Thermochemical Conversion of Forest Thinnings

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This is to certify that I have examined this copy of a master's thesis by

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and have found that it is complete and satisfactory in all respects,
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Abstract

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Years of active fire suppression on private and public land in the American west have led to unnaturally dense forests at increased risk to destructive wildfire. One way of reducing this risk is mechanical thinning, which removes some fraction of small diameter trees and brush from a stand. In addition to decreasing the risk of wildfire, thinning improves a forest's resistance to disease and insect infestation and those remaining trees mature more rapidly. Thinnings have limited commercial value, so revenue generated from sale of thinned material will not cover the cost of thinning. However, looking beyond traditional markets, there are multiple emerging energy and non-energy uses for thinnings which may have stronger economics.

This study quantifies bio-fuel production and end-use options on the basis of net thinning cost. This is the sum of all costs incurred from thinning to sale of final bio-energy product less the revenue realized by sale of this product. Options considered in this study include: cogeneration of heat and power using wood chips, co-fire of wood chips with coal for power generation, and production of wood pellets, bio-oil, and methanol. The net thinning cost for two non-energy options, the sale of wood chips for pulp and disposal of wood chips, are also calculated. The net thinning cost for these bio-fuels and end-uses has been calculated for a range of thinning operations and transportation distances from forest to end-use. Results indicate production of bio-fuels to be most economic for transportation distances greater than 400 km with co-fire preferred by a wide margin for shorter distances. For longer distances and thinning operations of modest size and

duration, the production of bio-oil (a low-grade liquid fuel) has the lowest cost. For large scale, long-term thinning operations, production of methanol (a high-grade liquid fuel) is preferred. Production of wood pellets is best suited for short-term or small thinning operations. Unfortunately, none of the scenarios under consideration result in a negative net thinning cost. That is, none of the scenarios are economically profitable. However, conversion of thinnings to bio-energy is much cheaper than landfill disposal and may be considered as a lowest cost disposal option.

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Glossary

dtpd: dry tons per day

odt: oven dry (0% moisture) ton

USD: United States Dollar
EUR: European Union Common Currency (Euro)

$ 000: thousands of USD

MJ: $1 \text{x} 10^6$ joule
GJ: $1 \text{x} 10^9$ joule

MW_e: $1 \text{x} 10^6$ watts of electrical energy
MW_{th}: $1 \text{x} 10^6$ watts of thermal energy

kWhr: one kilowatt of power consumed or produced in one hour
MWhr: $1 \text{x} 10^3$ kWhr

MBtu: $1 \text{x} 10^6$ Btu (British thermal units)

SO_x: oxides of sulfur
NO_x: oxides of nitrogen

SMB: small, modular bio-power

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1. Forest Thinning and Bio-Energy

Advances in fire fighting and prevention have suppressed natural burn cycles for decades in forests throughout the US. Natural burns are of relatively low intensity, consuming brush and some small diameter trees. This returns nutrients to the soil and decreases resource competition among remaining trees allowing the forest to mature. Suppression of these fires has resulted in unnatural volumes of brush and small-diameter trees in many forested areas [1]. Much of this growth is considered a ‘ladder fuel’, since if a fire does break out, it will provide a veritable ladder to the forest canopy. Once fire reaches the canopy, it rapidly spreads, consuming both ladder fuels and larger, valuable timber. Due to the abundance of fuel, wildfires burn much hotter than natural, lower intensity fires. The high temperatures scorch the earth and do more lasting damage to an ecosystem than natural fires. Wildfire is extremely difficult to contain and spreads rapidly across forested areas. Due, in part, to a growing abundance of ladder fuel, occurrences of wildfire have increased in recent years – as evidenced by large fires in California, Oregon, and British Columbia. So far, these fires have been largely restricted to unpopulated areas, but it would be naive to assume that this trend will continue indefinitely. A wildfire spreading into a populated suburban area would entail significant loss of personal property, or worse, loss of life. The Department of the Interior classifies over 120 million acres of U.S. forest at moderate to high risk of wildfire [2].

One approach to this problem is ‘thinning’ forests. Thinning involves the mechanical removal of ladder fuels (brush and some fraction of trees less than 6” in diameter) to create a more natural forest amenable to more frequent, low intensity burns [3]. Thinning reduces the risk of wildfire and has a number of other indirect benefits. Remaining trees face less competition for resources, maturing more quickly to valuable timber. Additionally, thinning improves the disease resistance of forests and reduces the risk of insect infestation [4]. However, thinnings have minimal commercial value in traditional markets. Sawmills are not equipped to use small-diameter wood, and other markets, such as pulp, have been economically depressed. As such, despite its benefits, ladder fuel thinning is not a profitable enterprise for landowners.

The Rural Technology Initiative at the University of Washington has performed a study on the costs and economic benefit of thinning [4]. The study focused on two northwest forests – Okanogan National Forest, in Washington, and Fremont National Forest, in Oregon. RTI estimated the cost of mechanical removal and collection of thinned timber at a logging deck to be between \$300 and \$500 per acre, balanced against a potential savings of \$1,291 to \$2,107 [4]. Savings include "reduced fire fighting and rehabilitation costs, facility losses and fatalities, protected habitats, sequestered carbon, saved water and other public values" [4]. However, these savings can not be monetized, and as such, are not able to directly cover the cost of thinning.

Despite these economic limitations, it is expected that thinning projects will, by necessity, proceed in the next decade, generating large volumes of biomass. The Forest Service and Department of the Interior are seeking more than \$30 billion in funding over the next ten years for ladder-fuel reduction activities [1]. If no other end-uses are identified, thinnings are expected to be burned in the field or land-filled if burning permits prove difficult to obtain. However, thinnings have a number of potential energy and non-energy uses and it would wasteful to dispose of so much raw material if other options would have stronger economics. On the energy side, thinnings may be used to generate electricity and heat or converted to a bio-fuel. Competing non-energy uses include pulp and forest products. Forest products encompass a number of options, including the manufacture of oriented strand board (OSB) and emerging small-wood industries [5]. Unlike use of thinnings for pulp or energy, forest products offer an opportunity for long-term carbon capture by sequestering biomass carbon in durable products. The only non-energy use quantified in this study is the sale of thinnings for pulp. As such, no options considered in this study allow for long-term carbon sequestration. However, all are effectively carbon neutral, since the carbon dioxide

(CO_2) released by the thermochemical conversion of biomass was originally removed from the atmosphere by the biomass growth.

Energy uses for thinnings may be very broadly grouped into thermochemical conversion for heat and power and thermochemical conversion to a higher grade bio-fuel. These categories may be further broken down to more specific options. Direct combustion, gasification, and co-firing are all options for producing heat and power. Bio-fuel production is similarly differentiated by the type of fuel produced.

1.1. Wood Chemistry

Wood is an oxygenated hydrocarbon. While the composition of wood is quite variable and contains many different species, a useful representative formula is $C_6H_9O_4$ [6]. In the Northwest, thinning operations will generally be carried out on softwood (conifer) species. As harvested, these softwoods typically have moisture contents of 50% by weight [7]. All moisture contents discussed in this study are defined on a wet basis.

$$\mathrm{MC} = \frac{\mathrm{M}}{\mathrm{D} + \mathrm{M}} \qquad \text{Equation 1.1}$$

where MC is the moisture content fraction, M is the mass of water, and D is the mass of bone dry biomass. Wood with a high moisture content is generally referred to a 'green' wood. Oven dried, or bone dry, wood is defined to have no free moisture.

Conifers usually contain little sulfur, so sulfur oxides (SO_x) are generally not formed during combustion. Nor is significant H_2S produced by pyrolysis. Woody biomass also contains mineral ash – nutrients absorbed from the soil during growth. Ash levels are usually less than 1% by weight for the bole (trunk) of softwood species, though bark ash content for firs can be as high as 3% [8].

The heating value of biomass is a function of species and moisture content. A regression of data presented in [9] suggests the following relation to determine the higher heating value for softwoods with a known moisture content.

$$\mathrm{HHV}\left(\frac{\mathrm{MJ}}{\mathrm{kg}}\right) = 19.380 - (19.376)(x_{\mathrm{moisture}}) \qquad \text{Equation 1.2}$$

where x_{moisture} is the moisture fraction of the wood. By this relation, green wood has a higher heating value of 9.69 MJ/kg.

Chemically, the constituent species of wood can be classified as extractives, cell wall components, and ash. Cell wall components consist of a carbohydrate fraction (cellulose and hemicellulose) and lignin, which acts as a binding agent. The term holocellulose is sometimes used to describe both the cellulose and hemicellulose fractions. Extractives include volatile oils, resins, fatty acids, pigments, and additional carbohydrates. Ash, extractive, lignin, and holocellulose fractions are given for a number of different softwoods and bark in Table 1.1 [8]. Relative fractions are presented on a moisture free mass basis. Pine and fir species are most prevalent in western forests.

Table 1.1 – Chemical Composition of Representative Softwoods and Bark

	Ash	Extractives	Lignin	Holocellulose
Softwood				
Western white pine	0.20	13.65	26.44	59.71
Western yellow pine	0.46	15.48	26.65	57.41
Yellow cedar	0.43	14.39	31.32	53.86
Incense cedar	0.34	20.37	37.68	41.60
Redwood	0.21	17.13	34.21	48.45
Bark				
Black spruce	2.1	24.78	45.84	27.28
Fir	3.1	30.37	39.16	27.37
White birch	1.5	21.6	37.8	39.1
Yellow birch	2.9	19.9	36.5	40.7
Beech	8.3	18.2	37.0	36.4

As can be seen in the table, bark tends to contain more lignin, extractives, and ash than softwood. This has implications for a number of the thermochemical conversion processes considered in this study.

1.2. Generation of Heat and Power

1.2.1. Direct Combustion

Direct combustion of biomass is the simplest and most developed type of thermochemical conversion. Direct combustion options include pile burners, stokers, suspension combustors, and fluidized beds. Hot flue gas from combustion is used to raise steam for a Rankine power cycle. If low-grade waste heat or steam from the cycle is used by an external process (e.g. space heating), the production of both electricity and heat is termed cogeneration. Well designed direct biomass combustion power systems have electrical efficiencies of around 30%. Cogeneration thermal efficiencies can be much higher, near 80% [10]. In 2002, there were 439 direct combustion facilities fired by timber residues with an installed capacity of 8.0 GW operating in the US [11]. An additional 4.3 GW of capacity exists for direct combustion of municipal solid waste (MSW), agricultural residues, and biogas. This is down from a peak in the 1990's, which was driven by PURPA subsidies for biomass power generation in California. Once the power subsidy expired, a number of facilities could no longer profitably operate and shut down [12].

As a practical matter, direct combustion of biomass for electricity alone has relatively weak economics and dedicated biomass facilities should operate in cogeneration (cogen) mode. In fact, many of the existing timber residue fired facilities are operated by the forest products industry, producing both power and process steam. This study quantifies the generation of heat and power using a circulating fluidized bed boiler. This modern design allows efficient, low emission combustion. Electricity produced by wood chip cogeneration is assumed to sell at a rate of \$45/MWhr, or \$12.5/GJ. Cogeneration heat is assumed to sell for \$4/MBtu, as an avoided cost for the purchase of heating oil. No purchaser for this heat has been explicitly identified.

1.2.2. Gasification Combined Cycle

A more efficient method for converting biomass to electricity is an integrated gasification combined cycle (IGCC) which can achieve electrical efficiencies around 40% [13]. This process involves first converting solid biomass to a syngas which is burned in a gas turbine. Waste heat from the gas turbine power cycle (Brayton cycle) raises steam in a heat recovery steam generator (HRSG) to produce additional electricity using a Rankine cycle. Gasification, of the type used in IGCC applications produces a syngas by heating biomass to 800-900^{o}C in sub-stoichiometric air. This syngas is primarily composed of CO, H_2, CO_2, H_2O, and N_2 with the relative proportions dependent on gasifier design and operating conditions. The mechanics of gasification are discussed in more detail in Chapter 8. Syngas from woody biomass also contains a number of contaminants - tars, particulate, and vapor phase alkali metals. A significant reduction in the levels of tar, particulate, and alkali metals is necessary to ensure reliable operation of the gas turbine. A simplified schematic of a biomass IGCC facility is given in Figure 1.1.

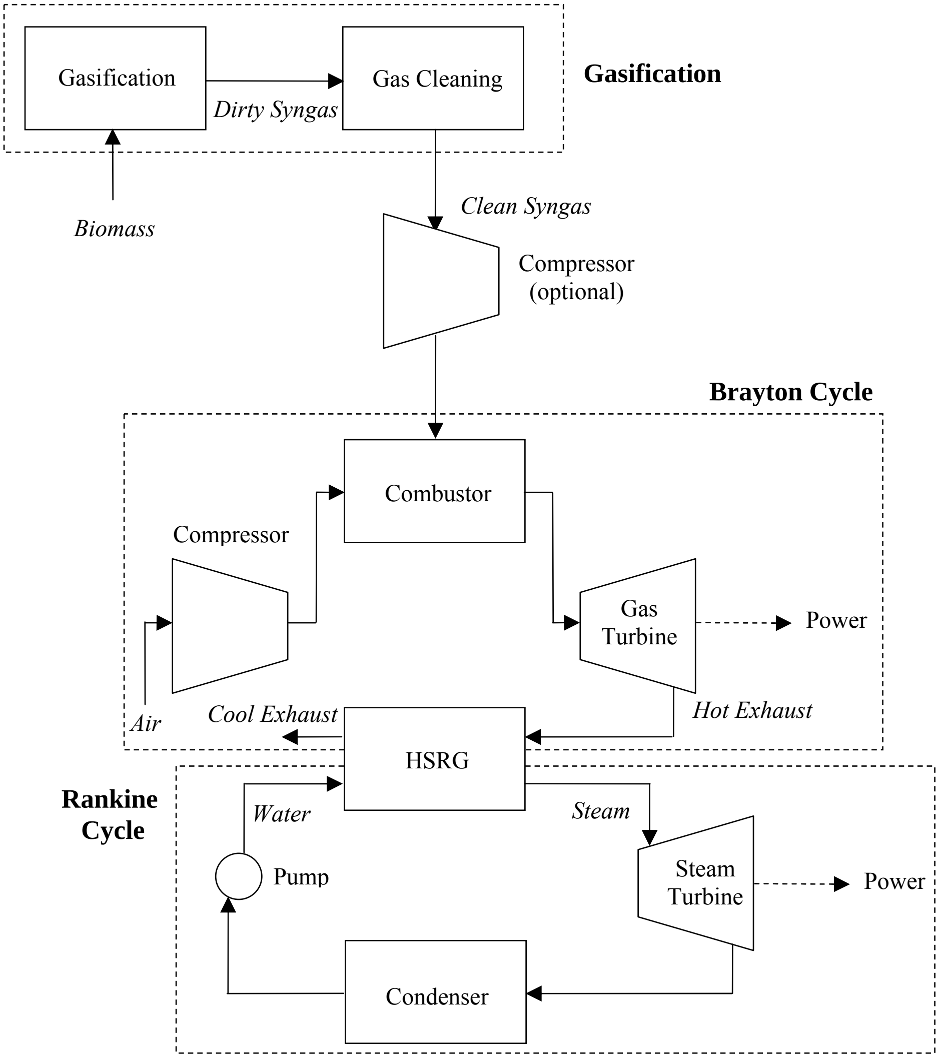

Figure 1.1 – Biomass IGCC Process Flow

In the late 1990's, a number of biomass IGCC demonstrations were carried out. The most notable of these were Värnamo, ARBRE, and McNeil.

The Värnamo system located in Värnamo, Sweden used a pressurized air-blown gasifier to produce 6 MW of electricity and 9 MW of thermal energy for district heating. Before the demonstration ended in 2000, the facility produced power from a variety of feedstocks, including biomass, straw, and refuse derived fuel (RDF) Since it was built as a demonstration project and not intended for commercial operation, it has been idle since the conclusion of the demonstration. Shakedown of the gasifier began in 1993 and was completed in 1996 – behind schedule due to fouling of downstream equipment by unanticipated syngas contaminants [14]. During the four years of testing between 1996 and 2000, engineers encountered, and satisfactorily resolved, a number of problems, such as mechanical failure of high temperature ceramic particulate filters for unknown reasons [14]. The Värnamo project provided a great deal of practical experience with biomass IGCC and, for this reason, may be considered a success.

ARBRE (ARable Biomass Renewable Energy project), a UK biomass IGCC facility fired on short rotation coppiced willow, was a demonstration intended for sustained operation. ARBRE used an atmospheric pressure, air blown gasifier coupled to an Alstom Typhoon turbine to produce 8 MW of electric power. The facility experienced a number of serious systems integration problems during commissioning [15], which resulted in a loss of confidence by the project's financial backers and led to the financial liquidation of the project [16]. Worse, farmers who had been contracted to produce energy crops now found themselves without a buyer [17]. The failure of this project is likely to have lasting repercussions for bio-energy efforts in the UK – especially those involving energy crops.

In the US, an indirect gasifier developed by Battelle-Columbus Labs (BCL), has been demonstrated at the McNeil Generating Station in Vermont. McNeil, a 50 MW facility, has existing capability to burn a variety of wood residues in a conventional stoker boiler. The BCL gasifier is indirectly heated, so the syngas produced is not diluted by nitrogen, as is the case in the other two direct air blown demonstrations. As a result, the heating value of the gas is higher (about 500 Btu/scf compared to 100-200 Btu/scf) and downstream gas compression requirements are reduced. Future Energy Resources

Corporation (FERCO) licensed the BCL design and further developed it as the *SilvaGas* process. FERCO experienced a number of issues with fuel handling and gas clean-up during commissioning – but these are reported to have been satisfactorily resolved [13]. While plans originally called for the McNeil demonstration to include firing of the syngas in a gas-turbine [18], financial constraints limited demonstration to co-fire of the syngas in the stoker boiler. FERCO has recently partnered with Alstom, the gas turbine manufacturer for the defunct ARBRE project, to build a commercial combined-cycle power plant in Devon, England [19]. This 23 MW_e facility would be fueled by agricultural waste and energy crops grown in the surrounding region (e.g. Micanthus grasses). However, this project faces significant public opposition – on grounds of aesthetic impact to the rural country-side and disputed assumptions on the yield of energy crops [20].

Given the problems each of these demonstrations encountered, it is hardly surprising that integrated gasification combined-cycle systems have been slow to reach commercialization.

Gasification combined cycle cogeneration has not been considered in this study. Follow-on work should consider the economics of IGCC. However, the challenges encountered in implementing this technology have important implications for the production of high-grade liquid bio-fuels. Production of these fuels requires a stream of low-contaminant syngas as an input to a gas-to-liquid (GTL) process.

1.2.3. Small Modular Biopower (SMB) Systems

Recently, a number of companies have begun to commercialize smaller-scale biomass-to-energy systems. These small, modular bio-power (SMB) systems have a rated capacity of at most of only a few hundred kW. This is significantly lower than traditional cogeneration power plants with rated capacities usually greater than 25 MW [10]. While the cost of these systems suffers from capital scale penalties, they may be readily transported to locations with a biomass feedstock – as opposed to bringing the feedstock to the power plant. Further, the small scale and low cost of these systems has allowed rapid iteration and refinement of their designs. For example, the Community Power Corporation (CPC) BioMax gasifier has been engineered to produce a syngas with tar levels suitable for gas-engine combustion without secondary tar removal [21]. Unfortunately, these systems have very low electrical generating efficiencies – 12% for the CPC BioMax [22] – and must operate in a cogeneration mode to be economically viable. Since this study focuses on large thinning operations, SMB systems are not considered as an end-use application. They do, however, show the potential for mobile and modularized bio-energy systems.

1.2.4. Co-fire

In pulverized coal boilers, it is possible to substitute biomass for a fraction of coal feedstock at existing facilities. Co-fire offers the possibility of producing bio-energy without the need to build a dedicated biomass power plant. Further, substitution of coal with biomass reduces emissions of SO_x and oxides of nitrogen (NO_x) relative to a dedicated coal facility. If, for some reason, the supply of biomass is disrupted, the plant may be fired entirely on coal, guaranteeing stable power output.

For woody biomass, substitution of 1-5% of coal on a mass basis requires only separate receiving and metal-screening equipment. At this level of co-fire, the coal pulverizers and burners should be able to process the biomass without difficulty. Higher levels of co-firing require dedicated receiving, storage, and pretreatment facilities, as well as burner modification [23]. Higher levels of biomass co-firing are possible by first gasifying the biomass and then injecting the produced gas into the pulverized coal boiler. For example, the circulating fluidized bed gasifier installed in Lathi, Finland makes use feedstock with up to 60% moisture and has been successfully operated on forest residues, agricultural waste, and refuse derived fuels (RDF). The gasifier has a rated capacity of 45 MW_{th} and can supply up to 15% of the heat input to the pulverized coal boiler [24].

For the purposes of this study, it has been assumed that the level of co-fire would necessitate dedicated biomass handling facilities and burner modification. However, for woody biomass gasification prior to co-firing should not be necessary. Electricity revenues are assumed to be the same as for wood-chip cogeneration at \$45/MWhr, or \$12.5/GJ. No sale of waste is assumed.

1.3. Bio-fuels from Thinnings

A number of bio-fuels may also be produced from woody biomass. While direct combustion of wood chips for power generation is better developed, for a forest far from industrial centers, the transportation cost of wood chips would constitute the majority of costs from thinning to end-use. For example, if wood chips are transported 450 km and converted to electricity in using co-fire, transportation costs account for more than 60% of the total cost. To reduce transportation costs, one would prefer to transport a bio-fuel with a higher mass than wood chips. Four bio-fuels have been considered in this study: wood chips (low-grade solid fuel), wood pellets (high-grade solid fuel), bio-oil (low-grade liquid fuel), and methanol (high-grade liquid fuel).

1.3.1. Low-Grade Solid Fuels

Wood chips are, in of themselves, a low-grade solid bio-fuel, though they are not conventionally thought of as such. Wood chips from forest thinnings have a low bulk density (350 kg/m^3) and low heating value (10 MJ/kg) [9]. If the entire tree is chipped, including bark, the product chips are referred to as ‘whole tree chips’. If thinnings are first debarked, then chipped, the product chips are referred to as ‘white chips’. White chips are more suitable for pulp sale than whole tree chips since bark is an undesirable contaminant to the pulping process. Commercial equipment is available for both stand-alone chipping and integrated chipping and debarking. Wood chips produced from freshly cut trees are considered ‘green’ and have a moisture content of 50% by weight. If wood is left in the forest for a season, moisture content of this ‘seasoned’ wood decreases to around 35% [25]. However, this approach would require sending heavy equipment into the forest twice – once for harvest and once for chipping. Due to the disruptive nature of this activity, and the fire danger posed by leaving thinnings in the forest for several months, the potential benefits of seasoning are not explored in this study.

If wood chips are sold for pulp and paper, western U.S. market rates have recently been around \$24/thousand board feet [26]. This correlates to \$1.3/GJ on an energy basis[1].

1.3.2. High-Grade Solid Fuels

High-grade solid fuels are characterized by higher bulk densities and heating values than wood chips. As a result, transportation costs are lower for the same initial mass of chips. This benefit is offset by the cost to convert the wood chips to a higher grade solid fuel. Wood pellets were chosen as a representative high-grade solid fuel for the purposes of this study. These small pellets (Figure 1.2) are produced by extruding ground and dried wood through a die at high pressure. This pressure raises the temperature of the wood, allowing the lignin fraction to flow and act as a binding agent once the pellets have been cooled.

Figure 1.2 – Wood Pellets

The Pellet Fuel Institute (PFI) has established standards for pellet fuels sold in the US (Table 1.2 [27]). Standards vary by country.

Table 1.2 – Pellet Fuel Standards (U.S.)

Parameter	Standard Pellet	Premium Pellet
Bulk Density	≥ 642 kg/m^3 (40 lb/ft^3)	
Diameter	6.35mm ≤ D ≥ 7.94mm (1/4" ≤ D ≥ 5/16")	
Maximum Length	38mm (1.5")	
Fines	< 0.5% by weight, able to pass through 1/8" screen	
Sodium Content	< 300 ppm	
Ash Content	< 3% by weight	< 1% by weight

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[1] Pulp chip revenue: $\frac{\$24}{1000\text{ bf}}\left(\frac{1000\text{ bf}}{83\text{ ft}^3}\right)\left(\frac{1\text{ ft}^3}{25\text{ dry lb}}\right)\left(\frac{2.2\text{ lb}}{1\text{ kg}}\right)\left(\frac{1\text{ dry kg}}{2\text{ wet kg}}\right)\left(\frac{1\text{ wet kg}}{9.69\text{ MJ}}\right)\left(\frac{1000\text{ MJ}}{1\text{ GJ}}\right)=\frac{\$1.3}{\text{GJ}}$

The low ash limit for premium pellets generally precludes the use of bark (high ash content) as a feedstock. On the wholesale market, 40 lb bags of pellets are assumed to be sold to a distributor for \$1/bag, or \$3.2/GJ[2]. Note that this is significantly lower than the retail price for pellets (\$3-4/bag), since pellets produced from thinning would be delivered to a distributor in bulk who would take responsibility for bagging, marketing, and distributing the product.

Due to their uniform nature, pellets are easier to handle than wood chips. They also burn more cleanly than wood chips due to lower moisture and ash content. They are commonly used for residential heating throughout Europe (especially the Nordics and Austria) and may also be used as a fuel for industrial boilers [28].

Large briquettes, another type of high-grade solid fuel, suitable as a power generation feedstock, have not been considered.

1.3.3. Low-Grade Liquid Fuels

When rapidly heated in the absence of oxygen, wood thermally decomposes into condensable vapors (oxygenated hydrocarbons and water), solid char, and light gases (e.g. CO, H_2). At room temperature, the vapors condense to a dark brown, viscous liquid with a distinctive smoky odor [25]. This primary product of the process, fast pyrolysis, is referred to as pyrolysis oil or bio-oil. The latter nomenclature is adopted for the purposes of this study. Relevant physical properties of bio-oil and its closest fossil analogue, #6 residual fuel oil, are presented in Table 1.3 [29].

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[2] Wood pellet revenue: $\frac{\$1}{40\,\text{lb}}\left(\frac{2.2\,\text{lb}}{1\,\text{kg}}\right)\left(\frac{1\,\text{kg}}{17.45\,\text{MJ}}\right)\left(\frac{1000\,\text{MJ}}{1\,\text{GJ}}\right)=\frac{\$3.2}{\text{GJ}}$

Table 1.3 – Physical Properties of Bio-oil

Property	Bio-oil	#6 Residual Fuel Oil
Density	1200 kg/m^3	940 kg/m^3
Moisture Content (wt %)	20-30%	0.1%
pH	2.5	-
Higher Heating Value (HHV)	16-19 MJ/kg	40 MJ/kg
Viscosity (at 50°C)	40-100	180
Solids (wt %)	0.2-1%	1%
Elemental Composition	(dry wt %)	
C	54-58	85
H	5.5-7.0	11
O	35-40	1
N	0-0.2	0.3
Ash	0-0.2	0.1

From the table, one sees that bio-oil has a number of unique characteristics, some more attractive than others. From a transportation standpoint, it has a desirable bulk density and heating value. However, bio-oil contains significant water – the sum of moisture in the feedstock and 'reaction water' produced by condensation and dehydration reactions during fast pyrolysis. The oil is polar in character and, as such, immiscible in petroleum fuels without the use of emulsifiers. This eliminates the possibility of direct blending with petroleum fuels as is common with bio-diesel. The presence of organic acids (carboxylic and acetic) in bio-oil result in a low pH [30], which, along with its high oxygen content, has implications for storage and end-use that are discussed more fully in Chapter 7.

While bio-oil is unsuitable as a transportation fuel, it is a sufficiently close analogue to #6 fuel oil [30] and may be substituted in industrial heating and power generation applications. This study assumes that bio-oil produced from thinnings will be sold as a fuel for industrial heating. A number of higher-value options for bio-oil have been proposed, such as upgrading to hydrogen [31] or methanol [32] or refining to produce valuable chemicals [30]. However, these options are still in the development phase and not quantified by this study.

Since no commercial market exists, as yet, for bio-oil, its market price has been estimated using #6 fuel oil as an analogue. For 2004, the price of #6 fuel oil received in Los Angeles has averaged \$0.77/gallon [33]. Converted to an energy basis for appropriate comparison, this implies bio-oil would sell for \$4.7/GJ[3]. Over the year, prices for #6 fuel oil have ranged from a high of \$1.01/gallon to a low of \$0.62/gallon.

1.3.4. High-Grade Liquid Fuels

High-grade liquid fuels are produced by gasification of biomass, cleaning of produced syngas, and a subsequent gas-to-liquid (GTL) process. Depending on the GTL process in question, methanol ethanol, synthetic diesel, or synthetic gasoline may be produced. High-grade liquid fuels have high bulk and energy densities and are suitable for use as transportation fuels. Methanol, in particular, is readily reformed for use in low-temperature fuel cells [34] and may also be used in internal combustion (IC) engines. Like low-grade liquid fuels, high bulk densities reduce transportation costs. Production of these fuels from wood chips is, however, quite costly and technically challenging. This study quantifies the production of methanol from thinnings. A wholesale market for methanol as a commodity chemical is well-established at \$1.00/gallon [35], or \$14.7/GJ[4] on an energy basis.

Production of synthetic diesel or gasoline using a Fischer-Tropsch process has not been considered.

While there is significant interest in producing high-grade liquid bio-fuels for transportation use, the transportation sector offers a number of unique barriers to bio-fuel adoption. Current sector energy consumption is dominated by petroleum (97%) [36] so, in the short-term, any new bio-fuel must be compatible with a petroleum infrastructure. That is to say, vehicles must be able to run on both bio-fuel and conventional fuel, since

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[3] Bio-oil revenue: $\left(\frac{\$0.77}{\text{gallon}}\right)\left(\frac{1\,\text{gallon}\ \#6}{154{,}000\ \text{BTU}}\right)\left(\frac{1\,\text{BTU}}{1055\ \text{J}}\right)\left(\frac{1\text{x}10^9\ \text{J}}{1\,\text{GJ}}\right)=\frac{\$4.7}{\text{GJ}}$

bio-fuel availability will be, initially, quite limited. Industrial bio-fuels, on the other hand face no such barriers. The industrial sector consumes a variety of fuels and fuel flexibility is much higher – the same process at different facilities may use different fuels. For example, researchers at the University of British Columbia have investigated the use of bio-oil in lime kilns for the pulp and paper industry [37]. Bio-oil could be used at a single paper facility without requiring the entire industry to adopt bio-oil fired lime kilns.

1.4. Economic Viability of Bio-energy from Thinnings

While modeling is necessary to quantify the costs and revenues associated with energy use of thinnings, we may make a few *a priori* observations. On an energy basis, thinning will cost approximately \$4/GJ[5]. This does not include the cost of chipping, producing a higher-grade bio-fuel, or transportation of the bio-fuel to an end-use market. Experience with biomass-based power generation in California indicates that plant operators may not be able to afford to pay anything for feedstock if they are to operate without a subsidy. And, in some cases, to operate profitably plant operators would need to be paid a 'tipping fee' for receiving biomass [38]. This suggests that revenue from direct combustion applications will not be able to cover the \$4/GJ cost of thinning. Furthermore, \$4/GJ exceeds the selling price of pulp chips and wood pellets, and is close to the price of bio-oil. This indicates that lower-value bio-fuel production is no more likely to cover the cost of thinning than direct combustion. Finally, a number of studies [34,39] quote a delivered wood chip cost of \$2/GJ as a baseline for economic, large scale high-grade liquid bio-fuels. This would indicate that for feedstock prices in excess of \$4/GJ, production of high-grade liquid fuels will also be unprofitable. However, the net cost of energy and non-energy applications must be compared to the cost of disposal of thinnings. Therefore, even if energy use of thinnings is not profitable, it may be less costly than disposal.

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[4] Methanol Revenue: $\left(\frac{\$1}{\text{gallon}}\right)\left(\frac{1\,\text{gallon}}{0.00379\,\text{m}^3}\right)\left(\frac{1\,\text{m}^3}{790\,\text{kg}}\right)\left(\frac{1\,\text{kg}}{22.7\,\text{MJ}}\right)\left(\frac{1000\,\text{MJ}}{1\,\text{GJ}}\right)=\frac{\$14.7}{\text{GJ}}$

Table 1.4 summarizes the characteristics of bio-fuels considered in this study. Energy and non-energy uses in italics have not been quantified by this study.

Table 1.4 – Bio-fuel Characteristics

	Wood Chips	Wood Pellets	Bio-oil	Methanol (MeOH)
Fuel Type	Low-grade Solid	High-grade Solid	Low-grade Liquid	High-grade Liquid
Description	– Thin chips, 25 mm on edge – Whole tree chips or bark free white chips	– Cylindrical, uniform pellets – 6 mm diameter, 20 mm long	– Dark brown, viscous liquid – Heterogeneous, non-equilibrium mixture of oxygenated hydrocarbons	– Clear, homogenous liquid – CH_3OH
Bulk Density (kg/m^3)	350	640	1200	790
Water (wt %)	50%	10%	20-30%	N/A[6]
Higher Heating Value (MJ/kg)	9.7	17.5	16-19	22.7
Revenue ($/GJ)	$1.3	$3.2	$4.7	$14.7
Energy Uses	– Steam cycle power generation – Co-fire – *Gasification power generation*	– Residential heating – *Steam cycle power generation*	– Industrial heating fuel – *Stationary dual-fuel diesel engine* – *Industrial turbine*	– *Internal combustion engine* – *Fuel cell*
Non-Energy Uses	– Pulp and paper – *Long-term forest products* – Disposal		– *Bio-refining feedstock*	– Commodity chemical
Production	– Chipping of thinnings	– Grinding and drying of chips – Pelletization	– Grinding and drying of chips – Fast pyrolysis	– Drying of chips – Gasification and syngas cleaning – Methanol synthesis

1.5. Bio-fuel Production Networks

An interesting question that arises when considering the production of bio-fuels from thinnings is the best location for fuel production. Production of bio-fuels at the logging deck by mobile units has the best transportation economics (since only densified fuel will

---

[5] Cost for thinning: $\left(\frac{\$40}{\text{wet ton}}\right)\left(\frac{1\ \text{wet ton}}{9.69\ \text{GJ}}\right)=\frac{\$4.1}{\text{GJ}}$

[6] Note: improperly stored methanol will absorb water from the environment, leading to undesirable phase separation

be transported), but would incur a number of production cost penalties because of low throughput. For reference, the logging deck serves as a central collection area for a thinning of approximately twenty acres of land. Thinning a large forest would require multiple logging decks. Conversely, production of bio-fuels at a large facility outside the forest has the benefit of very high throughputs, but faces higher transportation costs for transporting wood chips from the logging deck to bio-fuel production facility. Clearly, this is a question worth answering since it will determine the type of facility best suited for the conversion of thinnings to bio-fuel. The study considers four classes of facilities: mobile, transportable, stationary, and relocatable. These systems would produce wood pellets, bio-oil, or methanol.

1.5.1. Mobile Bio-fuel Production

Mobile bio-fuel production units would be brought to the logging deck like any other piece of harvesting machinery. It is envisioned that such a system would be mounted on a flatbed semi-trailer (like demonstration SMB systems) and have a rated capacity of no more than 10 dry tons per day (dtpd) [40]. Mobile units would remain at the logging deck for as long as required to convert all available thinnings – no longer than a week in most cases.

Although locating bio-fuel production at the logging deck is most advantageous with respect to transportation, because only densified bio-fuels will be moved, there are a number of concerns with this approach. First, at 10 dtpd rated capacity, these systems will be smaller than most conventional bio-energy facilities. As a result, scaling penalties will drive up equipment costs. Secondly, due to safety regulations governing remote work sites, two personnel will need to be on-site at all times during the three operational shifts. While this safety requirement can be met by the harvesting crew during one of the shifts, this means two operators will have to be paid during the other two shifts. These same two operators could run a much larger facility. Thus, mobile systems will also be subscale with respect to labor. It is worth noting that forestry operations generally do not operate on a three-shift schedule, so this, in itself, is a departure from conventional forestry. Finally, since grid electricity is not available within the forest, process power will be supplied by diesel generators – which produce power at higher cost than grid electricity.

Due to heavy wear and tear from transportation, the lifetime of mobile facilities is expected to be no more than 15 years.

1.5.2. Transportable Bio-fuel Production

One approach to mitigating two of the issues with mobile bio-fuel production would be to position a modular, transportable bio-fuel production system at a more central location within the forest. Such a system would be moved in several (three assumed) semi-trailer containers and assembled on-site. Transportable systems would be expected to remain in position for several months at a time. In determining the amount of time spent on site, the cost of moving the facility should be balanced against an increased collection radius for chip feedstock. Since a larger equipment footprint is allowed, rated capacities of 100 dtpd should be achievable [40]. This alleviates the sub-scale issues of mobile systems with respect to labor and capital cost. It does not, however, obviate the need for diesel generators and does add a transportation penalty by requiring that chips be moved from the logging deck to this more central location.

Due to heavy wear and tear from transportation, setup, and breakdown, the lifetime of transportable facilities is estimated to be no more than 15 years.

1.5.3. Stationary Bio-fuel Production

One option that eliminates all issues with in-forest production of bio-fuels is to establish a bio-fuel production facility on the outskirts of the forest. For thinning a large forest (or several small, nearby forests), a single stationary facility would process all chipped thinnings. Such a facility would benefit from economies of scale, strong utilization of labor, and access to grid electricity. However, since this facility would be located beyond the edge of the forest, additional penalties for transporting low-density chips will be incurred. Furthermore, facility lifetime becomes a significant issue. While mobile and transportable systems can be easily moved to new locations once nearby feedstock is exhausted, stationary systems have no such flexibility. A number of biomass to energy facilities have shut down or faced significant operating difficulties due to feedstock disruption [38] and facilities relying on thinning operations for feedstock should be no exception. Once the thinning operation is complete, there is no guarantee that feedstock would continue to be locally available. Therefore, for financial calculations, the lifetime of the facility is assumed to be equal to the duration of the local thinning operation. While some fraction of the facility cost is be salvaged at the end of life (estimated at 20%), this penalty makes stationary bio-fuel production unattractive for short-term thinning operations. However, rapid, short-term thinning operations most quickly reduce the risk of wildfire. Clearly, there is a trade-off to be made between bio-fuel production economics and the rate of thinning.

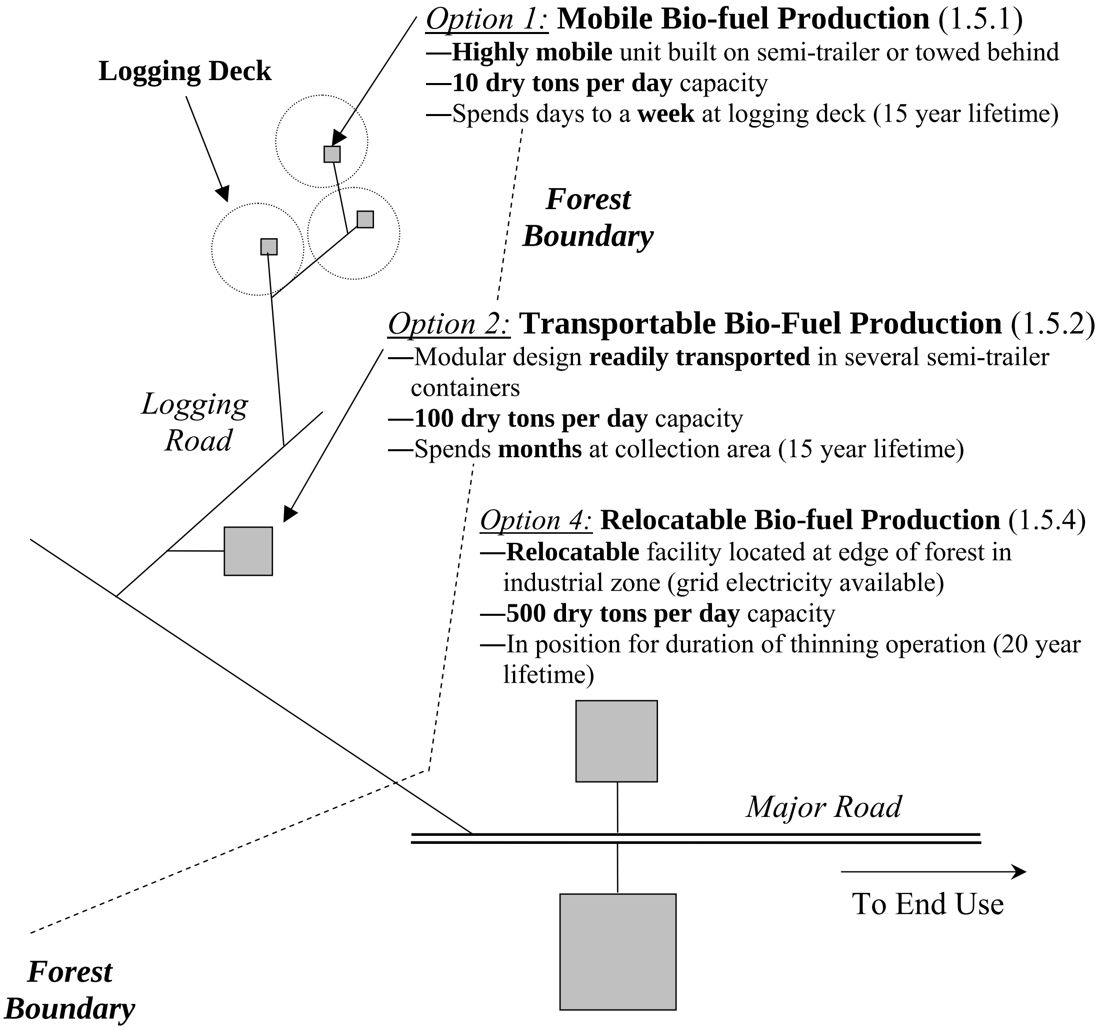
Stationary systems would be expected to have a lifetime of at least 30 years. However, this limit is never reached in the model because no thinning operation is modeled to last longer than 15 years.

