1995 U.S. EPA Symposium on Greenhouse Gas Emissions and Mitigation Research
Washington, DC, 27-29 June 1995

COST VERSUS SCALE FOR ADVANCED PLANTATION-BASED BIOMASS ENERGY SYSTEMS IN THE U.S.

Christopher I. Marrison* and Eric D. Larson
Center for Energy and Environmental Studies
School of Engineering and Applied Science
Princeton University, Princeton, NJ 08544

ABSTRACT

A unique feature of biomass energy systems is that the feedstock must be gathered from a wide area around the energy production facility. For a small-scale facility, transport costs will be relatively low, but capital cost per unit of output will be high. For a large-scale facility, transport costs will be high, but capital costs will be relatively low. At some intermediate scale, the total cost of energy should reach a minimum. This paper examines the effects of scale on the prospective costs of producing electricity and alcohol fuels from plantation-grown switchgrass in the North Central and Southeast regions of the US.

Site-specific biomass cost-supply curves for the year 2000 and 2020 are developed using projections of the Oak Ridge National Laboratory for switchgrass yields and costs as a function of land capability class. A geographic information system (GIS) is used to analyze soil quality distributions and road transport distances.

Conversion technologies considered include one commercial electricity generating technology--the steam rankine cycle--and one nearing commercial readiness--the gasifier/gas turbine combined cycle. Two alcohol fuels are considered: methanol via thermochemical gasification and ethanol via enzymatic hydrolysis. Both of these processes have the potential to be commercially ready early in the next century or sooner. Estimates of installed capital costs for all of these conversion systems drawn from published and other sources.

In all cases, the minimum cost of electricity (COE_{min}) or alcohol (COA_{min}) is reached at plant capacities that are larger than conventional wisdom might suggest. Up to these capacities, the rate of decrease in unit capital costs is more rapid than the rate of increase in biomass transportation costs. However, around the capacity corresponding to COE_{min} or COA_{min}, there is a wide range over which costs change very little. In general, higher biomass yields lead to larger capacities at COE_{min} or COA_{min}. Costs are higher in the NC than SE region, and (in both regions) costs are lower using year-2020 biomass costs compared to year-2000 costs.

INTRODUCTION

Biomass energy crops are of increasing interest worldwide because of the potential for using them in advanced electricity and transportation fuel production systems that promise cost-competitiveness with fossil fuel systems, while substantially reducing emissions of CO_2 to the atmosphere [Hall, et al., 1991; Turhollow and Perlack, 1991; Larson et al., 1995]. Also, in industrialized countries like the United States, economically viable bioenergy systems might help reduce government subsidies paid to farmers. Currently, the government pays farmers some $1.8 billion/year to keep erodible lands out of production under the Conservation Reserve Program (CRP). In addition, price-support payments, which many farmers need to maintain profitability,[1] were some $16.1 billion in 1993 [Flinchbaugh and Edelman, 1994]. Perennial energy crops would serve to reduce or

* Present address: Oliver, Wyman & Company, LLC, 666 Fifth Ave., New York, 10103.

[1] For example, corn farmers in Iowa received an average annual government payment of $45/acre from 1990 to 1992. During this same period, the profit per acre (gross income, including government payments, minus total economic costs) was $51 [Davis, 1994].

eliminate erosion on many CRP lands, while providing a revenue source to the farmer. With adequate, unsubsidized profitability, energy crops might help reduce the present level of price support payments.

A unique feature of biomass energy systems that is the focus of this paper is that the feedstock must be gathered from a wide area around the energy production facility. For a small-scale facility, transport costs will be relatively low, but capital cost per unit of output will be high. For a large-scale facility, transport costs will be high, but capital costs will be relatively low. At some intermediate scale, the total cost of energy should reach a minimum. This paper examines the effects of scale on the prospective costs of producing electricity and alcohol fuels from plantation-grown switchgrass in the North Central and Southeast regions of the US.

The components of the total cost of energy supply from biomass are *(1)* the cost to grow and deliver the biomass to the conversion facility and *(2)* the cost of the conversion. A number of studies have examined these two elements independently. For example, biomass cost-supply curves have been developed for some specific geographic regions by Graham and Downing [1993], Noon [1994], and English, et al. [1994], among others. A variety of studies (discussed later) have examined the capital and operating costs for biomass-to-electricity or biomass-to-fuels conversion systems. There do not appear to have been any previous efforts to marry biomass supply with biomass conversion studies, as done here, to examine the issue of energy cost versus scale.

BIOMASS COSTS

The starting point for the analysis was the selection of a specific site to provide case-study variations in soil quality and transportation distances for a typical agricultural area. A four-county area in South Central Iowa (Appanoose, Lucas, Monroe, and Wayne counties) was chosen, in large part because there is significant interest in this region in the development of biomass energy production on lands currently under CRP contracts [Cooper, 1993; Brown, 1994]. The total area is approximately 5100 km^2, over 90% of which is suitable for growing crops. Some 22% of the area is presently held under CRP contract [DNR, 1994]. Soil type [IGS, 1973] and road [USGS, 1986] maps of the region were digitized and loaded into a geographic information system (GIS). (See Marrison [1995] for details of the digitization process.)

The GIS system was used to calculate road transport distances from each acre to a central processing facility that was assumed to be located near the center of the region.[2] As detailed below, the cost of growing biomass on each acre (dependent primarily on soil type) was then calculated and added to the transport cost associated with the distance between that acre and the conversion facility. The characteristics of the Iowa site (relative soil quality and road layout) were taken to represent typical agricultural areas in the North Central (NC) region (which includes Iowa) and in the Southeast (SE) region.

Costs of Growing Biomass

Development of energy crops in the US is focussed on short-rotation woody crops for some regions and on herbaceous crops for others [Hohenstein and Wright, 1994]. Switchgrass is a primary candidate energy crop for the North Central (NC) and Southeast (SE) regions.

Switchgrass yield and cost projections made by analysts at the Oak Ridge National Laboratory [Walsh and Graham, 1995] provide the basis for biomass production costs presented here. Walsh and Graham give estimates of per-hectare yields and costs for four regions of the US (Northeast, North Central, Southeast, and South Central). They identify sub-regions by land capability class (LCC). LCC 1 has few restrictions on use for crops. LCC2 through LCC4 have variable suitability for crops, and LCC 5 through LCC 8 are generally unsuited for crop production. Within each LCC, soils are sub-defined by the primary reason for restrictions on their use as cropland: *e* -- erosion potential; *w* -- excessive water; *c* -- extreme climate; and *s* -- soil factors (salinity, shallowness, texture, etc.).

---

[2] The GIS is the MapBox package of Decision Images, Inc. of Princeton, New Jersey [Tomlin, 1990]. Transport distances for each map unit (acre) are found by locating the nearest point on the road system, and counting the distance along the road system to the conversion facility. The result is a map on which every acre has an assigned road transport distance.

For each sub-class of each LCC, Walsh and Graham estimate the area[3] and projected switchgrass yields. They also give projected plantation establishment costs (incurred in the first year), projected annual plantation maintenance costs (incurred over ensuing nine years, after which it is assumed the switchgrass would require replanting), and estimated annual land rents. Tables 1 and 2 give yield and cost estimates, respectively, for LCC2, LCC3, and LCC4 for the NC and SE regions. Areas classified as LCC1 are not shown, because they would probably not be used for energy cropping and, in any case, the total LCC1 area is relatively small--about 8% of the total area of the NC and SE regions included in the land capability classifications.

Tables 1 and 2 give two sets of yield and cost estimates--those projected to be achievable in the year 2000 and in 2020. Yields are projected to rise between 2000 and 2020 due primarily to improvements in switchgrass varieties and farm management practices. Costs per hectare are slightly higher in 2020 than in 2000 due to increased costs for fertilizer and for harvesting the higher yields. For either 2000 or 2020, projected yields are lower in the NC region than in the SE region, and per-hectare costs are generally higher (due largely to the higher land rents in the NC region).

As one check on Walsh and Graham's estimates, we examined estimates of switchgrass yields and costs made by Brown [1994], based on field experiments conducted between 1988 and 1992 in Chariton, Iowa, which lies within the four-county area selected for the case study analysis here. Soils there are less productive than in many other parts of Iowa. Brown estimates production costs based on measured test-plot yields and present local agricultural practices. In this respect, it is more reasonable to compare Brown's estimates with those of Walsh and Graham for year 2000 than for year 2020. Brown reports a measured average yield during 1988-1992 of 10.5 dry tonnes per ha/yr. Brown estimates establishment-year and subsequent annual maintenance costs to be \$270/ha and \$190/ha, respectively, excluding land rent of \$202/ha/yr.[4] By comparison, Walsh and Graham's estimates for the North Central region appear conservative.

For the selected site, the available soil map included three qualities of soil: loess, which is generally very good agricultural land; complex alluvial deposits, which is of intermediate quality for agriculture; and till-and-outcropping paleosols, which is the least desirable of the three for farming. We assumed that the yields and costs of switchgrass from these three soil types are given by area-weighted averages for LCC2, LCC3, and LCC4, respectively, as estimated by Walsh and Graham (Table 3).

Table 3 provides the inputs for calculating levelized switchgrass production costs per unit of useable biomass tonnage. The time-averaged tonnage (Table 4) accounts for an assumed zero yield in the establishment year, two-thirds of the steady-state (Table 3) yield in the next year, followed by eight years at the steady-state yield. Post harvest losses of 10% [UMinn, 1994] are also included. The levelized costs in Table 4 assume a discount rate of 6.5%, as used by Walsh and Graham [1995].

<u>Costs of Transporting Biomass</u>

The standard expression for transport costs takes the form

$$\text{Cost (in \$/tonne)} = \mathbf{A} + (\mathbf{TC}\cdot\mathbf{TD}) \tag{1}$$

where **A** is a constant fixed costs (e.g. truck loading and unloading), **TC** is the variable transport cost (\$ per tonne-km), and **TD** is the transport distance in km.

There are conflicting estimates in the literature for biomass transport costs. Some of the discrepancies arise because basic underlying assumptions are not made clear. For example, whether the distance to be used in

---

[3] Walsh and Graham include in the areas all agricultural cropland (including idled or fallow cropland), area in the conservation reserve program, and pastureland with high to medium potential for conversion to cropland. No forest land, wetlands, or urban areas are included.

[4] All costs in this paper are expressed in 1994 \$ using US GDP deflators [Council of Economic Advisors, 1995].

an equation of the form shown above is a single or round-trip distance is important. (In this paper, all distances are one-way distances: TD is the distance from the harvest site to the conversion facility.) In other cases, the moisture content of the load is not clearly specified. Typical moisture contents for transported biomass are 50% for wood chips and 10-20% for field-dried switchgrass [Miles and Miles, 1980].

