: Fuels or Char Materials	Main Products: Steam
B. Agitated solids bed	Metal retort (mixing conveyor)	Indirect-wall or fire tubes	--	DECO Energy Co. (Irvine, CA)	C	Tires	X	
				Enterprise Co. (Santa Ana, CA)	C	Refuse	X	
				Kemp Reduction Corp. (Santa Barbara, CA)	A	Refuse, FAR	X	
	Refractory chamber (vibrating conveyor)	Indirect-fire tubes	Cocurrent	PyroSol (Redwood City, CA)	C	Fluff from autos, refuse		X
				Pyrotek, Inc. (Santa Ana, CA)	A	Refuse, FAR	X	
C. Static solids bed	Metal chamber & conveyor belt	Indirect-fire tubes	Cross flow	Thermex, Inc. (Hayward, CA)	A	Tires	X	
	Rotary hearth furnace	Unknown	--	Carbon Development Corp. (Walled Lake, MI)	A	Tires	X	
IV MOLTEN METAL OR SALT BATHS								
A. Floating solids on bath (horizontal flow)	Moving molten lead hearth	Indirect by RHC*	--	Michigan Tech. Univ. (Houghton, MI) (PURETEC Pyrolysis System)	A	Refuse, FAR	X	
B. Mixed molten salt bed (various possible flow regimes)	Vertical shaft or back-mix vessel metal retort	Indirect by RHC*	--	Battelle Northwest (Richland, WA)	I	Refuse	X	
				Anti-Pollution Systems, Inc. (Pleasantville,NJ)	A	Refuse, sludge	X	
V MULTIPLE REACTOR SYSTEM								
A. Combined entrained bed/static bed reactor systems	Tubular metal retort and static hearth refractory chamber	Indirect-wall Direct	Cocurrent --	University of California (Berkeley, CA)	A	Pulping liquor	X	
B. Combined moving packed bed/entrained bed reactors	Vertical shaft Vertical shaft (char gasification)	Direct Direct	Countercurrent Cocurrent	Battelle Columbus Laboratories† (Columbus, OH)	A	Paper, biomass	X	
C. Combined static solids bed mechanically conveyed/moving packed bed reactor	Traveling grate refractory chamber Refractory lined shaft furnace	Direct Direct	Countercurrent Countercurrent	Mansfield Carbon Products, Inc. (Gallatin, TN)	A	Refuse	X	
VI BACK-MIX FLOW REACTORS								
Electrically heated stirred or mixed		Indirect-wall		DoE/Wood to Oil Process Development Unit†‡ (Albany, OR) Operator: Bechtel Corp. San Francisco, CA) (Thermochemical liquefaction process)	A	FAR	X	
				Firestone Tire and Rubber Company (Akron, OH) (Semicontinuous operation)	I	Tires	X	

†Pressure above atmospheric.
‡Recirculating heat carrier.
**FAR indicates forestry and/or agricultural residue.
*Product gas from reactor immediately fired in secondary combustion chamber.

§C. At commercial or demonstration stage of development
A. Active development program under way.
I. Inactive development or research program--process may be available for licensing or further development.

NOTE: Reactors that do not provide for automatic ash removal and thus do not operate in a continuous or semicontinuous flow mode with respect to feed input and ash removal are not included. One example of a commercially available system is the Kelley pyrolytic incinerator (Kelley Company, Inc., Milwaukee, WI) which does not provide for continuous ash removal. Ash quantities for paper trash or waste wood are small and reactor cleanout is required only once per week in some cases.

Table 27

BIOMASS GASIFICATION EXPERIMENTAL UNITS SPONSORED BY THE U.S. DEPARTMENT OF ENERGY

Contractor/Developer	Technology Type	Nominal Capacity: ST/D of As-Received Biomass Feedstock	Nominal Capacity: Dry ST/D, 50% Moisture Feedstock	Nominal Capacity: Dry ST/D, 10% Moisture Feedstock	Representative Biomass Feedstocks	Primary Energy Products	Comments
Battelle Columbus Division	Multi-solid fluidized bed*	-	-	0.2	Wood	IBG	Catalytic gasification; gasification with steam and recirculating hot solid
Battelle Pacific Northwest Division	Agitated fluidized bed	1.2	0.6	1.1	Wood	IBG	Catalytic gasification; gasification with steam, air, oxygen, and/or CO_2
Garrett Energy Research and Engineering	Multiple hearth furnace (Herreshoff type)	4.0	2.0	3.6	Manure, sawdust, cotton gin trash	IBG	Distinct hearth zones include direct contact drying; pyrolysis; combustion; ash cooling
Gilbert/Commonwealth Cos. Environmental Energy Engineering	Multiple operating modes	3.5-6	1.7-3	3.1-5.4	Wood, corn stover, cotton gin trash, bagasse	Gas, liquids, char (depends on operating mode)	Equipment may be operated as fluid bed; entrained bed; packed bed; falling particle bed
Texas Tech University	Variable velocity fluidized bed	0.5	0.25	0.4	Manure, wood, corn stover, mesquite cotton-gin trash, wheat straw	LBG, IBG	Gasification with steam, air, or oxygen (future)
University of Arkansas	Rotary pyrolytic kiln	40	20	36	Wood waste	LBG, charcoal	Technology licensed by A&P Coop; charcoal is desired product
University of Missouri - Rolla	Fluid bed (top feed)	2.5-3† 24‡	1.2-1.5† 12‡	2.2-2.7† 21.6	Wood	LBG, IBG	A. Coors gasifier; gasification with steam, air, oxygen (future) catalytic gasification (future)
Wright-Malta	Pressurized indirectly heated rotary kiln	6	3	5.4	Wood, peat, cornstalks	IBG	Gasification with catalyst and steam

*Unit normally operates with 10% moisture feedstock

†With Sleeve

‡No sleeve

Source: Sixth Biomass Thermochemical Conversion Contractors' Meeting, Tucson, Arizona, January 16-17, 1979

LBG - Low-Btu gas
IBG - Intermediate Btu gas
ST/D - Short tons per day

oxygen, wood may be used as a feedstock for technologies, for example, originally developed to handle more difficult feedstocks such as sludges or tires. American Fyr Feeder has developed a fixed bed wood gasifier which is at the demonstration scale.[36] Halcyon Associates, Inc., of East Andover, New Hampshire, currently offers a fixed bed gasifier for the production of low-Btu gas from wood. Reed, et al. have discussed the status of small, air-blown biomass gasifiers.[104] The sizes of these units generally lie in the range of 10 to 20 million Btu per hour of low-Btu product gas (equivalent to feedrates of 15 to 35 dry short tons per day of wood assuming a wood heating value of 17 million Btu per dry short ton and a gasifier thermal efficiency of 80 percent). Rutherford and Ruschin[105] have described the application of air-blown Mond gasifiers (offered by Davy Powergas, Ltd.) to the commercial production of ammonia from wood logs (18-inch diameter by 18-inch length maximum size) in Travencore, India, in the 1940's. Six gasifiers (5 operating, one spare) were needed to gasify 300-400 tons per day of wood. Much of the technology used in this plant is obsolete by today's standards. Feedstocks used by Mond gasifiers in gas engine service have included cotton seed husks, sawdust, wood blocks and logs, bagasse, and olive processing refuse.

Table 27 shows the status of experimental units being developed for biomass gasification with DOE sponsorship.

Gasifier Selection

Candidate gasifier technologies available for wood or biomass gasification are broadly grouped into fixed (moving) bed, fluid bed, entrained, and molten bath types, with variations of staged gasification, catalytic gasification (e.g., with alkali metal catalysts), and numerous additional categories as previously presented on Table 26. Compared with the gasification of high-sulfur eastern bituminous coal, wood should exhibit greater reactivity (higher carbon conversion); produce a product gas with a larger proportion of CO_2 (because of the oxygen in the wood), produce very little H_2S, and probably produce an ash/char mixture of lower bulk density than that of the coal (because of the cellulosic starting material). These and numerous other factors affect gasifier design. Current research on advanced wood gasification technologies is at an early stage of development, and optimum gasifier design and configurations are being developed. The following qualitative discussions lead to the selection of a specific gasifier for this analysis.

Fixed Bed

Battelle Northwest[37] has reported that gasification of wood chips with air and steam in a 3-foot diameter pilot plant unit proceeded "without difficulty," in part because of the free-flowing character of the wood chips. American Fyr Feeder and Halcyon Associates offer fixed bed wood gasifiers commercially. Condensate liquids are obtained, similar to the pyroligneous acids formed during the destructive distillation of wood. The prediction of the yields and product properties of these liquid fractions is difficult without experimental data. The carbon content of these liquids represents a loss of carbon for the synthesis gas yield.

Entrained Bed

These technologies may gasify any carbon-containing substance to a 50/50 mixture (approximately) of CO and H_2. Typical feedstock specifications for coal are 70 percent through 200 mesh. These fine particle sizes (large surface area) are required to overcome reaction-rate limitations in the short residence time burner flame. Since wood should be more reactive than coal toward gasification, the above specification may not be as stringent for wood feedstocks as for coal feedstocks. However, the size of wood particles required for entrained gasification is not believed to be established. If in fact wood flour is needed, then, based on the literature[38] and conversations with industry, feedstock preparation would be very expensive and very energy consuming because of the fibrous nature of the starting material. Current concepts for feeding solids to pressurized entrained beds include wet (e.g., water or oil slurries) or dry (e.g., lockhopper) systems. For dry systems (e.g., as installed for the Westinghouse and Synthane coal-gasification pilot plants), the bulk density of the wood flour may present flow problems. If water slurries are used (e.g., similar to the Texaco concept) thermal considerations suggest the need for extensive predrying of the wood to avoid delivering excessive amounts of liquid water to the gasifier. If oil slurries are used, an oil recovery step should be included in the top of the gasifier vessel (e.g., similar to the HYGAS concept), at added expense, since entrained gasifiers produce no condensible by-products.

The amount of ash in dry wood generally lies in the 1 to 2 wt% range. This value is considerably less than the ash content of most coals. When considering entrained beds, the question arises as to whether low-ash-content solids are suited for slagging operations. Discussions with industry suggested that such a problem may not be serious for gasifier operation.

Molten Bath

Molten carbonate and molten iron media have been studied as catalysts for coal gasification. Rapid gasification rates and high degrees of carbon conversion characterize these systems. The bulk of the ash and sulfur in the feed remain in the molten bath. As a consequence, expensive and potentially problematical media-recovery steps (e.g., quench, filtration and regeneration steps similar to the Semet-Solvay technology) are required.

A one-ton of coal per hour pilot plant is under construction for the Atomics International molten sodium carbonate technology. Work on the molten iron technology has been discontinued. These technologies are at early stages of development.

Fluid Beds

Commercially available fluid bed coal gasifiers (Winkler)[39] operate in the so-called dry ash mode. The two-stage Westinghouse coal gasification technology is designed to operate in the ash-agglomerating mode, or sticky-ash mode, as characterized by Jequier.[40] IGT has recently demonstrated the ash-agglomerating concept in a small atmospheric pressure unit and has proposed a single stage U-Gas™ technology, operating at pressure, also using this concept. Using the ash agglomerating mode of operation, carbon conversions may be increased from 80 to 85 percent (dry ash, bituminous coal feed) to 95 percent or greater (sticky ash, bituminous coal feed).

Currently, ERCO has demonstrated fluidized bed pyrolysis of wood in a laboratory unit.[41] BC Research has described[42] the successful, pilot-scale conversion of waste sawdust to low-Btu gas and charcoal in an air-blown, fluidized bed gasifier. Alberta Industrial Developments, Ltd., commercially offers a BC Research-licensed unit for the production of charcoal from wood waste in a fluid bed converter.

At elevated temperatures (e.g., above 1900°F) in the fluid bed, all condensible organic products may be cracked to lower boiling hydrocarbons. However, care must be exercised during operation never to permit sticky ash to be carried over in the gas to foul downstream equipment (radiant boilers[39] may be used to reduce the bulk temperature of the product gas if required). Certain classes of feedstocks (e.g., caking coals) may be unsuited for fluid bed gasification. Also, certain classes of biomass feedstock (e.g., grass straw) having large amounts of sodium or potassium carbonate in the ash may not be suitable for fluid bed gasification because of low ash melting points.[37] The fibrous nature of cellulose-containing feedstocks may require feedstock shredding to certain minimum dimensions for fluidization purposes. The lighter bulk density of biomass-type feedstocks and chars compared with most coal feedstocks and chars suggests that biomass fluid beds will possibly operate with different oxidant/feed and steam/feed ratios compared with coal fluid beds. Steam decompositions in fluid beds tend to be lower than in entrained beds or slagging gasifiers because of the lower temperatures used.

Catalytic Gasification

Work is currently in progress at Battelle Columbus[43] and Wright-Malta[44] concerning catalytic wood pretreatment and catalytic gasification with alkali metal catalysts. (Catalytic coal gasification is currently being studied by Exxon.)[45] These laboratory-scale experiments for wood are at early stages of development. Sufficient information is not available concerning catalytic wood gasification (or the transfer of this information from catalytic coal gasification) to permit an evaluation.

Selection

Again it is emphasized that wood may be gasified by a wide variety of types of gasifiers. Additional research may suggest one or two preferred types of gasifiers. However, for this analysis, fluid bed gasifiers were selected, based on the considerations outlined above, principally because the assumptions required to characterize fluid bed gasification of wood are believed to be no worse (and in some cases, better than) than the assumptions required to characterize wood gasification in other types of technologies.

Since SNG, methanol, ammonia, and IBG products were desired, oxygen blown gasification was considered.

The gasifier product is generally needed at pressure. Wood gasifiers available (e.g., American Fyr Feeder, Halcyon) or under development (BC Research, Battelle Pacific Northwest Laboratories) are operated at or near atmospheric pressure (an exception would be the Wright-Malta technology). Consequently, it was decided to use a conceptual, pressurized fluidized bed wood gasifier in the analysis, using a lock hopper feed system, because of potentially favorable economics and energy usage when contrasted with atmospheric pressure gasification and syngas compression.

Process Description

Table 28 presents the stream flows shown on Figure 13, the process flow diagram. Mass and energy balances are summarized on Tables 29 and 30, respectively. Green wood chips are assumed to be received by rail car with a maximum chip size of 2 inches. Chip is stockpiled and reclaimed by front end loaders and is conveyed to the wood preparation section of the plant. In the preparation section, the chip is air dried and reduced in size to the range of 3/8 inches to 1/4 inches using conventional equipment (rotary driers and hammermills or shredders or hot wood hogs). The size range was selected based on conversations with Davy Powergas, Incorporated, concerning the maximum size of coal particles fed to fluid bed coal gasifiers. The wood drying was assumed to remove 40 to 50 percent of the moisture in the green wood chips. The actual amount of moisture to be removed would be best determined by optimization studies, but such were not attempted here. Instead it was assumed that:

- Complete wood drying would impose a severe thermal penalty on the process and was not necessary.

Table 28

PRODUCTION OF SNG BY ADVANCED FLUID BED GASIFICATION OF WOOD--STREAM FLOWS
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	(1)	(2)		(3)		(4)		(5)	(6)		(7)		(8)		(9)		(10)		(11)		(12)	
	10^3 lb/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr
C	44.88							0.44														
H	4.74																					
O	31.795																					
N	0.165																					
S	0.08																					
Ash	1.67							1.67														
H_2O	83.33	32.54	1,806			60.73	3,371								7.64	424	22.12	1,228				
H_2						5.22	2,588								5.22	2,588	0.05	27			0.05	25
CO						60.36	2,155								60.36	2,155	0.06	2			0.04	1.3
CO_2						63.24	1,437		15.80	359	15.80	359			47.44	1,078	89.87	2,042	88.06	2,001	1.80	41
H_2S						0.07	2.2		0.07	2.2												
COS						0.02	0.3															
N_2		251.89	8,991	.73	26	0.90	32						251.89	8,991	.90	32	0.90	32			0.90	32
O_2		76.48	2,390	41.28	1,290								76.48	2,390								
CH_4						1.80	112								1.80	112	20.87	1,301			20.89	1,302
Total	166.66	360.91	13,187	42.02	1,316	192.34	9,697	2.11	15.87	361	15.80	359	328.37	11,281	123.36	6,389	133.87	4,632	88.06	2,001	23.68	1,401

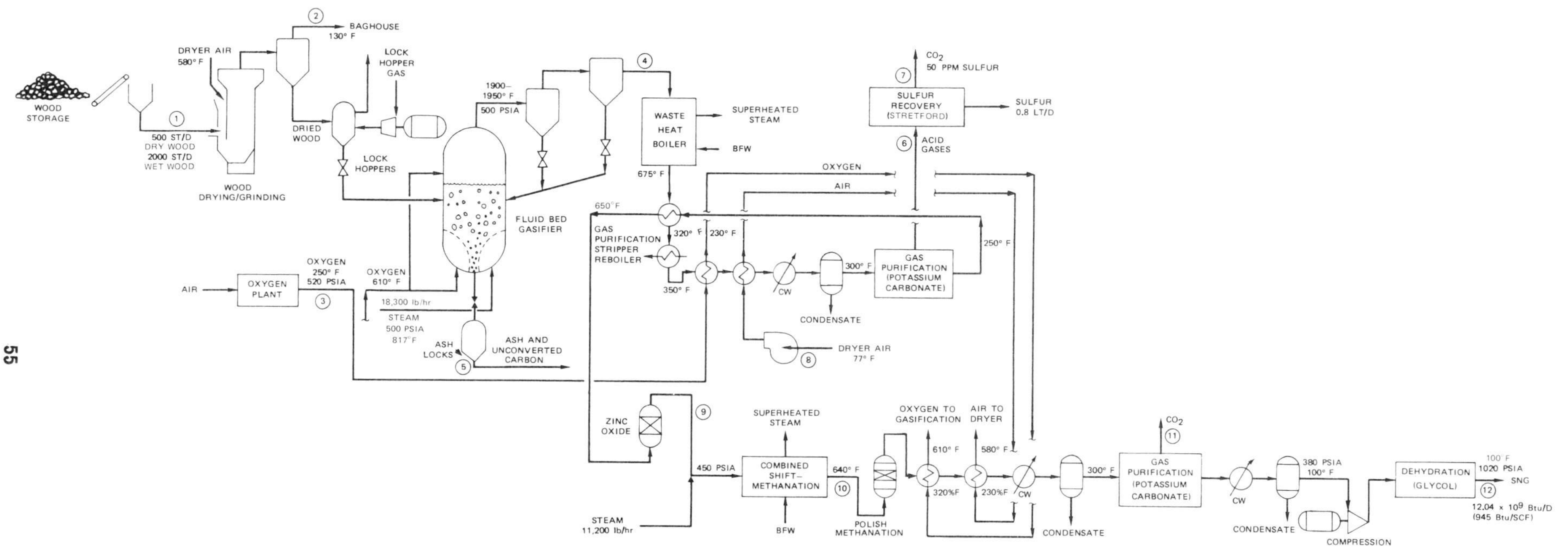

FIGURE 13. PRODUCTION OF SNG FROM WOOD BY ADVANCED FLUIDIZED BED GASIFICATION

Table 29

PRODUCTION OF SNG BY DIRECT GASIFICATION OF WOOD--
OVERALL MATERIAL BALANCE
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Thousands of Pounds per Hour
Input	
Wet wood	166.7
Water	586.0
Oxygen	42.0
Dryer air	328.3
Total	1,123.0
Output	
SNG	23.7
Ash and unburned carbon	2.1
CO_2 to stack	103.9
Dryer stack	360.9
Treated wastewater	252.6
Evaporation losses	379.7
Sulfur	0.1
Total	1,123.0

- Gasification would proceed with oxygen and steam and that the remaining wood moisture (after evaporation) would satisfy a portion of the gasifier steam requirements (the thermal penalty here is using oxygen to supply the latent heat of vaporization of the wood moisture).

The 3/8-inch x 0 chip flows by gravity to a Petrocarb-type lock-hopper system[46] for feeding to a gasifier operating at 500 psia. Petrocarb systems have successfully fed coal to the 600-psia Synthane gasifiers, according to a recent report by CE Lummus.[47] Its operation at 500 to 600 psi on material of lower bulk density and different physical properties than coal may require development.

Gasifier oxygen is furnished by a single train cryogenic oxygen plant providing about 500 short tons per day of 98 percent oxygen at 520 psia and 250°F. The temperature limitation is imposed because of compressor metallurgy considerations. As shown in Figure 13, the oxygen is preheated to 610°F before being fed to the gasifier.

Gasifier superheated steam is provided from back-pressure turbines.

Table 30

PRODUCTION OF SNG BY DIRECT GASIFICATION OF WOOD--
OVERALL ENERGY BALANCE
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Millions of Btu per Hour	Percent
Input		
Wet wood	796.7	100.0%
Total	796.7	100.0%
Output		
SNG	501.6	63.0
Heat rejected to cooling	250.6	31.4
Stack	35.1	4.4
Ash and unconverted carbon	7.1	0.9
Insulation and miscellaneous losses*	2.3	0.3
Total	796.7	100.0%

*Because of mechanical inefficiencies.

Gasifier oxidant/carbon and steam/carbon ratios were selected based on considerations of stoichiometry, steam decomposition, fluidizing velocities,[48] and corresponding values from coal gasification studies (e.g., C. F. Braun's[49] and prior SRI work). The ratios selected will vary with feedstock type. Because of the high reactivity of the wood, 99 percent carbon conversion was assumed.

Two gasifiers, each about 12 foot 8 inches ID and 51 foot tangent-to-tangent, are used. This diameter was selected to permit shop fabrication. Six inches of abrasion-resistant refractory lining are used to permit cold wall construction. The residence time of the wood chip in the bed is about 30 minutes, about half that generally used for coal,[48] because of the assumed high reactivity of wood.

Based on conversations with Davy Powergas, Incorporated, concerning fluid bed coal gasification, the rates of H_2S to COS in the gasifier effluent may be anticipated to be 6/1 to 8/1 (mol/mol). This ratio is considerably lower than corresponding ratios of 15/1 to 20/1 observed for fixed bed and entrained coal gasification technologies. For the work, a H_2S/COS ratio of about 7/1 was adopted.

About 70 percent of the gasifier char and unreacted carbon is assumed to leave with the product gas at 1900 to 1950°F. Radiant boiler tubes recessed in the top walls of the gasifier may be used[50] to reduce the bulk temperature of the gas below the initial ash deformation temperature to protect downstream equipment. Two external stages of hot cyclones are assumed to reduce the gas particulate loadings to 0.025gr per ACF or less. Alternative designs using Incoloy internal cyclones may be utilized, as described by Fluor. Since Occidental[50] reports that cyclones designed for coal char particles work poorly on wood char particles (because of bulk density and size differences), some development work may be indicated. Collected particulates are returned to the fluid bed.

The bottom of the gasifier is assumed to operate in the agglomerating-ash mode to reduce carbon loss. Jequier[40] has described the fundamentals of the concept. In this mode, the ash becomes sticky when heated above its deformation temperature, and adjacent small ash particles adhere, forming larger particles low in carbon content (recent data from Ignifluid boiler operation[51] show a carbon content of 1.8 to 5.1 percent in the discharged ash). The ash-agglomerating concept has been proposed for IGT's U-Gas™[48,52,53] coal gasification concept and the gasifier reactor in the Westinghouse coal gasification pilot plant[48,54] uses this concept. Development work may be needed for the application of this concept to biomass and wood feed materials.

Ash and unconverted carbon are discharged from the base of the gasifier to lockhoppers, quenched, and sent to disposal ponds.

Product gases are next cooled in waste heat boilers to about 675°F, generating high pressure superheated steam for turbine generators. The gases are further cooled by various exchangers to 300°F and sent to a hot potassium carbonate acid gas removal system. Equipment details for this system have been presented by R.M. Parsons[55] and are not repeated here.

In the hot carbonate unit, about 25 percent CO_2 removal is assumed to permit maximum carbon availability for the subsequent shift/methanation step. Half the COS is assumed to be hydrolyzed by the carbonate solution to H_2S

$$COS + H_2O = CO_2 + H_2S$$

and H_2S is assumed to be removed down to a level at which the partial pressures of H_2S and COS are equal at the exit of the acid gas removal system.

The acid gases from the carbonate system contain less than 1 mol% H_2S. Consequently, conventional Claus sulfur recovery systems cannot be used. Alternatives for the disposition of the H_2S (which cannot be vented) are Stretford sulfur recovery, incineration with the addition of sufficient syngas to ensure a combustible mixture, or directing the acid gas stream to on-site furnaces for combustion. The selection among these alternatives could be determined by optimization studies, but such were not attempted here. Instead, to allow for maximum siting flexibility and to comply with future air quality regulations, application of the Stretford sulfur recovery system was elected.

The Stretford technology is a wet oxidative extraction process in which H_2S reacts with sodium carbonate to form sodium hydrosulfide.[56] The hydrosulfide is oxidized to sulfur by dissolved sodium vanadate. The vanadium is catalytically oxidized back to its original oxidation state by air. A by-product sodium thiosulfate stream (containing vanadium) is sent to the plant wastewater treating facilities.

Sulfur is removed to very low levels (10 to 50 PPMV) in the treated tail gas. Stretford units find applications in natural gas treating and in the Beavon* tail gas treating system.[57] Equipment details of the Stretford technology have been presented by Bechtel[58] and are not repeated here.

Gases from the acid gas removal system are warmed to 650°F and sent to zinc oxide beds for final removal of sulfur compounds. This purification is necessary to protect the sulfur-sensitive shift/methanation catalyst.

Previous work at SRI has suggested that the use of developmental combined shift/methanation catalysts may affect economics of steam utilization compared with separate shift and methanation steps. A minimum steam requirement is found based on operating outside of the carbon forming regions. Combined shift/methanation technologies are under development by Texaco, Parsons, and others.

