Engineering economic analysis of biomass IGCC with carbon capture and storage

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Abstract

Integration of biomass energy technologies with carbon capture and sequestration could yield useful energy products and negative net atmospheric carbon emissions. We survey the methods of integrating biomass technologies with carbon dioxide capture, and model an IGCC electric power system in detail. Our engineering process model, based on analysis and operational results of the Battelle/Future Energy Resources Corporation gasifier technology, integrates gasification, syngas conditioning, and carbon capture with a combined cycle gas turbine to generate electricity with negative net carbon emissions. Our baseline system has a net generation of 123 MW_e, 28% thermal efficiency, 44% carbon capture efficiency, and specific capital cost of 1,730 $ kW_e^{-1}. Economic analysis suggests this technology could be roughly cost competitive with more conventional methods of achieving deep reductions in CO_2 emissions from electric power. The potential to generate negative emissions could provide cost-effective emissions offsets for sources where direct mitigation is expected to be difficult, and will be increasingly important as mitigation targets become more stringent.
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1. Introduction

Stabilizing atmospheric carbon dioxide (CO_2) concentrations at a level sufficient to avoid

dangerous interference with natural systems—the agreed goal of the Framework Convention on Climate Change—presents a fundamental challenge to industrial society. Biomass has long been investigated both as a (nearly) CO_2 neutral substitute for fossil fuels and as a means of offsetting emissions by sequestering carbon in terrestrial ecosystems [1]. The relatively recent

development of carbon capture and storage (CCS) technologies, conceived as a means toward fossil fuel use without atmospheric CO_2 emissions, provides a new suite of opportunities for biomass energy systems (biomass-CCS). This integration may yield distinct advantages by providing useful energy products and effectively removing carbon from the atmosphere–biosphere system.

We survey possible routes to biomass-CCS and present a simplified engineering economic model of a feasible, though non-optimal, biomass integrated gasification combined cycle (IGCC) system with CO_2 capture to illustrate the potential role and importance of biomass-CCS. The model is based on previously published process models and associated component cost estimates for major subsystems [2–4]. Our analysis focuses on system integration including: identification of component technologies and integration points; design modification to facilitate integration; integrated process stream modeling; and integrated economic modeling.

Three versions of the model are presented, two with CCS and a baseline without. Additional design alternatives exist as do alternate component technologies; no optimization has been performed. Moreover, alternate subsystem technologies, such as oxygen-blown gasification, could be applied to biomass fuels with potentially higher energy efficiency and fuel carbon capture rates. Assessing the engineering economic trade-offs of various systems for capturing CO_2 from biomass electricity or poly-generation systems is an important area for future research.

Section 2 discusses key issues for a biomass-CCS mitigation strategy and surveys possible biomass-CCS pathways. Technical and economic details of the current model are presented in Section 3. Section 4 provides both direct modeling results and a broader context within which these results can be interpreted. Finally, Section 5 discusses the implications of our results.

2. Background

CCS is primarily aimed at decoupling the fossil fueled energy sector from atmospheric carbon emissions. Integration of CCS with biomass energy systems could leverage similar technologies for a distinctly different benefit: effective generation of negative atmospheric carbon emissions as atmospheric carbon—fixed through photosynthesis—is captured and sequestered from the atmosphere for geologic timescales.

Biomass generally provides four routes for carbon mitigation: in situ sequestration by reforestation and conservation; remote sequestration by harvest and burial; substitution for fossil fuels; and substitution for fossil fuels with remote sequestration (biomass-CCS) [5,6]. Only biomass-CCS can both provide low-carbon energy products and effectively remove carbon from the natural carbon cycle. As a result, biomass-CCS offers the largest mitigation per unit biomass, or equivalently per unit land area, potentially important given limited agricultural resources [7].

Top-down estimates of the economics of stabilizing atmospheric CO_2 at an effective doubling of pre-industrial concentrations without biomass-CCS suggest marginal mitigation costs could exceed 1000 US dollars per metric ton carbon mitigated ($\$\,t\,C^{-1}$) [8]. These high marginal costs arise where *direct* mitigation is expected to be difficult, as in the transportation sector where the combination of mobile emissions sources and strong consumer performance expectations will likely drive up the cost of mitigation [9]. Negative emissions from biomass-CCS could offset these sources, providing *indirect* mitigation, at potentially lower cost. At the project level, sale of internally generated emissions offsets could provide additional revenues, depending on the carbon management and regulatory framework.