Transport cost estimates have been reviewed to establish a baseline relationship for transport costs. In Eqn. 1, A and TC both affect the transport cost. However, only TC matters in determining the capacity of an energy conversion facility that minimizes the total energy production cost [Marrison, 1995], so the focus of the discussion here is on the variable cost parameter, TC. For our subsequent analysis, we use A = \$3/dry tonne and TC = \$0.18/dry tonne-km as baseline parameter values for switchgrass bales.[5]

The variable cost we assumed here is about double that of the widely cited estimate by Bhat, et al. [1992],[6] but is supported by other analyses we have reviewed. Johnson [1987] and Lee and Johnson [1988] give the variable portion of wood chip transportation costs for a variety of different vehicle types (Table 5). The final column in Table 5 are our estimates (based on their results) of the cost of transporting 15% moisture content rectangular switchgrass bales. These estimates are based on hourly truck rental rates, truck-load volume capacities, and the bulk density of switchgrass bales (Table 5). The lowest cost option is the truck with a chip van: \$0.15/t-km (at 15% moisture) or \$0.18/dry tonne-km. In another analysis, Bludau [1990] gives transport cost estimates (based on cost quotations for short-haul freight) that agree well with the low-end estimates of Johnson.[7] For 50% moisture content wood chips the cost in 1994\$ per tonne is 2.57 + (0.10·TD), where TD is in km. For 15% moisture switchgrass bales, the cost is 2.57 + (0.15·TD). On a dry basis, the cost is 3.03 + (0.18·TD). Some transport costs in addition to those cited here are reviewed by Marrison [1995].

Total Costs of Biomass Delivered to the Conversion Facility

Production and transportation costs were summed to get the total cost of biomass delivered to the conversion facility from each acre of land. Fig. 1a shows qualitatively the cost distribution. Fig. 1b shows costs against total tonnage of biomass available at that cost or less within the four-county area studied (assuming 94% of the area is used for switchgrass production, which excludes, primarily, towns and lakes).

For the NC region using yield and cost projections for 2000, biomass costs start at \$71/dry tonne, or \$3.9/GJ.[8] The maximum production within a transport distance of 32 km (the limit of the four-county area examined[9]) is 1.7 million dry tonnes/year, with a marginal cost of \$79/tonne (\$4.3/GJ) and average cost of \$77/tonne (\$4.2/GJ). For NC-2020, biomass costs start at \$55/dry tonne (\$3.0/GJ), and the maximum production is 2.4 million dry tonnes/year [marginal and average costs of \$63/tonne (\$3.4/GJ) and \$61/tonne (\$3.3/GJ)]. Biomass costs are considerably lower in the SE region. For example, using 2020 projections biomass costs start at \$32/dry tonne (\$1.7/GJ) and rise to an average cost of \$39/dry tonne (\$2.1/GJ).

---

[5] Actual transport cost per tonne of useable biomass at the conversion facility is [3 + 0.18*TD]/0.9, which accounts for 10% post-harvest losses [UMinn, 1994], all of which are assumed (conservatively) to occur during storage at the conversion site.

[6] Bhat et al [1992] indicate that for herbaceous crops, the transportation cost per truck load is \$34.08 + 0.62·*d*, where *d* is the roundtrip distance. They further indicate that one load of switchgrass is 15.5 tonnes of field-dry crops. Assuming a moisture content of 15%, Bhat's expression for the transport cost per dry tonne becomes 2.6 + 0.094·TD, where TD is the one-way haul distance in km.

[7] Bludau's estimates are given originally in 1988 German marks. We converted his estimates to 1994 US dollars using the average 1988 exchange rate and the US GDP deflator.

[8] All fuel energy contents in this paper are given on a higher heating value basis. The higher heating value for switchgrass is assumed to be 18.44 GJ per dry tonne.

[9] The area analyzed is not circular (see Fig. 1a), but the greatest transport distance was limited in the analysis to the minimum distance between the conversion facility (near the center of the four county area) and the outer border of the area. This defined a circle with a radius of about 32 km.

ENERGY CONVERSION TECHNOLOGY COSTS

Several technologies are commercially available or under development for converting plantation-biomass into electricity or transportation fuels [Larson, 1993]. For electricity production, commercial steam-rankine cycle systems are considered here (see EPRI [1992]), together with two varieties of gasifier/gas turbine combined cycles (BIG/GTCC)--one using low-pressure gasification and one using pressurized gasification [Consonni and Larson, 1994]. BIG/GTCC systems are not commercially established at present, but are likely to be commercially ready by the turn of the century. The pressurized BIG/GTCC is more efficient than the low-pressure version, but is likely to be more capital intensive below a certain capacity range. Two alcohol production systems are considered: methanol via thermochemical gasification [Williams et al., 1995] and ethanol via enzymatic hydrolysis [Wyman et al., 1993]. For methanol production, only the initial gasification step is not commercial, but biomass gasifiers are under active commercial development worldwide. Advanced designs of enzymatic hydrolysis ethanol production are undergoing pilot-scale testing and development at the unit level in the USA [Wyman et al, 1993].

The analysis here requires only overall cost and performance characteristics, so details of the technologies are not discussed. The performance and cost characteristics assumed here are probably achievable within about a decade (or sooner) with continued commercialization efforts. Still further advances in the technologies have been identified and are likely to improve performance and/or lower costs compared to those assumed here. Uncertainties in the cost estimates among the different technologies are due largely to differences in the extent of commercial development and scaleup. Cost estimates for electricity technologies (especially the steam cycle) are more certain than those for the alcohol production systems.

Capital Costs

The total installed capital cost per unit of output capacity for each technology is assumed to vary with capacity as follows:

$$UnitCost = \mathrm{C} + \mathrm{D}\cdot(Capacity)^{\mathrm{E}} \tag{2}$$

where C, D, and E are constants for a given technology, values for which can be determined from available cost projections. For electricity generation, *UnitCost* is given in $\$/\mathrm{kW_e}$. For methanol and ethanol production, *UnitCost* is in $\$/(\mathrm{MJ/hr})_{\mathrm{output}}$. For all technologies considered, E is a negative number (unit cost falls with increasing capacity), and thus C corresponds to the unit cost for a very large facility. If the costs for two facilities with different capacities are available, values for two of the three coefficients in Eqn. 2 can be determined, once a value for the third coefficient is established.[10] Table 6 summarizes all of the capital cost information used to establish the parameter values for Eqn. 2. The notes to Table 6 provide details as to sources of the estimates.

For the electricity producing technologies, the capital costs for the "large" capacity systems (which establish the values for C) are our estimates based on several considerations. For the steam-rankine cycle, C ($1200/kW) is based on an extrapolation to 100 MW of a cost versus capacity relationship given by EPRI [1992]. Also, $1200/kW is 10 to 15% less than the cost given by EPRI [1993] for the least costly 300-MW coal-fired power plant with flue gas desulfurization. (FGD would not be needed with biomass.) For the biomass-gasifier/gas turbine (BIG/GT) systems, the values of C ($1200/kW for low-pressure BIG/GT and $1100/kW for pressurized BIG/GT) were set to force a cross-over in total electricity production costs between the systems in the 50 to 80 $\mathrm{MW_e}$ capacity range. Blackadder, et al. [1994] give a detailed analysis suggesting this cross-over range.

For the methanol and ethanol production facilities, the unit cost at the "large" capacity was set to achieve a value of E of -0.3, a typical scaling factor for total plant costs for many chemical processes [Holland

---

[10] For example, if a value for C is established, then $\mathrm{D} = (UnitCost_1 - \mathrm{C})/Capacity_1^{\mathrm{E}}$, where $\mathrm{E} = \{\log([UnitCost_1 - \mathrm{C}]/[UnitCost_2 - \mathrm{C}])\}/\{\log(Capacity_1/Capacity_2)\}$.

et al., 1985]. Two sets of cost estimates each for methanol and ethanol are given in Table 6. The set of estimates shown for only single-capacity methanol or ethanol plants were assumed to best represent likely future costs. The "earlier design" estimates (also shown in Table 6) were used, together with the selected value of E, to establish parameter values for Eqn. 2 (see Table 6, note *(i)*).

The capital cost-capacity relationships for electricity and for alcohol production are plotted in Fig. 2. These relationships can be considered most accurate for the capacity ranges shown in Table 6 (e.g. between 10 and 50 MW_e for the steam-rankine power plant technology).

To convert capital costs to annualized costs, capital charge rates (CCRs) of 0.101 for electricity and 0.151 for alcohol production plants are assumed. The electricity CCR assumes utility financing for renewable energy power plants, a 30-year life, 6.2% real pre-tax discount rate, and 38% income tax [EPRI, 1993]. For alcohol production, the CCR is based on average financial parameters for major US corporations between 1984 and 1988.[11]

Feedstock Costs and Operating and Maintenance Costs

Fuel/feedstock costs are determined by the efficiencies of the conversion systems. For simplicity, efficiencies are considered to be fixed with capacity for all except one technology (Table 6). Because the steam-rankine technology is commercial today, its efficiency at different capacities is well established, and an equation having the same form as Eqn. 2 was fitted to available performance estimates for use here.[12] For simplicity, operating and maintenance (O&M) costs per unit of output are also assumed fixed regardless of scale for each technology (Table 6).

TOTAL COST OF ELECTRICITY AND ALCOHOL FUELS VERSUS PLANT CAPACITY

The total levelized cost per unit of output (kWh for electricity and GJ for alcohol) can now be calculated by combining the cost of the feedstock with the capital charge and O&M charges. The levelized cost of electricity (COE) in \$/kWh is:

$$COE = (C_b \cdot 3.6)/(18.44 \cdot \eta_e \cdot 1000) + \mathit{UnitCost} \cdot CCR/(8766 \cdot CF) + OM \quad (3)$$

where C_b is the average delivered cost of biomass in \$/dry tonne (from Fig. 1b), 18.44 GJ/dry tonne is the higher heating value of switchgrass, η_e is the electricity generating efficiency (Table 6 for BIG/GT systems and footnote 12 for steam-rankine systems), *UnitCost* is the installed capital cost in \$/kW (from Fig. 2), CCR is the capital charge rate (0.101), 8766 is the average number of hours in a year, CF is the capacity factor (assumed to be 0.75), and OM is the O&M cost (Table 6). The levelized cost of alcohol (COA) in \$/GJ is:

$$COA = (C_b/18.44)/(\eta_a) + \mathit{UnitCost} \cdot CCR \cdot 1000/(8766 \cdot CF) + OM \quad (4)$$

where elements on the righthand side are defined as for Eqn. 3, except that η_a is the efficiency of alcohol production (Table 6), *UnitCost* is the installed capital cost in \$/MJ/hr (Fig. 2), CCR is 0.151, and CF is assumed to be 0.90.

Electricity Production Costs

Calculated baseline results for the COE versus scale for both the NC and SE regions are shown in Fig.

---

[11] Average financial parameters for major US corporations during 1984-1988 were 9.91% real return on equity, 6.2% real return on debt, 30% debt fraction, and 44% corporate income tax. The CCR also assumes a 25-year plant life and property tax plus insurance of 1.5% per year of the initial capital cost.

[12] For the steam-rankine cycle, η_e (%) = $100 \cdot [0.27 - 0.25 \cdot (MW_e)^{-0.56}]$, which assumes 20% efficiency at 10 MW_e [EPRI, 1992] and 27% efficiency at "large" scale (100 MW_e wet wood chip combustion) [EPRI, 1993].