1.5.4. Relocatable Bio-fuel Production

A final option would be a relocatable bio-fuel production facility. It is assumed that such a facility might have a capacity on the order of 500 dtpd, making it larger than transportable facilities and smaller than most stationary. The facility would be designed, at additional cost, to be readily broken down and moved to a new location at the conclusion of a thinning operation. These facilities would be located outside of the forest, with access to grid electricity to achieve most of the benefits of stationary bio-fuel production without the problem of long-term feedstock logistics.

Relocatable facilities have been modeled with a 20 year lifetime. This is shorter than the expected lifetime for stationary facilities due to increased wear and tear from facility relocation.

Figure 1.3 shows the layout of these four possible bio-fuel production facilities.



Option 1: **Mobile Bio-fuel Production** (1.5.1)
—**Highly mobile** unit built on semi-trailer or towed behind
—**10 dry tons per day** capacity
—Spends days to a **week** at logging deck (15 year lifetime)

Option 2: **Transportable Bio-Fuel Production** (1.5.2)
—Modular design **readily transported** in several semi-trailer containers
—**100 dry tons per day** capacity
—Spends **months** at collection area (15 year lifetime)

Option 4: **Relocatable Bio-fuel Production** (1.5.4)
—**Relocatable** facility located at edge of forest in industrial zone (grid electricity available)
—**500 dry tons per day** capacity
—In position for duration of thinning operation (20 year lifetime)

Option 3: **Stationary Bio-fuel Production** (1.5.3)
—**Stationary** facility located at edge of forest in industrial zone (grid electricity available)
—Sized so single facility consumes entire daily production from forest
—Lifetime equal to duration of thinning operation

Figure 1.3 – Layout of Theoretical Bio-fuel Production Network

2. Quantifying Options – Techno-economic Analysis

In differentiating different energy and non-energy options for thinning, cost is the simplest metric of comparison. The most appropriate measure of cost will include all costs from thinning to end-use, less revenue from the final product. The components of this 'net thinning cost' are shown in Figure 2.1.

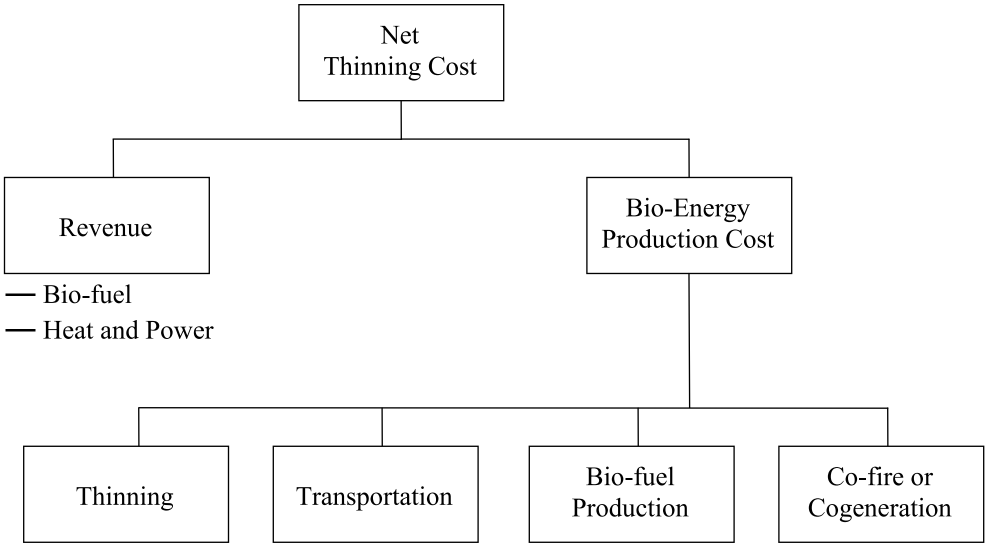


Figure 2.1 – Components of Net Thinning Cost

As shown in the above figure, costs incurred in the production of bio-energy have been broken down into:

- Thinning: costs directly related to mechanical thinning
- Transportation: cost to move bio-fuel (including chips)
- Bio-fuel Production: cost to produce a bio-fuel (including chips)
- Co-fire or Cogeneration: cost to produce heat and power from chips

End-uses involving the sale of bio-fuel are not explicitly modeled. For example, if methanol is produced and then sold, the model is agnostic as to whether it is used as a commodity chemical or reformed for use in a fuel cell.

The above costs may further be broken down into capital costs and operating costs. Capital costs relate to the purchase of tangible assets (e.g. equipment for bio-fuel production). These costs are typically incurred during process start-up. Operating costs are expenses relating to ongoing operations and are incurred over the life of a process. Operating costs may be further differentiated into fixed and variable costs. Variable costs are in proportion to process throughput. For example, the electricity consumption of a grinder is in proportion to the throughput of wood being ground. Fixed operating costs are independent of throughput and include various overhead and maintenance expenses.

In order to calculate the annual cost of a process, an annualized capital cost is added to the yearly operating cost. This annualized capital cost is given by multiplying capital cost by a capital recovery factor (CRF) given by [41].

$$CRF = \frac{i}{\left(1-\left(1+i\right)^{N}\right)} \quad \text{Equation 2.1}$$

where i is the annual interest rate and N is the lifetime of the investment. An annual interest rate of 8% is assumed. This is a compromise between commercial interest rates which may be as high as 12% and low interest, subsidized rates of 2%.

At the end of its planned use, a facility may have some residual, or 'salvage', value. This salvage value could be realized by sale of facility components which have not reached the end of their useful life. The annual impact of this salvage value is given by calculating the present value of the salvage and amortizing this over the facility lifetime.

$$\text{Annualized Salvage Value} = \frac{\left(\text{Salvage Value in Year N}\right)\left(CRF\right)}{\left(1+i\right)^{N}} \quad \text{Equation 2.2}$$

where i is the annual interest rate, N is the year of salvage, and CRF is calculated using the same interest rate and lifetime.

Salvage values and facility lifetimes are summarized in Table 2.1.

Table 2.1 – Salvage Values and Facility Lifetimes

Facility Type	Lifetime	Salvage
Mobile	15 years	0%
Transportable	15 years	0%
Stationary	Duration of thinning	20%
Relocatable	20 years	0%

Combining these concepts, net thinning cost is given by the following equation:

$$\begin{aligned}\text{Net Thinning Cost} = &\sum_{\text{All Processes}}(\text{Annualized Capital Cost - Annualized Salvage Value})\\ &+\sum_{\text{All Processes}}\text{Operating Cost} - \sum_{\text{End-Use}}\text{Revenue}\end{aligned} \qquad \text{Equation 2.3}$$

This 'net thinning cost' may then be used to compare different energy and non-energy options for thinning on an equal basis. This approach does not quantify increased technical risks for options with limited commercial experience (e.g. high-grade bio-fuel production). These subjective risks should, however, be taken into consideration when comparing different bio-energy options and are discussed in the reviews of bio-energy technologies in Chapters 6 – 10.

Net thinning costs are expressed through this report on a per wet ton thinned basis. That is, the absolute net thinning cost given by Equation 2.3 is divided by the annual tonnage of thinnings generated to normalize costs for different scales of operation.

2.1. Model Methodology

The modeling approach adopted in this study relies on a granular build-up of costs. To as great a level of detail as possible, physical inputs (e.g. biomass, power) and costs are identified for individual process steps. This gives transparency in modeling and ensures the cost model reasonably approximates the engineering specification of a system. The first step in a granular build is to identify process steps to as detailed a level as feasible and establish how they connect. A simple way to represent these connections, as well as inputs and outputs, is a flow diagram. An example is shown in Figure 2.2.

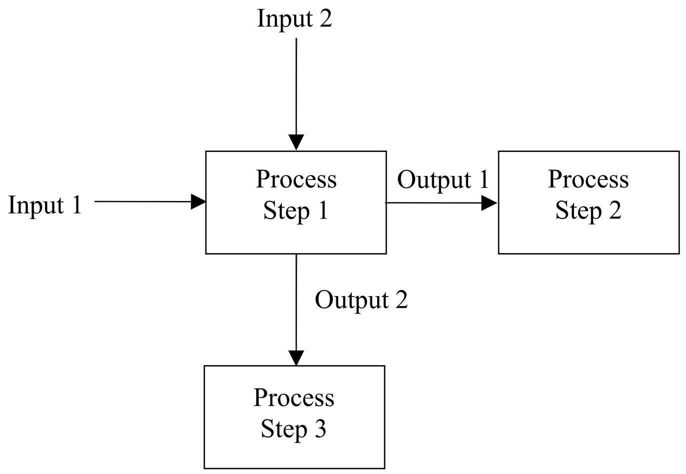


Figure 2.2 – Representative Process Flow Schematic

Each process will have one or more inputs. The most common inputs are biomass, heat, and power. Other possible inputs include steam or catalysts. Each process will also have one or more outputs. These will be upgraded biomass, a waste-byproduct, heat, or power. While it is not always possible to break a system down to individual pieces of equipment, it is generally possible to move beyond a black-box approach.

As a counter-example, consider a black-box approach. In one study of bio-oil production, a cost estimate of \$6/GJ is quoted [42]. However, the study does not make clear most of its underlying assumptions. For instance, what feedstock cost is factored into this cost estimate? Using cost numbers from black-box studies makes it very difficult to determine whether a given physical scenario is well-represented by the underlying cost model. For example, if a black-box approach is used and assumes that feedstock is received at 50% moisture, it would be difficult to know how the black-box cost estimate should be modified if feedstock is received at 10% moisture. A granular approach is generally taken in techno-economic studies [34,39] and provides greater transparency when follow-on work is attempted by other researchers.

2.2. Cost Elements

As previously discussed, bio-energy costs may be classified as capital costs – a charge representing an annual payment on the investment in equipment – or operating costs – the cost incurred during operation.

2.2.1. Capital Cost

Capital costs usually vary in relation to equipment capacity. Obviously, equipment with a higher capacity will cost more than equipment with a lower capacity. However, one piece of equipment with ten times the capacity of another will, in general, not cost ten times as much due to economies of scale. In this study, stationary bio-fuel production capacity varies significantly across scenarios since the capacity of stationary facilities is determined by the size and duration of the thinning operation. Since a number of different sizes of thinning operations were considered (10,000 acres per year to 100,000 acres per year), equipment capacity varies from 120 to 1200 dtpd. Also, it has been necessary to extrapolate known equipment to much lower throughputs to estimate mobile and transportable facility costs. This is done using a variety of methods, depending on the data available.

In a few cases, previously published systems studies have included cost regressions for process equipment [43]. These regressions are generally of the form given below:

$$\text{Capital Cost} = \text{A}(\text{Throughput})^{B} \qquad \text{Equation 2.4}$$

where *A* is a cost in USD and *B* is an exponent between 0 and 1.

In cases where regressions are not given explicitly, but capital costs are specified for a number of different equipment sizes, a regression may be developed by assuming a curve fit of the form of Equation 2.4. This same approach may be used when vendors are able to give cost quotes for a number of different equipment scales.

In a number of cases, costs are known only for a single equipment capacity. When these costs are for equipment still in demonstration or development [34], it is not possible to request additional quotes for equipment sizes from vendors. In these situations, scaling factors are used to adjust equipment costs using an equation of the form given below.

$$(\text{Capital Cost})_2 = (\text{Capital Cost})_1 \left(\frac{\text{Capacity}_2}{\text{Capacity}_1} \right)^{S_{\text{Capacity}}} \qquad \text{Equation 2.5}$$

where $S_{Capacity}$ is a scale factor for estimating equipment costs for different capacities. With a scale factor of 1, equipment costs scale linearly – meaning there is no economy of scale benefit. This may occur when process capacity exceeds the largest physically available equipment capacity and incremental process throughput would be met by two pieces of equipment, rather than a single larger piece of equipment. With a scale factor of 0, equipment costs are flat – meaning equipment with less capacity costs just as much. This may occur when process capacity falls below the minimum physically available equipment capacity. In some previously published systems studies, scale factors are specified [39]. When scale factors have not been specified, a generic scale factor of 0.7 is used in line with recommendations from previous work [10].

An additional consideration for emerging technologies is learning scale. Commonly, the first generation of any technology is significantly more expensive than those that succeed it due to experience gained in commissioning and constructing first generation systems. To quantify this effect, learning scale is defined as follows: for each doubling in the number of units produced one expects to see a percentage decrease in capital cost. Bridgwater et al. [43] indicate a 20% learning scale to be appropriate. This model uses a more conservative assumption of 10%. Capital cost for the n^{th} unit is given by the following equation:

$$(\text{Capital Cost})_n = (\text{Capital Cost})_{1^{\text{st}}\ \text{system}} \left(S_{Learning}\right)^{\ln(n)/\ln(2)} \qquad \text{Equation 2.6}$$

where $S_{Learning}$ is the learning scale defined above and n is the number of units built.

Since a significant number of mobile units would have to be constructed for even a moderately sized thinning operation, mobile units would be expected to strongly benefit from learning scale. For the purposes of this study, it is assumed that mobile unit capital costs will be modeled as 100th unit costs. 100th unit costs correspond to a 50% reduction in capital cost relative to 1st unit costs. Like mobile units, transportable facilities should also benefit from learning scale. However, since fewer units would be necessary for thinning due to higher equipment throughput, one would expect a lesser effect. For the purposes of this study, it is assumed that transportable facility capital costs will be modeled as 10th unit costs. The 10th unit costs correspond to a 30% reduction in capital cost relative to 1st unit costs. In the case of stationary facilities, since, by definition, only a single unit will be constructed, no learning scale benefit is anticipated, and stationary facility cost will be modeled as 1st unit costs. Again, with relocatable facilities, since only a few units will be constructed, no learning scale benefit is anticipated, and capital costs for these facilities will be modeled as 1st unit costs.

Published or quoted equipment costs may not necessarily include installation labor, piping, instruments, electrical systems, civil works etc. To properly account for additional required infrastructure and labor, an installation factor of 1.6 is used, in line with a published review of previously constructed bio-energy facilities [10]. This is referred to as direct plant cost (DPC) which is then further modified to project installed plant cost (IPC) and total plant cost (TPC) using factors given in Table 2.2 [43].

Table 2.2 – Plant Cost Multipliers

Cost Item	Factor
Engineering, design, supervision	15% DPC
Management overheads	10% DPC
Installed Plant Cost (IPC)	125% DPC
Commissioning	5% IPC
Contingency	10% IPC
Contractor's Fees	10% IPC
Interest During Commissioning	10% IPC
Total Plant Cost	135% IPC 169% DPC

These plant costs should be considered estimates, with accuracy no greater than 30%.

2.2.2. Operating Cost

Operating costs may be classified as variable – which vary in proportion to throughput – or fixed – which are incurred regardless of throughput. The majority of operating costs are variable.

External power purchases are a significant part of the cost chain for bio-fuel production. Power purchased from the grid, the case for stationary and relocatable bio-fuel production, is assumed to cost \$0.06/kWhr. Power production for mobile and transportable units is discussed separately in Chapter 5.

Labor costs are calculated by multiplying the number of working hours in a year by the number of operators required per shift. Above certain minimum staffing requirements mandated by safety needs, headcount requirements may be approximated by the following scaling relation:

$$(\text{Headcount})_2 = \frac{(\text{Capacity})_2}{(\text{Capacity})_1}(\text{Headcount})_1 (S_{Headcount})^{\ln\left(\frac{\text{Capacity}_2}{\text{Capacity}_1}\right) \Big/ \ln(2)} \qquad \text{Equation 2.7}$$

where Headcount is the number of required personnel per shift, capacity is the facility capacity, and $S_{Headcount}$ is the headcount scale. In practice, headcount scale usually varies between 70 and 100%. For the purposes of modeling, a headcount scale of 80% has been assumed.

Labor is accounted for at a rate of \$30.00/hr [7,44], which corresponds to a fully loaded headcount cost (e.g. including benefits).

Fixed operating costs for this study consist of general operations and maintenance charges and overhead (e.g. administration). These costs are modeled as a fraction of total plant cost as in Bridgwater et al. [43]. General operations and maintenance is modeled as 2.5% of total plant cost and overhead is modeled as 2.0%. This charge is incurred for all modeled processes.

Process specific fixed and variable operating costs (e.g. catalysts) are discussed in the technology reviews in Chapters 4 - 10.

2.2.3. Reference Currency

Costs and revenues listed in this study are in 2004 U.S. Dollars (2004 USD). In order to update costs from previous years, implicit price deflators (IDP) [41] are used as follows.

$$(\text{Cost})_{2004} = (\text{Cost})_{\text{Year X}}\left(\frac{\text{IDP}_{2004}}{\text{IDP}_{\text{Year X}}}\right) \qquad \text{Equation 2.8}$$

Implicit price deflators for all years are tabulated by the U.S. Federal Reserve and publicly available [45].

A number of costs are obtained from European studies, which list costs in Euros (EUR) or local currencies (prior to the adoption of the Euro in 2000). These costs are converted to USD, using the average exchange rate for that year [46] and then adjusted to 2004 USD using implicit price deflators.

2.3. Calculation of Key Metrics

This section lays out general analytical approaches used in this study for calculation of a few key process metrics.

2.3.1. Capacity Factor

Capacity factor is defined as the fraction of time a system operates at its rated capacity. This number is almost always less than 100% due to scheduled and unscheduled downtime. For production of bio-fuel, the following will reduce a system's capacity factor:

1. *Non-working days*: days when no bio-fuel production occurs
    a. Holidays: operations will not be carried out on federal holidays. (10 days)
    b. Extreme weather: for operations within the forest, extreme weather will sometimes make operation impossible. (20 days)

c. Harvest Window: harvesting operations may not take place throughout the year [57]. However, in most western U.S. forests in need of thinning, operations should be possible year-round [7].

Table 2.3 – Non-working Day Assumptions

	Mobile/Transportable Bio-fuel Production	Stationary/Relocatable Bio-fuel Production
Holidays	10 days	10 days
Extreme Weather	20 days	0 days
Harvest Window	12 months	12 months

2. *Transportation*: for mobile, transportable, and relocatable operations, time is spent moving equipment from site to site and for setup and breakdown. Specifics are discussed in section 5.2.
3. *Technical availability*: A system will not always be available for operation due to scheduled downtime for maintenance and/or unexpected outages. A general technical availability of 85% is assumed for all processes.
4. *Working hours per day*: for three-shift operation, as assumed in this model, equipment could be operated 24 hours a day.

Given these parameters, the capacity factor of a bio-energy system may be calculated by the following equation.

$$CF = \frac{(365 - \mathrm{D}_{\text{Non-Working}})(\mathrm{H}_{\text{Working}})(a_{\text{Technical}}) - \mathrm{H}_{\text{Transportation}}}{\text{Hours in year (8760)}}$$ Equation 2.9

where CF is the capacity factor, $\mathrm{D}_{\text{Non-Working}}$ are the number of non-working days per year, $\mathrm{H}_{\text{Working}}$ is the number of working hours per day, $a_{\text{Technical}}$ is the technical availability of a process, and $\mathrm{H}_{\text{Transportation}}$ is the numbers of hours spent transporting mobile, transportable, and relocatable bio-fuel production systems. Calculated capacity factors for the four types of production facilities considered are given in Table 2.4.

Table 2.4 – Bio-fuel Production Capacity Factors

Facility Type	Capacity Factor
Mobile	76%
Transportable	75%
Stationary	83%
Relocatable	81%

The higher capacity factors for stationary and relocatable production of bio-fuels will benefit their economics since less purchased capital will be required to convert the same volume of thinnings.

Once the capacity factor has been established, the annual feedstock consumption for a process is given by the following equation.

$$\text{Annual Consumption} = \left(\text{Rated Capacity}_{\text{dtpd}}\right)\left(CF\right)\left(\text{Days in year}\right) \qquad \text{Equation 2.10}$$

This metric determines the number of bio-fuel production units (e.g. mobile) necessary to process the thinnings generated from a given acreage of land.

$$\text{Required Units} = \text{Round - up}\left(\frac{\text{Annual Tonnage (dry) Thinnings}}{\text{Annual Consumption Single Unit}}\right) \qquad \text{Equation 2.11}$$

The number of units required is rounded up to the nearest whole integer. Implications of this rounding are discussed in section 2.4.

2.3.2. Power Consumption

Production of bio-fuels requires significant external power input to operate equipment. To supply this power, this model assumes, in order of preference, the following generation options:

1. *Grid electricity*: power from grid
2. *Dual-fuel diesel-electric generator* (fast pyrolysis only): bio-oil combustion with supplemental diesel fuel in dual-fuel diesel engine coupled to generator
3. *Diesel-electric generator*: diesel fuel combustion in diesel engine coupled to generator

2.3.3. Heat

Production of bio-fuels will require heat for feedstock drying and may require additional heat for endothermic thermochemical processes. This analysis assumes, in order of preference, generation of heat by means of:

1. *Byproduct combustion*: combustion of solid and gaseous byproducts (e.g. char)
2. *Diesel-generator exhaust*: sensible enthalpy in exhaust gases

3. *Wood chip combustion*: burning of feedstock

2.3.4. Feedstock Basis

Feedstock may either be considered on a wet or dry (moisture free) basis. Most equipment capacities in this study are given on a basis of dry tons per day (dtpd). Thinning output is usually presented on a wet tonnage basis. Quantities of wet and dry feedstock are related by the following equation.

$$\text{dry mass} = (\text{wet mass})(1 - \text{fraction moisture content}) \qquad \text{Equation 2.12}$$

2.3.5. Mass Yield

The mass yield for bio-fuel production processes is defined by the following equation.

$$\text{mass yield (\%)} = \frac{\text{mass bio - fuel produced (wet basis)}}{\text{mass feedstock input (wet basis)}} \qquad \text{Equation 2.13}$$

2.3.6. Energy Efficiency

Energy efficiency for a given conversion process may be determined by dividing energy output by input. That is, the fraction of the energy input is usefully available at the end of the process. This will always be less than 100% due to system losses. For example, the power used to chip raw thinnings is not imparted to the bio-fuel – rather it is dissipated as unrecoverable heat and sound.

For production of bio-fuels, process efficiency is given by the following equation.

$$\text{Efficiency} = \frac{\text{Energy content of bio - fuel}}{\left(\begin{array}{l}\text{Energy content of biomass feedstock} \\ + \text{External power} + \text{External heat}\end{array}\right)} \qquad \text{Equation 2.14}$$

For conversion of bio-fuels to heat and power, efficiency is given by the following equation.

$$\text{Efficiency} = \frac{\text{Net Electrical power} + \text{Saleable heat}}{\text{Energy content of bio - fuel}} \qquad \text{Equation 2.15}$$

2.4. Integrated Model Mechanics

A model has been constructed to calculate net thinning costs for a range of bio-fuel production and end-use options. Details of the model mechanics may be found in Appendix A. A case for the production of bio-fuel is defined by the selection of five parameters:

1. *Type of bio-fuel produced*: wood chips, pellets, bio-oil, or methanol
2. *Bio-fuel production facility*: mobile, transportable, stationary, relocatable
3. *Annual acreage thinned*: 10,000 – 100,000 acres
4. *Duration of thinning*: 1-15 years
5. *Average distance from logging deck to end-use*: 100-700 km

For the purpose of discussion in following sections, a base case is established with an annual acreage thinned of 80,000 acres, duration of 10 years, and transportation distance of 450 km. This base case approximates the thinning of Okanogan National Forest on the east side of the Cascade Crest in Washington. This large, national forest has nearly 800,000 acres at risk to wildfire [4].

In addition to the five above parameters which specify a bio-fuel production case, bio-fuel end-use must also be specified. When upgraded bio-fuels are produced, sale of the bio-fuel is the only end-use considered. In the case of wood chips, there are four possible end-uses – co-fire, cogeneration, disposal, and pulp sale. End-uses are summarized in Table 2.5.

Table 2.5 –Bio-fuel End-use Options

Bio-fuel	End-uses
Whole tree chips	Disposal (landfill) Cogeneration Co-fire
White chips	Pulp sale
Pellets	Sale for residential heating
Bio-oil	Sale for industrial combustion
Methanol	Sale as commodity chemical

For a given production case and end-use, the model calculates the net thinning cost using the following methodology.

The annual acreage thinned determines the annual thinning yield using an approach described in Chapter 3.

Once the annual thinning yield is known, stationary facility throughput is determined. Thinning duration sets the economic lifetime of a stationary facility. Mobile, transportable, and relocatable facility throughputs and lifetimes are not dependent on thinning duration or yield. With this information, the cost, capacity, and bio-fuel output of each facility type may be calculated.

As discussed previously, dividing the annual thinning yield by the annual throughput of each facility type gives the number of facilities required to handle the annual yield from a thinning operation. This number is rounded up to the nearest whole integer. For the base case, ninety-eight mobile units, ten transportable units, two relocatable facilities, or one stationary facility will be needed to meet the annual output of thinned biomass from a forest. Clearly, with larger facilities, especially relocatable facilities, utilization may become an issue. If slightly more than one relocatable facility is required, the model will calculate that two facilities are required, though each will have only slightly greater than 50% utilization. This 'whole-facility' problem is somewhat mitigated by the approach taken to calculate costs, which is described below.

For the purposes of discussion, in addition to an integer number of facilities, let us also consider a fractional number of facilities which would be needed to process the biomass generated from a thinning operation. The following equations are used to calculate annual bio-fuel output and cost.

$$\begin{aligned}&(\text{Bio - fuel Output})_{\text{Total}} = \\ &\qquad (\text{Bio - fuel Output})_{\text{Single Facility}}(\text{Facilities})_{\text{Fractional}}\end{aligned} \qquad \text{Equation 2.16}$$

$$
\begin{aligned}
(\text{Cost})_{\text{Total}} = {} & (\text{Fixed Cost})_{\text{Single Facility}}(\text{Facilities})_{\text{Integer}} \\
& + (\text{Variable Cost})_{\text{Single Facility}}(\text{Facilities})_{\text{Fractional}}
\end{aligned}
\qquad \text{Equation 2.17}
$$

By this approach, a facility has 75% utilization (e.g. 0.75 fractional facilities, 1.0 facility required) it would operate 75% of time and sit idle the other 25%. As a result, while fixed operating costs and amortized capital expenses will be incurred throughout the year, variable operating costs (e.g. labor) will only be incurred 75% of time.

The same general approach is used to calculate the cost of operating end-use facilities for heat and power generation.

When costs for harvest (Chapter 3) and transportation (Chapter 10) are added to the cost of producing bio-fuel, the result is a gross thinning cost. Bio-energy revenue is subtracted to give net thinning cost.

3. Harvest

Harvest is comprised of mechanical thinning and transport of thinned trees and brush to the logging deck – a central collection area for a given thinning operation. Each deck generally serves an area of roughly 20 acres [7]. Decks are located at the terminus of logging roads, which form a dendroid network. An overview of harvesting methods may be found in Han et al. [47]. In order to simplify this study, it has been assumed that thinnings will, at a minimum, be chipped at the logging deck prior to transportation or conversion. Discussion of chipping and debarking may be found in section 4.1. Artificial logs, baling, and whole-tree systems have not been considered.

Biomass yields from thinning are assumed to be 7.45 wet tons/acre. This yield has been derived by Michael Andreu in the College of Forest Resources [7] based on data published in [4]. Thinnings are assumed to be softwood with a moisture content of 50%. Total annual material generated by a thinning operation (wet tons) is given by:

$$\text{Annual Yield} = (\text{Annual Acreage Thinned})(\text{Acreage Yield}) \qquad \text{Equation 3.1}$$

For the base case of 80,000 acres, this corresponds to 596,000 wet tons per year. In power terms, this represents 183 MW of thermal energy.

Thinning costs have been estimated to be $40.2 per wet ton thinned [7]. Total thinning costs are obtained by multiplying this per ton figure by the annual yield.

$$\text{Cost of Thinning} = (\text{Annual Yield}_{\text{tons}})\left(\frac{\text{Cost}}{\text{ton yield}}\right) \qquad \text{Equation 3.2}$$

4. Fuel Handling and Pretreatment

All thermochemical conversion processes require fuel handling and most require pretreatment of input biomass prior to conversion. Facilities must have the capability to receive and store raw fuel on-site. Pretreatment will be necessary if delivered fuel does not meet conversion process requirements. For example, wood chips produced by standard chipping equipment are not a suitable feedstock for fast pyrolysis and require drying and grinding. In this section handling and pretreatment for wood chips are considered. For completeness, though no such systems are modeled in this study, fuel handling for pellets and liquid fuels is discussed in Appendix B.

4.1. Chipping and Debarking

Thinnings, as harvested, are not suitable for bio-fuel production processes. A drum chipper will be used to chip thinnings to a more manageable feedstock. Chipping will always be carried out at the logging deck. Drum chippers produce a chip with nominal dimensions of 25 mm x 25mm x 6mm [48]. Integrated units are capable of simultaneously debarking and chipping, though at higher cost. Debarking will be required for the production bio-fuels, where the presence of bark in the feedstock may adversely affect fuel yield or composition. For this study, two specific chippers were identified: the Bandit Industries 2090 chipper and Peterson 5000G debarker/chipper. Characteristics of these chippers are given in Table 4.1.

Table 4.1 – Chipping and Debarking Equipment Characteristics

Functionality	Model	Throughput (dtpd)	Power Requirement (kWhr/odt)
Chipping	Bandit Industries 2090 [49]	300	27
Chipping and Debarking	Peterson 5000G [50]	545	28.2

When downstream facilities are transportable, stationary, or relocatable, these chippers will be appropriate and equipment costs have been obtained from the manufacturers [49, 50]. However, these quotes are not appropriate for mobile bio-fuel production where it has been assumed that thinnings will be chipped on demand. In this case, it would be inefficient to couple a large chipper (300 or 545 dtpd) to a mobile bio-fuel production unit (10 dtpd). Chipping and debarking capital costs for mobile bio-fuel production have been estimated using a generic scaling factor of 0.7. Capital costs for chipping and debarking are presented in Table 4.2.

Table 4.2 – Chipping and Debarking Capital Cost

Functionality	Standard ($ 000)	Mobile ($ 000)
Chipping	$101 (300 dtpd)	$9 (10 dtpd)
Chipping and Debarking	$625 (545 dtpd)	$38 (10 dtpd)

Stand-alone chipping is an environmentally benign activity. However, when debarking is required, then there will be substantial byproduct bark – approximately 9% on a wet mass basis [47]. In this study it is assumed that bark will remain at, or around, the logging deck and that this will not constitute an environmental hazard. Given the high mineral content of the bark, dispersing it on-site may be beneficial to the long-term health of the forest. However, leaving large quantities of bark at a single location in the forest could present a fire danger. Assumptions regarding the final disposition of bark should be revisited in future work.

4.2. Wood Chip Handling and Pretreatment

Wood chips often require significant pretreatment prior to bio-fuel production or energy conversion. A flow diagram is given below in Figure 4.1.

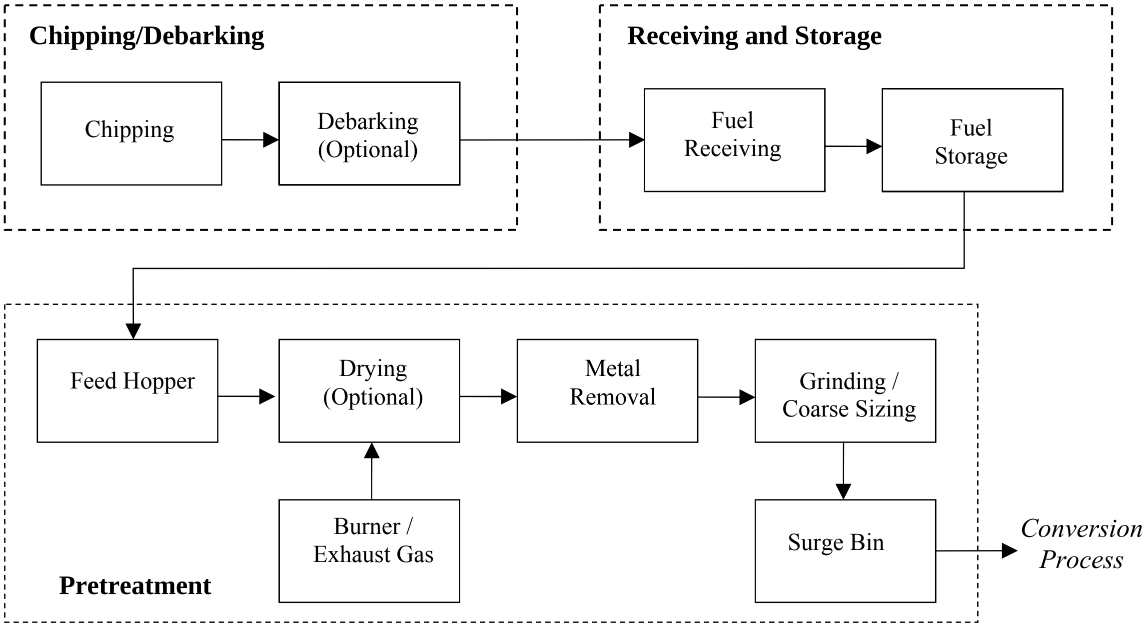


Figure 4.1 – Wood Chip Handling and Pretreatment

4.2.1. Fuel Receiving and Storage

Challenges in fuel handling have been common at most biomass conversion facilities and, as such, fuel handling warrants consideration [10]. This discussion is relevant for transportable, stationary, and relocatable facilities, which will be receiving wood chips produced at the logging deck. A chipper will be integrated into a mobile unit, allowing chips to be produced on demand.

Wood chips will arrive at transportable, stationary, and relocatable facilities in a standard chip van. Chip vans will be unloaded using a trailer dumper or whole-truck dumper, depending on facility size. For smaller facilities, trailer-only dumpers are most appropriate [48]. These systems tip up the chip van, pouring chips out onto a receiving pad. The truck cab must be decoupled prior to this operation. Whole truck dumpers raise both van and cab. Whole truck dumpers cost more, but unload vehicles more quickly since the cab need not be decoupled during dumping. For large biomass facilities expecting a steady stream of delivered chips, whole truck dumpers are most appropriate [48]. For this study it is assumed that transportable facilities will use trailer-only dumpers, while stationary and relocatable facilities will use whole-truck dumpers.

Once wood chips have been delivered, they are moved to on-site storage. While it would be possible to design facilities with the expectation of just-in-time delivery of chips, real-world experience with biomass conversion indicates this is impractically optimistic. On-site storage capacity of two to four weeks is recommended to mitigate the effect of possible feedstock disruption [48]. Wood chips are usually stored on an open pad, with size and cost estimated by methods discussed in Appendix C. Mobile bio-fuel production facilities do not require fuel yard equipment (dumper, storage pile, front-end loader) since the chipper/debarker will be directly integrated into the bio-fuel production system. That is, chips are blown into the feed hopper directly from the chipper.

For bio-fuel production, wood chips are moved from the storage pile (usually by front-end loader) into a feed hopper. From the feed hopper, a belt conveyor is assumed to move chips to a dryer.

Capital costs for fuel handling are adapted from [9] and [48] and presented in Table 4.3 for mobile, transportable, stationary, and relocatable facilities. The cost of some fuel yard equipment (dumper, front-end loader) is assumed to be flat for the scales of operation being considered. All capital costs listed are installed costs (installation factor of 1.0).

Table 4.3 – Wood Chip Fuel Handling Capital Cost

Facility	Equipment	Capital Cost ($ 000)	Installation Factor
Mobile Unit	Feed Hopper	$= (5.456)(dtpd)^{0.2939}$	1.0
	Belt Conveyor	$23 @ 100 dtpd, 0.62 scale factor	1.0
	Surge Bin	Assumed same as feed hopper	1.0
Transportable Facility	Trailer-only Dumper	$234 (flat cost)	1.0
	Storage Pile	$100 @ 3 acres, 0.5 scale factor	1.0
	Front End Loader	$75 (flat cost)	1.0
	Feed Hopper	$= (5.456)(dtpd)^{0.2939}$	1.0
	Belt Conveyor	$23 @ 100 dtpd, 0.62 scale factor	
	Surge Bin	Assumed same as feed hopper	1.0
Stationary and Relocatable Facilities	Whole Truck Dumper	$302 (flat cost)	1.0
	Storage Pile	$100 @ 3 acres, 0.5 scale factor	1.0
	Front End Loader	$250 (flat cost)	1.0
	Feed Hopper	$= (5.456)(dtpd)^{0.2939}$	1.0
	Belt Conveyor	$= (44.113)(dtpd)^{0.0253}$	1.0
	Surge Bin	Assumed same as feed hopper	1.0

4.2.2. Burners

Burners are used to supply process heat. Available burner feedstock varies depending on the bio-fuel being produced. In the case of the methanol and wood pellets, chip feedstock is most appropriate as a burner fuel. For bio-oil, fast pyrolysis produces combustible char and light gas as a by-product, which may be used as a burner feedstock in lieu of chips. If wood chips are used as a feedstock, a basic, pile burner should be appropriate. In pile burners, combustion occurs on a fixed bed, with combustion air blown in from above and below. For combustion of fast pyrolysis byproducts (char particles and light gases) a suspension combustor would be appropriate [6]. Here, rather than combustion on a fixed bed, combustible gas and small fuel particles are burned in a turbulent air environment [48]. In fast pyrolysis scenarios where heat release from byproducts is insufficient to meet total process heating needs, it has been assumed that small, supplemental quantities of bio-oil could also be sprayed into (and ignited) in a suspension combustor. This would be preferred to the installation of a separate pile burner for supplemental firing of wood chips.

As, previously discussed in section 1.1, the chemical formula for dry wood may be approximated as $C_6H_9O_4$. Assuming green chips (50% moisture) will be fed to the pile burner, combustion with excess air is described by the following stoichiometry, where *Φ* is the percentage excess air. For the purposes of this study, modeling of burner heat release assumes complete combustion of hydrocarbon feedstock with only CO_2 and H_2O as products.

$$\begin{aligned} C_6H_9O_4 + 8.1H_2O + 6.25(1+\phi)(O_2 + 3.76N_2) \rightarrow \\ 6CO_2 + 12.6H_2O + 23.5(1+\phi)(N_2) + 6.25\phi O_2 \end{aligned} \qquad \text{Equation 4.1}$$

For the purposes of drying (discussed in section 4.2.3) it is important to limit drying gas temperatures to 340°C (613 K) in order to suppress the formation of volatile organic compounds. Using a simple enthalpy balance

$$\sum H_{\text{Products},340^\circ\text{C}} = \sum H_{\text{Reactants}} \qquad \text{Equation 4.2}$$

the percentage of excess air may be determined to produce a drying gas stream at 340°C. The enthalpy of each component in the system may be expressed as

$$H = n\left(h_f^o + \left(h_T - h_{298}\right)\right) \qquad \text{Equation 4.3}$$

where n is the number of kmoles of the compound, h_o^f is the enthalpy of formation, h_T is the enthalpy at the temperature of interest and h_{298} is the enthalpy at 298 K. For wood chips, 845% excess air will produce a gas stream at 340°C. Practically speaking, most of this air would be mixed in downstream of the combustor. Details of this calculation for wood chips are given in Table 4.4 on the basis of 1 kmole of wood. Reactants are assumed to enter the combustor at ambient conditions. The heat of formation for representative wood has been back-calculated from its known higher heating value of 19.4 MJ/dry kg.

Table 4.4 – Enthalpy Balance for Combustion of Wood Chips

Component	kmoles	h_o^f (kJ/kmole)	h_{613K} (kJ/kmole)	h_{298K} (kJ/kmole)	h_T-h_{298} (kJ/kmole)	H (kJ)
Reactants						
$C_6H_9O_4$	1	-289,552			0	-289,552
H_2O	8.1	-285,000			0	-2,308,500
O_2	59	0			0	0
N_2	222	0			0	0
Total						-2,598,052

Products						
CO_2	6	-359,520	13,521	-8	13,529	-2,279,946
H_2O	12.6	-241,820	11,011	-5	11,016	-2,908,125
O_2	52.8	0	9,743	-24	9,767	515,538
N_2	222	0	9,331	-15	9,346	2,074,480
Total						-2,598,052

The same approach may be applied to determine heat release from fast pyrolysis byproducts and bio-oil in a suspension combustor. Combustion of fast pyrolysis byproducts with excess air (Φ) may be expressed by the stoichiometry below.

$$\begin{aligned} &\underbrace{C_{6.2}H_{5.1}O_{0.4}N_{0.1}}_{\text{Char}} + \\ &\quad \underbrace{3.7(0.17CO_2 + 0.54CO + 0.23CH_4 + 0.014C_2H_4 + 0.13H_2)}_{\text{Light Gas}} + \\ &\quad 10.2(1+\phi)(O_2 + 3.76N_2) \rightarrow 9.4CO_2 + 4.84H_2O + 38.4(1+\phi)N_2 + 10.2\phi O_2 \end{aligned} \tag{Equation 4.4}$$

The effect of inert ash has been neglected as a simplifying assumption. Determination of the elemental composition of char and light gas is discussed in the technology review of fast pyrolysis (Chapter 7).

Combustion of bio-oil with excess air (Φ) may be expressed by the stoichiometry below.

$$\begin{aligned} &C_{4.67}H_{6.5}O_{2.34} + 0.49H_2O + 5.13(1+\phi)(O_2 + 3.76N_2) \rightarrow \\ &\quad 4.67CO_2 + 3.74H_2O + 5.13\phi O_2 + 19.3(1+\phi)N_2 \end{aligned} \tag{Equation 4.5}$$

The fraction of water present in the bio-oil is a function of fast pyrolysis chemistry and moisture present in fast pyrolysis feedstock. The above stoichiometry is for bio-oil with 27% water content.

Enthalpy balances for the combustion of fast pyrolysis byproducts and bio-oil may be found in Appendix D.

Burner capital costs are difficult to estimate since burners are commonly packaged with boilers or may include the cost of the feedstock handling system. Burner capital cost assumptions are based on very rough information provided by [51] and presented in Table 4.5. A generic scale factor of 0.7 is assumed.

Table 4.5 – Burner Capital Costs

Burner Type	Reference Cost ($ MM)	Reference Scale (MBtu/hr)	Scale Factor
Pile Burner	$ 1.6	75	0.7
Suspension Burner	$ 0.75	15	0.7

Wood combustion systems can produce particulate, ash, carbon monoxide (CO) and oxides of nitrogen (NO_x). It has been assumed that a well-designed burner will be selected to limit CO and NO_x formation to acceptable levels without requiring additional emission control systems. Particulate arising from combustion will be controlled by a baghouse downstream of the dryer, as all product gases are routed through the dryer. The mineral ash waste from combustion is expected to be non-toxic and will not warrant any special disposal considerations. For mobile units and transportable facilities it is assumed that ash may be disposed of in the forest at no cost. A disposal charge of $25/ton is assumed for stationary and relocatable operations.