The relevant reactions are:

$$\text{Shift conversion:}\quad H_2O + CO \rightleftharpoons H_2 + CO_2$$

$$\text{Methanation:}\quad 3H_2 + CO \rightleftharpoons CH_4 + H_2O$$

In the conceptual design, shift and methanation reactions are assumed to proceed in a packed-tube reactor until limited by the adiabatic temperature rise. The gas mixture is cooled by steam generation and reacts further until limited by equilibrium considerations. Heat transfer surfaces are arranged to cool the gas as methanation proceeds.

The methane-rich gas leaving the combined shift/methanation reactor is sent to polish methanation to reduce the CO level to pipeline gas specifications.[49] CO_2 is removed in bulk by a second hot potassium carbonate system, and the SNG is dried and compressed to 1020 psia.

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*Developed and licensed by the Ralph M. Parsons Company and Union Oil Company.

From 2,000 wet short tons per day of wood, the calculations suggest that about 12 billion Btu per day of SNG can be produced. The higher heating value of the SNG is about 945 Btu per scf. The plant thermal efficiency (SNG out/wood in) is 63 percent. Based on the results of these preliminary calculations, the plant appears to be self-sufficient in terms of steam and electric power generation capability, using the high pressure steam generated from the waste heat boiler and the combined shift/methanation reactor to generate electricity and back pressure or extraction steam in steam turbine-generator sets.

Plant reliability is provided by redundancy in pump and compressor specifications and by two gasifier trains. Aspects of gasifier performance are discussed by Fluor.[53] The plant is designed to meet safe operating standards.

Economics

Table 31 shows the estimated capital investment for the production of SNG from wood. Wood storage, handling, and preparation facilities include wood drying and grinding facilities, dust collection, and the dryer air blower. Gasification facilities are the lockhopper system, (including compressors), gasifiers, external cyclones, ash locks, and waste heat boilers. Costs for the oxygen plant were obtained from Linde. Separately costing the shift and methanation steps produced the costs for the combined shift/methanation section. The utility facilities include two steam turbogenerator sets and a start-up wood-fired boiler, in addition to the items discussed in the Appendix, Economic and Design bases.

The estimated plant facilities investment is $80.3 million and the total capital investment, $92.7 million.

Figure 14 shows the effect of plant size on plant facilities investment. The 6 billion Btu per day SNG plant (500 dry short tons of wood per day) consists of a single gasifier, while the 36 billion Btu per day SNG plant consists of four gasifiers (14 feet OD) and two large steam turbogenerator sets. Single train acid gas removal systems and oxygen plants are used in each design. The plant facilities investment, expressed in a normalized fashion (e.g., dollars per billion Btu of SNG per day), decreases as plant size increases, reflecting economies of scale.

Table 32 shows the estimated major operating requirements. Operating labor requirements are estimated at 14-1/2 men per shift. The plant requires about 15.7 MW of electricity for operation, which is furnished from steam turbogenerator sets. The purchased water requirements reflect the steam requirements for gasification, combined shift/methanation, and boiler and cooling tower makeup (the cooling tower is assumed to require 5 percent makeup--2 percent blowdown, 3 percent evaporation losses).

Table 31

PRODUCTION OF SNG BY DIRECT GASIFICATION OF WOOD
AND COMBINED SHIFT/METHANATION--
ESTIMATED TOTAL CAPITAL INVESTMENT
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Millions of Dollars
Plant section investment	
Wood storage handling, and preparation	$ 5.6
Wood gasification	17.0
Oxygen plant	11.4
Acid gas removal	1.1
Combined shift/methanation	7.1
CO_2 removal	4.9
Compression and drying	0.7
Sulfur recovery	1.7
Utility facilities	20.3
General service facilities	10.5
Total plant facilities investment	$80.3
Land cost	0.3
Organization and start-up expenses	4.0
Interest during construction	6.1
Working capital	2.0
Total capital investment	$92.7
Depreciable investment	90.4
Debt capital	60.3
Equity capital	32.4

Table 33 presents the estimated annual operating costs and revenue requirements for the production of SNG by a regulated producer. The total revenue requirements are estimated to be $7.44 per million Btu of SNG. Sulfur recovery appears not to be justified from the viewpoint only of by-product revenues (because of the low feed sulfur content); however, it has been included, as previously mentioned, for reasons of air quality. Wood costs represent 29 percent of annual operating costs and labor-related costs, 21 percent.

Figure 15 shows the effect of plant size on revenue requirements for three feedstock costs. As plant sizes increase, revenue requirements are seen to decrease by 17 to 28 percent, reflecting economies of scale.

Table 32

PRODUCTION OF SNG BY DIRECT GASIFICATION OF WOOD--
ESTIMATED MAJOR OPERATING REQUIREMENTS
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

Operating labor (men per shift)	14.5
Electric power (kWh/hr)	
Plant needs	15,700
Purchased (if any)	0
Cooling tower circulation--ΔT = 20°F (gpm)	25,200
Purchased water (gpm)	1,200
Major compressors	
Service	Operating BHP
SNG compression	780
Oxygen plant - oxygen compressor	2900
Oxygen plant - air compressor	7150

Figure 16 shows the effect of wood cost, annual capacity or operating factor, and plant facilities investment on the revenue requirements from the sale of SNG. Revenue requirements change by about 16 cents per million Btu for every 10 cents per million Btu change in wood cost. As the annual capacity factor decreases from 90 to 70 percent, revenue requirements increase by 20 percent. Revenue requirements change by 50 cents per million Btu for every 10 percent change in plant facilities investment.

Costs for the production of SNG from wood appear to be higher by a factor of about two compared with costs[47,49] of producing SNG from coal. A contributing reason may be the great differences in plant sizes (6 to 36 billion Btu of SNG per day from wood; 250 billion Btu of SNG per day from coal). The SNG costs reported here are generally in line with those reported by Battelle[59] for the production of 13 billion Btu per day of SNG from sugar crop residues--\$5.41 to \$6.48/million Btu, (1976 dollars), depending on debt structure.

MITRE[41] considered the production of a high-Btu gas (800 Btu per scf) from wood using a Purox-type gasifier and methanation. In the analysis, the Purox technology did not appear to have been integrated into a complete process plant design with the methanation step. As a result of this and of the product heating value (800 Btu per scf), the gas selling prices appear to be low (at a wood cost of \$1.00 per million Btu, the estimated gas selling price is \$4.55 per million Btu for a gas production rate of 9.5 billion Btu per day).

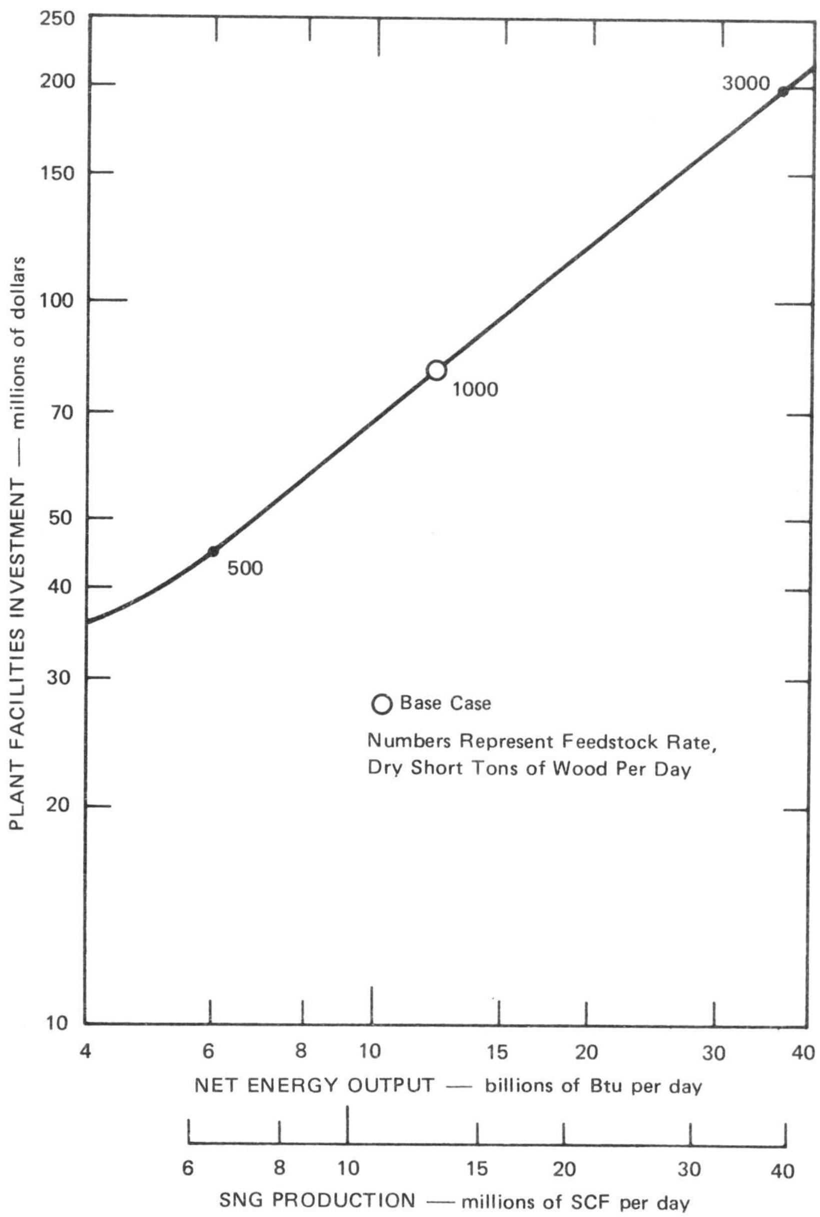

FIGURE 14 PRODUCTION OF SNG FROM WOOD BY DIRECT GASIFICATION AND COMBINED SHIFT/METHANATION — EFFECT OF PLANT SIZE ON PLANT FACILITIES INVESTMENT

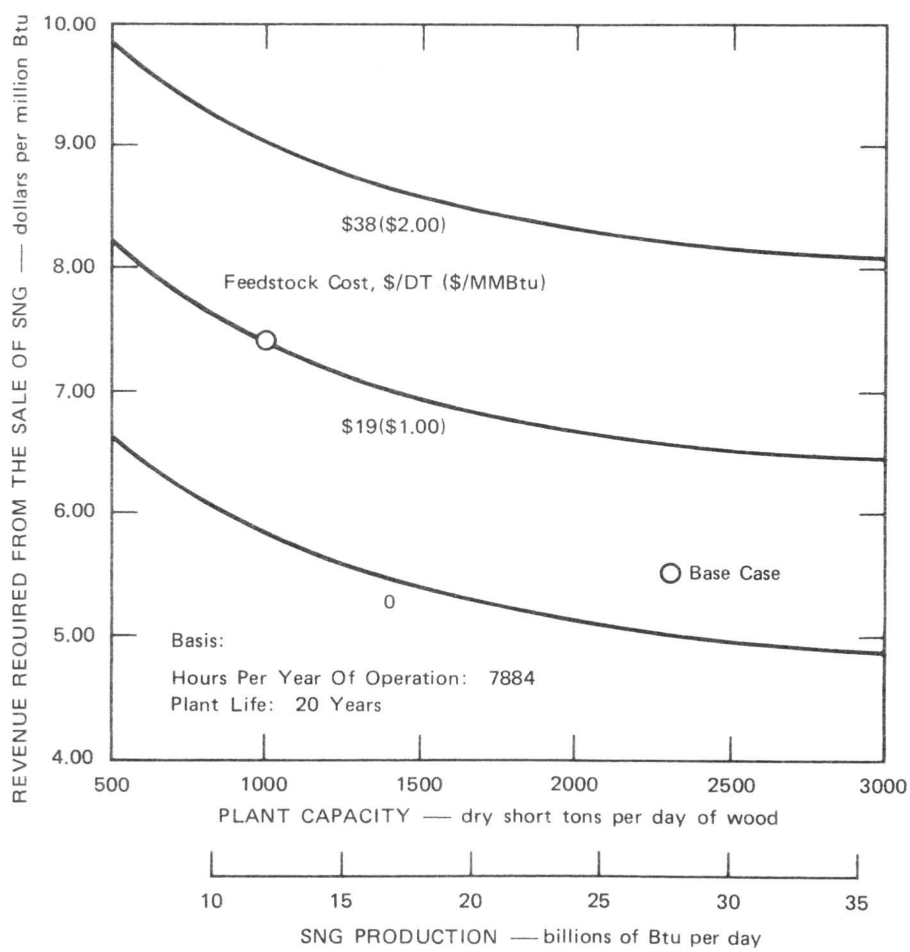

FIGURE 15 PRODUCTION OF SNG FROM WOOD BY DIRECT GASIFICAITON AND COMBINED SHIFT/METHANATION — EFFECT OF PLANT SIZE ON REVENUE REQUIRED FROM THE SALE OF SNG BY A REGULATED PRODUCER

Table 33

PRODUCTION OF SNG BY DIRECT GASIFICATION
OF WOOD AND COMBINED SHIFT/METHANATION--
ESTIMATED ANNUAL OPERATING COSTS AND REVENUE REQUIRED
FOR A REGULATED PRODUCER
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Millions of Dollars per Year	Dollars per Million Btu of SNG
Materials and supplies		
Wood at $9.56/short ton (wet)	$ 6.28	$ 1.59
Catalysts and chemicals	0.64	0.16
Maintenance materials	1.61	0.41
Total materials and supplies	$ 8.53	$ 2.16
Labor		
Operating labor	1.02	0.26
Supervision	0.15	0.04
Maintenance labor	1.61	0.41
Administrative and support labor	0.55	0.14
Payroll burden	1.17	0.29
Total labor costs	$ 4.49	$ 1.14
Purchased utilities		
Water	0.33	0.08
Electric power	--	--
Total purchased utilities	$ 0.33	$ 0.08
Fixed costs		
G&A expenses	1.61	0.41
Property taxes and insurance	2.00	0.50
Plant depreciation, 20-year	4.52	1.14
Total fixed costs	$ 8.13	$ 2.05
Total annual operating costs	21.48	5.43
Return on rate base and income tax*	7.97	2.01
Total revenue required*	$29.45	$ 7.44
Sources of required revenue		
SNG at $7.44/million Btu	29.44	7.44
Sulfur at $30/LT	0.01	--
Total revenue*	$29.45	$ 7.44
Revenue required (nonregulated producer)†	(42.52)	(10.75)

*20-year average values.

†DCF return: See the Appendix, Economic Bases.

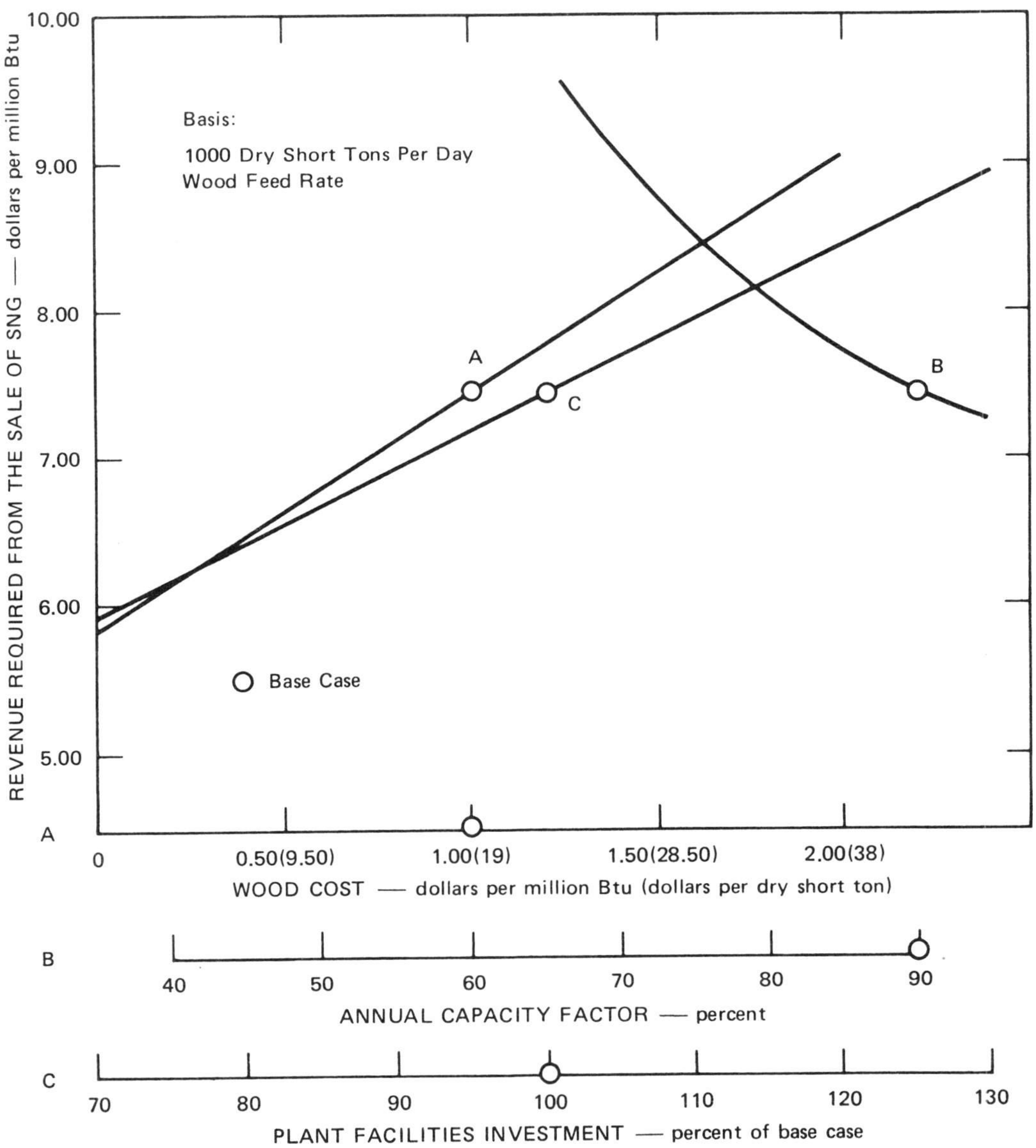

FIGURE 16 PRODUCTION OF SNG FROM WOOD BY DIRECT GASIFICATION AND COMBINED SHIFT/METHANATION — EFFECT OF VARIATION OF SELECTED PARAMETERS ON REVENUE REQUIRED FROM THE SALE OF SNG BY A REGULATED PRODUCER

Environmental Considerations

Table 34 shows the estimated emissions and environmental parameters. Sulfur and particulate emissions are controlled, and should be at low levels. Since no fuel is combusted on site, NO_x emissions are low. Solid wastes, aqueous wastes, and fresh water values are based on information previously presented.

Table 34

PRODUCTION OF SNG BY DIRECT GASIFICATION OF WOOD--
ESTIMATED EMISSIONS AND ENVIRONMENTAL PARAMETERS
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

Parameter	Units*	Value†
Sulfur (SO_x)	Lb SO_2/MMBtu	Tr
Nitrogen (NO_x)	Lb NO_x/MMBtu	Tr
Particulates	Lb/MMBtu	Tr
Solid waste	Lb/MMBtu	4.2
Aqueous waste	Gal/MMBtu	60
Fresh water	Gal/MMBtu	140
Land	Acre/billion Btu/day	4.2

*Million Btu of total energy output.

†Tr = trace.

IV PRODUCTION OF METHANOL FROM WOOD BY DIRECT GASIFICATION AND CHEM SYSTEMS SYNTHESIS

Methanol fuel produced from domestic carbonaceous sources may partially replace a portion of the nation's imported energy supplies (e.g., LPG, LNG, or petroleum). The chemical is clean burning and may be produced from biomass, coal, lignite, municipal waste, or any other liquid, solid, or gaseous carbon-containing material. Production of methanol from municipal wastes, agricultural residues, and other waste materials is being evaluated[60,61,62] as a means of solving two problems simultaneously: producing a valuable product and reducing disposal (land fill) costs while increasing the availability of landfill sites.

Several applications have been suggested for methanol:

- As an automotive fuel[63-66]
- As a fuel for industrial or utility[67,68] boilers or gas turbines[69] (particularly for utility peaking turbines)
- As a boiler igniter fuel
- For reconversion to SNG at another location
- For fuel cell fuel or for hydrogen generation
- For generating reducing gas for metallurgical furnaces
- For direct conversion to gasoline via the Mobil technology[70]
- As a biological feedstock for protein.[71]

The use of methanol as an automotive fuel is receiving increased attention by government and the automotive industry. The DOE and the Electric Power Research Institute are among the organizations sponsoring research on methanol manufacture and utilization.

Synthetic methanol production in the United States originates principally from natural gas feedstocks via steam-methane reforming and methanol synthesis. The synthesis technology has evolved from the high pressure technology of the 1920s-1960s to the low pressure (e.g., 50 to 100 atmospheres) technologies used today. Methanol synthesis catalysts also have evolved as the development of sulfur purification processes for the synthesis gas permitted more active, sulfur-intolerant catalysts to be used. Licensors for fixed bed methanol synthesis technologies include Imperial Chemical Industries, Japan Gas Chemical Co., Lurgi, Nissui-Topsoe, Vulcan Cincinnati, and J. F. Pritchard & Co.

Chem Systems, Inc. is developing a novel methanol synthesis technology under EPRI sponsorship.[72,73] The technology uses a three-phase fluidized bed reactor and a circulating inert hydrocarbon to remove the heat of reaction. The system may allow potentially greater waste heat recovery and higher per pass conversions of synthesis gas to methanol compared with the fixed-bed designs.

Since the Chem Systems technology may offer certain economic and thermal efficiency advantages compared with the conventional, fixed-bed technology, it was used in the conceptual design and economic evaluation for the production of methanol from wood. The information on which the analysis was based was taken from a recent EPRI report prepared by the R. M. Parsons Company.[74]

Process Description

This section describes the production of 572 short tons per day of Chem Systems type of methanol fuel from 2000 wet short tons per day of wood.

Figure 17 presents a schematic flow diagram. Table 35 lists the stream flows. Overall plant material and energy balances are presented on Tables 36 and 37, respectively.

Two thousand wet short tons per day of wood are gasified with oxygen and steam in a 500-psia fluid bed gasifier as previously discussed in the section on SNG production from wood. About 500 short tons per day of 98 percent oxygen are preheated to 610°F as shown in Figure 17, and fed to the gasifier.

Hot product gases are cooled to 725°F in a waste heat boiler, generating high pressure, superheated steam. About 70 percent of the water in the syngas is removed by cooling to 290 to 300°F, and the syngas is reheated by waste heat boiler effluent to 700°F before being sent to the high-temperature shift converter. This condensation step removes sufficient water to permit the shift reaction

$$H_2O + CO \rightleftharpoons H_2 + CO_2$$

to convert a portion of the carbon monoxide in the gas to hydrogen. No steam is added because of the moisture content of the feed gases.

The mol ratio of H_2/CO in the high-temperature shift effluent gases is about 1.8 to 1. This ratio is selected based on the desired 2/1 ratio of H_2 to CO for the Chem Systems synthesis step, plus an estimate of the losses of CO from the syngas in the cryogenic separation step.[74] With the composition of the gases from the wood gasifier used in this work, the H_2/CO ratio of 1.8 cannot be attained at the shift effluent unless some water is dropped out. An alternative to this condensation step would be to remove more wood moisture in the wood drying step, entailing perhaps more severe thermal penalties for the design.

