

**Economic Evaluation of CO₂ Sequestration Technologies
Task 4, Biomass Gasification-Based Processing**

Final Technical Report

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ABSTRACT

Biomass derived energy currently accounts for about 3 quads of total primary energy use in the United States. Of this amount, about 0.8 quads are used for power generation. Several biomass energy production technologies exist today which contribute to this energy mix. Biomass combustion technologies have been the dominant source of biomass energy production, both historically and during the past two decades of expansion of modern biomass energy in the U. S. and Europe. As a research and development activity, biomass gasification has usually been the major emphasis as a method of more efficiently utilizing the energy potential of biomass, particularly wood. Numerous biomass gasification technologies exist today in various stages of development. Some are simple systems, while others employ a high degree of integration for maximum energy utilization. The purpose of this study is to conduct a technical and economic comparison of up to three biomass gasification technologies, including the carbon dioxide emissions reduction potential of each. To accomplish this, a literature search was first conducted to determine which technologies were most promising based on a specific set of criteria. The technical and economic performances of the selected processes were evaluated using computer models and available literature. Using these results, the carbon sequestration potential of the three technologies was then evaluated. The results of these evaluations are given in this final report

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1.0 INTRODUCTION

Biomass derived energy currently accounts for about 3 quads of total primary energy use in the United States. Of this amount, about 0.8 quads are used for power generation (EPRI 2001). Several biomass energy production technologies exist today which contribute to this energy mix. Biomass combustion technologies have been the dominant source of biomass energy production, both historically and during the past two decades of expansion of modern biomass energy in the U. S. and Europe. As a research and development activity, biomass gasification has usually been the major emphasis as a method of more efficiently utilizing the energy potential of biomass, particularly wood. Gasification technology was first commercialized using coal, however biomass resources such as wood have a unique environmental advantage over traditional fossil fuels in that the gasification of biomass has a mitigating effect on global warming, when a renewable biomass fuel is used instead of a fossil fuel. Also, biomass feedstocks are typically lower in sulfur and nitrogen than most coals.

Numerous biomass gasification technologies exist today in various stages of development. Some are simple systems, while others employ a high degree of integration for maximum energy utilization. "Integration" refers in a general way to obtaining heat and multiple products, in addition to electricity from the fuel or feedstock used. In a specialized way in gasification power systems, "integration" refers to use of the heat and steam flows from the gasification and gas cleaning steps in the process, for enhancement of the other parts of the process. One important example of such integration is the use of steam raised in syngas cooling as part of the steam flow into the steam power section of an IGCC power plant. (IGCC is an integrated gasification combined cycle).

Advanced biomass gasification offers the flexibility of producing a fuel gas with sufficient energy content to be utilized in advanced integrated combined cycle power systems. The higher energy content of the advanced biomass gasification processes also improves the capability for the biomass-derived gas to be further processed for chemical production.

The purpose of this study is to conduct a technical and economic comparison of up to three biomass gasification technologies, including the carbon dioxide emissions reduction potential of each. To accomplish this, a literature search was first conducted to determine which technologies were most promising based on a specific set of criteria. The technical and economic performances of the selected processes were evaluated using computer models and available literature. Evaluation methods developed by EPRI (the Electric Power Research Institute) were then used to determine the carbon dioxide reduction potential of the technologies. The results of this study are summarized in this final report.

2.0 EXECUTIVE SUMMARY

Biomass derived energy currently accounts for about 3 quads of total primary energy use in the United States. Of this amount, about 0.8 quads are used for power generation (Renewable Energy Assessment Guide—TAG-RE, 2001). Several biomass energy production technologies exist today which contribute to this energy mix. Biomass combustion technologies have been the dominant source of biomass energy production, both historically and during the past two decades of expansion of modern biomass energy in the U. S. and Europe. As a research and development activity, biomass gasification has usually been the major emphasis as a method of more efficiently utilizing the energy potential of biomass, particularly wood. Numerous biomass gasification technologies exist today in various stages of development. Some are simple systems, while others employ a high degree of integration for maximum energy utilization. The purpose of this study is to conduct a technical and economic comparison of up to three biomass gasification technologies, including the carbon dioxide emissions reduction potential of each. To accomplish this, a literature search was first conducted to determine which technologies were most promising based on a specific set of criteria. The technical and economic performances of the selected processes were evaluated using computer models and available literature. The carbon sequestration potential of the three technologies was then evaluated. The results of these evaluations are summarized in this report

2.1 Literature Review

The literature search was compiled from over 250 sources including websites, journals, conference proceedings, books, and personal communications. From these sources, 22 biomass gasification technologies were screened to identify and define various systems for heat and/or electrical power generation. These systems are shown in Table 1.

Table 1
Biomass Gasification Systems Evaluated

Biomass Gasification for Heat and/or Power Generation	Biomass Gasification for Advanced Power Cycles
BG Technologies USA, Inc.	Foster Wheeler Bioneer, atmospheric updraft gasifier
BIVKIN Gasification Technology	Foster Wheeler Pyroflow atmospheric circulating fluidized-bed gasifier
Brightstar Synfuels Co.	Foster Wheeler Bioflow pressurized circulating fluidized-bed gasifier
Cratech Gasification System	Battelle High Throughput Gasification Process, (FERCO)
Energy Products of Idaho	GTI RENUGAS pressurized fluidized bed gasifier
Enerkem-Biosyn Gasification	Energy Farm Project in Di Cascian, Italy
PRM Energy Systems, Inc.	ARBRE Energy Project
Thermogenics	Brazil Biomass Integration Gasification-Gas Turbine Project
Thermoselect, S.A.	BioCoComb
TPS Termiska Processor AB	
Thermal Technologies, Inc.	
Etho Power Corporation	
Emery Gasification	

The technologies evaluated can be divided into two groups: simple systems suitable for developing countries which have large readily available biomass, and advanced systems needed for Western countries for power and combined heat/power generation. Advanced systems provide high efficiencies with reduced emissions to mitigate greenhouse gas emissions.

Each technology was evaluated based on the criteria described below.

- Efficiency
- Flexibility/Applicability/Fuel gas and synthesis gas
- Technical maturity
- Data availability
- Ease of operability
- Scalability
- High pressure for IGCC integration
- Feedstocks

- Industrial acceptance
- Size, footprint
- Simple system

Three technologies were identified for further evaluation based on their ability to best fulfill the rationale for concept selection, while representing a range of gasification technologies. These technologies are as follows: the GTI Renugas pressurized gasification technology, the Battelle High Throughput Gasification Process (FERCO), and the GTI Renugas atmospheric gasification technology.

A conceptual design was prepared for each of the three technologies selected. The design was used to compare the technical and economic feasibility of each technology. The process designs and the results of the comparison are given in the next section.

2.2 Comparison of Gasification Systems for Power, Fuel, and Chemical Production

Based on the results of the literature search, the pressurized Renugas process, the atmospheric Renugas process, and the atmospheric process developed by Battelle/FERCO were chosen for further evaluation. Using these three technologies, a base case power production scenario using an integrated combined cycle system was defined for each gasification technology. Two additional alternative scenarios were evaluated to compare the technical and economic feasibility of producing liquid fuel and chemicals from the product gases. Methanol and ammonia were chosen for evaluation as fuel and chemical products, respectively. The choice of methanol as a fuel was based on the potential to utilize methanol in combustion turbines for additional electricity production. Ammonia was chosen based on its abundance as a commodity chemical and on in-house expertise in the modeling of ammonia systems.

To determine the technical and economic feasibility of the scenarios described above, a base case power system design was developed for each gasification technology. ChemCad was used to model the Renugas gasification systems. Insufficient published data was available for the FERCO gasification system to allow the development of a ChemCad model within the time frame of this project. Instead, published information concerning the FERCO gas stream composition was used to develop a feed stream for the power, fuel, and chemical production models. The Battelle/FERCO process described in this study is derived from information published in the report entitled “Cost and Performance Analysis of Three Integrated Biomass Gasification Combined Cycle Power Systems” (Craig and Mann, 1990). Modeling of the three gasification technologies is described below.

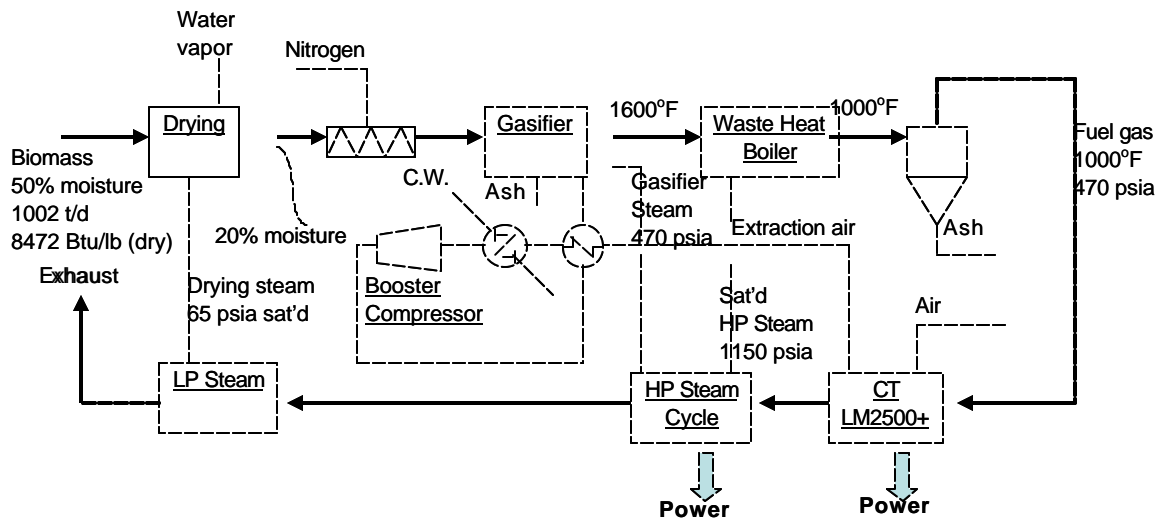
2.2.1 Pressurized and Atmospheric Renugas Gasification Models

The Renugas processes were modeled from detailed information provided by the developer for the pressurized version of the process. The initial model was constructed to almost exactly match the heat and material balance provided.

Figure 1 is a block flow diagram of the Renugas pressurized gasification process with integrated combined cycle power generation. Raw hardwood biomass containing 50 percent moisture is dried with low pressure steam to 20 percent moisture content. The partially dried biomass is fed via screw conveyor to the biomass gasifier. The gasifier operates at a pressure of 470 psia. A small amount of nitrogen (obtained by vaporizing liquid nitrogen) is fed to the conveyor to act as a seal against backflow of the pressurized hot gases from the gasifier. The biomass is partially oxidized with hot (>800°F) air in the gasifier. This air is obtained by extracting a portion of the air from the air compressor of the combustion turbine (CT) (about 10 percent of the CT air flow is extracted). The hot air from the CT's compressor is cooled and then compressed with a booster compressor to raise the pressure from nominally 350 psia to that of the gasifier, 470 psia. The CT air is partially cooled in an economizer, which rewarms the air from the booster compressor, thereby preserving most of the heat of compression in the CT compressor. The gasifier is operated at a temperature of 1600°F, which is set by controlling the rate of air extraction from the CT. Steam is also fed to the gasifier to promote carbon conversion. A carbon conversion of 99 percent is assumed based on the estimates of the Renugas process developer. Because there is no direct source of 470 psia steam in the process, steam is extracted from the high pressure (1150 psia) side of the steam cycle. The hot air from the CT's compressor is cooled and then compressed with a booster compressor to raise the pressure from nominally 350 psia to that of the gasifier, 470 psia. The CT air is partially cooled in an economizer, which rewarms the air from the booster compressor, thereby preserving most of the heat of compression in the CT compressor. The gasifier is operated at a temperature of 1600°F, which is set by controlling the rate of air extraction from the CT. Steam is also fed to the gasifier to promote carbon conversion. A carbon conversion of 99 percent is assumed based on the estimates of the Renugas process developer. Because there is no direct source of 470 psia steam in the process, steam is extracted from the high pressure (1150 psia) side of the steam cycle.

Figure 1

Renugas Pressurized Gasification System



The gasifier operates at a pressure of 470 psia. A small amount of nitrogen (obtained by vaporizing liquid nitrogen) is fed to the conveyor to act as a seal against backflow of the pressurized hot gases from the gasifier.

The biomass is partially oxidized with hot (>800°F) air in the gasifier. This air is obtained by extracting a portion of the air from the air compressor of the combustion turbine (CT) (about 10 percent of the CT air flow is extracted). The hot air from the CT's compressor is cooled and then compressed with a booster compressor to raise the pressure from nominally 350 psia to that of the gasifier, 470 psia. The CT air is partially cooled in an economizer, which rewarms the air from the booster compressor, thereby preserving most of the heat of compression in the CT compressor.

The gasifier is operated at a temperature of 1600°F, which is set by controlling the rate of air extraction from the CT. Steam is also fed to the gasifier to promote carbon conversion. A carbon conversion of 99 percent is assumed based on the estimates of the Renugas process developer. Because there is no direct source of 470 psia steam in the process, steam is extracted from the high pressure (1150 psia) side of the steam cycle.

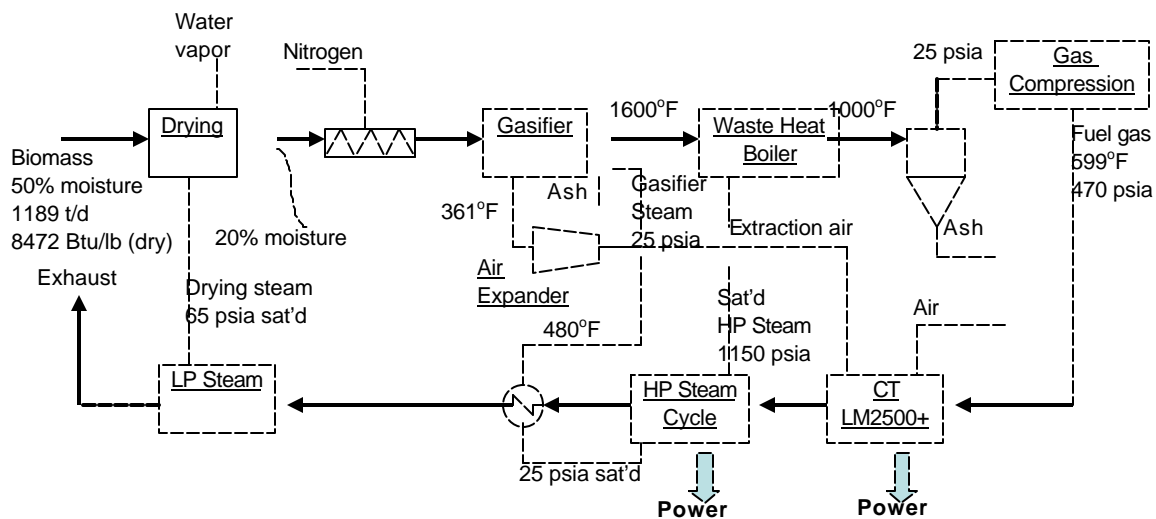
turbine in the steam cycle. At the point of extraction from the turbine, the steam is superheated by about 180°F.

Figure 2 is a block flow diagram of the Renugas atmospheric-pressure gasification process with integrated combined cycle power generation. The gasification process is essentially the same as the pressurized version discussed above except that the gasifier operates at a pressure near atmospheric (25 psia). A compression step has been added to raise the pressure of the fuel gas to 470 psia for firing in the CT. This step consists of an economizer heat exchanger (to cool the low-pressure gas by re-warming the compressed gas), a cooler, and a 5-stage intercooled compressor train.

Rather than the booster compressor, which is no longer needed, extraction air from the CT is routed through an air expander to generate supplemental power.

Figure 2

Renugas Atmospheric Gasification System



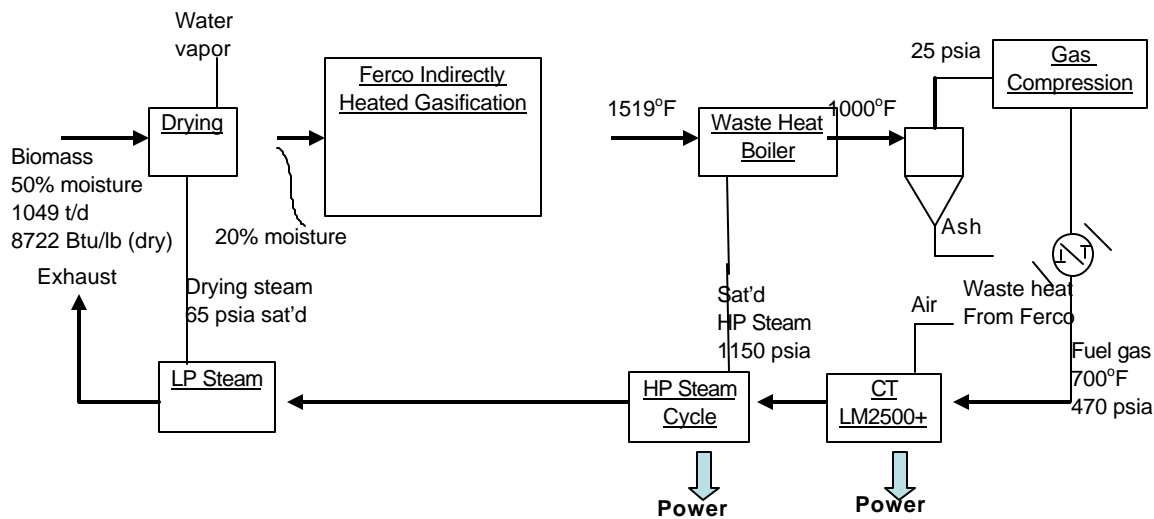
Steam for the gasifier is extracted at 25 psia from the steam turbine. Since this extracted steam is low quality (about 2 percent condensate), it was heated in the HRSG to 480°F, which is the steam temperature used by Renugas in their models.

2.2.2 Battelle/FERCO Gasification Model

Figure 3 is a block flow diagram of the FERCO gasification process with integrated combined cycle power generation. The FERCO gasification process was not modeled because of time constraints and because of a lack of detailed process information such as that provided by the developers of Renugas.

Figure 3

Battelle-FERCO Gasification System



Instead, the FERCO process was treated as a “black box,” with feedstock and gas production information derived from the open literature (Craig and Mann, 1990).

2.2.3 Gasification Plant Design

Using these models, a conceptual design was prepared for each of the base case systems and the methanol and ammonia scenarios. These designs are based on information found in the Craig and Mann report, internal TVA reports, and external contractor information. The following general premises were used to develop the conceptual designs:

- Wood as feedstock
- 1,000 ton per day nominal plant capacity
- 30 year plant life
- nth plant, minimal equipment redundancy
- 90.4% plant availability

The design consists of the following major plant areas: feedstock handling, feedstock drying, gasification, gas clean-up, combustion turbine, and HRSG.

2.2.4 Base Case Performance Summary

A summary of process data and system performance for the base case plant designs involving power production is given in Table 2.

Table 2

Process Data Summary and System Performance Results – Base Case CT System

	Pressurized Renugas	Atmospheric Renugas	FERCO
Gasifier Requirements			
Wood Flowrate, 20% moisture, tonnes/daymtpd (tpd)	569 (626)	675 (743)	596 (656)
Air Flowrate, kg/hr (lb/h)	25,630 (56,500)	43,549 (96,000)	-
Steam Flowrate,kg/h (lb/h)	1,379(3,039)	1,649(3,626)	11,162 (24,600)
Fuel Gas			
Fuel Gas Flowrate, kg/hr (lb/h)	5,701 (12,569)	73,535 (162,100)	43,948 (43,948)
Fuel Gas Heating Value, HHV, Wet Basis, MJ/kg (Btu/lb)	5.79 (2491)	4.40 (1892)	14.6 (6279)
Power Island			
Gas Turbine	LM2500+	LM2500+	LM2500+
Power Production Summary			
Gas Turbine Output, MW	31.7	33.45	30.05
Steam Turbine Output, MW	11.36	12.18	8.43
Net System Output, MW	42.05	41.86	36.05
Net Plant eff, HHV Basis, %	40.6%	34.0%	32.3%

As shown in the table, wood flowrates varied slightly for each system based on the heating value of the gas produced. As mentioned earlier, a nominal plant size of 1,000 tpd was selected for the design. The flowrate shown in the table are at 20% moisture, after the incoming biomass has been dried.