4.2.3. Drying

Drying reduces feedstock moisture to a level appropriate for downstream processes by vaporizing water. For this study, the delivered feedstock is assumed to be green chips (50% moisture) and drying will be required for bio-fuel production.

Many options exist for drying wet biomass and a thorough review of drying technology may be found in either [52] or [53]. For chip feedstock in the range of facility sizes considered, rotary drum dryers are most appropriate. Rotary drum dryers are the most common type of dryer and consist of a downward sloping, hollow, rotating cylinder. Chips are dried by hot exhaust gas. The rotation of the dryer causes the chips to tumble as they pass down the length, allowing good exposure of chip surfaces to the hot gas. Vaporized water is carried away in the flue gas stream. Rotary drum dryers are a co-current heat exchanger – the hottest gases first come in contact with the wettest chips. While a counter-current dryer – where the hottest gases would be exposed to the driest chips – could produce drier chips, counter-current operation increases the chance of a fire or dust explosion [52]. Rotary drum dryers are usually designed to dry feedstock to no less than 10% moisture [52].

The power to operate the dryer (specific energy consumption) and heat to vaporize water (specific heat consumption) are adapted from [48] and correspond to commercially available dryers. This information is presented in Table 4.6.

Table 4.6 – Rotary Drum Dryer Characteristics

Facility Type	Power Requirement (kWhr/odt)	Heat Requirement (MJ/kg water)
Mobile Unit	42.5	6.1
Transportable Facility	30.7	3.5
Stationary and Relocatable Facilities	33.7	3.5

The moisture removed from wood chips from drying may be obtained by the following relation

$$\text{Mass Moisture Removed} = W_{\text{i,dry}}\left(\frac{m_i - m_f}{(1-m_f)(1-m_i)}\right) \quad \text{Equation 4.6}$$

where $W_{\text{i,dry}}$ is the initial dry weight of the feedstock, and m_i and m_f are the initial and final moisture fractions, respectively.

As mentioned previously, heat for drying may be provided by utilizing waste heat from power generation or auxiliary combustion of some feedstock (chips, byproducts, products). Diesel engine and burner exhaust gas must be diluted by ambient air prior to reaching the dryer in order to meet a temperature requirement of 340$^{\text{o}}$C for dryer input gases. Temperatures above this limit will result in undesirable volatile organic (VOC) emissions. Assuming flue gases exit the dryer at 104$^{\text{o}}$C (above the dew point of water vapor), heat transferred to the dryer may be readily calculated by determining the sensible enthalpy loss for the drying gas.

$$Q = \sum_{\text{i}=\text{CO}_2,\,\text{H}_2\text{O},\,\text{O}_2,\,\text{N}_2} m_i h_i = \sum m_i c_{p,i}\left(T_i - T_f\right) \quad \text{Equation 4.7}$$

where Q is the heat transferred to the dryer per kmole fuel burned, m_i is the mass of a given product gas per kmole fuel burned, $c_{p,i}$ is the specific heat of the species, and T_i and

T_f are initial and final temperatures of the gas stream, respectively. The mass of CO_2, H_2O, O_2, and N_2 in the drying gas per kmole of fuel burned is fixed by burner (4.2.2) or diesel engine stoichiometry (5.1.1, 5.1.2). Multiplying this molar heat release by the molecular weight of the fuel, one obtains a figure for the amount of energy transferred to the dryer per mass of fuel (diesel, chips etc.) burned. This raw energy release is reduced by 10% to account for heat losses in the system between combustion and drying. Since dryer heat requirements are known (Table 4.6), we may readily determine the mass of fuel required to evaporate the mass of water given by equation 4.6.

Capital costs are also adapted from [48] and are installed costs. For modest changes in feedstock throughput, a linear scale factor appears appropriate.

Table 4.7 – Rotary Drum Dryer Capital Cost

Facility Type	Reference Cost ($ 000)	Reference Scale (dtpd)	Scale Factor
Mobile Unit	$17	15	1.0
Transportable Facility	$7	111	1.0
Stationary and Relocatable Facilities	$5	297	1.0

Emission of regulated pollutants is a key concern for dryer operation. Dryer flue gas will contain particulate matter and may contain volatile organic compounds (VOCs). Cyclones can reliably remove particulate down to 5μm diameter, but a baghouse, electrostatic precipitator (ESP), or wet scrubber would be necessary to control finer particulate [53]. Additionally, depending on operating temperatures in the dryer, volatile organic compounds (VOCs) may be released from the wood, resulting in 'blue-haze' – named such because the average VOC aerosol particle size reflects blue light. Pollution control equipment for removing particulate is ineffective at removing VOCs. In fact, VOC's may condense out and clog filters. The Best Available Control Technology (BACT) for wood dryers is wet electrostatic precipitation (WESP). As in ESP, charged plates attract fine particulate. However, unlike ESP, which operates above the dew point for water and organics, WESP operates below the dew point, condensing organics out on the collector plates. Water running over the plates removes these organics [53]. However, in and around forests being thinned, water may be quite scarce and the waste-water treatment facilities required for WESP impractical. Alternatively, and preferably, limiting drying gas temperatures to 340°C should suppress VOC formation. At these temperatures, the quantity of VOCs produced should be below air quality limitations [48]. This approach is in good agreement with published manufacturer data for rotary drum dryers [52] where inlet temperatures are generally below 300°C. As such, it is assumed that the rotary drum dryers modeled in this study will use low drying gas temperatures and employ a baghouse suitable for removal of fine particulate.

4.2.4. Baghouse

In a baghouse, cloth filters remove particulate from a gas stream. Filters are periodically cleaned by back-flushing the filter with clean gas. As previously discussed, the primary emission from the dryer should be particulate.

Baghouse costs have been estimated from [10], which presents baghouse costs for fluidized bed wood chip combustors. Baghouse filter capital costs are treated using a scale approach, with a reference cost of $866,000 [10] for a system with a volumetric flow rate of 65.8 m^3/s (Appendix E). A generic scale factor of 0.7 is assumed.

Flow rates of flue gases through the bag filter may be calculated by adding the molar flow rate of drying gas to the molar flow rate of water vapor evaporated from the feedstock chips. Molar flow rates for drying gases are dependent on the methods used to produce the gas (e.g. wood combustor, byproduct combustion). These flow rates can be calculated using previously determined molar gas compositions and heat releases per unit mass of fuel consumed. Fuel flow rates, determined by rated system capacity, allow us to calculate molar flow rates of gas through the bag filters. Molar flow rates are included in the burner enthalpy balances in Appendix D.

4.2.5. Grinding

The production of bio-oil and wood pellets requires significantly smaller feedstock than is produced by conventional chippers. Hammer mills are most commonly used to grind, or comminute, chips to small particles.

For fast pyrolysis, in order to achieve rapid, isothermal heating, feedstock particles must have at least one dimension not exceeding 3 mm. Reasons for this restriction are discussed in detail in section 7.1. The simplest approach to meeting this requirement would be to split chips (nominally 25x25x6 mm) in half (2 chips 25x25x3 mm). However it is neither feasible to split chips nor screen chips along a single dimension. As a result, chips must be ground down until they are able to pass through a 3 mm screen. For pelletization, maximum feedstock dimension is restricted to ½ the diameter of produced pellets (3 mm for 6 mm pellets) [27].

Hammer mills, using durable rotary hammers, are the usual choice for grinding wood to such small sizes [54]. After passing through the hammer mill, wood is screened, with oversize particles recycled to the upstream mill. The hammer mill's crushing action tends to generate wood fines, so that the average particle dimension is much smaller than the screen size. For example, if a hammer mill is used to resize chips to pass through the same screen, the average particle size will be only 0.32mm [55]. However, if a knife mill, which relies on a slicing action, is used to resize chips to pass through a 3.2mm screen, the average particle size will be 1.05mm. While knife mills do not produce as many fines, and are therefore more efficient, they are easily damaged by small stones [54]. Such contaminants are likely to be present when trees have been felled and dragged along the ground.

Hammer mill power requirements are presented in Table 4.8 [55]. Knife mill power requirements are included for purposes of comparison. Note that in the range of interest (3 mm), a knife mill would consume less than half the power of a hammer mill. Further study on the practicality of using knife mills for comminution of forest biomass may be warranted.

Table 4.8 – Hammer Mill Power Requirements

	Power Requirement (kWhr/odt)	
Screen Size (mm)	Hammer mill	Knife mill
1.6 (1/16")	137	132
2.4 (3/32")	127	88
3.2 (1/8")	127	53
6.4 (1/4")	105	28

Consideration of data in Table 4.8 indicates that grinding forestry chips to pass through a 3 mm screen should consume 127 kWhr/odt. This is in reasonably good agreement with another, less detailed, study [42] which estimated power consumption at 115 kWhr/odt for a similar screen size. At 127 kWhr/odt, grinding consumes slightly more than 2% of the energy content of the wood.

Capital costs for grinding and screening chips were obtained from Roskamp Champion, a leading manufacturer of hammer mills [56]. Quotes included equipment for grinding, metal separation, and conveyance of chips and feedstock and are presented in Table 4.9. Conveyance is by screw feeder into the hammer mill and pneumatic conveyor out. Cost regressions have been created for mobile and transportable facilities. For stationary and relocatable facilities, unit costs appear to be constant above 300 dtpd since quotes given for 300 and 600 dtpd have same unit cost ($/dtpd).

Table 4.9 – Grinding Capital Cost

	Process	Capital Cost ($ 000)	Installation Multiplier
Mobile and Transportable Facilities (Fast Pyrolysis, Pelletization)	Grinding	$= (4.551)(dtpd)^{0.4837}$	1.6 [10]
	Metal separation	$= (2.048)(dtpd)^{0.2216}$	1.6 [10]
	Ground Conveyance	$= (15.579)(dtpd)^{0.2200}$	1.6 [10]
Stationary and Relocatable Facilities (Fast Pyrolysis, Pelletization)	Grinding	$= (0.253)(dtpd)^{1.0}$	1.6 [10]
	Metal separation	$= (0.028)(dtpd)^{1.0}$	1.6 [10]
	Ground Conveyance	$= (0.186)(dtpd)^{1.0}$	1.6 [10]

4.2.6. Coarse Sizing

For methanol synthesis or direct use of wood chips (cogeneration, co-fire), a hammer mill will still be necessary to crush oversize pieces of feedstock. Oversized wood chips or chunks could damage or jam downstream equipment. A coarse screen upstream of the hammer mill passes correctly sized feedstock, sending only oversized chips to the hammer mill. As such, total power consumption is relatively low (~2.4 kWhr/odt [48]) since only a small fraction of the feedstock needs to be resized. Coarse sizing is assumed to include sizing, metal separation, and conveyance of chips (by belt conveyor).

Capital cost estimates for coarse sizing have been adapted from [48] and [56] and presented in Table 4.10 on a unit cost basis. Costs are presented separately for mobile/transportable and stationary/relocatable facilities owing to slight variations in the approach for calculating cost (see table footnotes).

Table 4.10 – Coarse Sizing Capital Cost

		Capital Cost ($ 000)	Installation Multiplier
Mobile/Transportable Facilities (Methanol Synthesis)	Coarse sizing	$= (21.328)(dtpd)^{0.2042}$	1.6 [10]
	Metal separation	$= (2.048)(dtpd)^{0.2216}$	1.6
	Belt Conveyor[7]	$68 @ 100 dtpd, 0.62 scale factor	1.0
Stationary/Relocatable Facility (Methanol Synthesis, cogeneration, and co-fire)	Coarse sizing	$= (21.328)(dtpd)^{0.2042}$	1.6
	Metal separation[8]	$= (0.028)(dtpd)^{1.0}$	1.6
	Belt Conveyor	$= (44.113)(dtpd)^{0.0253}$	1.0

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[7] Capital costs listed are in [48] only for large systems. Scaling factor obtained from implied scale in conveyance of ground feedstock – for which small system capital cost quotes were obtained [56].

[8] From [56] unit costs are constant above 300 dtpd.

5. Special Considerations for Mobile Operations

Field systems – mobile or transportable facilities – have a number of special needs compared to stationary or relocatable counterparts. These include power generation and equipment to enable mobility. Furthermore, while relocatable systems will have access to grid electricity, there will be significant costs associated with transporting these systems between sites.

5.1. Remote Power Generation

For mobile or transportable production of bio-fuels, grid electricity is not anticipated to be available to meet process needs. As such, power requirements must be met by diesel generators.

5.1.1. Dual-fuel Diesel Engine

Bridgwater et al. [43] have considered the use of dual-fuel diesel engines powered by bio-oil. This generator type will be used to supply power for mobile and transportable fast pyrolysis. The diesel engine plant includes engine and generator. Since dual-fuel engines capable of using bio-oil are not commercially available, Bridgwater et al. calculated a cost regression for existing dual-fuel engines and increased costs by 10% as an allowance for special modification necessitated by the corrosive nature of bio-oil. Modeling assumes the following:

- Diesel fuel meets 7.5% of engine energy input (bio-oil meets 92.5%)
- Electrical generating efficiency of 35%
- Parasitic engine load of 3%
- $\text{Total Plant Cost} = \$891{,}211\left(\text{Rated Power}_{\text{MW}_e}\right)^{0.9540}$
- Engine specific maintenance charge of \$0.01/kWhr
- Diesel fuel cost of \$2.50/gallon (includes premium for transportation to field)

In this study, it has been assumed that waste heat from diesel generators will be used for feedstock drying. While it is not common to use diesel waste heat directly for drying, complications are not anticipated. Assuming diesel fuel may be modeled as $C_8H_{14.4}$, complete, lean combustion (30% excess air), and that exhaust gas is available at 550°C [6], we may calculate the amount of excess air required to cool exhaust gases to 340°C (maximum dryer inlet temperature for environmental reasons) using a simple energy balance. Likewise, the same calculation may be carried out for the bio-fuel burned in the engine. Details of these calculations may be found in Appendix F. These calculations will also determine the molar flow rate of exhaust gas to the dryers – which is required to estimate bag filter capacity.

5.1.2. Diesel Engines

Conventional diesel engines will be used to provide power for mobile and transportable pelletization and methanol synthesis. The use of methanol synthesis purge gas in a dual-fuel engine was not considered. Capital cost estimation assumes diesel engine-generators cost 25% less than dual-fuel engines. Modeling assumes the following:

- Electrical generating efficiency of 40% [6]
- Parasitic engine load of 3%
- $\text{Total Plant Cost} = \$607{,}644\left(\text{Rated Power}_{\text{MW}_e}\right)^{0.9540}$
- Engine specific maintenance charge of \$0.01/kWhr
- Diesel fuel cost of \$2.50/gallon

5.1.3. Small modular bio-power (SMB) systems

A more environmentally benign option for field power generation would be small modular bio-power systems (SMB) – discussed in section 1.2.3. While these systems have low electrical generating efficiencies, in all scenarios being considered, waste heat from diesel engines meets less than 30% of process needs. As such, the low electrical efficiency of SMB systems would not be a liability, since there is an on-site demand for low-grade waste heat.

However, there is relatively little operational or financial data available on SMB systems. Moreover, gasification-gas engine systems, which are furthest along in development, have operational experience only in the 5-50 kW range. Transportable systems have power requirements in the 1000 kW range, which would necessitate significant scale-up of existing SMB system. While theoretically possible, this scale-up is described as challenging by those heading the development effort [21]. As such, SMB systems for remote power generation are not included in this model.

5.2. Mobility

5.2.1. Mobile Bio-fuel Production

Mobile bio-fuel production systems would be built on the foot-print of a conventional semi-trailer. It has been assumed that designing the system to fit in this restricted footprint will not entail a specific increase in capital cost. However, a capital charge of $60,000 is included for the flat-bed semi-trailer [44]. Since the system does not need to be broken down for transportation between sites, no specific setup and breakdown charges are assumed beyond operator labor. Setup and breakdown are expected to take 2 hours each [40]. An operating cost of $1/km is incurred for transporting mobile units between sites [57]. The average distance between logging decks where a mobile unit would be deployed is assumed to be 2 km. That is, every time a mobile unit is moved to a new deck, it is transported 2 km. For the base case, a mobile unit would be moved 37 times each year. Modeling results indicate the transportation cost associated with this movement is negligibly small, though it does reduce system capacity factor.

5.2.2. Transportable Bio-fuel Production

Transportable bio-fuel production systems will be modularized to fit within three semi-trailer vans which will be assembled on-site to a functional plant. For example, one semi-trailer might be dedicated to pretreatment equipment and another to a fast pyrolysis reactor. Like mobile units, it has been assumed that designing a modular system will not result in a specific increase in capital cost. However, a capital charge of $200,000 is assumed for the cost of the semi-trailer vans which hold the system in transit. Furthermore, since modest effort will be required to setup and breakdown transportable systems, a per-move operating cost equal to 1% of the system capital cost is assumed in excess of labor requirements. For transportable fast pyrolysis systems, this translates to a charge of approximately $200,000 per move. Setup and breakdown are expected to take

48 hours each [40]. An operating cost of \$3/km is incurred for transporting all three semi-trailer containers between sites [57]. The average distance between sites for transportable systems is assumed to be approximately 50 km. It has been assumed that transportable systems will be moved three times per year.

5.2.3. Relocatable Bio-fuel Production

It is challenging to model the cost of a relocatable bio-fuel production systems since the author is unaware of any systems of this type having been proposed. A number of assumptions have been made to roughly model this case. Since a modular design may be difficult to achieve for a large scale facility, plant capital costs are increased by 10% relative to a stationary facility of the same scale. As a comparison, the mobility cost for a transportable facility (cost of semi-trailer vans) effectively represents a 1% increase in plant costs. Furthermore, since significant effort will be required to setup and breakdown relocatable facilities, a per-move operating cost equal to 10% of the total capital cost is assumed in excess of labor requirements. Setup and breakdown are expected to take one month (1440 hours). Furthermore, given the potential size of some equipment involved a cost of \$100/km is incurred for transporting the components of a relocatable facility between sites. Since a relocatable system would likely be moved between large scale thinning operations, a transportation distance of 750 km between sites has been assumed. For example, a relocatable system used for thinning in Washington, might next be used for thinning in Oregon.

6. Pelletization

Pelletization produces pellets (high-grade solid fuel) from small particles of wood. The characteristics of pellets are described in 1.3.2. Pelletization is the simplest conversion process considered and is primarily mechanical in nature.

6.1. Process

To achieve proper pellet size and cohesion, feedstock must be no larger than 3 mm in any dimension and have been dried to no more than 10-15% moisture by volume [27]. As such, the feedstock of choice for commercial pelletization is dried sawdust and shavings which require minimal pretreatment at the pelletization facility [58]. Additionally, the inclusion of bark, a high ash feedstock, would result in pellets with ash contents exceeding established standards (see section 1.3.2). Further, pellets including bark have been reported to experience a higher rate of biodegradation [59]. Debarking is assumed to prevent this. Figure 6.1 shows a process flow diagram for pelletization.

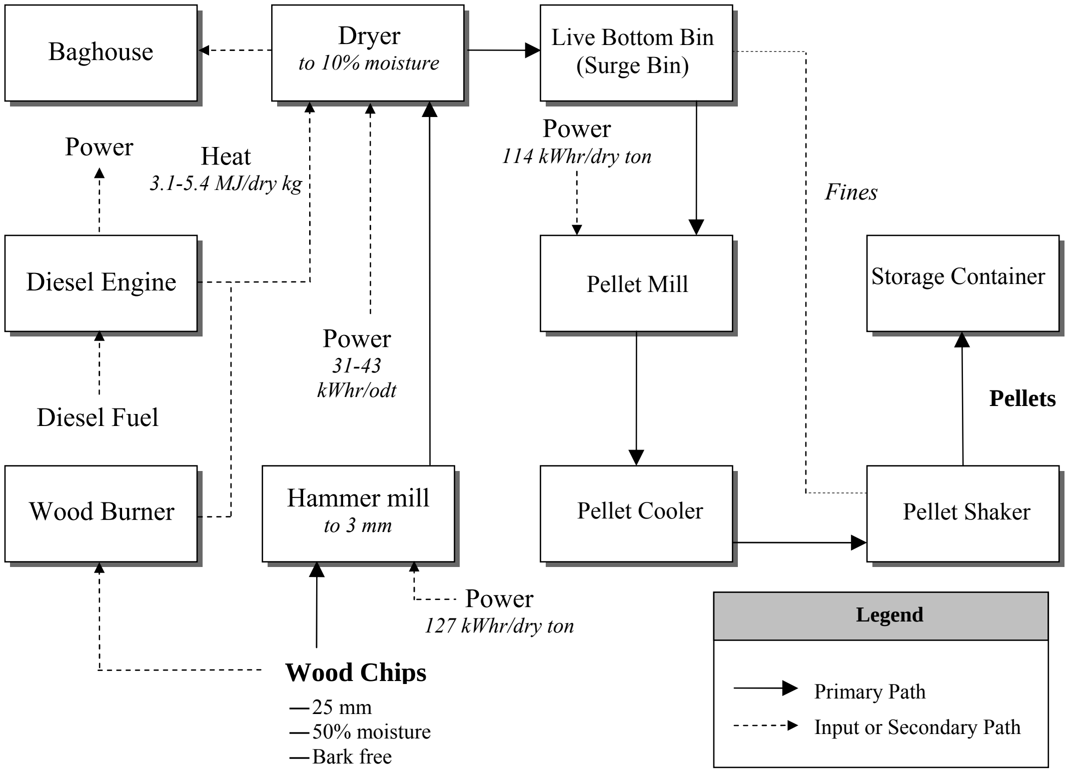

Figure 6.1 – Pelletization Process Flow

The core piece of equipment for pelletization is the pellet mill. Pellet mills use a roller to press wood through either a rotating or stationary die [27]. Under high pressure, the temperature of the wood rises to around 100°C. Under these conditions, the lignin fraction of the wood begins to flow. Pellets are cut to an appropriate length as they emerge from a stationary die or broken off by the centripetal force of a rotating die. Once cool, lignin serves as a the primary binding agent for pellet cohesion.

The production of pellets is estimated to require 114 kWhr/odt processed [27]. The only external heat input is for the drying of wood chips.

6.2. Technical Readiness

Of the bio-fuel production technologies under consideration, pelletization is the most developed. Pellet mills are commercially available in a number of capacities from several manufacturers (California Pellet Mill, Matador, EcoTre). The technology for pelletization of wood is simple and well-developed. It is anticipated that some minor repackaging of existing equipment would be required for use in mobile or transportable facilities. Breakage of dies during plant start-up can be quite costly [27] and often occurs because dies must be optimized for particular types of wood. It is possible that the variable nature of wood generated by thinning could make proper die selection challenging.

6.3. Heat and Power Integration

For mobile and transportable pellet production, process power will be supplied by diesel generators. The only heat input required will be for drying green chips. Waste heat from the diesel generators and combustion of chip feedstock will meet this demand. For stationary and relocatable pellet production, all heat for drying will be supplied by combustion of chip feedstock. Heat integration specifics are given in Table 6.1.

Table 6.1 – Pellet Production Heat Integration

Facility Type	Heat Demand (GJ/odt)	Diesel Generator Waste Heat	Chip Combustion
Mobile	5.4	11%	89%
Transportable	3.1	18%	82%
Stationary/Relocatable	3.1	0%	100%

6.4. Economics

Capital costs for pelletization have been adapted from older systems studies [27] and vendor quotes [60]. Cost regressions for equipment costs and are presented in Table 6.2. Installation factors have been determined from installation costs quoted in [27].

Table 6.2 – Pellet Production Capital Cost

	Equipment Cost Regression ($ 000)	Installation Multiplier
Live Bottom Bin	$= (8.255)(dtpd)^{-0.5192}$ [27]	1.8 [5]
Pellet Mill	$= (13.384)(dtpd)^{-0.3268}$ [27]	1.7 [5]
Pellet Cooler	$= (9.787)(dtpd)^{-0..6191}$ [27]	1.8 [5]
Pellet Shaker	$= (2.666)(dtpd)^{-0.7097}$ [27]	1.7 [5]
Storage	\$25,000 for 51 tons pellets, 70% scale factor[9]	1.6 [5]
Fork Lift	$= (8.289)(dtpd)^{-0.7707}$ [60]	1.0 [5]
Misc. Conveyors	$= (4.856)(dtpd)^{-0.7230}$ [60]	1.5 [5]

For stationary and relocatable facilities, labor requirements are determined by a scale relation. For pelletization, a reference headcount level of 2 personnel for a rated capacity of 100 dtpd and 80% headcount scale factor are assumed. For the base case, this corresponds to 8.9 operators per shift for a stationary facility and 6.0 operators per shift for a relocatable facility. Other operating costs associated with pelletization are presented in Table 6.3.

Table 6.3 – Pellet Production Operating Costs

	Cost
Die and Roller Replacement	\$5/ton pellets [27]
Additives	\$10/ton pellets (assumption)

It is not clear whether additives will be necessary, as pellet cohesion strongly depends on the particular feedstock. However, given the variable nature of the feedstock generated by thinning, the inclusion of a nominal additive cost seems prudent. In addition to the costs presented in Table 6.3, mobility and power costs will be incurred. Discussion of these costs may be found in Chapter 5.

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[9] 3 days on-site storage assumed. Cost estimate based on storage capacity and cost of pellet truck container.

Table 6.4 presents pellet production costs for base case assumptions. Costs are listed on a unit cost basis per wet ton of thinnings harvested. Stationary pelletization costs are for the base case discussed in section 2.4. ‘Other’ costs include pelletization specific operating costs, fixed maintenance and overhead, ash disposal, and mobility expenses. ‘Power’ includes cost of purchased electricity for stationary and relocatable facilities and fuel costs and diesel-generator maintenance for mobile and transportable facilities. Amortized ‘Mobility’ costs include the cost of trailers or containers as well as diesel generators.

Table 6.4 – Pellet Production Cost Chain

Cost ($/ton wet thinnings)	Mobile	Transportable	Stationary	Relocatable
Capital Cost				
Mobility	$2	$2	$-	$0
Pretreatment	$11	$5	$3	$2
Pelletization	$8	$3	$1	$2
Capital Cost	$21	$10	$4	$4
Operating Cost				
Labor	$72	$9	$4	$5
Power	$18	$19	$6	$7
Other	$14	$14	$7	$9
Operating Cost	$103	$43	$18	$21
Total Production Cost	$124	$52	$22	$25
Total Production Cost ($/GJ Pellets)	$19.3	$7.1	$3.0	$3.3

Table 6.4 also gives the total production cost on an energy basis ($/GJ pellets). In section 1.3.2, we specified the selling price of pellets at $3.2/GJ. As such, only stationary production of pellets would not exceed the selling price.

Considering Table 6.4, one sees a steady decrease from mobile to transportable to stationary production of pellets. Relocatable production costs are roughly 20% higher than for stationary production. The primary decrease from mobile to transportable production is with respect to labor, since personnel are better utilized in larger facilities. One also sees a substantial scale driven decrease in capital costs. Stationary and relocatable power expenses are significantly lower than for mobile or transportable operations since power is supplied by grid electricity, rather than diesel generators. Pelletization is not capital intensive, with only 15% of total production cost incurred by capital amortization for stationary pelletization and even lower fractions for other facility types.

Pelletization yields and conversion efficiencies for the four different facility types are listed in Table 6.5. Conversion efficiency is defined in section 2.3.6.

Table 6.5 – Pellet Production Characteristics

Facility	Energy Efficiency	Pellet Mass Yield	Pellet Production
Mobile	66%	41%	221,000 tons/yr
Transportable	75%	47%	252,000 tons/yr
Stationary	78%	45%	244,000 tons/yr
Relocatable	78%	45%	244,000 tons/yr

Efficiency and mass yield increases between mobile and transportable facilities due to decreased unit heat and power requirements for larger dryers. However, mass yield decreases for stationary and relocatable facilities because no waste heat is available from power generation and additional wood chips must be burned for drying. Energy efficiency does continue to increase, because power is being purchased from the grid and waste heat losses are external to the process.

6.5. Environmental Considerations

Emissions and appropriate pollution control for wood drying are discussed separately in section 4.2. Since all gaseous products are routed through the dryer, no additional gaseous pollution control will be required.

Excluding bark, production of pellets results in a single solid waste product – mineral ash. This is ash is a residue of wood chip combustion for dryer heat. The ash is non-toxic and should not present an environmental hazard.

6.6. Research Opportunities

With respect to woody biomass, pelletization offers limited research opportunities. The process is robust, well-developed, and highly scalable. Economic analysis indicates research should be focused on reducing pelletization specific operating costs – for example, designing more feedstock flexible dies and rollers.

7. Fast Pyrolysis

When wood is heated in the absence of oxygen, it decomposes to condensable vapors, char, and light gases. Condensable vapors include oxygenated hydrocarbons and water. When heating is rapid (>100°C/s) and residence time in the reaction environment is short (1-2 seconds), the thermochemical process is termed fast pyrolysis. For well-designed fast pyrolysis processes, the yield of condensable vapors can be as high as 75% on a dry mass basis [30].

To date, little progress has been made in using kinetic models to determine the chemical composition of fast pyrolysis products. Fast pyrolysis is a non-steady state process where mass transfer, heat transfer, and phase changes all play important roles [30]. As such, a black box approach is generally used to determine process yields. From a qualitative perspective, fast pyrolysis can be described using a Broido-Shafizadeh kinetic model (Figure 7.1) for the thermal decomposition of cellulose [30].

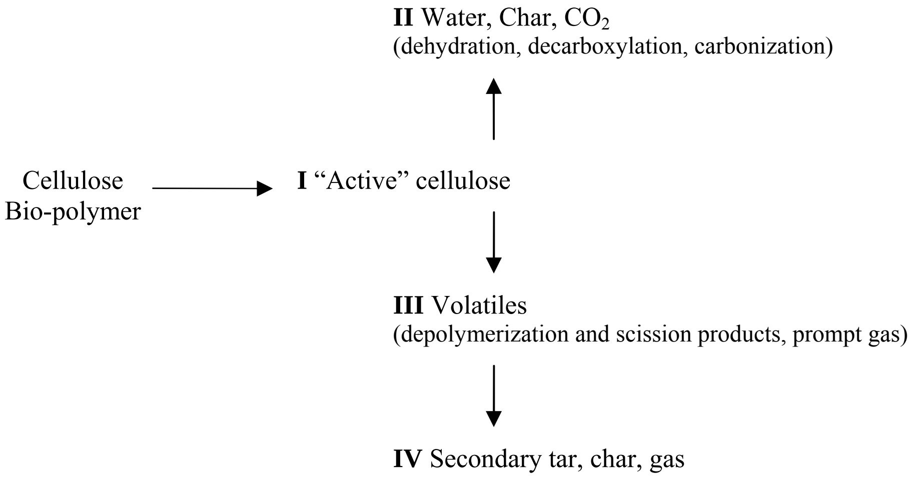

Figure 7.1 – Cellulose Decomposition Model

Yields of organics, water, char, and gas are a function of reaction temperature, as shown in Figure 7.2 [30]. Higher, more severe, reaction temperature favors the yield of light gases over organics. Lower severity favors the production of char. Organic yields are maximized between 500 and 550°C – making this the most desirable reaction temperature for fast pyrolysis.

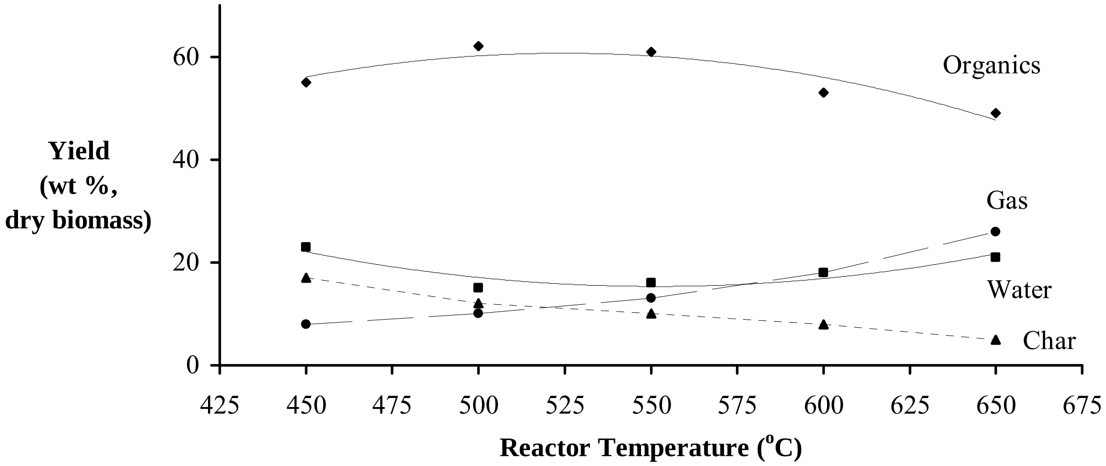

Figure 7.2 – Temperature Dependence of Fast Pyrolysis Products

The components of wood: hemicellulose, cellulose, lignin, and extractives decompose to different organics compounds. General decomposition products are given in Table 7.1 [30].

Table 7.1 – Fast Pyrolysis Decomposition Products

Biomass Components	Decomposition Products
Hemicellulose	acetic acid, furfural, furan
Cellulose	levoglucosan, 5-hydroxymethfurfural, hydroxyacetaldehyde, acetol, formaldehyde
Lignin	oligomers of high molecular mass
Extractives	fatty acids and resins (mostly immiscible with other components)

However, both the relative weighting and presence of various compounds depend on feedstock and reaction temperature. Condensable organic compounds produced from a number of different woody feedstocks are listed in Table 7.2 [61]. Water is the most abundant pure condensable vapor produced by fast pyrolysis.

Table 7.2 – Representative Condensable Vapors

Weight % Yield of Dry Biomass

	University of Waterloo – Fluidized Bed			NREL – Vortex
Component	**Poplar (504°C)**	**Maple (508°C)**	**Spruce (500°C)**	**Oak (~500°C)**
Acetic Acid	5.4	5.8	3.9	5.0
Formic Acid	3.1	6.4	7.2	3.3
Hydroxyacetaldehyde	10.0	7.6	7.7	4.3
Glyoxal	2.2	1.8	2.5	3.0
Methylglyoxal	*not found*	0.65	*not found*	*not found*
Formaldehyde	*not found*	1.2	*not found*	2.2
Acetol	1.4	1.2	1.2	1.8
Ethylene Glycol	1.1	0.6	0.9	*not found*
Levoglucosan	3.0	2.8	4.0	3.8
1,6-anhydroglucofuranose	2.4	*not found*	*not found*	*not found*
Fructose	1.3	1.5	2.3	*not found*
Xylose	*not found*	*not found*	*not found*	0.9
Glucose	0.4	0.6	1.0	*not found*
Cellobiosan	1.3	1.6	2.5	*not found*
Oligosaccharides	0.7	*not found*	*not found*	*not found*
Pyrolytic Lignin	16.2	20.9	20.6	24.9
Other Carbohydrates	11.9	17.1	12.9	5.8
Water	12.2	9.8	11.6	12.4

In aggregate, the condensed mixture oxygenated hydrocarbons and water is termed bio-oil. As discussed in section 1.3.3, bio-oil has a heating value between 16 and 19 MJ/kg, a bulk density of 1200 kg/m^3, and is physically characterized as a dark brown, freely flowing liquid with a smoky odor.

The hydrocarbon components of bio-oil are not in equilibrium. Reaction rates are greatly slowed during the condensation of the vapor phase, but are not negligibly slow. Even with careful storage, the composition of bio-oil will change over several months of storage. These continuing reactions cause ‘aging’, which is characterized by bio-oil viscosity increases, volatility decreases, and ultimately phase separation into a heavy non-aqueous phase and light aqueous phase. It is possible to stabilize bio-oil and retard aging effects by addition of 10% by weight methanol [62], though this increases production costs. Since these reaction rates are kinetically controlled, bio-oil should not be stored at elevated temperatures for extended period of time, as this will accelerate aging.

Bridgwater et al. [43] project the following yields from a commercial fast pyrolysis process on a dry feedstock basis: condensable organics – 59.9%, reaction water – 10.8%, char – 15.4%, ash – 0.8%, and light gases – 13.1%. Assuming chips are dried to 10% moisture prior to reaction, bio-oil produced will be 27% water by weight. The higher heating of bio-oil as a function of moisture content is given below [43].

$$\mathrm{HHV}_{\text{Bio-oil}}\,(\mathrm{MJ/kg}) = 22.5 - 25.41(\text{Fraction Moisture Content}) \qquad \text{Equation 7.1}$$

As seen in Figure 7.2, temperatures around $500^{\circ}\mathrm{C}$ favor production of condensable organics, while lower temperatures favor char. Char production is undesirable for a number of reasons. First, there is a direct substitution loss – wood converted to char may not be converted to condensable vapors. Char also catalyzes secondary cracking of condensable vapors to unrecoverable light gases (path III to IV in Figure 7.1). The more char present in a system, the higher the secondary light gas yield. Finally, char entrained in bio-oil accelerates ‘aging’ and also limits use of bio-oil in advanced combustion applications – such as combustion turbines. For these reasons, char suppression and removal is a key concern in reactor design.

The char produced by fast pyrolysis is characteristically quite similar to bituminous coal and typically has a heating value of 32 MJ/kg [30]. Nearly all mineral ash (sodium, potassium, calcium) is entrained in the char [63].

Light gases are produced both by primary wood reactions and secondary cracking of condensable vapors. For a fast pyrolysis process yielding 13% light gas on a dry weight basis, 5% will be produced by primary pyrolysis, with the balance produced by secondary vapor cracking. Primary and secondary light gas compositions are given in Table 7.3 [64].

Table 7.3 – Light Gas Composition

Component	Primary Gas (mass fraction)	Secondary Gas (mass fraction)
CO	39%	63%
CO_2	53%	9%
H_2	0.8%	1.4%
Light Hydrocarbons	6.7%	27%

Primary and secondary light gases have energy contents of approximately 11 MJ/nm^3 and 20 MJ/nm^3, respectively [64]. The mixture of primary and secondary gases has an energy content of 15-16 MJ/nm^3. For the purposes of calculating heat release from byproduct combustion, the light hydrocarbon fraction is assumed to consist exclusively of methane (CH_4) and ethylene (C_2H_4) [65]. The relative fractions of each have been chosen to give a mixture which approximates published values for light gas energy content and molecular weight. Details of this calculation are presented in Appendix G.

7.1. Process

Of the bio-fuel production technologies considered, fast pyrolysis has the most stringent feedstock characteristics in terms of moisture content and particle size.

Prior to undergoing fast pyrolysis, wood must be dried to at least 10% moisture. The water content of bio-oil will be the sum of the initial feedstock moisture and reaction water from dehydration and condensation reactions during fast pyrolysis. Feedstock moisture levels in excess of 10% will produce bio-oil with a water content greater than 30% - leading to phase separation of bio-oil into a light, aqueous phase and heavy, tar-like phase [66]. Neither of these fractions is suitable as a combustion feedstock, so conditions leading to phase separation should be avoided.

Fast pyrolysis of forest residues containing significant quantities of bark and needles has been shown to produce bio-oil with a number of different characteristics compared to bio-oil produced from wood alone. In experiments, bio-oil yield has been shown to be reduced to 60-65% by weight (compared to 75% for wood alone) and to separate quickly into two phases – a lighter, extractives rich phase (10-20% by weight) and a heavier phase resembling bio-oil produced from bark-free feedstock [25]. This is unsurprising given the immiscibility of extractive decomposition products in the products of holocellulose and lignin (Table 7.1). Debarking of thinnings prior to chipping is modeled under the assumption that this will be necessary to maximize the yield of a more uniform, stable bio-oil.

A primary consideration in fast pyrolysis, distinguishing it from slow pyrolysis (e.g. carbonization) is the rapid heating of wood to the optimal vapor yield temperature (500^oC). These heating rates are on the order of $100^oC/s$ [66]. This suppresses char formation, which is kinetically favored at lower temperatures. There are two approaches to satisfying the requirement for rapid heating.

The first is to use a feedstock with a small enough characteristic size that heating is effectively isothermal. This is the approach which has been taken in bubbling fluidized bed pyrolysis reactors. Experience in reactor operation at the lab and demonstration scale has shown this maximum size to be in the region of 2-3 mm for bubbling fluidized beds [30,42]. If larger particles are used, the temperature at the interior of the chip will be measurably lower than at the surface and significant char may be formed. It is important to note that this characteristic size is the minimum of all dimensions – that is, so long as the feedstock meets this size requirement along at least one dimension, heating should be effectively isothermal [40]. Chipping equipment used in forestry operations produces a rough chip with dimensions of about 25x25x6 mm. To use these chips as a fast pyrolysis feedstock in fluidized bed reactors, size reduction is necessary – typically using a hammer mill as discussed in 4.2.5. This arrangement results in feedstock with a *maximum* characteristic dimension of 2-3 mm, which exceeds the process requirement of a *minimum* characteristic dimension of 2-3 mm. However, to the author's knowledge, there is no practical technique for screening to a minimum dimension. The most practical approach using current technology may be to design chippers which produce a 'thin chip' (e.g. 25x25x3 mm) suitable for fast pyrolysis without additional sizing [40]. Circulating fluidized beds, which have been reported to tolerate feedstock with a characteristic size of up to 6 mm, have not yet been commercially demonstrated [30].

The second approach to suppressing char formation is to carry out fast pyrolysis in an ‘ablative’ mode. In ablative fast pyrolysis, the surface of the feedstock is rapidly heated and then swept away (ablated), exposing the wood beneath to the high temperature reaction environment. Ablation is sufficiently rapid that minimal heat is conducted to material adjacent to the immediate reaction zone. As a result, the temperature at the interior of the wood feedstock remains low enough that no significant thermal decomposition occurs prior to pyrolysis. Some of the earliest fundamental work on fast pyrolysis, carried out by Lede [67], investigated ablative fast pyrolysis using a heated, spinning disk pressed against a wooden dowel. Ablation rates of up to 30 mm/s were observed [67]. Commercial ablative fast pyrolysis systems would have the benefit of being able to utilize feedstock with large characteristic sizes. However, the design of ablative fast pyrolysis reactors is significantly more complex than for fluidized beds (further discussed in 7.1.1).