Three technological approaches are being advanced for fossil CCS: post-combustion capture (PCC), where CO_2 is scrubbed from combustion exhaust streams; oxyfuel, where combustion occurs in pure oxygen and CO_2 is separated by condensing water from the exhaust; and pre-combustion separation (PCS), where carbon is separated prior to combustion by gasification (of solid fuels), steam reforming, shift, and CO_2 scrubbing [10,11]. Note that PCS systems are uniquely flexible in their potential energy products, including gaseous fuels (e.g., hydrogen), liquid

fuels (e.g., methanol), or electricity, and may have cost advantages relative to PCC for new plants from lower energy requirements for carbon separation and higher conversion efficiencies of gas turbine and fuel cell power plants [10,12].

Biomass has important similarities with fossil fuels (particularly coal), including conversion technologies and the range of energy products that can be generated—dispatchable, base-load electricity as well as liquid and gaseous fuels. As a result, all three technological routes for CCS could be applied to biomass energy systems. Biological processes, such as bio-ethanol fermentation, provide additional CCS opportunities. Fig. 1 illustrates the major routes to biomass-CCS.

PCC or oxyfuel could be integrated with modern biomass boiler technologies or retrofitted to existing plants, though the small scale and low efficiency of existing biomass boilers would make this relatively inefficient. Alternatively, coal-fired power plants could be retrofitted to co-fire biomass *and* incorporate CCS such that biomass

carbon captured would more than offset incomplete capture of coal carbon [13]. With sufficiently stringent emissions controls, such a plant could be retrofitted to burn only biomass. The feasibility of this depends on (i) emissions controls inducing both a low purchase price for unmodified coal-fired power plants and (ii) financial dominance of large negative emissions over potentially high fuel costs, as well as (iii) local access to very large biomass resources.

Modern biomass gasification technologies could incorporate PCS. Syngas dilution with atmospheric nitrogen largely eliminates the benefits of PCS in air-blown gasification systems. However, indirectly heated, steam-blown systems or oxygen-blown systems could effectively leverage PCS. Oxygen-blown biomass gasification has been demonstrated and offers higher energy efficiencies and carbon capture; though somewhat less operating experience and economic data is available for these systems [14,15]. The current analysis is therefore modeled from the Battelle Columbus
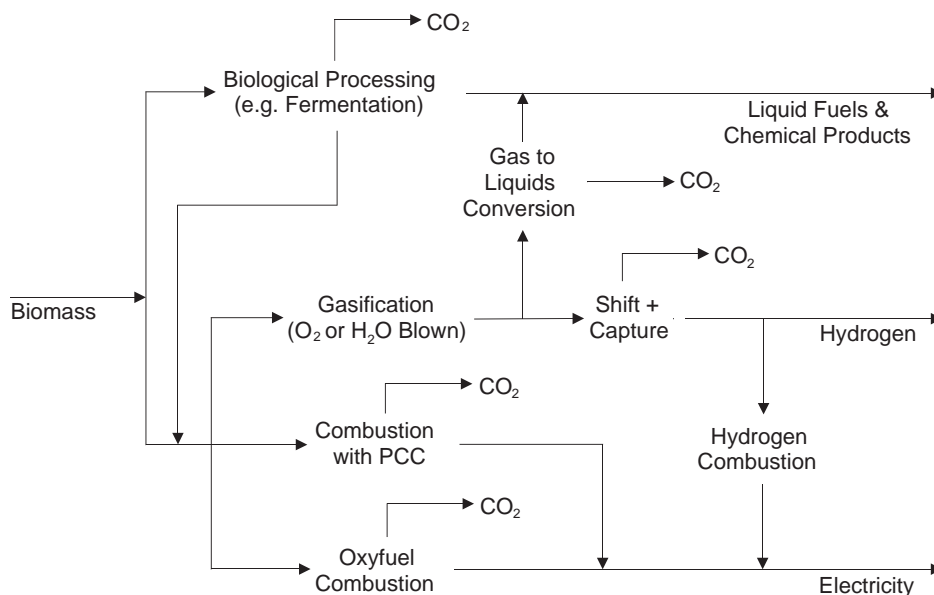

Fig. 1. Routes to biomass with CO_2 capture. The routes to biomass energy products with CCS include (from top to bottom) biological processing with capture of CO_2 by-products to produce liquid fuels, biomass gasification with shift and CO_2 separation to produce hydrogen, and biomass combustion to produce electricity with CCS—either by oxyfuel or PCC routes. These basic routes can be combined or integrated, for example, by gasification with CCS of residual biomass from biological processes, or by syngas conversion to liquid fuels with CCS, or by burning hydrogen-rich syngas to produce electricity with CCS—as in the current study.