2.2.5 Methanol and Ammonia Plant Designs

A plant design for the alternative scenarios involving methanol and ammonia was prepared. The plant would be almost identical to the base case design with the exception of the addition of an air separation unit for the Renugas systems and the addition of methanol and ammonia production systems. A cryogenic air separation unit was selected as the source of the 95 percent purity oxygen used in the production of methanol and ammonia. For methanol and ammonia production, the SMR units used in the designs are skid-mounted units manufactured by Hydro-Chem, a subsidiary of Linde AG. The units consist of a fired unit containing catalyst tubes.

2.2.6 Methanol Performance Summary

Process performance data for the methanol production scenario is shown in Table 3. For the methanol scenarios, the Renugas systems both use 95% oxygen during the gasification process as opposed to air used in the combustion turbine scenario.

Table 3

Process Data Summary and System Performance Results – Methanol

	Pressurized Renugas	Atmospheric Renugas	FERCO
Gasifier Requirements			
Wood Flowrate, 20% moisture, tonnes/day (tpd)	569 (626)	675 (743)	596 (656)
Air Flowrate, kg/hr (lb/h)	5,217 (11,500)	7,374 (16,256)	-
Steam Flowrate, kg/hr (lb/h)	1,379 (3,039)	1,644 (3,626)	11,162 (24,600)
Fuel Gas			
Fuel Gas Flowrate, kg/hr (lb/h)	32,949 (72,632)	38,103 (83,995)	19,937 (43,948)
Fuel Gas Heating Value, HHV, Wet Basis, MJ/kg (Btu/lb)	9.30 (3,997)	9.48 (4,076)	14.6 (6,279)
Power Production Summary			
Gas Turbine Output, MW	-	-	-
Steam Turbine Output, MW	1.25	1.77	-
Net System Output, MW	-4.21	-7.89	-2.99
Methanol Production Summary			
Methanol, tonnes/day (tpd)	283 (311)	325 (358)	291 (320)

As a result, the gas quantities produced by these two technologies are much smaller than in the combustion scenario.

2.2.7 Ammonia Performance Summary

Table 4 gives a summary of process performance for the ammonia production scenario. The gas streams for this scenario are the same as in the methanol scenario. In this scenario, a significant amount of electricity is produced through expansion in the process.

Table 4

Process Data Summary and System Performance Results – Ammonia

	Pressurized Renugas	Atmospheric Renugas	FERCO
Gasifier Requirements			
Wood Flowrate, 20% moisture, tonnes/day (tpd)	569 (626)	675 (743)	596 (656)
95% Oxygen Flowrate, kg/hr (lb/h)	5,217 (11,500)	7,374 (16,256)	-
Steam Flowrate, kg/hr (lb/h)	1,379 (3,039)	1,644 (3,626)	-
Fuel Gas			
Fuel Gas Flowrate, kg/hr (lb/h)	32,949 (72,632)	38,103 (83,995)	19,937 (43,948)
Fuel Gas Heating Value, HHV, Wet Basis, MJ/kg (Btu/lb)	9.3 (3,997)	9.48 (4,076)	14.6 (6,279)
Power Production Summary			
Gas Turbine Output, MW	-	-	-
Steam Turbine Output, MW	1.25	1.77	-
Net System Output, MW	-5.87	-7.09	-2.89
Ammonia Production Summary			
Ammonia, tonnes/day (tpd)	206 (227)	235 (259)	165 (181)

2.3 Economic Evaluation

An economic evaluation of the various integrated systems was conducted using conceptual designs described in the previous sections. The estimate is considered a “factored estimate” with much of the cost

information being derived from the study conducted by Craig and Mann and in-house TVA estimates. The Craig and Mann study uses 1990 as a reference year for cost estimating purposes. For the purpose of this study, a reference year of 2001 is used. Therefore, the costs as presented in the Craig and Mann study were corrected for capacity and cost year using a capacity factor of 0.6 and the Chemical Engineering Cost Index of 400. The balance of plant was based on 20% of the total for other plant costs.

Total capital investment and operating costs are summarized for the nine scenarios in Tables 5 and 6, respectively. As shown in Table 21, total capital investment for power production was essentially the same for the three processes. The least cost scenario was methanol production using the FERCO process.

Table 5

Total Capital Investment Summary

Technology	Power Production \$M/year	NH3 Production \$M/year	Methanol Production \$M/year
Pressurized Renugas	102.3	152.1	87.1
Atmospheric Renugas	103.7	162.3	87.4
FERCO	102.0	129.7	80.8

Operating costs for the systems ranged from \$6.42 million for power production using the pressurized Renugas system to \$10.76 million for the ammonia system using the FERCO gasification technology.

Table 6

Annual Operating Costs Summary

Technology	Power Production \$M/year	NH3 Production \$M/year	Methanol Production \$M/year
Pressurized Renugas	6.42	10.02	7.15
Atmospheric Renugas	6.77	8.18	8.93
FERCO	6.79	10.76	6.93

Revenue from each system is shown in Table 23. As shown, the atmospheric Renugas system for ammonia production had the highest revenue of the nine scenarios.

Table 7**Revenue Summary**

Technology	Power Production \$K/year	NH₃ Production \$K/year	Methanol Production \$K/year
Pressurized Renugas	13,321	14,982	12,410
Atmospheric Renugas	13,261	17,067	10,293
FERCO	11,421	11,946	12,796

A summary of the corresponding product quantities is shown in Table 8.

Table 8**Product Summary**

Technology	Power Production (MW)	NH₃ Production (T/D)	Methanol Production (TPD)
Pressurized Renugas	1009	227	311
Atmospheric Renugas	1005	259	358
FERCO	865	181	320

2.4 Cost Of Avoiding Fossil CO₂ Emissions

Using the three scenarios defined in the previous sections, the cost of carbon dioxide sequestration was evaluated. The cost of greenhouse gas mitigation using renewable energy technologies depends on both the difference between the generation costs of the renewable energy option--i.e., in these cases, the generation of electricity or the production of methanol or ammonia--and the low-cost alternative (e.g., coal or natural gas fuel or feedstock for electricity generation or methanol/ammonia production). The mitigation costs are usually expressed in units of the cost per unit fossil carbon emissions that are avoided, offset, captured, sequestered, etc.

The potential of each of the three biomass gasification systems to provide CO₂ emissions reduction was calculated. The three technologies were compared with three existing technologies: conventional coal-

fired power plants, advanced coal systems, and natural gas fired combined cycle systems. When compared with a conventional coal-fired plant, the cost in \$/tonne C for the high pressure Renugas, FERCO, and low-pressure Renugas was \$77.08, \$115.63, and \$154.17, respectively. For an advanced coal-fired plant, the emissions control costs in \$/tonne C were \$93.31, \$135.73, and \$178.14, respectively, for high pressure Renugas, FERCO, and low pressure Renugas. The emissions control costs for the natural gas combined cycle plant were \$218.81, \$312.61, and \$416.82, respectively for the high pressure Renugas, FERCO, and low pressure Renugas systems.

2.5 Conclusions

Based on the results of this study, it can be concluded that the two Renugas processes have the most potential to maximize power production via gasification. Ammonia and methanol production also tend to favor the Renugas processes, though the FERCO process produced slightly more methanol than the atmospheric Renugas system.

In order to show biomass gasification as among the lower cost, rather than higher cost, fossil carbon sequestration options, more ambitious R&D goals are necessary. These more ambitious goals would involve one or more or a combination of items such as better efficiency, lower cost fuel, lower O&M costs, and lower capital cost. The lower capital costs may be especially difficult to obtain, as the goals adopted in this report are already rather ambitious.

These ambitious goals are as follows: (1) a natural gas combined cycle at \$700/kW as applied at 100-MWe unit size as the power conversion option downstream of a biomass gasification system; (2) only \$300/kWe to construct the system that performs biomass gasification, gas cleanup and ash/char removal from the gasifier, and then sends clean gaseous fuel to the combined cycle power unit; and, (3) only \$100/kW for a system to receive, handle and feed solid biomass fuel (or “feedstock”) into the gasification/cleanup unit. It is possible that better efficiency, lower fuel cost and lower O&M costs are more likely to be achieved than are capital costs below the \$1100/kWe goal. A combination of all, plus added revenues from other bio-based products or environmental benefit revenues (such as waste disposal and water quality improvements) are also likely to be required in a system that becomes a low cost carbon sequestration option.

3.0 EXPERIMENTAL

The sources, techniques, and criteria used throughout the report to complete the literature search and the technical and economic evaluation of selected gasification technologies are described in this section.

3.1 Literature Search

The literature search was compiled from over 250 sources including websites, journals, conference proceedings, books, and personal communications. Examples of various sources include:

- DOE Information Bridge
- DOE Bibliographic Database
- Renewable Resources Data Center
- NREL Publications
- Gasification Company Websites
- EPRI publications
- Internal TVA reports
- Personal communications

A complete list of these sources is included in the bibliography section of this report. As stated in the introduction, the purpose of the literature search was to select up to three gasification technologies for technical and economic comparison. The specific set of criteria used is as follows:

- Efficiency
- Flexibility/Applicability/Fuel gas and synthesis gas
- Technical maturity
- Data availability
- Ease of operability
- Scalability
- High pressure for IGCC integration
- Feedstocks
- Industrial acceptance
- Size, footprint
- Simple system

3.2 Technical and Economic Comparison of Gasification Technologies

The technical and economic comparison of the three selected gasification technologies was prepared using published information. Depending on the level of data available for each process, the technical

performance of each gasification technology was determined using Chemcad. Literature values were used in areas where there was insufficient data available to prepare an actual model.

Economic values for the technologies were derived from in-house estimates, available literature, and personal communications. Standard cost estimating techniques from the EPRI Technical Assessment Guide were used to estimate capital and operating costs.

3.3 Carbon Sequestration Evaluation

“Carbon sequestration” usually refers to the avoidance of new additions of man-made carbon dioxide (CO₂) to the atmosphere. The specific way of avoiding CO₂ additions that is usually called “sequestration” is the capture and confinement (“sequestration”) of the CO₂ as it is generated in the combustion step in power or heat generation, thereby preventing what would otherwise be a new emission into the atmosphere of CO₂ from a carbon atom that had been locked in the earth’s surface in the form of a coal, oil or natural gas deposit.

In this study, biomass gasification technologies that can make power, steam, heat and chemical products from renewable biomass fuels, or “feedstocks,” are considered in terms of their ability to accomplish the same purpose as the usual “sequestration” technologies: namely, the avoidance of new emission of fossil carbon into the atmosphere. Biomass gasification accomplishes such avoidance by using as the feedstock carbon that was already in the atmosphere, so no new emission of a new carbon previously locked in the earth’s surface occurs. “Renewable” biomass feedstock is necessary to accomplish this. Unless the biomass used to make the electricity, heat, steam or other product is replaced by as much or more new growth of biomass to make more such feedstock the CO₂ that is put into the atmosphere upon combustion of biomass fuel- or combustion of the biomass gas or other product made from the biomass fuel—is not balanced by the taking of CO₂ from the atmosphere as the replacement biomass is grown. For this loop to be closed” in this way, all that matters is that an equal amount of biomass be grown somewhere in the world. Natural forests, man-made forests, and farms that grow energy crop fuels are all equally suitable as places where the replacement growth occurs. Here “equally suitable” means suitable for a balance of global carbon in the atmosphere: same amount pulled out of the atmosphere as is put in by the combustion to make energy or fuel or chemicals.

The method used here to evaluate biomass gasification technologies as carbon sequestration options is presented later in the report. In a word, the method is to estimate the cost of making electricity or chemicals via biomass gasification, subtract the cost of making the same product from fossil fuels or feedstocks, convert this “extra cost” into units of cost to “sequester carbon” as \$/tonne-C, and compare to other estimates of other ways to accomplish such carbon sequestration.

4.0 RESULTS AND DISCUSSION

The results of the literature survey and technical and economic evaluation are given in this section.

4.1 Literature Survey

Using the sources and methodology described in the previous section, 22 biomass gasification technologies were screened to identify and define various systems for heat and/or electrical power generation. These systems are shown in Table 9.

Table 9

Biomass Gasification Systems Evaluated

Biomass Gasification for Heat and/or Power Generation	Biomass Gasification for Advanced Power Cycles
BG Technologies USA, Inc.	Foster Wheeler Bioneer, atmospheric updraft gasifier
BIVKIN Gasification Technology	Foster Wheeler Pyroflow atmospheric circulating fluidized-bed gasifier
Brightstar Synfuels Co.	Foster Wheeler Bioflow pressurized circulating fluidized-bed gasifier
Cratech Gasification System	Battelle High Throughput Gasification Process, (FERCO)
Energy Products of Idaho	GTI RENUGAS pressurized fluidized bed gasifier
Enkern-Biosyn Gasification	Energy Farm Project in Di Cascian, Italy
PRM Energy Systems, Inc.	ARBRE Energy Project
Thermogenics	Brazil Biomass Integration Gasification-Gas Turbine Project
Thermoselect, S.A.	BioCoComb
TPS Termiska Processor AB	
Thermal Technologies, Inc.	
Etho Power Corporation	
Emery Gasification	

The technologies evaluated can be divided into two groups: simple systems suitable for developing countries which have large readily available biomass, and advanced systems needed for Western countries

for power and combined heat/power generation. Advanced systems provide high efficiencies with reduced emissions to mitigate greenhouse gas emissions.

Much information on the various gasification technologies was obtained from the internet through company websites, news releases, and various interest groups. The report published by Juniper Consultancy Services Ltd. entitled "Technology and Business Review: Pyrolysis and Gasification of Waste – A Worldwide Technology and Business Review," Vol. 1 & 2, 2000 was also used extensively. This survey summarizes simple systems for heat and/or power generation (that are suitable when efficiency and emissions are not priority factors) and advanced systems for power and combined heat/power generation. An extensive report describing each system is presented in the appendix.

4.1.1 Simple Biomass Gasification Systems

Simple gasification systems produce syngas with a low heat content at atmospheric or low pressure. The fuel syngas can be used for operating gas engines for small-scale power production. Syngas from these simple gasification systems can also be used as boiler fuel or to add heat to a boiler. TVA and EPRI have investigated this approach for a possible cofiring operation at TVA's Allen Fossil Plant in Memphis. All these are applications where the syngas does not have to be as clean nor as high in heat and feedstock gas content as is considered necessary for use in a gas turbine or in a chemical production operation. In general, the syngas from simple gasification is not suitable for advanced turbines or chemical production. Fourteen simple systems were reviewed. Each is briefly described below.

4.1.1.1 BG Technologies USA, Inc.

BG Technologies USA, Inc., has licensed gasification technology from Ankur Scientific Energy Technologies PVT, LTD., of India for worldwide distribution (www.bgtechnologies.net and www.ankurscientific.com). Ankur Scientific has over 400 installations worldwide using this technology for processing wood chips, palm nut shells, cotton stalks, rice hulls, maize cobs, soy husks, coconut shells, and sawdust. The BG Technologies electric system consists of a biomass gasifier, gas cleaning and cooling equipment, and a diesel generator. The diesel generator is operated under dual fuel mode using diesel and producer gas from the gasifier which reduces diesel consumption by about 70%. The main objective of this system is to displace some of the fuel requirement for the diesel generator. Three systems are offered at 100, 250, and 400 kW_e capacities with conversion efficiencies ranging from 70-75%.

4.1.1.2 BIVKIN Gasification Technology

The Netherlands Energy Research Foundation (ECN) in Petten, Netherlands, developed and built a pilot circulating fluidized bed (CFB) gasification plant using the BIVKIN (Biomassa Vergassings Karakteriserings Installatie) process in cooperation with Novem, Afvalzorg, and Stork (Van den Broek, et al., 1997). The plant was initially used at the ECN location in Petten for the characterization of more than 15 different biomass species, including wood, sludge, grass, and manure. ECN has been conducting tests to improve the gas quality so that it can be used for

electrical generation in a gas engine. The CFB gasifier is integrated with a 500 kW_e internal combustion (IC) engine at the pilot plant.

4.1.1.3 Brightstar Synfuels Co./Brightstar Environmental

Brightstar Synfuels, Co., (BSC) developed a gasification concept in 1989 with tests in a 25-90 kg/h (55.1-198.4 lb/h) pilot plant. They subsequently scaled up to a commercial unit in 1994 at a particleboard plant. The plant had a capacity of 17,600 kg/h (38,801 lb/h) of sander dust. It was terminated in 1995 because of problems with the heat recovery equipment used in the gas cooling system. A free standing Commercial Demonstration Facility (CDF) was built near Baton Rouge, Louisiana, in 1996 with design throughput of 680 kg/h (1,499 lb/h). The facility was operated continuously to prove the concept and refine the process. This facility was considered a commercial scale facility because of the "tubular entrained flow" design. Multiple gasifiers would be used in larger capacities. Various feedstocks such as sawdust and sander dust, bark and wood chips, pulp and paper mill sludge, rice hulls, sugar cane bagasse, and sewage sludge were tested. Louisiana State University's Institute for Environmental Studies supported the demonstration plant in Louisiana.

4.1.1.4 Cratech Gasification System

Western Bioenergy funded Cratech in Tahoka, Texas, in 1998 to develop a gasification project for converting straw, grass, and shells (www.westbioenergy.com). A 1 MW unit was developed and tested. The Cratech gasifier is a pressurized, air-blown fluidized-bed reactor. Biomass is injected with a biomass pressurization and metering unit. The product gas is passed through a hot-gas cleanup system followed by injection into a turbine combustor. The system uses the higher practical thermodynamic efficiency of the Brayton cycle over the Rankin cycle.

4.1.1.5 Energy Products of Idaho

Energy Products of Idaho (EPI) of Coeur d'Alene, Idaho, claimed to design and build the first fluidized bed combustor for firing wood which also operates on 100% paper sludge (Inland Empire Paper Company, Spokane, WA) (www.energyproducts.com). EPI has designed and supplied more than 79 gasification plants worldwide since 1973. Their expertise is in atmospheric fluidized-bed (AFB) gasifiers. The bed material can be either sand or char or a combination of both. The fluidizing medium is usually air. Their AFB can process fuel with moisture contents up to 55% and high ash contents over 25%. Temperature is maintained below the fusion temperature between the ash and the slag which increases the utilization of the slagging fuels. The product gas is cleaned by cyclones. The heating content of the gas is about 7.4 MJ/scm (200 Btu/scf). The EPI website listed a total of 63 operating units in the world. These facilities process a wide variety of biofuels such as wood waste, bark and wood chips, RDF, hogged fuel, agricultural waste, urban wood waste, coal, polyethylene terephthalate, and polyvinylbutyryl.

4.1.1.6 Enerkem-Biosyn Gasification

The Enerkem-Biosyn gasification process has a long history of development in Canada. Many transformations have occurred over the past decades (<http://solstice.crest.org/renewables/bioenergy-list-archive/9612/msg00266.html>). Canadian

Industries Limited (CIL) was formed in the early 1970s as a wholly owned Canadian subsidiary of Imperial Chemical Industries (ICI). CIL initiated the OMNIFUEL program to develop a versatile fluidized-bed technology to convert its industrial wastes into useful syngas for either energy or chemical synthesis. A pilot plant was constructed in Kingston, Ontario. This was discontinued after CIL restructured. BBC Engineering was formed and installed a 10 metric ton/h demonstration gasifier coupled to a boiler at the Levesque sawmill in Hearst, Ontario. The economics did not favor the commercialization of the process despite its technical success.

4.1.1.7 PRM Energy Systems, Inc.

PRM Energy systems, Inc., founded in 1973, has many years of experience in biomass gasification for electricity and heat generation. Their website contains information on their various commercial and demonstration projects around the globe. The gasification technology was developed at Producers Rice Mill, Inc. (PRM). The first two gasifiers were installed in 1982 to gasify rice husks to produce process heat and steam for a large rice parboiling facility. Many biomass feedstocks were tested between 1984 and 1988 in a full-scale PRM gasifier. These include rice hulls, rice straw, chicken litter, green bark, sawdust and chips, peat, wheat straw, corn cobs and stubble, peanut hulls, RDF (fluff, flake, and pellet), petroleum coke, cotton-gin waste, cotton-seed hulls, and low-grade coal. The rice residue gasification has been in operation since 1982 in U.S., 1985 in Australia, 1987 in Malaysia, and 1995 in Costa Rica.

The PRM process is marketed by PRM Energy Systems itself as well as through Primenergy, Inc., for the U.S. and the Philippines. Grupo Guascor of Spain covers France, Italy, Spain, and Portugal (Juniper Consultancy Services Ltd, 2000). The PRM process is fully proven and has operated continuously at various scales.