3a (year 2000) and Fig. 3b (year-2020) for all three electricity technologies. For small capacities, falling unit capital costs with scale for the conversion systems more than offset increasing biomass costs that arise from increased transportation costs. The total COE reaches a minimum (COE_{min}) at the capacity at which the rate of decrease in unit capital cost equals the rate of increase in the transport costs. At capacities larger than this, there is a very gradual rise in the COE as the transport costs become increasingly more important.

For a given technology, the considerably lower biomass costs projected for 2020 compared to 2000 or for the SE compared to the NC region, lead to considerably lower COE_{min} in 2020 compared to 2000 and in the SE compared to the NC region, as well as higher installed capacities at which COE_{min} are reached (Table 7).

In all cases, the capacity at which the COE_{min} is achieved is relatively large (e.g. up to 500 MW_e for the steam rankine cycle). However, because of the flatness of the COE curves around their minima, COE_{min} is closely approached at much smaller capacities: the capacity at which the COE is within 1% (5%) of COE_{min} is about half (one-quarter) of the capacity at COE_{min} (Table 7).

For the steam-rankine cycle, the capacities for being within 5% of the minimum COE (86-111 MW_e) are larger than existing biomass-fired steam-rankine power plants. Most such plants rely on low-cost biomass (e.g. byproducts of industrial processing), and their scales are set by the availability of feedstock, rather than by the economics of scale.

The COE_{min} with BIG/GTCC cycles are approached at much smaller capacities than with the steam-rankine cycles (COEs within 5% of COE_{min} at 27-91 MW_e--Table 7), because most of the scale economy gains in capital cost occur at smaller capacities (Fig. 2).

At any scale, the higher efficiency (and lower capital costs) of the BIG/GT systems make them a significantly less costly source of electricity than steam-rankine cycles. With the costs in Table 7, BIG/GTs would be competitive with power from new coal-fired plants: coal-based electricity in 2000 and in 2020 is projected to cost $0.049/kWh and $0.052/kWh, respectively, in the NC region and $0.047/kWh and $0.049/kWh, respectively, in the SE region.[13] BIG/GTCC systems might become competitive in the NC region only when year-2020 targets are achieved with the system using pressurized gasification. In the SE region, BIG/GTCC systems would compete in year 2000 as well as 2020.

Alcohol Fuel Production Costs

Calculated baseline results for the cost of methanol and ethanol versus scale for both the NC and SE regions are shown in Fig. 3c (year-2000) and Fig. 3d (year-2020). Similar patterns are observed as with the electricity costs, with one major difference: the capital costs of the fuel production facilities dominate the total costs for capacities up to those that can be supported by biomass supplied from the entire selected site (circular area of about 32 km radius). Even at capacities requiring transport of biomass from the 32-km limit, capital costs are still falling at a faster rate than biomass transport costs are rising. No absolute minimum is reached within the limits of the capacity scale shown in Fig. 3c and 3d.

Table 8 gives minimum values of COA and related capacities that are reached within the biomass supply constraints. When biomass costs are relatively lower, plant capacities that give minimum COAs are

---

[13] These electricity costs are based on capital and operating costs and performance estimates of the Electric Power Research Institute for 300 MW_e pulverized coal subcritical-steam plants with flue gas desulfurization in the East-West Central and Southeast regions [EPRI, 1993] (corresponding to the NC and SE regions in the analysis in this paper) and on electric utility steam-coal prices projected by the US Department of Energy for the West-North Central and South Atlantic regions [EIA, 1995]. For the NC region (in 1994$), the capital cost for the coal facility is $1662/$kW_e$, with fixed and variable O&M costs of $48.8/kW-yr and $0.0021/kWh, and a heat rate of 10.719 MJ/kWh. For the SE region, the corresponding figures are $1359/$kW_e$, $42.0/kW-yr, $0.0015/kWh, and 10.371 MJ/kWh. The DOE projects coal prices in 2000 and 2010. Assuming a continuation of the projected growth rate between 2000 and 2010 to estimate year 2020 prices, coal prices in the NC region in 2000, 2010, and 2020 would be $1.14/GJ, $1.27/GJ, and $1.40/GJ, respectively. For the SE region, the corresponding prices would be $1.56/GJ, $1.66/GJ, and $1.77/GJ.

larger. Correspondingly, capacities are smaller in the NC region than in the SE region. Methanol production costs reach 5% of COA_{min} at capacities of 1322 GJ/hr (169 million gal/yr) and 2018 GJ/hr (258 million gal/yr) for the NC and SE in 2000, respectively, and 1849 GJ/hr (236 million gal/yr) and 2786 GJ/hr (357 million gal/yr) in 2020. These capacities are comparable to those of the largest existing industrial biomass processing facilities or methanol-from-natural gas plants.[14]

Ethanol production costs approach a minimum at smaller plant capacities than for methanol. Capacities for a COA within 5% of the minimum range from 650-1470 GJ/hr (66-149 million gal/yr) among all of the cases considered (Table 8).

The COA_{min} for methanol in 2020 ranges from \$10.1-12.4/GJ (\$0.70-0.85/gallon), with the lower cost in the SE region (Table 8). The corresponding range for ethanol is \$8.6-11.2/GJ (\$0.75-0.97/gallon). For comparison, the average wholesale price of gasoline in 1993 in the US was about \$4.5/GJ (\$0.6/gallon), and is projected to rise to about \$6.8/GJ in 2010 (\$0.9/gal).[15] With these costs for gasoline, neither ethanol nor methanol are competitive on a per-unit of energy basis. However, ethanol and, especially, methanol can be readily used in fuel cell vehicles (FCVs) that are under intensive development for commercial application early in the next century [Williams, 1994]. With gasoline-equivalent fuel economies[16] of methanol-FCVs expected to be some 2.4 times those for comparable gasoline internal combustion engine vehicles [Ogden et al., 1994], methanol would be able to compete on a cost-per-vehicle-km basis with gasoline with methanol prices (in \$/GJ) up to 2.4 times those for gasoline.

Sensitivity Analysis

The above results change with changes in inputs, especially those relating to biomass production and transportation costs. To illustrate some of the effects, the SE region in year-2020 is considered. Four important input parameters are examined here: *(a)* planting density, i.e. the fraction of available land at the selected site that is used for biomass production (baseline value = 0.94); *(b)* variable transportation cost (\$0.18/dry tonne-km baseline); *(c)* yield (see Table 3); and *(d)* annual land rent (see Table 2).

Reducing the planting density raises transport costs and hence total energy costs for a given capacity. It also decreases the capacity at which the minimum energy cost is reached. For the baseline case, it was assumed that all agriculturally-suitable land in the selected area--94% of the area--was available to supply biomass. In practice, a diversity of crops would be planted. One initial bioenergy-crop strategy that has been proposed for Iowa [Brown, 1993] and other regions of the US is the use of lands currently under the Conservation Reserve Program for energy crop production. For the specific four-county area considered in our analysis, 22% of agricultural land is held under CRP contracts. The average for Iowa as a whole is about 8% [Brown, 1993].

With electricity generation, when the planting density is half that for the base case (0.5x0.94 = 0.47), COE_{min} is slightly higher than the baseline value. The capacity that gives COE_{min} drops by 10-15% for BIG/GT systems and by 30% for steam-rankine systems. When planting density is reduced further to 0.094 (=0.94x0.1), the COE still does not change dramatically, but the capacity that gives the minimum COE drops by 40-60% for

[14] The Puenta Arenas facility in Southern Chile is among the largest methanol-from-natural gas facilities operating today. Its capacity is about 300 million gal/yr. The capacities of the largest facilities in the US producing ethanol from corn today are of this order, and the largest ethanol-from-sugarcane factories in Brazil are about half this capacity. The biomass input capacity of a typical modern large integrated pulp and paper mill today is equivalent to that of a methanol-from-biomass facility that would have a capacity of about 300 million gal/yr.

[15] The 1993 gasoline cost is the 1993 average retail price of \$8.64/GJ (\$1.14/gal) (across all fuel grades of motor gasoline and including state and federal taxes) [EIA, 1995] minus \$0.31/gal in state and federal taxes and \$0.23/gal in distribution and filling station costs [Ogden, et al., 1994]. The US DOE projects an average retail gasoline price (including taxes) of \$10.85/GJ (\$1.43/gal) in 2010.

[16] For methanol, the gasoline-equivalent fuel economy (km/liter of gasoline equivalent) is the distance traveled per unit of methanol (in km/GJ) times 0.0349 GJ/liter, the higher heating value of gasoline.

BIG/GT technology and by over 85% for steam-rankine technology. With ethanol production, larger changes arise in both the value of COA_{min} and the capacity at which it is reached. For example, with a density of 0.094, values of COA_{min} rise by 30-40% and corresponding capacities fall by more than an order of magnitude. The very different result for electricity and for alcohol production is due to the greater flatness of the alcohol cost curves around the minimum.

Raising or lowering the variable transport cost has the predictable effect of raising or lowering COE_{min}, respectively, and decreasing or increasing the corresponding capacity (Table 9).

Changing the yield assumption has a small effect on the capacities at which the minimum COE or COA are reached, but a much larger impact on the value of COE_{min} and COA_{min} (Table 9). With higher yield, more biomass is available within a smaller radius, thereby lowering total production costs and transportation costs per tonne. Both of these costs impact the value of COE_{min} or COA_{min}, and increased transportation costs reduce the capacity required to achieve the minimum costs.

Modified input assumptions which change the unit cost of producing biomass by a fixed amount (regardless of capacity) shift the COE or COA curves up or down, but will not change the capacity at which minimum production costs are achieved. One such cost is the land rent. Table 2 gives baseline land rents, and Table 9 shows the impact of changing these by ± \$123 per hectare.[17]

CONCLUSIONS

This paper examined the impact of scale on prospective costs of electricity and alcohol fuels from plantation-grown biomass in the North Central and Southeast United States. All results are based on assumed biomass production and conversion technologies, most of which have not yet been commercially demonstrated and thus involve some uncertainty. The results are informative, nonetheless.

A key conclusion is that for any of the technologies examined, the capacity needed to achieve a minimum levelized energy production cost is larger than prevailing wisdom might suggest, but costs are relatively insensitive to large changes in the capacity around that value, so that production costs are not much different than the costs at much smaller capacities. For example, with pressurized biomass-gasifier/gas turbine systems, electricity costs are within 5% of the minimum at capacities that are 25%-30% of those at which the minimum cost is reached.