Laboratory/Future Energy Resources Corporation (BCL/FERCO) steam-blown system [2].

Biological processes provide additional opportunities for biomass-CCS. CO_2 is a byproduct of fermentation in bio-ethanol production, implying that CO_2 available for capture scales with ethanol production and that fuel carbon capture rates scale with conversion efficiency. The retrofit potential of this strategy implies nearly $9\,Mt\,C\,yr^{-1}$ is available at very low capture cost given global bio-ethanol production of approximately $40\,Mm^3$ in 2003 [16]. Bio-ethanol production generally also includes combustion—or gasification and combustion—of waste biomass, providing further carbon capture opportunities, with additional cost [17].

The ability to generate emissions offsets extends the scope of carbon mitigation with biomass and may provide cost-effective mitigation alternatives across the economy, fundamentally changing the economics of biomass-based mitigation. Negative emissions from biomass-CCS do not, however, offer a strict cap on mitigation costs since its costs must scale with the biomass supply curve, which may become steep if large-scale bioenergy crops compete for limited land resources. Environmental impacts may further constrain biomass mitigation potential [1]. However, the extraordinary heterogeneity of emissions sources provides many niches, and integrating CCS will extend the opportunities for biomass-based mitigation.

3. Methods

The simplified engineering economic model presented here was developed by integrating previously published ASPEN simulation results with associated cost estimates from several independent studies [2–4]. We do not claim that our cost and performance estimates represent today's realities; rather, they reflect a prospective view assuming a design benefiting from at least 10 years of aggressive research and development to refine component technologies and reduce requisite contingencies. These assumptions are consistent with and incorporated directly from the underlying process simulation studies.

3.1. Process design

The model includes four component subsystems: biomass gasification, syngas conditioning, carbon capture, and power generation (see Figs. 2 and 3). Gasification and syngas conditioning subsystems are modeled from two studies of the BCL/FERCO indirect gasifier [2,3]. Carbon capture and compression is incorporated from a design study of coal gasification with PCS [4]. The gas turbine combined cycle (GTCC) system is based on GE's H-class technology with performance modifications to accommodate hydrogen-rich fuel gas [18,19].

An integrated design is modeled from process blocks in the above-mentioned studies with minor
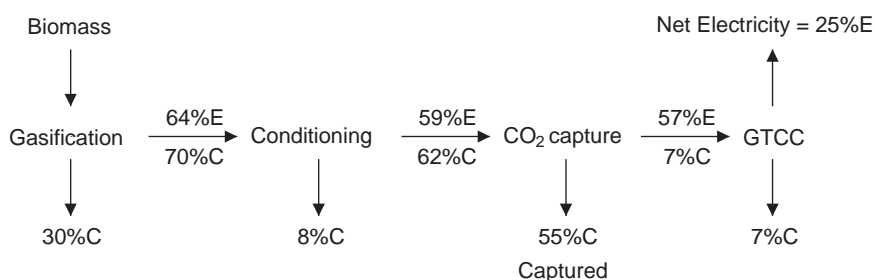