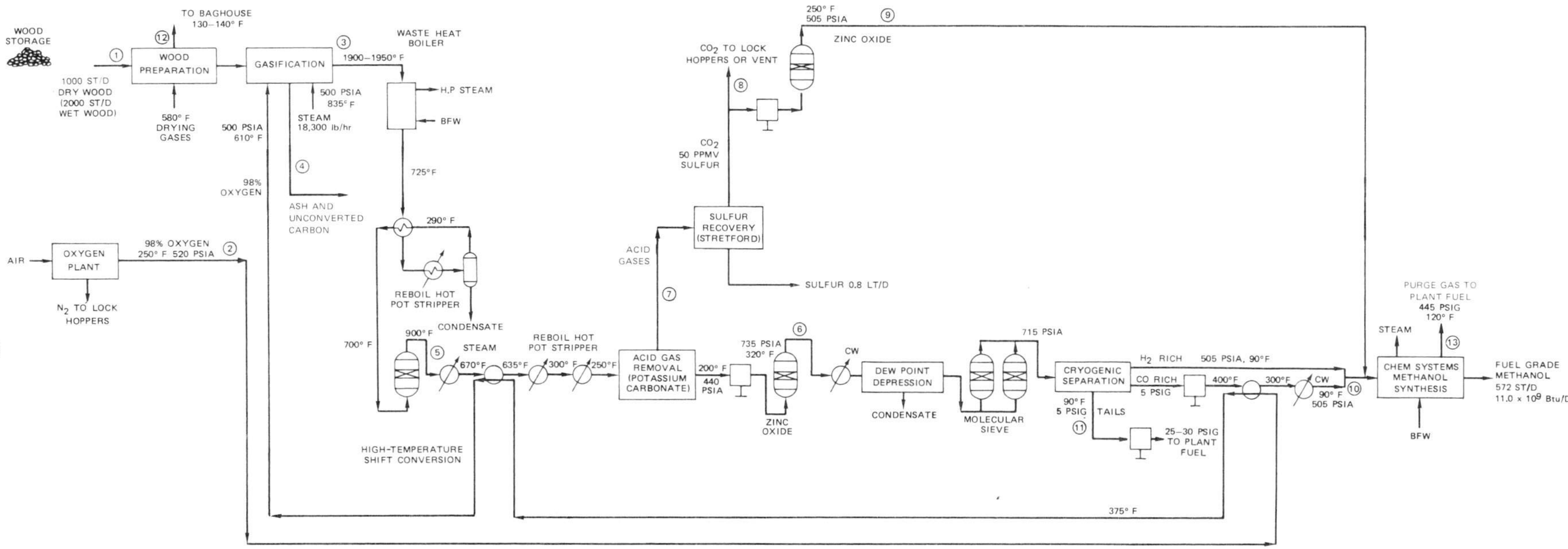

FIGURE 17 PRODUCTION OF METHANOL FROM WOOD BY DIRECT GASIFICATION OF WOOD AND CHEM SYSTEMS SYNTHESIS

Table 35

Table 35

PRODUCTION OF METHANOL FROM WOOD BY DIRECT GASIFICATION AND CHEM SYSTEMS SYNTHESIS--STREAM FLOWS
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	(1)	(2)		(3)		(4)	(5)		(6)	
	10^3 lb/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr
C	44.88					0.44				
H	4.74									
O	31.795									
N	0.165									
S	0.08									
Ash	1.67					1.67				
H_2O	83.33			60.73	3,371		7.44	413	2.31	128
H_2				5.22	2,588		6.16	3,054	6.16	3,054
CO				60.36	2,155		47.34	1,690	47.34	1,690
CO_2				63.24	1,437		83.71	1,902	0.04	1
H_2S				0.07	2.2		0.07	2.2		
COS				0.02	0.3		0.02	0.3		
N_2		0.73	26	0.90	32		0.90	32	0.90	32
O_2		41.28	1,290							
CH_4				1.80	112		1.80	112	1.80	112
Methanol										
	166.66	42.01	1,316	192.34	9,697	2.11	147.44	7,205	58.55	5,017

	(7)		(8)		(9)		(10)		(11)		(12)		(13)		Methanol Product
	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr
C															
H															
O															
N															
S															
Ash															
H_2O											38.41	2,132	0.01	0.8	
H_2							6.16	3,054					0.19	95	
CO							42.77	1,527	4.56	163			1.29	46	
CO_2	83.75	1,903	83.40	1,895	0.35	8					14.30	325	0.34	7.8	
H_2S	0.08	2.4													
COS															
N_2							0.64	23	0.25	9	255.51	9,120	0.64	23	
O_2											65.38	2,043			
CH_4							0.45	28	1.35	84			0.45	28	
Methanol													0.11	2.8	47.76
	83.83	1,905	83.40	1,895	0.35	8	50.02	4,632	6.16	256	373.60	13,620	3.03	203.4	47.76

Table 36

PRODUCTION OF METHANOL FROM WOOD BY DIRECT GASIFICATION AND CHEM SYSTEMS SYNTHESIS -- OVERALL MATERIAL BALANCE
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	Thousands of Pounds Per Hour
Input	
Wet wood	166.7
Water	775.5
Oxygen	42.0
Combustion and dryer air	331.3
Total	1,315.5
Output	
Methanol	47.8
Ash and unburned carbon	2.1
Dryer stack	373.6
CO_2 to stack	83.4
Treated wastewater	323.1
Evaporation losses	485.4
Sulfur	0.1
Total	1,315.5

Table 37

PRODUCTION OF METHANOL FROM WOOD BY DIRECT GASIFICATION AND CHEM SYSTEMS SYNTHESIS -- OVERALL ENERGY BALANCE
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	Millions of Btu Per Hour	Percent
Input		
Wet wood	796.7	99.1%
Electricity	7.5	0.9
Total	804.2	100.0%
Output		
Methanol	458.8	57.1
Heat rejected to cooling	281.2	35.0
Stack	44.4	5.5
Ash and unconverted carbon	7.1	0.9
Insulation losses	8.0	1.0
Miscellaneous losses*	4.7	0.5
Total	804.2	100.0%

*Because of mechanical inefficiencies.

The shifted gases are cooled to 250 to 300°F and sent to a hot potassium carbonate acid gas removal system. Carbon dioxide is removed to 0.02 vol%, and 95 percent H_2S removal and 70 percent COS removal (hydrolysis) is assumed. The acid gases containing less than 0.2 mol% H_2S are sent to a Stretford unit for sulfur recovery, as discussed in the section on SNG production from wood.

Purified syngas at 440 psia is compressed adiabatically to 735 psia and further desulfurized in a zinc oxide bed. The heat of compression is used to permit reasonable space velocities to be employed in the zinc oxide desulfurization step.

The sulfur-free (<1/4 grain per scf) syngas is sent to a dew point depression step (dehydration or absorption chilling) to remove the bulk of its moisture content. This step is necessary to permit reasonable sizes for the cold box feed preparation step (molecular sieves) to be used.

The molecular sieves remove the last traces of water and CO_2 in the gas before cryogenic separation. The cryogenic separation step, based on information received from Linde and on information contained in the R. M. Parsons report,[74] separates the syngas into three streams by using the pressure in the syngas to provide the necessary refrigeration. These streams are:

- A high pressure, hydrogen-rich stream containing about 95 percent hydrogen
- A low pressure, CO-rich stream containing about 93 percent CO and N_2
- A low pressure tails stream, containing most of the methane in the synthesis gas stream.

The CO-rich stream is compressed to 510 psia, cooled to 90°F, and combined with the hydrogen-rich stream. The H_2/CO mol ratio at this point is 2:1. This stream is combined with a small amount of CO_2 recycled from the Stretford tail gases to obtain the syngas composition specified in the R. M. Parsons report,[74] and sent to synthesis.

The cold box tails are compressed and sent to plant fuel needs.

The methanol synthesis reaction may be represented as:

$$2H_2 + CO = CH_3OH \quad .$$

In the Chem Systems synthesis[73,74] fresh synthesis gas is combined with recycle synthesis gas and passed upward through an expanded catalyst bed which is fluidized by an inert, nonmiscible hydrocarbon liquid. The hydrocarbon liquid serves as a heat carrier, absorbing the heat generated by the methanol synthesis and generating steam by being continuously circulated from the reactor top to the reactor bottom. This coolant allows close, uniform temperature control in the reactor, permitting higher per pass conversions of synthesis gas to methanol.

Reactor gaseous effluents are cooled to condense the methanol product and any entrained hydrocarbon liquid. The bulk of the noncondensible gas is recycled to the reactor, and a small purge stream is withdrawn to prevent the buildup of methane and nitrogen in the loop.

The purge stream, at pressure, is used as plant fuel. An alternative would be to use a power recovery turbine on the purge stream and to recover additional product methanol.

Table 38 shows the estimated composition of the Chem Systems methanol product. Distillation may be used to obtain a purified methanol product, if desired.

Table 38

PROPERTIES OF CHEM SYSTEMS METHANOL FUEL

	Weight Percent	Mol Percent
Methanol	95.4	94.48
Ethanol	1.0	
Isopropanol	1.0	1.16
Higher alcohols	0.1	
Water	2.5	4.36
Total	100.0	100.00

Higher heating value, Btu/lb 9,610
Btu/gal 63,930

Source: Reference 74

The information in the R. M. Parsons report[74] concerning the power requirements for and heat and energy balances of the Chem Systems synthesis were ratioed as appropriate for this analysis. The report suggests that the size of a single train synthesis loop is about 2,000 to 2,300 tons per day of methanol. Since the maximum production rate of methanol (for 6,000 wet tons per day of wood) is about 1,700 short tons per day, single train synthesis units are used for all cases analyzed. Tankage for ten days' storage of methanol is provided.

Fuel gas from the cryogenic tail stream and the methanol loop purge are burned to raise high pressure steam. The flue gases from the combustion are mixed with air to form a 700°F stream which is used for wood drying. Alternatively, the fuel gas may be sent to a steam-methane reformer for the production of additional synthesis gas, and another source of hot gases for the wood dryer would be required.

Plant power is partially provided by high pressure steam from the waste heat boiler, the fuel gas boiler, and the shift effluent steam generator. This steam is sent to an extraction-condensing turbine which provides 500 psia steam for the gasifier and low pressure steam for the Stretford unit. The plant requires about 2,200 kilowatts of purchased electricity, since in-plant generation is insufficient to satisfy the plant power requirements.

The thermal efficiency of the plant (methanol out/wood + electricity in) is about 57.1 percent, as shown in Table 38. The heat rejected to cooling amounts to about 35 percent, representing principally steam condensing, oxygen plant, and acid gas removal cooling requirements.

Plant reliability is provided by redundancy in pumps and compressor capacity and by two gasifiers. Although in the early stages of development, the Chem Systems technology, using recycle streams, has many conventional counterparts that use high pressure recycle loops with intermediate heat exchange (e.g., petroleum hydrocracking, ammonia synthesis, petroleum reforming, conventional methanol synthesis). Such plants are designed to meet personnel safety standards (e.g., see Reference 75).

Economics

Table 39 shows the estimated capital investment for the production of methanol from wood. Regulated utility financing is assumed.

Wood storage, handling, and preparation facilities consist of wood receiving, handling, drying, grinding, conveying, and dust collection facilities. Wood gasification facilities include two 12-foot 8-inch ID gasifiers, lock hopper feed systems and compressors, external cyclones, ash lock hoppers, waste heat boilers, and the equipment for the condensing step. Shift conversion facilities include one shift converter and several heat exchangers. Cryogenic separation facilities are the molecular sieves and cryogenic unit (with costs as furnished by Linde), compression (CO_2, recycle, CO-rich stream, and tails), and required cooling. Costs for the methanol synthesis unit were obtained from the report by R.M. Parsons.[74] Costs for the Stretford unit were based on information in a Bechtel report.[58] Utility facilities include the fuel gas boiler, steam turbine and condenser, combustion air blower, a tank of oil for start-up, and methanol storage in addition to the items listed in the Appendix.

The total plant facilities investment is estimated to be $88.0 million and the total capital investment is $101.5 million.

Figure 18 shows the effect of plant size on plant facilities investment. The PFI, expressed as dollars per ton per day of methanol, decreases as plant size increases, reflecting economies of scale. Single train oxygen, acid gas removal, shift conversion, sulfur recovery, and methanol synthesis units are used throughout. The number of

Table 39

PRODUCTION OF METHANOL FROM WOOD BY DIRECT GASIFICATION AND CHEM SYSTEMS SYNTHESIS -- ESTIMATED TOTAL CAPITAL INVESTMENT
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	Millions of Dollars
Plant section investment	
Wood storage, handling, and preparation	$ 4.7
Wood gasification	16.7
Shift conversion	1.5
Acid gas removal	5.4
Oxygen plant	11.4
Cryogenic separation	4.1
Syngas compression	1.3
Methanol synthesis	7.7
Sulfur recovery	1.8
Utility facilities	21.9
General service facilities	11.5
Total plant facilities investment	$88.0
Land cost	0.3
Organization and start-up expenses	4.4
Interest during construction	6.7
Working capital	2.1
Total capital investment	$101.5
Depreciable investment	99.1
Debt capital	66.0
Equity capital	35.5

gasifiers increases from one (at 500 ODT per day wood feedrate) to four (at 3,000 ODT per day wood feedrate).

Table 40 presents the estimated major operating requirements. Operating labor is estimated to be 15.5 men per shift. The plant electricity requirements are estimated at 19.1 MW, slightly over 10 percent of which is purchased. Fresh water requirements reflect the gasifier

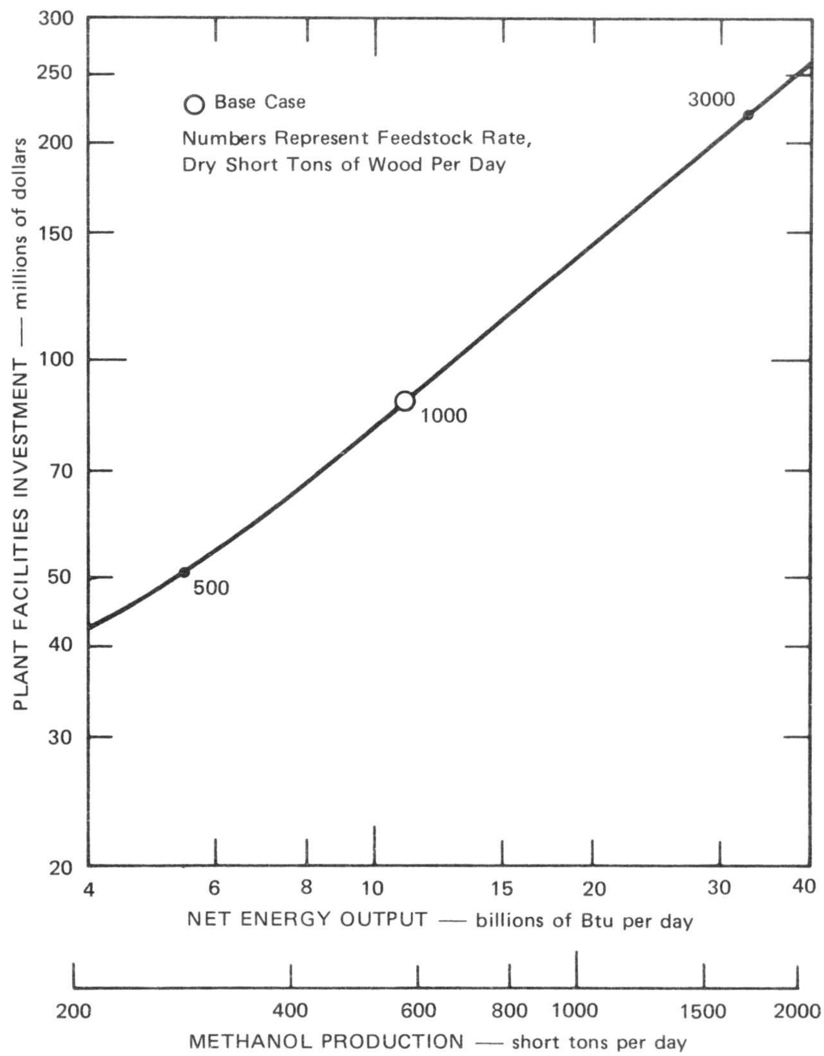

FIGURE 18 PRODUCTION OF METHANOL FROM WOOD BY DIRECT GASIFICATION AND CHEM SYSTEMS SYNTHESIS — EFFECT OF PLANT SIZE ON PLANT FACILITIES INVESTMENT

Table 40

PRODUCTION OF METHANOL FROM WOOD BY DIRECT GASIFICATION AND CHEM SYSTEMS SYNTHESIS -- ESTIMATED MAJOR OPERATING REQUIREMENTS
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

Operating labor (men per shift)	15.5
Electric power (kWh/hr)	
Plant needs	19,100
Purchased (if any)	2,200
Cooling tower circulation--$\Delta T = 20°F$ (gpm)	28,500
Purchased water (gpm)	1,540

Major compressors

Service	Operating BHP
Syngas compression	1,580
CO compression	2,580
Methanol recycle compressor	1,340
Oxygen plant - oxygen compressor	2,900
Oxygen plant - air compressor	7,150

steam needs as well as boiler and cooling tower makeup (the cooling tower is assumed to require 5 percent makeup--2 percent blowdown, 3 percent evaporation losses).

Table 41 presents the annual operating costs. Based on regulated utility financing, the revenue required from the sale of methanol is estimated to be $8.85 per million Btu. Wood costs represent 27 percent of the annual operating costs; labor-related costs, 21 percent; and fixed costs (including depreciation), 38 percent.

Figure 19 presents the effect of plant size on revenue requirements. As plant capacity increases from 500 ODT per day to 3,000 ODT per day of wood, revenue requirements fall by 18 to 26 percent, reflecting economies of scale.

Figure 20 presents the effect of varying feedstock cost, annual capacity or operating factor, and plant investment uncertainty on revenue requirements. For every 10 cents per million Btu change in wood cost, revenue requirements change by 16 cents per million Btu. As

Table 41

PRODUCTION OF METHANOL FROM WOOD BY DIRECT GASIFICATION AND CHEM SYSTEMS SYNTHESIS -- ESTIMATED ANNUAL OPERATING COSTS AND REVENUE REQUIRED FOR A REGULATED PRODUCER
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	Millions of Dollars Per Year	Dollars Per Million Btu of Methanol
Materials and supplies		
Wood at $9.56/short ton (wet)	$ 6.28	$1.73
Catalysts and chemicals	0.62	0.17
Maintenance materials	1.76	0.49
Total materials and supplies	$ 8.66	$2.39
Labor		
Operating labor	1.09	0.30
Supervision	0.16	0.04
Maintenance labor	1.76	0.49
Administrative and support labor	0.60	0.17
Payroll burden	1.26	0.35
Total labor costs	$ 4.87	$1.35
Purchased utilities		
Water	0.43	0.12
Electric power	0.43	0.12
Total purchased utilities	$ 0.86	$0.24
Fixed costs		
G&A expenses	1.76	0.49
Property taxes and insurance	2.20	0.60
Plant depreciation, 20-year	4.95	1.37
Total fixed costs	$ 8.91	$2.46
Total annual operating costs	23.30	6.44
Return on rate base and income tax*	8.73	2.41
Total revenue required*	$32.03	$8.85
Sources of required revenue		
Methanol at $8.85/million Btu	32.02	8.85
Sulfur at $30/LT	0.01	———
Total revenue*	$32.03	$8.85
Revenue required (nonregulated producer)†	(46.33)	(12.80)

*20-year average values.

†DCF return: See Appendix, Economic Bases.

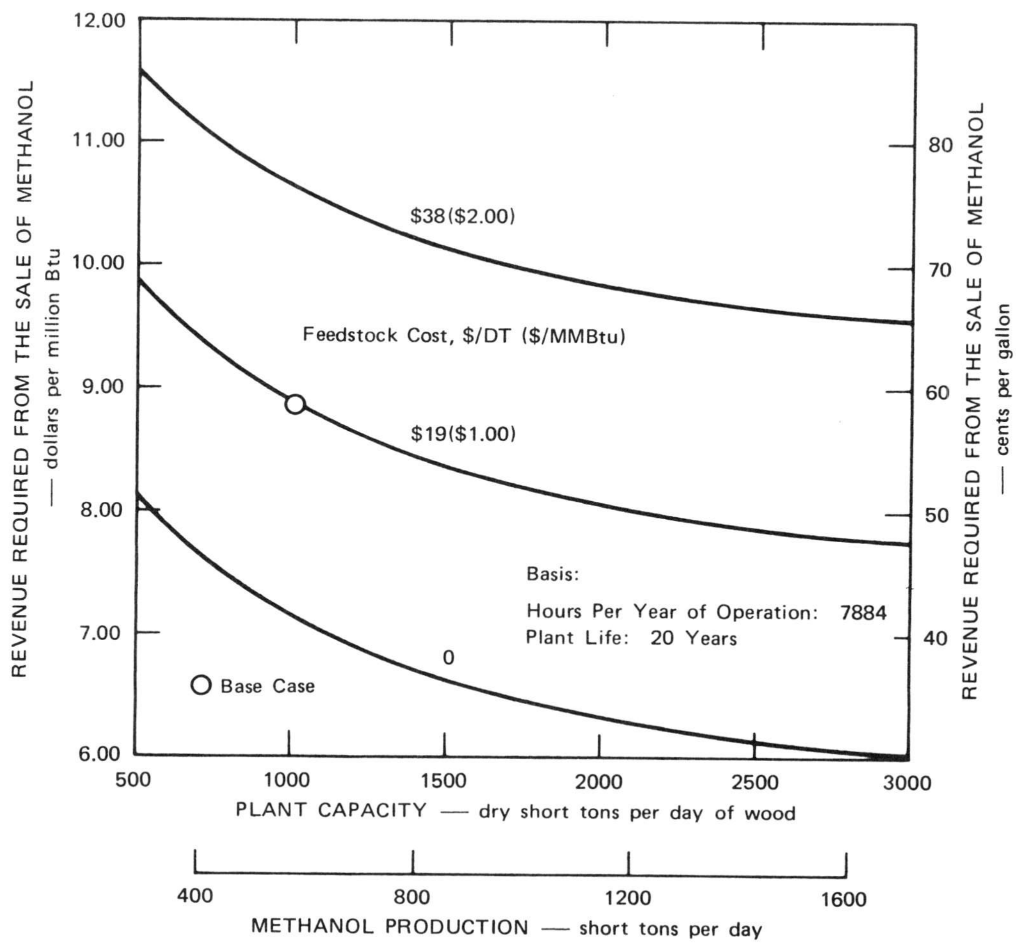

FIGURE 19 PRODUCTION OF METHANOL FROM WOOD BY DIRECT GASIFICATION AND CHEM SYSTEMS SYNTHESIS — EFFECT OF PLANT SIZE ON REVENUE REQUIRED FROM THE SALE OF METHANOL BY A REGULATED PRODUCER

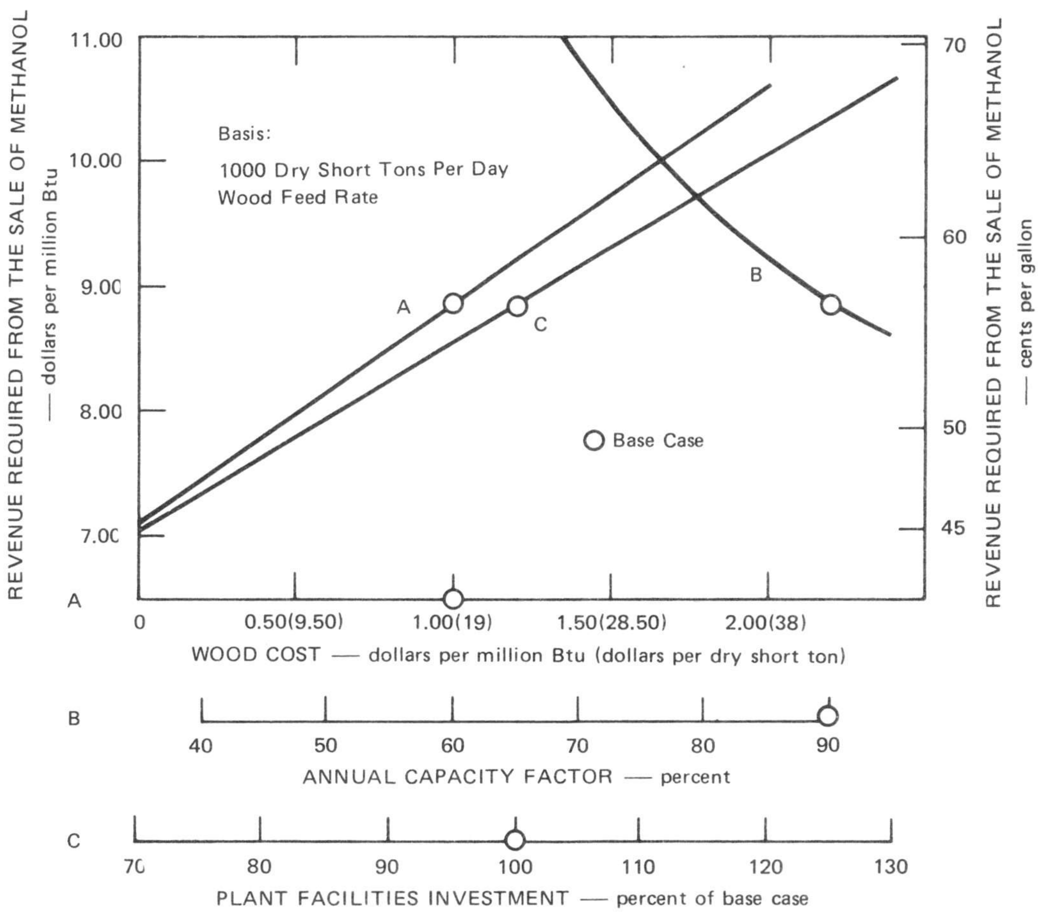

FIGURE 20 PRODUCTION OF METHANOL FROM WOOD BY DIRECT GASIFICATION AND CHEM SYSTEMS SYNTHESIS — EFFECT OF VARIATION OF SELECTED PARAMETERS ON THE REVENUE REQUIRED FROM THE SALE OF METHANOL BY A REGULATED PRODUCER

the annual capacity factor drops from 90 to 70 percent, revenue requirements increase by a factor of 1.2. For each 10 percent change in plant facilities investment, revenue requirements change by about 6.0 cents per million Btu.

The methanol costs presented here are generally higher than the levelized costs of \$5.18 to \$6.44 per million Btu reported by R. M. Parsons[74] for the production of methanol from coal. This may be explained in part by the lower production rates used here (300 to 1,700 short tons per day), contrasted with the larger (16,400 tons per day) rate used by Parsons as well as by the differences in feedstocks (e.g. carbon content). The costs presented here, however, are lower than the \$10 to \$12/million Btu values described by Lipinsky[59] for the production of 430 short tons per day of methanol from sugar crop residues.

Hokanson,[76] using 26 air-blown Moore-Canada gasifiers, reports an overall plant thermal efficiency of 38 percent for the conversion of 1,500 ODT per day of wood to methanol. The tabulation below suggests resulting methanol prices using a feedstock cost of \$19 per dry ton.

Methanol Production Rate		Methanol Price (1975\$)	
MMgal/yr	ST/D	¢/gal	\$/million Btu HHV
50	492	85¢	\$13.30
200	1970	50	7.82

These methanol prices are higher than those evaluated here and may be explained by the following differences between Hokanson's analysis and the current analysis. Hokanson used air-blown, atmospheric pressure gasification with a cryogenic separation step to remove the nitrogen in the syngas. This is believed to be energy-inefficient with respect to a design considering an oxygen-blown Moore-Canada gasifier or to the pressurized oxygen-blown gasification concept considered here. Additionally, Hokanson considered the methanol synthesis at 2500 psia. ICI,[77] Lurgi,[78] and others offer low pressure synthesis loops operating at 750 to 1,500 psia, and the present analysis considers a 500 psia advanced methanol synthesis.