There are important distinctions among cost-capacity characteristics of different systems. The cost of electricity generation (COE) is considerably lower at all scales for gasifier/gas turbine combined cycles (BIG/GTCCs) than for steam-rankine cycles, and BIG/GTCCs achieve minimum costs at much smaller capacities than steam-rankine cycles. Assuming year-2020 switchgrass production systems, the COE for steam-rankine cycles reaches within 5% of its minimum at 100-110 MW_e. BIG/GTCC COEs reach 5% of their minimum at capacities of 30 to 40 MW_e with unpressurized gasification and at 70 to 90 MW_e with pressurized gasification. The latter technology is the lowest-cost electricity producer at capacities larger than 50 to 75 MW_e. Electricity production costs are considerably lower in the SE region (4.3 to 4.6 c/kWh for BIG/GTCC) than in the NC region (5.4 to 5.7 c/kWh) due to lower delivered biomass costs.

Projected costs of alcohol production (COA) are lower for ethanol than for methanol by 8-10% in the North Central region and 15-17% in the Southeast region. Plant capacities that achieve a COA within 5% of the minimum for methanol are twice those for ethanol. Methanol facilities achieve COAs within 5% of the

---

[17] Land rent represents an opportunity cost arising from choosing to grow energy crops instead of using the land for another purpose. When reduced by \$123/ha, the land rent in the SE region would be negative (see Table 2). A negative land rent could represent a situation in which a biomass producer is receiving CRP payments while also using the CRP land for bioenergy production. Biomass crops like switchgrass are perennial, and thus substantially reduce soil erosion compared to annual row crops. Since erosion control is one objective of the CRP program, the production of energy crops on CRP lands may not be inconsistent with the goals of the CRP program. A continuation of CRP payments (for a limited period) might provide an important incentive to induce farmers to grow energy crops.

minimum when they are comparable in size to the largest existing industrial biomass processing facilities (e.g. a state-of-the-art pulp and paper mill).

Values of COE_{min} and COA_{min} change most significantly when assumed yields and/or land rents are changed, but the corresponding capacities change relatively little. In contrast, values of COE_{min} and COA_{min} change relatively little with changes in assumed variable transport costs and/or planting density, but corresponding capacities change significantly.

ACKNOWLEDGEMENTS

For financial support, the authors thank the Energy, W. Alton Jones, and Geraldine R. Dodge Foundations, the Merck Fund, and the Air and Energy Engineering Research Laboratory of the U.S. EPA.

REFERENCES

Bhat, M.G., English, B., and Ojo, M., "Regional Costs of Transporting Biomass Feedstocks," in *Liquid Fuels from Renewable Resources*, J.S. Cundiff (ed), American Soc. of Agricultural Engineers, St. Joseph, MI, 1992.

Blackadder, W.H., Lundberg, H., Rensfelt, E., and Waldheim, L., "Heat and Power Production via Gasification in the Range 5-50 MW_e," in *Advances in Thermochemical Biomass Conversion*, Bridgwater (ed), Chapman and Hall, London, 1994, pp. 449-475.

Bludau, D., et al, *Technical Improvement of Systems for Harvest, Transport, Storage and Dehydration of Wood and Straw for Energy under Consideration of Economical Aspects*, Com. of European Communities, EUR 12643 EN, prepared by Bayerische Landesanstalt fur Landtechnik Weihenstephan, Tech. Univ. Munchen, 1990.

Brown, R.C., *The Potential of Biomass Production and Conversion in Iowa*, Report from Iowa State University to the Iowa Energy Center, ISU-ERI-Ames 95009, Ames, Iowa, 1994.

Consonni, S. and Larson, E.D., "Biomass-Gasifier/Aeroderivative Gas Turbine Combined Cycles Part B: Performance Calculations and Economic Assessment," in *Proceedings, ASME Cogen Turbo Power '94*, American Society of Mechanical Engineers, New York, NY, 1994, pp. 611-623.

Cooper, J., "Agro-Energy: Agricultural Products for Renewable Energy," Chariton Valley Resource Conservation and Development, Inc., Centerville, Iowa, July 1993.

Council of Economic Advisors, *Economic Indicators*, USGPO, Washington, DC, April 1995.

Davis, T.D., "Determinants of Profitability in Corn and Soybean Production," unpublished manuscript, Department of Economics, Iowa State University, Ames, Iowa, 1994.

DNR (Department of Natural Resources), *Annual Agricultural Statistics*, State of Iowa, Des Moines, 1994.

Elliott, T.P. and Booth, R., *Brazilian Biomass Power Demonstration Project*, Special Project Brief, Shell International Petroleum Co., London, Sept. 1993.

EIA (Energy Information Administration), *Supplement to the Annual Energy Outlook 1995*, DOE/EIA-0554(95), US Gov't. Printing Office, Washington, DC, Feb. 1995.

English, B.C., et al, "An Evaluation of the Regional Supply of Biomass at Three Midwestern Sites," *Proceedings, First Biomass Conference of the Americas*, Burlington, VT, April 1994, pp. 106-111.

EPRI (Electric Power Research Institute), *Strategic Analysis of Biomass and Waste Fuels for Electric Power Generation*, EPRI TR-102773, Palo Alto, CA, 1992.

EPRI (Electric Power Research Institute), *TAG Technical Assessment Guide, Volume 1: Electricity Supply-1993 (Revision 7)*, TR-102275-V1R7, Palo Alto, CA, June 1993.

Flinchbaugh, B.L. and Edelman, M.A., "The Political Economy for the 1995 Farm Bill," in *1995 Farm Bill Issues Brief*, Iowa State University, Ames, Iowa, 1994.

Graham, R.L., and Downing, M., *The Potential Supply and Cost of Biomass From Energy Crops in the TVA Region*, Biofuels Feedstock Development Pgm., Oak Ridge National Lab., Oak Ridge, TN, December 1993.

Hall, D.O., Mynick, H.E., and Williams, R.H., "Cooling the Greenhouse with Bioenergy," *Nature*, V. 353, Sept. 5, 1991.

Hohenstein, W.G. and Wright, L.L., "Biomass Energy Production in the United States: an Overview," *Biomass and Bioenergy*, 1994, pp. 161-173.

Holland, F.A., Watson, F.A., and Wilkinson, J.K., "Process Economics," Chap. 25, *Perry's Chemical Engineers' Handbook*, Ch. 25, 6th ed., McGraw-Hill, NY, 1984.

IGS (Iowa Geological Survey), "Resource Development Land and Water Use Management, Eleven County Area South Central Iowa," Iowa City, Iowa, 1973.

Johnson, L.R., "Wood Residue Recovery, Collection and Processing," in *Biomass Energy Pjt. Development Guidebook*, for Pacific NW and Alaska Biomass Energy Pgm. by Vranizan et al, DE-AC79-BP61195, 1987.

Larson, E.D. "Technology for Electricity and Fuels from Biomass," *Ann. Rev. Energy & Env.*, 1993:567-630.

Larson, E.D., Marrison, C.I., and Williams, R.H., "CO_2 Mitigation Potential of Biomass Energy Plantations in Developing Regions," Ctr. Energy and Env. Studies, Princeton University, Princeton, NJ, April 4, 1995.

Lee, H.W., and Johnson, L.R., "Evaluation of Transport Systems for Forest Biomass," Paper ASAE #88-5034, American Society of Agricultural Engineers, Michigan, 1988.

Marrison, C.I, *The Effect of Plant Size on the Economics of Producing Energy From Biomass*, Working Paper 133, Center for Energy and Environmental Studies, Princeton University, Princeton, NJ, 1995.

Miles, T.R., and Miles, T.R., Jr., "Densification Systems for Agricultural Residues," *American Chemical Society Symposium Series*, No 130, 1980.

Noon, C.E., "TVA GIS-Based Biomass Resource Assessment," in *Proceedings, First Biomass Conference of the Americas*, NREL/CP-200-6758, National Renewable Energy Laboratory, Golden, CO, April 1994, pp. 74-78.

Ogden, J.M., Larson, E.D., and Delucchi, M.A., "A Technical and Economic Assessment of Renewable Transportation Fuels and Technologies," prepared for US Congress, Office of Technology Assessment, Washington, DC, May 27, 1994.

Tomlin, C.D., *Geographic Information Systems & Geographic Modeling*, Prentice Hall, Engelwood Cliffs, NJ, 1990.

Turhollow, A.F. and Perlack, R.D., "Emissions of CO_2 from Energy Crop Production," *Biomass and Bioenergy*, 1(3), 1991, pp. 129-135.

UMinn (U. of Minnesota), *Sustainable Biomass Energy Production, Volume 1, Dedicated Feedstock Energy Supply*, for National Renewable Energy Laboratory, Golden, CO, September 1994.

USGS (United States Geological Survey), 1:100000 scale topographic map, a) Appanoose County, b) Lucas

County, c) Monroe County, d) Wayne County, 1986.

Walsh, M.E., and Graham, R., *Biomass Feedstock Supply Analysis: Production Costs, Land Availability, Yields*, Biomass Feedstock Development Pgm., Oak Ridge National Lab., Oak Ridge, Tenn., 18 January 1995.

Williams, R.H., "Fuel Cells and Their Fuels for Cars," *Technology Review*, April 1994

Williams, R.H. and Larson, E.D., "Advanced Gasification-Based Biomass Power Generation," in *Renewable Energy: Sources for Fuels and Electricity*, Johansson, Kelly, Reddy, Williams (eds), Island Press, Wash. DC, 1993, pp. 729-785.

Williams, R.H., Larson, E.D., Katofsky, R.E., and Chen, J., "Methanol and Hydrogen from Biomass for Transportation," Center for Energy and Environmental Studies, Princeton University, June 1995.

Wyman, C.E., Bain, R.L., Hinman, N.D., and Stevens, D.J., "Ethanol and Methanol from Lignocellulosic Biomass," in *Renewable Energy: Sources for Fuels and Electricity*, Johansson, Kelly, Reddy, Williams (eds), Island Press, Washington, DC, 1993, pp. 865-923.

Table 1. Land areas and projected switchgrass yields in 2000 and 2020 by land capability class (LCC) in the North Central and Southeast Regions of the US [Walsh and Graham, 1995].

Land Capability Classification[a]	NORTH CENTRAL REGION			SOUTHEAST REGION		
	Area[b] (10^3 ha)	Yield (dry tonnes/ha)		Area (10^3 ha)	Yield (dry tonnes/ha)	
		2000	2020		2000	2020
LCC2c	3379	7.09	10.1	none	---	---
LCC2e	21638	9.29	13.3	2613	13.7	19.5
LCC2s	2769	9.76	13.9	806	14.1	20.2
LCC2w	17265	10.1	14.4	1051	13.9	19.8
LCC3c	2	8.33	11.9	none	---	---
LCC3e	15027	9.16	13.1	957	12.2	17.4
LCC3s	2011	7.18	10.3	472	13.0	18.5
LCC3w	4761	9.65	13.8	1049	13.6	19.4
LCC4e	5171	9.02	12.9	491	11.9	17.0
LCC4s	1452	7.47	10.7	278	12.7	18.1
LCC4w	934	6.82	9.76	512	12.6	18.1

(a) The lower-case letters indicates the primary restriction on land management: c = climate, e = erosion, s = soil quality, and w = wetness.

(b) The total area considered by Walsh and Graham [1995] includes agricultural cropland (including idled or fallow cropland], land in the conservation reserve program (CRP), and pastureland with high to medium potential for conversion to cropland. No forest land, wetlands, or urban areas are included.

