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TECHNO-ECONOMIC ANALYSIS OF BIOREFINERY UTILIZING GEOTHERMAL ENERGY FOR PROCESSING

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ABSTRACT

A techno-economic study of geothermal energy utilization in biorefineries is conducted using ASPEN Plus and corresponding economic analysis tools. The biorefinery is based on a gasification platform to produce synthesis gas, which in turn is synthesized to produce liquid transportation fuels. The biorefinery uses 2,000 metric tonnes of corn stover per day, and the products include hydrogen, gasoline, diesel fuel, and electricity. In this study, various streams of purchased steam are replaced by steam at 150°C derived from geothermal resources. Geothermal steam is used in various ways including as a gasifying agent, for syngas reforming, and biomass drying. Results show that the price of transportation fuels produced from the present biorefinery utilizing geothermal energy is comparable to that using the purchased steam. The major benefit of utilizing geothermal steam is the reduction of greenhouse gas emissions resulting from combustion of petroleum fuels used to generate the purchased steam.

1. INTRODUCTION

Geothermal energy is a renewable alternative to fossil energy for the supply of clean energy to meet increasing global energy demands. Geothermal heat is the energy derived from the earth's interior. This heat can be held in hot water or steam and represents a potentially vast energy resource. Typical engineered geothermal systems have the potential to reach temperatures between 100 °C to 180 °C, with geothermal resources in the Midwestern United States likely to be near the bottom of this range. Although modest by power generation standards, this temperature range is well suited to many of the process energy needs of an integrated biorefinery and biopower plant. It is of critical interest to explore the potential of integrating geothermal resources with biomass energy systems.

Biomass (e.g., wood, agricultural residues, forestry residues, energy crops, etc.) is a renewable fuel and is the fourth largest energy source following coal, oil, and natural gas. Compared to fossil fuels, the use of residual biomass has the advantage of reducing overall carbon emissions. Due to the concern about the effects of climate change, substantial research and development efforts are focused on the efficient utilization of biomass as an alternative energy source. The widespread availability of biomass is recognized, and it has the potential to supply a large amount of energy with less environmental impact than fossil fuels (Maniatis et al., 2002). The use of biomass as an energy source has increased in recent years and special attention is paid to biomass gasification.

Biomass can be converted to commercial products via biological or thermochemical processes (Lin et al., 2006, Caputo et al., 2005, Yoshioka et al., 2005). Biological conversion of low-value lignocellulosic biomass still faces challenges related to economic factors and low efficiency (Lin et al., 2006). Combustion, pyrolysis and gasification are the three main thermochemical conversion methods. Traditionally biomass is combusted to supply heat and power in the process industry. The net efficiency for electricity generation from biomass combustion can be relatively low, ranging from 20% to 40% (Caputo et al., 2005). Pyrolysis converts biomass to bio-oil in the absence of oxygen. At the present time, the limited use and difficulties in downstream processing of bio-oil may limit the widespread application of biomass pyrolysis technology in the short term (Faaij, 2006). On the other hand, gasification converts biomass, through partial oxidation, to a gaseous mixture with small quantities of char and condensable compounds. It is considered an effective method of converting the energy embedded in biomass, and it is also an alternative for the reuse of solid waste. The synthesis gas (syngas) derived from biomass gasification can be burned to generate heat and power or synthesized to produce liquid fuels.

This study considers the potential for utilizing geothermal energy to replace fossil fuel energy, including capital and production costs of a lignocellulosic biomass-to-liquid production plant based on the thermochemical pathway of gasification. The main focus is to produce liquid transportation fuels via Fischer-Tropsch synthesis with electricity as co-product using commercial technology available for implementation within the next 5 to 8 years. The proposed biorefinery uses 2,000 tonnes per day of corn stover. In a biorefinery, process heat and steam are used in various processes. The heat and steam are typically generated via combustion of fossil fuels (e.g., natural gas). This paper presents the technical and economic factors for a biorefinery utilizing geothermal energy in various processes within the plant.