MITRE[15] considered the production of methanol from wood using a Purox-type technology for wood gasification and a 1,500 psia synthesis loop. The Purox technology did not appear to have been integrated into a complete process plant design with the methanol synthesis step. As a result, the estimated selling prices of methanol are lower than those developed here.

Environmental Considerations

Table 42 shows the estimated emissions and environmental parameters. Sulfur and particulate emissions are controlled to low levels. A small amount of NO_x may be formed because of the combustion of the fuel gases. Solid waste, aqueous waste (ponded), and fresh water values are based on information previously presented.

Table 42

PRODUCTION OF METHANOL FROM WOOD BY DIRECT GASIFICATION AND CHEM SYSTEMS SYNTHESIS -- ESTIMATED EMISSIONS AND ENVIRONMENTAL PARAMETERS
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

Parameter	Units*	Value†
Sulfur (SO_x)	Lb SO_2/MMBtu	Tr
Nitrogen (NO_x)	Lb NO_x/MMBtu	0.04
Particulates	Lb/MMBtu	Tr
Solid waste	Lb/MMBtu	4.6
Aqueous waste	Gal/MMBtu	100
Fresh water	Gal/MMBtu	200
Land	Acre/billion Btu/day	4.5

*Millions of Btu of total energy output.

†Tr = trace.

V PRODUCTION OF OIL BY CATALYTIC LIQUEFACTION OF WOOD

Various investigators have shown alkaline metal catalysts (e.g., sodium carbonate or potassium carbonate) to be effective agents for the gasification and liquefaction of carbonaceous materials. Examples are:

- Catalytic coal gasification as described by Exxon[45]
- Catalytic wood gasification as described by Battelle[43] and Wright-Malta[44]
- Catalytic liquefaction of cellulosic materials (e.g., sawdust, sewage sludge) by the U.S. Bureau of Mines[79,80]
- Lignite hydrogenation by the COSTEAM process.[81]

Many cellulosic materials and wastes naturally contain adequate amounts of alkaline materials to react rapidly in the temperature range 700 to 750°F. However, to promote rapid reaction rates below about 600 to 650°F, the use of catalysts has generally been required.

In 1973, Dravo Corporation[82] performed a technical and economic feasibility study for the catalytic conversion of manure or waste wood to oil, based on earlier Bureau of Mines experimental results. The production of oil from manure was found to be infeasible. The study also included the conceptual design of a 3 ton-per-day pilot plant for waste wood liquefaction using three processing alternatives.

Rust Engineering Company provided the detailed engineering design for the pilot plant[83] in 1974. The pilot plant was subsequently constructed at the Metallurgical Research Center of the Bureau of Mines in Albany, Oregon. In 1975, Bechtel Corporation prepared a series of detailed recommendations[84] for the pilot plant under construction, including a consideration of alternative feedstocks (e.g., municipal solid wastes, agricultural wastes) in addition to wood wastes for processing at the facility. In late 1976, ERDA (now DOE) awarded a contract to Bechtel National, Inc., to monitor completion of construction and initially operate the facility. Based on a competitive procurement, DOE awarded a contract in 1978 to Wheelabrator Cleanfuel Corporation for the continued operation of the Albany facility.

Lindemuth[85] has recently discussed the activities entailed in the commissioning of the Albany facility, and has presented initial results and a preliminary economic assessment* of the process. Battelle Pacific Laboratories is currently providing analytical support to the Albany

*The economic assessment was based on the PERC process design.

facility. Catalytica Associates is providing expert advice on reaction catalysis under subcontract to Bechtel National, Inc.

A forthcoming report by Bechtel National, Inc. to DOE suggests that, based on the PERC flowsheet, the following economics may result:

Plant size (OD ton per day of wood)	500	2,500
Oil production rate (barrel per day)	800	4,000
Total construction cost* (millions of dollars)	\$41.2	\$127.0
Oil price at \$20/ODT wood cost (dollars per barrel)	\$57	\$44
At \$0/ODT wood cost	\$42	\$24

The analysis presented here used as a basis the information provided by Bechtel National, Inc. before the formal publication of its report. The analysis is also based on information provided by Catalytica Associates concerning reaction catalysis.

Process Description

Figure 21 is a schematic flow diagram for the production of 1,750 barrels per day of low-sulfur heavy fuel oil from 2,000 wet tons per day of wood. Table 43 presents the stream flows. Tables 44 and 45 present the overall mass and energy balances, respectively.

The idealized chemistry of wood liquefaction is somewhat different from that of coal liquefaction or petroleum hydroprocessing. In the latter two instances, hydrogen is added to the coal or to the oil, producing hydrogenated products. In wood liquefaction, the concept appears to center around oxygen removal.[80,82,86]

Based on the wood feedstock considered here, this reaction may be presented as:

$$\underbrace{C_6H_{7.56}O_{3.19}}_{\text{Wood}} + 1.69CO = \underbrace{C_6H_{7.56}O_{1.5}}_{\text{Oil}} + 1.69CO_2 \quad .$$

The liquefaction of wood is assumed to proceed in this analysis in a recycle system, using fresh wood, recycled oil, and unconverted wood, catalyst, and CO in a similar fashion as that evaluated by Bechtel.[86] Table 46 summarizes the design conditions. Differences between Bechtel's and SRI's design may be attributed principally to different wood feedstocks. The 580 to 600°F maximum temperature range in the liquefaction step in SRI's analysis was developed based on conversations with Catalytica Associates.

*Excluding land, owners' costs, and interest during construction.

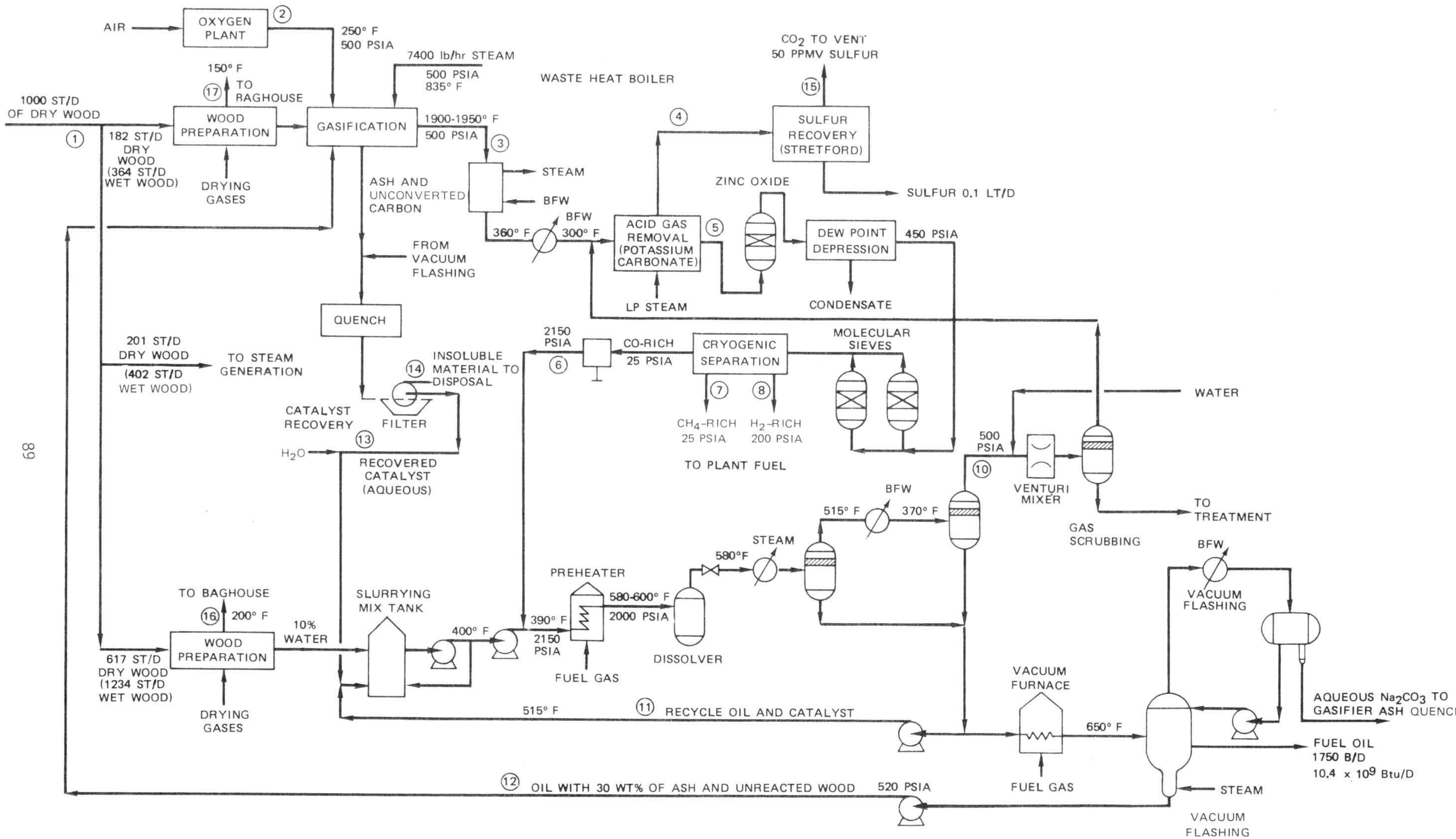

FIGURE 21 PRODUCTION OF OIL BY CATALYTIC LIQUEFACTION OF WOOD

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Table 43

PRODUCTION OF OIL BY CATALYTIC LIQUEFACTION OF WOOD--STREAM FLOWS
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	(1)	(2)		(3)		(4)		(5)		(6)		(7)		(8)		(9)		(10)		(11)	(12)	(13)	(14)	(15)		(16)		(17)		Fuel Oil Product
	10^3 lb/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr
C	44.88																						0.13							
H	4.74																													
O	31.795																													
N	0.165																													
S	0.08																													
Ash	1.67															4.32				3.29	0.97		1.27							
H_2O	83.33			14.97	831			2.02	112							7.60	422	7.60	422			1.88				74.89	4,157	7.76	431	
H_2				1.28	636			1.28	636					1.28	636															
CO				18.07	645			25.01	893	24.27	866.5	0.40	14.3	0.34	12	24.27	866.5	6.95	248											
CO_2				18.92	430	44.27	1,006	0.01	0.3									27.24	619					44.27	1,006	27.46	624	0.60	13.7	
H_2S				0.01	0.4	0.01	0.4	0	0.02																					
COS				0	0.06			0	0.02																					
N_2		0.30	10.6	0.32	11.5			0.95	34	0.84	30	0.03	1.1	0.10	3.4	0.84	30	0.84	30							162.69	5,807	24.71	882	
O_2		16.61	519																							20.13	629	4.58	143	
CH_4				0.54	34			0.83	52	0.29	18	0.54	34		Tr	0.29	18	0.29	18											
SO_2																										0.02	0.4			
Oil																133.16			Tr	133.16	7.78									31.07
Catalyst																3.54				2.74		0.80								
Moisture Ash Free Wood																59.52				8.08	2.37									
Total	166.66	16.91	530	54.11	2,588	44.28	1,006	30.10	1,727	25.40	914	0.97	49	1.72	651	233.54	--	42.92	1,337	147.27	11.12	2.68	1.40	44.27	1,006	285.19	11,217	37.65	1,470	31.07

Table 44

PRODUCTION OF OIL BY CATALYTIC LIQUEFACTION OF WOOD--
OVERALL MATERIAL BALANCE
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Thousands of Pounds per Hour
Input	
Wet wood	166.7
Oxygen	16.9
Combustion air	275.5
Water	259.8
Total	818.9
Output	
Oil	31.1
Dryer stacks	322.8
Boiler stack	39.0
CO_2 to stack	44.3
Gasifier ash and unconverted carbon	1.4
Boiler ash	0.3
Treated wastewater	157.8
Evaporation losses	222.2
Sulfur	negl
Total	818.9

Referring to Figure 21, wood for liquefaction (617 ODT/D) is dried to 10 percent moisture, ground, and slurried with recycle oil, unconverted wood, and catalyst. As in Bechtel's concept, fresh catalyst makeup is not believed to be required since alkaline values may be recovered from the gasifier ash stream.

The slurry is pumped to 2150 psia in paste or slurry pumps similar to those considered for solvent refined coal service. The high pressure mixture is combined with gases containing 95.5 mol% CO from the cryogenic separation unit and directed to the helical coil preheater. Plant fuel gases are burned in the preheater, raising the reaction mix temperature to 580 to 600°F. The mixture flows to a 6-foot 2-inch ID x 41-foot T/T stainless steel dissolver vessel for wood dissolution. The metallurgy used here may be similar to that installed in the SRC pilot plants at Ft. Lewis, Washington, or Wilsonville, Alabama.

Leaving the dissolver, the gases are cooled and flashed in stages to separate the unreacted gases and the CO_2 of reaction from the liquid phase (oil, wood, ash, and catalyst). All moisture entering the dissolver from the catalyst makeup stream and the feed wood is assumed to

Table 45

PRODUCTION OF OIL BY CATALYTIC LIQUEFACTION OF WOOD--
OVERALL ENERGY BALANCE
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Millions of Btu per Hour	Percent
Input		
Wet wood	796.7	100.0%
Total	796.7	100.0%
Output		
Oil	435.0	54.6
Heat rejected to cooling	145.0	18.2
Stacks	163.7	20.5
Ash and unconverted carbon	3.4	0.4
Insulation losses	36.3	4.6
Miscellaneous losses*	13.3	1.7
Total	796.7	100.0%

*Because of mechanical inefficiencies.

Table 46

PRODUCTION OF OIL BY CATALYTIC LIQUEFACTION OF WOOD--
LIQUEFACTION DESIGN CONDITIONS

	Bechtel	SRI
CO partial pressure at liquefaction inlet (psia)	2000	2000
Maximum temperature (°F)	650	580-600
Chemical CO consumption (lb CO/lb wood reacted)	0.5	0.36
Excess CO (% of theoretical)	40	40
Wood per pass conversion (%)	80	80
Oxygen in product oil (wt%)	23	23
Oil yield (lb/lb wood)	0.714	0.792
Wood conversion (%)	95.1	95.4

be present in the flashed gases. The details of this phase separation may require some development, since liquid-vapor equilibria are not well characterized at present.

The gases are cooled to 370 to 390°F, above the dewpoint, to condense any remaining liquid. The gases are next scrubbed in a high pressure venturi and sent to acid gas removal.

The acid gas removal system removes the CO_2 yield from the liquefaction reaction and the CO_2 from the gasifier product gases down to 0.02 vol%. The gasifier feeds partially dried wood and recycled oil, ash, and wood from the vacuum flashing step and operates in the same fashion as described in the section on the production of SNG from wood.

From acid gas removal, the gases are chilled, sent to a molecular sieve unit, and to cryogenic separation. Details of the cryogenic separation unit were provided by Linde. The cryogenic unit (97 percent CO recovery) was included to conserve compressor horsepower for the high pressure gases needed for liquefaction. If a minimum partial pressure of CO of 2000 psia is needed at the preheater inlet, the total pressure must be 4000 psia if the gases are 50 percent CO, and only 2150 psia if the gases are 97.5 percent CO. Based on preliminary comparisons of horsepower requirements of oxygen plants, gas compression, and cryogenic separation with the corresponding areas of the Bechtel design, the current concept may offer about 20 to 40 percent lower energy requirements.

The clean H_2-rich and CO-rich streams from cryogenic separation are combined and used as fuel for the preheater and vacuum furnaces. Hot flue gases from these furnaces are combined with hot flue gases from the wood boiler and used for wood drying.

The oil stream from the phase separation step is split into recycle and product streams. The product stream, containing unconverted wood and ash, is sent to vacuum flashing where it is assumed that the solids can be concentrated into a 30 wt% solution with oil which is recycled to the gasifier.

The solid-liquid separation step may prove to be problematical. Processing alternatives include pressurized filtration, dilution filtration, solvent deashing, and vacuum flashing. Vacuum flashing was adopted as the potentially least complex of these alternatives. The catalyst in the oil stream fed to the vacuum flashing unit is assumed to preferentially condense with the injected steam in the overhead receiver. An alternative would include a prewashing step for catalyst removal and recovery.

The product oil is assumed to have the elemental composition of C, H, and O previously stated, with small amounts of nitrogen, sulfur, and ash. It is assumed to have a heating value of 14,000 Btu per pound and a density of 425 pounds per barrel. The product oil may be unstable (e.g., polymerize), and additional development work is suggested.

Table 45 suggests that the thermal efficiency (oil out/wood in) may be about 54.6 percent. Wood is burned to meet plant energy needs, causing the high stack energy loss.

The process is at an early stage of development. Process safety has not been demonstrated, but analogies may be drawn to the safe operation of other, commercial high-pressure technologies (e.g., petroleum hydroprocessing, ammonia, and ethylene synthesis).

Economics

Table 47 shows the estimated capital investment for the production of 1,750 barrels per day of heavy low-sulfur fuel oil from 2,000 wet tons per day of wood. Wood storage, handling, and preparation facilities consist of wood receiving, handling, drying (both for gasification and liquefaction), and dust collection. Wood gasification facilities include a single gasifier, lock hoppers and compressors, external cyclones, a waste heat boiler, heat exchangers, and lock hoppers, and the high pressure oil/wood slurry pumps (costs for these were adapted from information previously received from Wilson-Snyder for coal/oil slurry pumps). Costs for the cryogenic separation plant (including molecular sieves) were based on information received from Linde. Wood slurrying and dissolving facilities include fuel bins, high pressure slurry pumps, the furnace, dissolver vessel, flash vessels, heat exchangers, and the venturi scrubber. Costs for the slurry pumps were based on the same Wilson-Snyder source. Those for the helical coil furnance were based on information previously received from American Schack. Costs for the high pressure dissolver vessel were based on information previously received from Chicago Bridge and Iron Company, Inc. Catalyst recovery costs were prorated from information in the Bechtel report. Costs for the vacuum flashing, including the furnace, overhead receiver, and related equipment, were based on information received from industry. Utility facilities consist of a one-day's capacity oil storage tank, boilers, steam turbogenerators, and combustion air blower, in addition to items discussed in the Appendix.

The plant facilities investment is estimated to be \$48.5 million and the total capital investment, \$56.7 million. The PFI may also be represented as \$27,700 per barrel of daily capacity. This value is above the ranges of \$15,000 to \$20,000 per daily barrel of capacity for synthetic oil from coal plants sized to produce 25,000 to 50,000 barrels per day of oil. A contributing reason for this may be the difference in the scales of the two operations.

Figure 22 presents the effect of plant size on plant facilities investment. The normalized investment decreases from about \$33,200 per daily barrel at 500 OD ton per day wood feedrate to \$22,400 per daily barrel at 3,000 OD ton per day wood feedrate, reflecting economies of scale in the oxygen plant, gasification plant, pressure vessels, and like equipment items. These values are lower than the \$31,800 to \$51,000 per

Table 47

PRODUCTION OF OIL BY CATALYTIC LIQUEFACTION OF WOOD--
ESTIMATED TOTAL CAPITAL INVESTMENT
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Millions of Dollars
Plant section investment	
Wood storage, handling, and preparation	\$ 4.9
Wood gasification	4.2
Oxygen plant	5.3
CO_2 removal	3.3
Cryogenic separation	2.0
CO-compression	2.8
Wood slurrying and dissolving	3.6
Catalyst recovery	0.7
Vacuum flashing	1.0
Sulfur recovery	1.5
Utility facilities	13.0
General services facilities	6.2
Total plant facilities investment	\$48.5
Land cost	0.3
Organization and start-up expenses	2.4
Interest during construction	3.7
Working capital	1.8
Total capital investment	\$56.7
Depreciable investment	54.7
Debt capital	36.9
Equity capital	19.8

daily barrel figures developed by Bechtel because of differences in design concepts and in specifications for spare equipment trains.

Table 48 presents the major operating requirements. Plant electric power needs are low because compressor drives may be driven by steam turbines. No purchased power is needed because wood and fuel gas are burned on site to satisfy plant energy needs. Purchased water requirements reflect the requirements for gasifier steam, vacuum column steam, and boiler and cooling tower makeup requirements (the cooling tower was assumed to require 5 percent makeup--2 percent blowdown and 3 percent evaporation losses).

Table 49 presents the estimated annual operating costs. The revenue required from the sale of oil is estimated to be \$37.79 per barrel, or \$6.35 per million Btu for a regulated producer. Wood costs

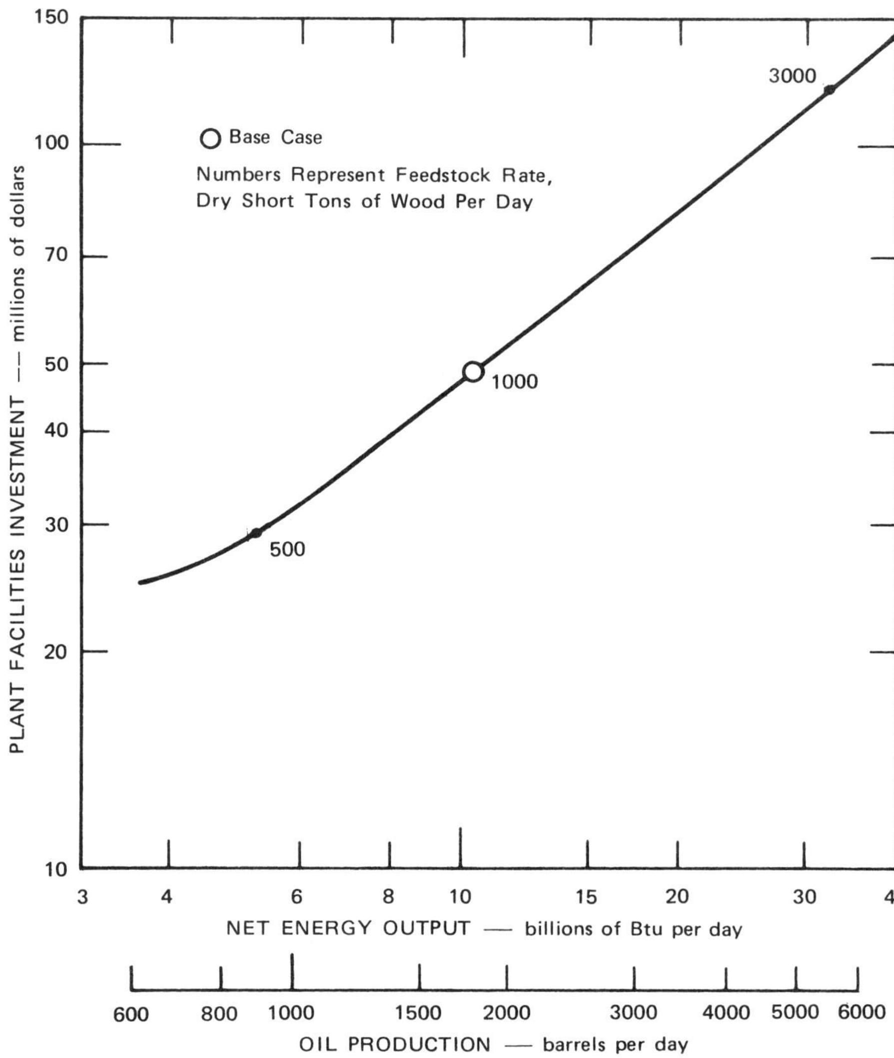


FIGURE 22 PRODUCTION OF OIL BY CATALYTIC LIQUEFACTION OF WOOD — EFFECT OF PLANT SIZE ON PLANT FACILITIES INVESTMENT

Table 48

PRODUCTION OF OIL BY CATALYTIC LIQUEFACTION OF WOOD--
ESTIMATED MAJOR OPERATING REQUIREMENTS
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

Operating labor (men per shift)	13.5
Electric power (kWh/hr)	
Plant needs	3,600
Purchased (if any)	0
Cooling tower circulation--ΔT = 20°F (gpm)	14,500
Purchased water (gpm)	730
Major compressors	

Service	Operating BHP
CO compression	2,630
Cryogenic recycle compressor	480
Oxygen plant--oxygen compressor	1,150
Oxygen plant--air compressor	2,870

represent 37 percent of annual operating costs and labor-related costs, 24 percent. Maintenance labor costs were assumed to be 3 percent of the plant facilities investment because of the complexity of the plant.

Figure 23 shows the effect of plant size on revenue requirements. As plant capacity increases from 500 to 3,000 OD ton per day of wood, revenue requirements decrease by 26 to 42 percent, reflecting economies of scale.

Figure 24 shows the effect of wood cost, annual capacity factor, and plant investment uncertainty on revenue requirements for a regulated producer. For every 10 cents per million Btu change in wood costs, oil costs change by $1.10 per barrel. As the annual capacity or operating factor drops from 90 to 70 percent, revenue requirements increase by 20 percent. For each 10 percent change in plant facilities investment, revenue requirements change by $2.25 per barrel.

Environmental Considerations

Table 50 shows the estimated emissions and environmental parameters. Sulfur emissions originate from the wood-fired boiler. NO_x emissions result from the combustion of wood and fuel gas. Particulate emissions are controlled. Solid waste, aqueous waste, and fresh water values are based on information previously presented.