Table 2. Projected costs in 1994 dollars[a] for switchgrass production in 2000 and 2020 by land capability class (LCC) in the North Central and Southeast Regions of the US [Walsh, 1995].

Land Capability Class[b]	NORTH CENTRAL REGION					
	Year 2000			Year 2020		
	Establishment[c] ($/ha)	Maint.[d] ($/ha/yr)	Land ($/ha/yr)	Establishment[c] ($/ha)	Maint[d] ($/ha/year)	Land ($/ha/yr)
LCC2c	326.41	266.71	136	334.55	295.98	136
LCC2e	327.17	294.90	217	337.20	346.63	217
LCC2s	327.17	294.90	217	337.20	346.63	217
LCC2w	327.17	294.90	217	337.20	346.63	217
LCC3c	130.39	254.71	58	345.32	326.71	58
LCC3e	327.17	294.90	217	337.20	346.63	217
LCC3s	326.41	266.71	136	334.55	295.98	136
LCC3w	327.17	294.90	217	337.20	346.63	217
LCC4e	327.17	294.90	217	337.20	346.63	217
LCC4s	326.41	266.71	136	334.55	295.98	136
LCC4w	326.41	266.71	136	334.55	295.98	136
SOUTHEAST REGION						
All LCC	415.28	285.01	71	429.30	376.88	71

(a) Costs originally given by Walsh and Graham [1995] in 1993 dollars are expressed here in 1994$ using the US GDP deflator [Council of Economic Advisors, 1995].

(b) The lower-case letters indicates the primary restriction on land management: c = climate, e = erosion, s = soil quality, and w = wetness.

(c) Excludes land rent--total first year cost is this establishment cost plus one year of land rent. Establishment costs include variable cash costs: seeds, fertilizer, chemicals, and machinery fuel, lubricants, and repairs; fixed cash costs: general overhead, taxes and insurance, interest on operating loans and on real estate loans; and costs of farmer-owned resources: capital replacement, other non-land capital, and labor.

(d) Excludes land rent--total annual maintenance cost is indicated maintenance cost plus land rent. Maintenance costs include variable cash costs: fertilizer, harvesting, and machinery fuel, lubricants, and repairs; fixed cash costs: general overhead, taxes and insurance, interest on operating loans and on real estate loans; and costs of farmer-owned resources: capital replacement, other non-land capital, and labor.

Table 3. Average projected yields and costs (in 1994$) for North Central and Southeast Regions.[a]

Land Class	Year 2000			Year 2020		
	Yield (dry t/ha/yr)[b]	First-year costs ($/ha)	Year 2-10 costs ($/ha/yr)	Yield (dry t/ha/yr)[b]	First-year costs ($/ha)	Year 2-10 costs ($/ha/yr)
	NORTH CENTRAL REGION					
LCC2	10.4	539.11	504.71	14.8	549.02	554.87
LCC3	10.0	537.68	502.80	14.2	547.57	552.58
LCC4	9.2	519.46	478.44	13.1	528.92	523.18
	SOUTHEAST REGION					
LCC2	15.2	486.99	356.42	21.7	501.04	448.50
LCC3	14.2	486.99	356.42	20.3	501.04	448.50
LCC4	13.6	486.99	356.42	19.4	501.04	448.50

(a) Average yields and average costs for each land capability class are calculated as area-weighted averages using the projected yields and costs by land capability sub-classification. For example, for land capability class 2, the average yield, Y_{LCC2}, is:

$$Y_{LCC2} = (A_{LCC2e} \cdot Y_{LCC2e} + A_{LCC2s} \cdot Y_{LCC2s} + A_{LCC2c} \cdot Y_{LCC2c} + A_{LCC2w} \cdot Y_{LCC2w})/A_{LCC2}$$

where A_{LCC2i} and Y_{LCC2i} are the area and yield for LCC2 subclassification, *i*, and A_{LCC2} is the total area of LCC2. The average first-year cost, EC_{LCC2}, is:

$$EC_{LCC2} = (A_{LCC2e} \cdot EC_{LCC2e} + A_{LCC2s} \cdot EC_{LCC2s} + A_{LCC2c} \cdot EC_{LCC2c} + A_{LCC2w} \cdot EC_{LCC2w})/A_{LCC2}$$

where EC_{LCC2i} is the establishment costs plus first-year land rent for LCC2 subclassification, *i*.

(b) Dry metric tonnes per hectare per year.

Table 4. Calculated time-averaged delivered biomass and total levelized cost of switchgrass production.

Land Class	Year 2000		Year 2020	
	Time-ave. biomass[a] (tonnes/ha/yr)	Levelized production cost[b] ($/dry tonne)	Time-ave. biomass[a] (tonnes/ha/yr)	Levelized production cost[b] ($/dry tonne)
	NORTH CENTRAL REGION			
LCC2	8.1	65.53	11.6	49.93
LCC3	7.8	68.04	11.1	51.87
LCC4	7.2	69.72	10.4	52.85
	SOUTHEAST REGION			
LCC2	11.9	32.95	16.9	28.12
LCC3	11.1	35.20	15.8	30.04
LCC4	10.6	36.79	15.1	31.40

(a) This is the average annual useable biomass delivered from a unit area to the conversion facility over a ten year period. It accounts for no yield in the establishment year, two-thirds of the steady-state yield in the next year, the steady state yield for the eight subsequent years, and 10% post harvest losses:

$$\text{Time Averaged Biomass} = [(0 + 0.667 + 8)\cdot Y_{steady}\cdot 0.9]/10 = 0.78\cdot Y_{steady}$$

where Y_{steady} are the steady-state yields given in Table 3.

(b) The levelized production cost is calculated from:

$$(\$/\text{dry tonne}) = (\$/\text{dry tonne})_{before\ losses}/(1\text{-}L)$$

where L is the post-harvest loss fraction, which is assumed to be 0.10 [UMinn, 1994]. (Tonnage loss occurs during harvest, in-field storage, transport, and on-site storage, but in calculating transportation costs (see text), we conservatively assume that all losses occur during storage at the conversion facility site, i.e. the full harvest tonnage must be transported to the facility, but only 90% is converted to power or fuel at the facility.) The cost before losses is given by:

$$(\$/\text{dry tonne})_{before\ losses} = \{E + M\cdot\sum_{n=1}^{9}[1/(1+i)^n]\}/\{Y_{steady}\cdot(0.667/(1+i) + \sum_{n=2}^{9}[1/(1+i)^n])\}$$

where E is the first year cost (establishment costs plus land rent) in \$/ha and M is the annual cost in years 2 through 10 (maintenance cost plus land rent) and Y_{steady} is the projected steady-state yield (Table 3), and i is the discount rate. A real discount rate of 6.5% is assumed [Walsh and Graham, 1995].

Table 5. Comparison of wood chip transport vehicles [Johnson, 1987].

Vehicle type	Truck Load Limits		Bulk density of load (t/m^3) to be both volume and weight limited[a]	Truck Operating Costs[b]		1994$ per tonne-km[c]	
	Weight (tonnes)	Volume (m^3)		(1994$/hr)	(1994$/km)	Wood chips[d]	Switchg. bales[e]
Truck with log trailer	22.7	54.2	0.42	60.2	1.38	0.16	0.21
Truck with chip van	22.7	76.4	0.30	60.2	1.38	0.11	0.15
Truck with 30-yard rock trailer	21.8	26.7	0.81	60.2	1.38	0.32	0.43
12-yard dump truck	10.9	12.5	0.87	48.1	1.06	0.53	0.71
12 yard dump truck with 10-yard dump trailer	22.7	21.4	1.06	60.2	1.33	0.39	0.51
Dump truck with 30-yard box	10.9	22.9	0.48	48.1	1.06	0.29	0.38
Truck with solid waste container	11.8	16.8	0.70	54.2	1.24	0.46	0.61

(a) Calculated from indicated load limits. Since typical bulk densities for most biomass are below these calculated limits, transport vehicle loads will typically be limited by volume, not weight.

(b) Based on hourly truck rental rates and average speeds of 43 kilometers per hour for tractors and 45 kilometers per hour for trucks. Original data converted to 1994$ using GDP deflator.

(c) Includes the cost for the time taken for the return (unladen) journey.

(d) Johnson indicates 50% moisture content, for which a bulk density of 0.32 tonnes/m^3 is assumed. (Miles and Miles [1980] indicate a typical range of bulk densities for 50% moisture content wood chips of 0.29-0.35 tonnes/m^3.)

(e) This is our calculation for 15% moisture content rectangular bales, which we assume have a bulk density of 0.24 tonnes/m^3. (Miles and Miles [1980] give a bulk density of 0.16 t/m^3 for a standard rectangular bale of "moist" straw. A slightly reinforced baler will achieve 0.24 t/m^3, and more expensive balers are able to produce bales at 0.43 t/m^3.)

Table 6. Estimates of the unit installed capital costs, conversion efficiencies, and operating and maintenance costs for systems for electricity or liquid fuels production from biomass at various capacities.

Electricity production systems	Capacity[a] (MW_e)	Generating efficiency (%)[b]	Capital cost (1994$/$kW_e$)	O&M cost[c] (1994$/kWh)
Steam rankine cycle[d]	10	20	3510	0.0125
	50	n.r.[e]	1647	0.0125
	large	27	1200	0.0125
Biomass-gasifier/gas turbine combined cycle (BIG/GTCC) using near-atmospheric pressure gasifier and wet scrubbing cleanup[f,g]	10	37	2577	0.008
	60	37	1288	0.008
	large	37	1200	0.008
Biomass gasifier/gas turbine combined cycle (BIG/GTCC) using pressurized gasifier and ceramic filter hot gas cleanup[h,g]	30	40	1800	0.008
	60	40	1425	0.008
	large	40	1100	0.008
Alcohol fuel production systems[i]	**Capacity (GJ/hour)[j]**	**Production efficiency (%)**	**Capital cost (1994$/MJ/hr)**	**O&M cost (1994$/GJ)**
Methanol via indirectly-heated gasifier[k]	811	60	317	2.61
Methanol via indirectly-heated gasifier, earlier design estimates[l]	1049	n.r.	162	n.r.
	5245	n.r.	112	n.r.
Ethanol, advanced enzymatic hydrolysis[m]	1355	50	151	2.18
Ethanol, enzymatic hydrolysis using earlier (circa-1990) process design[l]	590	40	341	2.46
	2956	40	230	2.46

(a) "Large" refers to the capacity at which it is assumed that the minimum unit installed capital cost is reached.

(b) 100 times the electricity or fuel production divided by the higher heating value of the input biomass.

(c) Assumed constant for all capacities.

(d) From EPRI [1992], except for the capital cost and efficiency of the large-capacity unit. For the latter, see text.

(e) Not required for the analysis in this paper.