4.1.1.8 Thermogenics

The Thermogenics gasifier is a directly heated, air-blown, continuous bottom fed, stratified updraft gasifier (Juniper Consultancy Services Ltd, 2000). It was designed specifically for processing MSW with a capacity of 0.5-3 metric ton/h (0.55-3.3 ton/h). The MSW is shredded and dried to a moisture content of 30% or less. It is introduced into the gasifier through the bottom. An external fuel source is used to heat the MSW to auto-thermal temperature. Gasification occurs around 980 °C (1,796 °F) at the bottom of the bed and 370 °C (698 °F) at the top. Char and particulates from the syngas are removed by a dust removal device and recycled to the gasifier. The syngas is cooled to condense the aerosols and passed through an electrostatic precipitator. The syngas can be used for power generation via gas engines or conventional boilers. The Thermogenics system has been reviewed favorably by NREL for MSW processing (Camp Dresser and McKee, 1996).

4.1.1.9 Thermoselect, S.A.

The development of the Thermoselect HTR (High Temperature Recycling) process began in 1989. A demonstration plant was built at Fondotoce in Italy and was operated for semi-commercial scale from 1994 to 1999. The process combines slow pyrolysis with fixed-bed oxygen-blown gasification and residue melting (Juniper Consultancy Services Ltd, 2000). The first stage of the process uses a high-pressure press to compact the feedstock to increase its bulk density, squeeze

out entrained air, and homogenize the material by dispersal of liquids. The second stage involves the pyrolysis of the compacted material by indirect heating while it flows down the pyrolysis channel.

4.1.1.10 TPS Termiska Processer AB

TPS Termiska Processer AB was established as a private company in 1992 to pursue the CFB for small- to medium-scale electricity production using biomass and RDF as feedstocks. TPS began work on the development of atmospheric pressure gasification for converting wood, peat, RDF, and other reactive solid fuels to energy in 1984. The gasification technology involves an air-blown circulating fluidized-bed (CFB) gasifier. It operates at 850-900 °C. The tarry product gas has a tar content of 0.5-2% of dry gas with a heating value of 4-7 MJ/Nm³ (107.4-187.9 Btu/scf). The system is favorable for fuel capacities greater than 10 MW_{th}.

4.1.1.11 Thermal Technologies, Inc.

A project at Camp Lejeune, North Carolina, was sponsored by the U.S. EPA and U.S. DOD Strategic Environmental Research and Development Program (Cleland, 1997). The Research Triangle Institute (RTI) is working under a Cooperative Agreement with EPA to complete the testing and demonstration. Other participants are the Marine Corps, North Carolina Department of Commerce, and Thermal Technologies, Inc. (TTI). The gasification technology used is the downdraft moving-bed gasifier from TTI.

4.1.1.12 Etho Power Corporation

Located in Kelowna, British Columbia, Canada, Etho Power developed a proprietary biomass electricity generating system that utilizes gasifiers, heat exchangers, and air turbines. It is claimed that the Etho system is more efficient, produces less emissions, and is less expensive than traditional biomass gasification systems. A demonstration system is located in Kelowna, British Columbia. The project is funded by the British Columbia provincial government, BC Hydro & Power Authority, and the National Research Council of Canada. Little information could be found on the gasification technology.

4.1.1.13 Emery Gasification

Emery Gasification is based in Salt Lake City, Utah. The company has developed a proprietary gasification technology for power production, chemical synthesis and industrial gases. Emery started the development in 1993. A 22.7-metric ton/day (25 ton/day) fixed-bed, air-blown gasifier was designed and built. The gasifier was operated for over 2,100 hours during a 20-month test period from late 1996 to the fall of 1998 with scrap tires as the principle feedstock. Biomass and MSW were also tested.

4.1.2 Advanced Biomass Gasification Systems

Advanced gasification systems generally involve integration with higher efficiencies and produce heat or combined heat/power generation. These systems are necessary for the high efficiencies and higher value products that enable companies in developed countries to use biomass at a large enough scale to help in controlling of greenhouse gas emissions. Seven companies that have advanced gasification systems are reviewed.

4.1.2.1 Foster Wheeler Gasification Technologies

Foster Wheeler owns several gasification patents and gasification technologies. A number of these were developed by Ahlstrom Pyropower (API). Foster Wheeler acquired API and has likewise acquired these gasification technologies. The different gasifiers are the atmospheric updraft gasifiers (Bioneer), atmospheric circulating fluidized-bed gasifiers (Pyroflow), and the pressurized circulating fluidized-bed gasifiers (Bioflow). These are described below.

4.1.2.1.1 Bioneer Atmospheric Updraft Gasifiers

Foster Wheeler developed the atmospheric updraft gasification technology for converting biomass to heat for small districts. These are known as the BIONEER gasifiers. A total of ten BIONEER gasifiers have been installed. The maximum plant size is 10 MW_{th} fuel input with most of the plants in the range of 3-8 MW_{th} input. These cannot be operated with sawdust or other smaller components because the feedstock is too fine to be effective in the process. These gasifiers are simple to operate, and the technology is well proven.

4.1.2.1.2 Pyroflow Atmospheric Circulating Fluidized-Bed Gasifiers

The next generation of gasifiers from Foster Wheeler is known as the Pyroflow gasifiers. They are atmospheric circulating fluidized-bed gasifiers (ACFB) developed in the 1980s.

4.1.2.1.3 Bioflow Pressurized Circulating Fluidized-Bed Gasifiers

The Swedish power company, Sydkraft AB, has constructed a co-generation plant at Värnamo, Sweden to demonstrate the integrated gasification combined cycle (IGCC) technology. Bioflow, Ltd., was formed as a joint venture between Ahlstrom and Sydkraft in 1992 to develop the pressurized air-blown circulating fluidized-bed gasifier. Foster Wheeler acquired a subsidiary of Ahlstrom that built the gasifier, and Bioflow became part of Foster Wheeler in 1995. The biomass integrated gasification combined cycle (BIGCC) plant in Värnamo was commissioned in 1993 and fully completed in 1996. It generates 6 MW_e and 9 MW_{th} for district heating in the city of Värnamo. This was the first complete BIGCC for both heat and power from biomass (Ståhl, 1997; Engström, 1999; and Ståhl, 1999).

4.1.2.2 Battelle High-Throughput Gasification Process (BHTGP) (FERCO)

Battelle Memorial Laboratory demonstrated high-throughput gasification through a cooperative effort involving the U.S Department of Energy, the National Renewable Energy Laboratory (NREL), Burlington Electric Department, and the Future Energy Resources Corporation (FERCO) (Bain, 1996). Therefore, later in this report this technology is labeled “Battelle FERCO” or simply “FERCO”. The project for IGCC demonstration began in August 1994. The demonstration was located at the McNeil wood-fired power plant in Burlington, Vermont. The power plant has a capacity of 50 MW_e and was built in 1984. The capital cost of the plant was \$67 million (1984) and was \$13 million below budget. It is owned by the Burlington Electric Department, Central Vermont Public Services Corp., Green Mountain Power Corp., and the Vermont Public Supply Authority. A total of 77.1 metric ton/h (85 ton/h) of wood chips can be processed.

The Battelle High-Throughput Gasification Process (BHGTGP) system uses a low-pressure indirectly heated biomass gasifier. It has been demonstrated successfully in a 9.1 metric ton/day (10 ton/day) Process Research Unit (PRU) at Battelle's Columbus Laboratories in West Jefferson since 1980. This system was designed especially for biomass to take advantage of its high reactivity, low ash, low sulfur, and high volatile matter content. It has operated for over 22,000 hours. FERCO of Atlanta, Georgia, has licensed the technology from Battelle. The gasifier will be operated as an IGCC eventually and includes heat recovery and a condensing steam turbine. The plant is 20 times the scale of the pilot plant that can process 181.4 metric ton/h (200 ton/h) of woody feedstock. It accounts for about 30% of the plant's load (Bain, 1996).

The first phase of design and construction was completed in 1998 by Zurn NEPCO of Portland, Maine, and Redmond, Washington. The second phase includes the start-up and shake-down testing which began in 1998 and continued through 1999. The final phase involves long-term operation and testing. A gas turbine was designed and installed during the final phase in 2000. The other companies and agencies that are evaluating the technologies include Weyerhaeuser, General Electric, International Paper, Centerior Energy, the State of Iowa, New York State Energy Research and Development Authority, and the U.S. Environmental Protection Agency.

FERCO has trademarked the process SilvaGasTM (January 2001). The SilvaGasTM process uses two physically separated, circulating fluidized-bed reactors. One reactor acts as a gasification reactor to convert the biomass to gas and residual char. The second reactor is a combustion reactor which burns the char to provide heat for gasification.

4.1.2.3 GTI Pressurized Fluidized-bed Gasifier (Renugas[®])

GTI has developed the Renugas[®] biomass gasification technology based on their success in the U-Gas[®] coal gasification technology and holds US Patents 4,592,762 and 4,699,632. . Bagasse, wood chips, whole tree chips, hard and soft woods, willow, rice and wheat straw, alfalfa, highway chippings, mixture of bark and pulp sludge, and pelletized RDF were all tested with the 10.9 metric ton/day (12 ton/day) PDU at GTI in Chicago

4.1.2.4 Energy Farm Project in Di Cascina, Italy

A project on biomass-based IGCC was planned for Di Cascina, Italy (Beenackers, 1997 and www.bioelettrica.it). This project was one of three BIGCC demonstration projects funded by the European Commission within the framework of the THERMIE Programme. The joint-stock company, BIOELETTRICA S.p.A. will implement the project. The shareholders of the company are USF Smogless S.p.A., EDP-Electricidade de Portugal S.A., Energia Verde S.p.A., Lurgi Umwelt GmbH, and Fumagalli S.p.A. They were awarded the contract to supply the main systems for the plant in May 1997. The plant design and testing are underway and is expected to enter into commercial operation in 2001. This project will demonstrate the technical and economic feasibility of power-generation from biomass using the IGCC concept. The gasification system features the Lurgi atmospheric air-blown circulating fluidized-bed gasifier integrated with a 11.9 MW_e, single-shaft, heavy-duty gas turbine, suited to burn the low-calorific value syngas produced by the gasifier. The gasifier is supplied from Lurgi, and the turbine is from Nuovo Pignone. A heat-recovery steam-generator will provide steam to a 5 MW_e condensing steam turbine.

4.1.2.5 ARBRE Energy Project

The third BIGCC project funded by the European Commission was the ARBRE project (Arable Biomass Renewable Energy) to be located at the 2,000 MW_e Eggborough Power station in the Aire Valley, North Yorkshire of UK. This project will provide a net electrical output of 8 MW_e with an efficiency of 30.6%. The biofuel for this project contains about 80% short rotation forestry based on 2,600 ha (6,424.6 acres) of a mixture of willow and hybrid poplar. The coppice will be used throughout the year with onsite covered storage. The feedstock is dried to 10-20% moisture by the low-grade heat from the system. The gasification technology is supplied by TPS.

4.1.2.6 Brazil Biomass Integration Gasification-Gas Turbine

A Biomass Integration Gasification-Gas Turbine (BIG-GT) project was proposed by Eletrobrás (Brazilian Electric Power Co.) and CHESF (Companhia Hidro Electrica do São Francisco) in April 1991. This involved building a 30 MW_e BIG-GT in the state of Bahia, Brazil, using wood or sugar cane bagasse as fuel. The project was named SIGAME (Wood Gasification Integrated System for Electricity Generation). The project was intended to confirm the technical and commercial viability of producing electricity from biomass using the integrated gasification combined cycle system. It was originally predicted that the commercial operation would begin in 2001. The proposed BIG-GT demonstration plant will produce about 40 MW_e and deliver about 32 MW of electricity to the grid.

4.1.2.7 BioCoComb Project

Biofuel for Co-Combustion (BioCoComb) is a project where syngas produced from biomass is co-combusted in a pulverized coal-fired power station. The project was supported by a European Community Thermie Fund and has been installed by Austrian Energy and Environment in Zeltweg, Austria. The power plant has a capacity of 137 MW of electricity from coal. The gasifier is capable of gasifying biomass such as bark, wood chips, and sawdust, and has a thermal capacity of 10 MW_{th}. The produced gas replaces about 3% of the coal fired in the boiler (Anderl, 1999).

4.1.3 Discussion of Literature Review

Each technology was evaluated based on the criteria described in section 2.0 “Experimental” and outlined again below:

- Efficiency
- Flexibility/Applicability/Fuel gas and synthesis gas
- Technical maturity
- Data availability
- Ease of operability
- Scalability
- High pressure for IGCC integration
- Feedstocks
- Industrial acceptance
- Size, footprint
- Simple system

Two measures of efficiency were included in the evaluation, cold gas efficiency and carbon conversion. Mature gasification technologies generally have a high cold gas efficiency and high carbon conversion. The moving bed gasifiers have the highest cold gas efficiency and highest carbon conversions. The fluidized-bed gasifiers have the lowest cold gas efficiency and lowest carbon conversion. High cold gas efficiency and carbon conversion do not necessarily result in the most economical technology. In the U.S., the Texaco gasification process, which has neither the highest cold gas efficiency or nor highest carbon conversion, has generally proven to be cost competitive with other gasification technologies (Takematsu 1991). This is accomplished through their development of auxiliary heat recovery systems, on-stream reliability and relative capital cost.

Fuel flexibility is obviously important for the production of both chemicals and heat and power. Air-blown gasifiers produce a fuel gas. Oxygen-blown gasifiers generally produce a gas suited for chemical synthesis. If the gasifier operates at atmospheric pressure, significant compression is usually required before the gas can be conditioned for synthesis. If the gasifier is operated at 400 psig or higher the gas is suited for all but the newest combustion turbines. Also, at 400 psig, no compression should be required before the gas is conditioned for chemical synthesis. Compression should only be required for the gas when it enters the synthesis loop. If the gasifier produces a syngas at elevated pressure that is low in inerts it is considered fully flexible.

In terms of maturity, the technology is considered mature and accepted by industry if there are commercial installations in operation. Several gasification technologies are in advanced states of demonstration and near-commercial. These include British Gas/Lurgi, H T Winkler, Shell and E-Gas (formerly known as Destec) (Simbeck 1993).

Assessments of size and footprint are based on gasifier pressure and whether the gasifier is air-blown or oxygen blown. Atmospheric gasifiers are relatively larger than pressurized systems and expected to be larger. Air-blown atmospheric gasifiers are expected to be even larger.

Factors identified during this review that significantly effect simplicity and ease of operation are the presence of tars and oils and the requirement for char recycle.

Using these criteria, the evaluation field was narrowed to include only advanced biomass gasification systems. Table 10 gives a comparison of these systems based on the evaluation criteria.

Table 10
Summary of Advanced Biomass Gasification Technologies

Process	Renugas®	TPS Termiska AB	Bioflow	SilvaGas®
Technology Owner(s)	GTI licensed to Carbona for licensed to PICHTR for Pacific Rim	TPS	Foster Wheeler	Battelle Columbus Laboratory, licensed to FERCO
Gasifier Type	Fluidized Bed	Circulating Fluidized Bed	Pressurized Fluidized Bed	Atmospheric Fluidized Bed
Feedstocks	Biomass	Biomass	Biomass	Biomass
Oxidant	Air/oxygen	Air	Air	Air
Ash	Ash	Ash		Ash
Operating Temperature, °C (°F)	(835) 1535	(850-900) 1562-1652	(950-1000) 1742-1832	(830) 1526
Maximum Operating Pressure, MPa (psig)	2.4 (333)	0.15 (21)	1.9 (262)	Atmospheric to low pressure
Efficiency: Cold Gas	Theoretical at over 76%, demonstration for the 100 tpd ranged from 55% to 77%.	not listed	not available	36% (estimate)
Efficiency: Electrical	30-35 % (estimate)	30.6%	32%	32% (net) (estimate)
Overall Efficiency	Not available	not found	83%	80% (estimate)
Carbon Conversion	over 95%	not found	over 90%	
Fuel Gas Heating Value, MJ/Nm ³ (Btu/ft ³)	10 (270)	4-7 (107-188)	5.3-6.3 (142-169)	15.5-17.3 (410-464)
Flexibility/Applicability/Fuel Gas & Synthesis Gas	The high pressure does not require compression. However, the presence of nitrogen lowers the heat content of the fuel gas even in the oxygen-blown mode. The low H ₂ /CO ratio may require extra shift reaction to increase the H ₂ /CO ratio for chemical production.	Fuel Gas, Syn Gas requires compression	It was demonstrate for fuel gas but not syn gas. The high pressure is suitable for syn gas and eliminates the need for compression.	Fuel Gas, Syn Gas requires compression
Technical Maturity, Industrial Acceptance	The operation under high pressure and oxygen-blown mode has not been demonstrated for sustained period of time. It may still be quite sometime before it	Yes and it is being demonstrated for IGCC.	It has been demonstrated successfully with many problems solved.	It is being demonstrated but it has not been demonstrated for a continual basis.
High Pressure for IGCC Integration	Yes but it hasn't been demonstrated.	Yes	Yes	No, the gas requires compression
Size, Footprint	Acceptable	Acceptable	Acceptable	Larger than single gasifier system
Simple System, Ease of Operability	The feed system may still need more development work for various biomass. The oxygen-blown mode has not been demonstrated at over 12 tpd.	not sure	Not sure	Yes
Scalability	Still need field verification; fully demonstrated at 12 tpd, it has been scaled up to 100 tpd at air-blown mode.	Fully	Fully	Fully

Table 10
Summary of Advanced Biomass Gasification Technologies

Process	Renugas®	TPS Termiska AB	Bioflow	SilvaGas®
Merits and Potential Challenges	The U-gas technology has been commercialized but the Renugas® technology still needs more developmental works.	It is being demonstrated in North Yorkshire U.K. for IGCC with hot gas cleanup and gas turbine. The net electric output is 8 MW _e .	It was demonstrated successfully at Värnamo, Sweden for both heat and power production.	It is being demonstrated at 250 tpd design capacity at Burlington, Vermont, U.S. It has not been demonstrated for IGCC yet.
Data Availability	Adequate	General information only.	limited	General information is available but specifics are not.

Table 10
Summary of Advanced Biomass Gasification Technologies (cont.)

Process	AFB	EPI	PRME
Technology Owner(s)	Foster Wheeler	Energy Products of Idaho	PRME Energy Corporation
Gasifier Type	Atmospheric Fluidized Bed	Atmospheric Fluidized Bed	Fluidized Bed
Feedstocks	Biomass	Biomass, petcoke, sewage and paper-mill sludge	Biomass
Oxidant	Air	Air	Air
Ash	Ash	Ash	Ash
Operating Temperature, °C (°F)	(800-1000) 1472-1832	(540-980) 1004-1796	Not available
Maximum Operating Pressure, Pa (psig)	Atmospheric to low pressure	Atmospheric to low pressure	Atmospheric to low pressure
Efficiency: Cold Gas	not available	not available	not available
Efficiency: Electrical	not available	not available	not available
Overall Efficiency	not available	not available	not available
Carbon Conversion	not available	not available	not available
Fuel Gas Heating Value, MJ/Nm ³ (Btu/ft ³)	not available	3.7-7.4 (100-200)	not available
Flexibility/Applicability/Fuel Gas & Synthesis Gas	Fuel Gas, Syn Gas requires compression	Suitable for low-BTU fuel gas but not suitable for chemical production via syngas. compression is needed for syn gas.	The system is designed for heat and power. It's probably not suitable for chemical conversion via syngas.
Technical Maturity, Industrial Acceptance	Many commercial plants built around the global mainly on pulp and paper mills.	Fully commercialized with several hundred tons of biomass per day plants.	Fully commercialized with several hundred tons of biomass per day plants.
High Pressure for IGCC Integration	not demonstrated, probably not suitable	Not suitable	The new plant in Italy that gasifies sansa will demonstrate the IGCC concept with gas cleanup system and an IC engine.
Size, Footprint	Acceptable	Acceptable	Acceptable
Simple System, Ease of Operability	Yes	Yes	Yes
Scalability	Fully	Fully	Fully
Merits and Potential Challenges	It is operational in Lahti, Finland to generate fuel gas for combustion in existing coal-fired boiler.	The gasification technology has been fully commercialized for heat and power production.	The gasification technology has been fully commercialized for heat and power production.
Data Availability	Limited	Limited, proprietary	Limited, propriety

4.1.4. Selected Biomass Gasification Systems

No one gasification technology satisfies all the factors previously identified as being preferred for concept selection. However, three technologies have been identified for further evaluation based on their ability to best fulfill the rationale for concept selection, while representing a range of gasification technologies. These technologies are as follows: the GTI Renugas pressurized gasification technology, the Battelle High Throughput Gasification Process (FERCO), and the GTI Renugas atmospheric gasification technology.