Due to the additional cost in capital and power for size reduction via a hammer mill and the challenge in developing commercial ablative or circulating fluidized bed reactors, current commercial applications for fast pyrolysis have been limited to cases where feedstock appropriately sized for bubbling fluidized beds (sawdust, shavings) is readily available. This is analogous to current commercial production of wood pellets.

A basic representative schematic of fast pyrolysis is shown in Figure 7.3.

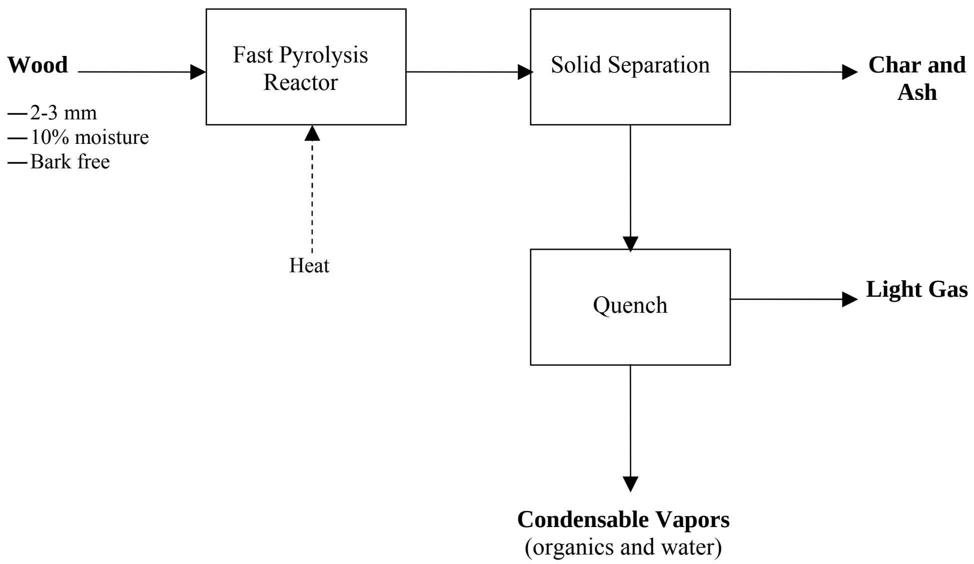

Figure 7.3 – Fast Pyrolysis Schematic

Wood dried and sized to specifications is fed into the fast pyrolysis reactor where rapid heating causes thermal decomposition to water, organics, light gases, and char. In order to suppress secondary vapor cracking, vapor residence time should be kept to a minimum, usually no longer than 1 second [66]. Solids (char and mineral ash) are then separated from vapors. Vapors then undergo a rapid quench (200^{o}C/s) [30], condensing oxygenated hydrocarbons and water. Remaining non-condensable gases are then either flared or burned for process heat.

7.1.1. Fast Pyrolysis Reactor

A number of reactor variants have been considered for fast pyrolysis of woody biomass. The three most common types are bubbling fluidized beds (BFB), circulating fluidized beds (CFB), and ablative reactors.

7.1.1.1. Bubbling Fluidized Bed

Bubbling fluidized beds (BFB) are the most common reactor variant. In BFBs, an inert gas is used to suspend wood particles undergoing fast pyrolysis. BFB reactors rely on isothermal heating to minimize char yields, so feedstock must be sized to no greater than 2-3 mm prior to reaction [30]. The requirement for an inert, non-oxidative fluidizing gas disallows the use of air as a fluidizing agent. In lab scale and pre-commercial demonstrations, nitrogen has been used. However, it is expected that re-circulation of non-condensable light gases would replace nitrogen as the fluidizing medium in commercial reactors.

7.1.1.2. Circulating Fluidized Bed

In circulating fluidized bed (CFB) reactors, hot sand is used as a heat transfer material to provide the energy input for pyrolysis. As in BFBs, feedstock particles are suspended using an inert fluidizing gas. Sand is heated by the combustion products of char in an external combustor. Char and sand are separated from light gas and condensable vapors exiting the reactor by a cyclonic separator. A schematic representation of a CFB reactor is given in Figure 7.4.

CFBs are suitable for high throughputs, making them preferred to BFBs for large scale installations [30]. Furthermore, CFBs may be capable of handling feedstock chips up to 6 mm in characteristic size. It is possible that the abrasive nature of the sand used as a heat transfer material may give rise to quasi-ablative conditions in the reaction zone. This would allow CFBs to use forestry chips without secondary grinding. However, CFBs for fast pyrolysis are not yet commercial and are, therefore, not considered for the base technology case. However, an advanced technology case does broadly consider the benefit of a system without a feedstock grinding requirement.

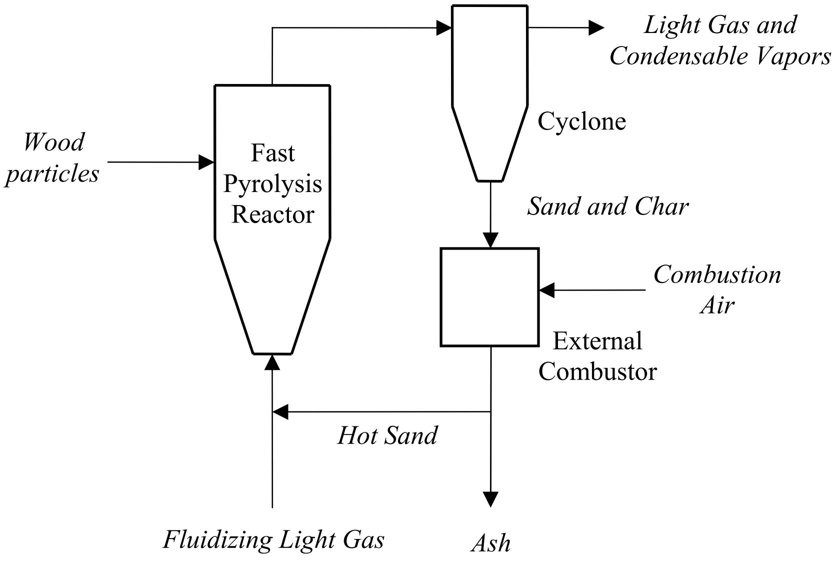

Figure 7.4 – Circulating Fluidized Bed Reactor Schematic

7.1.1.3. Ablative Reactors

Ablative fast pyrolysis reactors, theoretically capable of utilizing large feedstocks have been slower to develop. The most challenging aspect has been in designing mechanical processes to press feedstock onto a hot surface – the basis for ablative fast pyrolysis.

The National Renewable Energy Lab (NREL) pioneered the development of a vortex reactor [55] which accelerates feedstock to supersonic velocities in a swirl pattern. Centrifugal forces press feedstock particles against the hot reactor wall. Motion of the particles and friction against the wall provide an ablation mechanism. The original reactor was limited to very small particles of feedstock (<1 mm), such as sawdust. NREL was contracted to scale-up the vortex reactor, but the contracting company was unable to complete development for financial reasons [55].

Aston University in the UK has developed a purely mechanical ablative reactor [30] – the details of which have not been made public pending the filing of a patent [68]. Recently, a German company, PYTEC Thermochemische Anlagen, has developed a fast pyrolysis process for disposal of sawmill wood wastes. An automated feeding system mechanically presses four solid wood boards (10x47x350mm) against a heated, spinning disk (Figure 7.5) [69]. The approach is very much analogous to Lede's early ablative fast pyrolysis experiments. Ablation rates of 2.0-5.5 mm/s have been achieved and bio-oil yields are purported to be 55-70% on a dry mass basis [70].

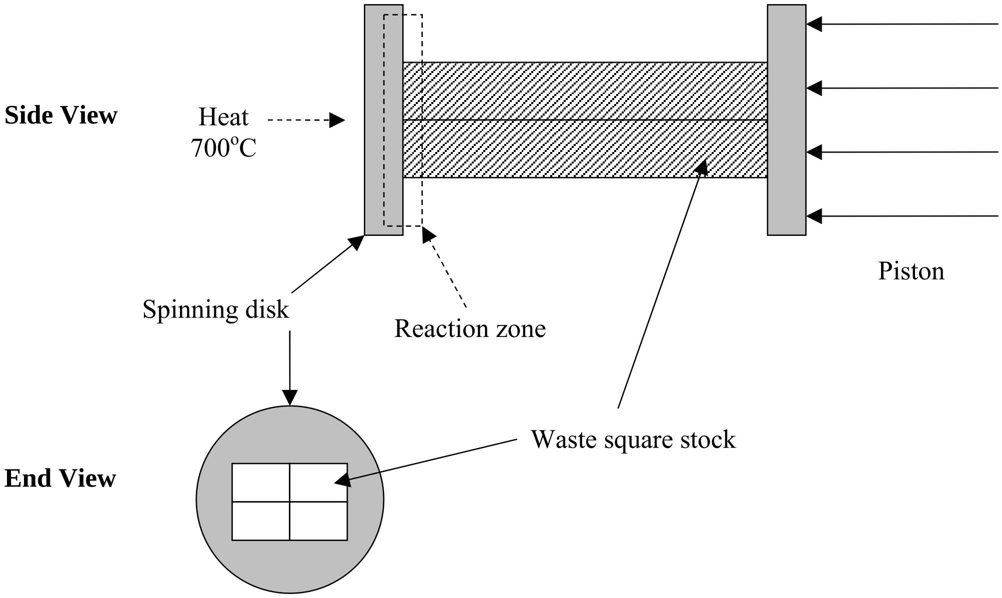

Figure 7.5 – Ablative Fast Pyrolysis Schematic

Given this promising development, commercialization of an ablative fast pyrolysis design capable of handling forestry chips may occur in the next few years. While ablative fast pyrolysis is not considered in the technology base case, an advance case does broadly consider the potential cost benefit of such systems.

7.1.1.4. Other Reactor Variants

In addition to the above systems, a few other reactor variants have been developed. Most notable are the rotating cone developed by the Biomass Technology Group (BTG) in the Netherlands [42], vacuum pyrolysis systems being commercialized by Pyrovac [71], and the auger transported bed by Renewable Oil International [40]. A comprehensive overview of fast pyrolysis reactor variants may be found in [30].

7.1.2. Solid Separation

The next step is to remove entrained char particles from the vapor stream exiting the reaction zone. Once vapors have been condensed, char filtration of the liquid phase is ineffective and produces a sludge-like waste product. As such, char should be removed while vapors remain in the gas phase [63]. Rapid char removal is required as the presence of char in a high temperature vapor stream will catalyze secondary vapor cracking reactions. Alkali metals from biomass ash are also concentrated in the char and must be minimized to meet tolerances of downstream equipment (e.g. turbines, engines). Furthermore, there is evidence that char entrained in the condensed vapors (bio-oil) accelerates 'aging' of bio-oil [66], reducing shelf-life.

Most fast pyrolysis processes use cyclone separation as the primary char removal mechanism. These filters use centrifugal force to separate out high density solids from the lower density vapor stream. Multi-clone (multiple cyclone) systems are effective at removing char and ash particles down to 5 μm in size [72]. Remaining solids are entrained in the condensed vapors during quench and usually make up about 1% by weight of bio-oil [30]

Even lower solid concentrations may be achieved using high temperature ceramic or sintered steel filters. This technique has been demonstrated at NREL and achieved solid concentrations of less than 100 ppm [63], relative to 10,000 ppm for cyclonic separation. However, as char is removed from the gas stream it accumulates on the filter surface, effectively creating a vapor cracking bed. This effect will, most optimistically, reduce condensable vapor yield by 10% [63]. Problems have been encountered in removing the char cake from filters over repeated runs [73] so the process should not yet be considered commercial. For the purposes of this study, it is assumed that bio-oil end-use applications will be able to tolerate 1% solids by weight and require only cyclonic separation.

7.1.3. Quench

Low-char vapors are rapidly cooled, condensing to a liquid product (bio-oil). Quench is conventionally achieved using a spray cooling column. Previously produced, cool bio-oil is sprayed into the top of the column, quenching hot vapors by impaction at cooling rates on the order of 200^{o}C/s [30]. Condensed liquids exit from the base of the column and are cooled to ambient temperatures using a heat exchanger. Non-condensable light gases exit from the top and are either flared or burned for process heat.

Commonly, water cooling is used as a heat transfer fluid to dissipate heat from the liquid product. However, as cooling water may not necessarily be available in and around forested areas, it is assumed that a forced convection heat exchanger will be used to dissipate heat.

7.1.4. Process Implications for Bio-oil Characteristics

For a given feedstock, residence time at elevated temperature has the greatest impact on final bio-oil composition. Bio-oil is a non-equilibrium mixture of oxygenated hydrocarbons, many of which react with each other. As is the case with most kinetically controlled interactions, these reactions occur more rapidly at higher temperatures. The rapid quench step of bio-oil production greatly reduces the rate of reaction. A combination of short vapor residence times, minimized char yields, and rapid quenching maximizes the fraction of low molecular weight organics (e.g. methanol) in the final product. These species lower bio-oil viscosity and reduce combustion ignition delay time. As residence time and char yield increase, light organics are cracked to non-condensable light gas, and their benefits lost [66].

7.2. Technical Readiness

Ensyn Corporation has four operational fast pyrolysis reactors, the largest of which is capable of processing 40 dry tons per day [74]. DynaMotive has one 10 dtpd reactor operating to produce bio-oil and another 100 dtpd unit scheduled to complete commissioning by late 2004. The newer reactor, located at a wood flooring company in West Lorne, Ontario, will produce bio-oil from wood wastes for cogeneration in an industrial turbine [75]. It does not seem unreasonable to conclude that stationary and relocatable fast pyrolysis for production of bio-oil from thinnings could be deployed in the near term.

Renewable Oil International has built a mobile fast pyrolysis system using an auger reactor with a capacity of 5 dtpd. In the near term, the company plans to scale up to 25 dtpd capacity, and in the longer term, a 100 dtpd unit [40]. Successful implementation of a mobile system indicates there should be few issues in design and implementation of mobile or transportable systems. However the particulars of a BFB reactor may vary somewhat from that of an auger reactor, particularly with respect to fluidizing gas requirements, as auger reactors do not use a fluidizing gas.

An additional impediment to the wider use of bio-oil is a lack specification for fuel characteristics – since without such standards, end-users have no assurances as to the quality bio-oil purchased. Diebold et al. [76] have established a set of standards for different grades of pyrolysis oils with an emphasis on combustion and storage characteristics. These standards are presented in Table 7.4 [76].

Table 7.4 – Proposed Bio-oil Specifications

Specification	Light bio-oil (~ASTM #2)	Light-medium bio-oil (~ASTM #4)	Medium bio-oil (~PORL100)	Heavy bio-oil (~Can. #6)
Viscosity, cSt	1.9-3.4 @ 40°C	5.5-24 @ 40°C	17-100 @ 50°C	100-638 @ 50°C
Ash, wt%	0.05	0.05	0.10	0.10
Pour point, C min	Report	Report	Report	Report
Conradson carbon, wt%	Report	Report	Report	Report
Accelerated aging rate @ 90°C, cSt/h	Report	Report	Report	Report
Water, wt%	32	32	32	32
LHV MJ/L min	18	18	18	Report
C, wt% dry	Report	Report	Report	Report
H, wt% dry	Report	Report	Report	Report
O, wt% dry	Report	Report	Report	Report
S, wt% dry	0.1 max	0.1 max	0.2 max	0.4 max
N, wt% dry	0.2 max	0.2 max	0.3 max	0.4 max
K + Na, ppm	Report	Report	Report	Report
Phase Stability @ 20°C after 8 h @ 90°C	Single phase	Single phase	Single phase	Single phase
Flash point, C minimum	52	55	60	60
Density, kg/m^3	Report	Report	Report	Report

This study assumes bio-oil produced will meet only the specification for heavy fuel oil given the relative immaturity of upgrading and stabilization techniques. Clearly, if production of higher grade oils could be managed at modest cost increase, process economics would improve.

7.3. Heat and Power Integration

Fast pyrolysis is mildly endothermic, with a heating requirement of 2.5 MJ/dry kg biomass for commercial systems [77]. This is about 25% higher than experimentally determined heats of pyrolysis of 1.97 MJ/dry kg for softwood pines [78], which is to be expected due to real world system losses.

In fluidized bed reactors, a number of different heat transfer mechanisms are possible. These include: indirect heating of reactor walls, heating of fluidizing gas, air addition for partial oxidation of feedstock, introduction of hot sand from an external combustor, or char combustion in heat tubes [65]. For circulating fluidized beds, heat transfer is by sand heated in an external combustor. In ablative systems the ablation surface must be indirectly heated. For the technology base case, a BFB with heat transfer by hot sand is assumed.

Process heat for fast pyrolysis and drying of chip feedstock will be generated by combustion of byproducts, diesel exhaust, and supplemental combustion of bio-oil. The primary source of heat will be combustion of pyrolysis byproducts (char, light gas) in a suspension combustor. Modeling of heat release for byproducts is discussed in section 4.2.2. Once heat from byproduct combustion and diesel exhaust has been applied against heat demand, any shortfall is made up by supplemental firing of bio-oil in the suspension combustor. This is preferred to wood chip combustion because bio-oil may be fired in the same type of combustor as byproducts. Use of wood chips would necessitate a second burner and add significant system cost and complexity. A summary of heat integration is presented in Table 7.5.

Table 7.5 – Fast Pyrolysis Heat Integration

Facility Type	Heat Demand (GJ/odt)	Diesel Generator Waste Heat	Byproduct Combustion	Bio-oil Combustion
Mobile	7.9	22%	63%	15%
Transportable	5.6	11%	89%	0%
Stationary/Relocatable	5.6	0%	89%	11%

Mobile units have the highest heat demand due to higher unit heat requirements for small dryers. Some supplemental bio-oil combustion is also necessary to meet heat demand. Transportable systems are able to meet heat demands without supplemental firing due to lower unit heating requirements. However, stationary and relocatable systems require supplemental bio-oil firing because no diesel generator waste heat is available.

Fast pyrolysis also requires significant power input to produce bio-oil. 40 kWhr/odt [43] will be consumed in the production of bio-oil and an additional 10 kWhr/ton of bio-oil is assumed to be consumed by convective cooling fans. A process flow diagram for fast pyrolysis showing full heat and power integration is presented in Figure 7.6.

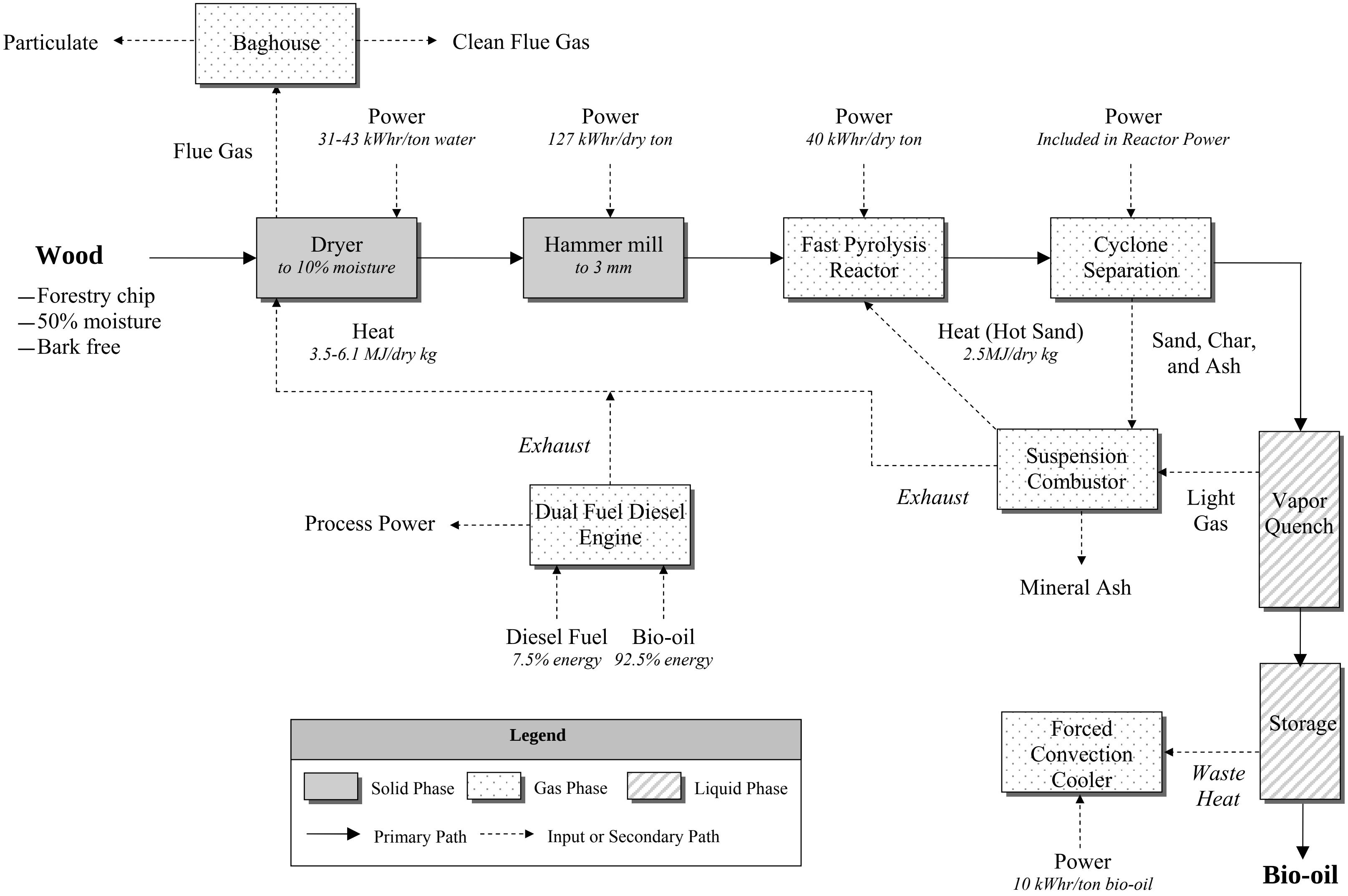

Figure 7.6 – Fast Pyrolysis Heat and Power Integration

7.4. Bio-oil End-Use Applications

A number of end-uses have been suggested for bio-oil, but not all are at the same point in commercial development. Most applications are combustion related, though recovery of high-value chemicals from bio-oil, which is at an early stage of development, may have stronger economics.

7.4.1. Industrial Heating

Bio-oil may be used in industrial heating (furnace and boiler) applications as a substitute for #6 residual fuel oil [30]. Since significant oxygen is present in the liquid fuel, less air is needed for combustion and adiabatic flame temperatures of 1700-2000 K are possible, compared to 2200-2300 K for residual fuel oil [29]. Due to the high solids and water content of bio-oil, special attention must be paid to burner design. Bio-oil flames should not be allowed to come into direct contact with furnace or boiler surfaces, as the flame will leave lacquer-like deposits which can only be mechanically removed [79]. Complete vaporization of bio-oil is not possible – nearly 50% mass remains as solid at the conclusion of boiling [30], so bio-oil is unsuitable for applications where complete vaporization is required. For stable combustion, it is advantageous to design injectors that atomize bio-oil. That is, the incoming bio-oil stream should be reduced to a cloud of small droplets, in order to allow good mixing of air and fuel prior to ignition. The lower the viscosity of the fuel, the finer the atomization achieved. However, the most common mechanism for reducing viscosity of residual fuel oils involves pre-heating. Since bio-oil aging is kinetically controlled, preheating prior to atomization accelerates these reactions and may result in phase separation or undesirable solid deposition in the injection nozzle [79]. The effect is exacerbated by designs where fuel is preheated in a recycling loop, with only a modest fraction injected on each cycle. For these reasons, it is important to design injection systems that balance between improved combustion by finer atomization and increased chance of severe bio-oil degradation.

Recently, the forest products industry has been showing an interest in bio-oil as an alternative to increasingly expensive natural gas burned in lime kilns. Furthermore, combustion of bio-oil in lime kilns would be CO_2 neutral, which would allow Canadian companies to meet CO_2 reduction targets under the Kyoto Protocol. The combustion of bio-oil in lime kilns has been studied by researchers at the University of British Columbia, who concluded that substitution of bio-oil for natural gas (with appropriate burner modification) should be feasible [37].

For industrial heating applications where a higher quality fuel is required, it may be possible to meet light fuel oil specification (Table 7.4) using hot gas filtration and methanol stabilization. As previously discussed, hot gas filtration could reduce solid content to less than 100 ppm. Methanol addition of 10% by weight [62] will slow aging reactions, reduce fuel viscosity [30], and reduce ignition delay [79]. However, since hot gas filtration is not yet commercially proven, bio-oils which could be substituted for higher grade fossil fuels have not been considered in this study.

Bio-oil combustion tests in an industrial boiler (4 MW_{th}) concluded that, with minor modification, bio-oil could be readily burned in conventional furnaces and boilers [79]. However, due to longer combustion time, the bio-oil flames are longer than those in fossil fuel combustion. This has implications for boiler design as the flame tip should not be allowed to come in contact with combustion chamber surfaces. Surfaces in contact with the flame will accumulate coke deposits. Emissions factors for bio-oil and a number of reference fuels are given in Table 7.6.

Table 7.6 – Industrial Boiler Emissions Factors for Representative Fuels

Fuel Type	O_2 (vol%)	NO_x (mg/MJ)	CO (mg/MJ)	Soot (Bac.)	Particles (mg/MJ)
Bio-oil	3.5	88	4.6	2.4	86
Heavy fuel oil	3.5	193	3	2	23
Light fuel oil	3.5	70	1	0.5	2
Natural gas	3.5	55	1	0	0

Not included in this table are SO_x emissions, which were zero for the bio-oil tested. Heavy fuel oil, in particular, contains appreciable sulfur and would generate SO_x during combustion. In comparison to heavy fuel oil, bio-oil combustion produces less than half the NO_x, equivalent CO and soot, and significantly more particulate. However, particulate emissions are generally less expensive to control than NO_x, so switching a boiler from heavy fuel oil to bio-oil might reduce the cost of emissions control.

7.4.2. Diesel Engine

In the near term, bio-oil could be used in dual fuel diesel engines for power generation and CHP applications [43]. Dual-fuel diesel engines fired on bio-oil require some modification (e.g. seal replacement) to accommodate the low pH and corrosive nature of the fuel. Conventional diesel fuel is used as a pilot, accounting for 7.5% of the total energy input to the engine [43]. A pilot fuel is necessary since the ignition delay and longer burning times of bio-oil (relative to diesel) [80] make stable combustion difficult [29]. It is also recommended that the engine injectors be flushed with methanol after use to avoid the build-up of solid deposits. While both Omrod and Wärtsilä have experimented with dual fuel diesel engines operating on bio-oil [29], no engines modified for use with bio-oil are commercially available.

Combustion of pure bio-oil in diesel engines does not appear promising. Experiments by Shihadeh et al. [80] found that while diesel engines operating on bio-oil could achieve nearly the same thermal efficiency as with diesel fuel, practical considerations render this approach undesirable. Bio-oil was characterized as having a long ignition delay and could not be reliably ignited without first preheating combustion air. The fuel injection system, which incorporated closed loop preheating, had to be modified to 'spill' the un-injected fraction of the preheated fuel rather than return it to the fuel tank. Even with this measure to reduce compounding polymerization by repeated exposure of bio-oil to high temperatures, injector nozzles needed to be replaced due to blockage after only six hours of operation. Worse, carbon build-up in the cylinder and exhaust ports made it necessary to remove and clean the head, valves, and pistons each after a day and scrape clean the cylinder walls. To quote the authors, "Clearly, this is not a desirable mode of operation in any practical situation…" [80].

A third option might be to use bio-oil/diesel blends in conventional diesel engines – as is possible with bio-diesel. However, the polar nature of bio-oil makes blending in any appreciable fraction impossible without the use of an emulsifier. Tests carried out by Bridgwater et al. [81] have determined that it is possible to create stable bio-oil/diesel emulsions (up to 75% bio-oil) using emulsifiers, though the technique used is *strongly* dependent on the properties of feedstock bio-oil [81]. These emulsions can be reliably ignited in a conventional diesel engine, though both fuel pump and injection nozzle need to be replaced by stainless steel components to limit corrosion. Due to the surfactants used as emulsifiers, emulsions of bio-oil and diesel have proved to be more corrosive than bio-oil alone [82].

7.4.3. Industrial Turbine

A bio-oil application entering demonstration is the industrial turbine for heat and power. Industrial, or ruggedized, turbines are more tolerant to fuel impurities than aero-derivative turbines and may be appropriate for bio-oil combustion. Experiments have determined bio-oil would be a suitable fuel, with some modification to the combustion chamber geometry to prevent solid deposition [83]. Orenda Aerospace, a division of Magellan Aerospace, has recently completed testing on a 2.5 MW_e (net) industrial turbine fired on pure bio-oil. The system is a modified version of the commercial OGT 2500 industrial turbine and achieves electrical generation efficiencies of 27.1% [75]. The first delivery of this turbine has been to DynaMotive's demonstration project in West Lorne, Ontario. Commissioning of the entire system is expected to be completed by late 2004 [84].

7.4.4. Chemical Upgrading

A higher-value end use for bio-oil than heat and electricity might be as a feedstock for bio-refining – that is, refinery operations producing valuable chemicals and fuels from bio-oil. Potential chemicals include acetic acid, food flavorings, adhesives, hydrogen, slow-release fertilizers, preservatives, and sugars [30]. DynaMotive has been pursuing some simple applications in this area. Rather than burning char for process heat, they have been funding development of techniques for converting char to an activated carbon product [85]. They have also pioneered a product trademarked BioLime, produced from bio-oil, which can be used to effectively scrub SO_x from coal combustor flue gases with high removal effectiveness [29].

With respect to transportation fuels, as part of the DOE hydrogen development program, NREL has been exploring the possibility of reforming bio-oil to produce hydrogen [86]. A representative schematic of the process is given below in Figure 7.7.

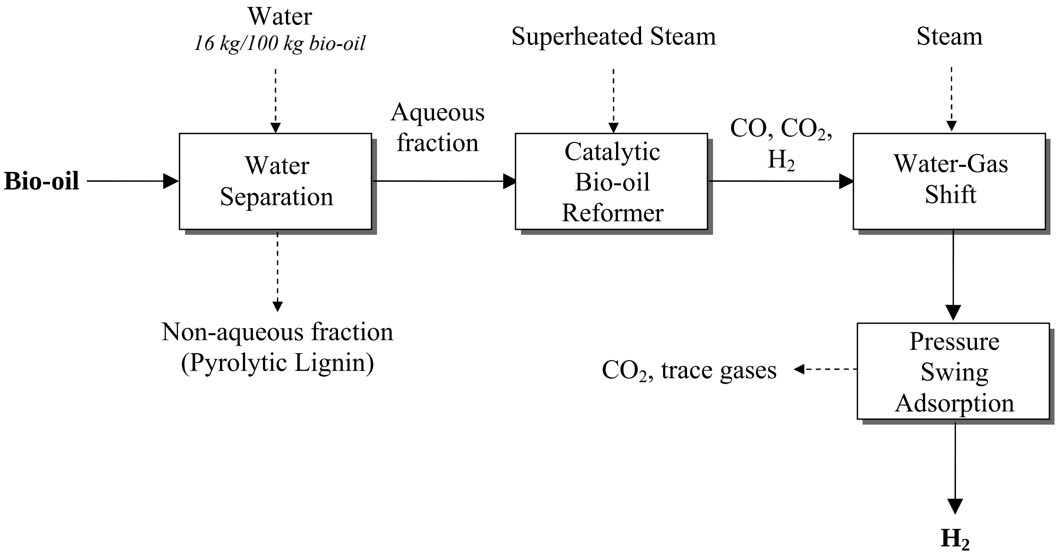

Figure 7.7 – Hydrogen Production from Bio-oil Schematic

The NREL process first forces bio-oil phase separation by adding additional water to the bio-oil feedstock. In this situation phase separation is desirable, because use of whole bio-oil leads to rapid catalyst deactivation in the downstream reformer. The non-aqueous fraction, primarily pyrolytic lignin, is removed and could be used as a phenolic resin for plywood manufacture [86]. The remaining aqueous fraction is injected as a spray into a reactor fluidized by superheated steam. In this reactor, a catalyst facilitates the cracking of bio-oil to a syngas consisting primarily of CO, CO_2, and H_2. A water-gas shift reactor maximizes the H_2 fraction. Hydrogen is then separated using pressure swing adsorption (PSA). While the process has been proven in the lab, there remains an issue with catalyst deactivation and attrition during reforming – even when reforming only the aqueous fraction. Work is on-going to identify more robust catalysts [61].

An overview of other chemical production concepts may be found in [29]. It has also been suggested that bio-oil could play the role of an intermediate to methanol (via a syngas intermediate). This could be especially relevant in European nations with limited biomass resources looking to increase use of renewable transportation fuels. Bio-oil could be used as a convenient bulk feedstock for import from agricultural nations [32].

7.5. Economics

Capital cost estimates for fast pyrolysis have been adapted from a study conducted by Bridgwater et al. [43] on the costs for the first generation of bio-oil production. The study developed regressions of 1st plant costs for bio-oil production and on-site bio-oil storage. Mobile and transportable systems are expected to benefit from learning scale (as discussed in 2.2.1). The regressions presented in Table 7.7 give total plant costs for the core of a fast pyrolysis plant – reactor, char separation, and quench system. Costs for pretreatment and fuel handling are discussed in Chapter 4.

Table 7.7 – Bio-oil Production Capital Cost

Facility Type	Total Plant Cost ($ 000)
Mobile	$= \$20.132(\text{kg/hr dry feedstock})^{0.6914}$
Transportable	$= \$28.184(\text{kg/hr dry feedstock})^{0.6914}$
Stationary and Relocatable	$= \$40.263(\text{kg/hr dry feedstock})^{0.6914}$

The cost of storage for bio-oil produced is given by equation 7.2. Since liquid fuel storage and handling is a mature technology, no learning improvement has been assumed.

$$\text{Bio} - \text{oil Storage (\$ 000)} = \$117.433(\text{kg/hr bio - oil produced})^{0.40} \qquad \text{Equation 7.2}$$

No operating costs specific to bio-oil production are assumed. Standard assumptions for power, mobility, ash disposal, and fixed operating costs apply. For stationary and relocatable bio-oil production, a reference headcount of 1 operator per shift for a rated capacity of 100 dtpd [40] and 80% scale have been assumed. This translates to 3.0 operators per shift for a relocatable facility and 4.4 operators per shift for a stationary facility.

Table 7.8 presents bio-oil production costs for base case assumptions. Costs are listed on a unit cost basis per wet ton of thinnings harvested. Stationary fast pyrolysis costs are for the base case discussed in 2.4. 'Other' costs include fixed maintenance and overhead, ash disposal, and mobility expenses. 'Power' includes cost of purchased electricity for a stationary or relocatable facility and fuel costs and generator maintenance for mobile and transportable operations. Amortized 'Mobility' costs include the cost of trailers or containers as well as diesel generators.

Table 7.8 – Bio-oil Production Cost Chain

Cost ($/ton wet thinnings)	Mobile	Transportable	Stationary	Relocatable
Capital Cost				
Mobility	$3	$2	$-	$1
Pretreatment	$13	$6	$4	$3
Fast Pyrolysis	$21	$12	$7	$8
Capital Cost	$37	$20	$11	$12
Operating Cost				
Labor	$72	$9	$2	$3
Power	$2	$2	$6	$6
Other	$14	$15	$4	$7
Operating Cost	$89	$26	$11	$15
Total Production Cost	$126	$46	$22	$27
Total Production Cost ($/GJ Bio-oil)	$21.5	$7.9	$3.8	$4.3

On an energy basis, production costs for stationary and relocatable facilities are below the $4.7/GJ projected selling price for bio-oil.

Considering Table 7.8, one sees a steady decrease from mobile to transportable to stationary production of bio-oil. Relocatable production costs are 20% higher than for stationary production. These cost trends follow the same patterns as pelletization for the same reasons. See section 6.4 for a discussion of these trends. For most types of facilities, costs are nearly evenly divided between capital and operations.

Fast pyrolysis yields and conversion efficiencies for the four different facility sizes are listed in Table 7.9.

Table 7.9 – Bio-oil Production Characteristics

Facility	Energy Efficiency	Bio-oil Mass Yield	Bio-oil Production
Mobile	45%	28%	153,000 tons/yr
Transportable	55%	34%	185,000 tons/yr
Stationary	59%	38%	206,000 tons/yr
Relocatable	59%	38%	206,000 tons/yr

Efficiency and mass yield increases between mobile and transportable facilities due to decreased unit heat and power requirements for larger dryers. Energy efficiency is even higher for stationary and relocatable facilities since power is being purchased from the grid and no bio-oil is used for power generation.

An interesting extension of this economic analysis is to forecast near-term bio-oil production cost reductions. First, given the number of existing demonstration units, one could conclude enough stationary facilities will be built in the next few years to bring down capital costs through learning scale. Therefore, for the second generation of stationary and relocatable fast pyrolysis facilities, 10th unit costs (30% capital cost reduction) will be more appropriate than 1st unit costs considered in the base case. Second, in the near term, either ablative or circulating fluidized beds should complete commercial demonstration. Since both variants are capable of using chips up to 6 mm characteristic size, the output of a conventional chipper will meet process requirements without power and cost intensive comminution. Failing this, conventional chippers and debarkers could possibly be modified to produce a 3 mm chip suitable for use in bubbling fluidized beds [40]. Bio-oil cost reductions for this ‘Advanced Fast Pyrolysis’ scenario are given in Table 7.10.

Table 7.10 – Advanced Bio-oil Production Cost Chain

Cost ($/ton wet thinnings)	Mobile	Transportable	Stationary	Relocatable
Capital Cost				
Mobility	$2	$1	$-	$1
Pretreatment	$13	$6	$4	$3
Fast Pyrolysis	$21	$12	$5	$6
Capital Cost	$36	$19	$9	$10
Operating Cost				
Labor	$72	$9	$2	$2
Power	$1	$1	$2	$3
Other	$14	$14	$3	$5
Operating Cost	$87	$24	$7	$10
Total Production Cost	$123	$43	$16	$20
Total Production Cost ($/GJ Bio-oil)	$21.0	$7.3	$2.7	$3.2

As with the base case, production costs for stationary and relocatable facilities are substantially below the $4.7/GJ selling price for bio-oil.

Cost reductions are most pronounced for stationary and relocatable bio-oil production due to significant capital cost reductions from learning scale.

7.6. Environmental Considerations

Emissions and appropriate pollution control for wood drying are discussed separately in section 4.2. Since all gaseous products are routed through the dryer, no additional gaseous pollution control will be required.

Excluding bark, production of bio-oil creates only a single solid waste product – mineral ash. This is ash is a residue of char combustion in the suspension burner. The ash is non-toxic and should not present an environmental hazard.

Due to the corrosive nature of bio-oil, particular care must be taken in identifying suitable storage containers. Over time, bio-oil will corrode most common steels and aluminum. Stainless steel and polymers are nearly unaffected [87].

An additional environmental concern is a bio-oil spill – as could be the case in a fuel truck accident. Since bio-oil is denser than water (specific gravity of 1.2), if it spills into a waterway it will sink to the bottom. This would, obviously, complicate spill clean-up and, of particular concern in the Northwest, damage salmon breeding grounds by coating gravel river beds with bio-oil. This is less of a concern for bio-oil production outside the forest than within where fuel trucks could be driving on forest roads in environmentally sensitive areas.

7.7. Research Opportunities

Bio-oil production and use offer a number of research opportunities. In addition to previously discussed areas of ongoing research, a number of novel research options may be possible as this is an emerging technology. One example is presented here.

Some light, volatile organic compounds (e.g. methanol) are not condensed during vapor quench. If these low molecular weight compounds could be captured, they would decrease the average molecular weight of the bio-oil, reducing viscosity and combustion delay time. Diebold [64] comments that these compounds may escape because their partial pressure exceeds their vapor pressure under quench conditions. As such, increasing the partial pressure of the light organics could prove beneficial if modestly elevated partial pressures allowed higher collection efficiencies for these low molecular weight species. Decreasing the volume of fluidizing gas would increase the partial pressure of light organics. Auger reactors (mentioned in 7.1.1.4) do not require a fluidizing gas, but liquid yields are 10% lower than for other common reactor variants [65]. As a result, a reactor which does not require fluidizing gas – and, therefore, maximizes light organic partial pressure – may not be ideal. It might be possible to identify an optimal level of fluidizing gas in a more conventional reactor which would maintain a high bio-oil yield while collecting additional light organics.

8. Methanol Synthesis

Methanol is produced from woody biomass by gasification, cleaning the resulting syngas, and synthesizing methanol from this gaseous feed. This is a complex process requiring many pieces of specialized equipment.

Gasification is defined as thermal decomposition of biomass in substoichiometic oxygen. This process involves drying, pyrolysis, reduction, and oxidation. Key reactions and enthalpies of reaction are given in Table 8.1 [88].

Table 8.1 – Representative Gasification Reactions

	H (kJ/mole)	
Reaction	**298 K**	**1000 K**
a. $CO + H_2O \leftrightarrow CO_2 + H_2$	-41.2	-34.77
b. $C + 2H_2 \leftrightarrow CH_4$	-74.93	-89.55
c. $C + H_2O \leftrightarrow CO + H_2$	131.4	136.0
d. $C + CO_2 \leftrightarrow 2CO$	172.6	170.7
e. $C + O_2 \leftrightarrow CO_2$	-393.8	-394.9

Char oxidation (reaction e), is strongly exothermic, providing heat for strongly endothermic reduction (reactions c and d) as well as pyrolysis and drying of biomass feedstock. As with fast pyrolysis, the pyrolytic step in gasification results in the thermal decomposition of woody biomass to char, tars, and light gases. Provided these intermediate products have a sufficiently long residence time at high temperature, they will be broken down to CO, H_2, H_2O, and CO_2 [88]. The four gases, in addition to nitrogen if air is used as an oxygen source for char combustion, will make up the majority of the gasifier product – syngas. In most gasifiers, syngas residence time will not be sufficient to break down all pyrolysis products and the syngas stream will also contain a number of light hydrocarbons (e.g. methane). A number of contaminants all also present in syngas, including heavy hydrocarbon tars, vapor phase alkali metals, and particulate. These contaminants are incompatible with most syngas end-uses and must be minimized. Clean syngas undergoes a number of reforming steps prior to methanol synthesis to achieve an optimal H_2:CO ratio (2:1). Figure 8.1 gives a basic process schematic for producing liquid methanol from woody biomass.