(f) The source for the two lower-capacity capital cost estimates is a personal communication from H. Lundberg (TPS Termiska Processer, AB, Stockholm, Sweden) to Robert Williams (Center for Energy and Environmental Studies, Princeton University) on October 29, 1994. TPS Termiska Processer is actively working to commercialize biomass-gasifier/gas turbine combined cycles that would use their near-atmospheric pressure circulating fluidized-bed gasifier system that includes a secondary tar cracking reactor and wet scrubbing for gas cleanup. For the capital cost at "large" capacity, see discussion in text. The efficiency is an estimate for a system of about 25 MW_e capacity that would use a General Electric LM2500 gas turbine [Elliott and Booth, 1993].

(g) The O&M cost estimate is based on two sources. One is the best "guestimate" of the O&M costs for a commercial, 25-30 MW_e BIG/GT facility in Brazil by industry experts involved in the development of the first commercial-scale BIG/GT demonstration project (to be built in Brazil). The "guestimate" is 0.5 to 1.0 cents per kWh (private communication from Phil Elliott, Shell International Petroleum Company, to Robert Williams, Center for Energy and Environmental Studies, Princeton University, Princeton, New Jersey, Oct. 26, 1994). Williams and Larson [1993] give estimates of O&M costs from 0.75 to 0.87 cents/kWh for 100-MW_e scale advanced BIG/GT systems.

(h) The source for the capital cost estimates for the two lower-capacity units is [Consonni and Larson, 1994]. It represents an estimate of the future commercial-level costs for a system that is being developed toward commercialization by Bioflow, a Scandinavian joint venture involving Sydkraft, Sweden's second largest electric utility, and Ahlstrom, the Finnish boiler and gasifier manufacturer. The system includes a circulating fluidized-bed gasifier and a ceramic hot-gas candle filter. For the capital cost of the large capacity unit, see discussion in text. The indicated efficiency is for a system of about 25 MW_e capacity that would use the General Electric LM2500 gas turbine [Elliott and Booth, 1993].

(i) Best estimates for methanol and ethanol system capital costs were available only for a single capacity. The scaling exponent, E, in Eqn. 2 was assumed to be -0.3, a typical value for scaling total plant costs for many chemical processes [Holland et al., 1985], and the values for coefficients C and D were established as follows. First, equations of the form of Eqn. 2 were determined for "earlier designs," for which two different-capacity cost estimates were available. These equations are: $(\$/MJ/hr)_{MeOH} = 31.4 + 1052 \cdot (GJ/hr)^{-0.3}$ and $(\$/MJ/hr)_{EtOH} = 51.4 + 1963 \cdot (GJ/hr)^{-0.3}$. The values for C and D in these equations were multiplied by the ratio of the single-capacity capital cost estimate to the capital cost predicted by the equations for the "earlier designs" at the same capacity. The resulting equations are given in the caption of Fig. 2.

(j) To convert GJ/hr to liters/hr, divide by the appropriate higher heating value: 0.0181 GJ/lit for methanol and 0.0228 GJ/lit for hydrous ethanol (95% ethanol, 5% water).

(k) From Williams et al., [1995]

(l) From Wyman et al. [1993].

(m) From Odgen, et al. [1994], based on Wyman et al. [1993].

Table 7. Calculated minimum cost of electricity (COE_{min}) as a function of installed capacity for the North Central and Southeast regions. Also shown are the capacities at which COE_{min} is reached and the capacities at which the COE is within 1% or 5% of COE_{min}.

Electricity technology	Year	Minimum COE (1994$/kWh)	Installed Capacity (MW_e)		
			For COE = minimum	For COE within 1% of minimum	For COE within 5% of minimum
NORTH CENTRAL REGION					
Steam-rankine cycle	2000	0.090	366	212	86
	2020	0.077	470	227	101
Low-pressure BIG/GTCC	2000	0.066	114	60	27
	2020	0.057	127	61	30
Pressurized BIG/GTCC	2000	0.062	269	123	65
	2020	0.054	290	137	72
SOUTHEAST REGION					
Steam-rankine cycle	2000	0.065	424	214	99
	2020	0.060	519	244	111
Low-pressure BIG/GTCC	2000	0.049	130	61	37
	2020	0.046	142	64	37
Pressurized BIG/GTCC	2000	0.046	285	140	85
	2020	0.043	319	154	91

Table 8. Calculated minimum cost of alcohol (COA_{min}) as a function of installed capacity for the North Central and Southeast regions. Also shown are the capacities at which COA_{min} is reached and the capacities at which the COA is within 1% or 5% of COA_{min}.

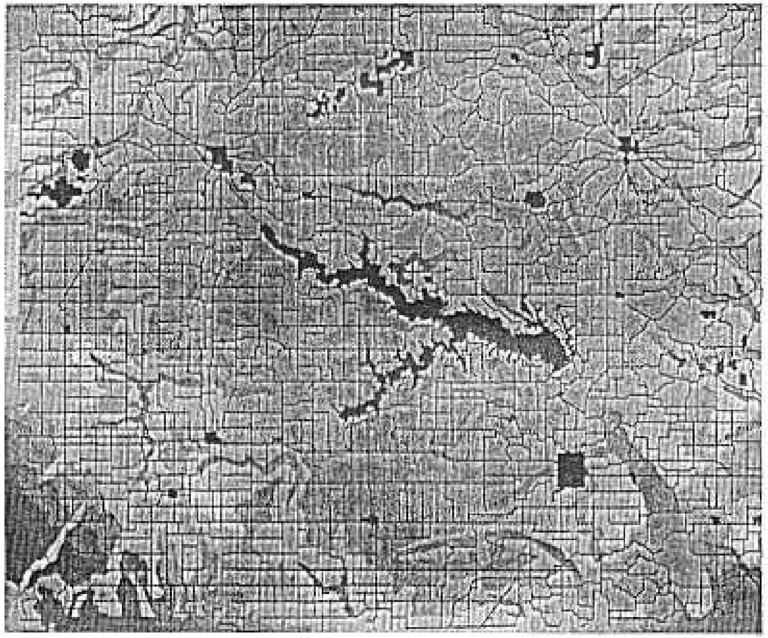
Alcohol production technology	Year	Minimum COA (1994$/GJ)	Installed Capacity (GJ per hour)		
			For COA = minimum[a]	For COA within 1% of minimum	For COA within 5% of minimum
NORTH CENTRAL REGION					
Methanol	2000	14.2	> 2700	2373	1322
	2020	12.4	> 3800	3235	1849
Ethanol	2000	13.1	> 2200	1532	652
	2020	11.2	> 3200	2267	952
SOUTHEAST REGION					
Methanol	2000	10.9	> 3800	3451	2018
	2020	10.1	> 5400	4930	2786
Ethanol	2000	9.4	> 3200	2435	1070
	2020	8.6	> 4500	3199	1471

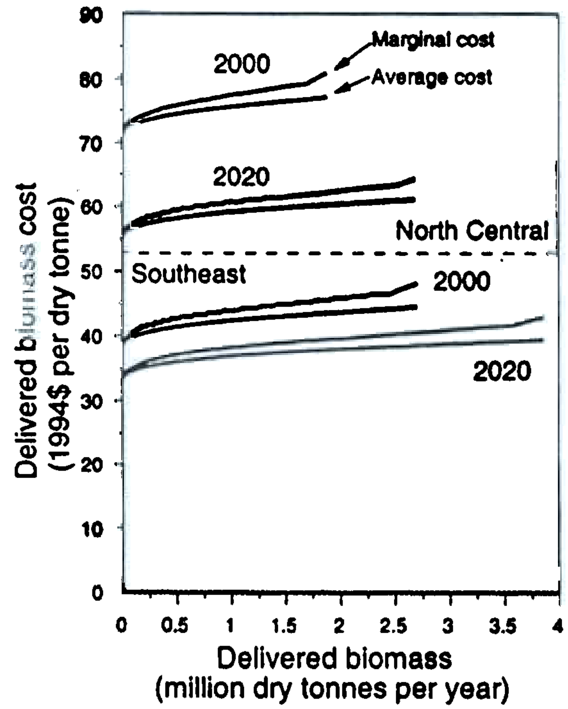
(a) For all cases, the biomass available at the site was exhausted before an absolute minimum COA was reached. The minimum COA values shown here are the lowest COAs achieved up to this limit in biomass supply.

Table 9. Results of sensitivity analysis for Southeast Region in 2020 showing impact on minimum energy production cost for each technology and capacity at which the minimum is reached.

	ELECTRICITY PRODUCTION						ALCOHOL PRODUCTION			
	Low-Pressure BIG/GTCC		Pressuized BIG/GTCC		Steam-rankine cycle		Methanol		Ethanol	
Parameter	COE_{min} (c/kWh)	Cap. (MW_e)	COE_{min} (c/kWh)	Cap. (MW_e)	COE_{min} (c/kWh)	Cap. (MW_e)	COA_{min} ($/GJ)	Cap. (GJ/hr)	COA_{min} ($/GJ)	Cap. (GJ/hr)
BASE CASE[a]	4.57	142	4.33	319	6.05	520	10.1	> 5500	8.6	> 4500
Variable transp. = $0.09/t-km	4.48	183	4.23	415	5.85	691	9.8	> 5500	8.3	> 4500
Variable transp. = $0.36/t-km	4.71	100	4.50	208	6.39	304	10.7	> 5500	9.3	3806
Planting density = 0.50-0.94	4.62	127	4.38	277	6.16	362	10.7	> 2700	9.0	> 2300
Planting density = 0.10-0.94	4.76	87	4.59	121	6.80	75	13.9	> 400	11.2	> 300
Yield = + 25% (dry t/ha/yr)	4.24	147	4.03	337	5.57	525	9.3	> 7000	7.8	> 5700
Yield = - 25% (dry t/ha/yr)	5.10	123	4.83	301	6.83	447	11.3	> 4100	10.0	> 3400
Land rent + $123/ha/yr ($50/ac/yr)	5.00	142	4.73	319	6.66	520	13.4	> 3800	12.4	> 3200
Land rent - $123/ha/yr ($50/ac/yr)	4.13	142	3.93	319	5.43	520	9.4	> 5500	7.8	> 4600

(a) The baseline values of the parameters examined in this table are as follows: variable transportation cost = $0.18/dry tonne-km; planting density = 0.94; yield = as in Table 3; land rent = as in Table 2.





