BIOMASS COFIRING WITH NATURAL GAS IN CALIFORNIA

CONSULTANT REPORT

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ABSTRACT

This report by EPRI for the California Energy Commission presents the major cost and performance parameters of systems that enable natural gas to be augmented by 10% biomass fuel. The basic natural gas fired power plant is taken to be a 400 MWe gas-turbine/combined-cycle (NGCC). The biomass component is to generate 40 MWe from biomass fuel. Two forms of the biomass section of the power plant are considered: (1) biomass gasification with the gas derived from the biomass combined with the natural gas and sent to the gas turbine topping cycle in the NGCC; and (2) solid biomass fuel fired in a duct burner to add combustion heat to the gas turbine exhaust heat to enable the steam bottoming cycle to generate an extra 40 MWe. The report derives estimates of the extra cost, in $/MWh, for the electricity thereby generated from biomass—the extra cost to use a renewable rather than a fossil energy source.

CONTENTS

1 INTRODUCTION

This project is designed to improve the economics of biomass power generation in California and to assure the future expansion of biomass generating capacity even as the overwhelming majority of new capacity additions are built to fire natural gas as the primary fuel. The approach is to use advanced concepts of cofiring to capitalize upon the more efficient natural gas-fired cycles while recognizing the inherent characteristics of biomass and its ash. This report presents results of the first phase of the entire project. The entire project will do the following:

- Perform a preliminary feasibility assessment of biomass gasification/cofiring in a natural gas-fired boiler, and in a duct burner downstream of a combustion turbine in a CCCT application;
- Perform a preliminary feasibility assessment of repowering an existing biomass-fired power plant with a small natural gas-fired combustion turbine, using the turbine exhaust as hot vitiated air to increase the efficiency of using biomass in the boiler;
- Identify partners for demonstrating these concepts at existing utility power plants, at new Independent Power Producer CCCT installations, or, perhaps, at an existing biomass-fired power plant
- Perform initial cost estimates of the most promising cofiring technology
- Begin finding support for the installation and demonstration of the cofiring technology, with particular emphasis on installing biofuel material handling and gasification systems plus modifications to steam generators (e.g., installing soot blowers).

It is significant that this project bases the economics of biomass on natural gas prices, and natural gas generation efficiencies. It is estimated that such projects would reduce the net station heat rates associated with biofuels from the current 15,000 to 20,000 Btu/kWh to levels as low as 10,000 to 11,000 Btu/kWh (for the biomass-based power in a boiler cycle) and even to 7,500 to 9,000 (for the biomass-based power in a combined cycle). Further, the capital investments required for such biofuel projects are much lower than the capital investments in spreader-stoker boiler-based systems. As such, these cofiring concepts have the potential to reduce the cost of biomass-based power by 40 to 50 percent when compared to the existing wood waste and agricultural waste generating stations.

With this project EPRI proposes to do the following:

- Develop conceptual designs and cost estimates for at least three California applications of biomass cofiring:

  1) Biomass heat injected into heat recovery steam generator of gas turbine combined cycle power systems.

  2) Biomass gasificaton (simple and without gas cleanup systems) as a means to add renewable energy into oil- and gas-fired boilers.

  3) Repowering existing biomass power plants with fossil-fuel-fired gas turbines, resulting in the use of less fossil fuel and in the improvement of the performance and economics of the biomass units being repowered.

The project objective is to provide renewable biomass power to the California market at a cost at least 40% below the existing 3¢/kWh gap between the 6¢/kWh recent biomass cost and the 3¢/kWh recent average electricity generation cost.

Beyond this initial phase the plan is to design and test biomass cofiring via gasification and/or specialized combustion for biomass heat input into oil- and gas-fired combustion turbine systems and boiler systems. The plan also includes selection of companies and concepts that best meet the objective.

This, the first report on the project, presents the preliminary cost analysis and the concept descriptions for two options for biomass cofiring in natural gas combined cycle power plants. These two options are:

1. Gasification of biomass and firing of the biogas along with the primary natural gas in the combustor of the gas turbine unit of the conventional natural gas combined cycle (NGCC) power system.
2. Firing the biomass fuel in a duct burner to augment the heat input to the steam bottoming cycle portion of the NGCC power plant.

This Report

In the next section, more background is presented, including the overall project scope and objectives.

In Section3, "Analysis," EPRI presents the spreadsheet used to analyze the various cofiring options. The basic 400 MWe natural gas combined cycle is presented in a table that includes the definitions and shows the calculation scheme. Other cases of 100%-natural-gas-firing are presented: $2.50, $3.25 and $4.00 as the gas price, and 400, 440 and 600 MWe as the power plant size. Then, the biomass gasification method of adding the biomass cofiring to the basic NGCC is also presented. The biomass case--at the level where 10% of the output is from the biomass fuel--is based on the goal for biomass gasification technology in the future, when a capital cost of $300/kW has been achieved. The $300/kW is to cover the biomass gasification and gas cleanup equipment. The NGCC part takes $500/kW and the biomass handling another $100/kW. The two biomass unit costs are applied only to the 10% (i.e., 40 MWe) of the output that is from the biomass fraction.

In Section 4 the gasification technology of today is presented in the same spreadsheet framework of analysis. This uses the current technology expected in the first field test or demonstration, where $600/kW is taken to be the capital cost of the gasification and gas cleanup system.

In Section 5 the approach that does not require gasification is presented. This is the duct burner case. In a duct burner system the extra heat and extra power comes from biomass added only to the bottoming cycle, i.e., the steam cycle part of the system, not the gas turbine part.

In Section 6 the cases are summarized, the **sensitivities** to biomass fuel cost and to natural gas system cost and performance are investigated, the sensitivity cases are discussed, and some conclusions are drawn.

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BACKGROUND

Today (i.e., in the year 2000) California has about 350 MW of direct combustion biomass power generating capacity in operation. (Another 200 MW of landfill gas and 170 MW of municipal waste combustion also exist.) Approximately 240 MW of the 570 MW direct combustion biomass capacity that was operating prior to 1994 is now shut down. Some 160 MW of that lost 240 MW could be returned to active use, if the economics so warranted. This existing and lost biomass capacity is dwarfed by the plans for new natural-gas-fired capacity. For the next round of new power generation capacity in California, some 17,000 to 20,000 MW of capacity based on natural gas are in various stages of planning and/or permitting. Therefore, the greatest opportunity to replace or expand biomass capacity lies in finding ways for biomass to be cofired along with or at the same site/facility with natural gas. EPRI has made biomass cofiring with coal its major emphasis in EPRI research and development since 1993. EPRI has a substantial program to test and demonstrate biomass cofiring with coal, mostly funded by DOE, both the DOE biomass power program and the DOE-FETC fossil energy program. The California project on natural gas options will benefit from the fuel handling and gasification aspects of the major DOE/EPRI program.

Objective

This project is designed to address the non-competitive nature of biomass power in California, using advanced concepts of cofiring to capitalize upon the more efficient natural gas-fired cycles while recognizing the inherent characteristics of biomass and its ash.