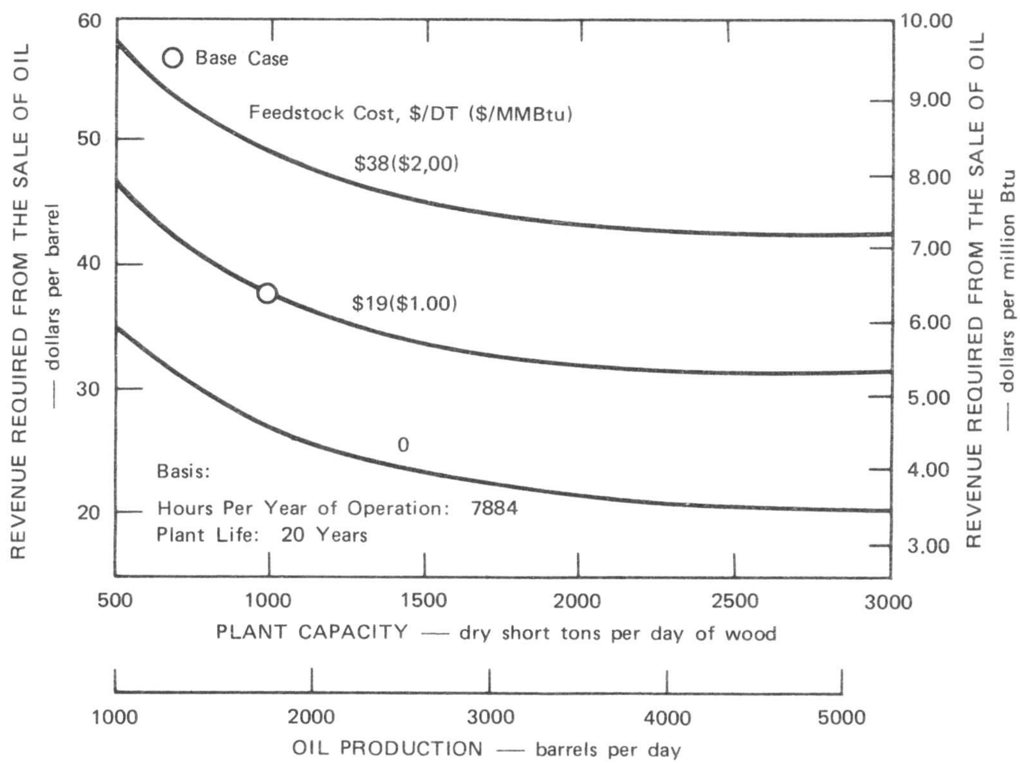


FIGURE 23 PRODUCTION OF OIL BY CATALYTIC LIQUEFACTION OF WOOD — EFFECT OF PLANT SIZE ON REVENUE REQUIRED FROM THE SALE OF OIL BY A REGULATED PRODUCER

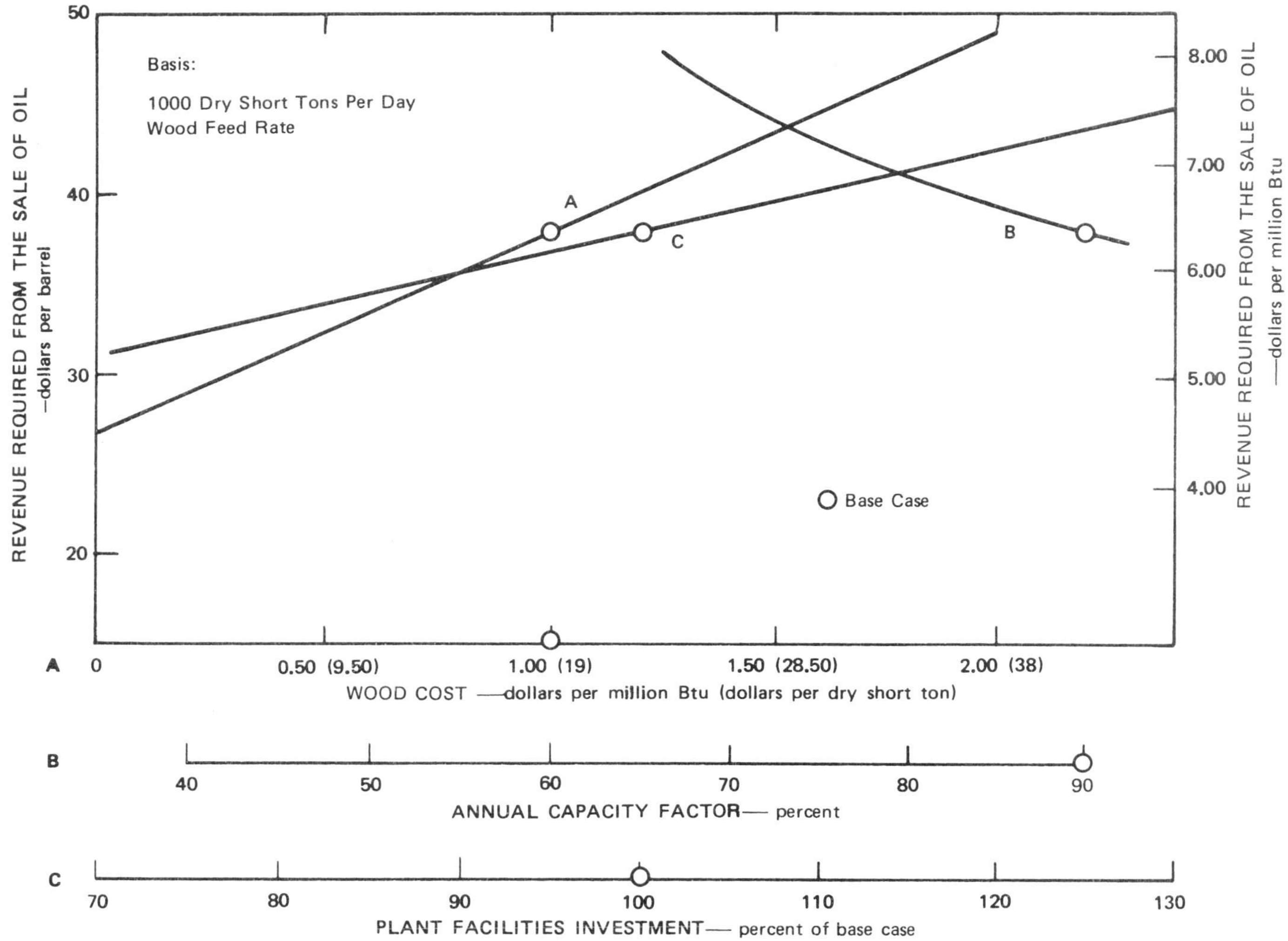


FIGURE 24 PRODUCTION OF OIL BY CATALYTIC LIQUEFACTION OF WOOD — EFFECT OF VARIATION OF SELECTED PARAMETERS ON THE REVENUE REQUIRED FROM THE SALE OF OIL BY A REGULATED PRODUCER

Table 49

PRODUCTION OF OIL BY CATALYTIC LIQUEFACTION OF WOOD--
ESTIMATED ANNUAL OPERATING COSTS AND
REVENUE REQUIRED FOR A REGULATED PRODUCER
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

	Millions of Dollars per Year	Dollars per Barrel of Oil	Dollars per Million Btu of Oil
Materials and supplies			
Wood at $9.56/short ton (wet)	$ 6.28	$10.90	$1.83
Catalysts and chemicals	0.34	0.60	0.10
Maintenance materials	0.97	1.69	0.28
Total materials and supplies	$ 7.59	$13.19	$2.21
Labor			
Operating labor	0.95	1.64	0.28
Supervision	0.14	0.25	0.04
Maintenance labor	1.45	2.53	0.42
Administrative and support labor	0.51	0.88	0.15
Payroll burden	1.07	1.86	0.31
Total labor costs	$ 4.12	$ 7.16	$1.20
Purchased utilities			
Water	0.21	0.35	0.06
Electric power	--	--	--
Total purchased utilities	$ 0.21	$ 0.35	$0.06
Fixed costs			
G&A expenses	0.97	1.69	0.28
Property taxes and insurance	1.22	2.11	0.35
Plant depreciation, 20-year	2.73	4.74	0.80
Total fixed costs	$ 4.92	$ 8.54	$1.43
Total annual operating costs	16.84	29.24	4.90
Return on rate base and income tax*	4.93	8.55	1.45
Total revenue required*	$21.77	$37.79	$6.35
Sources of required revenue			
Oil at $37.79/bbl	21.77	37.79	6.35
Sulfur at $30/LT	0	0	0
Total revenue*	$21.77	$37.79	$6.35
Revenue required (nonregulated producer)†	(29.82)	(51.77)	(8.70)

*20-year average values.

†DCF return: See Appendix, Economic Bases.

Table 50

PRODUCTION OF OIL BY CATALYTIC LIQUEFACTION OF WOOD--
ESTIMATED EMISSIONS AND ENVIRONMENTAL PARAMETERS
(Basis: 1,000 Dry Short Tons per Day Wood Feed Rate)

Parameter	Units*	Value†
Sulfur (SO_x)	Lb SO_2/MMBtu	0.07
Nitrogen (NO_x)	Lb NO_x/MMBtu	0.46
Particulates	Lb/MMBtu	Tr
Solid waste	Lb/MMBtu	4.0
Aqueous waste	Gal/MMBtu	45
Fresh water	Gal/MMBtu	100
Land	Acre/billion Btu/day	4.8

*Million Btu of total energy output.

†Tr = trace.

As is true for most heavy oil fractions, the oil produced from wood may contain carcinogens, suggesting the need for special handling and storage precautions.

VI PRODUCTION OF OIL AND CHAR BY PYROLYSIS OF WOOD

This section discusses the production of oil and char by pyrolysis of wood and the rationale for selecting a single type of pyrolysis technology for analysis.

An accepted definition of pyrolysis is a technology that thermally decomposes carbonaceous materials in the absence of oxygen. Examples are the destructive distillation of wood to produce methanol, activated carbon, and other products; the batch coking of coal in iron and steel making processes; and coking operations in the petroleum refining industry. The COED, COED/COGAS, and Battelle-Union Carbide technologies are examples of developing coal pyrolysis technologies. Tables 25, 26, and 27, presented in the section on the production of SNG from wood, list examples of pyrolysis technologies for solid wastes and residues.[35]

A broader definition of pyrolysis is adopted for this work to permit a greater generality of the analysis. Pyrolysis is defined as a technology that thermally decomposes carbonaceous materials, having at least one zone in which the thermal decomposition proceeds in the absence of oxygen.

Government and industry are developing several pyrolysis technologies. The principal technologies reviewed for this work are the fluid bed pyrolysis technology that the Energy Resources Company, Inc. is developing for EPA;[41,87] the Occidental flash pyrolysis technology,[50] developed using public and private funds; and the Tech-Air technology[88,89] being developed by the Tech-Air Corporation and the Engineering Experimental Station of the Georgia Institute of Technology with public and private sponsorship. An excellent review of fixed bed, entrained bed, and fluidized bed pyrolysis of cellulosic and carbonaceous matter has been presented by the Energy Resources Company, Inc. (ERCO).[41]

The ERCO technology is at an early stage of development, with a capacity of 0.50 short ton per hour. The Occidental pilot unit processed 4 tons per day of material. In contrast, the Tech-Air technology has been under development for about nine years and has reached the 50 dry-ton-per-day commercial prototype stage (Cordele plant).[90] Consequently, the technology chosen for analysis was patterned after the Tech-Air technology, because this technology is believed to be closest to commercialization and because of the availability of data.

Process Description

Figure 25 is a schematic flow diagram. Table 51 presents the stream flows. Tables 52 and 53 present the overall plant heat and material balances, respectively.

Based on an analysis of available data,[88,89] the following yield structure was assumed:

- Moisture-ash-free (MAF) char yield would be 30 percent by weight of the MAF wood feed.
- The yield of oil (with 12 wt% moisture) would be 25 wt% of the MAF wood feed.
- The water of reaction would be about 13 wt% of the MAF wood feed.

Assumed compositions of the low-sulfur oil and char are presented in Table 54. Gas yields were obtained by elemental balances, using an average product distribution based on Tatom's data[89] and assuming that hydrocarbons higher than methane were primarily unsaturated.

Wood is dried to 7 percent moisture and reduced in size to the range 1 inch x 0 to 0.5 inch x 0 in the wood preparation section. Fuel gas from the process is combusted and used for drying (about 1,600 Btu per pound of water evaporated is needed).

The dried wood is mixed with recycle oil and solids and sent to four pyrolyzers operating at slightly above atmospheric pressure. The pyrolyzers are sized for 150 to 200 pound per hour per square foot solids throughput and are 12-foot, 6-inches inside diameter by 20 feet tall. The height-to-diameter ratio was selected based on available information concerning fixed bed coal gasifiers.[91] Acid-resistant refractory lining is used.

Air enters the pryolyzer at the bottom through a distribution plate and burns a portion of the carbon in the downcoming wood, leaving char (at about 800 to 1000°F). The hot combustion gases flow countercurrently to the wood, promoting the pyrolysis reactions. The pyrolysis products (gas, oil, and entrained solids) leave the pyrolyzer vessel at 350 to 500°F, above the dew point of the gas. The reaction mix is quenched by 120°F recycled oil in an in-line mixing venturi. The reaction products are separated in a downstream vessel.

The water used in the pyrolysis is that entering with the wood and that of the pyrolysis reaction. The water principally exits the system in the gas and in the oil product (assumed to be about 12 percent by weight water). In this analysis, the amount of wood drying was determined based on the above considerations. This was done so that no water would be condensed in the quenching process, which would subsequently require treatment to remove organic material.

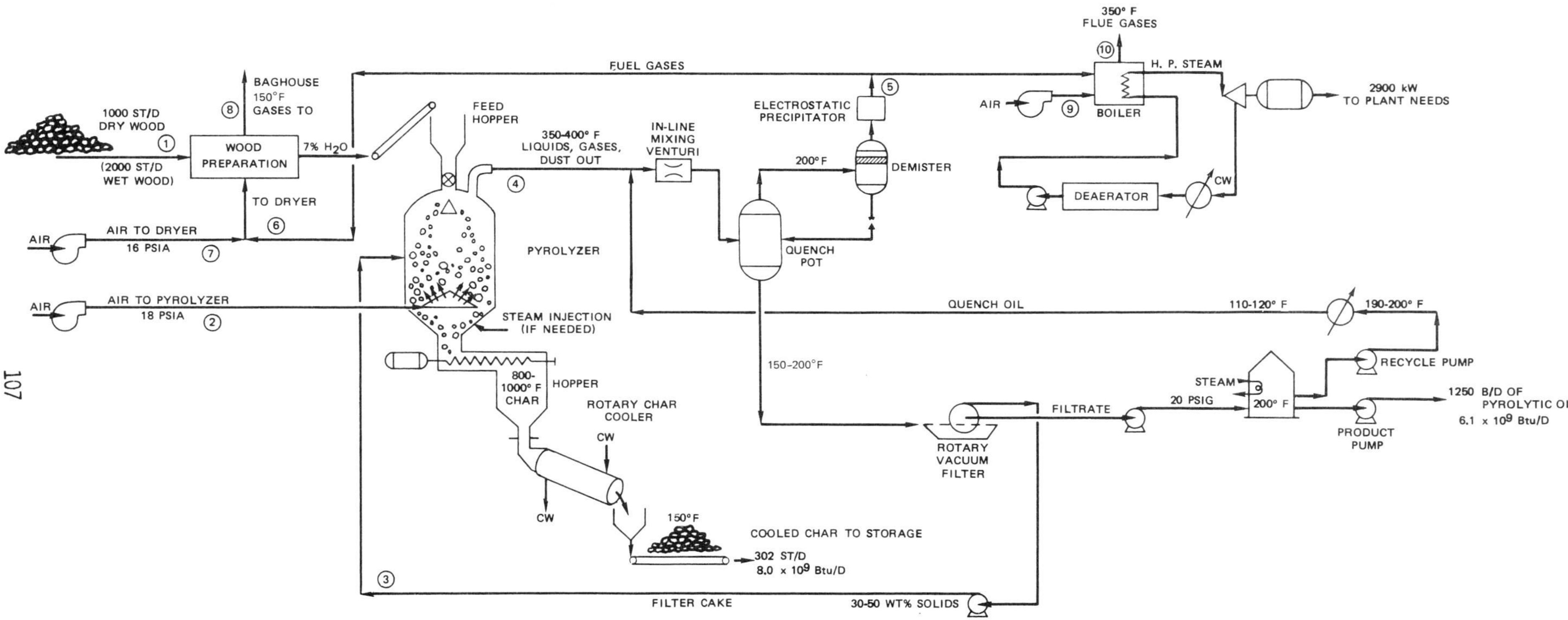


FIGURE 25 PRODUCTION OF OIL AND CHAR BY PYROLYSIS OF WOOD

Table 51

PRODUCTION OF OIL AND CHAR BY PYROLYSIS OF WOOD--STREAM FLOWS
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	(1)	(2)		(3)	(4)		(5)		(6)		(7)		(8)		(9)		(10)		Product Oil	Product Char
	10^3 lb/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	lbmol/hr	10^3 lb/hr	10^3 lb/hr
C	44.88																			
H	4.74																			
O	31.795																			
N	0.165																			
S	0.08																			
Ash	1.67																			
H_2O	83.33				13.91	772	13.91	772	9.87	548			95.03	5,275			7.21	400		
H_2					0.57	281	0.57	281	0.40	200										
CO					11.40	407	11.40	407	8.07	288										
CO_2					21.08	479	21.08	479	14.92	339			33.54	762			13.78	313		
N_2		22.10	789		22.13	790	22.13	790	15.69	560	620.78	22,158	636.47	22,718	22.33	797	28.77	1,027		
O_2		6.72	210								188.48	5,890	172.83	5,401	6.78	212	0.32	10		
CH_4					2.08	130	2.08	130	1.48	92										
C_2H_4					0.61	22	0.61	22	0.42	15										
C_3H_6					0.23	5.4	0.23	5.4	0.16	3.8										
Char				2.56	2.57	--	Tr													25.16
Oil				2.56	23.40	--	Tr												20.83	
Total	166.66	28.82	999	5.12	97.98	2,886	72.01	2,886	51.01	2,046	809.26	28,048	937.87	34,156	29.11	1,009	50.08	1,750	20.83	25.16

Table 52

PRODUCTION OF OIL AND CHAR BY PYROLYSIS OF WOOD -- OVERALL MATERIAL BALANCE
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	Thousands of Pounds Per Hour
Input	
Wet Wood	166.7
Air to pyrolyzer	28.8
Air to dryer and boiler	838.4
Total	1,033.9
Output	
Oil	20.8
Char	25.2
Dryer stack	937.9
Boiler stack	50.0
Total	1,033.9

Table 53

PRODUCTION OF OIL AND CHAR BY PYROLYSIS OF WOOD -- OVERALL ENERGY BALANCE
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	Millions of Btu Per Hour	Percent
Input		
Wet wood	796.7	100.0%
Total	796.7	100.0%
Output		
Oil	255.7	32.1
Char	332.1	41.7
Dryer stack	87.4	11.0
Boiler stack	11.2	1.4
Heat rejected to cooling	42.9	5.4
Insulation losses	28.4	3.6
Miscellaneous losses*	39.0	4.8
Total	796.7	100.0%

*Because of mechanical inefficiencies.

Table 54

PRODUCTION OF OIL AND CHAR BY PYROLYSIS OF WOOD --
ESTIMATED OIL AND CHAR COMPOSITIONS

	Char (weight percent)	Oil (weight percent)
C	78.5	58.8
H	4.6	5.6
O	8.8	23.4
N	0.5	0.2
S	<0.1	<0.1
H_2O	1.0	12.0
Ash	6.6	0.04
Total	100.0	100.0
Higher heating value (Btu/lb)	13,200	12,200
Density (pounds per barrel)		∿ 400

Pyrolysis gases at 190 to 200°F leave the quench vessel and are sent to a demister for removal of entrained oil. The gases are sent to wood drying and to an on-site boiler for power generation. The power generated is estimated to be about sufficient to balance plant needs.

Hot char from the pyrolyzer is dropped onto a water-cooled screw conveyor for transportation to an adjacent char cooler. The char cooler is an inclined rotary cooler and cools the char below its auto ignition temperature (∿150°F). The char product is conveyed to on-site storage.

Oil from the quench step is sent to rotary vacuum filtration for solids removal. This type of filter appears to operate satisfactorily based on conversations with Tech-Air personnel. A filtration rate of 10 pounds of solid removed per hour per square foot is selected, based on experience with sewage sludge filtration. Temperatures are maintained in the 150 to 200°F range for ease in filtration. The filter cake containing about 50 wt% solids is recycled by slurry pumps to the pyrolyzer. The filtrate, containing quench recycle and product oils with an assumed 0.04 wt% solids, is sent to limited on-site storage.

A large amount of oil is recycled to the quench venturi. The oil is cooled from 190 to 200°F to a temperature of about 120°F upsteam of the quench. The cooling required equals the latent heat of product oil condensation (assumed to be 200 to 300 Btu per pound) as well as the sensible heat of cooling the noncondensible gases and liquid oil product to 150 to 200°F. On this basis, the calculated ratio of recycle oil to net product oil lies in the range of 15/1 to 20/1 (weight/weight). This large oil recycle rate also serves to dilute the ash content of the total oil sent to filtration, permitting favorable filter operation.

Since the technology is assumed to operate near atmospheric pressure, plant power needs principally consist of electricity for air blowers, oil movement, and wood preparation. No process steam is believed to be needed. Cooling requirements and aqueous waste treating requirements are low, based on the assumptions used in the analysis.

Table 53 suggests that the overall plant thermal efficiency (char and oil out/wood in) is about 73.8 percent. The energy distribution in the products is about 45 percent in the oil and 55 percent in the char.

Based on conversations with Tech-Air personnel and on available data, very few sulfur compounds have been observed in the product gas. Consequently, all sulfur was assumed to leave with the oil and char.

Product oil properties have been discussed by Knight.[90] The oils are low in sulfur, ash, and nitrogen and should create few problems on combustion. The oils, however, are acidic and heat-sensitive and require certain precautions for storage and handling. Results of pyrolytic oil combustion tests have been reported by Sotter,[92] using pyrolytic oils produced by the Occidental technology. The oils exhibited stable, smoke-free combustion over a wide range of firing conditions. Tech-Air reports[88] that their oils have been sold commercially for use as a fuel in a cement kiln, a power boiler, and a lime kiln. Other fuel and feedstock applications are possible for the oils.

The potential operating safety and operating reliability of the technology are suggested by the operation of the Cordele plant for a number of years.

Economics

Table 55 presents the estimated capital investment. Wood storage, handling, and preparation facilities include wood receiving, handling, drying, grinding, dust collection, and combustion air blower. Wood pyrolysis and quench facilities consist of four pyrolyzers, screw conveyors, pyrolysis air blower, hot surge bin, electrostatic precipitator, quench pot, demister, and heat exchange. Costs for the pyrolyzers were developed based on information available in the literature[91,93,94] and from SRI information. Char cooling and handling facilities include four rotary coolers and char receiving and handling facilities. Utility facilities include the boiler, condensor, steam turbine-generator, oil product and recycle pumps, and oil storage tank, in addition to the items discussed in the Appendix.

Table 55

PRODUCTION OF OIL AND CHAR BY PYROLYSIS OF WOOD -- ESTIMATED TOTAL CAPITAL INVESTMENT
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	Millions of Dollars
Plant section investment	
Wood storage, handling, and preparation	\$ 6.7
Wood pyrolysis and quench	3.1
Oil filtration	0.4
Char cooling and handling	0.7
Utility facilities	4.9
General service facilities	2.3
Total plant facilities investment	\$18.1
Land cost	0.3
Organization and start-up expenses	0.9
Interest during construction	1.4
Working capital	1.5
Total capital investment	\$22.2
Depreciable investment	20.4
Debt capital	14.4
Equity capital	7.8

The PFI is estimated to be \$18.1 million and the total capital investment, \$22.2 million. The PFI may also be expressed as \$9,000 per ton of daily wood capacity.

Figure 26 presents the effect of plant size on plant facilities investment. The PFI, expressed as dollars per ton per day of wood capacity, decreases from about \$10,000 per ton per day for a 500 OD ton-per-day wood capacity to about \$8,000 per ton per day for a 3,000 OD ton-per-day wood capacity. This reflects economies of scale in such areas as quench vessels, wood drying, and steam generation. Multiple pyrolyzer vessels are used in all designs.