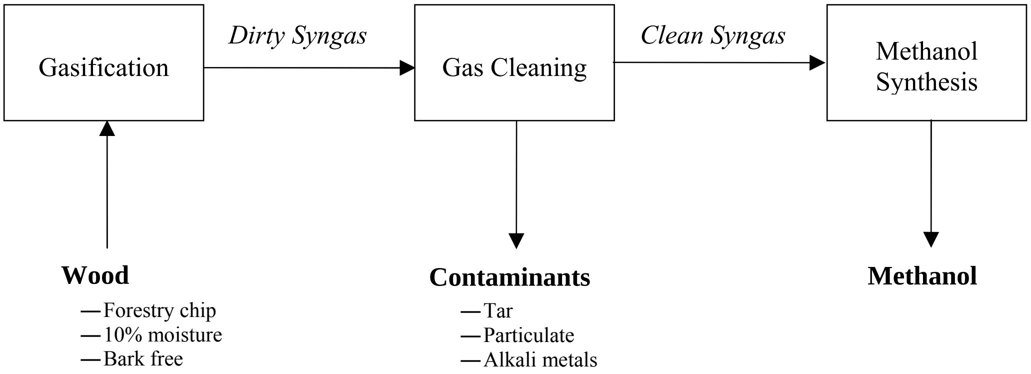

Figure 8.1 – Methanol Synthesis Schematic

8.1. Process

While the production of methanol from thinnings is technically challenging, feedstock requirements are minimal. Debarking has been assumed, though this is a conservative assumption since the chemical composition of bark might not impact the final product in the same way as it does with bio-oil or pellets. Forestry chips are suitable for gasification after being dried to 10% moisture. No additional comminution is necessary.

8.1.1. Gasification and Gas Cleaning

Gasification and gas cleaning may be considered on integrated basis as some syngas contaminants are a function of the gasifier type and operating parameters. A number of gasifier variants exist and may be categorized as direct or indirectly heated, pressurized or atmospheric, and fixed bed, fluidized bed or entrained flow.

For large scale facilities, fluidized bed and entrained flow gasifiers are preferred over fixed bed gasifiers, which are considered impractical for high biomass throughputs. In order to simplify cost modeling, it has been assumed that fluidized bed gasifiers will be used even for mobile and transportable bio-fuel production, even though a fixed bed might be feasible at this smaller scale.

The use of biomass in entrained flow gasifiers is problematic, since feedstock must be reduced to very small particles (100-600 μm) [34]. Entrained flow gasification requires nearly an order of magnitude smaller size reduction than fast pyrolysis (3000 μm) and would be *extremely* energy intensive considering the exponential nature of grinding power consumption for decreasing particle size [89]. For this reason, entrained flow gasification has received relatively little attention in the biomass community and is generally considered more suitable for coal, which may be readily pulverized. However, recently CHOREN, a German research group with funding from DaimlerChrysler, has developed an entrained flow gasifier to produce syngas for bio-fuel synthesis. In their patented Carbo-V process, biomass first undergoes a low temperature (500^{o}C) carbonization step – similar to the production of charcoal – to yield a 'bio-coke' and tar-heavy gas. With respect to grinding, bio-coke behaves much more like coal than biomass and may be pulverized to fine particles with only modest power consumption. Pulverized bio-coke and tar-heavy gas are then converted to syngas in an entrained flow gasifier at very high temperature (1500^{o}C). At this temperature, virtually all tars are thermally destroyed, resulting in a tar-free syngas [90]. Relatively little technical literature appears to be publicly available for this process, but a key concern would be the pure oxygen required for high temperature gasification. Air separation is highly scale intensive and requires very high biomass throughputs (>1500 dtpd) to be economic. Thus, this process may not be a good match for the sort of throughputs typical of thinning. Due to a lack of technical and economic information and this possible capacity mismatch, entrained flow gasification has not been considered in this study.

In fluidized bed gasifiers, feedstock is suspended in a turbulent layer by the upward flow of a fluidizing gas which counteracts gravitational forces. With direct gasifiers, the fluidizing gas contains oxygen, which exothermically reacts with some of the feedstock to provide the heat necessary to drive the endothermic gasification process. Air is, unfortunately, not a suitable fluidizing gas, since direct air gasification produces a syngas heavily diluted by nitrogen. Since much of the cost of downstream equipment scales with gas volume throughput, nitrogen dilution in the syngas stream (~50%) would greatly increase the cost of this equipment. Nitrogen dilution also reduces catalyst selectivity. For this reason, if direct gasification is to be used, oxygen must be separated from nitrogen prior to injection into the gasifier. As mentioned in the discussion of entrained flow gasifiers, air separation to produce oxygen is generally uneconomic at a scale consistent with thermochemical conversion of biomass. This effect would be particularly acute for lower throughput mobile and transportable systems. For this reason, direct gasification has not been considered. Indirect gasification circumvents this limitation by supplying reaction heat via an inert heat transfer material, usually sand and operates at lower temperatures (800-900^{o}C) than entrained flow gasifiers. Cyclones separate char from syngas exiting the gasifier. This char undergoes combustion in a separate fluidized bed and mixes with sand. Hot sand is introduced back into the first fluidized bed where it provides heat for gasification. The sand is entrained in the syngas along with char and separated by the same cyclones that remove char. Since combustion is external to gasification, syngas is undiluted by nitrogen. The gasifier bed is fluidized by recycling some of the syngas produced [34]. An indirect gasifier appears most appropriate for the production of syngas from thinnings. A schematic diagram of an indirect gasifier is presented in Figure 8.2.

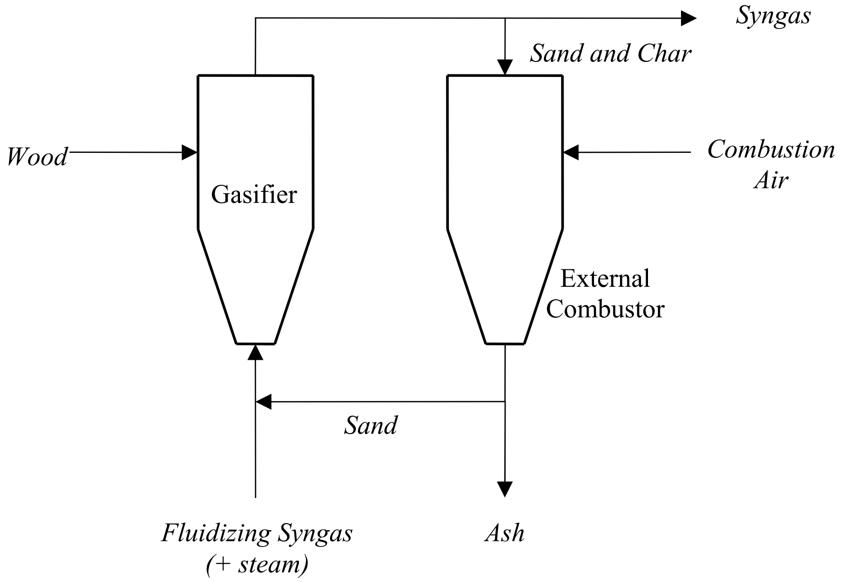

Figure 8.2 – Indirect Gasifier Schematic

Since indirect gasification occurs in the absence of oxygen, it is, by definition, pyrolytic. A consequence of this and lower gasification temperatures is that indirect gasification produces more heavy hydrocarbons (tars) than direct or entrained flow gasification. Syngas composition for entrained flow, direct, and indirect fluidized bed gasifiers is presented in Table 8.2 [34]. Note the high levels of CH_4 and heavy hydrocarbons (C_2+) for indirect gasification.

Table 8.2 – Syngas Composition

Mole Fraction	Direct Gasification[10]	Indirect Gasification[11]	Entrained Flow[12]
H_2O	31.8%	19.9%	18.4%
H_2	20.8%	16.7%	30.7%
CO	15.0%	37.1%	39.0%
CO_2	23.9%	8.90%	11.8%
CH_4	8.2%	12.6%	0.1%
C_2+	0.3%	4.8%	0%

The cost of downstream equipment may be further reduced by operating the gasifier at high pressure. However, this arrangement introduces the challenge of feeding biomass at elevated pressures. A number of systems have been proposed for this type of operation (lockhopper, rotary valve, piston), but all have experienced problems in commercial scale-up [39]. Furthermore, there has been, to date, no development of high pressure indirect gasification systems. For these reasons, a system operating at atmospheric pressure has been assumed.

Once syngas has been produced, the next step is to remove contaminants from the gas stream. In order: tar, particulate, and alkali metals. Specific equipment is shown in Figure 8.3. For downstream methanol synthesis, particulate levels should be 3-5 ppm and alkali metal concentration around 20 ppb [39].

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[10] Institute of Gas Technology – oxygen fluidized

[11] *SilvaGas* gasifier – Future Energy Resources Corporation (FERCO), developed by Battelle Columbus Labs

[12] Shell entrained flow gasifier – estimated biomass performance

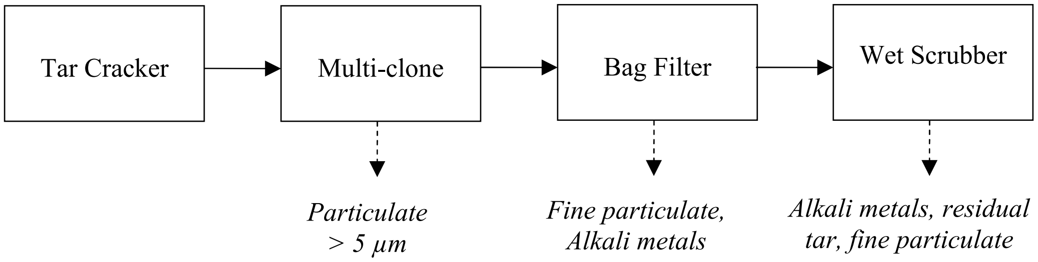

Figure 8.3 – Gas Cleaning Process Flow

Though there is no generally accepted definition of 'tar', a number of studies have defined tars as hydrocarbons with a molecular weight greater than benzene (78 kg/kmole). Tar destruction is not an issue in close-coupled gasification-combustion (e.g. Lahti co-fire project [24]) since tars have no opportunity to condense and remains in the gas phase from formation to end-use. If tars are allowed to condense, they may foul or plug heat exchangers and pipes and deactivate catalytic beds [72]. A thorough discussion of tar formation mechanisms may be found in [91]. Methods to reduce syngas tar levels may be categorized as primary (occurring within the gasifier) and secondary (occurring outside the gasifier). Primary measures include specification of gasifier operating parameters (e.g. temperature, steam ratio) and incorporation of a tar cracking catalyst in the gasifier bed. Secondary measures include tar crackers and condensing scrubbers, as in Figure 8.3 [92]. Much research and development effort has been directed towards secondary tar reduction measures. However, the recent development of small, modular biopower systems (section 1.2.3) has seen gasifiers designed to produce low-tar syngas by primary methods. Small system design may be iterated at low cost, allowing a trial-and-error approach to the complex problem of tar reduction. However, this approach is less practical for large-scale systems where iteration can be quite costly. Since primary tar reduction methods remain unproven at large scale, it is assumed that a tar cracker will be necessary. The tar cracker is an additional reactor, operating at approximately the same temperature as the gasifier (800-900^{o}C), with a catalytic bed material to promote cracking of heavy, condensable hydrocarbons to lighter species. Cracking is preferred over removal, because these heavy hydrocarbons have a significant energy content which must be recovered to achieve high thermal efficiency for the overall bio-fuel production process. To date, the challenge has been in identifying a catalyst capable of sustained tar cracking. Many promising catalysts developed in the lab have lifetimes too short (either due to attrition or deactivation) to be practical in a commercial process. A thorough review of tar catalyst research may be found in [93].

Particulate must then be removed from the low-tar free syngas. Multi-clones, centrifugal effect separators, operating in series, can effectively remove more than 90% of particulate greater than 5 μm in diameter. However, they are ineffective at removing smaller particulate. Multi-clones are able to operate at high temperatures and are limited only by material considerations [72].

A number of approaches are suitable for removing small diameter particulate. Barrier filters are the most common and include bag filters, which have been selected in previous systems studies of methanol synthesis from biomass [39]. Bag filters have a porous surface of a woven material which allows gas to pass through, while capturing particulate. In theory, bag filters can remove particulate of any size, but as pore size decreases and filter thickness increases, pressure drop over the filter increases. In general, it is not practical for bag filters to remove particulate with a diameter smaller than 0.5 μm [72]. Captured particulate is removed from filters by periodically back-flushing the system with a pulse of clean gas. Due to material constraints, bag filters may only operate up to around 350^{o}C [72]. As a consequence, syngas must be cooled from gasifier temperatures (800-900^{o}C) prior to fine particulate removal. If heavier tars have not been cracked upstream of the bag filter, at these temperatures they will condense and foul the filter.

Alkali vapors are formed in the gasifier by the vaporization of biomass ash. The most common method of removal involves cooling syngas to below 600^{o}C. At this temperature, alkali vapors will condense to fine particulate less than 5 μm in diameter. The bag filter used for particulate removal will also capture a number of these condensed aerosols [72].

Previous methanol synthesis studies have used web scrubbing as a necessary contaminant reduction measure [39]. Water is sprayed into the gas stream and removes contaminant particles by impaction. With a modest pressure drop, wet scrubbers are capable of removing 99.9% of particles over 2 μm and 95-99% of particles over 1 μm in diameter. The wet scrubber should remove residual tars, fine particulate, and condensed alkali metals. Because the sprayed water must be in the liquid phase and the system operates at atmospheric pressure, the gas must be cooled to below $100^{o}C$ prior to wet scrubbing. The condensed effluent from the wet scrubber must undergo waste-water treatment before being recycled or discharged. This is a concern worthy of further consideration.

The gas cleaning approach described above is referred to as wet, cool gas cleaning due to the use of water and low temperatures. Though effective, this approach has two drawbacks. Wet scrubbing gives rise to an effluent stream of polluted water. Waste-water treatment would likely entail the use of evaporation ponds (as is the case in SO_2 removal using limestone slurries) where polluted water would be allowed to evaporate, leaving a residual sludge. Clearly, this approach would be especially problematic for mobile and transportable bio-fuel production as it would require digging new evaporation ponds at each location. In addition to the added expense of waste water treatment, this pollution stream may increase the difficulty in obtaining a permit to operate a facility of this type, especially in areas with scarce water resources. Secondly, the required cooling has an associated thermodynamic penalty, since the clean syngas must be reheated prior to methanol synthesis. For this reason, there has been significant interest in the development of hot, dry gas cleaning systems. While these are not yet commercial, they would have the advantage of cleaning syngas without creating a pollution stream or incurring thermodynamic penalties. While high temperature particulate removal has been demonstrated at Värnamo (see section 1.2.2), high temperature processes for complete removal of tar and alkali metals remain commercially unproven. As such, hot, dry gas cleaning is not considered as a base case for methanol production from thinnings. A review of progress in high temperature gas cleaning may be found in [72].

8.1.2. Methanol Synthesis

The gasification and clean-up approach described above is nearly identical for the production of any high-grade liquid bio-fuel. Once a clean syngas is available, any number of processes developed for the petrochemical industry may be used to produce a liquid or gaseous fuel. These fuels include methanol, synthetic diesel, and hydrogen. Equipment specific to the production of methanol is shown in Figure 8.4. Prior to steam reforming, syngas is generally compressed to reduce the size of downstream equipment. Compression is usually to between 1 and 3.5 MPa (compression ratio of 10-35) and represents a significant fraction of the total process power demand [34].

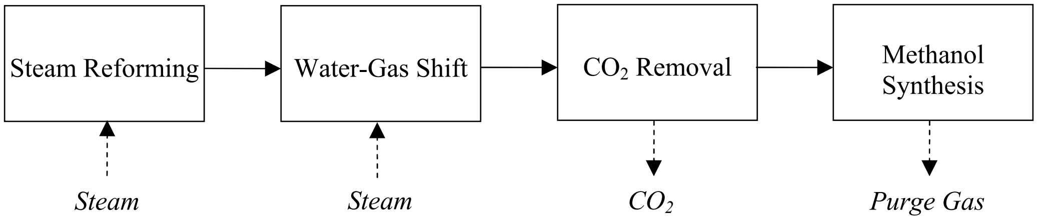

Figure 8.4 – Methanol Synthesis Process Flow

For indirect gasifiers, in addition to CO, H_2, CO_2, and H_2O, syngas contains light hydrocarbons (e.g. methane) with significant energy content. The energy in these compounds is commonly recovered by steam reforming syngas over a nickel catalyst to CO and H_2. Reformers typically operate between 830°C and 1000°C, so the syngas stream must be reheated and pressurized after wet scrubbing. Steam to carbon molar ratio should be 3.5:1 to prevent coking. Steam reforming reactions are presented below. These reactions are highly endothermic so external heating is required [39].

$$\mathrm{CH_4 + H_2O \rightarrow CO + 3H_2} \qquad \text{Equation 8.1}$$

$$\mathrm{C_2H_4 + 2H_2O \rightarrow 2CO + 4H_2} \qquad \text{Equation 8.2}$$

$$\mathrm{C_2H_6 + 2H_2O \rightarrow 2CO + 5H_2} \qquad \text{Equation 8.3}$$

$$\mathrm{C}_n\mathrm{H}_m + n\mathrm{H_2O} \rightarrow n\mathrm{CO} + \left(n + \frac{m}{2}\right)\mathrm{H_2} \qquad \text{Equation 8.4}$$

Once higher hydrocarbons have been reduced to CO and H_2, the syngas stream passes through a shift reactor where the ratio of H_2:CO is adjusted for optimal methanol production via the water-gas shift reaction over a catalyst. The equilibrium relation for the water-gas shift is given in Equation 8.5.

$$CO + H_2O \leftrightarrow H_2 + CO_2 \qquad \text{Equation 8.5}$$

An H_2:CO ratio of 2:1 is ideal, which would be suggested by the molecular structure of methanol – CH_3OH.

This shift can either occur in two reactors, one at high temperature (360°C) over an iron-oxide-chromium oxide catalyst and a second at low temperature (190°C) over a zinc oxide-copper oxide catalyst or in a single reactor operating at 210°C. The steam to carbon monoxide ratio should be 3:1 to prevent coking [39].

The yield of methanol synthesis from syngas varies with the molar ratio of (H_2 - CO_2) to (CO + CO_2). For the methanol synthesis reaction to proceed, this ratio must be at least 2.03. To meet this requirement, some CO_2 must be removed from the syngas. This may be readily accomplished via the SELEXOL process – a mature method for CO_2 separation. The SELEXOL process will also remove acid gases and hydrocarbons heavier than butane that may have survived the steam reforming step [39]. Other emerging methods of CO_2 removal are discussed in Hamelinck et al. [39].

Conventionally, methanol is produced by two gas-phase reactions over a copper catalyst. This catalyst cannot tolerate either sulfur or chlorine, so acid gas removal prior to methanol synthesis is critical. For the woody biomass considered in this study, neither sulfur nor chlorine should be present in the feedstock.

$$CO + 2H_2 \leftrightarrow CH_3OH \qquad \text{Equation 8.6}$$

$$CO_2 + 3H_2 \leftrightarrow CH_3OH + H_2O \qquad \text{Equation 8.7}$$

While both these reactions are exothermic, the entire process operates isothermally and adiabatically between 230°C and 260°C due to a cooling from pressurization of unreacted syngas in a recycle loop. Methanol is produced by multiple passes through the reactor, with unreacted and CO and H_2 recycled after each pass [39].

Without the use of advanced chemical process modeling tools, such as ASPEN+, it is not a simple matter to accurately predict methanol yields for the overall process. As such, previous modeling results for a system of similar configuration to the one described above are used to determine yield. On an energy basis, 0.606 GJ of methanol is assumed to be produced for every GJ of wood input to the gasifier [34]. Note that this is different than process feedstock input, since a fraction of wood chips delivered to the site will be burned to provide process heat.

Purge gas from the methanol recycle loop, primarily CO_2 and H_2O with some residual CO and H_2, is assumed to be burned in a steam cycle for power generation. More advanced approaches for larger facilities have considered purge gas combustion in a combined cycle system. However, the low energy content of purge gas may cause combustion instability. Use of a steam turbine is only considered for stationary and relocatable systems since it would be difficult to justify the mechanical complexity of such a system for smaller mobile and transportable units. An option not considered here would be to burn purge gas in a reciprocating engine – a technology which would be appropriate to the scale of mobile and transportable bio-fuel production.

The process described above is the conventional approach to methanol synthesis from syngas. Each of the steps described, steam reforming, shifting, CO_2 removal, and methanol synthesis is the subject of ongoing research and development. The appendices of the systems study of methanol and hydrogen production by Hamelinck et al. [39], which the methanol portion of this study draws heavily upon, provides a good overview of ongoing avenues of research.

8.2. Technical Readiness

Of the biomass conversion technologies considered in this study, methanol synthesis is the farthest from commercialization. Synthetic diesel is currently being produced using the Carbo-V process developed by CHOREN using an entrained flow, oxygen blown gasifier coupled to a Fischer-Tropsch process [90]. Fuel produced in this manner is currently two to three times as expensive as conventional diesel. While methanol synthesis equipment could conceivably be coupled to this to produce methanol, the oxygen required for entrained flow gasification remains problematic from a cost standpoint.

Indirect gasification, which could produce a syngas free of nitrogen without the need for air separation, faces a legal hurdle. The technology developed by Battelle-Columbus Labs has been exclusively licensed to Future Energy Resources Corporation (FERCO). Any development of methanol synthesis using indirect gasification, as developed by Battelle-Columbus, would have to be licensed from FERCO.

Treatment of waste water generated by cold-gas cleaning may make permitting a methanol synthesis plant problematic for stationary facilities and impractical in the field. Both direct and indirect gasification will require wet gas cleaning in the near-term. Hot, dry gas cleaning may be a viable longer-term option, but this approach remains unproven at commercial scale. Direct gasification produces negligible tar, so cleaning would be limited to particulate and alkali metal vapors. Indirect gasification would require removal of particulate, alkali metal vapors, and significant quantities of tar.

A further challenge to field use is the amount of equipment required for methanol synthesis – much more than either pelletization or fast pyrolysis. Designing systems of 10 and 100 dtpd capacities within such restrictive footprints as a semi-trailer bed may be difficult to achieve. Lower throughputs – for example 5 dtpd for mobile systems and 50 dtpd for transportable – would significantly increase the price of produced methanol on a unit cost basis (e.g. $/GJ).

8.3. Heat and Power Integration

True heat and power integration is beyond the scope of this work as it would require more complex modeling tools, such as ASPEN+. Most of the gas cleaning and reforming stages occur at different temperatures, necessitating multiple heat exchangers to cool down and then reheat syngas for optimal thermal efficiency [39]. However, we may still perform some basic heat and power integration. Hamelinck et al. [39] estimate power consumption for methanol synthesis (excluding pretreatment) to be 33.3 kWhr/GJ methanol produced. For mobile and transportable production, this demand will be met by diesel generators. For stationary and relocatable production, the steam power cycle fired on purge gas is projected to meet 32% of process power needs. The balance is met by purchase of grid electricity. Based on a consideration of previous work [34,39] it appears that process heating needs (exclusive of pretreatment) may be met without external input. However, it is conservatively assumed that no excess heat will be available for drying from downstream processes. As such, it is assumed that drying heat will be supplied by diesel exhaust and wood chip combustion. A breakdown of heat inputs is presented in Table 8.3.

Table 8.3 – Feedstock Drying Heat Integration

Facility Type	Drying Heat Demand (GJ/odt)	Diesel Generator Waste Heat	Wood Chip Combustion
Mobile	5.3	16%	84%
Transportable	3.1	26%	74%
Stationary/Relocatable	3.1	0%	100%

8.4. Economics

Capital costs for methanol synthesis have been adapted from a detailed systems study by Hamelinck et al. [39]. Costs are presented in Table 8.4. These are 1st system costs applicable to stationary and relocatable production of methanol. For mobile and transportable production, learning scale improvements of 50% and 30%, respectively, have been applied. Costs are grouped into the categories of gasification, gas cleaning, methanol synthesis, and power generation. Note, as previously discussed, the capital cost for steam cycle power generation is only applicable to stationary and relocatable facilities.

Table 8.4 – Methanol Production Capital Cost

	Reference Cost ($ MM)	Reference Scale	Scale Factor	Installation Multiplier
Gasification				
Gasifier	$16.1	1650 dtpd	0.65	1.7
Tar Cracker	$3.2	34.2 m^3 gas/s	0.7	1.7
Gas Cleaning				
Cyclones	$2.7	34.2 m^3 gas/s	0.7	1.7
Heat Exchanger	$7.3	39.2 kg steam/s	0.6	1.7
Baghouse Filter	$1.7	12.1 m^3 gas/s	0.65	1.7
Condensing Scrubber	$7.1	12.1 m^3 gas/s	0.7	1.7
Methanol Synthesis				
Compressor	$11.6	13.2 MW_e	0.85	1.7
Steam Reformer	$9.8	1390 kmol gas/hr	0.6	1.7
Shift Reactor	$38.5	15.9 Mmol CO + H_2/hr	0.85	1.0
CO2 Removal	$56.5	9,909 kmol CO_2/hr	0.7	1.0
Methanol Production	$23.1	88 tons MeOH/hr	0.7	1.7
Power Generation				
Steam Turbine Plant	$5.3	10.3 MW_e	0.7	1.7

There are two issues in adapting these costs for modeling methanol synthesis in this study. First, the reference capacities for key equipment are larger, by nearly a factor of two, than the largest stationary systems considered. As a result, extrapolation to smaller scale mobile and transportable systems should be considered speculative. Secondly, reference scales are very specific to the equipment being considered and require identifying a number of intermediate products. In contrast equipment costs for pelletization and fast pyrolysis could be estimated using only a few pieces of information, usually feedstock input and process output. Since reference capacities can not be obtained without detailed process modeling, an approximate method was determined for computing throughputs at different scales. Using total plant costs presented in [39], it was possible to back-out the various throughputs and capacities used in that study. Assuming that these capacities scale directly with feedstock input, constants of proportionality were calculated to determine equipment capacities for the systems considered in this study. These constants are tabulated in Table 8.5.

Table 8.5 –Proportionality Constants for Calculating Equipment Capacity

Parameter	Proportionality Constant
High temperature heat exchanger steam generation	0.0164 kg steam per dtpd
Compressor power input	0.0067 MW_e per dtpd
Steam reformer throughput	2.68 kmol gas/hr per dtpd
Shift reactor throughput	0.0003 Mmol CO + H_2/hr per dtpd
CO_2 removal capacity	0.5 kmol CO_2/hr per dtpd
Steam turbine power output	0.0045 MW_e per dtpd

To calculate the capacity of a given piece of equipment one applies the following relation.

$$(\text{Reference Capacity})_i = (\text{Feedstock Input})(\text{Constant of Proportionality})_i \qquad \text{Equation 8.8}$$

These constants of proportionality are *highly* process specific and should not be applied to other methanol synthesis configurations (e.g. entrained flow gasification).

Two operating costs are specific to methanol synthesis in excess of standard operating cost assumptions (e.g. fixed O&M). These are the cost of reaction water (steam reforming, water-gas shift) and catalyst for the tar cracker. From [34], steam demand for the type of process being modeled is quite modest at 0.38 kg steam/kg dry feedstock. Commercial water rates of \$1.3/m^3 have been assumed for stationary and relocatable production of methanol. For transportable and mobile production this cost has been arbitrarily increased by a factor of five to account for the cost of transporting water into the field. In all cases, the cost of reaction water is relatively low compared to the other operating costs. With respect to the catalyst, Bridgwater et al. [43] estimate consumption of dolomite (a suitable primary catalyst) to be 0.68 kg dolomite/kg dry feedstock and the cost of dolomite at \$29/ton. This cost is appreciable and highlights the benefit of developing more robust catalysts with lower attrition rates. The cost of waste water treatment from a condensing scrubber is highly site specific and not included, as per [43].

For stationary and relocatable facility labor requirements, a reference headcount level of 2 personnel for a rated capacity of 100 dtpd and 80% scale factor are assumed. For the base case, this translates to 8.9 operators per shift for a stationary facility and 6.0 operators per shift for a relocatable facility.

Table 8.6 presents methanol production costs for base case assumptions. Costs are listed on a unit cost basis per wet ton of thinnings harvested. Stationary methanol synthesis costs are for the base case discussed in section 2.4. 'Other' costs include reaction water, catalyst, fixed maintenance and overhead, ash disposal, and mobility expenses. 'Power' includes cost of purchased electricity for a stationary or relocatable facility and fuel costs and generator maintenance for mobile and transportable operations. Amortized 'Mobility' costs include the cost of trailers, containers, and diesel generators.

Table 8.6 – Methanol Production Cost Chain

Cost ($/ton wet thinnings)	Mobile	Transportable	Stationary	Relocatable
Capital Cost				
Mobility	$3	$2	$-	$4
Pretreatment	$11	$5	$3	$2
Methanol	$70	$48	$34	$35
Capital Cost	$84	$54	$37	$41
Operating Cost				
Labor	$72	$9	$4	$5
Power	$26	$30	$6	$7
Other	$40	$46	$20	$31
Operating Cost	$138	$84	$30	$43
Total Production Cost	$223	$138	$67	$84
Total Production Cost ($/GJ Methanol)	$56.4	$30.5	$15.5	$17.8

Compared to the selling price of methanol of $14.7/GJ, production cost for methanol will, in all cases, exceed the selling price.

Considering Table 7.8, one sees a rapid decrease from mobile to transportable to stationary production of methanol. Relocatable production costs are almost 25% higher than for stationary production. These cost trends follow the same patterns as pelletization for the same reasons. See section 6.4 for a discussion of these trends. The cost chain is heavily weighted towards capital and capital related (e.g. fixed maintenance) costs.

Methanol yields and conversion efficiencies for the four different facility types are listed in Table 8.7.

Table 8.7 – Methanol Production Characteristics

Facility	Energy Efficiency	Methanol Mass Yield	Methanol Production
Mobile	39%	19%	104,000 tons/yr
Transportable	44%	22%	120,000 tons/yr
Stationary	46%	21%	114,000 tons/yr
Relocatable	46%	21%	114,000 tons/yr

Efficiency and mass yield increases between mobile and transportable facilities due to decreased unit heat and power requirements for larger dryers. Energy efficiency increases further for stationary and relocatable production since purge gases are being used to produce process power rather than being flared off.

Among a number of limitations to near-term production of bio-methanol is the use of condensing scrubbers for gas cleaning. This cleaning process results in a stream of waste water which will require treatment and may increase the difficulty in permitting a methanol production facility. For field units, the water requirement for a wet scrubber may be a 'show stopper' due to the volume of water ($1m^3$ per $1000m^3$ gas [39]) and the technical difficulty of small-scale waste water treatment. Also, cooling syngas for cleaning and then reheating for steam reforming incurs a thermodynamic penalty. As discussed previously, an alternative to this cold, wet gas cleaning would be hot, dry gas cleaning – which is relatively far from commercialization. Once developed, hot gas cleaning would eliminate both the quench and waste water issues with current gas cleaning technology. Estimates for the capital cost of hot gas cleaning [39] have been included in an 'Advanced Methanol Synthesis' case. It has been assumed that hot gas cleaning may be substituted for cold gas cleaning without affecting syngas composition or throughput. Unlike the case for advanced fast pyrolysis, no learning scale benefit is assumed as there are no commercial demonstrations of methanol synthesis using the technology considered in this study. Methanol production costs for this near term, advanced technology case are presented in Table 8.8.

Table 8.8 – Advanced Methanol Production Cost Chain

Cost ($/ton wet thinnings)	Mobile	Transportable	Stationary	Relocatable
Capital Cost				
Mobility	$3	$2	$-	$4
Pretreatment	$11	$5	$3	$2
Methanol	$67	$45	$33	$33
Capital Cost	$81	$52	$35	$39
Operating Cost				
Labor	$72	$9	$4	$5
Power	$26	$29	$6	$7
Other	$39	$44	$19	$30
Operating Cost	$137	$82	$30	$42
Total Production Cost	$218	$134	$65	$81
Total Production Cost ($/GJ Methanol)	$55.3	$29.7	$15.0	$17.2

As with the base technology case, production costs for methanol exceed the selling price of $14.7/GJ.

While the nominal cost decline relative to the base case is quite modest, one should remember that base case costs exclude waste water treatment. Also, there are unquantified benefits with respect to permitting that improve the viability of the advanced technology case relative to the base technology case.

8.5. Environmental Considerations

Emissions and appropriate pollution control for wood drying are discussed separately in 4.2. Since all gaseous products are routed through the dryer, no additional gaseous pollution control will be required.

Excluding bark, production of bio-oil creates only a single solid waste product – mineral ash. This is ash is a residue of char combustion in the suspension burner. The ash is non-toxic and should not present an environmental hazard.

The use of a wet scrubber during gas cleaning also produces a stream of contaminated waste water that must be treated before re-use or discharge. As previously discussed, this will increase the difficulty in obtaining a permit to operate a methanol production facility – especially in areas where water is scarce.

8.6. Research Opportunities

Though synthesis of methanol and other high-grade liquid bio-fuels has received significant attention and development effort over the years, research continues in several areas.

Oxygen gasification, and the Carbo-V process in particular, would benefit from the development of cheap, small-scale air separation. Existing commercial air separation units are economic only at very large scale. While coal gasification systems are able to achieve such facility scale, the low energy density of biomass precludes similarly sized biomass facilities due to the logistic challenge of feedstock procurement.

With respect to indirect gasification, continued research is necessary in the area of catalytic tar destruction. An ideal catalyst would be robust (current catalysts suffer from rapid attrition), eliminate more than 99% of tars in a single pass, and retain high activity levels over long periods of time.

Hot, dry gas cleaning would strengthen the technical and economic viability of methanol production with both direct and indirect gasification. Hot gas cleaning would increase process efficiency by obviating thermodynamically inefficient cooling and reheat and also eliminating a major pollution stream (liquid effluent).

There may also be novel approaches to gasification which could optimize CO:H_2 ratios without a water-gas shift step. For example, it has been proposed that gasification oxygen could be produced by electrolysis and the hydrogen inserted downstream to optimize the CO:H_2 ratio [94]. Additionally, some nickel catalysts proposed for tar cracking also catalyze the water-gas shift reaction and reforming of hydrocarbons present in the syngas. This could potentially combine tar cracking, steam reforming, and water-gas shift into a single step, decreasing the complexity and footprint for a methanol production facility [93]. Along broader lines, if a bio-fuel production facility could be co-located with an existing process that produces waste oxygen, this would greatly improve the economics of oxygen gasification. For example, waste oxygen from wind or hydro electrolysis for hydrogen production could be used for a nearby oxygen gasification facility.

9. Heat and Power Generation

The production of heat and power from wood has been discussed in some detail in Chapter 1. Here, the emphasis is on the modeling of processes to produce heat and power. Only heat and power applications using wood chips as a feedstock are considered. While bio-oil can be used as a feedstock for heat and power, the most promising prime-mover, the industrial turbine, has just entered its first demonstration. As such, no capital cost data could be obtained from either DynaMotive or Orenda Aerospace.

9.1. Wood Chip Cogeneration

As discussed in section 1.2.1, the wood chip cogeneration scenario assumes that wood chips will be burned in a high-efficiency fluidized bed boiler and that a buyer will be found for low-grade heat or steam. A process flow diagram for this scenario is given in Figure 9.1.

Wood chips, including bark, are fed into a dryer, where moisture levels are reduced to 10%. Drying is assumed to be by flue gas from the boiler. Steam raised in the boiler is expanded through a turbine and/or extracted as saleable heat. Low pressure steam is then condensed. Condensate is de-aerated and supplemented with make-up water before being re-circulated to the boiler.

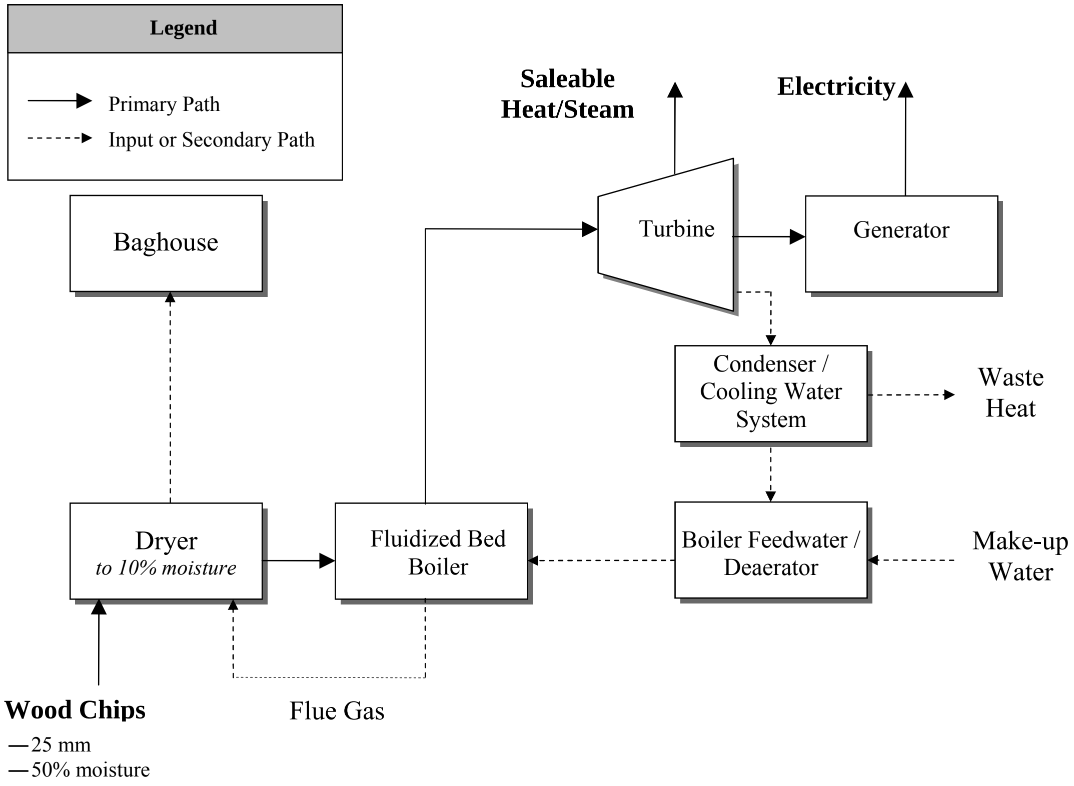

Figure 9.1 – Wood Chip Cogeneration Process Flow

A heat to power ratio of 1.44 has been assumed [10] – that is, 1.44 MJ of saleable heat will be produced for every gross MJ of electric power produced. Nearly 40% of heat generated is used to dry received chips, and the remainder is assumed sold to an end-user at $4/Mbtu. This arrangement results in a net thermal efficiency of 56%. A 5% parasitic load is assumed for ancillary process (e.g. dryer, pumps).

9.1.1. Economics

Capital costs for wood chip cogeneration have been adopted from Bain et al. [10] and are presented in Table 9.1. Fuel handling and pretreatment costs are as stated for stationary facilities in Chapter 4, with the exception of the dryer, where capital cost data from [10] have been substituted.

Table 9.1 – Wood Chip Cogen Capital Cost

	Reference Cost	Reference Scale	Scale Factor	Installation Multiplier
Pretreatment				
Pretreament and Fuel Handling		*as per Chapter 4 specifications*		
Dryer	\$2,840,286	28 MW_e	0.7	1.6
Cogeneration				
Boiler	\$13,213,230	28 MW_e	0.7	1.6
Boiler Feedwater/Deaerator	\$1,655,720	28 MW_e	0.7	1.6
Steam Turbine/Generator	\$4,406,151	28 MW_e	0.7	1.6
Cooling Water System	\$1,970,128	28 MW_e	0.7	1.6
Baghouse and Cooling Tower	\$865,979	28 MW_e	0.7	1.6

The gross efficiency of a wood-chip fired power plant is assumed to be 30% [10]. Power produced is subject to a 5% parasitic load [10], resulting in a net plant efficiency of 25%. The reference scale in the above table is for *gross electrical power output*. The following relation has been used to determine the gross electrical power output for a given feedstock input.

$$P_{\text{Gross,MW}} = \eta\left(\dot{m}_{\text{Feedstock, wet kg/s}}\right)\left(HHV_{\text{Feedstock, MJ/kg}}\right) \qquad \text{Equation 9.1}$$

where η is the gross plant efficiency, the mass flow of wet feedstock is known, and the higher heating value of the biomass feedstock is 9.69 MJ/kg. For the base case discussed in section 2.4, the cogeneration facility would have gross rated capacity of 66 MW_e.

Labor costs given in [10] imply a reference headcount of 2 personnel for a facility with 300 dtpd feedstock input. A headcount scale factor of 80% is assumed. For the base case, this results in a headcount requirement of 4.5 personnel per shift.

In addition to standard O&M costs, the following cogeneration specific costs [10] are assumed on a gross power basis.

Table 9.2 – Wood Chip Cogen Operating Cost

Item	Cost
Misc. Chemicals	\$0.0018/kWhr
Make-up Water	\$0.0005/kWhr
Ash Disposal	\$0.0005/kWhr

The cost-chain for the production of heat and power is presented in Table 9.3. 'Other' operating costs include fixed operations and maintenance, miscellaneous chemicals, make-up water, and ash disposal.

Table 9.3 – Wood Chip Cogeneration Cost Chain

	Cost (\$/wet ton thinnings)
Capital Cost	
Pretreatment	\$3
Conversion	\$19
Capital Cost	\$22
Operating Cost	
Labor	\$2
Other	\$10
Operating Cost	\$11
Total Production Cost	\$33
Total Production Cost (\$/GJ Electricity)	\$15.1

For the base case, a cogeneration facility would produce 457x10^6 kWhr of saleable power and 1.4x10^6 MBtu of saleable heat. The production cost of \$11.5/GJ compares favorably to the economic selling price of electricity (\$14.5/GJ).