The main objective of this project is to return electricity generation with biomass to a cost-competitive position with technologies currently being used in California. In doing so this project will achieve significant environmental benefits as well as economic benefits. This goal will be achieved by implementing the progression of activities leading to the installation of one or more cofiring demonstrations that increase the efficiency of electricity generation with biomass while integrating it with natural gas generation. It is important to understand how the improved efficiencies are derived. Therefore, the key elements of the concept are summarized here, immediately below.

Concepts to be Evaluated

For the gasification of biomass and it firing along with natural gas as the gaseous fuel into the gas turbine combustor of a NGCC power plant, the advantage comes from the much higher efficiency of the entire combined cycle (CC) approach as well as from the high efficiency of the modern gas turbine (or, combustion turbine, “CT”) itself. The NGCC cycle with modern equipment can achieve heat rates in the range from 7400 Btu/kWh (0.46 net thermal efficiency, HHV basis) with commercial equipment today to 6100 Btu/kWh (0.56 efficiency) with advanced equipment within 10 years. The biomass gasification stage will introduce inefficiency, but only in the biomass portion itself and not in the main natural gas portion. The efficiency range for the biomass conversion is expected to be from about 9000 Btu/kWh today (0.38 efficiency) to about 7500 Btu/kWh (0.46 efficiency) as a future goal.

For the gasification of biofuel and the cofiring of this gas into a duct burner between the turbine and the heat recovery steam generator (HRSG) of a NGCC plant, the advantage comes from the efficiency of combustion with the turbine exhaust, providing cheap additional HRSG capacity while avoiding many of the losses normally penalizing direct combustion of biofuels.

The two concepts above are the subject of this report. In addition, this project will, in a later stage, address other ways to combine biomass with natural-gas-based technologies, as described in the next two paragraphs.

For the gasification of biofuel and the cofiring of this gas in a natural gas-fired boiler, cofiring offers the opportunity to take advantage of more severe steam conditions (e.g., 2400 psig/1000°F or 3500 psig/1000°F) main steam conditions and the associated reheat cycles common to large boilers. These contrast with the typical biomass power plant with main steam conditions on the order of 850 psig/850°F, and without reheat steam. The difference in cycle efficiency is dramatic. Cofiring gasified biomass into a high pressure, reheat cycle gives the biofuel the advantages of the larger boiler technologies.

For the installation of a combustion turbine to supply hot (e.g., 800°F to 1,000°F), vitiated air to the combustion of the wood fuel in an existing boiler, the efficiency gains come from the very elevated temperatures of the combustion air for the biofuel. Further, this approach provides a low cost combined cycle approach, although its efficiency is not equal to that of the modern NGCC installation.

Benefit

Cofiring can cut costs of biomass-based power generation from the $0.06/kWh or more, seen in California's 1985-92 experience, to only $0.03 to $0.04/kWh, because existing equipment is used to advantage and fuel costs are offset against natural gas at $2.00/Mbtu, or more. Small modular biomass will not be a bulk power generator of consequence in California, but the environmental benefits can be substantial and the new industry created will have its value, although not as quantifiable.

The market will build biomass power after this cofiring project has shown that it can be done, equipment is available, and costs will, in fact, be low enough to result in market-driven power sales.

Ratepayers will become electricity buyers in a competitive market and a growing number of them will want to buy renewable solar energy. Biomass offers that, and this project offers ways to make that power available at close-to-market, or below-market, costs.

Project Summary

With this project, EPRI proposes to collaborate with the CEC and other principals to:

1. Perform an initial feasibility assessment of biomass gasification/cofiring in a natural gas-fired boiler, and in a duct burner downstream of a combustion turbine in a NGCC power plants. This report presents results of this stage of the project.

2. Screen feasibility of repowering an existing biomass-fired power plant with a small natural gas-fired combustion turbine, using the turbine exhaust as hot vitiated air to increase the efficiency of using biomass in the boiler.

3. Lay the groundwork for demonstrating these concepts at the respective appropriate sites: a new NGCC plant, an existing utility power plant, and at an existing biomass-fired power plant.

In the later phases of the work, EPRI and the CEC will plan and develop detailed design and cost estimates of the most promising cofiring technology. Then, in a final phase, in collabor-ation with industry and other partners as they are found, the plan is to support the installation and demonstration of the cofiring technology, with particular emphasis on installing biofuel material handling and gasification systems plus modifications to steam generators (e.g., in-stalling soot blowers).

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ANALYSIS

As shown in Table 3-1, EPRI set up the base case for a natural gas combined cycle (NGCC) and then defined changes in the basic NGCC required to enable such a plant to cofire 10% biomass.

Table 3-1
Basic NGCC and Definitions

Capacity factor:	0.75	Heat rate on nat. gas:	7,500	Capital recov. factor:	0.200
Operating hours per year:	6570	Heat rate on biomass:	9,000	Person-yr, fully-loaded:	$70,000

Case No. and Name ==> / Description of Line	Basic NGCC Plant	Lin. No.	Definitions, Explanations and Calculations
Base size on nat.gas, MWe	400	1	
Added by biomass, MWe	0	2	
Total size, MWe	400	3	Lines 1 + 2
Base capital cost, $/kW	500	4	
Gasification adds, $/kW-bio	0	5	To be used for added cost of the biomass gasification system
Biomass adds, $/kW-bio	0	6	To be used for added cost of the biomass fuel handling system
Capital total, base, $M	$ 200	7	Line 1 times 4
Capital total, gas'tion, $M	$ -	8	To be used for line 2 times 5
Capital total, biomass, $M	$ -	9	To be used for line 2 times 6
Capital: base+gas+bio, $M	$ 200	10	
Total capital cost, $/kW	$ 500	11	
Normal staff, number	20	12	
Biomass added staff	0	13	Staff to be added to run biomass systems that are added
Normal staff total, $M/yr	$1.40	14	Line 12 times cost per person-year, above
Biomass staff, $M/yr	$0.00	15	Line 13 times cost per person-year, above
An.Maint., normal, % of cap.	3.00%	16	% allowance applied to the basic NGCC plant
" " , gasification, %	4.00%	17	% allowance applied to the gasification part of the biomass system
" " , biomass, %	5.00%	18	% allowance applied to the biomass fuel handling part
An.Maint., normal, $M	$ 6.00	19	Line 16 times 7
" " , gasification, $M	$ -	20	Line 17 times 8
" " , biomass, $M	$ -	21	Line 18 times 9
Fuel cost nat. gas, $/MBtu	$ 2.50	22	
Fuel cost biomass, $/MBtu	$ 1.50	23	
An. nat. gas fuel, $M	$ 49.28	24	Gas price times heat rate times hours times MW size gas
An. biomass fuel, $M	$ -	25	Biomass price times biomass heat rate times hours times MW biomass
An. capital recover., $M	$ 40.00	26	Line 7 times annual capital recovery rate, above
Tot. annual cost, $M	$96.68	27	Sum: Lines 14+15 and 19+20+21 and 24+25 and 26
Tot. annual electricity, GWh	2,628	28	Line 3 times hours (above) times 0.001
Cost of generation, $/MWh	$ 36.79	29	Line 27 divided by (0.001 x Line 28)
Extra cost, $M/yr	$ -	30	
Extra generation, GWh	N.A.	31	These last four lines (30-33) are calculated from comparisons and differ-
Cost of extra gen., $/MWh	N.A.	32	ences among cases: case with biomass less basic case.
Bio extra - gas extra, $/MWh	N.A.	33	

The costs for the basic NGCC case are a function of the size of the NGCC plant and the price that the plant must pay for its natural gas fuel. Table 2-2 presents three plant sizes (400, 440 and 600 MWe) and three natural gas prices ($2.50, $3.25 and $4.00/MBtu).