Figure 27 presents the capital costs for wood pyrolysis as developed here (and deflated by 15 percent to represent mid-1975 costs) in

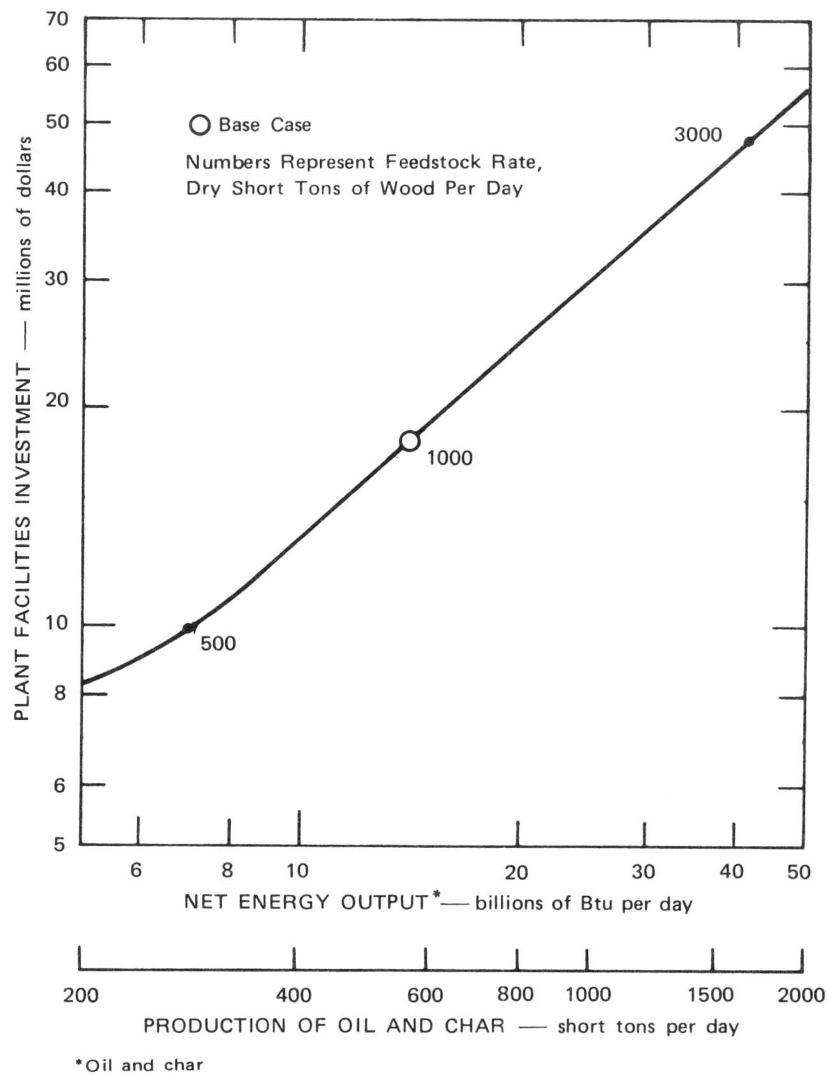
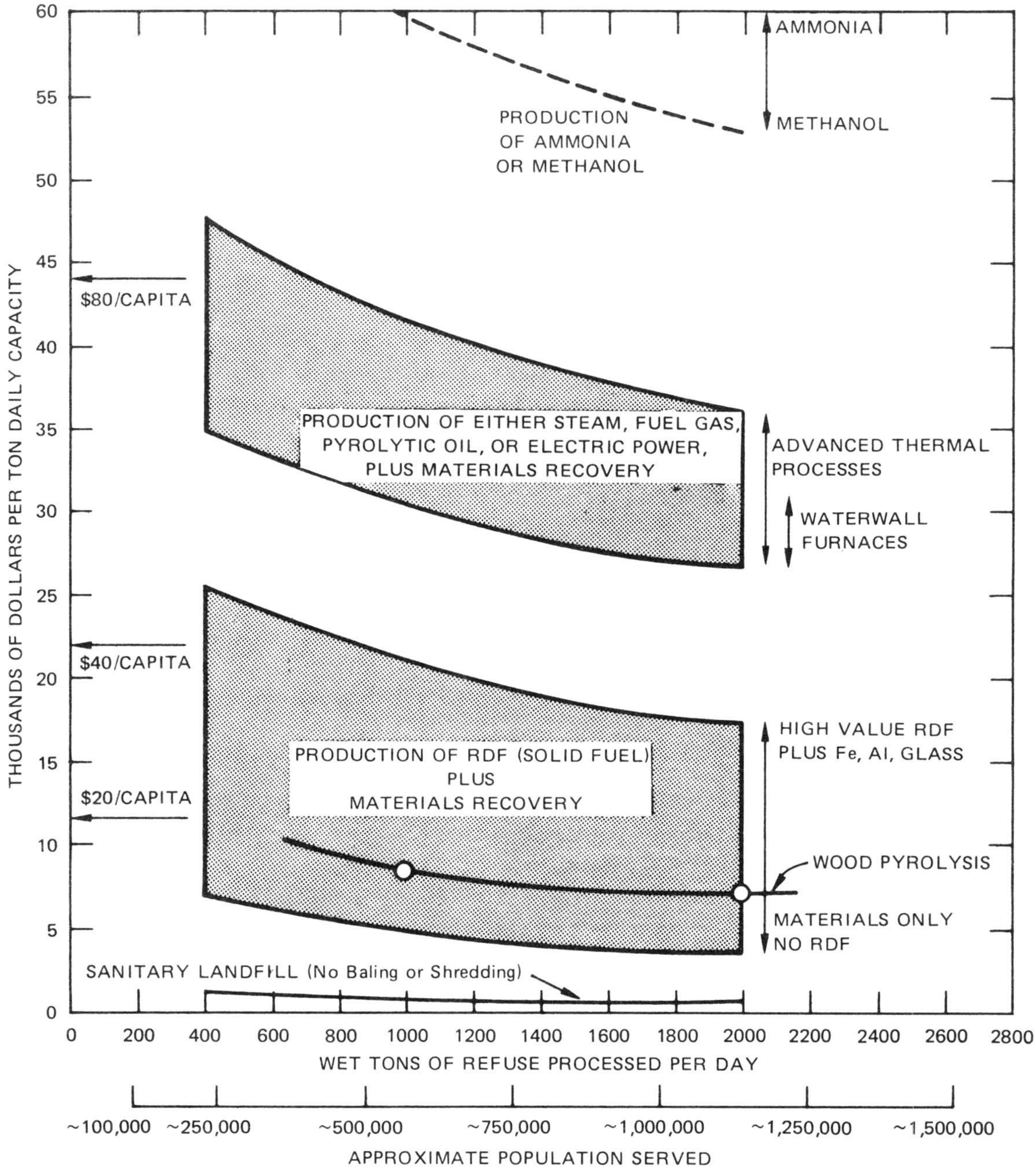


FIGURE 26 PRODUCTION OF OIL AND CHAR BY PYROLYSIS OF WOOD — EFFECT OF PLANT SIZE ON PLANT FACILITIES INVESTMENT



NOTE: Mid–1975 costs

SOURCE: 'The Costs for Processing Munincipal Refuse and Sludge', paper presented by J.L. Jones at the Fifth National Conference on Acceptable Sludge Disposal Techniques, Orlando, Florida, January 31, 1978.

FIGURE 27 CRUDE APPROXIMATION OF RELATIVE INVESTMENT REQUIREMENTS BASED ON ACTUAL AND ESTIMATED COSTS FOR REFUSE PROCESSING AND CONVERSION, MODIFIED TO INCLUDE WOOD PYROLYSIS COSTS perspective with capital costs for refuse processing and conversion. The wood pyrolysis costs are seen to fall toward the low end of the refuse processing costs, reflecting the simplicity of the wood pyrolysis technology compared with refuse (no inorganics reclamation) and possibly the somewhat optimistic assumptions regarding the wood technology in this analysis.

Table 56 presents the major operating requirements. As evaluated here, the technology would appear to require low power and cooling requirements as contrasted with the other technologies for the thermochemical conversion of biomass.

Table 56

PRODUCTION OF OIL AND CHAR BY PYROLYSIS OF WOOD -- ESTIMATED MAJOR OPERATING REQUIREMENTS
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

Operating labor (men per shift)	16.5
Electric power (kWh/hr)	
Plant needs	2,900
Purchased (if any)	0
Cooling tower circulation--ΔT = 20°F	4,200
Purchased water (gpm)	220

Table 57 presents the estimated operating costs for a regulated producer. The total revenue requirements are estimated to be \$3.15 per million Btu of oil and char. Wood costs represent 50 percent of annual operating costs and labor-related costs, 32 percent. Maintenance labor was assumed to be 8 percent of the plant facilities investment because of the low PFI value.

Figure 28 shows the effect of plant size on revenue requirements. As plant capacity increases from 500 OD tons per day of wood to 3,000 OD tons per day of wood, revenue requirements fall by 15 to 35 percent, reflecting economies of scale.

Figure 29 charts the selling price of pyrolytic oil as a function of the selling price of char. The char is low in sulfur and nitrogen and may be sold for boiler fuel or other uses. If the char is sold for \$1.00 per million Btu (\$26 per ton), the pyrolytic oil selling price would be about \$6.00 per million Btu, or \$29 per barrel.

Figure 30 shows the effect of wood cost, annual capacity factor, and plant investment uncertainty on the revenue requirements from the sale of oil and char. For every 10 cents per million Btu change in

Table 57

PRODUCTION OF OIL AND CHAR BY PYROLYSIS OF WOOD -- ESTIMATED ANNUAL OPERATING COSTS AND REVENUE REQUIRED FOR A REGULATED PRODUCER
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	Millions of Dollars Per Year	Dollars Per Million Btu of Oil and Char
Materials and supplies		
Wood at $9.56/short ton (wet)	$ 6.28	$1.36
Catalysts and chemicals	0.02	0
Maintenance materials	0.36	0.08
Total materials and supplies	$ 6.66	$1.44
Labor		
Operating labor	0.91	0.20
Supervision	0.14	0.03
Maintenance labor	1.45	0.31
Administrative and support labor	0.50	0.11
Payroll burden	1.04	0.22
Total labor costs	$ 4.04	$0.87
Purchased utilities		
Water	0.06	0.01
Electric power	--	--
Total purchased utilities	$ 0.06	$0.01
Fixed costs		
G&A expenses	0.36	0.08
Property taxes and insurance	0.45	0.10
Plant depreciation, 20-year	1.02	0.22
Total fixed costs	$ 1.83	$0.40
Total annual operating costs	12.60	2.72
Return on rate base and income tax*	2.02	0.43
Total revenue required*	$14.62	$3.15
Sources of required revenue		
Oil and char	14.62	3.15
Total revenue*	$14.62	$3.15
Revenue required (nonregulated producer)†	(17.87)	(3.86)

*20-year average values.

†DCF return: See Appendix, Economic Bases.

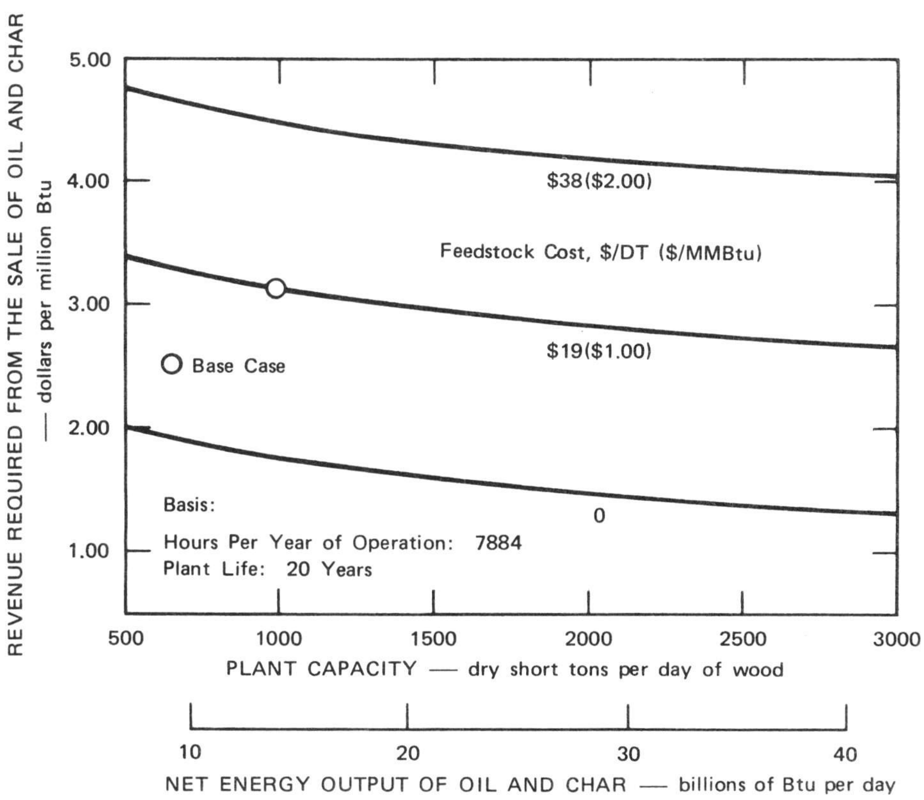


FIGURE 28 PRODUCTION OF OIL AND CHAR BY PYROLYSIS OF WOOD — EFFECT OF PLANT SIZE ON REVENUE REQUIRED FROM THE SALE OF OIL AND CHAR BY A REGULATED PRODUCER

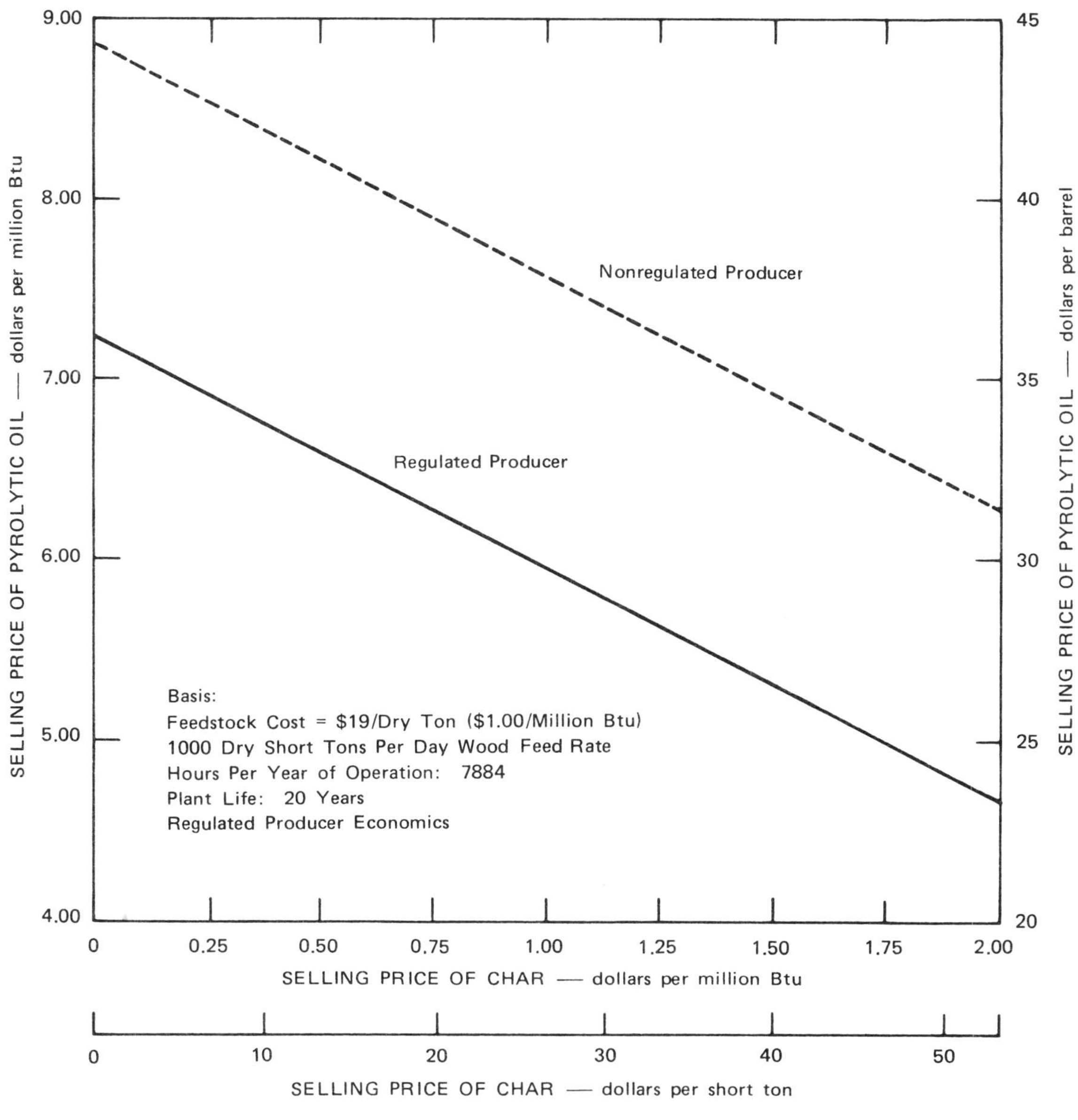


FIGURE 29 PRODUCTION OF OIL AND CHAR BY PYROLYSIS OF WOOD — SELLING PRICE OF PYROLYTIC OIL AS A FUNCTION OF SELLING PRICE OF CHAR

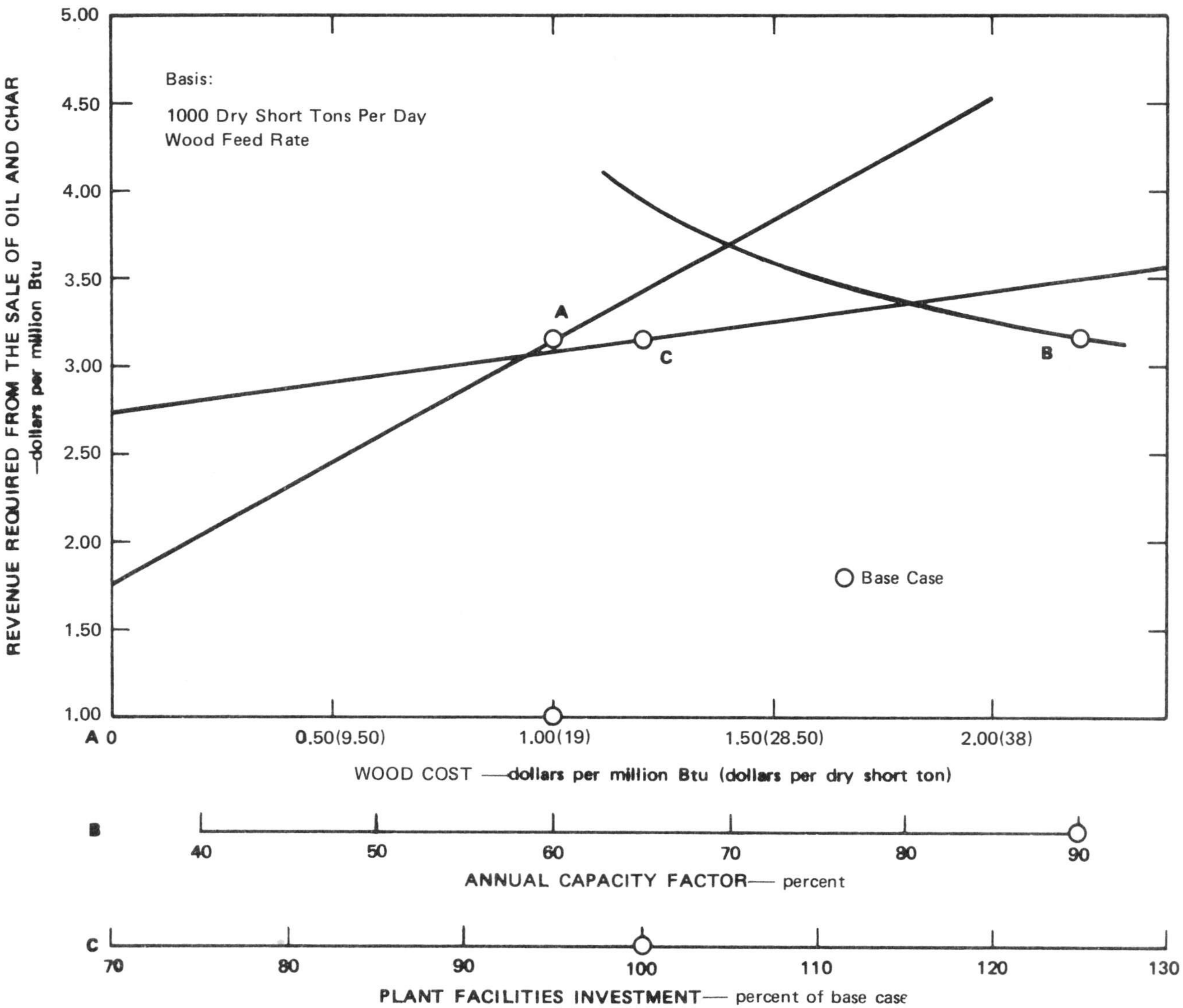


FIGURE 30 PRODUCTION OF OIL AND CHAR BY PYROLYSIS OF WOOD — EFFECT OF VARIATION OF SELECTED PARAMETERS ON REVENUE REQUIRED FROM THE SALE OF OIL AND CHAR BY A REGULATED PRODUCER

wood costs, revenue requirements change by 14 cents per million Btu, reflecting the high thermal efficiency of the technology. As the annual capacity factor drops from 90 to 70 percent, revenue requirements increase by a factor of 1.2. For every 10 percent change in plant facilities investment, revenue requirements change by 14 cents per million Btu, reflecting the low capital cost of the technology.

The oil product costs presented here are in general agreement with those presented by MITRE.[41]

Environmental Considerations

Table 58 presents the estimated emissions and environmental parameters. Sulfur emissions are assumed to be negligible, as previously stated. NO_x emissions result from the combustion of plant fuel gas. Particulate emissions are controlled. Solid wastes are assumed negligible.

Gikis et al.,[23] have pointed out the potential of carcinogens in the pyrolytic oil, suggesting the need for special product handling procedures.

Table 58

PRODUCTION OF OIL AND CHAR BY PYROLYSIS OF WOOD -- ESTIMATED EMISSIONS AND ENVIRONMENTAL PARAMETERS
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

Parameter	Units*	Value†
Sulfur (SO_x)	Lb SO_2/MMBtu	Tr
Nitrogen (NO_x)	Lb NO_x/MMBtu	0.22
Particulates	Lb/MMBtu	Tr
Solid waste	Lb/MMBtu	Tr
Aqueous waste	Gal/MMBtu	17
Fresh water	Gal/MMBtu	45
Land	Acre/billion Btu/day	3.5

*Million Btu of total energy output.

†Tr = Trace.

VII PRODUCTION OF AMMONIA FROM WOOD BY DIRECT GASIFICATION AND CONVENTIONAL AMMONIA SYNTHESIS

Anhydrous ammonia is an essential building block for all synthetic nitrogen fertilizers as well as being an important industrial chemical. Ammonia, together with derivatives such as ammonium nitrate and nitric acid, are widely used in the production of intermediate compounds for plastics, synthetic fibers, and explosives and serves other specialty markets in metallurgical processing, pulp and paper manufacturing, and other industries.

Before World War II, about 90 percent of the world's synthetic ammonia production was coal-based. Today the figure is probably less than 15 percent; this capacity is based principally on older coal gasifier types (e.g., Koppers Totzek,[60] Winkler,[39] McDowell-Wellman.[61] In the United States, ammonia is principally made by the steam reforming of natural gas or naphtha.

Recent activities in the United States include an interest in the production of ammonia from coal, for example:

- TVA's plans for a $46 million demonstration plant for ammonia from coal at Muscle Shoals, Alabama,[95] using Texaco gasification technology.
- A feasibility study (Phase I for $10 million) is being conducted by W. R. Grace & Co for ERDA (now DOE) which will evaluate the production of 1200 tons per day of ammonia from coal.[96]

The production of ammonia from municipal solid waste[58,60] is also being considered. Brown has discussed several existing or developing coal gasification technologies in terms of their ease of retrofitting existing ammonia plants[97] (which use natural gas or naphtha as feedstock).

Ammonia technology and catalysts have evolved with time. A recent discussion of alternative ammonia feedstocks and plant designs was presented by Buividas.[98] Practically any carbon-containing feedstock may be used to produce ammonia, such as biomass, coal, lignite, solid wastes, and residues, and petroleum fractions. The DOE is sponsoring the development of the SGFM (synthesis gas from manure) technology at Texas Tech, with the intent of producing ammonia or other products from this feedstock.

Process Description

Figure 31 is a schematic drawing for the production of about 500 short tons per day of anhydrous ammonia from 2,000 short tons per day of wood. Table 59 presents the stream flows and Tables 60 and 61 the overall plant material and energy balances, respectively.

About 1,640 wet short tons per day of wood are gasified with oxygen and steam in a 500-psia fluid bed gasifier as discussed in the section on SNG production from wood. Since in-plant energy recovery is insufficient to meet plant energy requirements, 360 short tons per day of wood are combusted and used for on-site power generation. A recent article by Netzer and Moe[99] suggests that coal-based ammonia plants may require on-site power generation because heat recovery from process streams is insufficient for all plant energy needs. About 410 short tons per day of 98 percent oxygen, preheated to 610°F as shown in Figure 31, are estimated to be needed for wood gasification.

Gasifier product gases are cooled to 600°F in a waste heat boiler, generating high pressure superheated steam. The gases are sent to a high-temperature shift conversion unit, where about 70 percent of the CO is shifted to hydrogen. Because of the high CO_2 concentration in the gas (occasioned by the high oxygen content of the feed wood), it is probably not practical or economical to shift more CO (which would require the addition of steam) in the high-temperature shift step. No steam is added because of the large volume of water in the gasifier effluent.

Shift outlet gases are cooled to 250 to 300°F and sent to a hot potassium carbonate unit. Here, CO_2 is removed in bulk, down to 1/2 vol%; 60 percent COS removal (hydrolysis) is assumed, and H_2S is removed down to the same partial pressure as COS at the outlet of the unit.

Acid gases are sent to a Stretford sulfur recovery unit.

Product gases are next directed to a zinc oxide bed for removal of the trace sulfur compounds because the low-temperature shift catalyst is sulfur-sensitive. Steam is added at the inlet of the low-temperature shift converter. At the outlet of the low-temperature shift converter, about 97.5 percent of the CO in the original gasifier effluent has been converted to hydrogen. Since shifting of CO to hydrogen is equilibrium-limited, a great deal more steam would be needed (for example, double the 10,400 pounds per hour shown in Figure 31) to increase the overall CO conversion slightly (for example, to 99 percent, based on the amount of CO in the gasifier effluent).

The gases from the low-temperature shift conversion, containing predominantly hydrogen, are cooled to 250 to 300°F and sent to a hot potassium carbonate unit where the CO_2 is removed down to about 0.3 vol%. Removal down to this level was advised by Linde as being reasonable for feeds to pressure swing absorption (PSA) units.