4.1.4.1 GTI Pressurized Renugas System

The pressurized Renugas technology was selected because of the following criteria:

- High cold gas efficiency
- High carbon conversion
- Flexibility (can produce either a low-btu gas in air-blown mode that is suited for a fuel gas or a medium-btu gas in oxygen-blown mode that can be conditioned to a synthesis gas for production of chemicals or fuels such as methanol and SNG)
- High pressure 3.14 mPa (435 psia) for IGCC integration
- Extensive operation at 1-ton per hour
- Industrial acceptance (selected by DOE for two large-scale projects)
- Simple system (gas produces low tars, pressurized syngas, minimal recycle)
- Tested with many biomass feedstocks
- Data is available
- The plant size is relative small because of the high pressure

4.2.1.2 GTI Atmospheric Renugas System

The atmospheric Renugas technology was selected because:

- High cold gas efficiency
- High carbon conversion
- Flexibility (can produce either a low-btu gas in air-blown mode that is suited for a fuel gas or a medium-btu gas in oxygen-blown mode that can be conditioned to a synthesis gas for production of chemicals or fuels such as methanol and SNG)
- Extensive operation at 1-ton per hour
- Industrial acceptance (selected by DOE for a large-scale project in Kentucky)
- Simple system (gas produces low tars, minimal recycle)
- Tested with many biomass feedstocks
- Data is available
- The plant has relatively low capital requirements because of its low pressure

4.1.4.3. Battelle Columbus Laboratory (FERCO) System

The Battelle Columbus Laboratory technology was selected based on the following criteria:

- Relative high cold gas efficiency
- High carbon utilization (char is combusted and the heat is recovered)
- Flexibility (produces a medium-btu gas that can be used either as a fuel gas or conditioned to a synthesis gas for production of chemicals or fuels such as methanol and SNG)
- Extensive operation at Battelle Laboratories and at Burlington Vermont.
- Industrial acceptance (FERCO project selected for sponsorship by DOE)
- Simple system (oxygen is not required to produce a medium-Btu gas, so an air separation plant can be avoided)
- Tested with several biomass materials
- Substantial operating history that should provide adequate data

A conceptual design has been prepared for each of the three technologies selected. The design was used to compare the technical and economic feasibility of each technology. The process designs and the results of the comparison are given in the next section.

4.2 Comparison of Gasification Systems for Power, Fuel, and Chemical Production

Based on the results of the literature search, the pressurized Renugas process, the atmospheric Renugas process, and the atmospheric process developed by Battelle/FERCO were chosen for further evaluation. Using these three technologies, a base case power production scenario using an integrated combined cycle system was defined for each gasification technology. Two additional alternative scenarios were evaluated to compare the technical and economic feasibility of producing liquid fuel and chemicals from the product gases. Methanol and ammonia were chosen for evaluation as fuel and chemical products, respectively. The choice of methanol as a fuel was based on the potential to utilize methanol in combustion turbines for additional electricity production. Ammonia was chosen based on its abundance as a commodity chemical and on in-house expertise in the modeling of ammonia systems.

To determine the technical and economic feasibility of the scenarios described above, a base case power system design was developed for each gasification technology. ChemCad was used to model the Renugas gasification systems. Insufficient published data was available for the FERCO gasification system to allow the development of a ChemCad model within the time frame of this project. Instead, published information concerning the FERCO gas stream composition was used to develop a feed stream for the power, fuel, and chemical production models.

4.2.1 Base Case Gasification Process Models

The methodology used to develop the Renugas gasification system process models is described in this section, along with the basis for and description of the Battelle/FERCO system. As mentioned earlier, the Battelle/FERCO gasification process was not modeled. The Battelle/FERCO process described in this study is derived from information published in the report entitled “Cost and Performance Analysis of Three Integrated Biomass Gasification Combined Cycle Power Systems” (Craig and Mann, 1990). Modeling of the three gasification technologies is described below.

4.2.1.1 Pressurized and Atmospheric Renugas Gasification Models

The Renugas processes were modeled from detailed information provided by the developer for the pressurized version of the process. The initial model was constructed to almost exactly match the heat and material balance provided. The gasifier itself was modeled as a series of four reactors as follows:

- 1) A fixed-conversion type of reactor, which generated the major hydrocarbon species in the gas—benzene, ethylene, and naphthalene—as a proportion of the hydrogen in the feedstock. This same reactor generated ammonia by converting all nitrogen in the feedstock to ammonia.
- 2) A Gibbs free-energy reactor, which carried out all of the general reactions involving carbon, oxygen, and steam to equilibrium (i.e., simple gasification at equilibrium)

- 3) A second Gibbs reactor, which matched the predicted methane content of the gas by setting a temperature of approach to equilibrium for the methanation reaction.
- 4) A third Gibbs reactor, which matched the predicted shift reaction equilibrium by setting a separate temperature of approach.

Although an exact match of the developer's data was sought in the initial model, the methods employed by these reactors are sufficiently general in principle that the model is considered predictive, i.e. any changes in operating parameters such as feedstock, gasifier pressure and temperature, or oxidant type (air or oxygen), will result in a reasonably good estimate of the gasifier's new output and operation. Carbon conversion in the model was handled by simply bypassing some of the carbon around the reactors. Usually, carbon conversion in a gasifier is a function of physical mechanics (e.g. mixing or time of contact) within the reactor rather than a function of equilibrium or reaction chemistry.

Table 11 shows the feedstock analysis used for the Renugas process models (both pressurized and atmospheric versions). The feedstock was modeled as a non-conventional component series of solids which, collectively, have the same high heating value as the dry biomass.

Table 11

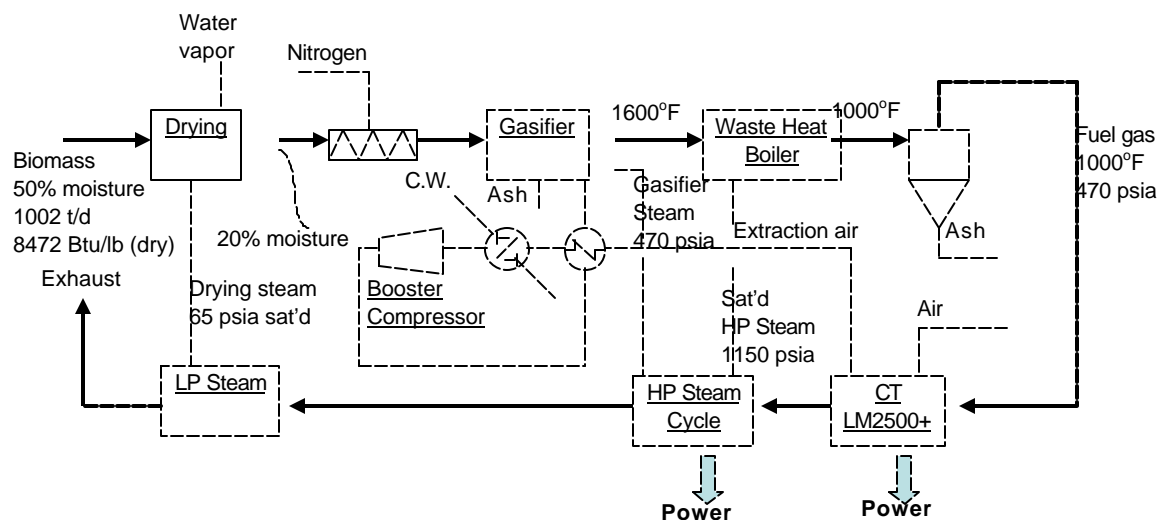
Analysis of Renugas Model Feedstock

Component	Ultimate Analysis (weight %, dry basis)
Carbon	48.51
Hydrogen	6.17
Nitrogen	0.12
Oxygen	44.22
Sulfur	0.04
Ash	0.94
HHV, Btu/lb (dry)	8472
Moisture, as received	50%

Figure 4 is a block flow diagram of the Renugas pressurized gasification process with integrated combined cycle power generation. Raw hardwood biomass containing 50 percent moisture is dried with low pressure steam to 20 percent moisture content. The partially dried biomass is fed via screw conveyor to the biomass gasifier.

Figure 4

Renugas Pressurized Gasification System



The gasifier operates at a pressure of 3.39 mPa (470 psia). A small amount of nitrogen (obtained by vaporizing liquid nitrogen) is fed to the conveyor to act as a seal against backflow of the pressurized hot gases from the gasifier.

The biomass is partially oxidized with hot 427°C (>800°F) air in the gasifier. This air is obtained by extracting a portion of the air from the air compressor of the combustion turbine (CT) (about 10 percent of the CT air flow is extracted). The hot air from the CT's compressor is cooled and then compressed with a booster compressor to raise the pressure from nominally 2.52 mPa (350 psia) to that of the gasifier, 3.39 mPa (470 psia). The CT air is partially cooled in an economizer, which rewarms the air from the booster compressor, thereby preserving most of the heat of compression in the CT compressor.

The gasifier is operated at a temperature of 871°C (1600°F), which is set by controlling the rate of air extraction from the CT. Steam is also fed to the gasifier to promote carbon conversion. A carbon conversion of 99 percent is assumed based on the estimates of the Renugas process developer. Because there is no direct source of 3.39 mPa(470 psia) steam in the process, steam is extracted from the high pressure 8.29 mPa (1150 psia) turbine in the steam cycle. At the point of extraction from the turbine, the steam is superheated by about 82°C (180°F).

The hot, 871°C (1600°F), raw gas leaving the gasifier is cooled to 538°C (1000°F) in a waste heat boiler. Saturated steam is produced at a pressure of 8.29 mPa (1150 psia) and is routed to

the high pressure steam cycle for superheating and subsequent power generation. The gas is filtered to remove entrained solids. Finally, the clean fuel gas is routed to the CT for firing and power generation in the combined cycle.

A simplifying assumption made for this study is that the CT burner system will have the capability of producing low NO_x emissions, even if the fuel gas contains some ammonia (about 0.08 percent, in this case). (Normally, ammonia converts directly to NO_x during conventional firing.) Burner systems of this type are currently under development, according to the Renugas process developer.

Because the fuel gas has a relatively low heat content compared with natural gas 6.11 mJ/Nm₃ (165 Btu/scf HVV, in this case, versus about 37.0 mJ/Nm₃ (1000 Btu/scf) for natural gas), and therefore a relatively high mass flow rate, air extraction from the CT is necessary to prevent a condition in which either the torque limit on the CT drive shaft is exceeded or the compressor goes into surge. Even with air extraction, however, the added mass loading through the CT expander increases the gross power output by about 11 percent to 31.7 MW from a base figure of 28.5 MW output on natural gas.

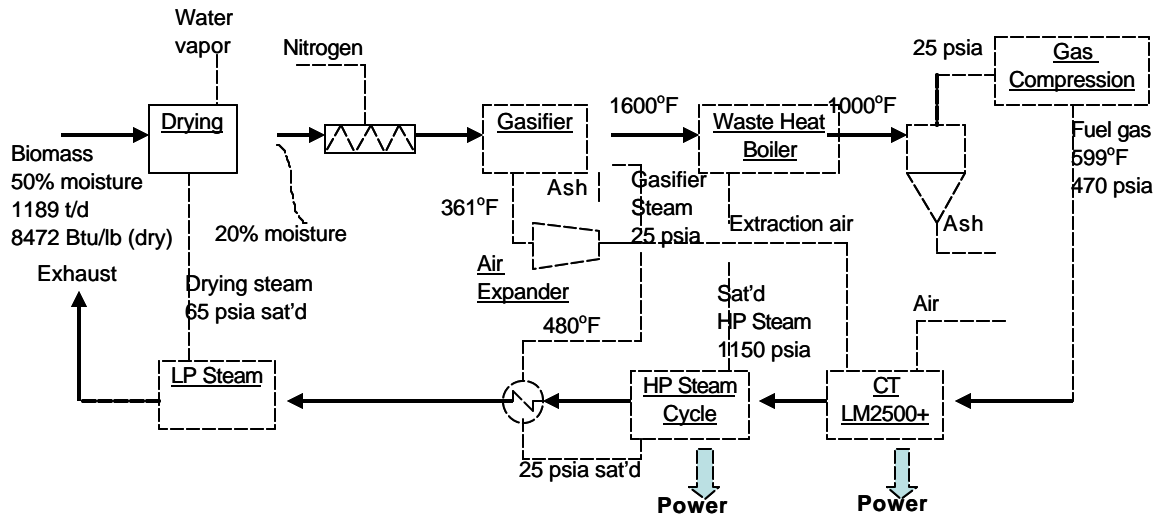
The hot exhaust from the CT enters a heat recovery steam generator (HRSG). For purpose of power production, the HRSG operates as a single pressure 8.29 mPa (1150 psia), non-reheat cycle (i.e., superheat only). Low pressure saturated steam .468 mPa (65 psia) was also generated for drying the biomass feedstock. Normally, two or three pressure steam generation for power generation would be used in a conventional natural gas-fired combined cycle. However, after generating steam at 8.29 mPa (1150 psia), there was only sufficient heat left in the exhaust to perform the needed biomass drying. It should be noted that the pressure selection of 8.29 mPa (1150 psia) and the configuration (non-reheat) was not optimized for maximum power output. However, this pressure and configuration was used consistently for all three gasification methods.

Figure 5 is a block flow diagram of the Renugas atmospheric-pressure gasification process with integrated combined cycle power generation. The gasification process is essentially the same as the pressurized version discussed above except that the gasifier operates at a pressure near atmospheric 180 kPa (25 psia). A compression step has been added to raise the pressure of the fuel gas to 3.39 mPa (470 psia) for firing in the CT. This step consists of an economizer heat exchanger (to cool the low-pressure gas by re-warming the compressed gas), a cooler, and a 5-stage intercooled compressor train.

Rather than the booster compressor, which is no longer needed, extraction air from the CT is routed through an air expander to generate supplemental power.

Figure 5

Renugas Atmospheric Gasification System



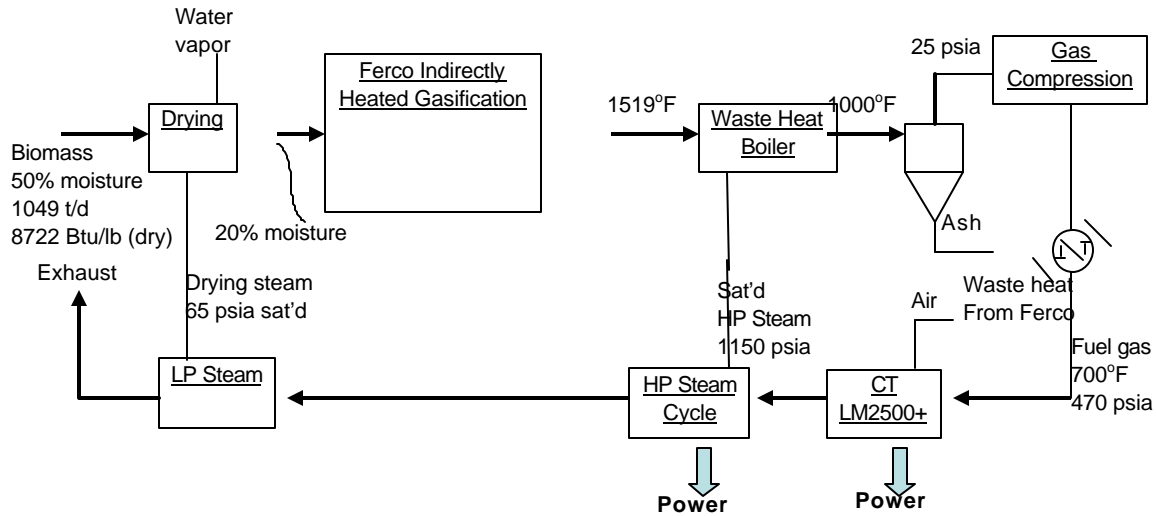
Steam for the gasifier is extracted at 180 kPa (25 psia) from the steam turbine. Since this extracted steam is low quality (about 2 percent condensate), it was heated in the HRSG to 249°C (480°F), which is the steam temperature used by Renugas in their models.

4.2.1.3 Battelle/FERCO Gasification Model

Figure 6 is a block flow diagram of the FERCO gasification process with integrated combined cycle power generation. The FERCO gasification process was not modeled because of time constraints and because of a lack of detailed process information such as that provided by the developers of Renugas.

Figure 6

Battelle-FERCO Gasification System



Instead, the FERCO process was treated as a “black box,” with feedstock and gas production information derived from the open literature (Craig and Mann, 1996). Table 12 gives the analysis of the feedstock used as the basis of the FERCO system.

Table 12

Analysis of FERCO Model Feedstock

Component	Ultimate Analysis (weight %, dry basis)
Carbon	50.88
Hydrogen	6.04
Nitrogen	0.17
Oxygen	41.9
Sulfur	0.09
Ash	0.92
HHV, Btu/lb (dry)	8722
Moisture, as received	50%

With indirect gasification, a pre-heated stream of sand (or some other solid medium) provides the heat input needed to gasify the biomass. In turn, char residue from this gasification step is

combusted in air in a separate char combustor vessel to provide the energy to heat the sand. Operation of both the char combustor and the gasifier is at near atmospheric pressure 180 kPa (25 psia). Because air never enters the gasifier, the fuel gas is not diluted with nitrogen and therefore has significantly higher heat content than gases from direct gasifiers. The fuel gas from the Ferco gasifier has sufficiently high heat content

13.5 mJ/Nm₃ (365 Btu/scf HHV) such that, when fired, no extraction of air from the CT is necessary and therefore the air expander found in the Renugas atmospheric gasification process is obviated.

Other than the elimination of the air expander, the integration of the gasifier with the combined cycle was similar to that for Renugas atmospheric gasification. There was one assumption made regarding internal process operation of the FERCO process. It was assumed that there was sufficient waste heat within the FERCO process to heat the fuel gas to 371°C (700°F) just prior to firing in the CT. This assumption is based on the statement in regarding indirect gasification that stated, “After compression, the syngas is heated indirectly to 371°C (700°F) with process heat from the quench and char combustor flue gas” (Craig and Mann, 1990).

4.2.2 Gasification Plant Design

Using these models, a conceptual design was prepared for each of the base case systems and the methanol and ammonia scenarios. These designs are based on information found in the Craig and Mann report, internal TVA reports, and external contractor information. The following general premises were used to develop the conceptual designs:

- Wood as feedstock
- 1,000 ton per day nominal plant capacity
- 30 year plant life
- nth plant, minimal equipment redundancy
- 90.4% plant availability

The design consists of the following major plant areas: feedstock handling, feedstock drying, gasification, gas clean-up, combustion turbine, and HRSG. Each section is described below.

4.2.2.1 Feedstock Handling and Preparation

Wood chips sized to about 5 cm (2 inches) would be delivered to the plant site by truck. The wood would be unloaded and moved to a storage yard. The wood yard would have sufficient storage area to store a one week supply. The plant is assumed to be located close to roads or railroad spurs which would be sufficient to allow adequate delivery of the feedstock. The moisture content of the as is chips is estimated at 50%. A rotary kiln dryer would be used to dry the chips to a moisture content of 20% prior to feeding. For the high pressure Renugas system, a feed lockhopper and pressurized feed hopper would be used to meter the feed into an injection screw that feeds the gasifier.

4.2.2.3 Gasification

The gasification systems have been described in the previous sections. The commercial designs for these systems were taken from the report by Craig and Mann.

4.2.2.4 Gas Clean-up

For the pressurized Renugas system, a primary cyclone is used to remove char and ash. Direct quench is used to condense the alkali species, followed by ceramic candle filters for alkali and particulate removal. For the atmospheric Renugas and FERCO systems, it was assumed that the fuel gas would enter a circulating fluidized tar cracking unit, followed by gas cooling, and particulate filtration.

4.2.2.5 Heat Recovery Steam Generator

Gas turbine exhaust would be fed to the heat recovery steam generator (HRSG). The HRSG would incorporate a superheater, high and low pressure boilers and economizers.

4.2.2.6 Steam Turbine

The steam turbine system consists of high and low pressure power turbines and a generator.

4.2.2.7 Combustion Turbine

The CT used in the design was a General Electric LM2500+, an aeroderivative-type CT which produces nominally 28.5 MW at a heat rate of about 9.5 mJ/kWh (9,000 Btu/kWh) when operated on natural gas at ISO conditions. The LM2500+ produces a desirable combination of good efficiency with moderate size.

In addition to the major process areas mentioned above, the plant design includes plant areas for cooling and potable water, instrumentation, waste treatment, and disposal, electrical, controls, piping, etc.

4.2.3 Base Case Process Plant Performance

The performance of each base case system design is described in this section. Primary inputs such as wood, air, and steam rates are given. The resulting fuel gas characteristics are also shown. Electricity production is given for the base case systems.