Table 3-2

Pure NGCC Cases: Plant Size and Gas Cost

Case No. and Name ==>		$2.50/MBtu Gas Price			$3.25/MBtu Gas Price			$4.00/MBtu Gas Price		
		1. Basic	2. Larger	3. Large	4. Basic	5. Larger	6. Large	7. Basic	8. Larger	9. Large
	Line	400-MWe	440-MWe	600-MWe	400-MWe	440-MWe	600-MWe	400-MWe	440-MWe	600-MWe
Description of Line	No.	NGCC	NGCC	NGCC	NGCC	NGCC	NGCC	NGCC	NGCC	NGCC
Base size on nat.gas, MW	1	400	440	600	400	440	600	400	440	600
Added by biomass, MWe	2	0	0	-	0	0	-	0	0	-
Total size, MWe	3	400	440	600	400	440	600	400	440	600
Base capital cost, $/kW	4	500	486	461	500	486	461	500	486	461
Gasification adds, $/kW-bio	5	0	0	0	0	0	0	0	0	0
Biomass adds, $/kW-bio	6	0	0	0	0	0	0	0	0	0
Capital total, base, $M	7	$200	$214	$277	$200	$214	$277	$200	$214	$277
Capital total, gas'tion, $M	8	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capital total, biomass, $M	9	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capital: base+gas+bio, $M	10	$200	$214	$277	$200	$214	$277	$200	$214	$277
Total capital cost, $/kW	11	$500	$486	$461	$500	$486	$461	$500	$486	$461
Normal staff, number	12	20	20	24	20	20	24	20	20	24
Biomass added staff	13	0	0	0	0	0	0	0	0	0
Normal staff total, $M/yr	14	$1.40	$1.40	$1.68	$1.40	$1.40	$1.68	$1.40	$1.40	$1.68
Biomass staff, $M/yr	15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
An.Maint., NGCC, % capital	16	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
" " , gasification, % cap.	17	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
" " , biomass, % cap.	18	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
An.Maint., NGCC, $M	19	$6.00	$6.42	$8.30	$6.00	$6.42	$8.30	$6.00	$6.42	$8.30
" " , gasification, $M	20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
" " , biomass, $M	21	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fuel cost nat. gas, $/MBtu	22	$2.50	$2.50	$2.50	$3.25	$3.25	$3.25	$4.00	$4.00	$4.00
Fuel cost biomass, $/MBtu	23	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
An. nat. gas fuel, $M	24	$49.28	$54.20	$73.91	$64.06	$70.46	$96.09	$78.84	$86.72	$118.26
An. Biomass fuel, $M	25	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
An. Capital recover., $M	26	$40.00	$42.77	$55.33	$40.00	$42.77	$55.33	$40.00	$42.77	$55.33
Tot. annual cost, $M	27	$96.68	$104.79	$139.22	$111.46	$121.05	$161.39	$126.24	$137.31	$183.57
Tot. annual electricity, GWh	28	2,628	2,891	3,942	2,628	2,891	3,942	2,628	2,891	3,942
Cost of generation, $/MWh	29	$36.79	$36.25	$35.32	$42.41	$41.87	$40.94	$48.04	$47.50	$46.57
Extra cost, $M/yr	30	-	$8.11	$42.54	-	$9.59	$49.93	-	$11.07	$57.33
Extra generation, GWh	31	-	263	1,314	-	263	1,314	-	263	1,314
Cost of extra gen., $/MWh	32	-	$30.86	$32.38	-	$36.49	$38.00	-	$42.11	$43.63
Fuel cost only, $/MWh	33	$18.75	$18.75	$18.75	$24.38	$24.38	$24.38	$30.00	$30.00	$30.00

Note: Capital cost was scaled from 400 to 440 MW at 0.7 power law, and from 400 to 600 MW at 0.8. For all cases, the heat rate was 7500 Btu/kWh and the capacity factor was 75% (6570 hours/year). Capital recovery factor was 0.20/year and fully-loaded cost of operating staff was $70,000/person-year. All these are the same as in Table 2-1 above and in Table 2-3 below, as shown at the top of those tables:

Capacity factor:	0.75	Heat rate on nat. gas:	7,500	Capital recovery factor:	0.200
Operating hours per year:	6570	Heat rate on biomass:	9,000	Person-yr, fully-loaded:	$70,000

For the biomass cofiring addition to the basic 400 MWe NGCC, a 10% cofiring level was chosen. This means that 10% of the net electricity output is to be due to the biomass fraction of the fuel input. Therefore, an additional 40 MWe is to be from the biomass system added to make the whole plant a 440 MWe net generation source. Table 3-3 shows the biomass gasification case, with "goal" technology: gasification/gas-cleanup at a $300/kW capital cost.

Table 3-3
Gasification with "Goal Technology" at $300/kW

Capacity factor: 0.75	Heat rate on nat. gas: 7,500	Capital recovery factor: 0.200
Operating hours per year: 6570	Heat rate on biomass: 9,000	Person-yr, fully-loaded: $70,000