9.1.2. Environmental Considerations

Fluidized bed boilers allow efficient, low emission combustion of wood – especially compared to older, stoker boilers. Emission factors for fluidized bed and stoker boilers based on a survey of wood-fired power plants in the state of California are given in Table 9.4 [10]. The relative levels of carbon monoxide emissions between conventional stoker and more advanced fluidized beds make a compelling case of the use of fluidized beds.

Table 9.4 – Wood Chip Boiler Emission Factors

Emission	Fluidized Bed (lb/MWhr)	Stoker (lb/MWhr)	Ratio Stoker:Fluidized Bed
SO_x	0.08	0.08	1
NO_x	0.9	2.1	2.3
CO	0.17	12.2	71.7
Particulate	0.3	0.5	1.7

While the steam cycle in wood-chip cogeneration does require some make-up water, there is no liquid effluent from the process.

The combustion of wood chips does result in ash – a solid waste product. However, biomass ash is non-toxic and does not require hazardous material disposal.

9.2. Co-fire with Wood Chips

As discussed in section 1.2.4, co-fire will incorporate a dedicated biomass feedstock handling system and burner modification. At the anticipated level of co-fire (15-30% mass substitution), coal pulverizers should be capable of crushing both coal and biomass without excessive power consumption.

A body of work exists on the cost of modifying facilities for co-fire – some in the public domain, some private. A comprehensive study on the cost of retrofitting existing plants for co-fire with woody biomass was carried out by the ANTARES group [95]. However, the publicly available version of the report includes only qualitative data – all cost information has been redacted. While, this missing information has been synthesized into co-fire cost data in [10], there is limited transparency into the underlying data.

The layout of a co-fire power plant is given in Figure 9.2 [10].

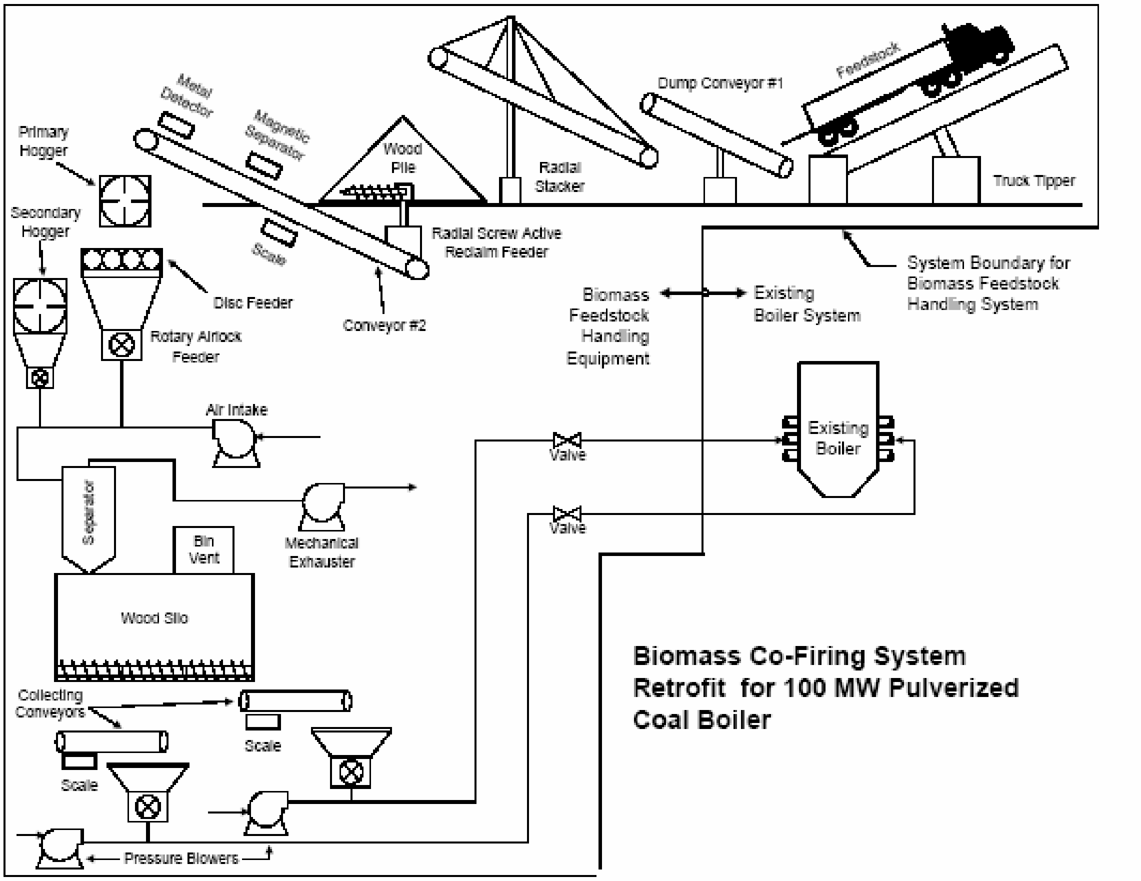

Figure 9.2 – Co-fire Process Flow

9.2.1. Economics

Since the pretreatment process in [10] is specific to co-fire, costs from the ANTARES study are used in lieu of pretreatment developed in Chapter 4 with the exception of costs for the whole-truck dumper, front-end loader, and storage pile. Capital costs for co-fire are presented in Table 9.5.

Table 9.5 – Co-fire Capital Cost

	Reference Cost	Reference Scale	Scale Factor	Installation Multiplier
Pretreatment				
Conveyor	$508,825	45 MW_e	0.7	1.6
Metal Separation	$138,322	45 MW_e	0.7	1.6
Hogging Tower	$839,807	45 MW_e	0.7	1.6
Pneumatic Conveyor (vacuum)	$177,841	45 MW_e	0.7	1.6
Live Bottom Silo	$217,362	45 MW_e	0.7	1.6
Collecting Conveyors	$261, 822	45 MW_e	0.7	1.6
Rotary Airlock Feeder	$24,700	45 MW_e	0.7	1.6
Pneumatic Conveyor (pressure)	$671,846	45 MW_e	0.7	1.6
Controls	$414,964	45 MW_e	0.7	1.6
Co-fire				
Civil Works	$1,452,372	45 MW_e	0.7	1.6
Burner Modification	$118,561	45 MW_e	0.7	1.6
Electrical	$647,145	45 MW_e	0.7	1.6

The *net efficiency* of a co-fire power plant is assumed to be 32.5% [10]. The reference scale in the above table is for biomass net electrical power output. The following relation may be used to determine the biomass electrical power output for a given feedstock input.

$$P_{\text{Biomass, MW}} = \eta\left(\dot{m}_{\text{Feedstock, wet kg/s}}\right)\left(\text{HHV}_{\text{Feedstock, MJ/kg}}\right) \qquad \text{Equation 9.2}$$

where η is the net plant efficiency, the mass flow of wet feedstock is known, and the higher heating value of the biomass feedstock is 9.69 MJ/kg. For the base case discussed in section 2.4, the rated biomass firing capacity would be 73 MW_e. This corresponds to a biomass feed rate of 21 wet kg/s. A 1000 MW coal-fired power plant with the same net efficiency as the one considered in this study would consume roughly 100 kg/s of coal. Therefore, the biomass feed would substitute for 20% of coal mass flow, putting it in the range of facilities which would require a dedicated biomass feedstock handling system and burner modification (15-30% by mass) [23].

Labor costs given in [10] imply a reference headcount of 2 personnel for a facility with 300 dtpd feedstock input. A headcount scale factor of 80% is assumed. For the base case, this gives a headcount requirement of 4.5 personnel per shift.

In addition to standard O&M costs, the following additional costs [10] are assumed on a net power basis.

Table 9.6 – Co-fire Operating Cost

Item	Cost
Misc. Chemicals	\$0.0018/kWhr
Make-up Water	\$0.0005/kWhr
Ash Disposal	\$0.0005/kWhr

A cost-chain for the production of electricity by co-firing is presented in Table 9.7. ‘Other’ operating costs include fixed operations and maintenance, miscellaneous chemicals, make-up water, and ash disposal.

Table 9.7 – Co-fire Cost Chain

	Cost (\$/wet ton thinnings)
Capital Cost	
Pretreatment	\$3
Conversion	\$2
Capital Cost	\$5
Operating Cost	
Labor	\$2
Other	\$10
Operating Cost	\$12
Total Production Cost	\$17
Total Production Cost (\$/GJ Electricity)	\$5.3

Power generation for the base case is 521×10^6 kWhrs per year. Production costs compare quite favorably to the selling price of electricity (\$14.5/GJ).

9.2.2. Environmental Considerations

Co-firing with biomass does not require modification to a coal-fired power plant’s pollution control systems. In fact, co-firing with biomass reduces emissions relative to coal. Since woody biomass does not contain appreciable sulfur, SO_x emissions decrease in direct proportion to mass substitution by biomass. Additionally, biomass reduces primary combustion temperatures, decreasing thermal NO_x.

Despite these benefits, there are some in the environmental and regulatory community who do not support co-fire. This is because investment in co-firing may retard development of dedicated biomass power plants. In there near-term, given the increasing scarcity of natural gas and oil and continued public resistance to nuclear power, it seems likely that coal-fired power plants will continue to meet much of the global base power load. While co-fire is only an incremental improvement over coal-only power generation, it is an improvement and, in the author's opinion, should be welcomed. Moreover, if the emissions of a co-firing coal plant are sequestered, there will be a net reduction in atmospheric CO_2.

10. Transportation of Bio-fuels

One of the key benefits to the production of bio-fuels is the reduced transportation cost for fuels with a higher bulk density than wood chips. For this study it has been assumed that all transportation will be via truck. However, a transportation network including both truck and train might result in lower transportation costs over long distances. This option should be considered in future work, but is not included in this model.

10.1. Vehicle Specification

Three types of vehicles are used to transport bio-fuels: chip vans for wood chips, pellet trucks for pellets, and fuel tankers for bio-oil and methanol. To model transportation economics one must establish a number of vehicle characteristics.

10.1.1. Carrying Capacity

For a given load of bio-fuel, the carrying capacity of truck will determine how many trucks are necessary for transportation. All vehicles are restricted by federal transportation regulations to a gross vehicle weight (vehicle and load combined) of 36,300 kg [9]. Each vehicle also has a limited volumetric carrying capacity. Whichever limit is met first determines the maximum vehicle load. The vehicle weight for fuel tankers is lower than chip vans or pellet trucks, so fuel tankers are able to carry a heavier bio-fuel load. Maximum mass loads and volumetric capacities for each type of truck are presented in Table 10.1 [9]. In the absence of other data, pellet trucks have been assumed to be identical to chip vans.

Table 10.1 – Vehicle Transportation Limits

Parameter	Chip Van	Pellet Truck	Fuel Tanker
Maximum bio-fuel load	25,000 kg	25,000 kg	31,000 kg
Maximum bio-fuel volume	80 m^3	80 m^3	36 m^3

For transportation of wood chips, pellets, and bio-oil, vehicles are limited by maximum weight restrictions. For methanol transport, fuel tankers are volume limited and are only able to carry 28,440 kg.

10.1.2. Loading and Unloaded Time

In addition to time spent driving, vehicles must be loaded and unloaded. Loading and unloading times for different fuel types are given in Table 10.2. Loading times for wood chips are limited by chipper/debarker throughputs. Other load and unload times are assumptions made relative to chip van times.

Table 10.2 – Vehicle Load and Unload Times

Parameter	Chip Van	Pellet Truck	Fuel Tanker
Load Time	1 hr [49]	½ hr	½ hr
Unload Time	½ hr [9]	½ hr	½ hr

10.1.3. Economics

Vehicle capital cost is the total for the cab, undercarriage, and container (e.g. tank). Costs are given in Table 10.3. This model does not consider the option of leasing vehicles. Vehicle lifetime is assumed to be 15 years. Total capital cost for the transportation network is obtained by multiply the cost per truck by number of trucks required. The determination of the number of trucks required is discussed in 10.3.

Table 10.3 – Vehicle Capital Cost

Parameter	Chip Van	Pellet Truck	Fuel Tanker
Cab	$80,000 [44]	$80,000 [44]	$80,000 [44]
Undercarriage	$60,000 [44]	$60,000 [44]	$60,000 [44]
Container	$25,000 [9]	$25,000	$90,000 [44]
Vehicle Cost	$165,000	$165,000	$230,000

Operating costs include fuel, labor, and maintenance. Fuel cost is given by Equation 10.1.

$$\text{Fuel Cost} = \frac{(\text{Distance Driven})}{(\text{Vehicle Fuel Economy})}(\text{Fuel Price}) \qquad \text{Equation 10.1}$$

All truck types are assumed to have a fuel economy of 6 miles/gallon [44] and the price of diesel fuel is assumed to be $2.00/gallon. The calculation of distance driven is described in 10.3.

Labor cost is given by the following relation.

$$\text{Labor Cost} = (\text{Delivery Time})(\text{Labor Rate})(\text{Number of Drivers}) \qquad \text{Equation 10.2}$$

The labor rate is assumed to be $30.00/hour and includes benefits and overhead. The number of drivers is governed by the delivery time. Since the number of hours a driver can operate a vehicle is limited to 12 hours/day [44], it has been assumed that for round-trips greater than 12 hours, two drivers will be needed. This doubles the labor cost for the entire trip because both drivers will be in the truck for the total time. Delivery time is the sum of the time to drive the round-trip distance, time to load and unload the vehicle, turn-around time, and delay time. A turn-around time of 10 minutes and a delay multiplier of 1.08 [47] are assumed. The delay multiplier acts on the sum of load and turn-around time to account for delays in this activity. No such multiplier is applied to driving times. The calculation of driving time is described in 10.3.

Maintenance is estimated as a fixed maintenance cost of 5% of vehicle cost and a variable non-fuel operating cost of 1% of vehicle cost [44].

10.2. Transportation Distances

A few key transportation distances must be established to determine transportation costs.

10.2.1. Logging Deck to End-user

The distance from the logging deck to end-user is the key driver of transportation costs. As such, it has been varied across different scenarios from a base case value of 450 km – down to 100 km and up to 700 km. The transportation distance from logging deck to end-user is assumed to be the same for all bio-fuels. This does not necessarily represent a real-world situation where some facilities may be closer than others. For example, if a forest in eastern Washington is thinned, the nearest buyer of pulp chips is almost 500 km away. However, it is likely that a landfill could be located much closer and a buyer for bio-oil at an intermediate distance.

10.2.2. Logging Deck to Major Road

The distance from the logging deck to a major road establishes the distance traveled on poorer quality logging roads. It has been assumed that the maximum speed on a logging road is 40 km/hr. The distance driven on these types of roads is conservatively estimated at 60 km. Once outside of the forest on major roads, the average speed for a truck is assumed to increase to 88 km/hr (55 mph).

10.2.3. Logging Deck to Bio-fuel Production Facility

Stationary and relocatable facilities are assumed to be located 80 km from the logging deck. Taken along with the distance from the logging deck to a major road (60 km), the assumption is that this class of facility will be sited within 20 km of the forest. Locating a stationary facility further away has no economic benefit, as transportation penalties continue to increase without any offsetting improvement in operating and capital cost for bio-fuel production. It is possible that a stationary or relocatable facility could be sited more than 20 km from an individual forest if this allowed thinnings from multiple forests to be brought to this single location. This type of scenario is not explicitly considered in the model.

The distance from the logging deck to a transportable facility may be estimated based on the collection radius for such a system – given by the following equation.

$$\mathrm{A}_{\text{Collection}} = \frac{\mathrm{A}_{\text{Total Thinning}}}{(\text{number of transportable units})(\text{sites per year})} \qquad \text{Equation 10.3}$$

where $\mathrm{A}_{\text{Collection}}$ is the collection area for a transportable system at a given site and $\mathrm{A}_{\text{Total Thinning}}$ is the total acreage thinned in a given year. Assuming that this collection area may be approximated as a circle of radius R with the transportable bio-fuel production system at the center, the average distance from any point on the circle to the center may be calculated by the following relation.

$$\bar{r} = \frac{\int_0^R r\,dA}{\int_0^R dA} = \frac{\int_0^R 2\pi r^2\,dr}{\int_0^R 2\pi r\,dr} = \frac{2}{3}R \qquad \text{Equation 10.4}$$

where $\bar{r}$ is the average straight line distance from any point within the collection radius to the center. Given the nature of forest roads, one would expect driving distance to be longer than the straight line distance. This may be accounted for by multiplying the average straight line distance by a 'winding factor'. A winding factor of 50% is assumed, consistent with [43]. Average transportation distance from the logging deck to a transportable unit is then given by Equation 10.5.

$$D = \left(\frac{A_{\text{Collection}}}{\pi} \right)^{1/2} \left(\frac{2}{3} \right) \left(1 + F_{\text{Winding}} \right) \qquad \text{Equation 10.5}$$

where *D* is the driving distance. For most thinning operations, *D* will be less than 2 km.

10.3. Transportation Network

In order to determine the two key cost drivers – miles driven and delivery time – we must first calculate the number of deliveries a truck can make in a given day. The time per delivery will be the sum of driving time and loading time. Loading time, as described previously, includes time to load, unload, turn-around, and a delay allowance. Trucks and drivers are assumed to have an availability of 85% [44], that is, in an average 24 hour day they will be able to make deliveries for 20.4 hours. Dividing this available time by the time per delivery, gives the possible numbers of deliveries per day per truck.

$$\frac{\text{Deliveries}}{\text{Truck/Day}} = \frac{\text{Driving} + (\text{Load} + \text{Unload} + \text{Turn - Around})(\text{Delay Multiplier})}{(24\text{ hours})(\text{Truck Avaiability})} \qquad \text{Equation 10.6}$$

The total load that must be conveyed each day is determined by the demand of the upstream production or use facility. That is, the average daily trucking load will be equal to the average daily feedstock input for the facility feedstock is being delivered to. Note that, as discussed in section 4.2.1, all facilities have a feedstock storage capability to buffer supply disruptions. In practice, this would mean that trucks would begin making deliveries to a transportable facility to build up a supply of feedstock before the facility begins operating. The average daily demand for a bio-fuel production facility is determined by dividing its annual feedstock consumption by the number of days it operates each year.

$$\text{Average Daily Demand} = \frac{\text{Annual Feedstock Consumption (wet kg)}}{(365)(\text{Capacity Factor})} \qquad \text{Equation 10.7}$$

From 10.1.1 we know the carrying capacity of each truck class. By dividing the average daily demand of the upstream facility by truck capacity, we may obtain the number of deliveries required per day. Dividing this by the number of possible deliveries per truck per day, gives us the number of required trucks. The number of trucks is rounded up to the nearest whole integer.

$$\text{Trucks Required} = \text{Integer}\left(\frac{\text{Average Daily Demand}}{\text{Truck Capacity} \Big/ \frac{\text{Deliveries}}{\text{Truck/Day}}} \right) \qquad \text{Equation 10.8}$$

Once we have this information, it is a simple matter to compute total delivery time and distance driven each year. Multiplying the number of deliveries per day and the number of operational days of the upstream facilities, we obtain the number of deliveries per year. Multiplication by the delivery time per trip (section 10.1.3) gives the total delivery time for the year. This in turn may be used to obtain labor cost by Equation 10.2. Likewise, knowing the number of deliveries and distance of each delivery gives us the total distance driven and, therefore, fuel cost by Equation 10.1.

10.4. Base Case Transportation Cost

Transportation costs for base case bio-fuel production scenarios are presented in Table 10.4 on the basis of cost per wet ton thinned. Note that for transportable, stationary, and relocatable production of bio-fuels, there are two transportation steps. The first is to move wood chips from the logging deck to fuel production facility, and a second to move upgraded bio-fuel to the end-user.

Table 10.4 – Transportation Cost

Net Thinning Cost ($/wet ton thinned)	Wood Chips	Wood Pellets	Bio-oil	Methanol
Mobile				
Bio-fuel	$41	$15	$8	$6
Transportable				
Chips		$2	$2	$2
Bio-fuel		$17	$10	$7
Total	N/A	$19	$12	$10
Stationary				
Chips		$7	$7	$7
Bio-fuel		$8	$6	$3
Total	N/A	$15	$12	$10
Relocatable				
Chips		$7	$7	$7
Bio-fuel		$8	$6	$3
Total	N/A	$15	$12	$10

Note that the total transportation costs for transportable, stationary, and relocatable facilities are nearly identical and only production of bio-fuels at the logging deck appreciably decreases total transportation cost. This is partially because transportable facilities have the highest mass yields than stationary and relocatable facilities.

11. Results

The economic and operating information discussed in the Chapters 3-10, has been integrated into the modeling approach laid out in Chapter 2 to determine net thinning cost for production of bio-fuels from thinnings. Net thinning cost is defined as the cost to harvest thinnings, transport bio-fuel, and produce bio-energy, less revenue realized from bio-energy sale.

11.1. Base Case Results

As stated in section 2.4, the base case for analysis assumes 80,000 acres thinned per year for 10 years with a transportation distance from logging deck to end-use of 450 km. Note that for stationary and relocatable production of bio-fuels, this constitutes 80 km from the logging deck to production facility and 370 km from production facility to end-use. Net thinning costs for the base case are given in Table 11.1.

Table 11.1 – Base Case Net Thinning Cost

Net Thinning Cost ($/wet ton thinnings)	Mobile Bio-fuel Production	Transportable Bio-fuel Production	Stationary Bio-fuel Production	Relocatable Bio-fuel Production
Base Technology Bio-fuel Options				
Pelletization	$162	$93	$59	$61
Fast Pyrolysis	$159	$81	$54	$58
Methanol Synthesis	$214	$126	$59	$74
Advanced Technology Bio-fuel Options				
Advanced Fast Pyrolysis	$156	$76	$48	$52
Advanced Methanol Synthesis	$210	$122	$57	$71
Wood Chip Options				
Disposal			$79[13]	
Pulp Sale			$71	
Co-fire			$63	
Wood Chip Cogen			$75	

In the near term, within the accuracy of the model, production of bio-oil, methanol, pelletization, and co-fire with coal are effectively cost equivalent and represent the lowest net thinning costs. Pulp sale and wood chip cogeneration do not appear to be viable options. Even though disposal assumes a transportation distance of only 80 km, the cost

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[13] Landfill: 80 km transportation distance and $25/wet ton disposal cost assumed. Open Burning: Estimated between $70 and $80 per wet ton thinned [96].

of disposal is much higher than for the stationary production of bio-fuels. As such, even though converting thinnings to bio-energy is not a profitable enterprise, the cost is lower than disposal.

A special word of caution regarding methanol synthesis in comparison to other options is warranted. As discussed in the technology review section of this report, unlike other thermochemical conversion processes, methanol synthesis is neither commercial nor demonstrated outside of the lab. This study has also not attempted to quantify the cost or practicality of waste-water treatment from the wet scrubber included in the design. For the two advanced, near-term technology scenarios considered, advanced fast pyrolysis incorporates technical improvements nearing commercial demonstration and learning scale reductions justified by the construction of first generation facilities. However, for methanol synthesis, the technology enhancement – hot, dry gas cleaning – remains relatively far from commercial demonstration.

11.1.1. Bio-fuel Production Facility Type

The net thinning costs for the four different classes of facilities (mobile, transportable, stationary, and relocatable) follow the same trend as bio-fuel production costs discussed in Chapters 6, 7, and 8 with stationary costs lowest, followed, in order of increasing cost, by relocatable, transportable, and mobile production. As mentioned previously, these decreasing production costs must be balanced against rising transportation costs. However, as shown in Table 10.4, transportation costs increase minimally for stationary bio-fuel production relative to mobile or transportable. Clearly, the increased cost of transporting wood chips to a stationary facility does not outweigh the production cost reductions from larger scale, better labor utilization, and low-cost grid electricity. Figure 11.1 shows net thinning costs for bio-oil production broken down into harvest, production, transportation, and revenue. For simplicity, costs for relocatable production are not presented since stationary and relocatable bio-fuel production have very similar cost chains.

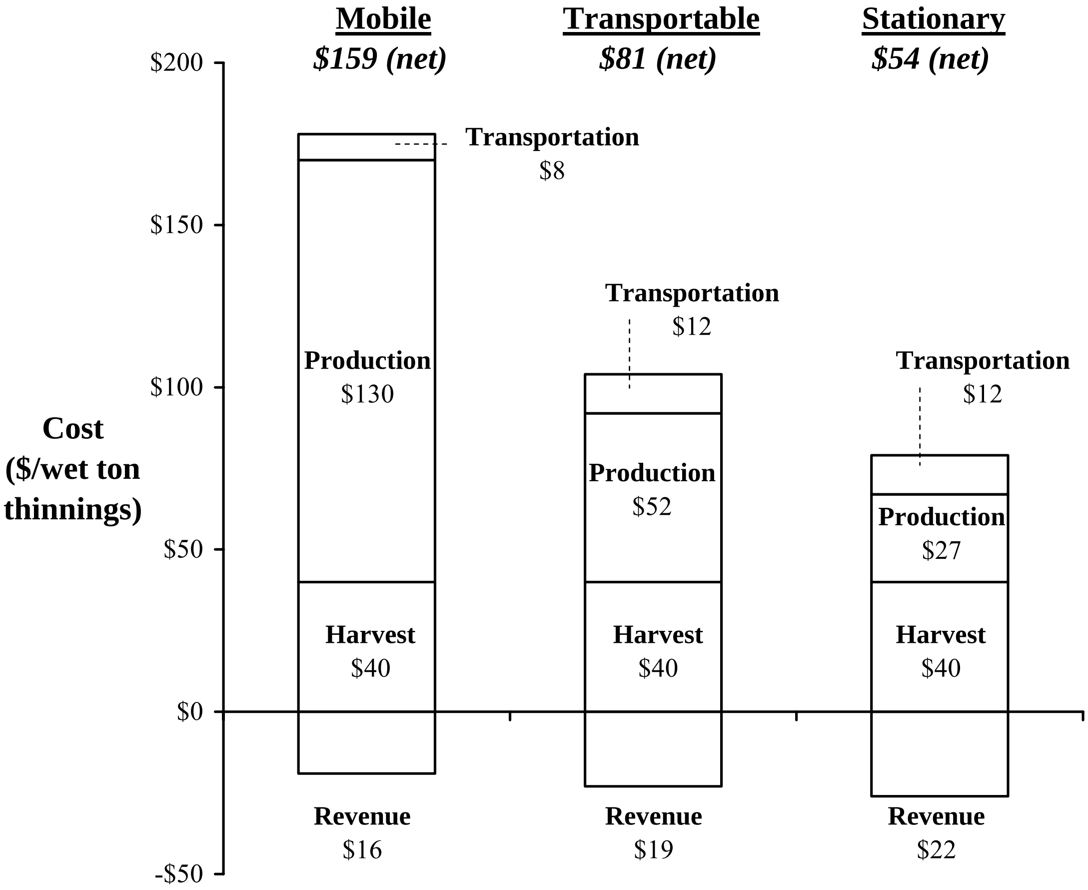

Figure 11.1 – Bio-oil Production Cost Chain (Base Case)

As is readily apparent from the above figure, production costs decrease rapidly as facility size increases. While there is an offsetting rise in transportation costs, it is an order of magnitude smaller and is of little consequence.

Cost chains for other types of bio-fuel production may be found in Appendix H. For base case values, stationary production of bio-fuels is preferred over all other production options.

As mentioned in Section 1.5.1, it is assumed that all operations inside and outside the forest will operate around the clock. Twenty-four hour a day operation is achieved using a three shift cycle (eight hours each) – which is a departure from conventional forestry operations which typically employ a single shift. Refineries and power plants – close analogues to stationary and relocatable bio-fuel facilities – routinely operate in three-shift cycles. If operations within the forest are restricted to a single shift, the cost of mobile and transportable bio-fuel production increases by more than $100 per wet ton thinned due to a steep drop in equipment capacity factor. In addition to a two-thirds reduction in possible operating time, an hour to warm-up and another to shut-down equipment reduces the daily bio-fuel production window to one-quarter of that for three-shift operation. Since trucks and chippers will also be restricted to this window, transportation and chipping costs will also increase for stationary and relocatable bio-fuel production. However, these increases are much more modest, in the range of $2 to $5 per wet ton thinned. The relative insensitivity of stationary and relocatable bio-fuel production to restrictions on operating time within the forest further recommends this approach over mobile and transportable bio-fuel production.

A logical next step is to understand how the results of the base case change as parameters are varied. From Figure 11.2, gives the relative cost fractions bio-fuel transportation and production and end-use.

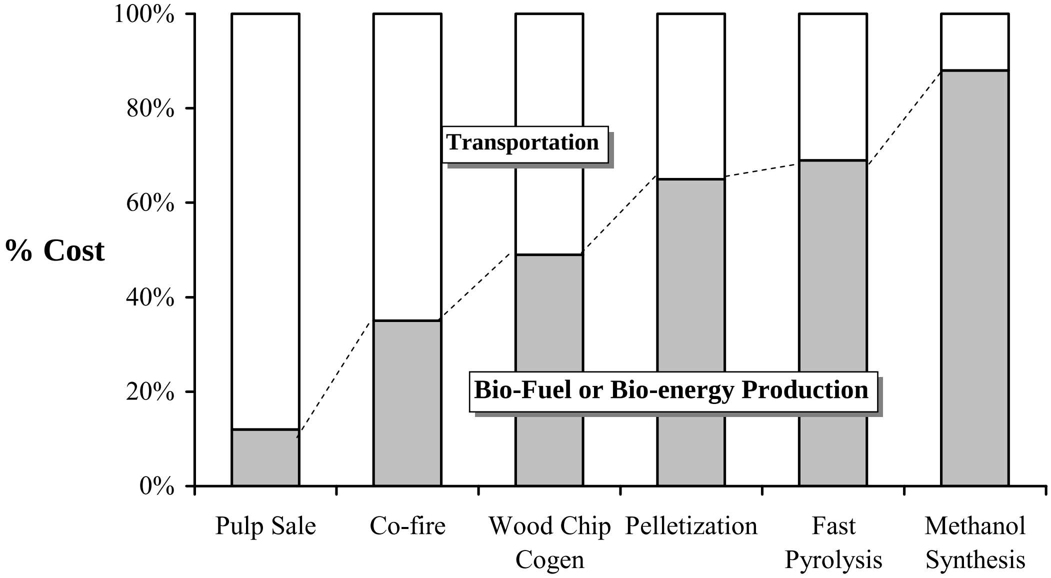

Figure 11.2 – Transportation-Production Cost Fractions

Cost fractions presented in the above figure are for only transportation and bio-energy production – these do not include harvest cost or the net effect of revenue from bio-energy sale. Bio-fuel production cost chains are for the case of stationary production. Applications involving only wood chips have cost chains most heavily weighted towards transportation, while for upgraded bio-fuels, transportation accounts for less than 30% of total cost. From this figure, one may anticipate the result of varying total transportation distance (logging deck to end-user). The higher the transportation cost fraction, the more sensitive net thinning cost will be to transportation distance.

11.2. Dependence of Net Thinning Cost on Transportation Distance

Given the impact of different impact of transportation distances on the cost chain, a logical next step would be to vary the transportation distance and identify the impact on net thinning cost. Thinning acreage and duration are maintained at base case values. The result of parameter variation is shown in Figure 11.3. Bio-fuel production is by stationary facilities – the lowest cost option for the base case thinning yield and duration.

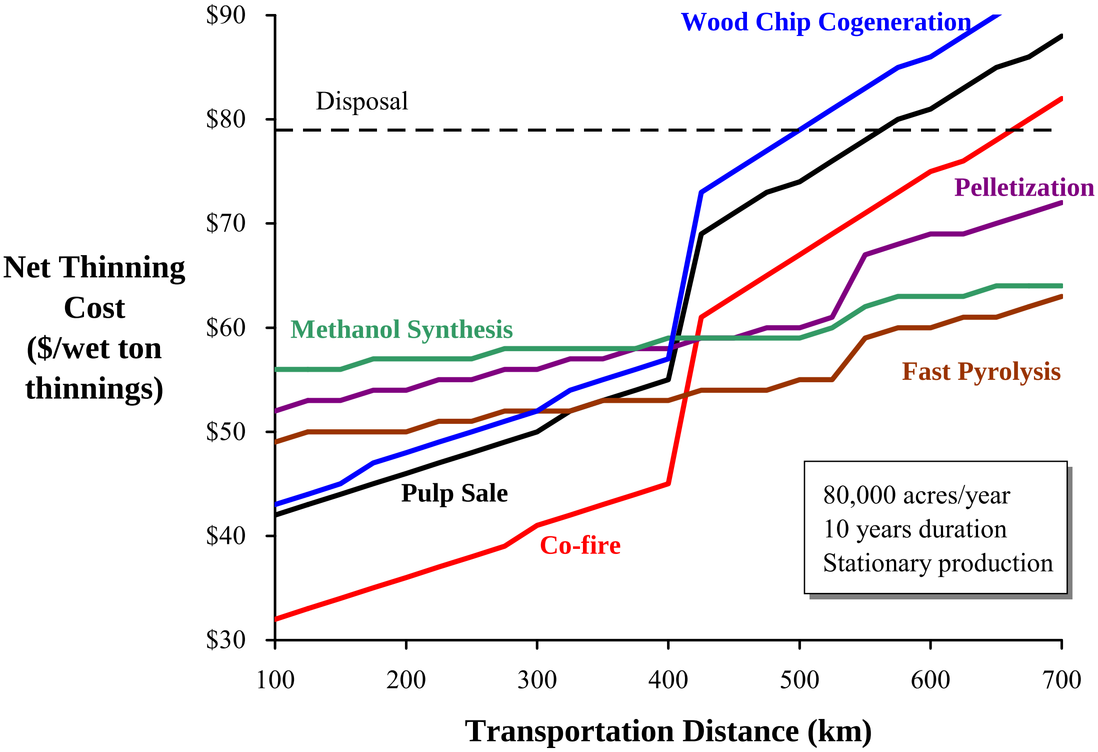

Figure 11.3 – Net Thinning Cost Dependence on Transportation Distance (Base Technology)

The most notable feature of the above plot is the jump around 400 km for applications involving the transportation of wood chips and around 525 km for applications involving the transportation of upgraded bio-fuels. This sharp increase occurs once the transportation distance is longer than can be safely driven in a round-trip by a single driver. This limit is discussed in section 10.3. For upgraded bio-fuels, this jump is offset by the distance from the logging deck to stationary facility (shorter delivery to end-use facility) and shorter loading times.

The slope of the lines for different options is a function of bio-fuel density and mass of bio-fuel transported – the two key cost drivers for a given transportation distance. Applications requiring wood chip transportation to end-use have the steepest slopes. The slope for pellets is lower, as would be expected for the higher density fuel. The slope for fast pyrolysis and methanol synthesis is roughly equivalent as the higher density of bio-oil is offset by a higher mass yield than for methanol synthesis. These results follow the same general pattern as the gross cost chains shown previously in Figure 11.2.

From Figure 11.3, one sees that for base case thinning yield and duration, upgraded bio-fuels are only attractive for transportation distances of greater than 400 km. Under these conditions, bio-oil has marginally better economics than methanol. For distances less than 400 km, co-fire is clearly the lowest cost option.

Figure 11.4 shows wood chip applications compared to advanced, but near-term, bio-oil and methanol production discussed in 7.5 and 8.4.

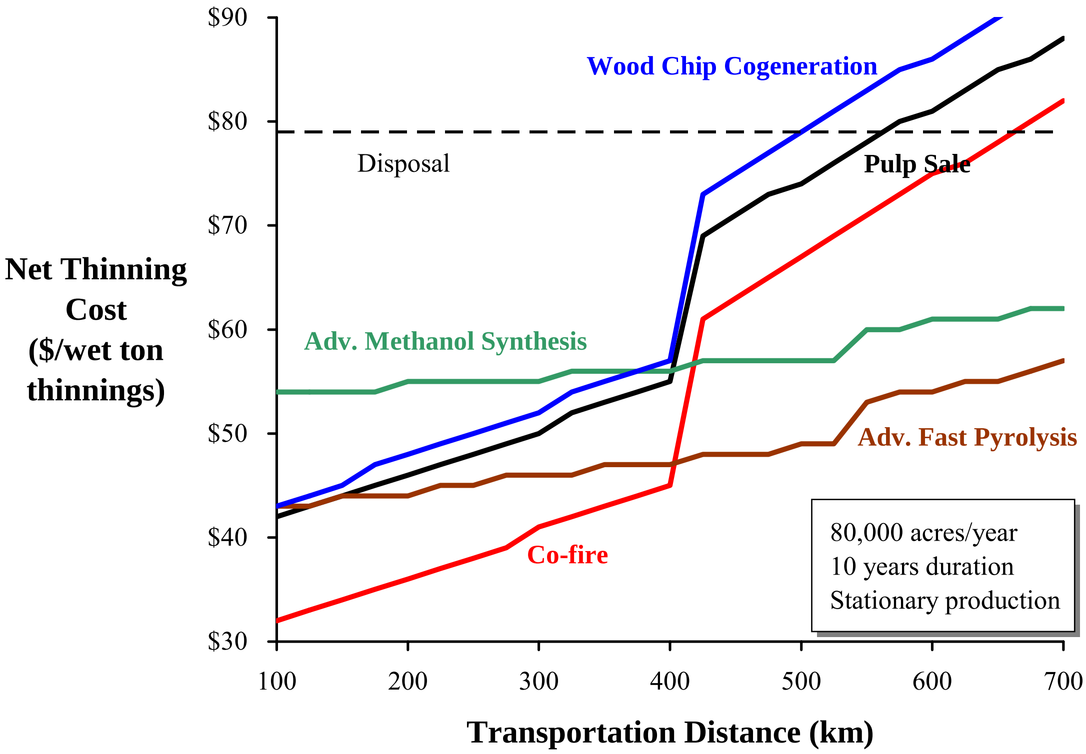

Figure 11.4 – Net Thinning Cost Dependence on Transportation Distance (Advanced Technology)

The net thinning cost for advanced fast pyrolysis appears quite interesting. Cost to produce bio-oil would be significantly lower than methanol and would be competitive with pulp sale and wood chip cogeneration for nearly any transportation distance. This observation is particularly relevant for regions where co-fire may not be an option due to a scarcity of coal-fired power plants (e.g. California, Pacific Northwest).

11.3. Dependence of Net Thinning Cost on Thinning Acreage and Duration

The next set of parameters to be varied is thinning duration and acreage thinned as the variation in these parameters will affect the economics of stationary bio-fuel production. For a given transportation distance, acreage thinned, and duration of thinning, the net thinning cost for each bio-fuel production and use scenario is calculated. The lowest cost option is then determined and logged in a grid, as shown in Table 11.2. The grid for 1 year and 10,000 acres defines the type of data – an example of which is shown for 3 years.

Table 11.2 – Net Thinning Cost Grid

Transportation Distance: 100 km

	Duration	**1 year**	**3 years**	**5 years**
Acreage	**10,000 acres**	*End-Use* *Facility Type* *Net Thinning Cost*	Pulp Sale N/A $43	
	20,000 acres			

Each transportation distance considered (100 – 700 km, steps of 100 km) is represented by an individual grid. Each element in the grid corresponds to a specific acreage and duration of thinning. Previous consideration of the impact of transportation distance on cost would indicate the most interesting results for the base technology case are likely to be found for transportation distances above 400 km.

Grid results for an average transportation distance of 200 km are presented in Figure 11.5. This is a simplified grid showing lowest cost regions only – rather than specific costs for each grid box. Detailed grid data are presented in Appendix I.

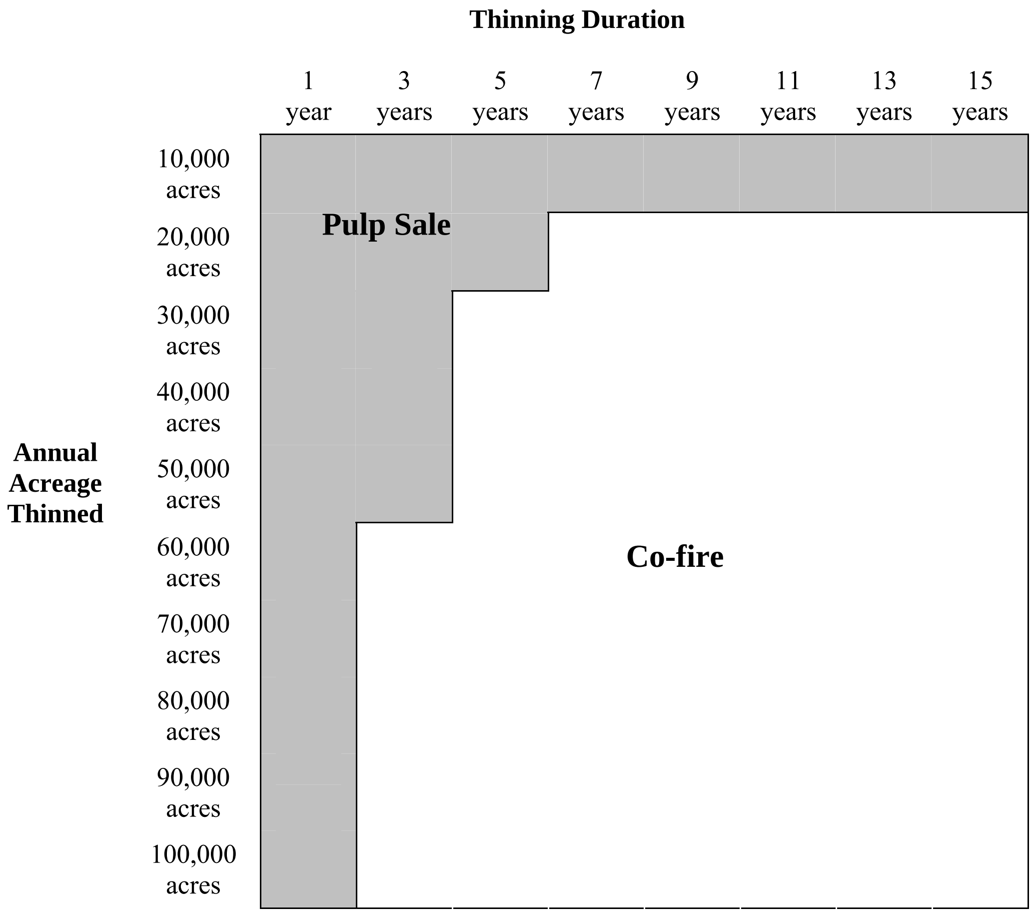

Figure 11.5 – Grid Results (200 km, Base Technology)

For this transportation distance, co-fire dominates the grid results for all but low-yield, short duration thinning operations – where pulp sale is preferred. Low yields or short durations incur significant capital cost penalties for stationary facilities because rated capacity would be low and facility lifetime short. Pulp sale is preferred because it has the lowest capital cost requirements of an revenue generating option.