(b)

Fig. 1. Levelized total cost of switchgrass delivered to an energy conversion facility from a 5100 km$_2$ four-county area in south central, Iowa, as estimated from a GIS analysis.
(a) **Qualitative results: extent of shading reflects relative cost, taking account of soil productivities and road-transport distances to the facility at a one-acre resolution. Black areas represent towns, lakes, and other areas where biomass cannot be grown. The conversion facility is assumed to be on the edge of the centrally located lake. Costs generally rise with radial distance away from the facility. In some places land that is physically further from the facility but more productive than land closer to the facility gives lower biomass costs.**
(b) **Quantitative results: switchgrass cost-supply curve for production systems in 2000 and 2020 in the North Central and Southeast regions of the USA. Costs rise with tonnage supplied due to increasing transportation distances and/or decreasing soil productivities.**

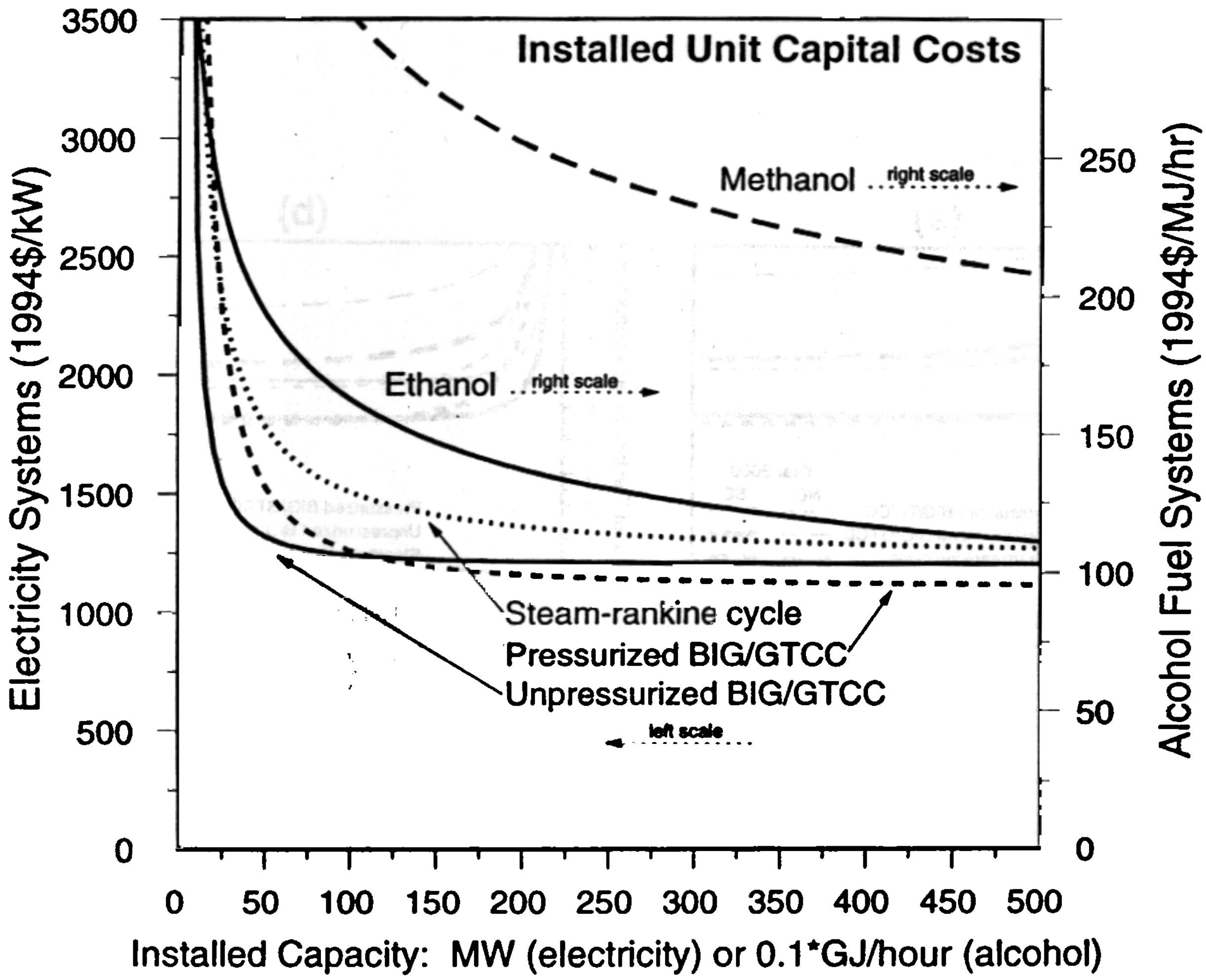


Fig. 2. Estimated installed capital costs of biomass-fed electricity generation and alcohol fuel production. The curves plot the following derived relationships:

Steam-rankine cycle, $\$/kW = 1200 + (22195)\cdot MW^{-0.93}$
Pressurized BIG/GTCC, $\$/kW = 1100 + (110420)\cdot MW^{-1.42}$
Unpressurized BIG/GTCC, $\$/kW = 1200 + (47198)\cdot MW^{-1.56}$
Methanol: $\$/MJ/hr = 57.7 + (1934)\cdot(GJ/hr)^{-0.3}$
Ethanol: $\$/MJ/hr = 28.0 + (1070)\cdot(GJ/hr)^{-0.3}$

1995 U.S. EPA Symposium on Greenhouse Gas Emissions and Mitigation Research
Washington, DC, 27-29 June 1995

COST VERSUS SCALE FOR ADVANCED PLANTATION-BASED BIOMASS ENERGY SYSTEMS IN THE U.S.

Christopher I. Marrison* and Eric D. Larson
Center for Energy and Environmental Studies
School of Engineering and Applied Science
Princeton University, Princeton, NJ 08544

ABSTRACT

A unique feature of biomass energy systems is that the feedstock must be gathered from a wide area around the energy production facility. For a small-scale facility, transport costs will be relatively low, but capital cost per unit of output will be high. For a large-scale facility, transport costs will be high, but capital costs will be relatively low. At some intermediate scale, the total cost of energy should reach a minimum. This paper examines the effects of scale on the prospective costs of producing electricity and alcohol fuels from plantation-grown switchgrass in the North Central and Southeast regions of the US.

Site-specific biomass cost-supply curves for the year 2000 and 2020 are developed using projections of the Oak Ridge National Laboratory for switchgrass yields and costs as a function of land capability class. A geographic information system (GIS) is used to analyze soil quality distributions and road transport distances.

Conversion technologies considered include one commercial electricity generating technology--the steam rankine cycle--and one nearing commercial readiness--the gasifier/gas turbine combined cycle. Two alcohol fuels are considered: methanol via thermochemical gasification and ethanol via enzymatic hydrolysis. Both of these processes have the potential to be commercially ready early in the next century or sooner. Estimates of installed capital costs for all of these conversion systems drawn from published and other sources.

In all cases, the minimum cost of electricity (COE_{min}) or alcohol (COA_{min}) is reached at plant capacities that are larger than conventional wisdom might suggest. Up to these capacities, the rate of decrease in unit capital costs is more rapid than the rate of increase in biomass transportation costs. However, around the capacity corresponding to COE_{min} or COA_{min}, there is a wide range over which costs change very little. In general, higher biomass yields lead to larger capacities at COE_{min} or COA_{min}. Costs are higher in the NC than SE region, and (in both regions) costs are lower using year-2020 biomass costs compared to year-2000 costs.

INTRODUCTION

Biomass energy crops are of increasing interest worldwide because of the potential for using them in advanced electricity and transportation fuel production systems that promise cost-competitiveness with fossil fuel systems, while substantially reducing emissions of CO_2 to the atmosphere [Hall, et al., 1991; Turhollow and Perlack, 1991; Larson et al., 1995]. Also, in industrialized countries like the United States, economically viable bioenergy systems might help reduce government subsidies paid to farmers. Currently, the government pays farmers some $1.8 billion/year to keep erodible lands out of production under the Conservation Reserve Program (CRP). In addition, price-support payments, which many farmers need to maintain profitability,[1] were some $16.1 billion in 1993 [Flinchbaugh and Edelman, 1994]. Perennial energy crops would serve to reduce or

* Present address: Oliver, Wyman & Company, LLC, 666 Fifth Ave., New York, 10103.

[1] For example, corn farmers in Iowa received an average annual government payment of $45/acre from 1990 to 1992. During this same period, the profit per acre (gross income, including government payments, minus total economic costs) was $51 [Davis, 1994].

eliminate erosion on many CRP lands, while providing a revenue source to the farmer. With adequate, unsubsidized profitability, energy crops might help reduce the present level of price support payments.

A unique feature of biomass energy systems that is the focus of this paper is that the feedstock must be gathered from a wide area around the energy production facility. For a small-scale facility, transport costs will be relatively low, but capital cost per unit of output will be high. For a large-scale facility, transport costs will be high, but capital costs will be relatively low. At some intermediate scale, the total cost of energy should reach a minimum. This paper examines the effects of scale on the prospective costs of producing electricity and alcohol fuels from plantation-grown switchgrass in the North Central and Southeast regions of the US.

The components of the total cost of energy supply from biomass are *(1)* the cost to grow and deliver the biomass to the conversion facility and *(2)* the cost of the conversion. A number of studies have examined these two elements independently. For example, biomass cost-supply curves have been developed for some specific geographic regions by Graham and Downing [1993], Noon [1994], and English, et al. [1994], among others. A variety of studies (discussed later) have examined the capital and operating costs for biomass-to-electricity or biomass-to-fuels conversion systems. There do not appear to have been any previous efforts to marry biomass supply with biomass conversion studies, as done here, to examine the issue of energy cost versus scale.

BIOMASS COSTS

The starting point for the analysis was the selection of a specific site to provide case-study variations in soil quality and transportation distances for a typical agricultural area. A four-county area in South Central Iowa (Appanoose, Lucas, Monroe, and Wayne counties) was chosen, in large part because there is significant interest in this region in the development of biomass energy production on lands currently under CRP contracts [Cooper, 1993; Brown, 1994]. The total area is approximately 5100 km^2, over 90% of which is suitable for growing crops. Some 22% of the area is presently held under CRP contract [DNR, 1994]. Soil type [IGS, 1973] and road [USGS, 1986] maps of the region were digitized and loaded into a geographic information system (GIS). (See Marrison [1995] for details of the digitization process.)

The GIS system was used to calculate road transport distances from each acre to a central processing facility that was assumed to be located near the center of the region.[2] As detailed below, the cost of growing biomass on each acre (dependent primarily on soil type) was then calculated and added to the transport cost associated with the distance between that acre and the conversion facility. The characteristics of the Iowa site (relative soil quality and road layout) were taken to represent typical agricultural areas in the North Central (NC) region (which includes Iowa) and in the Southeast (SE) region.

Costs of Growing Biomass

Development of energy crops in the US is focussed on short-rotation woody crops for some regions and on herbaceous crops for others [Hohenstein and Wright, 1994]. Switchgrass is a primary candidate energy crop for the North Central (NC) and Southeast (SE) regions.

Switchgrass yield and cost projections made by analysts at the Oak Ridge National Laboratory [Walsh and Graham, 1995] provide the basis for biomass production costs presented here. Walsh and Graham give estimates of per-hectare yields and costs for four regions of the US (Northeast, North Central, Southeast, and South Central). They identify sub-regions by land capability class (LCC). LCC 1 has few restrictions on use for crops. LCC2 through LCC4 have variable suitability for crops, and LCC 5 through LCC 8 are generally unsuited for crop production. Within each LCC, soils are sub-defined by the primary reason for restrictions on their use as cropland: *e* -- erosion potential; *w* -- excessive water; *c* -- extreme climate; and *s* -- soil factors (salinity, shallowness, texture, etc.).