Case No. and Name ==> Description of Line	Line No.	1. Basic 400-MWe NGCC	2. BGCC Biomass Gasfcatn	3. $4.00 gas, basic NGCC	4. $4.00 Gas, with BGCC	5. Difference: Case 4 - Case 3	6. 440 MW NGCC at $4.00	7. 440 MW NGCC at $2.50
Base size on nat.gas, MW	1	400	400	400	400	0	440	440
Added by biomass, MWe	2	0	40	0	40	40	0	0
Total size, MWe	3	400	440	400	440	40	440	440
Base capital cost, $/kW	4	500	486	500	486	-14	486	486
Gasification adds, $/kW-bio	5	0	300	0	300	300	0	0
Biomass adds, $/kW-bio	6	0	100	0	100	100	0	0
Capital total, base, $M	7	$200	$214	$200	$214	$14	$214	$214
Capital total, gas'tion, $M	8	$0	$12	$0	$12	$12	$0	$0
Capital total, biomass, $M	9	$0	$4	$0	$4	$4	$0	$0
Capital: base+gas+bio, $M	10	$200	$230	$200	$230	$30	$214	$214
Total capital cost, $/kW	11	$500	$522	$500	$522	$22	$486	$486
Normal staff, number	12	20	20	20	20	0	20	20
Biomass added staff	13	0	8	0	8	8	0	0
Normal staff total, $M/yr	14	$1.40	$1.40	$1.40	$1.40	$0.00	$1.40	$1.40
Biomass staff, $M/yr	15	$0.00	$0.56	$0.00	$0.56	$0.56	$0.00	$0.00
An.Maint., normal, % of cap.	16	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
" " , gasification, %	17	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
" " , biomass, %	18	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
An.Maint., normal, $M	19	$6.00	$6.41	$6.00	$6.41	$0.41	$6.42	$6.42
" " , gasification, $M	20	$0.00	$0.48	$0.00	$0.48	$0.48	$0.00	$0.00
" " , biomass, $M	21	$0.00	$0.20	$0.00	$0.20	$0.20	$0.00	$0.00
Fuel cost nat. gas, $/MBtu	22	$2.50	$2.50	$4.00	$4.00	$4.00	$4.00	$2.50
Fuel cost biomass, $/MBtu	23	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
An. nat. gas fuel, $M	24	$49.28	$49.28	$78.84	$78.84	$0.00	$86.72	$54.20
An. biomass fuel, $M	25	$0.00	$3.55	$0.00	$3.55	$3.55	$0.00	$0.00
An. capital recover., $M	26	$40.00	$45.96	$40.00	$45.96	$5.96	$42.77	$42.77
Tot. annual cost, $M	27	$96.68	$107.84	$126.24	$137.40	$11.16	$137.31	$104.79
Tot. annual electricity, GWh	28	2,628	2,891	2,628	2,891	263	2,891	2,891
Cost of generation, $/MWh	29	$36.79	$37.30	$48.04	$47.53	$42.47	$47.50	$36.25
Extra cost, $M/yr	30	-	$11.16	$18.40	$11.16	($126.24)	$126.15	($32.52)
Extra generation, GWh	31	-	263	(263)	263	(2,628)	2,628	0
Cost of extra gen., $/MWh	32	-	$42.47	($70.03)	$42.47	$48.04	$48.00	#DIV/0!
Bio extra - gas extra, $/MWh	33	-	$0.00	($118.07)	($5.53)	#DIV/0!	$48.00	#DIV/0!

4

HIGHER COST GASIFICATION

Table 4-1 is the same as Table 3-3, except that $600/kW has been entered for the gasification cost, instead of the $300/kW goal value used in Section 3.

Table 4-1

Gasification with Current Technology at $600/kW

Capacity factor:	0.75	Heat rate on nat. gas:	7,500	Capital recovery factor:	0.200
Operating hours per year:	6570	Heat rate on biomass:	9,000	Person-yr, fully-loaded:	$70,000

Case No. and Name ==> Description of Line	 No.	1. Basic 400-MWe NGCC	2. BGCC Biomass Gasfcatn	3. $4.00 gas, basic NGCC	4. $4.00 gas, with BGCC	5. Diff. Case4 - Case 3	6. 440MW NGCC at $4.00	7. 440MW NGCC at $2.50
Base size on nat.gas, MW	1	400	400	400	400	0	440	440
Added by biomass, MWe	2	0	40	0	40	40	0	0
Total size, MWe	3	400	440	400	440	40	440	440
Base capital cost, $/kW	4	$500	$486	$500	$486	($14)	$486	$486
Gasification adds, $/kW-bio	5	$0	$600	$0	$600	$600	$0	$0
Biomass adds, $/kW-bio	6	$0	$100	$0	$100	$100	$0	$0
Capital total, base, $M	7	$200	$214	$200	$214	$14	$214	$214
Capital total, gas'tion, $M	8	$0	$24	$0	$24	$24	$0	$0
Capital total, biomass, $M	9	$0	$4	$0	$4	$4	$0	$0
Capital: base+gas+bio, $M	10	$200	$242	$200	$242	$42	$214	$214
Total capital cost, $/kW	11	$500	$550	$500	$550	$50	$486	$486
Normal staff, number	12	20	20	20	20	0	20	20
Biomass added staff	13	0	8	0	8	8	0	0
Normal staff total, $M/yr	14	$1.40	$1.40	$1.40	$1.40	$0.00	$1.40	$1.40
Biomass staff, $M/yr	15	$0.00	$0.56	$0.00	$0.56	$0.56	$0.00	$0.00
An.Maint., normal, % of cap.	16	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
" " , gasification, %	17	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
" " , biomass, %	18	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
An.Maint., normal, $M	19	$6.00	$6.41	$6.00	$6.41	$0.41	$6.42	$6.42
" " , gasification, $M	20	$0.00	$0.96	$0.00	$0.96	$0.96	$0.00	$0.00
" " , biomass, $M	21	$0.00	$0.20	$0.00	$0.20	$0.20	$0.00	$0.00
Fuel cost nat. gas, $/MBtu	22	$2.50	$2.50	$4.00	$4.00	$4.00	$4.00	$2.50
Fuel cost biomass, $/MBtu	23	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
An. nat. gas fuel, $M	24	$49.28	$49.28	$78.84	$78.84	$0.00	$86.72	$54.20
An. Biomass fuel, $M	25	$0.00	$3.55	$0.00	$3.55	$3.55	$0.00	$0.00
An. Capital recover., $M	26	$40.00	$48.36	$40.00	$48.36	$8.36	$42.77	$42.77
Tot. annual cost, $M	27	$96.68	$110.72	$126.24	$140.28	$14.04	$137.31	$104.79
Tot. annual electricity, GWh	28	2,628	2,891	2,628	2,891	263	2,891	2,891
Cost of generation, $/MWh	29	$36.79	$38.30	$48.04	$48.53	$53.43	$47.50	$36.25
Extra cost, $M/yr	30	-	$14.04	$15.52	$14.04	($126.24)	$123.27	($32.52)
Extra generation, GWh	31	-	263	(263)	263	(2,628)	2,628	0
Cost of extra gen., $/MWh	32	-	$53.43	($59.07)	$53.43	$48.04	$46.90	#DIV/0!

5

DUCT BURNER COFIRING OPTION

Table 5-1 presents the duct burner method of biomass cofiring. In this case, the biomass fuel adds heat to the steam cycle only, not to the gas turbine.