2. MODEL FORMULATION

The following steps were taken to perform this study. (1) Using the criteria described in Section 2.1, a gasification scenario was selected for detailed analysis. (2) A process model for this scenario was developed using Aspen Plus process engineering software. (3) Equipment lists were generated and unit costs were evaluated using literature sources and Aspen Icarus Process Evaluator. (4) Capital investments were estimated and fuel product value (PV) at zero net present value and 10% internal rate of return (after tax) was determined for the n^{th} plant scenario. (5) Analysis for the pioneer plant was conducted for each scenario to estimate the capital investment and product value for the first plant of its kind.

2.1. Scenario Selection

Based on the previous experience with biomass by many companies (Aden et al. 2002) and the availability of performance data, a low temperature, fluidized bed gasifier was chosen. Advantages of fluidized bed gasification are simple construction and operation, lower capital cost, and high heat transfer rates within the bed. Catalytic tar reduction and water scrubbing were considered for syngas cleaning. Due to the uncertainty in commercial readiness for hot gas cleaning, e.g. catalytic tar cracking, cold gas cleaning (i.e. direct quench water scrubbing) was chosen in this study. Catalytic synthesis was chosen for fuel production. The feed rate used in this study is consistent with feasible agricultural residue outputs at the assumed feedstock delivery price. This scenario was chosen based on the following criteria:

- The technology under consideration should be commercially feasible in the next 5 to 8 years and preferably with a high level of technology development.
- The size of the biorefinery should be feasible with current agricultural output.
- The end products should be compatible with the present transportation infrastructure, i.e. gasoline and diesel fuel.

2.2. Process Design

Beginning at the plant entry gate, it was assumed that corn stover feedstock (25 wt% moisture and 6% ash content, wet basis) is purchased for $75 per tonne (Swanson et al. 2010). Cost of transportation and grower payment was assumed to be included in feedstock price. The main operational areas include preprocessing, where biomass is dried and ground according to the requirements of each gasification technology, gasification, where ground biomass is pressurized and gasified to produce medium energy content syngas, syngas cleaning, where syngas is cooled and cleaned of undesired components, fuel synthesis, where clean syngas is catalytically reacted to produce raw mixtures of hydrocarbons via the Fischer-Tropsch process, hydroprocessing, where the raw fuel is further refined, power generation, where unconverted syngas is combusted to provide electric power, and air separation unit, where nitrogen is removed from air to provide oxygen for gasification. Based on previous gasification units in operation, it was assumed that 85% annual availability (7500 h per year) is feasible for the n^{th} plant (Evaluation, 2005). The main assumptions used in the n^{th} plant scenario are as follows:

- Plant capacity is 2,000 tonnes/day.
- All financial values are adjusted to the year of 2007.
- Product Value (PV) of the fuel is evaluated at 10% internal rate of return.
- Life of the plant is 20 years.
- Plant availability is 310 days per year.

3. BASELINE CONDITION

The baseline scenario is a 2,000 tonnes per day corn stover-fed gasification biorefinery that produces gasoline and diesel fuel as well as electricity for export. It is based on a pressurized, oxygen/steam blown fluidized bed gasifier. Steam purchased at 200 °C is used in three processes, including biomass drying, as a gasification agent, and steam-methane reforming. Biomass drying requires 15,000 tonnes/day of steam, which is recycled and reheated using the heat generated from biochar combustion. For gasification and steam reforming, the requirements are 352 tonnes/day and 1,000 tonnes/day, respectively.

4. ECONOMIC ANALYSIS

Capital investment and annual operating costs and product value are estimated considering the operation of a plant for 20 years. Total capital investment includes equipment cost, installation cost, and indirect cost. A discounted cash flow rate-of-return (DCFROR) analysis is also conducted. A product value (PV) per gallon of "gasoline equivalent" is determined at a net present value of zero, given a 10% rate of return on investment. All financial values are adjusted to and reported for the 2007 cost year. Using literature sources and Aspen Icarus Process Evaluator software, the equipment employed in this study are sized and the corresponding costs are estimated. After total purchased equipment cost (TPEC) and total installed cost (TIC) are determined, indirect costs are applied. Indirect costs (IC) include engineering and supervision, construction expenses, and legal and contractor's fees at 32%, 34%, and 23% of TPEC, respectively (Peters and Timmerhaus, 2003). Project contingency is added as 20% of total direct and indirect cost (TDIC). TDIC is set as the sum of IC and total installed costs (TIC). With project contingency added the Fixed Capital Investment is determined. Total Capital Investment (TCI) is determined by adding working capital to Fixed Capital Investment (FCI) and thereby represents the overall investment required. Table 1 lists the capital costs.