---

[2] The GIS is the MapBox package of Decision Images, Inc. of Princeton, New Jersey [Tomlin, 1990]. Transport distances for each map unit (acre) are found by locating the nearest point on the road system, and counting the distance along the road system to the conversion facility. The result is a map on which every acre has an assigned road transport distance.

1995 U.S. EPA Symposium on Greenhouse Gas Emissions and Mitigation Research
Washington, DC, 27-29 June 1995

COST VERSUS SCALE FOR ADVANCED PLANTATION-BASED BIOMASS ENERGY SYSTEMS IN THE U.S.

Christopher I. Marrison* and Eric D. Larson
Center for Energy and Environmental Studies
School of Engineering and Applied Science
Princeton University, Princeton, NJ 08544

ABSTRACT

A unique feature of biomass energy systems is that the feedstock must be gathered from a wide area around the energy production facility. For a small-scale facility, transport costs will be relatively low, but capital cost per unit of output will be high. For a large-scale facility, transport costs will be high, but capital costs will be relatively low. At some intermediate scale, the total cost of energy should reach a minimum. This paper examines the effects of scale on the prospective costs of producing electricity and alcohol fuels from plantation-grown switchgrass in the North Central and Southeast regions of the US.

Site-specific biomass cost-supply curves for the year 2000 and 2020 are developed using projections of the Oak Ridge National Laboratory for switchgrass yields and costs as a function of land capability class. A geographic information system (GIS) is used to analyze soil quality distributions and road transport distances.

Conversion technologies considered include one commercial electricity generating technology--the steam rankine cycle--and one nearing commercial readiness--the gasifier/gas turbine combined cycle. Two alcohol fuels are considered: methanol via thermochemical gasification and ethanol via enzymatic hydrolysis. Both of these processes have the potential to be commercially ready early in the next century or sooner. Estimates of installed capital costs for all of these conversion systems drawn from published and other sources.

In all cases, the minimum cost of electricity (COE_{min}) or alcohol (COA_{min}) is reached at plant capacities that are larger than conventional wisdom might suggest. Up to these capacities, the rate of decrease in unit capital costs is more rapid than the rate of increase in biomass transportation costs. However, around the capacity corresponding to COE_{min} or COA_{min}, there is a wide range over which costs change very little. In general, higher biomass yields lead to larger capacities at COE_{min} or COA_{min}. Costs are higher in the NC than SE region, and (in both regions) costs are lower using year-2020 biomass costs compared to year-2000 costs.

INTRODUCTION

Biomass energy crops are of increasing interest worldwide because of the potential for using them in advanced electricity and transportation fuel production systems that promise cost-competitiveness with fossil fuel systems, while substantially reducing emissions of CO_2 to the atmosphere [Hall, et al., 1991; Turhollow and Perlack, 1991; Larson et al., 1995]. Also, in industrialized countries like the United States, economically viable bioenergy systems might help reduce government subsidies paid to farmers. Currently, the government pays farmers some $1.8 billion/year to keep erodible lands out of production under the Conservation Reserve Program (CRP). In addition, price-support payments, which many farmers need to maintain profitability,[1] were some $16.1 billion in 1993 [Flinchbaugh and Edelman, 1994]. Perennial energy crops would serve to reduce or

* Present address: Oliver, Wyman & Company, LLC, 666 Fifth Ave., New York, 10103.

[1] For example, corn farmers in Iowa received an average annual government payment of $45/acre from 1990 to 1992. During this same period, the profit per acre (gross income, including government payments, minus total economic costs) was $51 [Davis, 1994].

eliminate erosion on many CRP lands, while providing a revenue source to the farmer. With adequate, unsubsidized profitability, energy crops might help reduce the present level of price support payments.

A unique feature of biomass energy systems that is the focus of this paper is that the feedstock must be gathered from a wide area around the energy production facility. For a small-scale facility, transport costs will be relatively low, but capital cost per unit of output will be high. For a large-scale facility, transport costs will be high, but capital costs will be relatively low. At some intermediate scale, the total cost of energy should reach a minimum. This paper examines the effects of scale on the prospective costs of producing electricity and alcohol fuels from plantation-grown switchgrass in the North Central and Southeast regions of the US.

The components of the total cost of energy supply from biomass are *(1)* the cost to grow and deliver the biomass to the conversion facility and *(2)* the cost of the conversion. A number of studies have examined these two elements independently. For example, biomass cost-supply curves have been developed for some specific geographic regions by Graham and Downing [1993], Noon [1994], and English, et al. [1994], among others. A variety of studies (discussed later) have examined the capital and operating costs for biomass-to-electricity or biomass-to-fuels conversion systems. There do not appear to have been any previous efforts to marry biomass supply with biomass conversion studies, as done here, to examine the issue of energy cost versus scale.

BIOMASS COSTS

The starting point for the analysis was the selection of a specific site to provide case-study variations in soil quality and transportation distances for a typical agricultural area. A four-county area in South Central Iowa (Appanoose, Lucas, Monroe, and Wayne counties) was chosen, in large part because there is significant interest in this region in the development of biomass energy production on lands currently under CRP contracts [Cooper, 1993; Brown, 1994]. The total area is approximately 5100 km^2, over 90% of which is suitable for growing crops. Some 22% of the area is presently held under CRP contract [DNR, 1994]. Soil type [IGS, 1973] and road [USGS, 1986] maps of the region were digitized and loaded into a geographic information system (GIS). (See Marrison [1995] for details of the digitization process.)

The GIS system was used to calculate road transport distances from each acre to a central processing facility that was assumed to be located near the center of the region.[2] As detailed below, the cost of growing biomass on each acre (dependent primarily on soil type) was then calculated and added to the transport cost associated with the distance between that acre and the conversion facility. The characteristics of the Iowa site (relative soil quality and road layout) were taken to represent typical agricultural areas in the North Central (NC) region (which includes Iowa) and in the Southeast (SE) region.

Costs of Growing Biomass

Development of energy crops in the US is focussed on short-rotation woody crops for some regions and on herbaceous crops for others [Hohenstein and Wright, 1994]. Switchgrass is a primary candidate energy crop for the North Central (NC) and Southeast (SE) regions.

Switchgrass yield and cost projections made by analysts at the Oak Ridge National Laboratory [Walsh and Graham, 1995] provide the basis for biomass production costs presented here. Walsh and Graham give estimates of per-hectare yields and costs for four regions of the US (Northeast, North Central, Southeast, and South Central). They identify sub-regions by land capability class (LCC). LCC 1 has few restrictions on use for crops. LCC2 through LCC4 have variable suitability for crops, and LCC 5 through LCC 8 are generally unsuited for crop production. Within each LCC, soils are sub-defined by the primary reason for restrictions on their use as cropland: *e* -- erosion potential; *w* -- excessive water; *c* -- extreme climate; and *s* -- soil factors (salinity, shallowness, texture, etc.).

---

[2] The GIS is the MapBox package of Decision Images, Inc. of Princeton, New Jersey [Tomlin, 1990]. Transport distances for each map unit (acre) are found by locating the nearest point on the road system, and counting the distance along the road system to the conversion facility. The result is a map on which every acre has an assigned road transport distance.

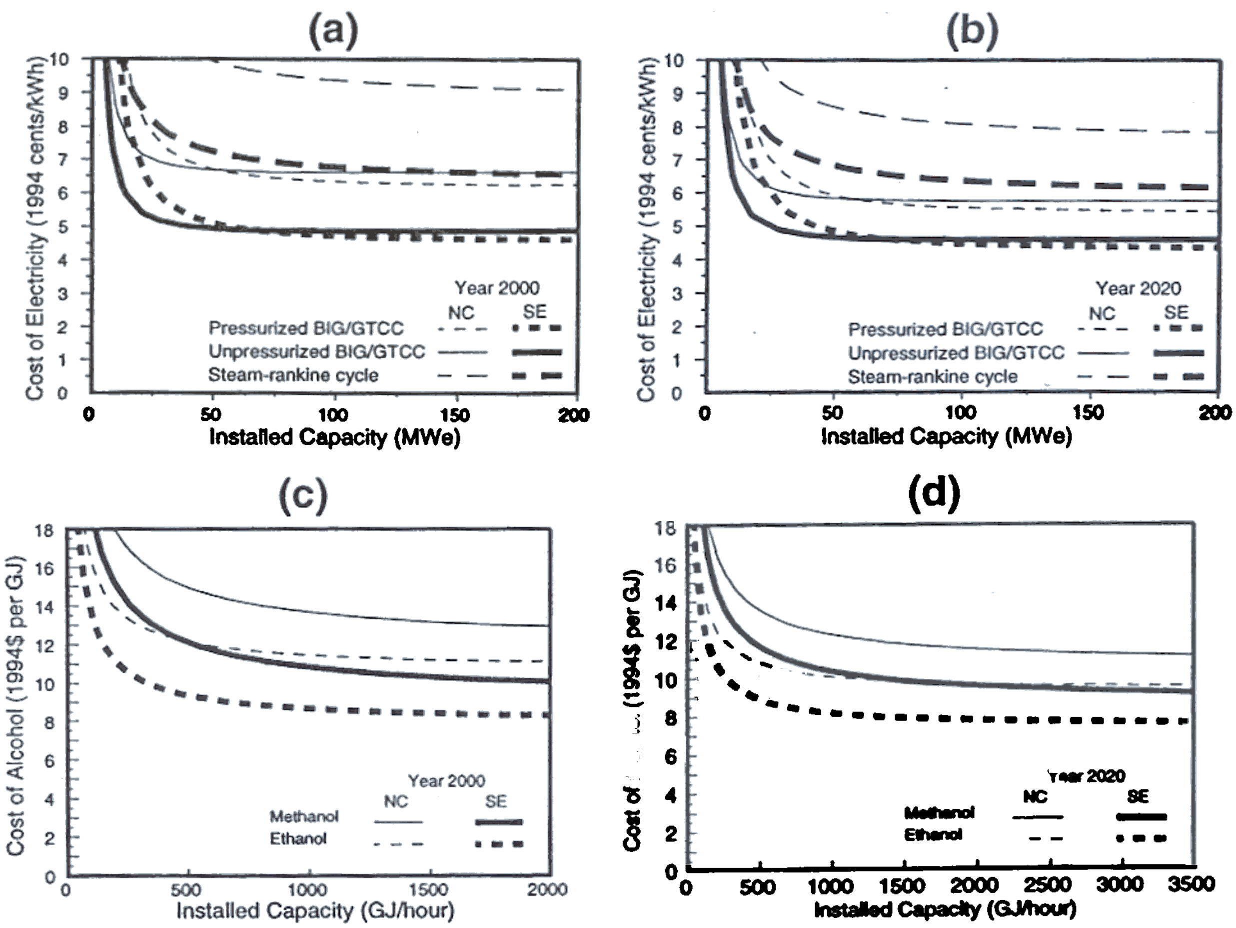


Fig. 3. *(a) and (b)* Total levelized cost of electricity production as a function of installed capacity for the selected site in the NC and SE regions in 2000 and 2020. *(c) and (d)* Total levelized cost of methanol and ethanol production as a function of capacity.