Table 5-1
Duct Burner Cofirng Option

Capacity factor	0.75	Heat rate on nat. gas	7,500	Capital recov. Factor	0.200
Op. hours per year	6570	Heat rate on biomass	13,000	Person-yr, fully-loaded	$70,000

Case No. and Name ==> Description of Line	1. Basic 400MW NGCC	2. Duct Burner w/ HRSG	3. $4.00 Gas w/ NGCC	4. $4.00 Gas w/ Duct Br.	5. Diff. Case4 - Case 3	6. 440MW NGCC w/ $4.00 gas	7. 440MW NGCC w/ $2.50 gas
Base size on nat.gas, MW	400	400	400	400	0	440	440
Added by biomass, MWe	0	40	0	40	40	0	0
Total size, MWe	400	440	400	440	40	440	440
Base capital cost, $/kW	500	500	500	500	0	486	486
Ductburn-HRSG adds, $/kW-b	0	671	0	671	671	0	0
Biomass adds, $/kW-bio	0	100	0	100	100	0	0
Capital total, base, $M	$ 200	$ 200	$ 200	$ 200	$ -	$ 214	$ 214
Capital total, DbHRSG, $M	$ -	$27	$ -	$ 27	$ 27	$ -	$ -
Capital total, biomass, $M	$ -	$ 4	$ -	$ 4	$ 4	$ -	$ -
Capital: base+gas+bio, $M	$ 200	$ 231	$ 200	$ 231	$ 31	$ 214	$ 214
Total capital cost, $/kW	$ 500	$ 525	$ 500	$ 525	$ 24.64	$ 486	$ 486
Normal staff, number	20	20	20	20	0	20	20
Biomass added staff	0	8	0	8	8	0	0
Normal staff total, $M/yr	$1.40	$1.40	$1.40	$1.40	0	$1.40	$1.40
Biomass staff, $M/yr	$0.00	$0.56	$0.00	$0.56	$ 0.56	$0.00	$0.00
An.Maint., normal, % of cap.	3.00%	3.00%	3.00%	3.00%		3.00%	3.00%
" " , ductburn-HRSG, %	4.00%	4.00%	4.00%	4.00%		4.00%	4.00%
" " , biomass, %	5.00%	5.00%	5.00%	5.00%		5.00%	5.00%
An.Maint., normal, $M	$ 6.00	$ 6.00	$ 6.00	$ 6.00	$ -	$ 6.42	$ 6.42
" " , ductburn-HRSG, $M	$ -	$ 1.07	$ -	$ 1.07	$1.07	$ -	$ -
" " , biomass, $M	$ -	$ 0.20	$ -	$ 0.20	$ 0.20	$ -	$ -
Fuel cost nat. gas, $/MBtu	$2.50	$ 2.50	$ 4.00	$ 4.00	$ -	$ 4.00	$ 2.50
Fuel cost biomass, $/MBtu	$1.50	$1.50	$ 1.50	$ 1.50	$ -	$ 1.50	$ 1.50
An. nat. gas fuel, $M	$49.28	$49.28	$78.84	$ 78.84	$ -	$ 86.72	$ 54.20
An. Biomass fuel, $M	$ -	$ 5.12	$ -	$ 5.12	$ 5.12	$ -	$ -
An. Capital recover., $M	$40.00	$46.17	$40.00	$ 46.17	$ 6.17	$ 42.77	$ 42.77
Tot. annual cost, $M	$96.68	$109.80	$126.24	$139.37	$13.13	$137.31	$104.79
Tot. annual electricity, GWh	2,628.0	2,890.8	2,628.0	2,890.8	262.8	2,890.8	2,890.8
Cost of generation, $/MWh	$ 36.79	$ 37.98	$ 48.04	$ 48.21	$ 49.95	$ 47.50	$ 36.25
Extra cost, $M/yr	-	$13.13	$ -	$13.13	$ 13.13	$11.07	$8.11
Extra generation, GWh	N.A.	262.8	N.A.	262.8		262.80	262.80
Cost of extra gen., $/MWh	N.A.	$ 49.95	N.A.	$ 49.95		$ 42.11	$ 30.86
Bio extra - gas extra, $/MWh	N.A.	$ 19.08	N.A.	$ 7.83			

In Table 5-1 above the added cost for the biomass energy conversion system as an addition to the cost of the steam cycle part of the basic NGCC. The assumptions used to calculate the added cost of of this larger steam cycle and the fired duct that provides the added heat are shown in Table 5-2.

Table 5-2
Steam Cycle Cost in Duct Burner Case

Item	Description and Explanation
130 MW-base	Size of original steam cycle for 400-MW NGCC
40 MW-added	Added to have 40 MWe of biomass
170 MW-total	Total from expanded steam cycle
$1,000 /kW-base	Assumed cost per kW of the steam cycle
$130 M base	Cost of original steam cycle within the NGCC
0.7 law to170 MW	Power law for economy of scale to go to larger size
$156.85 M total	Result from power law: $\$130 \times (170/130)^{0.7}$
($130.00) M base	Less cost of steam cycle for basic NGCC
$26.85 M extra	Extra cost to have 170 MW instead of 130 MW

Result: Extra cost of 40 MW = $26.85M / 40,000 kW = $671/kW.
$671 $/kW ← adopted as cost per kW to add extra fired-steam-cycle size at the 130- to 170-MW scale.

The scope of the duct burner must include addition of all equipment to fire the biomass, which will include the cost to modify what would otherwise be the standard unfired heat recovery steam generator (HRSG). These modifications will include adding soot-blowing capability to the HRSG, and perhaps changing tube spacing. "Duct burner" refers to the firing of a fuel in a duct as the fuel and combustion-air flow together toward the steam generator. This type of add-on is already done in pure natural-gas-fired combined cycle systems as a way to augment power output.

The principal advantage of the duct burner option is the greater certainty of success today, before the second and third rounds of biomass gasification demonstrations have proved the reliability and low cost of biomass gasification technology. The duct burner avoids the need to have a gas cleanup (or “conditioning”) system that can assure that the gas is cleaned to very low levels of tar, alkali and particulate matter—cleaned to the strict inlet standards required for protection and reliable operation of the gas turbine. Any approach that adds a bottoming steam cycle, instead of directly adding fuel to the gas turbine topping cycle, will also have this advantage. Hence, fluidized bed combustion is such an option. The duct burner approach appeared to be the lower cost option in a study done by Foster Wheeler for EPRI and DOE at the start of the EPRI/TVA/DOE biomass cofiring program in 1994. Also, the duct burner, using natural gas fuel, is already a standard way to boost the power output of NGCC power systems in the 500-MWe size class.

6

SUMMARY AND CONCLUSIONS

Table 6-1 summarizes six cases that reflect some alternative situations and choices that can be used to derive estimates of the extra cost of renewable power, when that renewable power comes from biomass cofiring in a natural-gas-fired gas-turbine combined-cycle power plant (NGCC). All of the cases are for biomass at the 10% level in what would otherwise be a 400 MWe NGCC. The biomass share is 40 MWe out of a 440 MWe total in all the biomass cases.