The technology map is relatively insensitive to transportation distances up to 400 km. Beyond this point the map changes dramatically due to the sharp rise in wood chip transportation costs noted and explained in Figure 11.3. Figure 11.6 gives grid results for a transportation distance of 500 km – a distance at which densified bio-fuels are attractive.

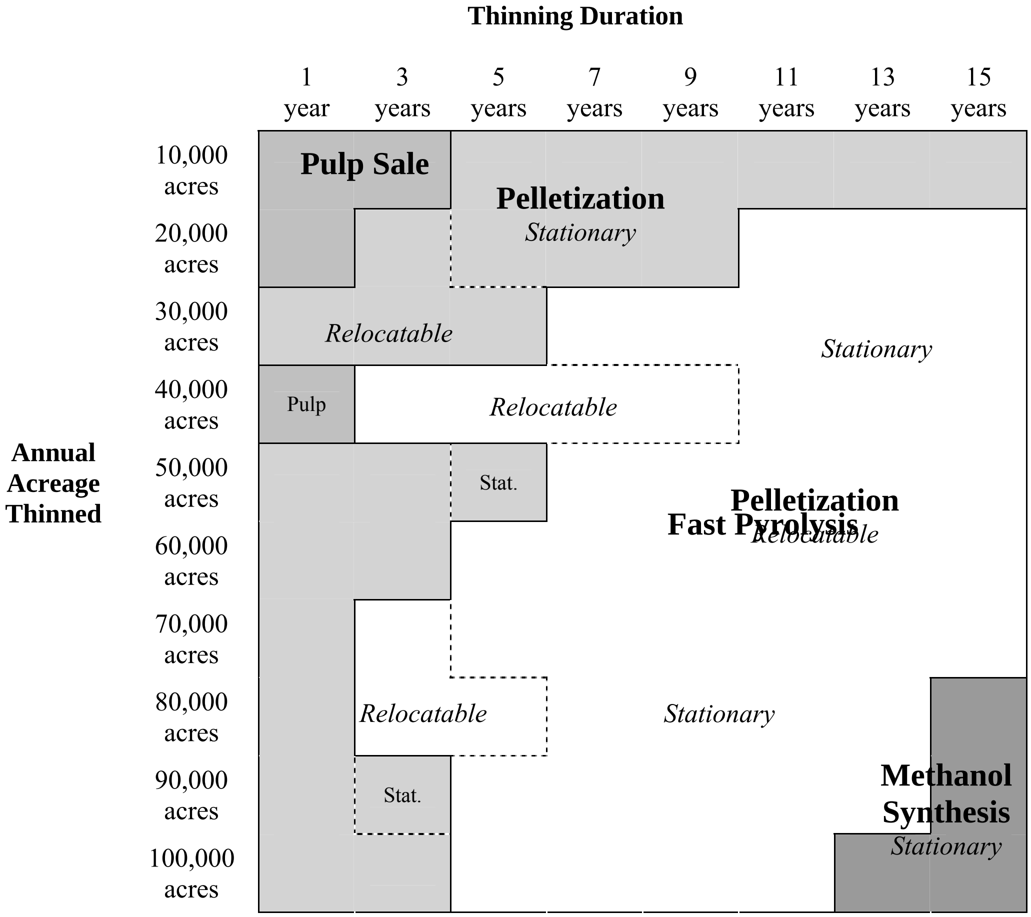

Figure 11.6 – Grid Results (500 km, Base Technology)

At this distance, while pulp sale continues to be the preferred solution for very small acreages and short durations, co-fire has vanished from the grid, replaced by production of densified bio-fuels. Production of methanol is the lowest cost option for very large, long term thinning operations. In these cases, capacity is sufficiently high and plant lifetime sufficiently long to justify the high capital cost of methanol synthesis. Pelletization is preferred for short durations or low acreage yields since the production of pellets is not capitally intensive. Fast pyrolysis is preferred for moderate yields over a range of thinning durations.

However, the advanced case shown in Figure 11.7 indicates for this transportation distance, fast pyrolysis is positioned to become the preferred technology for all but the smallest and shortest duration operations.

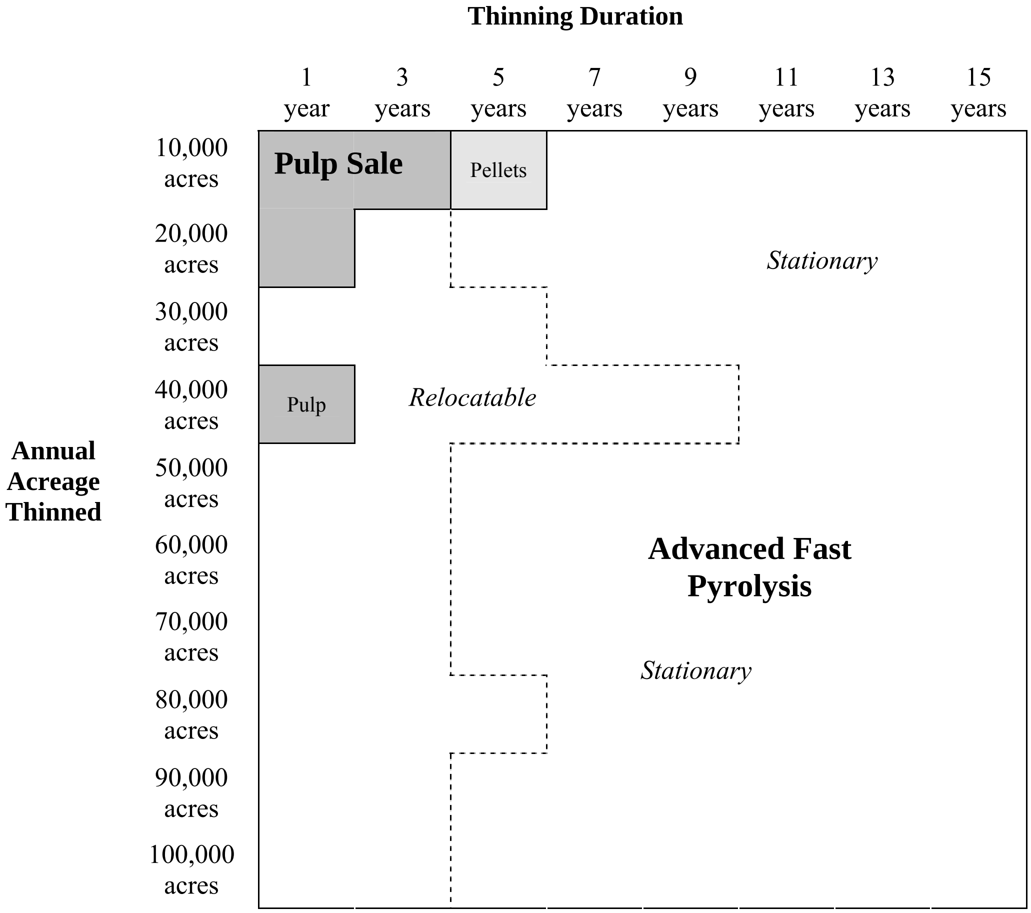

Figure 11.7 – Grid Results (500 km Transportation Distance, Advanced Technology)

Given the relative scarcity of coal fired power plants in the Pacific Northwest and California, it may be difficult to identify facilities capable of co-firing biomass in these regions. An advanced technology case for a short transportation distance (200 km) without the possibility of co-fire is given in Figure 11.8.

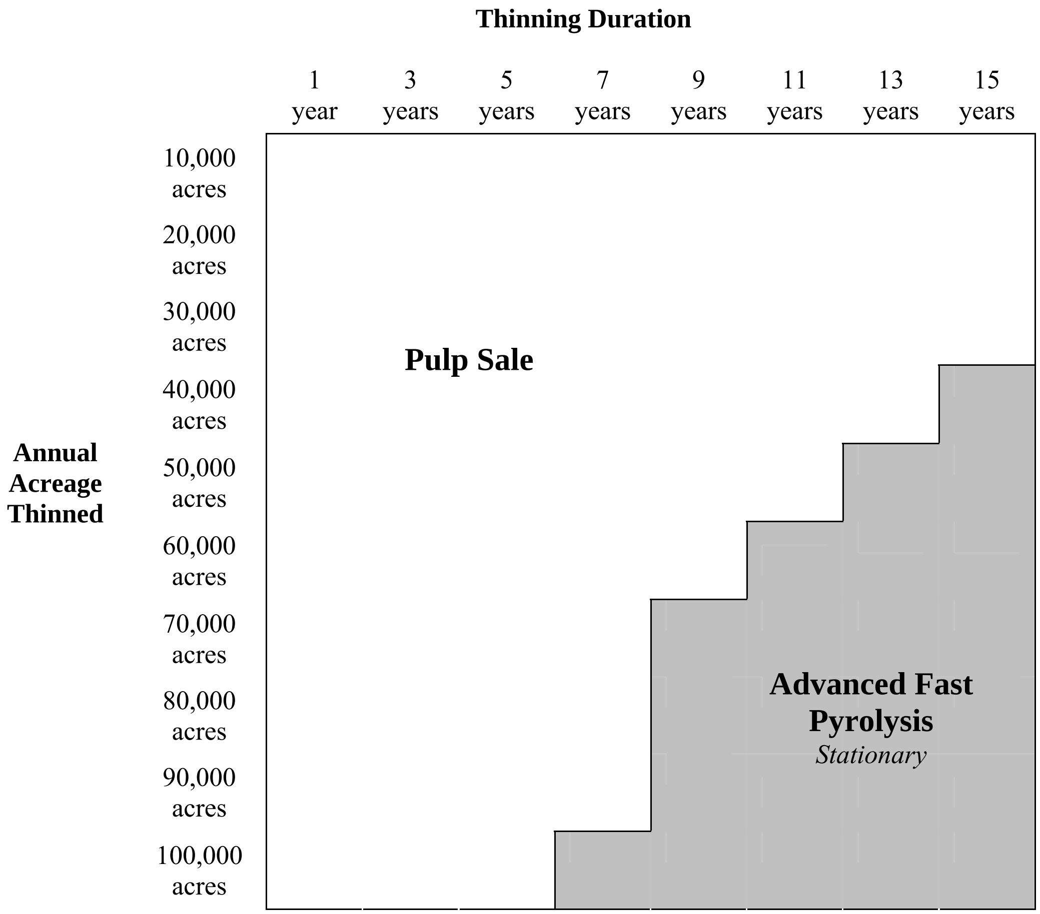

Figure 11.8 – Grid Results (200 km, Advanced Technology, No Co-fire)

Figure 11.8 bears out the expectations of Figure 11.4, which explored advanced technology net thinning cost as a function of transportation distance for base case thinning duration and scale. With process cost reductions from the elimination of grinding and learnings from first generation facilities, next generation fast pyrolysis is positioned to be the lowest option for thinning relatively close to industrial centers. For moderately large thinning operations or longer thinning durations, advanced fast pyrolysis for the production of bio-oil would be preferred to pulp sale or wood chip cogeneration.

An interesting next step within the forestry community would be to create a similar grid with probabilities for thinning duration, yields, and transportation distances. For example, if most thinning will occur on a small scale and over a short time, further development of fast pyrolysis for producing bio-oil for thinnings would not be justified. Likewise, if all thinning operations will be of massive forests over a long period of time, methanol synthesis should be pursued even though Figure 11.6 shows methanol production to be preferred only for a very restricted subset of cases. However, it would seem likely that probabilities will not be clustered in a corner, but rather spread evenly over most of the yields and durations considered. This broad distribution would confirm the choice of fast pyrolysis as a preferred option for the thermochemical conversion of forest thinnings for long transportation distances.

11.4. Base Case Sensitivities

In addition to the three chosen parameters, the model has hundred of inputs relating to harvest, transportation, and bio-fuel production. While a full sensitivity study is beyond the scope of this project, a few keys variables have been studied with the results shown in Table 11.3 for transportation distance, thinning duration, and acreage for the base case.

Table 11.3 – Base Case Sensitivities

Net Thinning Cost ($/wet ton thinnings)	Base Case	Unit Revenue ($/GJ)		Interest Rate		Thinning Yield	
		-25%	+25%	2%	12%	5 tons/acre	10 tons/acre
Fast Pyrolysis							
Mobile	$159	$164	$154	$146	$169	$161	$158
Transportable	$81	$87	$75	$74	$87	$83	$82
Stationary	$54	$60	$48	$50	$57	$57	$52
Relocatable	$58	$65	$52	$53	$63	$68	$60
Pelletization							
Mobile	$162	$167	$157	$155	$168	$163	$161
Transportable	$93	$99	$88	$90	$96	$95	$94
Stationary	$59	$65	$54	$57	$61	$61	$58
Relocatable	$61	$67	$56	$59	$63	$65	$62
Methanol Synthesis							
Mobile	$214	$224	$199	$185	$236	$217	$213
Transportable	$126	$139	$109	$107	$140	$130	$129
Stationary	$59	$73	$43	$47	$68	$67	$54
Relocatable	$74	$87	$58	$57	$87	$104	$80

Changes to revenue and interest rate have a significant impact on methanol synthesis – since it is the most capitally intensive process and produces the most valuable bio-fuel. Changing the thinning yield has relatively little impact on process economics. Revenue assumptions are a key concern since, as the price of fossil fuel fluctuates, so will the price of bio-oil and methanol.

12. Conclusions and Discussion

This study has identified conditions under which production of densified bio-fuels from forest thinnings would have favorable economics in comparison to the default option of disposal. As expected, thermochemical conversion of thinnings – whether for the production of heat and power or a bio-fuel – will not pay for thinning. No scenario results in a negative net thinning cost.

12.1. Technology Conclusions

12.1.1. Co-fire with Coal

For transportation distances from the logging deck to an end-user of less than 400 km, co-fire is the preferred option by a wide margin. However, the relative scarcity of coal fired power plants in California and Pacific Northwest may limit the regional viability of this option. For example, since there are only a few coal fired power plants in the states of Oregon and Washington, if these plants are unwilling to co-fire thinnings there are no other close opportunities for co-fire.

12.1.2. Wood Chip Cogeneration

In cases where co-fire is not a possibility, wood chip cogeneration offers the lowest net thinning cost for transportation distances of less than 400 km. However, near-term improvements in fast pyrolysis would negate this advantage. Furthermore, a buyer must be identified for low-grade waste heat, which may not be trivial.

12.1.3. Pulp Sale

The economics of pulp sale are quite similar to wood chip cogeneration. Pulp sale is preferred for small or short duration thinning operations since it is the least capitally intensive of all options. However, as with co-fire, the general scarcity of pulp mills complicates matters. Furthermore, the wood of juvenile trees being thinned may not produce pulp with preferred characteristics.

12.1.4. Pelletization (High-grade Solid Bio-fuel)

For the base technology case, pelletization would be preferred for moderate yields and short thinning durations since it is not capital intensive. However, near-term improvements in fast pyrolysis would allow bio-oil economics to surpass those of pellets in nearly all cases.

12.1.5. Fast Pyrolysis (Low-grade Liquid Bio-fuel)

Fast pyrolysis of thinnings has been identified as the bio-fuel production option of choice for transportation distances greater than 400 km. Fast pyrolysis has the strong potential to become competitive with options other than co-fire at much shorter distances in the near-term, pending the success of the first generation of demonstration projects and the development of reactors capable of using larger sized feedstock. Further research and development in this area is warranted. Especially, end-use capabilities for bio-oil need to be examined and reliably demonstrated.

12.1.6. Methanol Synthesis (High-grade Liquid Bio-fuel)

For thinning operations which would produce very large volumes of feedstock for extended periods of time, methanol production is the lowest cost option. Like fast pyrolysis, transportation distance must be greater than 400 km for production to be preferred. However, the production of methanol from thinnings is complicated by the technology's immaturity. Furthermore, the use of wet scrubbing to clean product syngas may create a permitting show-stopper. If this is the case and deployment of methanol synthesis must wait for the successful development of hot, dry gas cleaning, methanol synthesis may find itself competing at a significant disadvantage against low-cost next-generation fast pyrolysis. Since all high-grade bio-fuel production processes rely on nearly identical gas cleaning technologies, other high-grade fuels such as synthetic diesel and hydrogen are unlikely to be adopted more quickly.

12.2. Bio-fuel Production

The production of bio-fuels using mobile (10 dry tons per day) and transportable (100 dry tons per day) facilities is significantly more costly than production at a stationary or relocatable facility. As such, it is recommended that systems of these scales not be pursued beyond technical demonstration. This, however, is a valuable role as smaller systems lend themselves better to technical development than large-scale demonstrations. Once the technology has been proven, large systems should be built in order to realize projected bio-fuel production costs.

The economics of bio-fuel production from thinnings are much preferred to disposal in most cases. Further study is needed to understand the competitiveness of bio-fuel production with non-energy uses of thinnings, such as new forest products.

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Appendix A – Model Documentation

This appendix covers the layout and operation of the model developed to predict net thinning cost. It is written assuming a strong understanding of advanced Microsoft EXCEL features (e.g. look-up tables) and familiarity with Visual Basic for Applications (VBA) programming.

The easiest way to gain familiarity with the model is through the use of EXCEL's native formula auditing tools. These allow a user to trace calculation dependence forward and backwards through the model. Bear in mind that the utility of formula auditing is somewhat reduced by the use of VLOOKUP functions indexing large blocks of data (e.g. pulling inputs from the 'Data' spreadsheet into the 'Biofuel Production' spreadsheet. In these cases, formula auditing will list every cell in the look-up range as a dependent of the look-up calculation. There is no simple auditing tool to determine what specific cell a VLOOKUP function is indexing.

First, it should be noted that, within the model, cell shading and text color have significance. Cells without shading are standard EXCEL calculations. Cells shaded light yellow are user inputs. Cells shaded light blue are cells populated by VBA macros. Within the context of this shading scheme, text color also has significance. For unshaded cells, black text indicates standard calculation, light blue text a link from a different spreadsheet, and grey text generally refers to a reference flag for a VLOOKUP function. Grey text is also used in places where a 'residual' calculation from early iterations has been left in the model structure, but does no longer feeds calculations further up the chain. For user input cells (yellow shading), black text indicates a standard input and red text an input based on assumption or one that is frequently changed when testing sensitivities. Macro output cells (blue shading) are always written in black text.

A.1. Model Operation

This section covers operation of the model for a given set of user defined inputs.

A.1.1. Single Bio-fuel Production and End-Use Case

Manual calculation of net thinning cost for a defined production and end-use case may be done using the controls on the 'Master' spreadsheet.

The following options may be specified on 'Master'.

- *Intra and Extra-forest Operation Time:* This sets the number of hours each day operations are allowed inside and outside the forest. This number should be a multiple of 8 – single shifts are assumed to be 8 hours long.
- *Industrial Proximity*: This sets which set of transportation distances defined on the 'Data' sheet to use. 'Parameter' distances are constant for all end-uses other than disposal. 'Case Study' distances may be set by the user to model the variable distances to different end-users that would be encountered in a specific thinning operation.
- *Harvest*: This sets which set of harvesting parameters (e.g. yield per acre) defined on the 'Data' sheet to use. Both are currently set to nearly the same value. 'Parameter' and 'Case Study' options are the same as for *Industrial Proximity.*
- *Preprocessing*: Sets chipping or chipping and debarking for initial fuel handling. For bio-fuel production options which can not tolerate bark, chipping and debarking should be selected.
- *Mobile Bio-fuel Production*: Sets type of mobile bio-fuel production. Options are: pelletization, fast pyrolysis, advanced fast pyrolysis, methanol synthesis, advanced methanol synthesis, and none.
- *Transportable Bio-fuel Production*: Sets type of transportable bio-fuel production. Options are the same as for mobile bio-fuel production.

- *Stationary Bio-fuel Production*: Sets type of stationary bio-fuel production. Options are the same as for mobile bio-fuel production.
- *Relocatable Bio-fuel Production*: Sets type of relocatable bio-fuel production. Options are the same as for mobile bio-fuel production.
- *Bio-fuel Conversion*: Sets bio-fuel end-use. Options are: wood chip cogen, co-fire, disposal, and bio-fuel sale. Bio-oil cogen and pellet cogen are also available, though the cost inputs for these scenarios are highly speculative.
- *Cogen Heat Utilization*: Sets the fraction of saleable waste heat actually sold. 100% for standard cogen case. 0% saleable fraction with wood chip cogen selected as an end-use would be the case for generation of only electricity at a dedicated biomass facility.
- *Revenue Modifiers*: Allows subsidies to be applied against net thinning cost. No subsidies have been applied in cases discussed in model results.

Note that there is no safeguard against selecting nonsensical combinations of bio-fuel production and end-use. For example, a user could select mobile fast pyrolysis, stationary pelletization, and co-fire as an end-use and produce a meaningless net thinning cost.

The ‘Master’ sheet also summarizes model output. Beneath the ‘Model Output’ header, information is given with respect to physical system outputs (bio-fuel, heat, and power), gross thinning costs (harvest, transportation, production, end-use), and revenue. Costs are presented on an absolute, per acre, per energy, and per wet ton basis. Only per ton costs have been included in the discussion of thesis results.

A.1.2. All Bio-fuel Production and End-Use Cases

An automated routine has been written to simplify the calculation of net thinning cost for the range of bio-fuel production and end-use scenarios considered. Scenarios to be considered are located under the ‘Standard Scenarios’ header on the

'Automation_Control' sheet. 26 different scenarios are defined. The names entered in the set-up grid *must identically match* the names listed in the drop down boxes on the 'Master' sheet for the macro to work correctly.

Results are tabulated on the 'Automation_Result' sheet in the blue, macro written cells at the top of the sheet. To run the macro, click the 'Populate Scenarios' button at the top left of this sheet. Only costs on a per ton wet thinnings basis are written to this sheet. Costs listed are broken down into harvest, bio-fuel production and end-use, transportation from logging deck to bio-fuel production facility, and transportation from bio-fuel production facility to end-use. Revenues are split out for bio-fuel, power, and heat. Column R of this sheet calculates a delta between the net thinning cost of the current case and that of the base case defined in section 2.4.

This automation allows sensitivities around the base case to be quickly run. It also eliminates the possibility of errors which could arise if net thinning costs for all production and end-use scenarios were recalculated by manual selection on the 'Master' sheet.

A.1.3. Transportation Distance Parameter Study

An automated routine has been written to study the effect of transportation distance on net thinning cost. Scenarios to be considered are located under the 'Parameter Study' heading on the 'Automation_Control' sheet. Note that this is a restricted subset of all possible scenarios (e.g. considers only stationary bio-fuel production). Above the scenario list is a table for setting 'sweep variables' for the parameter study. For a 'sweep variable' the following information must be defined: starting value, ending value, step size, and default value (resets at end of parameter study). The location of the input cell for this variable in the model must also be defined. Finally, the first row to write data to on the 'Automation_Parameter' page must be set.

Output is generated by clicking the ‘Parameter Calculation’ button at the top of the ‘Automation_Parameter’ page. The macro will repopulate the range of blue cells and automatically update the graph. Table values are net thinning cost on a per wet ton thinned basis.

Note that the ‘Automation_Control’ sheet does allow for additional (up to eight total) parameters to be varied. Additional parameters should be set-up using values for transportation distance as a template.

A.1.4. Grid Outputs

The grid outputs on ‘Automation_Grid’ are the most comprehensive set of results calculated by the model. Depending on processing speed, these grids can take anywhere from one to three hours to populate. Once the code begins running, screen updating is periodically disabled, so if another application is started, EXCEL can generally not be brought back into focus. Focus will return to EXCEL once the macro has finished running.

Much as in the transportation parameter calculations, ‘sweep variables’ must be defined at the top of the page. For the grid outputs, these are transportation distance, annual acreage thinned, and thinning duration. Below the setup for ‘sweep variables’ the model lists the current lowest cost production facility type for each type of bio-fuel (e.g. mobile, transportable, stationary, and relocatable). Beneath that, the lowest cost option for three cases is listed: base technology, advanced technology, and advanced technology excluding co-fire. These three cases correspond to the grid outputs discussed in Chapter 11. Net thinning costs on a per ton basis are read from the ‘Automation_Result’ sheet. Therefore, unlike the transportation distance parameter study, the full set of bio-fuel production and end-use options are considered when populating the grid.

To populate the grid, click the ‘Populate Grid’ button at the top of the page. In sequence, previous grid data will be erased, new grid data created, and grid output color coded by production and end-use scenario. Effectively, this routine runs the macro on the 'Automation_Result' page for different values of the three 'sweep variables'. To populate the grids, the macro automates the testing of over 13,000 production and end-use scenarios.

Each grid corresponds to a different transportation distance – indicated in the box above the grid. Grid elements correspond to a particular acreage thinned and duration of thinning. The first line of grids corresponds to the base technology case, the second to the advanced technology case, and the third to the advanced technology case, excluding co-fire.

A.1.5. Changing Detailed Inputs

In addition to transportation distance, total acreage thinned, and thinning duration, the model has literally hundreds of other user defined inputs that can be altered as needed. Revenue inputs are located on the 'Revenue' spreadsheet. Most other inputs are located on the 'Data' spreadsheet and are grouped under relevant headings. Some detailed cost and operational inputs are defined on the 'Backup' group of sheets (sheets prefixed Backup). Sources are generally given in the columns to the right of the input cell. Remember, cells with blue text are *never* user inputs, but rather link to other cells within the workbook. *Do not manually overwrite blue text cells*.

Since there is no automated method for restoring defaults once input values have been changed, it is recommended that a backup copy of the workbook be created before changes are made.

A.2. Model Layout

The thinning conversion model resides within a single MS EXCEL workbook. The model is compatible with EXCEL 2003 and XP and should be compatible with EXCEL 2000. Further downward compatibility is doubtful. The model is composed of a set of spreadsheets and visual basic macros. A concise overview of spreadsheets and macros is given below.

A.2.2. Spreadsheet Descriptions

Spreadsheets have been arranged by functionality. The first spreadsheet ('Master') is the master control for the model as described in A.1.1. The next sheets include the prefix "Automation" and are used to setup and record the outputs of macros which automate model output for different cases. The functions of the sheets 'Automation_Control', 'Automation_Result', 'Automation_Parameter', and 'Automation_Grid' are defined above.

Revenue

This sheet contains calculations and input for bio-fuel and bio-energy revenues. Sheet layout is fairly intuitive, with revenues on an energy basis at the top, potential subsidies next, and wholesale revenue inputs at the bottom.

Harvest

This sheet calculation cost and yield for both individual logging decks and the entire thinning operation.

Deck Preprocessing

This sheet calculates the cost and yield of chipping and chipping/debarking at the logging deck. Outputs for mobile, transportable, stationary, and relocatable facilities are listed by column at the top. The sheet's calculations are dynamic – that is, there is not a separate calculation for chipping and chipping/debarking, but rather a single calculation section.

Biofuel Production

This sheet includes all model mechanics for calculating cost and output of various bio-fuel production options. Summary data is given at the top for the production scenario current selected by the values on the 'Master' sheet. There is a separate calculation section for each type of bio-fuel production technique (e.g. fast pyrolysis). Base and advanced production cases are considered as two separate techniques.

Calculations for each bio-fuel production technique are broadly grouped into operations and cost. The operations section calculates various physical aspects of bio-fuel production (e.g. capacity factor, quantity of bio-fuel production, power requirement). Process throughputs are considered first, followed by heat and power integration. The cost section calculates capital and operating costs based on the physical aspects of production (e.g. power cost is a function of power consumed). At the bottom of the cost section, cost chains are summarized and overall energy efficiency calculated. There is also an incomplete feature to calculate total fuel consumption for each production scenario, which would be useful for comparative lifecycle analysis.

A note of explanation regarding equipment rated capacity. Many equipment costs in the model scale with rated biomass capacity on a dry ton per day basis. However, for methanol synthesis and pelletization some fraction of the feedstock input to the process will be burned for process heat. As such, equipment including and downstream of the dryer will see a lower throughput of biomass than fuel handling equipment upstream of the dryer. Equipment costs downstream of the dryer are calculated using this lower throughput and equipment costs upstream of the dryer are calculated using the full throughput.

Biofuel Conversion

This sheet contains calculations for the cost of bio-fuel end-use. Layout and methodology is identical to the 'Biofuel Production' sheet.

Transportation

This sheet calculates bio-fuel transportation costs. Primary transportation consists of the transport of wood chips to bio-fuel production facility or wood chips to end-use.

Secondary transportation consists of transport of upgraded bio-fuels from the bio-fuel production facility to end-use. Secondary transportation costs are, by definition, zero for end-use applications involving wood chips. Layout and methodology follow the same pattern as the 'Biofuel Production' sheet, broken down along lines of operations and cost.

Data

The 'Data' spreadsheet contains all of the input data for the 'Harvest', 'Biofuel Production', 'Biofuel Conversion', and 'Transportation' sheets. These sheets retrieve data using VLOOKUP functions. If inserting new values in this sheet for a particular operation, make certain the line is inserted above the *'Insert New Rows Above this Line*' notation. In sequence, inputs include:

- *Layout Options*: Sets options for drop-down menus on 'Master' sheet.
- *Conversion Matrix*: Defines inputs and outputs for bio-fuel production processes.
- *Transportation Distances*: Sets transportation distances for 'Case Study' and 'Parameter' options.
- *Material Properties*: Defines material properties for bio-fuels in study. Defined properties include heating value, bulk density, and moisture content.
- *Financial Inputs*: Defines equipment lifetimes, salvage values, and interest rates used in capital cost calculations.
- *Harvest*: Defines harvest parameters, such as cost, yield, and duration. Also defines transportation distances from the logging deck to stationary bio-fuel production facilities and distance from logging deck to a major road.
- *Transportation*: This section defines all inputs to the 'Transportation' sheet (e.g. vehicle cost, loading and unloading times, driving speeds etc.)
- *Operational Days*: Defines working and non-working days for different facility types.
- *Mobile Operations*: Defines mobility parameters such as site separation and number of sites served per year. Also defines fixed and variable mobility costs.
- *External Inputs*: Defines costs for externally purchased power (grid electricity), water, and hourly labor costs.

- *Pretreatment*: Defines cost, as well as heat and power requirements for dryers. Also defines feedstock storage pile parameters.
- *Diesel Engine*: Efficiency and operating cost (fuel, maintenance) for diesel engines.
- *Preprocessing*: This section contains all inputs for the 'Deck Preprocessing' sheet.

Sections beyond this point contain operational and cost data for bio-fuel production and end-use scenarios (e.g. data to populate 'Biofuel Production' and 'Biofuel Conversion' sheets). Much of the data in this section is linked. That is, inputs common across multiple bio-fuel production and end-use options are entered only once.

Backup

This set of sheets contains raw, detailed data on cost and operational parameters. These sheets are less organized than others in the model and contain limited internal commenting. The inputs on these sheets are at a low enough level that changing values would likely have a fairly minimal impact on net thinning cost. These sheets contain a fair deal of 'scratch work' which does not flow into model calculations. Use auditing tools to determine if particular information on these sheets is live or inactive.

A.2.3. VBA Module Descriptions

In places, the visual basic code references specific cells in spreadsheets. If spreadsheet layout is altered (e.g. columns and rows added or deleted), the macro will no longer run correctly. Code references specific cells on sheets 'Automation_Control', 'Automation_Result', 'Automation_Parameter', and 'Automation_Grid'. *Be sure you understand how the macro code works before altering the layout of these sheets.*

Standard

Sets 'Master' values to inputs specified on 'Automation_Control' and writes output values to 'Automation_Result'.

Parameter

Runs single 'sweep variable' parameter study according to set-up on 'Automation_Control' and writes output values to 'Automation_Parameter'.

GridPlot

Runs grid automation according to set-up on 'Automation_Grid'. Calls subroutines 'GridErase' and 'GridColor' as well as 'Standard'.

GridColor

Colors grid automation output according to bio-fuel production scenario. Colors may be added or modified within the SELECT CASE architecture of the code.

GridErase

Erases all data on 'Automation_Grid' sheet.

Appendix B – Pellet and Liquid Fuel Handling

B.1 - Wood Pellets

The receiving of wood pellets is much like that of wood chips – employing half-truck or whole-truck dumpers depending on facility size. However, pellets must be protected from the elements by either a building or silo. Pellets left outside will absorb moisture from the air or rain, at best reducing combustion efficiency and at worst causing rot and disintegration. The cost of such a building or silo would be substantial, estimated at several million dollars for a large scale pellet fired power plant with appreciable fuel storage. However, pellets do not require any magnetic screening or pretreatment since pellet quality should be assured by the upstream production process. Figure B.1 shows a schematic for pellet fuel handling.

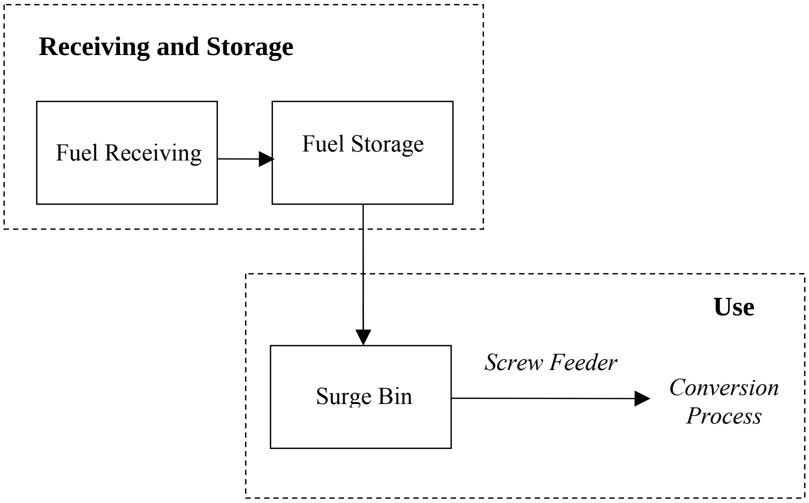


Figure B.1 – Fuel Handling for Wood Pellets

Wood pellet handling capital costs and scale factors are given in Table B.1 and adapted from [48] and [56].

Table B.1 – Wood Pellet Fuel Handling Capital Cost

Equipment	Capital Cost ($ 000)	Installation Factor
Truck Dumper	$302 (flat cost)	1.0
Storage Silo	$2,532 @ 74 dtpd, 0.5 scale factor	1.0
Front-end Loader	$250 (flat cost)	1.0
Feed Hopper	$=(5.456)(dtpd)^{0.2939}$	1.6
Screw Feeder	$=(7.350)(dtpd)^{0.0337}$	1.0

B.2 - Liquid Fuels

Liquid fuels are substantially easier to receive and store than solid fuels. Liquid fuel arriving by a tanker truck drains by gravity into a receiving well, and is then pumped to a storage tank. On demand, fuel is pumped out of the storage tank [9]. A schematic diagram is presented in Figure B.2.

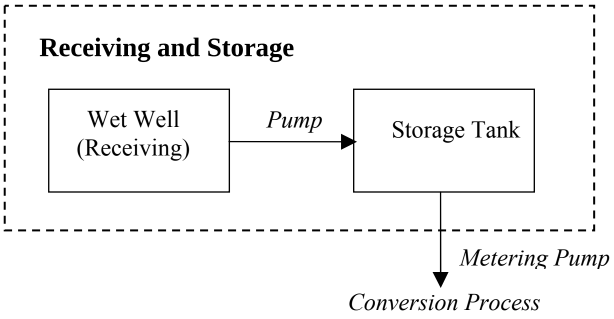


Figure B.2 – Fuel Handling for Liquid Fuels

Capital costs are adapted from [9] and presented in Table B.2. The liquid fuel storage tank is the primary cost. With the exception of the storage tank, costs are assumed to be flat for all relevant scales. Storage tank costs are expected to vary nearly linearly in the range of sizes under consideration. All costs listed are installed costs.

Table B.2 – Liquid Fuel Handling Capital Cost

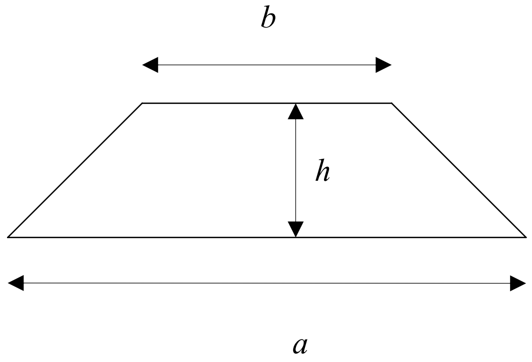
Equipment	Reference Cost ($ 000)	Reference Scale	Scale Factor
Wet Well	$100	N/A – flat cost	N/A
Receiving Pump	$24	N/A – flat cost	N/A
Storage Tank	$2,000	2 @ 2,500,000 gallons	0.9
Metering Pump	$24	N/A – flat cost	N/A
Hose and Fittings	$20	N/A – flat cost	N/A

Appendix C – Wood Chip Storage Pile Geometry

Assuming the wood chip storage pile to be a truncated square pyramid its volume will be given as

$$V = \frac{1}{3}\left(a^2 + ab + b^2\right)h$$

where V is the pile volume and a, b, and h are as defined in the figure below.



Assuming that the angle between the side and the base is 45° it can be readily shown that

$$b = a - 2h$$

Solving for a, we may obtain

$$a = h \pm \sqrt{\frac{V}{h} - \frac{1}{3}h^2}$$

Since the height of the storage pile should be no greater than 6 m for transportable systems and 9 m for stationary or relocatable bio-fuel production, the dimension of the base of the pile may be readily calculated for a known volume of chips. This volume is set by the feedstock storage requirement – 14 days for a transportable system and 28 days for stationary and relocatable facilities.

An additional buffer of 3.5 m is estimated around the edge of the pile.

Appendix D – Burner Enthalpy Balances

Fast Pyrolysis Byproducts

Char Heat of Formation

Reactants	kmoles	hf	h	h298	h-h298	h (kJ/kmole)
Char	1	-262,865			0	-262,865
O2	7	0			0	0
N2	27	0			0	0
Total						-262,865

Products	kmoles	hf	h	h298	h-h298	h (kJ/kmole)
CO2	6.20	-393,520			0	-2,439,824
H2O(g)	2.55	-241,820			0	-616,641
O2	0.00	0			0	0
N2	27	0			0	0
Total						-3,056,465

Hp	-3,056,465		
Hr	-262,865		
Hp - Hr	2,793,600	2,793,600	0

Byproduct Combustion

Excess Air	786%

Reactants	kmoles	hf	h	h298	h-h298	h (kJ/kmole)
CO2	0.63	-393,520			0	-247,524
CO	1.67	-110,530			0	-184,032
CH4	0.85	-74,850			0	-63,697
C2H4	0.52	52,280			0	27,081
H2	0.48	0			0	0
Char	1	-262,865			0	-262,865
O2	90.34	0			0	0
N2	339.69	0			0	0
Total						-731,038

Products	kmoles	hf	h613	h298	h-h298	h (kJ/kmole)
CO2	9.4	-393,520	13,521	-8	13,529	-3,571,915
H2O(g)	4.8	-241,820	11,011	-5	11,016	-1,117,089
O2	80.1	0	9,743	-24	9,767	782,764
N2	339.74	0	9,331	-15	9,346	3,175,202
Total						-731,038

Hp	-731,038
Hr	-731,038
Q	0

Product Flow

	kmoles	cp (kJ/kg)	Ti	To	Tave (K)	Q	
CO2	9.4	1.0104	340	104	495	98,621	
H2O(g)	4.8	1.9612	340	104	495	40,323	
O2	80.1	0.9850	340	104	495	596,194	
N2	339.7	1.0670	340	104	495	2,395,514	
						3,130,652	kJ/kmole char
						35.86	MJ heat to dryer/kg char burned
						7.21	MJ heat to dryer/kmole flue gas

Bio-oil

Bio-oil Heat of Formation

Excess Air	0%

Reactants	kmoles	hf	h	h298	h-h298	h (kJ/kmole)
C4.67H6.5O2.34	1.0	-1,030,582			0	-1,030,582
H2O(l)	0.49	-285,000			0	-140,271
O2	5.13	0			0	0
N2	19.3	0			0	0
Total						-1,170,853

Products	kmoles	hf	h	h298	h-h298	h (kJ/kmole)
CO2	4.7	-393,520			0	-1,837,738
H2O(g)	3.74	-241,820			0	-904,933
O2	0.0	0			0	0
N2	19.3	0			0	0
Total						-2,742,672

Hp	-1,170,853			HHV	15.7	MJ/kg
Hr	-2,742,672	*Target*		MW	99.98	kg/kmol
Hp - Hr	1,571,819	1,571,819	-	HHV	1,571,819	KJ/kmol

Bio-oil Combustion

Excess Air	570%

Equation Coef	
Air	5.13
CO2	4.67

Reactants	kmoles	hf	h	h298	h-h298	h (kJ/kmole)
C4.67H6.5O2.34	1.0	-1,030,582			0	-1,030,582
H2O(l)	0.0	-285,000			0	0
O2	34.4	0			0	0
N2	129.3	0			0	0
Total						-1,030,582

Products	kmoles	hf	h613	h298	h-h298	h (kJ/kmole)	MW
CO2	4.7	-393,520	13,521	-8	13,529	-1,774,558	44
H2O(g)	3.3	-241,820	11,011	-5	11,016	-750,112	18
O2	29.3	0	9,743	-24	9,767	285,743	32
N2	129.3	0	9,331	-15	9,346	1,208,344	28
Total						-1,030,582	

Hp	-1,030,582	
Hr	-1,030,582	
Q	0	Adiabatic combustion and mixing - goal seek excess air to zero

MW Bio-oil	99.98

Product Flow

	kmoles	cp (kJ/kg)	Ti	To	Q	
CO2	4.7	1.0104	340	104	48,996	
H2O(g)	3.3	1.9612	340	104	27,076	
O2	29.3	0.9850	340	104	217,637	
N2	129.3	1.0670	340	104	911,628	
					1,205,337	kJ/kmole wood
					12.06	MJ heat to dryer/kg bio-oil burned
					7.24	MJ/kmole flue gas

Wood Chips

Wood Heat of Formation

Excess Air	0%

Reactants	kmoles	hf	h	h298	h-h298	h (kJ/kmole)
C6H9O4	1	-289,552			0	-289,552
H2O(l)	8	-285,000			0	-2,308,500
O2	6	0			0	0
N2	24	0			0	0
Total						-2,598,052

Products	kmoles	hf	h	h298	h-h298	h (kJ/kmole)
CO2	6	-393,520			0	-2,361,120
H2O(g)	13	-241,820			0	-3,046,932
O2	0	0			0	0
N2	24	0			0	0
Total						-5,408,052

Hp	-2,598,052		
Hr	-5,408,052		
Hp - Hr	2,810,000	2,810,000	-

Wood Chip Combustion

Excess Air	845%

Equation Coef

Air	6.25
CO2	6

Reactants	kmoles	hf	h	h298	h-h298	h (kJ/kmole)
C6H9O4	1.0	-289,552			0	-289,552
H2O(l)	8.1	-285,000			0	-2,308,500
O2	59.0	0			0	0
N2	222.0	0			0	0
Total						-2,598,052

Products	kmoles	hf	h613	h298	h-h298	h (kJ/kmole)	MW
CO2	6.0	-393,520	13,521	-8	13,529	-2,279,946	44
H2O(g)	12.6	-241,820	11,011	-5	11,016	-2,908,125	18
O2	52.8	0	9,743	-24	9,767	515,538	32
N2	222.0	0	9,331	-15	9,346	2,074,480	28
Total						-2,598,052	

Hp	-2,598,052	
Hr	-2,598,052	
Q	0	Adiabatic combustion and mixing - goal seek excess air to zero

MW Wood	145

Product Flow

	kmoles	cp (kJ/kg)	Ti	To	Q	
CO2	6.0	1.0104	340	104	62,949	
H2O(g)	12.6	1.9612	340	104	104,973	
O2	52.8	0.9850	340	104	392,661	
N2	222.0	1.0670	340	104	1,565,080	
					2,125,663	kJ/kmole wood
					14.66	MJ heat to dryer/kg wood burned
					7.25	MJ/kmole flue gas

Appendix E – Baghouse Reference Scale

Assuming wood may be represented as $C_6H_9O_4$ and that moisture levels are assumed to be 50%, combustion with excess air may be written as:

$$\begin{aligned} &\mathrm{C_6H_9O_4} + 8.1\mathrm{H_2O} + 6.25(1+\phi)(\mathrm{O_2} + 3.76\mathrm{N_2}) \rightarrow \\ &\qquad 6\mathrm{CO_2} + 12.6\mathrm{H_2O} + 23.5(1+\phi)(\mathrm{N_2}) + 6.25\phi\mathrm{O_2} \end{aligned}$$

Assuming the fluidized bed combustor operates with 30% excess air, complete combustion will produce 51 kmole flue gas per kmol wood burned. Further assuming 30% efficient electricity production, the 28 MW_e facility in [10] would consume 4.82 kg dry wood/second. If flue gases pass through the baghouse at 473 K (200^oC) and atmospheric pressure, the volumetric flow rate through the baghouse will be 65.8 m^3/s.