Table 1: Capital cost estimation method for n^{th} plant scenario.

Parameter	**Method**
Total Purchased Equipment Cost (TPEC)	Aspen Icarus Process Evaluator®
Total Installed Cost (TIC)	TPEC * Installation Factor
Indirect Cost (IC)	89% of TPEC
Total Direct and Indirect Costs (TDIC)	TIC + IC
Contingency	20% of TDIC
Fixed Capital Investment (FCI)	TDIC + Contingency
Working Capital (WC)	15% of FCI
Total Capital Investment (TCI)	FCI + WC

5. RESULTS

5.1 Baseline Condition

The breakdown of costs and resulting total capital investment is shown in Tables 2 and 3. Total capital investment is $498 million. Major areas of investment are the gasification area, the fuel synthesis area, the syngas cleanup section. The prices of the fuels are calculated considering the capital costs, operating costs, and equipment costs.

Table 2: Results from the baseline biorefinery.

Parameter	**Present study**
Plant Size (tonnes/day)	2,000
Total Capital Investment ($MM)	498
Availability (hour/year)	7,500
Rate of Return (%)	10
Fuel Yield (MMGGE/yr)	32.3
Product Value ($/GJ)	39.80
Product Value ($/GGE)	**4.92**

Table 3: Capital investment breakdown for the n^{th} plant scenario.

Area	**Installation Cost**	
	($MM)	%
Preprocessing	22.7	9
Gasification	28.2	11
Syngas Cleaning	29.3	12
Fuel Synthesis	58.7	23
Hydroprocessing	29.5	12
Power Generation	38.9	15
Air Separation Unit	19.5	8
Balance of Plant	27.2	11
Total Installed Cost	**253.9**	
Indirect Cost	**107.2**	
Total Direct and Indirect Cost	**361.1**	
Contingency	**72.2**	
Fixed Capital Investment	**433.3**	
Working Capital	**65.0**	
Total Capital Investment	**498.3**	

In addition to the fuel that is produced, the biorefinery uses the non-condensable gases from the gasification and upgrading processes to produce excess power of 16MW which is sold as a byproduct. An energy balance of the scenario shows that the biomass to fuels efficiency for this present study is 39%. This efficiency is low partially because mass and energy loss occurs in the production and removal of char and tar. Char and tar energy loss is 7.5% of the energy in the biomass. In this scenario char is combusted in a fluidized bed combustor to provide heat for biomass drying. A carbon balance analysis shows only a 26% conversion of carbon from biomass to fuels. Throughout the scenario steam and cooling water are required as utilities. Since a pinch analysis (a method to optimize heat exchange) is not undertaken for this study, integration of the heat streams is not optimized.

5.2 Study 1: Using Geothermal Steam for Gasification and Reforming

In the following scenario, geothermal energy is used for gasification and steam-methane reforming instead of purchased steam. Steam is generated from geothermal resources. The temperature of the geothermal steam is ~150 °C. It is available at a rate of 40 to 60 kg/sec. This steam is used as a gasification agent at a rate of 352 tonnes/day and as a reforming agent with a flow rate of 1,000 tonnes/day. Results are obtained initially for the case in which the price of geothermal steam is $5/MMBtu. The price of the transportation fuel product is determined by taking into account the capital costs, the operating costs, and equipment costs of all the units in the biorefinery. Results are shown in Table 4.