Table 6-1
Summary of Cases

Number label for case	1	2	3	4	5	6
Total plant size, MWe	400	440	440	440	440	440
Technology label for case	NGCC	NGCC	NGCC	BGCC	BGCC	Duct burn.
Cost label for gas	$2.50 gas	$2.50 gas	$4.00 gas	Goal*	Today*	$4.00 gas
Total plant capital cost per unit, $/kW	$500	$486	$486	$522	$550	$525
NGCC part per unit, $/kW	$500	$486	$486	$486	$486	$500
Gasification or duct burner part per unit, $/kW	$0	$0	$0	$300	$600	$671
Biomass handling part per unit, $/kW	$0	$0	$0	$100	$100	$100
Plant cost NGCC part, $M	$200.0	$214.0	$214.0	$214.0	$214.0	$200.0
Plant cost, gasif or duct burner part, $M	$0.0	$0.0	$0.0	$12.0	$24.0	$27.0
Plant cost, biomass handling part, $M	$0.0	$0.0	$0.0	$4.0	$4.0	$4.0
Sum: total plant cost, $M	$200.0	$214.0	$214.0	$230.0	$242.0	$231.0
Total annual cost, $M	$96.7	$104.8	$137.3	$137.4	$110.7	$139.4
Unit cost of natural gas, $/MBtu	$2.50	$2.50	$4.00	$4.00	$2.50	$4.00
Annual cost of all fuel, $M	$49.3	$54.2	$86.7	$82.4	$52.8	$84.0
Total generation, GWh per year	2628	2891	2891	2891	2891	2891
Unit cost of generation, $/MWh	$36.79	$36.25	$47.50	$47.53	$38.30	$48.21
Extra annual cost for biomass (or larger size), $M/yr	$0.0	$8.1	$11.1	$11.2	$14.0	$13.1
Extra annual gen. (biomass or larger size), GWh	0	263	263	263	263	263
Unit cost of extra gen. (biomass or larger size), $/MWh	N.A.	$30.86	$42.11	$42.47	$53.43	$49.95
Extra cost of biomass over 400 MWe nat gas, $MWh	N.A.	N.A.	N.A.	($5.57)	$16.64	$13.16
Alternate calculation of extra cost (all in $/MWh):						
Extra cost from adding to nat gas capacity	N.A.	N.A.	N.A.	$42.11	$30.86	$42.11
Extra cost from adding biomass capacity	N.A.	N.A.	N.A.	$42.47	$53.43	$49.95
Alternate result for extra cost of biomass gen	N.A.	N.A.	N.A.	$0.36	$22.57	$7.84

*Note that $4.00/MBtu is gas price in "goal" case, and $2.50/MBtu is used in "today" case. $4.00 is used in the duct burner case.

Sensitivity Analysis

Biomass fuel cost has bee set at $1.50/Btu in all of the analysis presented above. There have been times in the early 1990s when fuel cost nearly twice this amount for some biomass power plants in California. $1.50/ MBtu is the equivalent of about $25/ton (dry weight basis). In order to show the effect of higher biomass costs and to investigate the sensitivity of selected cases to other changes in costs and heat rate, Table 6-2 was developed.

Table 6-2
Sensitivities

Case No.:	1	2	3	4	5	6	7	8
Label (3 lines):	Bio low $1.50 Gas: $4	Bio mid $2.50 Gas: $4	Bio high $3.50 Gas: $4	NGCC base eff Gas: $4	NGCC hi eff Gas: $4	NGCC low $/kW Gas: $4	NGCC best Gas: $4	Demo. (Gas at $2.50)
Biomass:								
Fuel cost, $/MBtu	$1.50	$2.50	$3.50	$1.50	$1.50	$1.50	$1.50	$2.50
Heat rate, Btu/kWh	9000	9000	9000	9000	9000	9000	9000	9000
Capital cost, conv., $/kW	$300	$300	$300	$450	$450	$450	$450	$600
Capital cost, handling, $/kW	$100	$100	$100	$100	$100	$100	$100	$100
Natural Gas:								
Heat rate, Btu/kWh	7500	7500	7500	7500	6350	7500	6350	7500
Capital cost, NGCC, $/kW	$486	$486	$486	$486	$486	$389	$389	$486
Results (all in $/MWh):								
COE of the case	$47.53	$48.35	$49.17	$48.03	$43.85	$44.64	$40.45	$39.12
Cost of the biomass gen.	$42.47	$51.51	$60.51	$47.99	$47.99	$45.64	$45.65	$62.45
Cost of the nat gas alternative	$42.11	$42.11	$42.11	$42.11	$37.52	$39.77	$35.17	$30.84
Extra cost of biomass	$0.36	$9.40	$18.40	$5.88	$10.47	$5.87	$10.48	$31.61
Project size:								
Cost to build 440 MWe, $M	$230	$230	$230	$236	$236	$193	$193	$242
Cost of 40 MWe biomass, $M	$16	$16	$16	$22	$22	$22	$22	$28
Nat. gas fuel budget, $M/yr	$78.8	$78.8	$78.8	$78.8	$66.8	$78.8	$66.8	$49.3
Biomass fuel budget, $M/yr	$3.6	$5.9	$8.3	$3.6	$3.6	$3.6	$3.6	$5.9
Biomass O&M budget, $M/yr	$1.2	$1.2	$1.2	$1.5	$1.5	$1.5	$1.5	$1.7

Values used for all, unless otherwise noted) are as shown to right ➔	0.75 annual capac fac	6570 hours / year	0.200 capital recovery	$70,000 operator/ yr (fully loaded)	9000 biomass heat rate Btu/kWh	7500 ←NGCC heat rate today 6350 ←NGCC heat rate goal (7500 Btu/kWh base case NGCC, and 6350 hi eff case)

Heat rates are HHV basis and correspond to these efficiencies: 9000 ➔ 0.379; 7500 ➔ 0.455; 6350 ➔ 0.537.

Notice that $4.00/MBtu has been used for the natural gas price for all except Case 8 in Table 6-1. This last case is to represent today's situation where a demonstration is to be done at a plant that has a long term gas contract at an average price of $2.50, free of spot market episodes of very high prices.

Comments and Conclusions Based on the Sensitivity Cases

Case 1: Biomass $1.50/MBtu and a $300/kW gasification system. The case that motivates the project is Case 1, because it reflects the goal situation: biomass gasification has been driven down in cost to a $300/kW gasification unit plus a $100/kW biomass fuel handling/processing line. Natural gas fuel has risen to $4.00/ MBtu, thereby making the biomass more competitive. Biomass fuel cost has been driven down to $1.50/ MBtu. The extra cost for the 40 MWe from biomass is only $0.36/MWh. This extra cost is calculated versus the NGCC plant's alternative to be built at 440 MWe rather than 400 MWe and get the extra 40 MWe from firing more natural gas. The marginal cost of those extra 40 MWe from natural gas is only $42.11/ MWh, not the average cost of the $47.50 shown in Table 6-1 for a 440 MWe NGCC. This is because, at the margin, the plant owner need add only the slight $14M to build the plant at 440 MWe rather than the $200M for the basic 400 MWe size.

Note that this method of calculating the natural gas alternative to the biomass is used **for all of the cases in Table 6-2.** This method gives the fair cost, and the **lowest cost, of the natural gas option** that might be seen as the alternative for an owner considering whether or not to try the extra 40 MWe from biomass. It is appreciably lower than the average, not marginal, cost of the full 400 MWe from a pure 400 MWe NGCC. This method amounts to selecting the highest extra cost of the biomass option. It is the method that gives the extra cost value shown as the bottom line of all of the full-cost-detail tables in this report, i.e., Tables 3-3, 4-1 and 5-1.