4.2.3.1 Fuel Gas Composition

A summary of the composition of the gas streams produced by each gasification technology is shown in Table 13. The Renugas systems are both air blown, resulting in fuel gas streams high in nitrogen. Because of the presence of nitrogen in the Renugas streams, the HHV is much less than that of the FERCO system. FERCO's HHV is 14.6 mJ/kg (6,279 Btu/lb) while the pressurized Renugas is 5.79 mJ/kg (2,491 Btu/lb) and the atmospheric Renugas is 4.40 mJ/kg (1,892 Btu/lb). However, because of the higher gas flow rates of the Renugas processes, the heat flow in MMBtu/h is higher for the Renugas than the FERCO system.

Table 13

**Summary of Fuel Gas Stream Compositions –
Base Case Combustion Turbine Scenario**

Item	Pressurized Renugas	Atmospheric Renugas	FERCO
Mol. Wt.	25.1	24.64	21.88
Temperature, °C (°F)	538 (1000)	538 (1000)	538 (1000)
Pressure, mPa (psia)	3.38 (470)	.180 (25)	.180 (25)
Composition, mol%			
Hydrogen	11.50%	14.22%	16.07%
Carbon monoxide	11.70%	12.74%	32.69%
Carbon dioxide	15.79%	13.14%	10.19%
Water	17.87%	16.90%	24.29%
Methane	7.52%	2.48%	11.99%
Benzene	0.24%	0.19%	0.00%
Ethylene	0.04%	0.03%	4.13%
Napthalene	0.08%	0.06%	0.30%
Nitrogen	34.75%	39.66%	0.00%
Argon	0.43%	0.50%	0.00%
Hydrogen sulfide	0.01%	0.01%	0.06%
Ammonia	0.08%	0.06%	0.28%
HHV, mJ/kg (Btu/lb)	5.79 (2491)	4.40 (1892)	14.6 (6279)
Heat flow (HHV), mJw (MMBtu/h)	295837 (280.4)	323585 (306.7)	291089 (275.9)
Cold gas efficiency, %	79.3%	73.1%	72.4%

Cold gas efficiencies are also shown in Table 5. The pressurized Renugas system has the highest cold gas efficiency at 79.3%. The FERCO and atmospheric Renugas are relatively close at 72.4% and 73.1%, respectively.

4.2.3.2 Base Case Performance Summary

A summary of process data and system performance for the base case plant designs involving power production is given in Table 14.

Table 14

Process Data Summary and System Performance Results

	Pressurized Renugas	Atmospheric Renugas	FERCO
Gasifier Requirements			
Wood Flowrate, 20% moisture, tonnes/daymtpd (tpd)	569 (626)	675 (743)	596 (656)
Air Flowrate, kg/hr (lb/h)	25,630 (56,500)	43,549 (96,000)	-
Steam Flowrate,kg/h (lb/h)	1,379(3,039)	1,649(3,626)	11,162 (24,600)
Fuel Gas			
Fuel Gas Flowrate, kg/hr (lb/h)	5,701 (12,569)	73,535 (162,100)	43,948 (43,948)
Fuel Gas Heating Value, HHV, Wet Basis, MJ/kg (Btu/lb)	5.79 (2491)	4.40 (1892)	14.6 (6279)
Power Island			
Gas Turbine	LM2500+	LM2500+	LM2500 +
Power Production Summary			
Gas Turbine Output, MW	31.7	33.45	30.05
Steam Turbine Output, MW	11.36	12.18	8.43
Net System Output, MW	42.05	41.86	36.05
Net Plant eff, HHV Basis, %	40.6%	34.0%	32.3%

As shown in the table, wood flowrates varied slightly for each system based on the heating value of the gas produced. As mentioned earlier, a nominal plant size of 909 tonnes/day (1,000 tpd) was selected for the design. The flowrate shown in the table are at 20% moisture, after the incoming biomass has been dried.

As shown in the table, air usage was 25,630 kg/hr (56,500 lb/hr) at 472 °C (882 °F) for the pressurized Renugas model and 43,549 kg/hr (96,000 lb/hr) at 182 °C (361 °F) for the atmospheric Renugas system. ISO starting conditions of 15 °C (59 °F) and 60% relative humidity were used for the air streams. Steam rates for the Renugas models were set at 0.15 wt./wt. carbon. The pressurized Renugas system was estimated to use 1,379 kg/hr (3,039 lb/hr) of steam at 3.39 MPa (470 psia) and 361 °C (682 °F). The atmospheric Renugas model required 1,645 kg/hr (3,626 lb/hr) at 180 kPa (25 psia) and 249 °C (480 °F). Steam for the FERCO system was estimated to be 11,162 kg/hr (24,600 lb/hr) based on information presented in the Craig and Mann study.

Electricity production ranged from a total of 38.48 MW for the FERCO system, up to 49.75 MW for the atmospheric Renugas system. Internal energy consumption is also shown in the table. Taking these loads into account, the net power production for the pressurized Renugas, FERCO, and the atmospheric Renugas system are 42.05 MW, 36.05 MW, and 41.86 MW, respectively. Heat rates and thermal efficiencies are also shown in the table. The pressurized Renugas system has the highest thermal efficiency at 40.6%. The FERCO system and the atmospheric Renugas system are close at 32.3% and 34.0%, respectively.

4.2.4 Methanol and Ammonia Process Models

For the purpose of studying chemical production (ammonia and methanol), the Renugas process was modeled as an oxygen-blown system. Chemical production from an air-blown gasifier is problematic because the nitrogen in the synthesis gas from the gasifier dilutes and retards the synthesis reactions. Models of oxygen-blown Renugas were constructed for both pressurized and atmospheric gasification. Gasifier pressures of 3.39 MPa and 180 kPa (470 and 25 psia) and an operating temperature of 871 °C (1600 °F) were the same as that assumed for the air-blown models.

4.2.4.1 Methanol Production Model

For methanol production, the reforming of the biomass syngas takes place in a single stage primary reformer integrated into a heat recovery unit (HRU). Steam reforming is an endothermic process and requires the HRU as a heat source to drive the reaction. Integrated steam reforming is a complex system that requires high temperatures, an external water source, and a complex flow scheme. Benefits include the inherent energy conservation of the HRU and the composition (maximized carbon monoxide content) of the synthesis gas after reforming.

Biomass syngas, is mixed with steam and fed into the primary reformer where it is decomposed into hydrogen, carbon monoxide, and carbon dioxide over a nickel catalyst. The ratios of the hydrogen, carbon monoxide, water, and carbon dioxide, once the water is removed, are sufficient for the methanol reaction. No further processing, either additional secondary reforming or shift reactions are needed, prior to methanol synthesis.

Heat is supplied to the reformer by firing the waste steam containing methane from the methanol separation section of the process and makeup biomass syngas. This provides all the heat necessary to drive the reformer reactions.

The fresh feed gas from the SMR unit is mixed with recycle gas. The mixed synthesis gas for the reforming system and the recycled is heated by the reactor effluent. It then passes through a zinc oxide guard bed for trace sulfur impurity removal (normally used with natural gas) before being sent to the methanol synthesis reactor. The catalyst remains in the reactor.

Part of the product methanol reactor exit gas is recompressed and recycled back to the reactor and the rest is sent to the methanol separation equipment. Preheating the reactor feed gas and the recycled crude methanol cools the crude methanol. Final cooling of the crude methanol is done with cooling water or refrigeration. The cooled crude methanol flows to a separator where the unconverted product gas and crude methanol are separated. The exhaust gas (or unreacted methane stream) is returned to the reformer where it is fired to generate the heat required for the steam methane reforming.

4.2.4.2 Ammonia Production Model

Ammonia can be produced from biomass syngas by using an SMR as with methanol production. Hydro-Chem, mentioned earlier as the methanol plant supplier, can also supply a skid-mounted NH_3 plant.

Feed gas from the SMR goes through a catalyzed three stage shift conversion where most of the carbon monoxide is converted to carbon dioxide resulting in additional hydrogen. The SMR gas contains sufficient water to drive the equilibrium conversion, and it is not necessary to add steam to supplement the shift reaction.

Equilibrium is favored by lower temperature but higher temperature is necessary to initialize and increase the shift reaction rate. Compression to 2.88 MPa (400 psia) increases the gas temperature to about 343 °C (650 °F), which is optimum for the initial stage. The model uses a three (3) stage shift with cooling after each stage. Medium pressure (MP) and low pressure (LP) steam is generated by cooling the gas between the high, medium, and the low temperature shift reactors. Final cooling prior to the hydrogen separation is with cooling water that lowers the gas temperature to about 43 °C (110 °F) for feed to a pressure swing adsorption (PSA) unit for H_2 purification. The process model used a slightly lower hydrogen purity because of the need for a methanator as explained below. Usually with lower purity comes higher recovery, but the same percent hydrogen recovery (76%) was used in the models to remain conservative.

A methanator is usually not needed after hydrogen purification. However, with slightly less hydrogen purity to coincide with the less pure nitrogen, a methanator is used in the process model to remove the oxygenated compounds. Oxygenated compounds (typically CO , CO_2 , or O_2) cause ammonia reactor temperatures to increase. Temperature excursions cause damage to

the ammonia catalyst and, therefore, oxygenated compounds need to be removed from the ammonia reactor feed gas. The nitrogen and hydrogen gases are mixed and compressed to the ammonia reactor feed pressure prior to the methanator. High pressure is not detrimental to methanation. This raises the gas temperature to about 316 °C (600 °F), which is normal for the methanation reaction.

Methane is an inert in the ammonia reactor and will build up to a certain extent in the recycle stream. Since most of the methane was removed from the SMR gas in the hydrogen PSA, the additional methane should not be a problem. Under the conditions of methanation, the oxygen, which enters with the nitrogen, is thought to react with hydrogen to form water. Some oxygen may react with carbon monoxide and be converted to carbon dioxide, but carbon dioxide is eliminated with the second reaction. Equilibrium conditions in the methanator favor the third reaction since there is an excess of H₂ as the driving force.

After methanation, the gas is cooled by generating MP and LP steam. Cooled recycle, at about a 3:1 weight ratio to the methanized feed, is mixed with the methanized feed. These mixing results in an ammonia reactor feed stream at 24 °C (75 °F), which condenses the water formed in the methanator. As previously mentioned, a controller makes sure the correct molar ration of hydrogen to nitrogen is at 3:1 by adjusting the air to the nitrogen PSA unit. This ratio is based on the combined recycle plus methanized feed.

The ammonia reactor exit stream is at 393 °C (740 °F) and is cooled by generating MP steam followed by pre-heating the ammonia reactor feed to 149 °C (300 °F). It is further cooled using cooling water followed by refrigerant cooling to drop the temperature to 6.7 °C (-20 °F). Liquid ammonia is separated from recycle gases in the recycle flash unit. Recycle flash operates just slightly below ammonia reactor operating pressure. A small amount of purge, set at 4.54 kg/hr (10 lb/hr), is removed from this recycle stream before it is re-compressed and mixed with the methanized feed. The ratio of recycle to methanized feed is about 3:1. This is fairly typical and depends on the amount of purge, the amount of impurities in the loop, and the amount of conversion obtained in the ammonia reactor.

A product flash unit, operating at about 1.08 MPa (150 psia), is used to remove most of the lighter entrained gases, concentrating the recycle flash bottoms from 98.3% to 99.3% ammonia. The resulting product is a 99.3% anhydrous ammonia.

4.2.5 Methanol and Ammonia Plant Designs

A plant design for the alternative scenarios involving methanol and ammonia was prepared. The plant would be almost identical to the base case design with the exception of the addition of an air separation unit for the Renugas systems and the addition of methanol and ammonia production systems. A cryogenic air separation unit was selected as the source of the 95 percent purity oxygen used in the production of methanol and ammonia. For methanol and ammonia production, the

SMR units used in the designs are skid-mounted units manufactured by Hydro-Chem, a subsidiary of Linde AG. The units consist of a fired unit containing catalyst tubes.

4.2.6 Methanol and Ammonia Process Plant Performance

The performance of each system for ammonia and methanol production is given in this section. Gas composition for chemical production is given along with primary process inputs and product outputs.

4.2.6.1 Methanol and Ammonia Gas Stream Composition

Table 15 gives the composition of the gas streams used for methanol and ammonia production. Because the Renugas systems are now oxygen-blown, the composition of the resulting fuel gas differs from original base case air-blown scenario, in that very little nitrogen is present.

Table 15

**Summary of Fuel Gas Stream Compositions –
Methanol and Ammonia Production Scenarios**

Item	Pressurized Renugas	Atmospheric Renugas	FERCO
Mol. Wt.	23.3	22.35	21.88
Temperature, °C (°F)	437 (818)	437 (819)	538 (1000)
Pressure, MPa (psia)	3.37 (468)	.166 (23)	.180 (25)
Composition, mol%			
Hydrogen	16.03%	22.20%	16.07%
Carbon monoxide	14.10%	20.63%	32.69%
Carbon dioxide	23.58%	20.66%	10.19%
Water	30.84%	25.40%	24.29%
Methane	12.73%	8.15%	11.99%
Benzene	0.34%	0.34%	0.00%
Ethylene	0.06%	0.06%	4.13%
Napthalene	0.11%	0.11%	0.30%
Nitrogen	1.70%	1.71%	0.00%
Argon	0.37%	0.43%	0.00%
Hydrogen sulfide	0.02%	0.01%	0.06%
Ammonia	0.11%	0.11%	0.28%
HHV, MJ/kg (Btu/lb)	9.3 (3997)	9.48 (4076)	14.6 (6279)
Heat flow (HHV), MJ/h (MMBtu/h)	306,282 (290.3)	361,145 (342.3)	291,089 (275.9)
Cold gas efficiency, %	82.1%	81.6%	72.4%

As expected, the lack of nitrogen in the Renugas scenarios caused an increase in the heat flow, HHV, and cold gas efficiencies as compared to the base case scenario. No changes were made in gasifier operation for the FERCO system, therefore the gas stream composition is the same in this scenario as in the base case FERCO system.

4.2.6.2 Methanol Performance Summary

Process performance data for the methanol production scenario is shown in Table 16. For the methanol scenarios, the Renugas systems both use 95% oxygen during the gasification process as opposed to air used in the combustion turbine scenario.

Table 16

Process Data Summary and System Performance Results – Methanol

	Pressurized Renugas	Atmospheric Renugas	FERCO
Gasifier Requirements			
Wood Flowrate, 20% moisture, tonnes/day (tpd)	569 (626)	675 (743)	596 (656)
Air Flowrate, kg/hr (lb/h)	5,217 (11,500)	7,374 (16,256)	-
Steam Flowrate, kg/hr (lb/h)	1,379 (3,039)	1,644 (3,626)	11,162 (24,600)
Fuel Gas			
Fuel Gas Flowrate, kg/hr (lb/h)	32,949 (72,632)	38,103 (83,995)	19,937 (43,948)
Fuel Gas Heating Value, HHV, Wet Basis, MJ/kg (Btu/lb)	9.30 (3,997)	9.48 (4,076)	14.6 (6,279)
Power Production Summary			
Gas Turbine Output, MW	-	-	-
Steam Turbine Output, MW	1.25	1.77	-
Net System Output, MW	-4.21	-7.89	-2.99
Methanol Production Summary			
Methanol, tonnes/day (tpd)	283 (311)	325 (358)	291 (320)

As a result, the gas quantities produced by these two technologies are much smaller than in the combustion scenario. As shown, the flowrates for the pressurized Renugas, FERCO, and atmospheric Renugas are 32,948 kg/hr (72,632 lb/hr), 19,937 kg/hr (43,948 lb/hr), and 38,103 kg/hr (83,995 lb/hr), respectively. As is expected, the HHV's for the Renugas processes are higher in this scenario than in the combustion turbine system. Based on the amount of power generated and the various parasitic loads, a net power requirement is realized

for all three systems. The pressurized and atmospheric Renugas processes require 4.21 MW and 7.89, respectively, and the FERCO system uses 4.96 MW. Methanol production for the pressurized Renugas system is 283 tonnes/day (311 tpd). The atmospheric Renugas and the FERCO processes are estimated to produce 325 tonnes/day (358 tpd) and 291 tonnes/day (320 tpd), respectively.

4.2.6.3 Ammonia Performance Summary

Table 17 gives a summary of process performance for the ammonia production scenario. The gas streams for this scenario are the same as in the methanol scenario. In this scenario, a significant amount of electricity is produced through expansion in the process.

Table 17

Process Data Summary and System Performance Results – Ammonia

	Pressurized Renugas	Atmospheric Renugas	FERCO
Gasifier Requirements			
Wood Flowrate, 20% moisture, tonnes/day (tpd)	569 (626)	675 (743)	596 (656)
95% Oxygen Flowrate, kg/hr (lb/h)	5,217 (11,500)	7,374 (16,256)	-
Steam Flowrate, kg/hr (lb/h)	1,379 (3,039)	1,644 (3,626)	-
Fuel Gas			
Fuel Gas Flowrate, kg/hr (lb/h)	32,949 (72,632)	38,103 (83,995)	19,937 (43,948)
Fuel Gas Heating Value, HHV, Wet Basis, MJ/kg (Btu/lb)	9.3 (3,997)	9.48 (4,076)	14.6 (6,279)
Power Production Summary			
Gas Turbine Output, MW	-	-	-
Steam Turbine Output, MW	1.25	1.77	-
Net System Output, MW	-5.87	-7.09	-2.89
Ammonia Production Summary			
Ammonia, tonnes/day (tpd)	206 (227)	235 (259)	165 (181)

The resulting net energy requirement for each system is as follows: 5.87 MW for the pressurized Renugas process, 4.86 MW for the FERCO system, and 10.85 MW for the atmospheric Renugas. Ammonia production for the pressurized and atmospheric Renugas

systems is 206 tonnes/day (227 tpd) and 235 tonnes/day (259 tpd), respectively. The FERCO system is estimated to produce 165 tonnes/day (181 tpd) of ammonia.

4.2.7 Economic Evaluation

An economic evaluation of the various integrated systems was conducted using conceptual designs described in the previous sections. The estimate is considered a “factored estimate” with much of the cost information being derived from the study conducted by Craig and Mann and in-house TVA estimates. The Craig and Mann study uses 1990 as a reference year for cost estimating purposes. For the purpose of this study, a reference year of 2001 is used. Therefore, the costs as presented in the Craig and Mann study were corrected for capacity and cost year using a capacity factor of 0.6 and the Chemical Engineering Cost Index of 400. The balance of plant was based on 20% of the total for other plant costs. Additional capital cost premises are listed below in Table 18.

Table 18

General Capital Cost Premises

Cost Category	Percent of Process Plant
General plant facilities	10
Engineering fees	15
Contingency	20
Start-up costs	4
Spare parts	1
Working capital	60 days operating cost

Operating costs are based on an average year of operation and include various direct costs such as raw materials and conversion costs, the premises of which are shown in Table 19.

Table 19

Direct Operating Cost Premises

Cost Category	Cost/unit
Wood	\$0.63/1000 MJ (\$0.66/million Btu)
Boiler feed water	\$0.66/cubic meter (\$2.50/1000 gallon)
Cooling water	
Ash disposal	\$8.80/tonne (\$8.00/ton)
Operating labor	\$15.00/hour
Supervision and clerical	25% of operating labor

Indirect costs are also included in the estimate and are derived from the premises shown in Table 20.

Table 20

Indirect Operating Cost Premises

Cost Category	Premise
Maintenance costs	4% of process plant cost
Insurance and local taxes	2% of process plant
Royalties	0.5% of electricity revenue

Selling price for the three products produced in these scenarios is shown in Table 21.

Table 21

Selling Price of Process Products

Product	Selling Price
Electricity	\$40/MWh
Methanol	\$133/tonne (\$121/ton)
Ammonia	\$220/tonne (\$200/ton)

Using these overall cost premises, capital and operating costs were estimated for the various integrated systems. These costs are described in the next section.

4.2.7.1 Capital Cost Estimate – Base Case CT System

Table 22 summarizes the capital costs for electricity production using the pressurized Renugas system, the atmospheric Renugas system, and the Battelle-FERCO system. As shown in the table, wood handling and drying costs are essentially the same for each system. The slight variations are based on the difference in feedrate for the three systems. As mentioned earlier, this difference in feedrate is due to the energy content of the gas produced by each system. For the purposes of this study, the size of the combustion turbine was held constant, therefore, the feedrate of wood to the gasifier varies for each system depending on the amount required to produce the desired energy content of the gas stream.