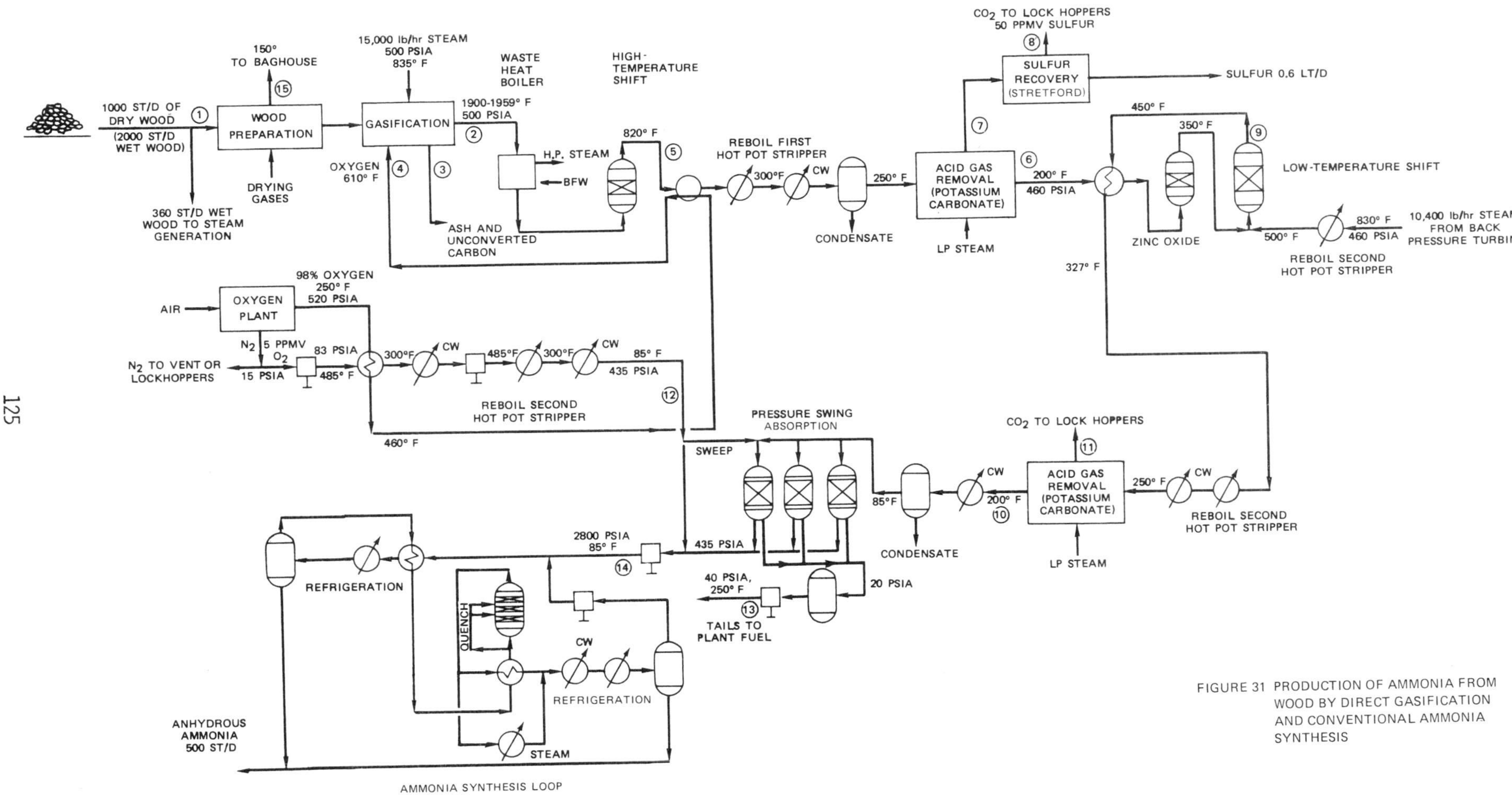


FIGURE 31 PRODUCTION OF AMMONIA FROM WOOD BY DIRECT GASIFICATION AND CONVENTIONAL AMMONIA SYNTHESIS

Table 59

PRODUCTION OF AMMONIA FROM WOOD BY DIRECT GASIFICATION AND CONVENTIONAL AMMONIA SYNTHESIS--STREAM FLOWS
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	(1) 10^3 lb/hr	(2) 10^3 lb/hr	(2) lbmol/hr	(3) 10^3 lb/hr	(4) 10^3 lb/hr	(4) lbmol/hr	(5) 10^3 lb/hr	(5) lbmol/hr	(6) 10^3 lb/hr	(6) lbmol/hr	(7) 10^3 lb/hr	(7) lbmol/hr	(8) 10^3 lb/hr	(8) lbmol/hr
C	44.88			0.36										
H	4.74													
O	31.795													
N	0.165													
S	0.08													
Ash	1.67			1.36										
H_2O	83.33	49.80	2,764				27.51	1,527	1.87	104				
H_2		4.28	2,122				6.77	3,359	6.77	3,359				
CO		49.49	1,767				14.84	530	14.84	530				
CO_2		51.84	1,178				106.28	2,415	0.92	21	105.36	2,394	105.36	2,394
H_2S		0.06	1.8				0.06	1.8	0	0.1	0.06	1.9		
COS		0.02	0.3				0.02	0.3	0	0.1				
N_2		0.73	26		0.61	21.6	0.73	26	0.73	26				
O_2					33.82	1,057								
CH_4		1.48	92				1.48	92	1.48	92				
SO_2														
Ammonia														
Total	166.66	157.70	7,951	1.72	34.43	1,079	157.69	7,951	26.61	4,132	105.42	2,396	105.36	2,394

	(9) 10^3 lb/hr	(9) lbmol/hr	(10) 10^3 lb/hr	(10) lbmol/hr	(11) 10^3 lb/hr	(11) lbmol/hr	(12) 10^3 lb/hr	(12) lbmol/hr	(13) 10^3 lb/hr	(13) lbmol/hr	(14) 10^3 lb/hr	(14) lbmol/hr	(15) 10^3 lb/hr	(15) lbmol/hr	Ammonia Product 10^3 lb/hr
C															
H															
O															
N															
S															
Ash															
H_2O	4.45	247	1.94	108					0.09	5			54.79	3,041	
H_2	7.64	3,792	7.64	3,792					0.23	114	7.41	3,678			
CO	2.69	96	2.69	96					2.69	96					
CO_2	20.02	455	0.53	12	19.50	443			0.53	12			38.51	875	
H_2S															
COS															
N_2	0.73	26	0.73	26			38.83	1,386	5.21	186	34.35	1,226	130.53	4,659	
O_2													6.11	191	
CH_4	1.48	92	1.48	92					1.48	92					
SO_2													0.03	0.5	
Ammonia															41.64
Total	37.01	4,708	15.01	4,126	19.50	443	38.83	1,386	10.23	505	41.76	4,904	229.97	8,766	41.64

Table 60

PRODUCTION OF AMMONIA FROM WOOD BY DIRECT GASIFICATION AND CONVENTIONAL AMMONIAL SYNTHESIS -- OVERALL MATERIAL BALANCE (Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	Thousands of Pounds Per Hour
Input	
Wet wood	166.7
Oxygen	34.4
Combustion air	164.0
Nitrogen	38.8
Water	831.3
Total	1,235.2
Output	
Ammonia	41.6
Ash and unburned carbon	2.0
Dryer stack	230.0
CO_2 to stack	124.9
Treated wastewater	335.8
Evaporation losses	500.8
Sulfur	0.1
Total	1,235.2

The gases are cooled to 70 to 80°F by chilling and sent to a molecular sieve PSA unit. The PSA unit produces a stream of practically pure hydrogen, suitable for ammonia synthesis.[101,102] Based on conversations with Linde, recycle compression is used to ensure 97 percent hydrogen recovery.

The hydrogen is mixed in a 3/1 mol ratio with nitrogen (with a maximum of 5 ppmv O_2[100]) from the oxygen plant, compressed to 2,500 to 2,800 psia, and sent to the ammonia synthesis loop. In the loop, hydrogen and nitrogen react to form ammonia by:

$$3N_2 + N_2 = 2NH_3 \quad .$$

The ammonia converter may be a single, multibed reactor or several single beds in series. The refrigeration plant provides the necessary refrigeration for the loop, and liquid anhydrous ammonia at -28°F is produced. Optimization is necessary to maximize heat recovery from the loop.[96]

Table 61

PRODUCTION OF AMMONIA FROM WOOD BY DIRECT GASIFICATION AND CONVENTIONAL AMMONIA SYNTHESIS -- OVERALL ENERGY BALANCE
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	Millions of Btu Per Hour	Percent
Input		
Wet wood	796.7	100.0
Total	796.7	100.0%
Output		
Ammonia	372.9	46.8
Heat rejected to cooling	335.6	42.1
Stacks	59.6	7.5
Ash and unconverted carbon	6.2	0.8
Insulation losses	16.5	2.1
Miscellaneous losses*	5.9	0.7
Total	796.7	100.0%

*Because of mechanical inefficiencies and the like.

Based on an analysis of information received from industry, the literature, and SRI information, a (higher heating) value of 21,727 million Btu of synthesis gas (Stream 14 in Figure 31) was used as a basis for producing one short ton of ammonia. The syngas is essentially inert-free, and no purge gas stream from the loop is required as would be the case if methanation were used to remove the final traces of CO from the syngas (carbon oxides poison the ammonia catalyst).

A recent study by Bechtel, producing 533 short tons per day of ammonia[60] from municipal solid waste, uses PSA syngas purification. AE & CI's 1,100 short ton per day ammonia-from-coal plant at Modderfontein, South Africa,[103] uses cryogenic purification of the syngas, as does the 1,500 short ton per day conceptual design for ammonia from coal published by Fluor.[99] Based on information from Linde, it was decided to design the 250 and 500 short ton per day ammonia plants using PSA syngas purification and cryogenic syngas purification for the 1,500 short ton per day ammonia plant.

Based on conversations with industry, common practice considers the use of reciprocal compressors for plant sizes below about 500 to 600 short ton per day of ammonia because of minimum flow restrictions on centrifugal compressors. Above this range, however, centrifugal compressors can be used with higher pressure synthesis loops. As a result, the largest ammonia plant studied here (based on 3,000 ODT per day wood feedrate) is slightly more efficient than would be anticipated by extrapolation from the other two designs, producing 1,544 short tons per stream day of anhydrous ammonia.

One day's storage is provided on-plot for the liquid ammonia. Permanent storage (which could amount to as much as three to four months' production of ammonia because of the seasonal nature of the demand for ammonia) is assumed to be provided off-plot in an adjacent bulk storage depot owned and operated by others.

Gases for the wood dryer are provided by combined hot (780°F) stack gases from combustion of the 360 wet short tons per day of wood and from the combustion of fuel gases (from the PSA unit) in a boiler.

High pressure steam generated from the wood/fuelgas boiler, waste heat boiler, and the ammonia synthesis plant is used to generate electric power and extraction steam from steam turbine-generator sets for the smaller plant sizes; it is used to drive centrifugal compressors with back pressure and condensing turbines for the largest plant size (3,000 ODT per day wood feedrate).

Plant reliability is provided by redundancy in pumps and compressor capacity and by two gasifiers. Ammonia plant safety records are well known.[75,102]

The heat rejected to cooling in Table 61 principally represents the cooling requirements of the potassium carbonate units, compressor intercoolers, the oxygen plant, and steam turbine condensers.

Economics

Table 62 presents the estimated capital investment for the production of ammonia from wood. Wood storage, handling, and preparation facilities consist of wood receiving, handling, drying, grinding, conveying, and dust collection facilities. As discussed for the direct combustion cases, the wood used for power generation is assumed to require no special prepreparation. Wood gasification facilities include two gasifiers, lock hopper feed systems and compressors, external cyclones, ash lock hoppers, and waste heat boilers. The oxygen plant is assumed to provide high-purity nitrogen. The high-temperature shift conversion facilities include the fixed bed converter and associated exchanges. The low-temperature shift conversion facilities are the fixed bed converter and associated exchangers. The PSA facilities consist of the PSA unit, PSA recycle compressor (preliminary costs furnished by Linde), nitrogen compressor and intercoolers, and the PSA tails compressor. Preliminary costs for the ammonia synthesis loop are based on discussions with M. W. Kellogg and from information in the literature.[58] Stretford costs are based on a report by Bechtel.[58] Utility facilities include steam turbine generator sets, a wood/fuelgas boiler (also used for start-up), one day's refrigerated ammonia storage, and a combustion air blower, in addition to the items listed in the Appendix.

Table 62

PRODUCTION OF AMMONIA FROM WOOD BY DIRECT GASIFICATION AND CONVENTIONAL AMMONIA SYNTHESIS -- ESTIMATED TOTAL CAPITAL INVESTMENT
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	Millions of Dollars (Nonregulated Producer)	Millions of Dollars (Regulated Producer)
Plant section investment		
Wood storage, handling, and preparation	\$ 4.5	
Wood gasification	13.4	
Oxygen plant	9.6	
Shift conversion (high temperature)	3.1	
Acid gas removal	4.6	
Shift conversion (low temperature)	1.6	
CO_2 removal	1.7	
Pressure swing absorption, compression (N_2)	4.9	
Syngas compression	3.8	
Ammonia synthesis loop	6.9	
Sulfur recovery	1.8	
Utility facilities	27.2	
General service facilities	12.4	
Total plant facilities investment	\$ 99.5	\$ 95.5
Land cost	0.3	0.3
Organization and start-up expenses	4.8	4.8
Interest during construction	--	7.3
Working capital	2.2	2.2
Total capital investment	\$102.8	\$110.1
Depreciable investment		107.6
Debt capital		71.6
Equity capital		38.5

The plant facilities investment is estimated to be $95.5 million and the total capital investment, $102.8 or $110.1 million for a non-regulated and a regulated producer, respectively.

Figure 32 shows the effect of plant size on plant facilities investment. The PFI, expressed as dollars per ton per day of ammonia, decreases as plant size increase, reflecting economies of scale (actually, the curve should break between 600 short ton per day and 1,000 short ton per day of ammonia production, reflecting the switch from reciprocal to centrifugal compressors; however, this refinement was not attempted here). Single train oxygen, acid gas removal, shift conversion, sulfur recovery, and ammonia synthesis units are used throughout.

Table 63 gives the major operating requirements. Operating labor is estimated to be 16.5 men per shift. Fresh water requirements reflect gasifier steam needs, shift steam needs, and boiler and cooling tower makeup (the cooling tower is assumed to require 5 percent makeup, -2 percent blowdown, 3 percent evaporation losses).

Tables 64 and 65 present the annual operating costs for a nonregulated and a regulated producer, respectively. The concept of an ammonia plant being organized as a regulated utility operation may not be generally accepted, but municipally owned plants (which use municipal wastes or feedstocks) have been considered.[60] Consequently, the discussion emphasizes nonregulated financing and includes reference to regulated operation as may be appropriate.

Based on nonregulated financing, the required revenue from the sale of ammonia is estimated to be $300 per short ton. Wood costs represent 33 percent of annual operating costs (excluding depreciation) and labor-related costs, 28 percent. Under regulated financing, the ammonia price drops to about $205 per short ton.

Figure 33 presents the effect of plant size on revenue requirements for three different wood feedstock costs. As plant capacity increases from 500 to 3,000 ODT per day of wood, revenue requirements decrease by 26 to 31 percent, reflecting economies of scale.

Figure 34 presents the effect of varying feedstock cost, annual capacity or operating factor, and plant investment uncertainty on revenue requirements for a nonregulated producer. For every 10 cents per million Btu change in wood cost, revenue requirements change by $3.90 per short ton. As the annual capacity factor drops from 90 to 70 percent, revenue requirements increase by 23 percent. For each 10 percent change in plant facilities investment, revenue requirements change by about $24 per short ton. Figure 35 presents analogous information for a regulated producer.

The ammonia costs presented for a regulated utility operation are similar to those presented by Lipinsky[59] for an ammonia production rate

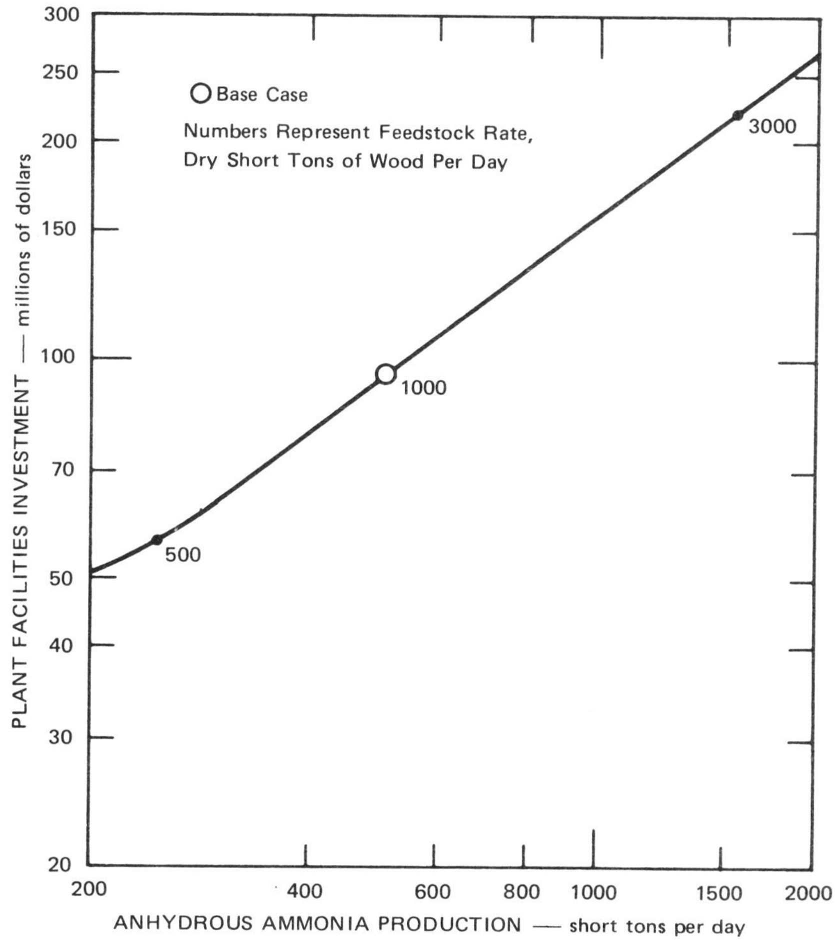


FIGURE 32 PRODUCTION OF AMMONIA FROM WOOD BY DIRECT GASIFICATION AND CONVENTIONAL AMMONIA SYNTHESIS — EFFECT OF PLANT SIZE ON PLANT FACILITIES INVESTMENT

Table 63

PRODUCTION OF AMMONIA FROM WOOD BY DIRECT GASIFICATION AND CONVENTIONAL AMMONIA SYNTHESIS -- ESTIMATED MAJOR OPERATING REQUIREMENTS
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

Operating labor, men per shift	16.5
Electric power, kWh/hr	
Plant needs	22,600
Purchased (if any)	0
Cooling tower circulation (ΔT = 20°F), gpm	33,600
Purchased water, gpm	1,660
Major compressors	

Service	Operating BHP
Oxygen plant - oxygen compressor	2,350
Oxygen plant - air compressor	5,840
Syngas compressor	5,620
Ammonia loop - recycle compressor	1,170
Ammonia loop - refrigeration compressor	2,380
Nitrogen compressor	2,960

of 690 short tons per day, using sugar crop residues as feedstock. The ammonia costs developed here are higher by about 25 to 35 percent than those presented by Fluor[100] for a 1,500 short ton per day ammonia-from-coal plant using a bituminous coal feedstock at $1.00 per million Btu. These differences may be explained by considering the moisture and carbon content differences between wood and coal feedstocks.

MITRE[15] evaluated the production of ammonia from wood using Purox technology and conventional ammonia synthesis. The Purox technology did not appear to have been integrated into a complete process plant design with the ammonia synthesis. As a result, the estimated selling prices of ammonia are lower than those developed here.

Environmental Considerations

Table 66 presents the estimated emissions and environmental parameters. Small amounts of NO_x and SO_2 are emitted from the wood fired boiler. Particulate emissions are controlled. Solid waste, aqueous waste (ponded), and fresh water values are based on information previously presented.

Table 64

PRODUCTION OF AMMONIA FROM WOOD BY DIRECT GASIFICATION AND CONVENTIONAL AMMONIA SYNTHESIS -- ESTIMATED ANNUAL OPERATING COSTS AND REVENUE REQUIRED FOR A NONREGULATED PRODUCER
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	Millions of Dollars Per Year	Dollars Per Short Ton of Ammonia
Materials and supplies		
Wood at $9.56/short ton (wet)	$ 6.28	$ 38.27
Catalysts and chemicals	0.68	4.13
Maintenance materials	1.91	11.64
Total materials and supplies	$ 8.87	$ 54.04
Labor		
Operating labor	1.16	7.05
Supervision	0.17	1.06
Maintenance labor	1.91	11.64
Administrative and support labor	0.65	3.95
Payroll burden	1.36	8.29
Total labor costs	$ 5.25	$ 31.99
Purchased utilities		
Electric power	--	--
Fresh water	0.47	2.87
Total purchased utilities	$ 0.47	$ 2.87
Fixed costs		
G&A expenses	1.91	11.64
Property taxes and insurance	2.39	14.55
Total fixed costs	$ 4.30	$ 26.19
Total annual operating costs	18.89	115.10
Capital charges for a 15% DCF return	30.36	184.99
Total revenue required	$49.25	$300.09
Sources of revenue required		
Ammonia at $300/ST	49.24	300.05
Sulfur at $30/LT	0.01	0.04
Total revenue	$49.25	$300.09

Table 65

PRODUCTION OF AMMONIA FROM WOOD BY DIRECT GASIFICATION AND CONVENTIONAL AMMONIA SYNTHESIS -- ESTIMATED ANNUAL OPERATING COSTS AND REVENUE REQUIRED FOR A REGULATED PRODUCER
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

	Millions of Dollars Per Year	Dollars Per Short Ton of Ammonia
Materials and supplies		
Wood at $9.56/short ton (wet)	$ 6.28	$ 38.27
Catalysts and chemicals	0.68	4.13
Maintenance materials	1.91	11.64
Total materials and supplies	$ 8.87	$ 54.04
Labor		
Operating labor	1.16	7.05
Supervision	0.17	1.06
Maintenance labor	1.91	11.64
Administrative and support labor	0.65	3.95
Payroll burden	1.36	8.29
Total labor costs	$ 5.25	$ 31.99
Purchased utilities		
Water	0.47	2.87
Electric power	--	--
Total purchased utilities	$ 0.47	$ 2.87
Fixed costs		
G&A expenses	1.91	11.64
Property taxes and insurance	2.39	14.55
Plant depreciation, 20-year	5.38	32.79
Total fixed costs	$ 9.68	$ 58.98
Total annual operating costs	24.27	147.88
Return on rate base and income tax*	9.46	57.63
Total revenue required*	$33.73	$205.51
Sources of required revenue		
Ammonia at $205/ST	33.72	205.47
Sulfur at $30/LT	0.01	0.04
Total revenue*	$33.73	$205.51

*20-year average values.

Table 66

PRODUCTION OF AMMONIA FROM WOOD BY DIRECT GASIFICATION AND CONVENTIONAL AMMONIA SYNTHESIS -- ESTIMATED EMISSIONS AND ENVIRONMENTAL PARAMETERS
(Basis: 1,000 Dry Short Tons Per Day Wood Feed Rate)

Parameter	Units*	Value†
Sulfur (SO_x)	Lb SO_2/MMBtu	0.066
Nitrogen (NO_x)	Lb NO_x/MMBtu	0.38
Particulates	Lb/MMBtu	Tr
Solid waste	Lb/MMBtu	4.48
Aqueous waste	Gal/MMBtu	99
Fresh water	Gal/MMBtu	220
Land	Acre/billion Btu/day	4.6

*Million Btu of total syngas to ammonia loop.

†Tr = Trace.