Case 2: Biomass $2.50/MBtu and a $300/kW gasification system. Same as Case 1 but with biomass fuel cost at $2.50, not the usual $1.50, per million Btu (MBtu). Again, the goal cost is adopted for the biomass gasification system, $300/kW. The overall average cost of the electricity has gone up only a little, from $47.53/MWh to $48.35/MWh, because the biomass is only 10% of the fuel source. But, the extra annual cost total, i.e., the annual $M/yr above the $M/yr for the 400 MWe plant on pure natural gas, divided by the extra electricity generated, the 40 MWe x 6570 hrs = 263 GWh, gives the cost of the biomass part as $51.51/MWh, and that is $9.40/MWh above the $42.11 of the marginal cost of getting the extra 263 GWh via simply building the NGCC as a 440 MWe instead of 400 MWe.

Case 3: Biomass $3.50/MBtu and a $300/kW gasification system. Next step up in biomass fuel cost, now $3.50/MBtu instead of the $1.50 in Case 1 and $2.50 in Case 2. The goal cost for the gasification system is kept: $300/kW. Now with the same, conservative method of calculating the extra cost from the power plant owner's perspective, the biomass 40 MWe system is generating the 263 GWh/year of renewable electricity at an extra cost of $18.40/MWh.

The "Project Size" section of Table 6-2 indicates how large the biomass costs--capital, fuel, and operating (O&M, meaning the sum of the operating staff added to perform the biomass operations and the maintenace costs of the biomass equipment--are with respect to the total capital cost of the whole project and the annual cost of the major fuel, i.e., the natural gas. At this very high $3.50/MBtu fuel cost the biomass fuel budget is now over 10% of that for the $4.00/MBtu natural gas, $8.3M biomass vs. $78.8M natural gas. The capital cost of the biomass system, with its $300/kW low cost (goal value) for the gasification sytem is $16M of the total $230M spent to build the whle plant, biomass plus the major natural gas system.

Case 4: Biomass $1.50/MBtu and a $450/kW gasification system. This case goes back to the basic low cost goal for the biomass fuel at $1.50/MBtu, but allows for a higher cost to build the biomas gasification system: $450/kW instead of $300/kW. This case is not one of those in the earlier tables. None of the remaining cases (Cases 4 through 8) are from the earlier tables, but they use the same methods of calculation and comparison. This Case 4 is the first of a set of four (Cases 4 through 7) to probe the sensitivity of the results to assumptions made regarding the cost and efficiency of the NGCC system. Here the base case cost of $486/kW is used, as is the base case efficiency: 7500 Btu/kWh, which is done on the higher heating value basis (HHV basis) and is the equivalent of a thermal efficiency value of 0.379. The base case cost of $486/kW is a $500/kW value for a 400 MWe system, adjusted by a 0.7 power law to the larger size of 440 MWe.

Case 5: High Efficiency NGCC with Biomass Gasification at $450/kW. This case keeps the same cost of the NGCC, namely the base case of $486/kW for a 440 MWe system, but allows the efficiency to be much higher, reaching a goal value of 0.537, which matches a 6350 Btu/kWh value for a HHV heat rate that was used in recent DOE Energy Information Administration (EIA) reports as a case of advanced natural gas com-bined cycle technology, most of the advance being in the gas turbine (e.g., higher turbine inlet temperature and inter-cooling between stages of compression). The biomass gasification has been kept at the Case 4 value of $450/kW. This is above the goal cost of $300/kW, but is a value achievable sooner than the goal value, and by keeping the biomass part at the same set of values for Cases 4-7 the NGCC changes can be explored most clearly.

Case 6: Low Cost NGCC with Biomass at $450/kW. This is Case 4 with the cost, but not the heat rate, of the NGCC system improved. The cost is cut by 20%, from $500/kW for a 400 MWe system to $400/kW. With the 0.7 power law applied, this becomes $389/kW for 440 MWe.

Case 7: Best NGCC, both in Efficiency and in Cost. Here the high efficiency is combined with the low cost to give the best NGCC case. Cost is 20% below today, i.e., $400/kW for a 400 MWe system, as in Case 6, and, as in that case, this becomes $389/kW for 440 MWe. The high efficiency of Case 5, which is 0.537 or 6350 Btu/kWh, is applied, along with the low cost. On the biomass side, the $450/kW of Cases 5 and 6 is continued, in order to leave this unchanged while seeing the effect of improvements on the NGCC side.

Case 8: Possible Demonstration Plant with Gas at $2.50/MBtu, Biomass $2.50/MBtu and a $600/kW Gasification System. The last case shown in Table 6-2 is a possible first-of-a-kind demonstration that could be started in 2001 or 2002. Gas is assumed to cost only $2.50/MBtu, as a continuation of the low gas prices for long term contracts in the 1998-1999 period. (All the other cases in Table 6-2 assumed a high future gas price of $4.00/MBtu.) A higher biomass fuel cost is assumed for Case 8: $2.50 rather than the goal of $1.50/ MBtu. The biomass gasification system is taken to have the current high capital cost of $600/kW for a 40 MWe system. This gasification cost is 2x the goal cost of $300/kW, used in Cases 1-3 in Table 6-2, and 33% above the higher-than-goal $450/kW adopted for Cases 4-7.

Case 8 is very expensive compared to the others. The high cost of a biomass gasification system built today, before improvements and multiple-unit experience have cut the cost, also is reflected in higher costs of main-tenance: 4%/year on $600/kW x 40 MWe, rather than that 4%/year applied to $300/kW x 40 MWe. The low cost of natural gas in Case 8 makes expensive the extra cost of the biomass electricity over that from simply running the operation as 440 MWe from 100% natural gas. Biomass fuel at the $2.50/MBtu cost contributes to the high expense of the 40 MWe of extra power coming from the renewable source instead of the $2.50/ MBtu natural gas. (All the other cases in Table 6-2, except for Cases 2 and 3, use the low cost goal for the biomass fuel: $1.50/MBtu.) The result of these assumptions that reflect the recent and, perhaps still current, period of low fossil and high renewable costs, gives the cost of conventional electricity from natural gas as only $32.84/MWh versus $62.45 for the biomass-based electricity: a premium of $31.61/MWh for the renewable biomass electricity.

Size and Cost of a Demonstration Project

Case 8 in Table 6-2 shows the size, in units of various dollar costs, of the possible first-of-a-kind demonstra-tion. (As in all the cases in that table, the bottom five lines of the case give some cost items to show the relative financial sizes of the natural gas and biomass parts of the various cases.) For the demonstration plant represented by Case 8, these numbers that measure the financial size are as follows: $242 million, the total cost to build the project; $28 million, the extra capital cost to build the 40 MWe of biomass capacity, rather than to build the plant as a 440 MWe NGCC at $486/kW and $214 million; $49.3 million per year, the fuel budget for the natural gas part of the plant at $2.50/MBtu for 400 MWe x 6750 hours/year, or 2628 GWh, at a 7500 Btu/kWh heat rate; $5.9 million/year, the fuel budget for the biomass part at $2.50/MBtu x 40 MWe x 6570 hours/year x 9000 Btu/kWh; and, $1.7 million/year, the cost of the operation and maintenance of the 40-MWe biomass system--$0.56M for 8 people on the operating staff at $70,000 each per year as the fully-loaded cost, plus $0.96M to maintain the 40 MWe gasification system, plus $0.20M as the maintenance cost of the 40 MWe biomass solid-fuel handling/processing system.