Table 22

Summary of Capital Costs for the Combustion Turbine System

Cost Category	Capital Costs, \$K (2001)		
	Pressurized Renugas	Atmospheric Renugas	FERCO
Plant Section Description			
Wood Handling	2,749	3,046	2,826
Wood Drying	2,908	3,222	3,499
Gasification	21,555	24,541	9,110
Gas Cleanup	2,638	Inc w Gasif	12,452
Tar Cracker	Not Req'd	Inc w Gasif	292
Direct Quench	Not Req'd	Inc w Gasif	69
Boost Compressor	573	Inc w Gasif	3,655
Char Combuster System	Not Req'd	Inc w Gasif	Inc w Gasif
Combustion Turbine System	9,608	9,608	9,608
HRSG	4,137	4,137	4,137
Steam Cycle	8,155	8,504	6,819
Balance of Plant	11,210	11,355	11,173
Substation	3,728	3,718	3,399
Subtotal, Process plant cost	67,263	68,133	67,039
General Plant Facilities	6,726	6,813	6,704
Engineering Fees	10,089	10,220	10,056
Project Contingency	13,453	13,627	13,408
Prepaid Royalties	336	341	335
Startup Costs	2,691	2,725	2,682
Spare Parts	673	681	670
Working Capital	1,070	1,128	1,132
Land	0	0	0
Total Capital Requirement	102,301	103,667	102,025

Using the Craig and Mann study as a reference, the cost of the gasification system for the pressurized Renugas, the atmospheric Renugas and the Battelle-FERCO system was \$21.5, \$24.5 and \$9.1 million, respectively. Though the FERCO system appears to be the least cost option, the cost for gas clean-up given in the Craig and Mann study is fairly high at \$12.45 million. Gas-clean-up costs are included in the cost of gasification for the atmospheric Renugas process and are shown to be minimal (\$2.6 million) in the pressurized Renugas system. If the cost of clean-up was included in the gasification cost for both the pressurized Renugas and the Battelle FERCO system, the cost for the gasification systems would then be \$24.2 million for the pressurized Renugas, \$21.6 million for Battelle-FERCO, and \$24.5 million for atmospheric Renugas.

A tar cracker was used in the two low pressure systems to reduce the molecular weight of the larger hydrocarbons that may be present in the gas stream. The cost for this system was included in the atmospheric Renugas cost. The cost of tar cracking for the FERCO system was estimated at \$292,000.

No costs were included for land in each scenario. It was assumed that the facility would be located at an existing industrial site. Working capital for each scenario is based on 60 days of operating cost. The remaining capital costs are calculated as percentages of process plant cost as shown in Table 15. As summarized in Table 15, total capital investment costs for pressurized Renugas, FERCO, and atmospheric Renugas are \$102.3, \$102.0, and \$103.7 million, respectively.

4.2.7.2 Annual Operating Cost Estimate – Base Case CT System

Annual operating costs for the three systems are summarized in Table 23. Wood costs as shown are estimated to be \$0.63/1000 MJ (\$0.66/million Btu). The wood is estimated to have a Btu content of 19.7 MJ/kg (8,472 Btu/lb) for the Renugas systems. The FERCO system used the slightly higher energy content of 20.3 MJ/kg (8,722 Btu/lb) for Aspen as mentioned in the Craig and Mann report. As mentioned earlier, the plant size is based on a nominal 434 kg/d (1,000 lbs per day) of as is wood. However, based on the energy content of the gas produced by each system, the feed rate varies slightly for each system.

Table 23**Summary of Annual Operating Costs –Combustion Turbine Scenario**

Cost Category	Operating Costs, \$K/year		
	Pressurized Renugas	Atmospheric Renugas	FERCO
Wood delivered, \$0.63/1000 MJ (\$0.66/million Btu), 19.7 MJ/kg (8472 Btu/lb) (dry)	1,849	2,194	1,936
BFW	77	21	73
Cooling Water	0	0	0
Ash disposal	19	22	326
Operating Labor	300	300	300
Supervision and Clerical	75	75	75
Maintenance Costs	2,691	2,725	2,682
Insurance and Local Taxes	1,345	1,363	1,341
Royalties	67	66	57
Other Operating Costs inc w Main Costs	0	0	0
Total Operating Costs before Cost of Capital and ROI	6,423	6,767	6,790

Ash is disposed of at a cost of \$8.80/tonne (\$8.00 per ton). Ash disposal costs are minimal for the Renugas systems, however, the FERCO process includes large disposal costs for the additional sand that is purged to prevent buildup of ash in the system. Operating labor is estimated at 20,000 hours per year at \$15.00 per hour for each system. Supervision and clerical were estimated as a percentage of operating labor. Maintenance and taxes and insurance costs were calculated using a percentage of the operating costs.

Royalties are based on revenue. In this scenario, all revenue is derived from the sale of electricity. As discussed earlier, the pressurized and atmospheric Renugas systems generate 42.05 and 41.86 MW, respectively. The FERCO system produces less electricity at 36.05 MW. Revenue from the sale of electricity produced by each system is based on a selling price of \$40 per MWh. Using this selling price, annual revenue for the pressurized Renugas, FERCO, and atmospheric Renugas was estimated to be \$13.3, \$11.4, and \$13.2 million, respectively. Total annual operating costs, excluding the cost of capital and return on investment (ROI), for the pressurized Renugas, FERCO, and atmospheric Renugas systems were estimated to be \$6.42 million, \$6.79 million, and \$6.77 million, respectively.

4.2.7.3 Capital Cost Estimate – Methanol Production System

Table 24 gives an estimate of capital costs for methanol production using the three gasification technologies for syngas production. As described in the design section of the report, for methanol production, 95% oxygen was used during gasification in the Renugas processes. Therefore, the flowrate of the resulting gas streams are smaller than those produced for combustion turbine operation (FERCO remained the same). This reduction in gas flowrate, resulted in smaller equipment sizes for the Renugas processes for the methanol production scenario. Capital costs for the Renugas gasifiers are therefore lower than in the combustion turbine scenario. As mentioned in the design section of this report, the methanol production system costs are based on a study conducted by TVA in 1999. The costs were corrected for capacity and inflation. Using the factors described earlier for the remaining plant costs, total capital investment costs for the methanol system using pressurized Renugas, FERCO, and atmospheric Renugas, were \$87.1 million, \$80.8 million, and \$81.4 million, respectively.

Table 24

Summary of Capital Costs – Methanol Production Scenario

Cost Category	Capital Costs, \$K (2001)		
	Pressurized Renugas	Atmospheric Renugas	FERCO
Wood Handling	2,749	3,046	2,826
Wood Drying	2,908	3,222	3,499
Air Separation	5,384	6,626	Not Required
Gasification	17,370	17,539	9,110
Gas Cleanup	2,638	Inc w Gasif	12,452
Tar Cracker	Not Req'd	Inc w Gasif	292
Direct Quench	Not Req'd	Inc w Gasif	69
Boost Compressor	573	Inc w Gasif	3,655
Char Combuster System	Not Req'd	Inc w Gasif	Inc w Gasif
Combustion Turbine System	Not Req'd	Not Req'd	Not Required
HRSG	758	934	Not Required
Steam Recycle	1,076	1,325	Not Required
Methanol Production	13,568	12,128	13,820
Methanol Storage	815	728	830
Balance of Plant	7,114	6,713	6,380
Substation	0	0	0
Subtotal, Process Plant Cost	57,070	53,136	52,933
General Plant Facilities	5,707	5,314	5,293
Engineering Fees	8,560	7,970	7,940
Project Contingency	11,414	10,627	10,587
Prepaid Royalties	285	266	265
Total Capital at Mechanical Comp	83,036	77,313	77,017
Startup Costs	2,283	2,125	2,117
Spare Parts	571	531	529
Working Capital	1,192	1,489	1,155
Land	0	0	0
Total Capital Requirement	87,082	81,459	80,819

4.2.7.4 Annual Operating Costs – Methanol Production System

Annual operating costs for this scenario are shown in Table 25 and are similar to those calculated for the combustion turbine scenario. However, as described in the design section, because there is no combustion turbine, electricity must be purchased for each methanol production system. Electricity requirements vary considerably for each technology. Both Renugas processes require an air separation unit. The atmospheric Renugas process and the FERCO process also require fuel gas compression. As a result, the electricity costs for the pressurized Renugas, FERCO, and the atmospheric Renugas systems are \$1.33 million, \$0.95 million, and \$3.06 million, respectively. All other operating costs are estimated as discussed in the previous section.

Table 25

Summary of Annual Operating Costs – Methanol Production Scenario

Cost Category	Operating Costs, \$K/year		
	Pressurized Renugas	Atmospheric Renugas	FERCO
Wood delivered, \$0.63/1000 MJ (\$0.66/million Btu), 19.7 MJ/kg (8472 Btu/lb) (dry)	1,849	2,194	1,936
BFW	42	3	58
Cooling Water	48	40	50
Electricity	1,334	3,060	947
Ash disposal	19	22	326
Operating Labor	300	300	300
Supervision and Clerical	75	75	75
Maintenance Costs	2,283	2,125	2,117
Insurance and Local Taxes	1,141	1,063	1,059
Royalties	62	51	64
Other Operating Costs inc w Main Costs	0	0	0
Total Operating Costs before Cost of Capital and ROI	7,152	8,934	6,932

Revenue from the technologies is based on the sale of methanol. Pressurized Renugas, FERCO, and atmospheric Renugas each produce 283 (311), 291 (320, and 235 tonnes/day (258 tons per day), respectively. At selling price of \$133/tonne (\$121 per ton), the annual revenue from using each technology is \$12.4 million for pressurized Renugas, \$12.8 million for FERCO, and \$10.3 million for atmospheric Renugas.

4.2.7.5 Total Capital Investment – Ammonia Production System

Table 26 gives a summary of capital costs for the ammonia production system. The costs are similar to those presented for the methanol production scenario. The costs shown for the ammonia production section were derived from in-house estimates based on production of ammonia from landfill gas.

Table 26

Summary of Capital Costs – Ammonia Production Scenario

Cost Category	Capital Costs, \$K (2001)		
	Pressurized Renugas	Atmospheric Renugas	FERCO
Wood Handling	2,749	3,046	2,826
Wood Drying	2,908	3,222	3,499
Air Separation	5,384	6,626	Not Req'd
Gasification	17,370	17,539	9,110
Gas Cleanup	2,638	Inc w Gasif	12,452
Tar Cracker	Not Req'd	Inc w Gasif	292
Direct Quench	Not Req'd	Inc w Gasif	69
Boost Compressor	573	Inc w Gasif	3,655
Char Combuster System	Not Req'd	Inc w Gasif	Inc w Gasif
Combustion Turbine System	Not Req'd	Not Req'd	Not Required
HRSG	758	934	Not Required
Steam Recycle	1,076	1,325	Not Required
Ammonia Production	50,705	54,754	44,187
Ammonia Storage	815	728	830
Balance of Plant	7,114	6,713	6,380
Substation	0	0	0
Subtotal, Process Plant Cost	57,070	53,136	52,933
General Plant Facilities	5,707	5,314	5,293
Engineering Fees	8,560	7,970	7,940
Project Contingency	11,414	10,627	10,587
Prepaid Royalties	285	266	265
Total Capital at Mechanical Comp	83,036	77,313	77,017
Startup Costs	2,283	2,125	2,117
Spare Parts	571	531	529
Working Capital	1,192	1,489	1,155
Land	0	0	0
Total Capital Requirement	152,101	162,298	129,735

As shown in the table, total capital investment costs for the pressurized Renugas, atmospheric Renugas, and FERCO systems are \$152.1 million, \$162.3 million, and \$129.7 million, respectively.

4.2.7.6 Annual Operating Costs – Ammonia Production System

A summary of annual operating costs for the ammonia production scenario are shown in Table 27. As in the methanol case, electricity costs are significant for each gasification technology. The bulk of the electricity costs result from compression costs. In the atmospheric processes, the fuel gas stream must be compressed prior to ammonia production. There are also considerable power loads from refrigeration requirements.

Table 27

Summary of Annual Operating Costs – Ammonia Production Scenario

Cost Category	Operating Costs, \$K/year		
	Pressurized Renugas	Atmospheric Renugas	FERCO
Wood delivered, \$0.63/1000 MJ (\$0.66/million Btu), 19.7 MJ/kg (8472 Btu/lb) (dry)	1,849	2,194	1,936
BFW	38	46	19
Cooling Water	303	307	218
Electricity	1,860	2,246	916
Ash disposal	19	22	326
Operating Labor	300	300	300
Supervision and Clerical	75	75	75
Maintenance Costs	2,283	2,125	2,117
Insurance and Local Taxes	1,141	1,063	1,059
Royalties	62	51	64
Other Operating Costs inc w Main Costs	0	0	0
Total Operating Costs before Cost of Capital and ROI	10,018	10,760	8,177

All other costs are calculated as discussed in previous scenarios. As shown in the table, total annual operating costs for the Renugas and FERCO systems are \$10.02 million for pressurized Renugas, \$10.76 million for atmospheric Renugas and \$8.18 million for FERCO.

4.2.7.7 Summary of Economic Evaluation

Total capital investment and operating costs are summarized for the nine scenarios in Tables 28 and 29, respectively. As shown in Table 28, total capital investment for power production was essentially the same for the three processes. The least cost scenario was methanol production using the FERCO process.

Table 28

Total Capital Investment Summary

Technology	Power Production \$M/year	NH3 Production \$M/year	Methanol Production \$M/year
Pressurized Renugas	102.3	152.1	87.1
Atmospheric Renugas	103.7	162.3	87.4
FERCO	102.0	129.7	80.8

Operating costs for the systems ranged from \$6.42 million for power production using the pressurized Renugas system to \$10.76 million for the ammonia system using the FERCO gasification technology.

Table 29

Annual Operating Costs Summary

Technology	Power Production \$M/year	NH3 Production \$M/year	Methanol Production \$M/year
Pressurized Renugas	6.42	10.02	7.15
Atmospheric Renugas	6.77	8.18	8.93
FERCO	6.79	10.76	6.93

Revenue from each system is shown in Table 30. As shown, the atmospheric Renugas system for ammonia production had the highest revenue of the nine scenarios.

Table 30

Revenue Summary

Technology	Power Production \$K/year	NH3 Production \$K/year	Methanol Production \$K/year
Pressurized Renugas	13,321	14,982	12,410
Atmospheric Renugas	13,261	17,067	10,293
FERCO	11,421	11,946	12,796

A summary of the corresponding product quantities is shown in Table 31.

Table 31

Product Summary

Technology	Power Production (MW)	NH3 Production (T/D)	Methanol Production (T/D)
Pressurized Renugas	1009	227	311
Atmospheric Renugas	1005	259	358
FERCO	865	181	320

Based on the results of this portion of the study, it can be seen that the two Renugas processes appear to have the most potential to maximize power production via gasification. Ammonia and methanol production also tend to favor the Renugas processes, though the FERCO process produced slightly more methanol than the atmospheric Renugas system.

Process developments such as hot gas clean-up have the potential to improve the economics of biomass gasification. The effect of such improvements will be discussed in the next section along with the evaluation of the carbon sequestration potential of the three technologies.

4.3 Cost Of Avoiding Fossil CO2 Emissions

Using the three scenarios defined in the previous sections, the cost of carbon dioxide sequestration was evaluated. The cost of greenhouse gas mitigation using renewable energy technologies depends on both the difference between the generation costs of the renewable energy option--i.e., in these cases, the generation of electricity or the production of methanol or ammonia--and the low-cost alternative (e.g., coal or natural gas fuel or feedstock for electricity generation or methanol/ammonia production). The mitigation costs are usually expressed in units of the cost per unit fossil carbon emissions that are avoided, offset, captured, sequestered, etc. In this section, the extra costs of the renewable power generation technologies are converted into terms of cost per unit fossil carbon emission avoided.

It is known that several “greenhouse gases” contribute to humanity’s effect on the radiation balance in the atmosphere and, hence, on potential global temperature and climate effects. They include carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), and certain chloro-fluorocarbons (CFCs). (The CFCs have become most widely known for their chemical effects in the stratosphere, reacting with and depleting the ozone layer. They also absorb infrared radiation and affect global heat balance. This occurs much lower than the stratosphere, down in the main mass of the atmosphere, i.e., the troposphere.) The relevant impacts of the greenhouse gases on the radiation balance vary between the greenhouse gases. Table 32 presents numbers that show this (Hughes 2000).

Table 32

Greenhouse Warming Strengths of the Key Gases

<u>Gas</u>	Lifetime in the <u>Atmosphere</u>	<u>Infrared absorbing strength relative to CO₂</u>		
		<u>20-year</u>	<u>100-year</u>	<u>500-year</u>
Carbon dioxide (CO ₂)	variable	1	1	1
Methane (CH ₄)	12 years (+-3)	56	21	7
Nitrous oxide (N ₂ O)	120 years	280	310	170
Chlorofluorocarbons (CFC)	not given	4900	3800	not given

Source: U.S. Dept. of Energy EIA, "Emissions of Greenhouse Gases in the US: 1996" Oct.1997.

In Table 32, different timeframes, as well as the four different gases, are shown because the non-CO₂ gases gradually are converted into CO₂ over the years and will eventually be at the same strength as CO₂, but not until well beyond the timeframes of interest here. In order to assess emission controls

applied to different gases on a common basis for global warming purposes, the emissions of the different greenhouse gases are normalized to a common basis by expressing them as equivalent CO₂ emissions. On a mass basis, and for a 100-year timeframe, methane (CH₄) absorbs 21 times as much of the earth's outgoing infrared radiation as carbon dioxide (CO₂). Therefore, we say that the mass of the equivalent CO₂ emission is 21x the mass of the methane put into the landfill gas energy system. In this section of the report the costs of greenhouse gas reduction will be expressed and compared on the basis of dollars per metric ton (tonne) of elemental carbon (\$/tonne C), based on the absorbing strength when that carbon atom is in a CO₂ molecule--the "CO₂ equivalent." When methane is the fuel, the carbon atom is in a CH₄ molecule. Hence, the factor per unit of energy will be less than the 21x. Here we use a factor of only 7.64, which is 21 x (16/44). The 16/44 is because each molecule of methane has a mass of 16, molecular weight, and goes into one atom of carbon in a carbon dioxide molecule of weight 44.

In addition to depending on the type of gas whose emission is reduced or avoided, the analysis leading to cost per unit weight of fossil CO₂ emissions avoided must take into account the type of fuel, technology and emitted gas that would otherwise have been used to generate the electricity replaced by the renewable technology. The amount of fossil carbon emission avoided by using a renewable resource instead of a fossil fuel power generation technology depends on the fossil fuel type that is "avoided" and on the conversion technology that would have been used to make the power from that fossil fuel. Table 33 shows the fuel effect, based on the carbon intensity of the various fuels, as measured in units of weight of carbon per unit of energy content of the fuel.

Table 33

Fuel Effect on Fossil Carbon Intensity

<u>Name of Fuel</u>	<u>Heat Content - HHV</u>		<u>Carbon Content</u>		<u>Fossil Carbon Intensity</u>	
	<u>(Btu/lb)</u>	<u>(MJ/kg)</u>	<u>(lb-C/lb)</u>	<u>(kg-C/kg)</u>	<u>(lb-C/MBtu)</u>	<u>(kg-C/MJ)</u>
Coal	13,700	31.798	0.78	0.78	56.9	24.5
Oil	18,000	41.778	0.85	0.85	47.2	20.3
Natural gas	23,800	55.240	0.76	0.76	31.9	13.8
Wood (dry)	8,000	18.568	0.45	0.45	Zero*	Zero*

*Note: "Fossil" carbon intensity is the measure relevant to greenhouse gas, and by this measure wood from renewable growth of trees is zero in carbon intensity. If the carbon in the fuel is put straight into the same formula used for the fossil fuels, then the carbon intensity for the wood is 54.2 lb-C/MBtu or 23.4 kg-C/MJ.

Next, Table 34 shows the effect of conversion technology, and, therefore, combines the effects of carbon intensity in the fuel with the efficiency of converting the fuel to electricity. Table 34 gives the emissions of carbon dioxide (or carbon) from present and future fossil fuel technologies, both coal-based and natural-gas-based.. Efficient pulverized coal units emit about 0.95 tons CO₂ per MWh of electricity generation, which is 0.26 tons C per MWh. Advanced IGCC technology will reduce these CO₂ emissions factors by about 20%. Advanced natural gas-combined cycle plants with efficiencies as high as 54% will emit about 0.37 tons CO₂ (0.10 tons C) per MWh. Therefore, to convert the extra cost of the renewable electricity, given in \$/MWh, into units of \$/tonne-C for the greenhouse gas reduction achieved, the \$/MWh is simply divided by the tonne-C/MWh of the fuel-technology combination that is considered to be the fossil technology replaced by the renewable one.