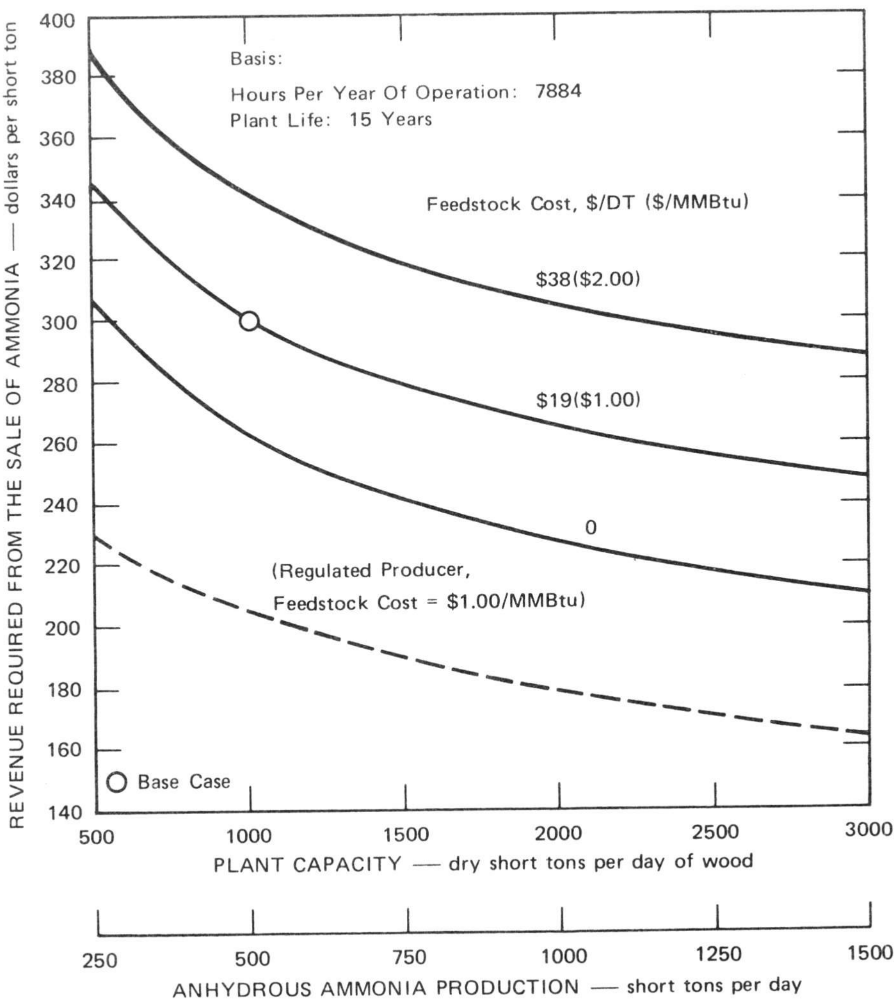


FIGURE 33 PRODUCTION OF AMMONIA FROM WOOD BY DIRECT GASIFICATION AND CONVENTIONAL AMMONIA SYNTHESIS — EFFECT OF PLANT SIZE ON REVENUE REQUIRED FROM THE SALE OF AMMONIA BY A NONREGULATED PRODUCER

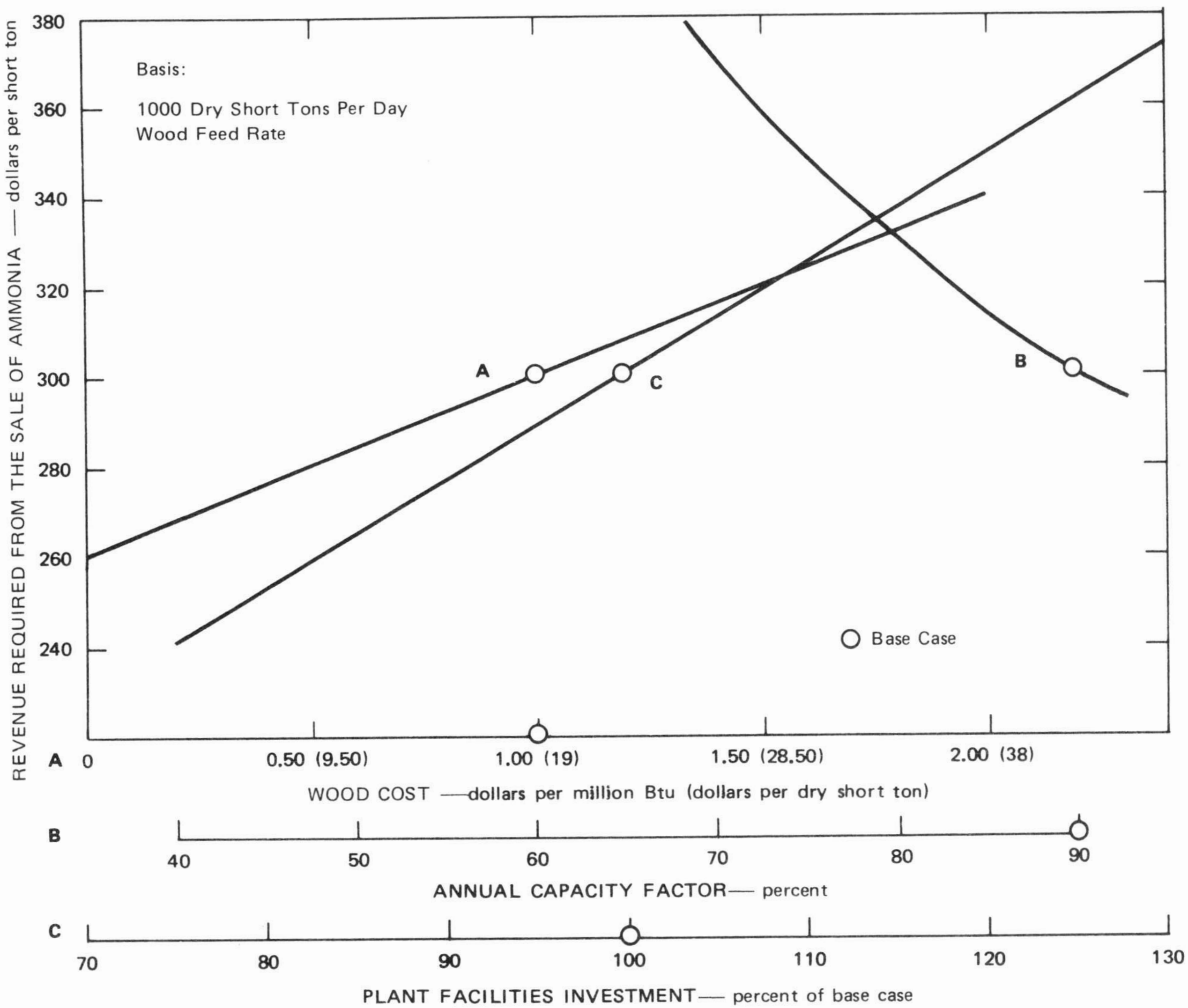


FIGURE 34 PRODUCTION OF AMMONIA FROM WOOD BY DIRECT GASIFICATION AND CONVENTIONAL AMMONIA SYNTHESIS — EFFECT OF VARIATION OF SELECTED PARAMETERS ON REVENUE REQUIRED FROM THE SALE OF AMMONIA BY A NONREGULATED PRODUCER

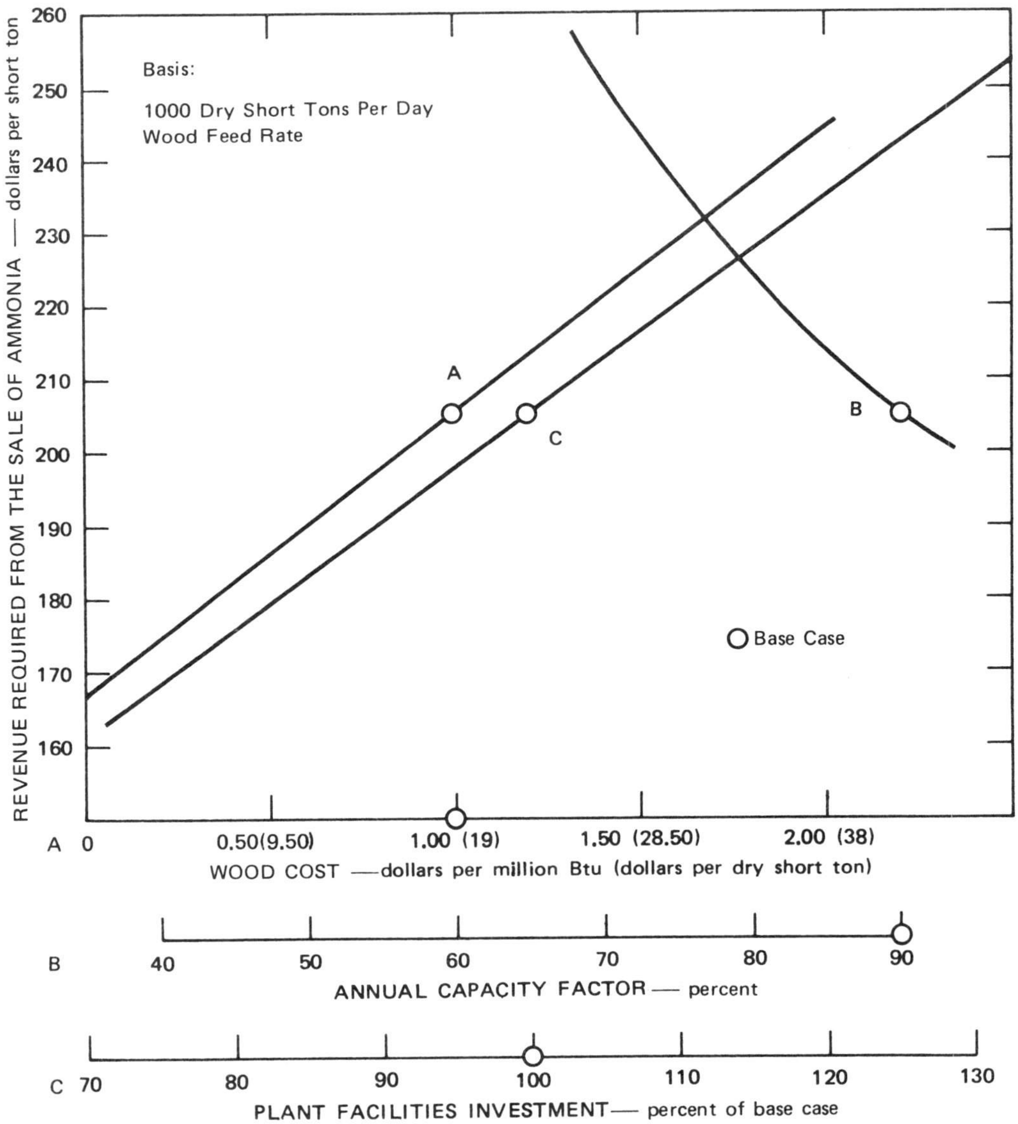


FIGURE 35 PRODUCTION OF AMMONIA FROM WOOD BY DIRECT GASIFICATION AND CONVENTIONAL AMMONIA SYNTHESIS — EFFECT OF VARIATION OF SELECTED PARAMETERS ON REVENUE REQUIRED FROM THE SALE OF AMMONIA BY A REGULATED PRODUCER

Appendix

ECONOMIC AND DESIGN BASES OF CONVERSION PLANTS

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Appendix

ECONOMIC AND DESIGN BASES OF CONVERSION PLANTS

Three general areas are covered in the discussion of the economic and design bases of biomass conversion plants.

- Capital investment--including a definition of the boundaries of the capital investment for a conversion plant, plant capacities; discussions of nonplant investments such as interest during construction, land, royalties, working capital, start-up costs; and discussions of depreciable investment and plant operating schedules.
- Operating and maintenance costs--including feedstock costs, purchased materials (e.g., water, catalysts, maintenance materials), labor, fixed costs (e.g., property taxes and insurance), and by-product credits.
- Financial analysis--including taxes, services of investment capital, interest rates, rates of return on equity, depreciation, project life, and revenue requirements.

Capital Investment

Biomass Conversion Plant Organizational Structure

The operation of a conversion plant under conventions of regulated utility organization and financing or nonregulated industry organization and financing significantly affects product prices. Based on a consideration of the likely markets to be served by the products of biomass conversion facilities, the following conventions were adopted for the work:

- Products from conversion plants appropriate to regulated industry organization and financing include intermediate-Btu gas, SNG, electric power, and fuel oil and methanol for utilities.
- Products from conversion plants appropriate to nonregulated industry organization and financing include steam, fuel oil, and methanol for industry; ammonia; and ethanol.

Conversion plants producing fuel oil and methanol may be organized along regulated as well as nonregulated industry lines. In the regulated case, the interpretation would be that of dedicated conversion facilities producing fuel oil or methanol for consumption by electric utilities located in the same geographic region.

Investment Factors--Conversion Plant

The plant facilities investment (PFI) is the total cost of the plant erected and ready for start-up. It consists of all process facilities, necessary utilities, and general plant facilities, including equipment and all direct and indirect costs of installation. The PFI does not include an across-the-board contingency factor. However, judgment has been used in developing costs for specific sections of each process, depending on the level of commercial experience that has been developed. Sensitivities of product cost were made for wide variations from the base case PFI. Paid-up royalties are included in the PFI as appropriate.

Plant facilities investments were developed by consulting with equipment vendors and engineering firms that specialize in construction of specific equipment or plant sections such as hydrogen or oxygen plants, from companies that have announced their intention to own synthetic fuels plants, and from literature sources.

The total capital investment includes the plant facilities investment, cost of land,* working capital,* and start-up costs* for the general conversion plant considered here. When considering debt-financed ventures (as typified by regulated utility plants), interest during construction* is included in the total capital investment.

Certain investments and operating costs are estimated by applying percentage factors against either investments or operating costs that have been previously estimated in detail. For example, investments required for start-up costs, and plant maintenance are estimated as percentages of the plant facilities investment. Similarly, supervision, administrative labor, and payroll burden are estimated as percentages of the operating labor costs. This method of estimating certain investments and operating costs follows current engineering practice for preparing budget estimates for alternative projects.

All monetary figures for investments and operating costs are given in late 1977 constant U.S. dollars. The philosophy of "mature plant" operation, as opposed to a pioneering venture, is followed in the general evaluation approach. Product transportation facilities are not included in the plant facilities investment, and product prices are on a "plant gate" basis.

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*Discussed later in this section.

Conversion Plant Utilities Investment

Facilities are provided for generating all steam required for gas compression or process needs by heat recovery or by burning plant fuel. Raw water is purchased at $0.60 per 1,000 gallons and electric power at $0.025 per kilowatt-hour.

The plant utilities investment includes the following facilities:

- Raw water filtering and softening facilities
- Cooling water system (includes either air cooling or wet cooling towers, distribution system, and blowdown treatment)
- Boiler feedwater demineralizers and deaerators
- Water distribution
- Wastewater collection and treatment
- Emission control equipment
- Plant fuel system
- Steam generation, distribution system, condensate lines, and boiler blowdown treatment facilities, if not separately identified.
- Electric power substation and distribution system
- Instrument air and inert gas systems
- Ash disposal
- Fuel gas handling.

Storage facilities for gaseous products are not included in the conversion plant investments.

Conversion Plant General Facilities Investment

The plant general facilities investment comprises the following buildings, shops, and installations:

- Office buildings
- Laboratory
- Flare and relief systems
- Maintenance shops
- Supplies warehouse
- Control laboratory
- Cafeteria, dispensary, and change house

- Plant roads, parking areas, walks, and storm sewers
- Plant communications system
- Plant fences, guard houses, and lighting system
- Fire protection facilities.

The utilities and general facilities costs do not include provision for site-specific offsites such as dams, water pipelines, power generation, stream diversion, access roads, railroads, air strips, bridges, tunnels, products pipelines, or townsite development. Many or most of these items may be necessary to the completion of a project in a remote area. Since it is assumed that in most cases electric power and makeup fresh water are purchased and delivered to the plant, the utilities investment does not include investment for water supply development and delivery.

Conversion Plant Emissions

The control of plant emissions is based on standards that the EPA has established or proposed for similar industrial operations (e.g., coal conversion or petroleum refining).

Sulfur and ammonia are recovered where appropriate, and by-product values are credited against operating costs.

Conversion Plant Capacities and Feedstocks: Thermochemical Missions and Biochemical Missions

Table A-1 lists the base feedstock rates and ranges in feedstock rates considered for the thermochemical and biochemical missions. For the thermochemical missions, a feedstock rate of 1,000 dry short tons per day of wood was selected as representing a near-term goal. The analysis also considered feedstock rates up to 3,000 dry short tons per day of wood as a longer term goal.

Conversion plant sizes were referred to by feedstock input rate rather than a product output rate (e.g., 250 million scf per day of SNG) to reflect the viewpoint that biomass conversion technologies tend to be feedstock limited.

Interest During Construction

Regulated industry plants are constructed with funds borrowed at 10 percent interest, which is compounded during the construction period and is capitalized with the plant investment.

Nonregulated industry plants are constructed with equity funds assumed to yield a 15 percent DCF rate of return covering the construction period and for the remainder of project life.

Table A-1

CONVERSION PLANT CAPACITIES AND FEEDSTOCKS FOR BIOMASS CONVERSION MISSIONS

Biomass Feedstock	Conversion Option	Primary Product	Base Feedstock Rate (dry short tons/day)	Range in Feedstock Rate Considered (dry short tons/day)
Wood	Catalytic liquefaction	Fuel oil	1,000	500-3,000
Wood	Steam/oxygen gasification	Methanol	1,000	500-3,000
Wood	Steam/oxygen gasification	Ammonia	1,000	500-3,000
Wood	Steam/oxygen gasification	SNG	1,000	500-3,000
Wood	Combustion	Electric power	1,000	500-3,000
Wood	Combustion	Steam	1,000	500-3,000
Wood	Pyrolysis-maximum liquid	Fuel oil and char	1,000	500-3,000
Manure	Anaerobic digestion	Intermediate-Btu gas or SNG	50* 30†	50-1,100* 30-700†
Wheat straw	Anaerobic digestion	Intermediate-Btu gas or SNG	500	500-3,000
Wheat straw	Enzymatic hydrolysis and fermentation	Ethanol	~3,000	--
Sugar cane	Conventional milling and fermentation	Ethanol	~2,500	--
Marine crops	Anaerobic digestion	Intermediate-Btu gas or SNG	1,000‡	1,000-6,000‡
Aquatic crops	Acid hydrolysis and fermentation	Ethanol	~1,100	--
Sugar cane (and sweet sorghum)	Advanced separation and fermentation	Ethanol	2,050	--
Corn stover	Purdue hydrolysis and fermentation	Ethanol	1,600	--
Wood	Steam/oxygen gasification	Intermediate-Btu gas	1,000	500-3,000
<u>Euphorbia</u>	Solvent extraction	Oil	3,000	--

*From environmental feedlots.

†From nonenvironmental feedlots.

‡Dry ash free basis.

Land Investment

Land required for the plant site is assumed to be valued at $5,000 per acre ($12,354 per hectare) in rural U.S. locations and $25,000 ($61,880 per hectare) in urban locations. Land cost includes rough grading and site preparation.

Working Capital

Working capital is provided for payroll and other cash operating expenses plus funds for feedstock purchase until receipt of accounts receivable. It includes the following items:

- Three months' total labor expense
- Two months' other cash operating expenses
- One month's feedstock supply.

Organization and Start-Up Costs

These costs include equipment modification and repair during start-up, operator training, property taxes and insurance during construction, and materials consumed during start-up. These costs are 5 percent of the plant facilities investment for nonelectric power plant facilities and 3 percent of investment for electric power plant facilities. Regulated industry start-up costs are capitalized, while nonregulated industry start-up costs are expensed.

Depreciable Investment

Regulated industry plant depreciable investment is the sum of plant facilities investment, interest during construction, paid-up royalties, and start-up expenses, typical of a regulated utility.

Nonregulated industry plant depreciable investment includes plant facilities investment and paid-up royalties, representative of an industrial venture.

Plant On-Stream Factor

After the start-up period is completed, the biomass conversion plants are generally assumed to operate on-stream 90 percent of the time, or 328.5 days per year. Conversion plants producing electric power are assumed to operate 80 percent of the time (292 days per year), as would be typical of a new base-load power plant.

Construction Period

Estimated construction periods appropriate to the technologies under consideration are used. These periods range, for example, from about two years for small biomass-fired steam electric power plants to about four years for large ammonia or methanol production facilities using biomass feedstock.

Conversion Plant Construction, Start-Up, and Operating Schedule

The example shown below gives the assumed time schedule and percentage distribution of positive and negative cash flows for construction funds, land purchase, working capital, operating costs, and revenue received during the project life. A four-year plant construction schedule is shown.

Start of Year	Depreciable Investment	Land	Working Capital	Variable Cash Operating Costs‡	Revenue*	Paid-Up Royalties
1	- 5%	100%				
2	-20					
3	-50					
4	-25					-100%
5†			-100%	- 60%	+ 60%	
6				- 90	+ 90	
7				-100	+100	
Final year of project			+100	-100	+100	

*Percentage of maximum.

†Start-up

‡Fixed operating costs (e.g., labor, property taxes) are assumed to be at maximum levels for every year of plant operation.

Operating and Maintenance Costs

Feedstock Costs

The following feedstock costs delivered to the biomass conversion plant are assumed for the base case economic evaluations. Since feedstock cost can be highly variable, depending on location and market conditions, its effect on product cost is determined over the range of costs indicated.

Feedstock	Base Cost* ($/dry ton)	Sensitivity Range ($/dry ton)
Woody plants	$19	$19-38
Manure (from any feedlots)	5	0-10
Cellulosic material (low moisture)	25	6-40
High sugar content plants (bagasse)	15	0-30
Marine crop (kelp)	60	68-200†
High-moisture crops	35	10-60
Euphorbia crops	16	0-32

Catalysts and Chemicals

The annual consumption and costs of chemicals and catalysts are estimated for each process based on current U.S. market prices.

Maintenance Materials and Supplies

Maintenance materials and supplies are estimated as 2 percent of the plant facilities investment.

Labor Factors

The following assumptions were made for conversion plant operating labor:

Plant operating labor ($/hr)	8
Plant supervision (% of plant operating labor)	15
Maintenance labor (% of plant facilities investment)	2
Administrative labor (% of operating, supervision, and maintenance labor)	20
Payroll burden (% of all labor)	35

*1977 dollars; midpoint of expected cost range.

†Dry ash-free basis.

Administrative and support labor is assumed to include plant manager, process engineers, laboratory technicians, clerks, secretaries, telephone operators, janitors, guards, and firemen. Payroll burden is assumed to cover costs of health insurance, disability insurance, vacations, sick leave, and retirement payments.

Fixed Costs

Annual local property taxes and insurance are estimated to be 2.5 percent of the plant facilities investment.

General administrative and overhead expenses are assumed to be 2 percent of the plant facilities investment. These include head office expenses for accounting, purchasing, legal services, office supplies, communication, travel fees, and contracted services.

By-Product Credits

Revenue from the sale of by-products is based on the following values.

By-Product	Dollar Credit	Units
Sulfur	\$ 30	Dollars per long ton
Ammonia	130	Dollars per short ton
Char/plant residue	Variable	
Export power	Variable	
C_5 sugars	Variable	
Animal feed	Variable	

Purchased Utilities

Electric power is purchased at 2.5 cents per kilowatt-hour, and water is purchased at 60 cents per thousand gallons delivered to the plant.

Financial Analysis

Income Taxes

Federal and state corporate taxes are assumed to total 52 percent applied to taxable income, reflecting a federal corporate tax rate of 48 percent plus a 4 percent state income tax rate. Since state taxes are normally deducted for federal reporting purposes the 4% state tax represents an estimate of the average net state tax impact.

Investment Tax Credit

The present U.S. industrial investment tax credit of 10 percent is not taken in the financial analysis of the base cases.

Sources of Investment Capital--Regulated Ventures

Regulated industries are assumed to partially finance the total capital investment of proposed biomass conversion facilities with debt capital. A typical ratio of debt-to-equity capital of 65/35 was used in this analysis. Table A-2 shows the base financial parameters used for this work.

Table A-2

FINANCIAL PARAMETERS STUDIED

Conversion Plant Organizational Structure	Base Percent Debt Capital (%)	Base Percent Equity Capital (%)	Base Debt Capital Interest Rate (%)	Base Return on Equity Capital (%)
Regulated	65%	35%	9%	15%
Nonregulated	0	100	0	15

Source of Investment Capital--Nonregulated Ventures

The base case financial analysis assumes that all funds for the total capital investment are provided from equity capital and yield a 15 percent DCF rate of return both during the plant construction period and over the life of the project. Since these projects are capital intensive, 100 percent equity financing results in high capital charges.

Depreciation and Project Life

The depreciation tax life is assumed equal to the project life for the regulated biomass conversion plant base cases. The following depreciation schedules and project lives are used.

Conversion Plant Organizational Structure	Depreciation Tax Life (years)	Depreciation Schedule
Regulated	20	Straight-line*
Nonregulated	15	SOYD†

*Straight-line depreciation schedule was used for regulated plants, since that is normal practice for regulated utilities.

†Sum-of-years' digits accelerated depreciation schedule was used because it is a method frequently used for industrial investments.

Revenue Required--Regulated Industry

The accounting methods permitted and required of regulated U.S. utilities vary somewhat with the regulatory agency. The method applied in SRI studies has been used by the U.S. Federal Power Commission.* Organization and start-up costs, interest during construction, and paid-up royalties are capitalized as part of the depreciable investment. Straight-line depreciation is calculated for each year of the project. This depreciation is subtracted from the undepreciated investment each year to obtain the depreciated plant investment. The rate base in any year is the sum of the depreciated plant investment, the cost of land, and the working capital. The return on rate base in a weighted average of the return and the simple interest rate on debt as follows:

$$P = d(i) + (1-d)r$$

where:

P = return on rate base
d = debt fraction
i = interest on debt
$1-d$ = equity fraction
r = return on equity.

In the base case, using the following values: $d = 0.65$, $i = 0.09$, and $r = 0.15$, the return on rate base (P) equals 11.1 percent. The total revenue required is the sum of return on rate base, income tax, and operating cost.

*Federal Power Commission, Final Report, The Supply-Technical Advisory Task Force--Synthetic Gas--Coal, Appendix I (April 1973).

The by-product credit, if any, also is calculated separately, and the net product revenue is obtained by subtracting it from the total revenue required.

As noted, the return on rate base is derived as a dependent variable. Even though in rate cases much more complicated calculations are used, the principal effect of such calculations is to provide another approach to determining the return on rate base. Thus, sensitivity analysis of return on rate base shows the net effect of a number of factors.

Revenue Required--Nonregulated Industry

Discounted cash flow (DCF) analysis is used to determine the revenue required to yield a desired rate of return on equity investment over the life of the project. A detailed discussion of DCF analysis is not attempted in this report. Very briefly, the net cash flow for any year is the sum of positive and negative cash flows consisting of revenue received, operating costs, income tax, equity investment, and payments for debt principal and interest. The annual net cash flow is discounted each year by multiplying it by the appropriate discount factor defined by the following equation:

$$d = \frac{1}{(1 + i)^n}$$

where:

d = discount factor
i = DCF rate of return on equity investment
n = year of project life to which cash flow applies

The revenue required to yield the desired rate of return on equity investment is determined by iterative calculation such that the sum of all discounted positive and negative annual cash flows over the life of the project will be zero.

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