One possible way to fund the project represented as Case 8 in Table 6-2 would be as follows: (1) power plant owner pays all the costs of the natural gas system and 20% of the extra costs to build and operate the biomass component; (2) Federal government pays 40% of the extra costs to build and operate the biomass component; and (3) State government pays the same share as Federal. In such as case, the costs and funding would break down as shown in Table 6-3.

Table 6-3
Costs and Funding of a Demonstration Project

Description	Cost	Units	Owner	Federal	State
Capital (total:10/30/60%, years 1/2/3)					
Natural gas system	$214	Million	$214		
Biomass system (gasification + handling)	$28	Million	$5.6	$11.2	$11.2
Annual (each year, years 4, 5, and 6)					
Natural gas fuel cost	$49.3	M / year	$42.9		
Biomass fuel cost	$5.9	M / year	$1.2	$2.4	$2.4
Biomass operating/maintenance costs	$1.7	M / year	$0.3	$0.7	$0.7

7

SI UNITS AND CONVERSION FACTORS

System of International Units Conversion Table

For calculation purposes, convert British units to System of International (SI) units by combining the quantity in British units by one or more fractions of the form M/B, each fraction consisting of the number and units in column M divided by 1 of the unit in column B. Each such fraction (including their units) is unity; when you combine the fractions together the units should cancel, leaving a result in SI units only.

Example: $\dfrac{1}{8700\ \text{Btu/kWh}} \times \dfrac{3.6\ \text{E6J/kWh}}{1055\text{J/Btu}}$ = 39.2% thermal efficiency

British unit (B)	Metric equivalent (M)	
ACRE	= 4047 m2	
ATMOSPHERE atm	= 101.325 kPa	
BARREL (petroleum, 42 gal) bbl	= 0.15899 m3	
BAR	= 100 kPa	
BRITISH THERMAL UNIT Btu	= 1055 J	
CUBIC FOOT ft3	= 0.02832 m3	
degree Farenheit (°F)	= F-32/1.8 degree Celsius (°C)	
ft3/min	= 471.9 cm3/s	= 0.0004719 m3/s
scfm (60F, 1 atm)	= 0.4474 liter/s	= 0.0004474 m3/s (0c, 1 atm)
CUBIC INCH in3	= 1.6387 E-5 m3	
CUBIC YARD yd3	= 0.7646 m3	
FOOT ft	= 0.3048 m	
ft of water @ 68F	= 2.989 kPa	
ft/min	= 0.5080 cm/s	= 0.005080 m/s
ft-lbf (*torque*)	= 1.356 J	
GALLON gal	= 3.7854 liter	= 0.0037854 m3
Gpm	= 0.22715 m3/h	= 6.309 E-5 m3/s
HORSEPOWER hp	= 746 W	
INCH in	= 0.0254m	
in Hg	= 3.3864 kPa	
in H2O	= 0.249 kPa	
KWh	= 3.6 E6J	= 3.6 MJ
MILE mi	= 1609.3 m	= 1.6093 km
Mph	= 0.4470 m/s	
OUNCE (*wt*) oz	= 0.02835 kg	
OUNCE (*liq*) oz	= 0.02957 liter	= 2.957 E-5 m3
POISE p	= 0.1000 N-s/m2	= 0.1000 Pa-s
POUND (*mass*)	= 0.4536 kg	
lb/ft3	= 16.018 kg/m3	

Lbf	= 4.448 N	
lbf/in2	= 6.895 kPa	
QUART	= 0.9464 liter	= 9.464 E-4 m3
TON ton (short)	= 907.2 kg	
TON (tonne)	= 1000 kg	

Adapted from American National Standards Institute ANSI Z210.1-1976/ASTM E 380-93/IEEE Std 268-1976.

Some Units of Special Interest for Biomass Power

1 Btu = 1055 joules = 1055 J; 1 GJ = 10^9 J = 0.948 x 10^6 Btu = 0.948 MBtu

1 toe = energy equivalent of one metric ton of oil

1 Gtoe = 10^9 toe = 41.9 EJ = 41.9 x 10^18 J = 39.7 x 10^15 Btu = 39.7 quads

1 ha = 100m x 100m = 10^4 m^2 = 2.471 acres

1 ton = 1 short ton = 0.9072 metric ton = 0.9072 tonne

Higher Heating Value (HHV) of typical biomass = 16 MBtu per dry short ton

1 MBtu/dryton = 1.055 GJ / 0.91 dry tonne = 1.16 GJ per dry metric ton

1 toe = 41.9 GJ; 16 MBtu/ton = 18.61 GJ/tonne = 2.25 toe/tonne

1 dry ton per acre per year = (2.471*0.9072) / 2.25 = 0.9955 toe/ha/year

1 square mile = 640 acres = 259 ha = 2.59 x 10^6 m^2 = 2.59 square km

Direct normal solar flux = 1000 W/m^2 (typical, nominal value)

Average <u>annual</u> solar energy rate ("insolation" or "solar flux") = 200 watts/m^2

200 W = 200 J/sec = 200 x 3600 / 1055 Btu/hour = 682 Btu/h

3413 Btu = 3.60 MJ = 1 kWh; 1 year = 8760 hours;

200 W = 5.98 MBtu/year; 200 W/m^2 = 518 MW per sq mile = 15.5 x 10^12 Btu/yr per square mile = 15.5 quad/year per 1000 square miles = 6.3 EJ/year per 1000 sq km

Energy Equivalents Table from EIA's Annual Energy Outlook (1998)

1 quadrillion Btu = 1 quad = 25.2 million tons of oil equivalent (Mtoe)

1 kWh = 3.6 megajoules (MJ) = 3412 Btu of electricity consumption

1 short ton of coal for electric utilities = 20.525 million Btu

1 barrel crude oil = 0.159 cubic meter volume crude oil = 5.8 million Btu

1 cubic foot natural gas = 0.0283 cubic meter volume at STP = 1028 Btu
Therefore, heating value (HHV), if methane @ 1028 Btu/std.ft3, is 23,068 Btu/lb.

Metric Prefixes:

10^3 kilo k;	10^6 mega M;	10^9 giga G;
10^12 tera T;	10^15 peta P;	10^18 exa E.

Mass: 1 pound mass (lb) = 0.4536 kg

Length: 1 mile = 1.609 km

Area: 1 square foot (ft2) = 0.0929 sq meter

Volume: 1 gallon (US) = 3.785 liter

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