Appendix F – Diesel Engine Waste Heat

Diesel Fuel

Excess Air 30%

Diesel MW 114 kg/kmole

Products	kmoles	MW	kg	cp (kJ/kg)	Ti C	To	Tave	hin	hout
CO2	8	44	352	1.0104	550	340	445	195,606	120,920
H2O (g)	7.2	18	130	1.9612	550	340	445	139,794	86,418
O2	3.4	32	108	0.98504	550	340	445	58,251	36,010
N2	37.1	28	1,040	1.06703	550	340	445	610,439	377,362
Cooling Air									
O2	8.5	32	271	0.98504	25	340	183	6,667	90,671
N2	31.8	28	891	1.06703	25	340	183	23,760	323,136
								1,034,517	1,034,517

Flue Gas to Dryer

	kg	kmoles	cp	Ti	To	Q	
CO2	352	8	1.0104	340	104	83,933	
H2O (g)	130	9	1.9612	340	104	59,984	
O2	378	16	0.9850	340	104	87,931	
N2	1,931	107	1.0670	340	104	486,228	
						718,077	kJ/kmole diesel
						6.30	MJ heat to dryer/kg diesel combusted
						7.48	MJ heat to dryer/kmole flue gas

Bio-oil Fuel

Excess Air	30%	
Bio-oil MW	99.98	kg/kmole

Products	kmoles	MW	kg	cp (kJ/kg)	Ti C	To	Tave	hin	hout
CO2	4.67	44	205	1.0104	550	340	445	114,185	70,587
H2O (g)	3.25	18	59	1.9612	550	340	445	63,102	39,008
O2	1.539	32	49	0.9850	550	340	445	26,681	16,494
N2	25.07544	28	702	1.0670	550	340	445	412,046	254,719
Cooling Air									
O2	5.2	32	166	0.98504	25	340	183	4,090	55,627
N2	19.5	28	546	1.06703	25	340	183	14,577	198,245
								634,681	634,681

Flue Gas to Dryer

	kg	kmoles	cp	Ti	To	Q	
CO2	205	5	1.0104	340	104	48,996	
H2O (g)	59	3	1.9612	340	104	27,076	
O2	215	7	0.9850	340	104	50,060	
N2	1,249	45	1.0670	340	104	314,411	
						440,543	kJ/kmole bio-oil
						4.41	MJ heat to dryer/kg bio-oil combusted
						7.44	MJ heat to dryer/kmole flue gas

Appendix G – Fast Pyrolysis Light Gas Composition

Feedstock	100	kg
Standard Conditions		
T	273	K
P	101.325	kPa
R	8.314	kJ/kmole K
Light Gas	13%	
Primary Gas	5%	
Secondary Gas	8%	

Gas Composition

Primary Gas	Fraction	Quantity (kg)	MW	Quantity (kmoles)	Mass Density (kg/m3)	LHV (kJ/kg)	LHV (MJ/nm3)		
CO2	53.0%	2.65	44	0.060	1.96	0	-		
CO	39.0%	1.95	28	0.070	1.25	10,107	12.6		
HC	6.7%	0.335	22	0.015	0.97	48,330	46.8		
H2	0.8%	0.04	2	0.020	0.09	120,910	10.8		*Delta*
Total							11.0	11.0	0.0
Secondary Gas									
CO2	9.0%	0.45	44	0.010	1.96	0	-		
CO	63.0%	3.15	28	0.113	1.25	10,107	12.6		
HC	27.0%	1.35	16	0.083	0.73	49,895	36.4		
H2	1.4%	0.07	2	0.035	0.09	120,910	10.8		*Delta*
Total							20.0	20.0	0.0
Total Gas						LHV (kJ/kg)	LHV (MJ/nm3)		
CO2	31%	3.1	44	0.070	1.96	0	-		
CO	51%	5.1	28	0.182	1.25	10,107	12.6		
HC	17%	1.685	17	0.098	0.77	49,584	38.0		
H2	1%	0.11	2	0.055	0.09	120,910	10.8		*Delta*
Total					1.38	11.9	16.3	15.0	1.3
								10.9	MJ/kg

Hydrocarbon Mix

Primary

	MW	LHV (kJ/kg)	Mass Density	LHV (MJ/nm3)	Mole Fraction
CH4	16	50016	0.72	35.8	53%
C2H4	28	47249	1.25	59.1	47%
	21.7			46.8	

Secondary

	MW	LHV (kJ/kg)	Mass Density	LHV (MJ/nm3)	Mole Fraction
CH4	16	50016	0.72	35.8	97%
C2H4	28	47249	1.25	59.1	3%
	16.3			36.4	

Calculated Total

	MW	LHV (kJ/kg)	Mass Density	LHV (MJ/nm3)	Fraction
CH4	16	50016	0.72	35.8	90%
C2H4	28	47249	1.25	59.1	10%
	17.2			38.0	100%

	Mass Fraction	MW		Mole Fraction
CO2	31.0%	44	0.007049	17%
CO	51.0%	28	0.0182234	45%
CH4	15.2%	16	0.0095008	23%
C2H4	1.6%	28	0.0005772	1.4%
H2	1.1%	2	0.0055028	13%
		24.5	0.0408532	

Appendix H – Bio-fuel Production Cost Chains

Fast Pyrolysis	Mobile	Transportable	Stationary	Relocatable
Harvest	40	40	40	40
Bio-fuel Production	130	52	27	32
Primary Transportation	8	2	7	7
Secondary Transportation	-	10	6	6
Revenue	19	23	26	26
Net Cost	159	81	54	58

Pelletization	Mobile	Transportable	Stationary	Relocatable
Harvest	40	40	40	40
Bio-fuel Production	128	58	27	29
Primary Transportation	15	2	7	7
Secondary Transportation	-	17	8	8
Revenue	20	23	23	23
Net Cost	162	93	59	61

Methanol	Mobile	Transportable	Stationary	Relocatable
Harvest	40	40	40	40
Bio-fuel Production	226	143	73	87
Primary Transportation	6	2	7	7
Secondary Transportation	-	7	3	3
Revenue	58	67	64	64
Net Cost	214	126	59	74

Advanced Fast Pyrolysis	Mobile	Transportable	Stationary	Relocatable
Harvest	40	40	40	40
Bio-fuel Production	127	48	21	25
Primary Transportation	8	2	7	7
Secondary Transportation	-	11	6	6
Revenue	19	26	26	26
Net Cost	156	76	48	52

Advanced Methanol Synthesis	Mobile	Transportable	Stationary	Relocatable
Harvest	40	40	40	40
Bio-fuel Production	222	140	70	84
Primary Transportation	6	2	7	7
Secondary Transportation	-	7	3	3
Revenue	58	67	64	64
Net Cost	210	122	57	71

Wood Chip Cogen	Stationary
Harvest	40
Bio-fuel Production	39
Primary Transportation	41
Secondary Transportation	-
Revenue	44
Net Cost	75

Co-fire	Stationary
Harvest	40
Bio-fuel Production	22
Primary Transportation	41
Secondary Transportation	-
Revenue	39
Net Cost	63

Pulp Sale	Stationary
Harvest	40
Bio-fuel Production	5
Primary Transportation	37
Secondary Transportation	-
Revenue	12
Net Cost	71

Appendix I – Grid Results

Base technology case, 100 km transportation distance

Duration	1	3	5	7	9	11	13	15
10,000	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43
20,000	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Co-fire $41	Co-fire $40	Co-fire $39	Co-fire $38	Co-fire $38
30,000	Pulp Sale $42	Pulp Sale $42	Co-fire $41	Co-fire $38	Co-fire $37	Co-fire $36	Co-fire $36	Co-fire $35
40,000	Pulp Sale $42	Pulp Sale $42	Co-fire $39	Co-fire $36	Co-fire $35	Co-fire $35	Co-fire $34	Co-fire $34
50,000	Pulp Sale $42	Co-fire $42	Co-fire $37	Co-fire $35	Co-fire $34	Co-fire $33	Co-fire $33	Co-fire $33
60,000	Pulp Sale $42	Co-fire $40	Co-fire $36	Co-fire $34	Co-fire $33	Co-fire $33	Co-fire $32	Co-fire $32
70,000	Pulp Sale $42	Co-fire $39	Co-fire $35	Co-fire $33	Co-fire $32	Co-fire $32	Co-fire $31	Co-fire $31
80,000	Pulp Sale $42	Co-fire $38	Co-fire $34	Co-fire $33	Co-fire $32	Co-fire $31	Co-fire $31	Co-fire $31
90,000	Pulp Sale $42	Co-fire $38	Co-fire $34	Co-fire $32	Co-fire $31	Co-fire $31	Co-fire $30	Co-fire $30
100,000	Pulp Sale $42	Co-fire $37	Co-fire $33	Co-fire $32	Co-fire $31	Co-fire $30	Co-fire $30	Co-fire $30

Base technology case, 200 km transportation distance

Duration	1	3	5	7	9	11	13	15
10,000	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47
20,000	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47	Co-fire $46	Co-fire $44	Co-fire $44	Co-fire $43	Co-fire $42
30,000	Pulp Sale $46	Pulp Sale $46	Co-fire $45	Co-fire $43	Co-fire $42	Co-fire $41	Co-fire $40	Co-fire $40
40,000	Pulp Sale $46	Pulp Sale $46	Co-fire $43	Co-fire $41	Co-fire $40	Co-fire $39	Co-fire $39	Co-fire $38
50,000	Pulp Sale $46	Pulp Sale $46	Co-fire $42	Co-fire $40	Co-fire $39	Co-fire $38	Co-fire $37	Co-fire $37
60,000	Pulp Sale $46	Co-fire $45	Co-fire $41	Co-fire $39	Co-fire $38	Co-fire $37	Co-fire $37	Co-fire $36
70,000	Pulp Sale $46	Co-fire $44	Co-fire $40	Co-fire $38	Co-fire $37	Co-fire $36	Co-fire $36	Co-fire $36
80,000	Pulp Sale $46	Co-fire $43	Co-fire $39	Co-fire $37	Co-fire $36	Co-fire $36	Co-fire $35	Co-fire $35
90,000	Pulp Sale $46	Co-fire $42	Co-fire $38	Co-fire $37	Co-fire $36	Co-fire $35	Co-fire $35	Co-fire $35
100,000	Pulp Sale $46	Co-fire $41	Co-fire $38	Co-fire $36	Co-fire $35	Co-fire $35	Co-fire $34	Co-fire $34

Base technology case, 300 km transportation distance

Duration	1	3	5	7	9	11	13	15
10,000	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale
	$51	$51	$51	$51	$51	$51	$51	$51
20,000	Pulp Sale	Pulp Sale	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$51	$51	$51	$51	$49	$48	$47	$47
30,000	Pulp Sale	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$50	$50	$50	$48	$46	$45	$45	$44
40,000	Pulp Sale	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$51	$51	$48	$46	$44	$44	$43	$43
50,000	Pulp Sale	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$50	$50	$46	$44	$43	$43	$42	$42
60,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$50	$50	$45	$43	$42	$42	$41	$41
70,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$50	$48	$44	$43	$42	$41	$41	$40
80,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$50	$48	$44	$42	$41	$40	$40	$40
90,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$50	$47	$43	$41	$40	$40	$40	$39
100,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$50	$46	$42	$41	$40	$40	$39	$39

Base technology case, 400 km transportation distance

Duration	1	3	5	7	9	11	13	15
10,000	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale
	$55	$55	$55	$55	$55	$55	$55	$55
20,000	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$55	$55	$55	$54	$53	$52	$52
30,000	Pulp Sale	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$55	$55	$52	$51	$50	$50	$49
40,000	Pulp Sale	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$55	$53	$50	$49	$48	$48	$48
50,000	Pulp Sale	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$55	$51	$49	$48	$47	$47	$47
60,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$54	$50	$48	$47	$46	$46	$46
70,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$53	$49	$47	$46	$46	$45	$45
80,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$52	$48	$47	$46	$45	$45	$44
90,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$52	$48	$46	$45	$45	$44	$44
100,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$51	$47	$46	$45	$44	$44	$44

Base technology case, 500 km transportation distance

Duration	1	3	5	7	9	11	13	15
10,000	Pulp Sale	Pulp Sale	Pellet	Pellet	Pellet	Pellet	Pellet	Pellet
			Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$75	$75	$75	$72	$71	$70	$69	$69
20,000	Pulp Sale	Pellet	Pellet	Pellet	Pellet	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis
		Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$75	$71	$70	$67	$66	$64	$63	$62
30,000	Pellet	Pellet	Pellet	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis
	Relocatable	Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary
	$71	$66	$65	$65	$62	$60	$59	$58
40,000	Pulp Sale	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis
		Relocatable	Relocatable	Relocatable	Relocatable	Stationary	Stationary	Stationary
	$75	$62	$61	$60	$59	$58	$57	$56
50,000	Pellet	Pellet	Pellet	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis
	Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$72	$68	$64	$60	$58	$57	$56	$55
60,000	Pellet	Pellet	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis
	Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$71	$66	$63	$59	$57	$56	$55	$54
70,000	Pellet	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis
	Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$70	$65	$62	$58	$56	$55	$54	$53
80,000	Pellet	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Methanol Synthesis
	Relocatable	Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary
	$72	$62	$60	$57	$55	$54	$53	$52
90,000	Pellet	Pellet	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Methanol Synthesis
	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$71	$65	$60	$57	$55	$53	$53	$51
100,000	Pellet	Pellet	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Methanol Synthesis	Methanol Synthesis
	Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$70	$65	$59	$56	$54	$53	$51	$49

Base technology case, 600 km transportation distance

Duration	1	3	5	7	9	11	13	15
10,000	Disposal	Disposal	Disposal	Disposal	Disposal	Pellet	Pellet	Fast Pyrolysis
						Stationary	Stationary	Stationary
	$79	$79	$79	$79	$79	$78	$78	$77
20,000	Disposal	Disposal	Pellet	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis
			Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$79	$79	$78	$75	$72	$70	$69	$68
30,000	Disposal	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis
		Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary
	$79	$74	$72	$71	$68	$66	$65	$64
40,000	Disposal	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis
		Relocatable	Relocatable	Relocatable	Relocatable	Stationary	Stationary	Stationary
	$79	$68	$66	$66	$65	$64	$63	$62
50,000	Disposal	Pellet	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis
		Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$79	$76	$71	$66	$64	$62	$61	$61
60,000	Disposal	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis
		Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$79	$74	$69	$65	$63	$61	$60	$60
70,000	Pellet	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Methanol Synthesis
	Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$78	$70	$68	$64	$62	$61	$60	$58
80,000	Disposal	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Methanol Synthesis	Methanol Synthesis
		Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary
	$79	$68	$66	$63	$61	$60	$58	$56
90,000	Disposal	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Methanol Synthesis	Methanol Synthesis	Methanol Synthesis
		Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$79	$74	$66	$62	$60	$59	$56	$54
100,000	Pellet	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Methanol Synthesis	Methanol Synthesis	Methanol Synthesis
	Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$78	$71	$65	$62	$60	$57	$55	$53

Base technology case, 700 km transportation distance

Duration	1	3	5	7	9	11	13	15
10,000	Disposal	Disposal	Disposal	Disposal	Disposal	Disposal	Disposal	Disposal
	$79	$79	$79	$79	$79	$79	$79	$79
20,000	Disposal	Disposal	Disposal	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis
				Stationary	Stationary	Stationary	Stationary	Stationary
	$79	$79	$79	$77	$74	$72	$71	$70
30,000	Disposal	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis
		Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary
	$79	$76	$74	$73	$70	$68	$67	$66
40,000	Disposal	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis
		Relocatable	Relocatable	Relocatable	Relocatable	Stationary	Stationary	Stationary
	$79	$70	$68	$68	$67	$66	$65	$64
50,000	Disposal	Disposal	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis
			Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$79	$79	$73	$68	$66	$65	$64	$63
60,000	Disposal	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Methanol Synthesis
		Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$79	$76	$71	$67	$65	$64	$63	$62
70,000	Disposal	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Methanol Synthesis	Methanol Synthesis
		Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$79	$72	$70	$66	$64	$63	$61	$59
80,000	Disposal	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Methanol Synthesis	Methanol Synthesis
		Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary
	$79	$70	$68	$65	$63	$62	$59	$57
90,000	Disposal	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Methanol Synthesis	Methanol Synthesis	Methanol Synthesis
		Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$79	$76	$68	$65	$63	$60	$57	$55
100,000	Disposal	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Fast Pyrolysis	Methanol Synthesis	Methanol Synthesis	Methanol Synthesis
		Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$79	$73	$67	$64	$62	$59	$56	$54

Advanced technology case, 100 km transportation distance

Duration	1	3	5	7	9	11	13	15
10,000	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43
20,000	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Co-fire $41	Co-fire $40	Co-fire $39	Co-fire $38	Co-fire $38
30,000	Pulp Sale $42	Pulp Sale $42	Co-fire $41	Co-fire $38	Co-fire $37	Co-fire $36	Co-fire $36	Co-fire $35
40,000	Pulp Sale $42	Pulp Sale $42	Co-fire $39	Co-fire $36	Co-fire $35	Co-fire $35	Co-fire $34	Co-fire $34
50,000	Pulp Sale $42	Co-fire $42	Co-fire $37	Co-fire $35	Co-fire $34	Co-fire $33	Co-fire $33	Co-fire $33
60,000	Pulp Sale $42	Co-fire $40	Co-fire $36	Co-fire $34	Co-fire $33	Co-fire $33	Co-fire $32	Co-fire $32
70,000	Pulp Sale $42	Co-fire $39	Co-fire $35	Co-fire $33	Co-fire $32	Co-fire $32	Co-fire $31	Co-fire $31
80,000	Pulp Sale $42	Co-fire $38	Co-fire $34	Co-fire $33	Co-fire $32	Co-fire $31	Co-fire $31	Co-fire $31
90,000	Pulp Sale $42	Co-fire $38	Co-fire $34	Co-fire $32	Co-fire $31	Co-fire $31	Co-fire $30	Co-fire $30
100,000	Pulp Sale $42	Co-fire $37	Co-fire $33	Co-fire $32	Co-fire $31	Co-fire $30	Co-fire $30	Co-fire $30

Advanced technology case, 200 km transportation distance

Duration	1	3	5	7	9	11	13	15
10,000	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale
	$47	$47	$47	$47	$47	$47	$47	$47
20,000	Pulp Sale	Pulp Sale	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$47	$47	$47	$46	$44	$44	$43	$42
30,000	Pulp Sale	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$46	$46	$45	$43	$42	$41	$40	$40
40,000	Pulp Sale	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$46	$46	$43	$41	$40	$39	$39	$38
50,000	Pulp Sale	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$46	$46	$42	$40	$39	$38	$37	$37
60,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$46	$45	$41	$39	$38	$37	$37	$36
70,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$46	$44	$40	$38	$37	$36	$36	$36
80,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$46	$43	$39	$37	$36	$36	$35	$35
90,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$46	$42	$38	$37	$36	$35	$35	$35
100,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$46	$41	$38	$36	$35	$35	$34	$34

Advanced technology case, 300 km transportation distance

Duration	1	3	5	7	9	11	13	15
10,000	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51
20,000	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Co-fire $51	Co-fire $49	Co-fire $48	Co-fire $47	Co-fire $47
30,000	Pulp Sale $50	Pulp Sale $50	Co-fire $50	Co-fire $48	Co-fire $46	Co-fire $45	Co-fire $45	Co-fire $44
40,000	Pulp Sale $51	Pulp Sale $51	Co-fire $48	Co-fire $46	Co-fire $44	Co-fire $44	Co-fire $43	Co-fire $43
50,000	Pulp Sale $50	Pulp Sale $50	Co-fire $46	Co-fire $44	Co-fire $43	Co-fire $43	Co-fire $42	Co-fire $42
60,000	Pulp Sale $50	Co-fire $50	Co-fire $45	Co-fire $43	Co-fire $42	Co-fire $42	Co-fire $41	Co-fire $41
70,000	Pulp Sale $50	Co-fire $48	Co-fire $44	Co-fire $43	Co-fire $42	Co-fire $41	Co-fire $41	Co-fire $40
80,000	Pulp Sale $50	Co-fire $48	Co-fire $44	Co-fire $42	Co-fire $41	Co-fire $40	Co-fire $40	Co-fire $40
90,000	Pulp Sale $50	Co-fire $47	Co-fire $43	Co-fire $41	Co-fire $40	Co-fire $40	Co-fire $40	Co-fire $39
100,000	Pulp Sale $50	Co-fire $46	Co-fire $42	Co-fire $41	Co-fire $40	Co-fire $40	Co-fire $39	Co-fire $39

Advanced technology case, 400 km transportation distance

Duration	1	3	5	7	9	11	13	15
10,000	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale
	$55	$55	$55	$55	$55	$55	$55	$55
20,000	Pulp Sale	Pulp Sale	Pulp Sale	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$55	$55	$55	$54	$53	$52	$52
30,000	Pulp Sale	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$55	$55	$52	$51	$50	$50	$49
40,000	Pulp Sale	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
		Relocatable	Relocatable					
	$55	$54	$52	$50	$49	$48	$48	$48
50,000	Pulp Sale	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$55	$51	$49	$48	$47	$47	$47
60,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$54	$50	$48	$47	$46	$46	$46
70,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$53	$49	$47	$46	$46	$45	$45
80,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$52	$48	$47	$46	$45	$45	$44
90,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$52	$48	$46	$45	$45	$44	$44
100,000	Pulp Sale	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire	Co-fire
	$55	$51	$47	$46	$45	$44	$44	$44

Advanced technology case, 500 km transportation distance

Duration	1	3	5	7	9	11	13	15
10,000	Pulp Sale	Pulp Sale	Pelletization	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis
			Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$75	$75	$75	$72	$68	$66	$65	$64
20,000	Pulp Sale	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis
		Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$75	$70	$66	$61	$59	$57	$56	$55
30,000	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis
	Relocatable	Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary
	$68	$60	$58	$57	$55	$53	$52	$52
40,000	Pulp Sale	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis
		Relocatable	Relocatable	Relocatable	Relocatable	Stationary	Stationary	Stationary
	$75	$55	$54	$53	$53	$52	$51	$50
50,000	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis
	Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$72	$63	$57	$53	$51	$50	$49	$49
60,000	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis
	Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$68	$60	$56	$52	$51	$50	$49	$48
70,000	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis
	Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$65	$57	$55	$51	$50	$49	$48	$47
80,000	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis
	Relocatable	Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary
	$71	$55	$53	$51	$49	$48	$47	$47
90,000	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis
	Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$68	$59	$53	$50	$49	$48	$47	$46
100,000	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis	Advanced Fast Pyrolysis
	Relocatable	Relocatable	Stationary	Stationary	Stationary	Stationary	Stationary	Stationary
	$66	$57	$53	$50	$48	$47	$46	$46

Advanced technology case, 600 km transportation distance

Duration	1	3	5	7	9	11	13	15
10,000	Disposal $79	Disposal $79	Disposal $79	Advanced Fast Pyrolysis Stationary $78	Advanced Fast Pyrolysis Stationary $74	Advanced Fast Pyrolysis Stationary $72	Advanced Fast Pyrolysis Stationary $70	Advanced Fast Pyrolysis Stationary $69
20,000	Disposal $79	Advanced Fast Pyrolysis Relocatable $75	Advanced Fast Pyrolysis Stationary $72	Advanced Fast Pyrolysis Stationary $67	Advanced Fast Pyrolysis Stationary $65	Advanced Fast Pyrolysis Stationary $63	Advanced Fast Pyrolysis Stationary $62	Advanced Fast Pyrolysis Stationary $61
30,000	Advanced Fast Pyrolysis Relocatable $74	Advanced Fast Pyrolysis Relocatable $66	Advanced Fast Pyrolysis Relocatable $64	Advanced Fast Pyrolysis Stationary $63	Advanced Fast Pyrolysis Stationary $61	Advanced Fast Pyrolysis Stationary $59	Advanced Fast Pyrolysis Stationary $58	Advanced Fast Pyrolysis Stationary $58
40,000	Disposal $79	Advanced Fast Pyrolysis Relocatable $61	Advanced Fast Pyrolysis Relocatable $59	Advanced Fast Pyrolysis Relocatable $59	Advanced Fast Pyrolysis Relocatable $58	Advanced Fast Pyrolysis Stationary $57	Advanced Fast Pyrolysis Stationary $57	Advanced Fast Pyrolysis Stationary $56
50,000	Advanced Fast Pyrolysis Relocatable $78	Advanced Fast Pyrolysis Relocatable $69	Advanced Fast Pyrolysis Stationary $63	Advanced Fast Pyrolysis Stationary $59	Advanced Fast Pyrolysis Stationary $57	Advanced Fast Pyrolysis Stationary $56	Advanced Fast Pyrolysis Stationary $55	Advanced Fast Pyrolysis Stationary $55
60,000	Advanced Fast Pyrolysis Relocatable $74	Advanced Fast Pyrolysis Relocatable $65	Advanced Fast Pyrolysis Stationary $62	Advanced Fast Pyrolysis Stationary $58	Advanced Fast Pyrolysis Stationary $56	Advanced Fast Pyrolysis Stationary $55	Advanced Fast Pyrolysis Stationary $54	Advanced Fast Pyrolysis Stationary $54
70,000	Advanced Fast Pyrolysis Relocatable $71	Advanced Fast Pyrolysis Relocatable $63	Advanced Fast Pyrolysis Stationary $60	Advanced Fast Pyrolysis Stationary $57	Advanced Fast Pyrolysis Stationary $56	Advanced Fast Pyrolysis Stationary $54	Advanced Fast Pyrolysis Stationary $54	Advanced Fast Pyrolysis Stationary $53
80,000	Advanced Fast Pyrolysis Relocatable $76	Advanced Fast Pyrolysis Relocatable $61	Advanced Fast Pyrolysis Relocatable $59	Advanced Fast Pyrolysis Stationary $57	Advanced Fast Pyrolysis Stationary $55	Advanced Fast Pyrolysis Stationary $54	Advanced Fast Pyrolysis Stationary $53	Advanced Fast Pyrolysis Stationary $53
90,000	Advanced Fast Pyrolysis Relocatable $74	Advanced Fast Pyrolysis Relocatable $65	Advanced Fast Pyrolysis Stationary $59	Advanced Fast Pyrolysis Stationary $56	Advanced Fast Pyrolysis Stationary $54	Advanced Fast Pyrolysis Stationary $53	Advanced Fast Pyrolysis Stationary $53	Advanced Methanol Synthesis Stationary $52
100,000	Advanced Fast Pyrolysis Relocatable $72	Advanced Fast Pyrolysis Relocatable $63	Advanced Fast Pyrolysis Stationary $58	Advanced Fast Pyrolysis Stationary $55	Advanced Fast Pyrolysis Stationary $54	Advanced Fast Pyrolysis Stationary $53	Advanced Fast Pyrolysis Stationary $52	Advanced Methanol Synthesis Stationary $51

Advanced technology case, 700 km transportation distance

Duration	1	3	5	7	9	11	13	15
10,000	Disposal $79	Disposal $79	Disposal $79	Disposal $79	Advanced Fast Pyrolysis Stationary $77	Advanced Fast Pyrolysis Stationary $74	Advanced Fast Pyrolysis Stationary $73	Advanced Fast Pyrolysis Stationary $72
20,000	Disposal $79	Advanced Fast Pyrolysis Relocatable $77	Advanced Fast Pyrolysis Stationary $74	Advanced Fast Pyrolysis Stationary $69	Advanced Fast Pyrolysis Stationary $67	Advanced Fast Pyrolysis Stationary $65	Advanced Fast Pyrolysis Stationary $64	Advanced Fast Pyrolysis Stationary $63
30,000	Advanced Fast Pyrolysis Relocatable $76	Advanced Fast Pyrolysis Relocatable $68	Advanced Fast Pyrolysis Relocatable $66	Advanced Fast Pyrolysis Stationary $65	Advanced Fast Pyrolysis Stationary $63	Advanced Fast Pyrolysis Stationary $61	Advanced Fast Pyrolysis Stationary $60	Advanced Fast Pyrolysis Stationary $60
40,000	Disposal $79	Advanced Fast Pyrolysis Relocatable $63	Advanced Fast Pyrolysis Relocatable $61	Advanced Fast Pyrolysis Relocatable $61	Advanced Fast Pyrolysis Relocatable $61	Advanced Fast Pyrolysis Stationary $60	Advanced Fast Pyrolysis Stationary $59	Advanced Fast Pyrolysis Stationary $58
50,000	Disposal $79	Advanced Fast Pyrolysis Relocatable $71	Advanced Fast Pyrolysis Stationary $65	Advanced Fast Pyrolysis Stationary $61	Advanced Fast Pyrolysis Stationary $59	Advanced Fast Pyrolysis Stationary $58	Advanced Fast Pyrolysis Stationary $57	Advanced Fast Pyrolysis Stationary $57
60,000	Advanced Fast Pyrolysis Relocatable $76	Advanced Fast Pyrolysis Relocatable $68	Advanced Fast Pyrolysis Stationary $64	Advanced Fast Pyrolysis Stationary $60	Advanced Fast Pyrolysis Stationary $59	Advanced Fast Pyrolysis Stationary $57	Advanced Fast Pyrolysis Stationary $57	Advanced Fast Pyrolysis Stationary $56
70,000	Advanced Fast Pyrolysis Relocatable $73	Advanced Fast Pyrolysis Relocatable $65	Advanced Fast Pyrolysis Stationary $63	Advanced Fast Pyrolysis Stationary $59	Advanced Fast Pyrolysis Stationary $58	Advanced Fast Pyrolysis Stationary $57	Advanced Fast Pyrolysis Stationary $56	Advanced Fast Pyrolysis Stationary $55
80,000	Advanced Fast Pyrolysis Relocatable $78	Advanced Fast Pyrolysis Relocatable $63	Advanced Fast Pyrolysis Relocatable $61	Advanced Fast Pyrolysis Stationary $59	Advanced Fast Pyrolysis Stationary $57	Advanced Fast Pyrolysis Stationary $56	Advanced Fast Pyrolysis Stationary $55	Advanced Fast Pyrolysis Stationary $55
90,000	Advanced Fast Pyrolysis Relocatable $76	Advanced Fast Pyrolysis Relocatable $67	Advanced Fast Pyrolysis Stationary $61	Advanced Fast Pyrolysis Stationary $58	Advanced Fast Pyrolysis Stationary $56	Advanced Fast Pyrolysis Stationary $55	Advanced Fast Pyrolysis Stationary $55	Advanced Methanol Synthesis Stationary $53
100,000	Advanced Fast Pyrolysis Relocatable $74	Advanced Fast Pyrolysis Relocatable $65	Advanced Fast Pyrolysis Stationary $60	Advanced Fast Pyrolysis Stationary $58	Advanced Fast Pyrolysis Stationary $56	Advanced Fast Pyrolysis Stationary $55	Advanced Methanol Synthesis Stationary $54	Advanced Methanol Synthesis Stationary $52

Advanced technology case, 100 km transportation distance, No co-fire

Duration	1	3	5	7	9	11	13	15
10,000	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43
20,000	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43	Pulp Sale $43
30,000	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42
40,000	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42
50,000	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42
60,000	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42
70,000	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Advanced Fast Pyrolysis Stationary $42
80,000	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Advanced Fast Pyrolysis Stationary $42	Advanced Fast Pyrolysis Stationary $41
90,000	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Advanced Fast Pyrolysis Stationary $41	Advanced Fast Pyrolysis Stationary $41
100,000	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Pulp Sale $42	Advanced Fast Pyrolysis Stationary $42	Advanced Fast Pyrolysis Stationary $41	Advanced Fast Pyrolysis Stationary $41

Advanced technology case, 200 km transportation distance, No co-fire

Duration	1	3	5	7	9	11	13	15
10,000	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47
20,000	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47	Pulp Sale $47
30,000	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46
40,000	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Advanced Fast Pyrolysis Stationary $46
50,000	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Advanced Fast Pyrolysis Stationary $45	Advanced Fast Pyrolysis Stationary $45
60,000	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Advanced Fast Pyrolysis Stationary $45	Advanced Fast Pyrolysis Stationary $45	Advanced Fast Pyrolysis Stationary $44
70,000	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Advanced Fast Pyrolysis Stationary $46	Advanced Fast Pyrolysis Stationary $45	Advanced Fast Pyrolysis Stationary $44	Advanced Fast Pyrolysis Stationary $43
80,000	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Advanced Fast Pyrolysis Stationary $45	Advanced Fast Pyrolysis Stationary $44	Advanced Fast Pyrolysis Stationary $43	Advanced Fast Pyrolysis Stationary $43
90,000	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Advanced Fast Pyrolysis Stationary $44	Advanced Fast Pyrolysis Stationary $43	Advanced Fast Pyrolysis Stationary $43	Advanced Fast Pyrolysis Stationary $42
100,000	Pulp Sale $46	Pulp Sale $46	Pulp Sale $46	Advanced Fast Pyrolysis Stationary $46	Advanced Fast Pyrolysis Stationary $44	Advanced Fast Pyrolysis Stationary $43	Advanced Fast Pyrolysis Stationary $42	Advanced Fast Pyrolysis Stationary $42

Advanced technology case, 300 km transportation distance, No co-fire

Duration	1	3	5	7	9	11	13	15
10,000	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51
20,000	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51
30,000	Pulp Sale $50	Pulp Sale $50	Pulp Sale $50	Pulp Sale $50	Pulp Sale $50	Pulp Sale $50	Advanced Fast Pyrolysis Stationary $50	Advanced Fast Pyrolysis Stationary $49
40,000	Pulp Sale $51	Pulp Sale $51	Pulp Sale $51	Advanced Fast Pyrolysis Relocatable $50	Advanced Fast Pyrolysis Relocatable $50	Advanced Fast Pyrolysis Stationary $49	Advanced Fast Pyrolysis Stationary $48	Advanced Fast Pyrolysis Stationary $47
50,000	Pulp Sale $50	Pulp Sale $50	Pulp Sale $50	Pulp Sale $50	Advanced Fast Pyrolysis Stationary $49	Advanced Fast Pyrolysis Stationary $47	Advanced Fast Pyrolysis Stationary $47	Advanced Fast Pyrolysis Stationary $46
60,000	Pulp Sale $50	Pulp Sale $50	Pulp Sale $50	Advanced Fast Pyrolysis Stationary $50	Advanced Fast Pyrolysis Stationary $48	Advanced Fast Pyrolysis Stationary $47	Advanced Fast Pyrolysis Stationary $46	Advanced Fast Pyrolysis Stationary $45
70,000	Pulp Sale $50	Pulp Sale $50	Pulp Sale $50	Advanced Fast Pyrolysis Stationary $49	Advanced Fast Pyrolysis Stationary $47	Advanced Fast Pyrolysis Stationary $46	Advanced Fast Pyrolysis Stationary $45	Advanced Fast Pyrolysis Stationary $45
80,000	Pulp Sale $50	Pulp Sale $50	Pulp Sale $50	Advanced Fast Pyrolysis Stationary $48	Advanced Fast Pyrolysis Stationary $46	Advanced Fast Pyrolysis Stationary $45	Advanced Fast Pyrolysis Stationary $45	Advanced Fast Pyrolysis Stationary $44
90,000	Pulp Sale $50	Pulp Sale $50	Pulp Sale $50	Advanced Fast Pyrolysis Stationary $47	Advanced Fast Pyrolysis Stationary $46	Advanced Fast Pyrolysis Stationary $45	Advanced Fast Pyrolysis Stationary $44	Advanced Fast Pyrolysis Stationary $44
100,000	Pulp Sale $50	Pulp Sale $50	Advanced Fast Pyrolysis Stationary $50	Advanced Fast Pyrolysis Stationary $47	Advanced Fast Pyrolysis Stationary $45	Advanced Fast Pyrolysis Stationary $44	Advanced Fast Pyrolysis Stationary $44	Advanced Fast Pyrolysis Stationary $43

Advanced technology case, 400 km transportation distance, No co-fire

Duration	1	3	5	7	9	11	13	15
10,000	Pulp Sale $55	Pulp Sale $55	Pulp Sale $55	Pulp Sale $55	Pulp Sale $55	Pulp Sale $55	Pulp Sale $55	Pulp Sale $55
20,000	Pulp Sale $55	Pulp Sale $55	Pulp Sale $55	Pulp Sale $55	Pulp Sale $55	Pulp Sale $55	Advanced Fast Pyrolysis Stationary $55	Advanced Fast Pyrolysis Stationary $54
30,000	Pulp Sale $55	Pulp Sale $55	Pulp Sale $55	Pulp Sale $55	Advanced Fast Pyrolysis Stationary $53	Advanced Fast Pyrolysis Stationary $52	Advanced Fast Pyrolysis Stationary $51	Advanced Fast Pyrolysis Stationary $50
40,000	Pulp Sale $55	Advanced Fast Pyrolysis Relocatable $54	Advanced Fast Pyrolysis Relocatable $52	Advanced Fast Pyrolysis Relocatable $52	Advanced Fast Pyrolysis Relocatable $51	Advanced Fast Pyrolysis Stationary $50	Advanced Fast Pyrolysis Stationary $49	Advanced Fast Pyrolysis Stationary $49
50,000	Pulp Sale $55	Pulp Sale $55	Pulp Sale $55	Advanced Fast Pyrolysis Stationary $52	Advanced Fast Pyrolysis Stationary $50	Advanced Fast Pyrolysis Stationary $49	Advanced Fast Pyrolysis Stationary $48	Advanced Fast Pyrolysis Stationary $48
60,000	Pulp Sale $55	Pulp Sale $55	Advanced Fast Pyrolysis Stationary $54	Advanced Fast Pyrolysis Stationary $51	Advanced Fast Pyrolysis Stationary $49	Advanced Fast Pyrolysis Stationary $48	Advanced Fast Pyrolysis Stationary $47	Advanced Fast Pyrolysis Stationary $47
70,000	Pulp Sale $55	Pulp Sale $55	Advanced Fast Pyrolysis Stationary $53	Advanced Fast Pyrolysis Stationary $50	Advanced Fast Pyrolysis Stationary $48	Advanced Fast Pyrolysis Stationary $47	Advanced Fast Pyrolysis Stationary $47	Advanced Fast Pyrolysis Stationary $46
80,000	Pulp Sale $55	Advanced Fast Pyrolysis Relocatable $53	Advanced Fast Pyrolysis Relocatable $52	Advanced Fast Pyrolysis Stationary $49	Advanced Fast Pyrolysis Stationary $48	Advanced Fast Pyrolysis Stationary $47	Advanced Fast Pyrolysis Stationary $46	Advanced Fast Pyrolysis Stationary $46
90,000	Pulp Sale $55	Pulp Sale $55	Advanced Fast Pyrolysis Stationary $52	Advanced Fast Pyrolysis Stationary $49	Advanced Fast Pyrolysis Stationary $47	Advanced Fast Pyrolysis Stationary $46	Advanced Fast Pyrolysis Stationary $46	Advanced Fast Pyrolysis Stationary $45
100,000	Pulp Sale $55	Pulp Sale $55	Advanced Fast Pyrolysis Stationary $51	Advanced Fast Pyrolysis Stationary $48	Advanced Fast Pyrolysis Stationary $47	Advanced Fast Pyrolysis Stationary $46	Advanced Fast Pyrolysis Stationary $45	Advanced Fast Pyrolysis Stationary $45