The price of the transportation fuels obtained from the present economic analysis indicates that geothermal steam can be used as a substitute for the purchased steam. In the original baseline condition using purchased steam, approximately 4,000 tonnes/day of natural gas is needed to produce the steam. By the use of geothermal steam, this natural gas is no longer required, thus reducing consumption and fossil fuel and greenhouse gas emissions significantly. As a result, the entire biorefinery becomes more environmentally sustainable with the use of geothermal energy. A sensitivity study is conducted by varying the price of the geothermal energy, and the results are shown in Table 5. It can be seen that the product value is within a reasonable range when the cost of geothermal energy varies between $3 and $7 per MMBtu. Thus, using geothermal energy in a biorefinery appears to be viable.

Table 4: Results of the current biorefinery utilizing geothermal energy for gasification and reforming

Parameter	**Present study**
Plant Size (tonnes / day)	2000
Fuel Yield (MMGGE/yr)	32.3
Product Value ($/GGE)	**4.96**

Table 5: Sensitivity analysis of geothermal steam price

	Price of geothermal steam ($ /MMBtu)	Cost of gasoline ($/GGE)
Baseline	n/a	$4.92
	$0	$4.8
	$3	$4.89
	$5	$4.96
	$7	$5.02

5.3 Study 2: De-centralized Biomass Drying

In this scenario, geothermal energy is used to dry biomass instead of combusting char to produce the process steam. This results in decreased greenhouse gas emissions and allows for extra revenue generation from the sale of biochar. A range of the total amount of biomass that could be dried using one geothermal reservoir was determined by varying the initial temperature, exit temperature, and the flowrate of the geothermal steam that was used to dry the biomass. Values used were chosen for regional expectations for a location near Iowa State University (Ames, Iowa). Results of this study are shown in Table 6. It can be seen that one geothermal well is not sufficient to meet the biomass requirements of a 2,000 tonne/day refinery. Rather, between four and nine wells are required based on the operating conditions of each well, depending on the inlet and outlet temperature of the geothermal steam in the heat exchanger used for drying and the steam flow rate. For the nominal condition (Case 5), about 7 to 8 wells would be required. This suggests a benefit would be gained by building several smaller de-centralized locations to dry and process the biomass before transporting it to one large gasification facility. Major benefits from this include decreased shipping costs of the stover as well as decreased thermal load applied to geothermal resources at the central location.

A sensitivity study is conducted by varying the number of de-centralized drying facilities, and analyzing the effect on the final cost of the product fuel. The results of this analysis are shown in Table 7. For this study, the cost of geothermal steam is assumed to be zero and the benefit from decreased transportation costs and profits from the sale of biochar are not considered. The price of the transportation fuels obtained from the present economic analysis using geothermal steam is between $0.05 and $0.51 per gallon more expensive than the base case utilizing purchased steam. This indicates that a de-centralized geothermal drying concept is economically viable and could become increasingly important with future legislation on greenhouse gas emissions.

Table 6: Drying parametric study

CASE	Initial GS Temp (°C)	Final GS Temp (°C)	Stover Dried (Tonne/day) Flowrate 40 kg/s	50 kg/s	60 kg/s
1	130	100	-	221	235
2	130	110	-	-	-
3	130	120	-	-	-
4	150	100	261	327	395
5	150	110	217	261	319
6	150	120	-	221	236
7	170	100	371	468	542
8	170	110	320	396	479
9	170	120	262	329	396

Table 7: Sensitivity analysis of number of drying facilities

	Number of Drying Facilities	Cost of gasoline ($/GGE)
Baseline	n/a	$4.92
	4	$4.97
	5	$5.06
	6	$5.14
	7	$5.25
	8	$5.34
	9	$5.43

6. CONCLUSIONS

According to the current analysis, geothermal energy can be substituted for purchased steam in a biorefinery at a comparable cost while resulting in lower greenhouse gas emissions and greater availability of additional co-products which can be sold. Major variables contributing to the cost of producing transportation fuels from geothermal energy sources include the production price of geothermal steam and the extraction temperatures and flow rates available. Cost of transportation fuels produced utilizing geothermal steam range from $4.80 to $5.43 compared to producing them from purchased steam at a cost of $4.92.

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