Table 34

Technology Effect on Fossil Carbon Intensity

Fuel - <u>Technology (HHV eff.)</u>	English units:	Carbon	Heat	<u>Fossil Carbon Emission</u>	
		Content	Rate	CO ₂	C
		<u>(lb/MBtu)</u>	<u>(Btu/kWh)</u>	<u>(ton/MWh)</u>	<u>(ton/MWh)</u>
Coal -					
Typical existing (0.341)		56.9	10,000	1.04	0.28
Pulverized, 95% scrubbed (0.376)		56.9	9,087	0.95	0.26
Advanced, IGCC (0.467)		56.9	7,308	0.76	0.21
Natural gas -					
Existing steam plant (0.331)		31.9	10,300	0.60	0.16
Advanced, CC (0.538)		31.9	6,350	0.37	0.10
Advanced, CT (0.427)		31.9	8,000	0.47	0.13
Advanced, fuel cell (0.637)		31.9	5,361	0.31	0.09
	SI units:	Carbon	Heat Rate	CO ₂	C
		<u>(kg/GJ)</u>	<u>(kJ/kWh)</u>	<u>(tonne/MWh)</u>	<u>(tonne/MWh)</u>
Coal -					
Typical existing (0.341)		24.52	10,550	0.95	0.26
Pulverized, 95% scrubbed (0.376)		24.52	9,587	0.86	0.24
Advanced, IGCC (0.467)		24.52	7,710	0.69	0.19
Natural gas -					
Existing steam plant (0.331)		13.74	10,867	0.55	0.15
Advanced, CC (0.538)		13.74	6,699	0.34	0.09
Advanced, CT (0.427)		13.74	8,440	0.43	0.12
Advanced, fuel cell (0.637)		13.74	5,656	0.29	0.08

Source: EIA 1998 (“EIA Kyoto”), Tables 16, 17 (pages 73-75), U.S. DOE, October 1998.

4.3.1 Converting Power Costs into CO2 Reduction Costs

The results of applying this procedure are shown in Table 35. Examples of how Table 35 was calculated for several cases follow, with special emphasis on two cases that are somewhat different from the rest: biomass cofiring, and landfill gas. In biomass cofiring the fossil alternative is not a new fossil power plant, but, instead, is simply the operation of the existing coal-fired plant on 100% coal, with no biomass displacing any of the coal. In landfill gas, which here refers to landfill gas power generation, the burning of the biomass-derived methane gas avoids the emission by the landfill of a greenhouse gas 21 times as powerful, per unit weight, as the carbon dioxide in infrared absorbing and warming strength. Taking this greenhouse strength into account makes the cost of avoiding the CO2 equivalent much lower, by the 7.64 factor derived above.

Table 35

Conversions of Power Costs into CO2 Reduction Costs

<u>Renewable Technology</u>	<u>Extra Cost</u> (\$/MWh)	<u>Carbon Intensity Displaced</u>		<u>Cost of CO2 Reduction</u>	
		<u>Coal</u> (tonne-C/MWh)	<u>Natural Gas</u> (tonne-C/MWh)	<u>Coal</u> (\$/tonne-C)	<u>Natural Gas</u> (\$/tonne-C)
Biomass cofiring (low cost end of range)	\$ (5.00)*	0.264	not applicable	\$ (18.97)*	not applicable
Biomass cofiring (high cost end of range)	\$18.00	0.264	not applicable	\$68.28	not applicable
Biomass gasification or other advanced biomass	\$10.00	0.264	0.090	\$37.93	\$111.11
Wind	\$10.00	0.264	0.090	\$37.93	\$111.11
Geothermal	\$7.00	0.264	0.090	\$26.55	\$77.78
Solar Thermal	\$47.00	0.264	0.090	\$178.28	\$522.22
Solar PV	\$14.00	0.264	0.090	\$53.10	\$155.56
Landfill gas***	\$5.00	2.013	0.687	\$2.48	\$7.28

***The landfill gas conversion factors are based on the 21x stronger greenhouse warming effect of CH4 vs. CO2, and also the factor of 16/44 to convert from a weight basis to a mole basis.

The above results are taken from the EPRI report “Greenhouse Gas Reduction with Renewables” published in December 2000 as EPRI No. TR-113785 (Hughes 2000). They are shown here to provide further comparisons to the biomass gasification technologies that are the subject of this report. Further results from that earlier report by EPRI are presented in the subsection immediately below.

4.3.2 Total Supply Curve for Renewables

Table 36 shows the “supply curve” adopted in the EPRI report on renewables for greenhouse gas reduction (Hughes 2000) for the U.S.

Notice that solar PV residential has a high-cost **retail** value as the price of the fossil alternative: **\$100/MWh**, not \$42/MWh. Central station solar has the \$42/MWh as the alternative fossil price to be subtracted to derive the extra cost of the renewable option.

Biomass cofiring has zero as the cost of the fossil alternative, not \$42/MWh. As explained earlier, this is because, with the alternative being to run the coal plant on 100% coal, the costs were taken to be only the increment above the costs to build and operate the coal plant and to buy the coal fuel: \$0.25/MBtu extra for the biomass fuel, and capital and labor costs that are only the addition above the baseline existing plant and operating staff, plus extra maintenance only for the biomass equipment added to the plant. Because of the need for rapid payback on plant modifications paid out of the plant's annual capital improvement budget, capital recovery on biomass cofiring is at 33% per year, not 21%, on the capital cost of the biomass modifications.

Table 36
Supply Curve For All Renewables

Energy Source, Technology, and Other	Capacity GW	Annual Gen. TWh/year	Capital Cost \$/MWh	O&M Cost \$/MWh	Fuel Cost \$/MWh	Total Cost \$/MW	Alternative Cost \$/MWh	Extra Cost \$/MWh	Carbon Cost \$/tonne-C	Cumulative Generation TWh/year	Cum Carbon Reduction Mtonne-C/yr	Cum. Extra Cost \$Billion/year
Geothermal, hot low cost	2	15.0	29.00	7.40	0.00	36.40	42.00	-5.60	-23.69	15	3.6	(0.1)
Wind Class +5	9	35.0	33.50	6.60	0.00	40.10	42.00	-1.90	-8.04	50	13.0	(0.3)
Landfill Gas, 2 MW	4	24.0	38.30	10.00	6.50	54.80	42.00	12.80	7.10**	74	58.6**	(0.0)
Biomass, existing generation	7	45.0	0.00	20.00	24.00	44.00	42.00	2.00	8.46	119	70.3	0.1
Animal Wastes, 300 kW	4	24.0	52.30	20.00	0.00	72.30	42.00	30.30	16.80**	143	113.5**	0.8
Biomass Cofiring, blended*	3	20.0	2.40*	1.00*	2.80*	6.20	0.00	6.20	26.23	163	118.2	0.9
Geothermal, hot average cost	3	22.0	33.84	15.00	0.00	48.84	42.00	6.84	28.94	185	123.4	1.0
Geothermal, warm low cost	10	74.0	42.00	12.00	0.00	54.00	42.00	12.00	51.00	259	140.8	1.8
Biomass, advanced technology	40	260.0	35.60	10.20	11.40	57.20	42.00	15.20	64.50	519	202.2	5.8
Wind Class 4	16	48.0	43.10	8.50	0.00	51.60	42.00	9.60	40.62	567	213.5	6.3
Solar PV, residential good	10	27.5	108.70	5.20	0.00	113.90	100.00	13.90	58.81	595	220.0	6.9
Biomass Cofiring, separate*	4	27.0	9.80*	2.70*	2.80*	15.20	0.00	15.20	64.50	622	226.3	7.3
Wind Class 3	24	52.0	60.30	11.90	0.00	72.20	42.00	30.20	127.77	674	238.5	8.7
Geothermal, warm average cost	20	149.0	56.40	20.00	0.00	76.40	42.00	34.40	145.54	823	273.6	13.8
Solar PV, central good	10	23.0	79.50	1.20	0.00	80.70	42.00	38.70	163.73	846	279.0	14.7
Solar PV, residential average	12	22.0	140.30	6.40	0.00	146.70	100.00	46.70	197.58	868	284.2	15.7
Solar Thermal, 25 MW	10	27.0	79.20	10.20	0.00	89.40	42.00	47.40	200.54	895	290.6	17.0
Solar PV, central average	22	40.0	100.70	1.50	0.00	102.20	42.00	60.20	254.69	935	300.0	18.6

TOTALS 210 GWe 934.5 TWh Cost of last increment = \$254.69/tonne C Average cost = \$62.00/tonne C

* Biomass cofiring costs are incremental, i.e., costs above normal coal-fired operation, so fuel at \$0.25/MBtu is \$1.50/MBtu when coal is \$1.25. Capital is only the add-on to handle and fire the biomass, and O&M also is only the increment. Also, fast payback in these cases: 33% annual capital recovery rate, not just 21%.

**Animal wastes and landfill gas technologies eliminate a methane (CH₄) emission and therefore have a conversion to cost per tonne-C in CO₂ equivalents that is less by factor of (1/21) x (44/16), due to CH₄ being a stronger absorber of heat by 21x per unit weight. And, also, the CO₂-equivalent tonne-C/year of carbon reduction for the two technologies is a factor of 21 x (16/44) = 7.64 greater.

4.3.3 Sensitivity of Results

The costs of carbon reduction in Table 36 are derived from differences between the estimated future costs of the renewable technologies and the costs adopted for the fossil alternatives. The extra cost in \$/MWh are the same versus both fossil alternatives, because values for the cost of electricity from new, not existing, coal- and gas-fired power plants were selected to be the same, namely \$42/MWh. As discussed in the section above, the conversion from extra \$/MWh to cost in \$/tonne-C of fossil carbon emission avoided depends on the carbon intensity in tonne-C/MWh of the fossil power system whose emission is avoided. The carbon costs in \$/tonne-C in Table 36 are based on the coal case, which is 0.236 tonne-C/MWh. If natural gas in an efficient advanced combined cycle is the fossil option avoided, then the factor is 0.09 tonne-C/MWh, and the resulting carbon avoidance cost is higher by a factor of $0.236/0.09$, or 2.62. (The last three columns in Table 37 at the very end of this section show examples of extra cost in \$/MWh being converted to \$/tonne-C for both coal and natural gas as the advanced fossil power plant carbon emission avoided.)

Both the coal and the gas alternatives are estimated at essentially the same cost of 4.2¢/ kWh which is also \$42/MWh. A 15%, or 0.6¢/kWh, change in that 4.2¢/kWh cost will change the carbon reduction cost by \$6/MWh which converts to \$6 per 0.95 tonne of CO₂ or $(12/44) \times 0.95 = 0.26$ tonne of C, i.e., \$23/tonne-C. This uncertainty of \$23/tonne-C is equal to the total carbon reduction cost values near the low-cost end, and is in the range of 7% to 10% of the values at the high end of the carbon costs estimated in Table 36.

Of course, there is a similar uncertainty associated with the estimates of the costs of the renewable technologies themselves. The uncertainty of these will range from 15% of 4¢/kWh, i.e., 0.6¢/kWh or \$6/MWh, to values as large as 30% of high costs like 10¢ to 20¢/kWh at the high-cost, high-uncertainty end (i.e., 30% of costs as high as \$100/MWh to \$200/MWh). These translate into uncertainties in carbon reduction costs as large a proportion as $\pm 100\%$ of the cost at the low end of \$20/tonne-C, to values on the order of $\pm 30\%$ of some \$200 to \$500/tonne-C at the high-cost, high-uncertainty end.

4.3.3.1 Some Specific Sensitivities

Economic Parameters. The one dominant economic parameter is set the same for all the technologies, except for cofiring. This is the 21% “fixed charge rate,” or annual capital recovery factor, used in all except biomass cofiring. As explained in Section 4 and above, for cofiring this is set at a rate of 33%, because cofiring must compete with other near-term capital expenditures for improvements at existing coal-fired plants.

As also pointed out earlier, in all the above cases solar PV has been given the advantage of a \$100/MWh, which is 10¢/kWh, alternative price. Because the other

renewables are shown as competing against a \$42/MWh fossil alternative, this is nearly a \$60/MWh, or \$150/tonne-C, effect in favor of PV residential. However, the advantage is real, at least during the near- to mid-term while solar PV enters residential, commercial and remote location markets rather than bulk power markets. It reflects the actual and substantial retail versus wholesale generation price differential, and it reflects the fact that the best openings for solar PV will be where the sunlight itself is the distribution system and beats the cost of putting in the wires or bringing in high-cost diesel fuel.

Fuel Costs for Geothermal and Biomass. Biomass is the only renewable technology that pays for fuel as an ongoing operating cost. In some analyses, but not as done here, geothermal has a “fuel” input in the form of hot water flowing into the power plant. However, in this report and in the Technology Characterizations report (Hughes 2000), the cost to obtain this "geothermal fuel" is taken to be a capital expense, not a fuel cost. (The capital is spent to drill and complete the wells, and to buy and install the pipelines/pumps/etc. that bring hot water to the power plant and take the cooler water back from the plant into the injection wells, which inject it back into a cool part of the underground reservoir.) Therefore, for geothermal as done here, the non-capital costs are operating costs, not fuel costs. And, being for the most part fixed costs for payroll and maintenance, these operating costs are unlike fuel costs in that they are not tied closely to the plant heat rate nor to variations in the "fuel" flow rate, the rate of geothermal fluid flow to and from the plant.

Biomass. For biomass, fuel cost is very important in the economics. The fuel cost used for “advanced biomass” merits special comment, because energy crops are the fuel assumed when a potential capacity of 40 GWe is named in Table 36. Fuel cost of \$1.50/MBtu is the basis for the “advanced biomass” case, together with a high efficiency, i.e., the low heat rate of 7600 Btu/kWh, which corresponds to a higher heating value (HHV) efficiency of 45%. The \$1.50/MBtu is low compared to current estimates for energy crop costs when “dedicated biomass feedstock supply systems” are studied. A 1998 paper from the Oak Ridge National Laboratory (ORNL) on the price necessary to displace conventional farm crops gave \$2.50/MBtu and \$3.50/MBtu as the prices needed to bring millions of acres into energy crop production (Walsh 1998). The much lower price of \$1.50/MBtu is justified here for two reasons:

1. The energy crop could be the coproduct of a pulp/fiber farm, where a high-value fiber product is 70 to 80% of the mass grown and harvested and pays nearly all of the planting, cultivating and harvesting cost.
2. The fuel has a much lower cost of harvesting than that used in ORNL analysis (about \$5/dry ton, versus the \$20/dry ton apparently used in Walsh 1998).

These two measures to reduce costs are capable of reducing the total cost of energy crop fuel by \$1.00 to \$2.00/MBtu, having the effect of reducing a \$3 to \$4 per million Btu cost down to the \$1 to \$2 per million Btu range. These ways to reduce energy crop costs are discussed in a 1995 EPRI paper and a 1998 EPRI report (Hughes & Wiltsee 1995, Wiltsee 1998). The harvesting improvement is addressed in the first EPRI Whole Tree Energy report (EPRI 1993) and also in studies on energy from willows by Niagara Mohawk, DOE and EPRI (Wiltsee 1998, Niagara Mohawk & SUNY 1995).

The “existing biomass” category in the supply curve in Table 36 also uses a \$1.50/MBtu fuel cost, as does the separate feed biomass cofiring line. This \$1.50 is at the midpoint of a wide range of possible biomass fuel costs. Today, the wood-derived biomass that is the fuel for existing biomass power plants, and for most cofiring operations at coal-fired plants in the near-term future, comes at costs ranging from \$0.50/MBtu to \$2.50/MBtu. On a dry-weight basis the price range for biomass fuels both for today and for studies of future options is from a low of \$8 to a high of \$40, per dry ton. (Since normal green wood freshly cut is about 50% moisture, this range in dry weight costs is a range from \$4 to \$20 per “as-received” ton, at this 50% moisture value.) The low end, at \$0.50/MBtu, is enough to pay typical transportation costs to move the fuel some 30 to 70 miles (50 to 110 km) from source to power plant. Given such a large range in possible biomass fuel costs, the resulting range in carbon reduction costs is very large. Table 37 shows this. The range of biomass power plant efficiencies is also taken into account in Table 37. The low efficiency end of this range is that seen in some of today's high-heat-rate plants at 16,000 Btu/kWh (16.9 MJ/kWh, and 21% efficiency on a higher heating value, HHV, basis) to future advanced plants such as biomass gasification (IGCC) at 7500 Btu/kWh (7.9 MJ/kWh and 46% efficiency on an HHV basis).

Table 37

Sensitivity to Biomass Fuel Cost and Conversion Efficiency

Case Identification (Fuel Cost, Heat Rate)	Biomass Fuel Cost (basis: 8300 Btu/lb. dry)		Heat Rate (Btu/kWh)	Result: Fuel Cost (\$/MWh)	Result: Carbon Cost (\$/tonne-C)**	
	\$/dry ton	\$/MBtu			Coal at 0.236 tonne-C/MWh	Nat. gas at 0.09 tonne-C/MWh
Low cost, HR = 7,500	\$8.30	\$0.50	7,500	\$3.75	\$15.89	\$41.67
Low cost, HR = 10,000	\$8.30	\$0.50	10,000	\$5.00	\$21.19	\$55.56
Low cost, HR = 16,000	\$8.30	\$0.50	16,000	\$8.00	\$33.90	\$88.89
Mid-range, HR = 7,500	\$24.90	\$1.50	7,500	\$11.25	\$47.67	\$125.00
Mid-range, HR = 10,000	\$24.90	\$1.50	10,000	\$15.00	\$63.56	\$166.67
Mid-range, HR = 16,000	\$24.90	\$1.50	16,000	\$24.00	\$101.69	\$266.67
High cost, HR = 7,500	\$41.50	\$2.50	7,500	\$18.75	\$79.45	\$208.33
High cost, HR = 10,000	\$41.50	\$2.50	10,000	\$25.00	\$105.93	\$277.78
High cost, HR = 16,000	\$41.50	\$2.50	16,000	\$40.00	\$169.49	\$444.44

**Coal case is advanced pulverized coal plant with scrubber at a heat rate of 9087 Btu/kWh. Natural gas is an advanced combined cycle at a heat rate of 6350 Btu/kWh. These efficiencies are (HHV basis) 37.6% for the coal, and 53.7% for the natural gas. Emission factors are 519 lb-C/MWh or 0.236 tonne-C/MWh for the coal, and 201 lb-C/MWh or 0.09 tonne-C/MWh for the natural gas. Values from EIA Kyoto report (EIA 1998), pages 73 and 75.

4.3.4 Methodology in this Report for Biomass Gasification Technologies

The same approach as above was employed for the current report on biomass gasification as a CO2 reduction measure. Details of the calculations are shown in Table 38.

Table 38

Electricity: CO2 Control Costs and Comparison of Technologies

<u>Issue/Item</u>	<u>Units</u>	<u>GII</u> <u>Renu HP</u>	<u>Battelle</u> <u>FERCO</u>	<u>GII</u> <u>Renu LP</u>
Efficiency				
Fuel input (mass, wet basis)	ton/24-hr-day	1002	1049	1189
Fuel moisture (wet basis)	%	50%	50%	50%
Heat content (HHV, dry)	Btu/lb	8472	8722	8472
Heat content (LHV, dry)	Btu/lb	7746	7996	7746
Fuel input (energy HHV)	Mbtu/hr	353.7	381.2	419.7
Fuel input (energy LHV)	Mbtu/hr	323.4	349.5	383.7
Net power output	MWe	42.05	36.05	41.86
Heat rate (HHV)	Btu/kWh	8,412	10,575	10,027
Efficiency (HHV basis)	%	40.6%	32.3%	34.0%
Efficiency (LHV basis)	%	44.4%	35.2%	37.2%
Carbon: fossil CO2				
Coal: C per unit energy	lb/Mbtu	57.1	57.1	57.1
Replace coal of 10,000 HR	tonCO2 / MWh	1.046	1.046	1.046
Coal in metric C (not CO2)	tonneC / MWh	0.259	0.259	0.259
Coal: C per unit energy	lb/Mbtu	57.1	57.1	57.1
Replace coal of 9087 HR	tonCO2 / MWh	0.951	0.951	0.951
Coal in metric C (not CO2)	tonneC / MWh	0.236	0.236	0.236
NG: C per unit energy	lb/Mbtu	31.7	31.7	31.7
Replace NG of 6,350 HR	tonCO2 / MWh	0.369	0.387	0.387
NG in metric C (not CO2)	tonneC / MWh	0.091	0.096	0.096
Capital cost				
Electricity capital req.	\$000	47,000	48,873	47,628
Electricity, cap. req. per kW	\$/kW	1,118	1,300	1,138
Electricity (per input biomass)	\$/ (ton/day)	\$46,906	\$46,590	\$40,057
Cost per tonne C				
Coal PC Coal conventional: \$/MWh	\$/MWh	\$42.00	\$42.00	\$42.00
Biomass option \$/MWh	\$/MWh	\$65.55	\$76.36	\$66.38
Extra \$/MWh vs coal	\$/MWh	\$23.55	\$34.36	\$24.38
C avoided vs coal conv	tonneC / MWh	0.259	0.259	0.259
Cost in \$/tonne C conv	\$/ tonneC	\$77.08	\$115.63	\$154.17
Coal adv.PC Coal advanced: \$/MWhr	\$/MWh	\$42.00	\$42.00	\$42.00
Biomass option \$/MWh	\$/MWh	\$65.55	\$76.36	\$66.38
Extra \$/MWh vs coal	\$/MWh	\$23.55	\$34.36	\$24.38
C avoided vs coal advncd	tonneC / MWh	0.236	0.236	0.236
Cost in \$/tonne C advncd	\$/ tonneC	\$93.31	\$135.73	\$178.14
NGCC adv.NG: \$/MWh	\$/MWh	\$42.00	\$42.00	\$42.00
Biomass option \$/MWh	\$/MWh	\$65.55	\$76.36	\$66.38
Extra \$/MWh vs NG	\$/MWh	\$23.55	\$34.36	\$24.38
C avoided vs NG	tonneC / MWh	0.091	0.091	0.091
Cost in \$/tonne C	\$/ tonneC	\$218.81	\$312.61	\$416.82

Table 38 (cont.)

Electricity: CO₂ Control Costs and Comparison of Technologies

Plant characteristics:	Technology ==>	<u>Renu HP</u>	<u>FERCO</u>	<u>Renu LP</u>
Net power out, MWe	MWe	42.05	36.05	41.86
Annual gen, MWh/yr	MWh/yr	280,000	240,006	278,687
Capacity factor		0.760	0.760	0.760
Hours/year, hrs	Hours	6659	6658	6658
Total capital requirmt, \$000	\$000	47,000	48,873	47,628
Capital cost, \$/kW	\$/kW	1,118	1,300	1,138
HHV efficiency		40.6%	32.3%	34.0%
HHV heat rate	Btu/kWh	8412	10575	10027

Table 38 shows the cost and performance numbers that characterize the three biomass gasification technologies covered in detail in this report. The table steps through the calculation that converts \$/MWh of the biomass-based electricity into \$/MWh “extra”—meaning above the \$42/MWh adopted as the fossil-fuel-based alternative from new, not existing, coal-fired PC and advanced natural gas combined cycle (NGCC) power plants. Note that the \$42/MWh applies to the NGCC when demand for more natural gas -- to fuel 100 to 200 GWe or more of new power plants in the US -- has caused the price to be \$4.00/MMBtu instead of the \$2.50/MMBtu natural gas prices of most recent years. The \$ values are in 2001\$ but are intended to reflect future costs – the future costs still expressed as they would be in today’s dollars. The relevant concern here is with technologies that would be the commercial options some five to fifteen years in the future. The R&D and initial deployments have begun, and they will continue over the next five years.

Table 39 presents the technology “goal” cases that were used in Table 38. These goal cases have greatly reduced capital costs—on the order of \$1100/kWe rather than the “current” values derived in the detailed analysis of the tables presented prior to this section. The goal values of Table 38 were adopted to be consistent with the method described here and adopted in the “greenhouse gas report” EPRI TR-113785 (Hughes 2000). The lower portion of Table 39 shows the “current” cases, so that the reader can see how the “goal” cases differ. In general the goal cases are more “optimistic”—i.e., lower cost. However, there are two exceptions to this:

1. Biomass fuel costs are set at \$1.50/MMBtu, up from the \$0.66/MMBtu of the “current” cases. This is to allow for the use of larger amounts of more expensive residue fuels and also some energy crop fuels.

2. The “goal” capacity factor is set at 0.76 rather than 0.904. This is to be more consistent with capacity factors used in the earlier study, the “greenhouse gas report” (Hughes 2000).

The costs per metric ton (\$/tonne-C) in Tables 38 and 39 are unacceptably high to show biomass gasification as among the lower cost, rather than higher cost, fossil carbon reduction options. More ambitious R&D goals are probably needed. Better efficiency, lower cost fuel, and lower O&M costs are more likely to be achieved than are capital costs below the \$1100/kWe goal.

Table 39

Goal Costs Adopted for the CO₂ Cost Analysis (Electricity)

	<u>"Goal" Cost Cases</u>			<u>"Goal" Cost Cases</u>		
	Renu HP	FERCO	Renu LP	Renu HP	FERCO	Renu LP
	<u>High Capac. Factor (90.4%)</u>			<u>Low" Capac. Factor (76.0%)</u>		
Cap. Req.						
\$000	47,000	46,873	47,628	47,000	46,873	47,628
\$/kW	1,118	1,300	1,138	1,118	1,300	1,138
MWe	42.05	36.05	41.86	42.05	36.05	41.86
MWh	333,000	285,500	331,500	280,000	240,006	278,687
cap.fctr.	0.904	0.904	0.904	0.760	0.760	0.760
hours/yr	7919	7919	7919	6659	6658	6658
	<u>An.Oper.Cost</u>			<u>An.Oper.Cost</u>		
	High P Renu HP	Atm. FERCO	Atm. Renu LP	High P Renu HP	Atm. FERCO	Atm. Renu LP
Fuel: \$1.50/MMBtu	4,202	4,202	4,202	4,202	4,202	4,202
BFW	77	77	77	77	77	77
CW		0	0	0	0	0
Ash	19	19	19	19	19	19
30@70	2,100	2,100	2,100	2,100	2,100	2,100
4@70	280	280	280	280	280	280
3%	1,410	1,406	1,429	1,410	1,406	1,429
Ins./Tax.	800	800	800	800	800	800
Royal.	67	67	67	67	67	67
Other	0	0	0	0	0	0
Total of fuel+O&M	8,955	8,951	8,974	8,955	8,951	8,974
20% Capital	<u>9,400</u>	<u>9,375</u>	<u>9,526</u>	<u>9,400</u>	<u>9,375</u>	<u>9,526</u>
Tot. \$000	18,355	18,326	18,500	18,355	18,326	18,500
\$/MWh	55.12	64.19	55.81	65.55	76.36	66.38

Table 39 (cont.)

Goal Costs Adopted for the CO₂ Cost Analysis (Electricity)

"Current" Cases for Comparison:	<u>"Current" Cost Cases</u>			<u>"Current" Cost Cases</u>		
	Renu HP	FERCO	Renu LP	Renu HP	FERCO	Renu LP
	High Capac. Factor (90.4%)			"Low" Capac. Factor (76.0%)		
Cap. Req.						
\$000	102,301	102,025	103,667	102,301	102,025	103,667
\$/kW	2,433	2,830	2,477	2,433	2,830	2,477
MWe	42.05	36.05	41.86	42.05	36.05	41.86
MWh	333,036	285,516	331,531	280,000	240,006	278,687
cap.fctr.	0.904	0.904	0.904	0.760	0.760	0.760
\$/kW	2,433	2,830	2,477	2,433	2,830	2,477
MWe net output	42.05	36.05	41.86	42.05	36.05	41.86
	Annual Costs, \$K (2001)			Annual Costs, \$K (2001)		
Technology ==>	<u>Renu HP</u>	<u>FERCO</u>	<u>Renu LP</u>	<u>Renu HP</u>	<u>FERCO</u>	<u>Renu LP</u>
Wood delivered, \$0.66/million						
Btu, 8472 Btu/lb (dry)	1,849	1,936	2,194	1,849	1,936	2,194
BFW	77	73	21	77	73	21
Cooling Water	0	0	0	0	0	0
Ash disposal	19	326	22	19	326	22
Operating Labor	300	300	300	300	300	300
Supervision and Clerical	75	75	75	75	75	75
Maintenance Costs	2,691	2,682	2,725	2,691	2,682	2,725
Insur. and Local Taxes	1,345	1,341	1,363	1,345	1,341	1,363
Royalties	67	57	66	67	57	66
Other Operating Costs	0	0	0	0	0	0
Total Fuel + O&M	6,423	6,790	6,767	6,423	6,790	6,767
Capital at 20%/yr	<u>20,460</u>	<u>20,405</u>	<u>20,733</u>	<u>20,460</u>	<u>20,405</u>	<u>20,733</u>
Total	26,883	27,194	27,500	26,883	27,194	27,500
\$/MWh	80.72	95.25	82.95	96.01	113.31	98.68

4.3.5 Capital Cost Breakdown and Cost of Gas Cleanup

The cleanup or “conditioning” of the raw gas out of the gasifier is a critical part of the complete gasification system. For high-efficiency power and high-value fuels/chemicals, this cleanup step must achieve rather high purity as well as efficient use of energy. To investigate the cost of gas cleanup as a fraction of the total cost of building the biomass gasification system, Table 40 was prepared. The table is based on a proprietary cost analysis of a large pilot plant for gasification only – i.e., no gas turbine, no steam turbine and no generator and electricity export systems. If the plant had the turbines and boiler (HRSG), power generation, electrical substation, etc. added it would be a 15 MWe (net) system, assuming a 9000 Btu/kWh (net) heat rate. This gasification-only system, including feeding, drying, gasification, gas cleanup and ash handling, was estimated to cost \$577/kW, or \$8.6 million, in 2001 dollars. If the HRSG, turbines, etc. could be added at the cost of a pure natural gas (not biomass) combined cycle power plant at \$700/kW, this would be a \$1277/kW biomass gasification combined cycle (BGCC). At only about \$1300/kW at such a small size it would represent the achievement of the capital cost goal for biomass gasification power. This point is addressed further below.

On cost breakdown and the capital cost contribution of the gas cleanup system, Table 40 shows details that sum to 61.7 \$/kW for the gas cleanup, out of a total of 388/kW for the gasification system subtotal, before civil/structural, electrical and instruments/controls are included. After including such necessary scope, and distributing those items as shown in Table 40, the total is 91.7 out of the 577 \$/kW. Note that Table 40 assigns the ash handling system to the gasification proper, and does not include it in the gas cleanup. These results put the cost of gas cleanup as about 1/7 of the cost of the total biomass gasification “add-on” to make a simple natural gas combined power plant a biomass gasification CC instead.

Table 40

Cost Breakdown of Feeding, Drying, Gasification and Gas-Cleanup (Year 2001 \$)

<u>Component or Subsystem</u>	<u>\$M*</u>	<u>\$/kW</u>	<u>feed</u> <u>\$/kW</u>	<u>dryer</u> <u>\$/kW</u>	<u>gasif.</u> <u>\$/kW</u>	<u>clean</u> <u>\$/kW</u>	<u>total</u> <u>\$/kW</u>
Solid fuel input handling	0.25	14.6	14.6				14.6
Sludge input handling	0.21		[sludge dropped from scope]				0.0
Dryer output handling	0.36	21.0	21.0				21.0
Dryer and drying system	1.91	111.5		111.5			111.5
Flue gas duct from boiler, Plus air comp., water, etc.	0.58	33.8	13.5	20.3			33.8
Misc. & undefined (10%)	<u>0.33</u>	<u>18.1</u>	<u>4.9</u>	<u>13.2</u>	<u>0.0</u>	<u>0.0</u>	<u>18.1</u>
Total for Biomass Fuel Handling (including drying 50% moisture to 20%)	3.64	199.0	54.1	145.0	0.0	0.0	199.0
Gasifier feed system	0.68	39.7			39.7		39.7
Gasifier and bed drain	0.29	16.9			16.9		16.9
Piping and insulation, including steam piping	0.12	7.0			7.0		7.0
Misc. & undefined (20%)	<u>0.22</u>	<u>12.8</u>			<u>12.8</u>		<u>12.8</u>
Total for Gasifier and Bed Drain	1.31	76.4			76.4		76.4

Table 40 (cont.)

Cost Breakdown of Feeding, Drying, Gasification and Gas-Cleanup (Year 2001 \$)

<u>Component or Subsystem</u>	<u>\$M*</u>	<u>\$/kW</u>	feed dryer gasif. clean				total
			<u>\$/kW</u>	<u>\$/kW</u>	<u>\$/kW</u>	<u>\$/kW</u>	
Cyclone (hot)	0.09	5.3				5.3	5.3
Heat out to steam/air (i.e., gas cooling)	0.30	17.4				17.4	17.4
Filter for cooled gas	0.29	16.9				16.9	16.9
Flare (50 ft high)	0.08	4.7			4.7		4.7
Major piping	0.26	15.2			6.1	9.1	15.2
Other pipe and insulation	<u>0.08</u>	<u>4.7</u>			<u>1.9</u>	<u>2.8</u>	<u>4.7</u>
Sub Total for Gas Handling	1.10	64.1			12.7	51.4	64.1
Ash handling	0.51	29.8			29.8		29.8
Burner/Boiler Mods	0.16		[burnr/boilr mods dropped from scope]				
Misc. & undefined (20%)	0.35	18.8			8.5	10.3	18.8
Total for Gas and Ash Handling	2.12	112.6			51.0	61.7	112.7
Sum: Feed, Dry, Gasify, Cleanup Gas and Handle Ash (basic equip- ment installation, without civil- structural, I&C and electrical)		388.0	54.1	145.0	127.4	61.7	388.2
Civil - Structural	0.85	49.6	6.9	18.5	16.3	7.9	49.6
Building (8400 ft2)	0.78	45.5	6.3	17.0	14.9	7.2	45.5
Misc. & undefined (10%)	0.16	9.3	1.3	3.5	3.1	1.5	9.3
Total for Civil/Struct./Building	1.79	104.5	14.5	39.0	34.3	16.6	104.5

Table 40 (cont.)

Cost Breakdown of Feeding, Drying, Gasification and Gas-Cleanup (Year 2001 \$)

<u>Component or Subsystem</u>	<u>\$M*</u>	<u>\$/kW</u>	<u>feed</u> <u>\$/kW</u>	<u>dryer</u> <u>\$/kW</u>	<u>gasif.</u> <u>\$/kW</u>	<u>clean</u> <u>\$/kW</u>	<u>total</u> <u>\$/kW</u>
Grounding, lighting and conduit	0.47	27.6	3.8	10.3	9.1	4.4	27.6
Power cables and terminations	0.03	1.6	0.2	0.6	0.5	0.3	1.6
Control cable and terminations	0.01	0.8	0.1	0.3	0.2	0.1	0.8
Instrument cable and terminations	0.02	0.9	0.1	0.3	0.3	0.1	0.9
Switch gear and transformer	0.08	4.7	0.7	1.7	1.5	0.7	4.7
Motor control center, plus local control stations	<u>0.09</u>	<u>5.3</u>	<u>0.7</u>	<u>2.0</u>	<u>1.7</u>	<u>0.8</u>	<u>5.3</u>
Sub Total - Electrical	0.70	40.8	5.7	15.2	13.4	6.5	40.8
Instruments and controls	0.67	39.1	5.4	14.6	12.8	6.2	39.1
Adjustment/correction	-0.06	-3.5	-0.5	-1.3	-1.1	-0.6	-3.5
Misc. & undefined (10%)	0.13	7.6	1.1	2.8	2.5	1.2	7.6
Total for Electrical + Inst./Controls	1.44	84.0	11.7	31.4	27.6	13.4	84.0
Total for Entire Plant (2001\$)	10.31*	576.5	80.3	215.4	189.3	91.7	576.6

* Note: The \$M column is for a 1.56 inflation adjustment from 1987. The other numbers are based on 1.35 and are \$/kWe (net), assuming a 9000 Btu/kWh (net) heat rate. Also, note that this "entire plant" is biomass gasification and clean-up, alone, with no generation of electricity. It is just the biomass gasification system that would have to be built in addition to a conventional natural gas combined cycle to make a complete power plant at the 9000 Btu/kWh heat rate.

4.3.6 Capital Cost Goal

The cost goal shown in the DOE-EPRI “RETC” report (NREL & EPRI 1997) was approximately \$1100/kW at 100-MW unit size. Table 42 displays costs at various unit sizes based on the \$1277/kW at the small size (15 MW) and scaling these costs with a 0.8 power law to 42, 50 and 100 MW sizes. At 100 MW the figure is \$870/kW, approximately 20% below the \$1100 cost goal of RETC (NREL & EPRI 1997).

Table 41 shows that a pilot plant of 15-MWe equivalent size that can be built for only \$8.6 million may be the equivalent of achieving a cost goal of only \$870/kWe (net) for a 100-MWe full power plant. On the 100-MWe plant the feeding/drying/gasification/gas-cleanup/ash-handling aspects of the plant would have to come to only \$329/kW, leaving \$541/kW as the cost of the basic gas-fired combined cycle power plant. Achieving such a goal would make a significant improvement in the cost of avoiding a tonne-C of fossil carbon emission. This is the cost goal that should be pursued in biomass gasification IGCC R&D.

Table 41

Scaling for Size

<u>Description</u>	<u>\$M</u>	<u>Size (MW)</u>	<u>\$/kW</u>
<u>Gasification-only Pilot Plant:</u>			
15-MWe size equivalent	8.6	14.73	576.6
Power law for scaling	0.7		
42-MWe size equivalent	17.9	42	426
50-MWe size equivalent	20.2	50	405
100-MWe size equivalent	32.9	100	329
<u>Whole BGCC Power Plant:</u>			
15-MWe size equivalent	18.8	14.73	1276.3
Power law for scaling	0.8		
42-MWe size equivalent	43.5	42	1035
50-MWe size equivalent	50.0	50	1000
100-MWe size equivalent	87.0	100	870

5.0 CONCLUSIONS

The costs of CO₂ avoidance or “sequestration” from the technologies described in this report are generally too high to justify the goals adopted in the calculations in Section 4.3. That section gives values for the three scenarios (or three biomass gasification technology options) as shown in Table 42 below.

Table 42

Summary of CO₂ Control Costs

Biomass Gasification Technology	CO₂ Control Cost Comparison (\$/tonne C)		
	Conventional Coal	Advanced Coal	Natural Gas Combined Cycle
GTI Renugas HP	\$77.08	\$93.31	\$218.81
Battelle FERCO	\$115.63	\$135.73	\$312.61
GTI Renugas LP	\$154.17	\$178.14	\$416.82

The renewable biomass source replacing a fossil fuel source is the equivalent of sequestration technology applied to a fossil fuel source. Rather than add cost to the fossil generation technology to perform operations to concentrate CO₂, capture that CO₂ and then transport and sequester it, the renewable biomass technologies simply generate the electricity from biomass whose carbon came from the atmosphere in the recent past and, thereby, avoid the addition of any new fossil carbon as CO₂ injected into the atmosphere. In effect, this method keeps the carbon in the ground in its “already sequestered” form, as coal, petroleum or natural gas.

Because the cost of this approach to sequestration depends on what fossil fuel source is avoided and on the efficiency and cost of the fossil fuel power generation technology that is avoided, the calculated sequestration costs in \$/tonne-C vary greatly even if the cost of applying the renewable electricity were to be fixed, i.e., held as a constant all at the same value.

Low cost carbon sequestration values are usually in the \$10 to \$30 per tonne of fossil carbon sequestered. Tables 38 and 39 are unacceptably high cost compared to such low cost carbon sequestration cases. In order to show biomass gasification as among the lower cost, rather than higher cost, fossil carbon sequestration options, more ambitious R&D goals are necessary. These more ambitious goals would involve one or more or a combination of items such as better efficiency, lower cost fuel, lower O&M costs, and lower capital cost. The lower capital costs may be especially difficult to obtain, as the goals adopted in Section 4.3 are already rather ambitious.

These ambitious goals are as follows: (1) a natural gas combined cycle at \$700/kW as applied at 100-MWe unit size as the power conversion option downstream of a biomass gasification system; (2) only \$300/kWe to construct the system that performs biomass gasification, gas cleanup and ash/char removal from the gasifier, and then sends clean gaseous fuel to the combined cycle power unit; and, (3) only \$100/kW for a system to receive, handle and feed solid biomass fuel (or “feedstock”) into the gasification/cleanup unit. It is possible that better efficiency, lower fuel cost and lower O&M costs are more likely to be achieved than are capital costs below the \$1100/kWe goal. A combination of all, plus added revenues from other bio-based products or environmental benefit revenues (such as waste disposal and water quality improvements) are also likely to be required in a system that becomes a low cost carbon sequestration option.

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