Fig. 2. Process schematic with carbon and energy flows. A general schematic with carbon and energy flows illustrates the 25% net efficiency and 55% carbon capture rate of the biomass-CCS system with steam reforming. Note that nearly 30% of the biomass carbon is emitted during char combustion, a peculiarity of this gasification system, and an additional 11% is emitted to provide heat for steam reforming. Eliminating steam reform avoids this loss, but reduces the CO_2 available for capture and results in additional emissions from the gas turbine.
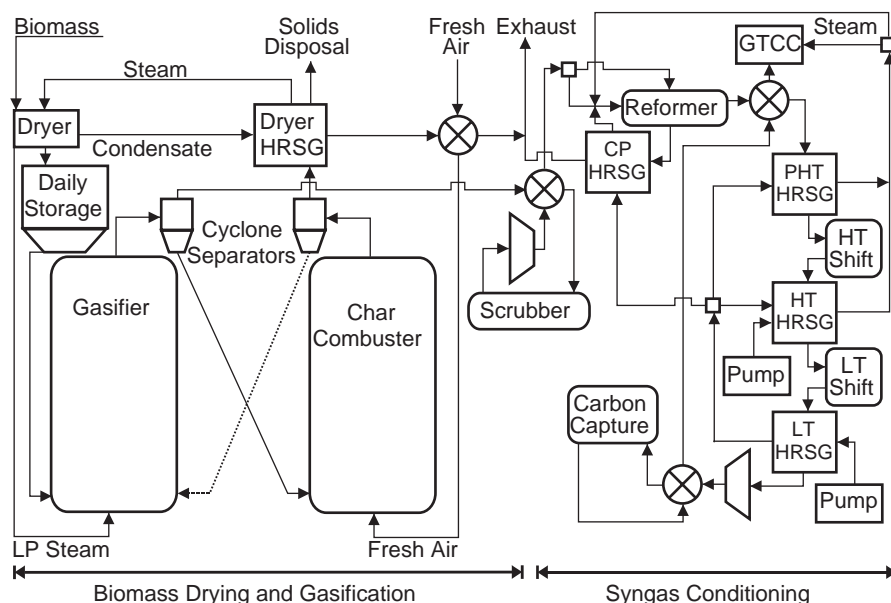
Fig. 3. Process flows for gasification and syngas conditioning with steam reform. Key aspects of the gasification and syngas conditioning design include (i) the close integration of gasifier and char combustor, fundamental to the BCL/FERCO design, (ii) the close coupling of the gasifier and dryer systems, from the design by Raymond et al. [3], (iii) the steam sources for reform and shift reactors, and (iv) the steam diversion and syngas heating for fuel gas humidification.

modifications to balance stream compositions, pressures, temperatures, and flow rates so as to conserve heat, chemical energy, and mass. These modifications include (i) scaling of component technologies, (ii) substitution of process heat sources and uses, (iii) addition of supplemental generation capacity, and (iv) addition and heat duty modification of heat exchangers. Models of transformation from input to output streams for individual process blocks are linearly scaled from the original subsystem analyses (e.g., CH_4 in the steam reformer output is ~41% of the CH_4 input based on Ref. [2]).

The BCL/FERCO system is unique in that heat for gasification is provided indirectly by char combustion in a separate reaction vessel. Circulating sand provides heat transfer between the combustor and gasifier (Fig. 3). This system avoids syngas dilution with nitrogen; however, roughly 30% of fuel carbon is emitted as char combustor flue gas. These losses are inherent to indirectly heated (non-oxygen) systems; design modifications could limit them (with additional cost), but they

are not explored here. The BCL/FERCO system also appears to have relatively high throughput, high-energy efficiency, and capital cost advantages relative to other biomass gasifiers [3]. Although the system is not yet in commercial use, a demonstration facility with a capacity roughly one-sixth that modeled here is in operation at the McNeil Station in Vermont [20].

The gasifier converts ~23% of input carbon to methane and higher hydrocarbons. Addition of steam reforming prior to water–gas shift improves the carbon capture rate by shifting some of the methane to CO_2, CO and H_2, but raises costs and lowers energy efficiency as we describe in Section 4.

Integration of gasification with syngas conditioning is addressed in an NREL study [2]; however, that study included sophisticated integration of gasification, conditioning, and a pressure swing adsorption (PSA) system to produce high purity hydrogen. We replace the PSA with a glycol scrubber, which is more cost effective given lower purity requirements. Several modifications,

Table 1
Comparison of gas streams integrating biomass gasification and CO_2 capture

Parameter[a]	Scrubber input as modeled here[b]	Syngas from NREL study[c]	Scrubber input from IGCC study[d]
H_2	61%	62%	58%
CO_2	35%	34%	37%
CH_4	3%	3%	4%
CO	1%	1%	0%
Molar flow (Mmol h^{-1})	5.3	2.6	5.3
Temperature (°C)	13	24	13
Pressure (Mpa)	3.1	2.6	3.1
Cold gas HHV (MW$_{th}$)	255	118	252

[a]Units are mole fractions or as noted. Chemical components representing less than 1% of the molar flow are omitted. Mole fractions do not add to one due to rounding errors and omitted compounds.
[b]From the current model BIGCC-CCSr (with steam reform).
[c]From the NREL study of biomass gasification for hydrogen production [2].
[d]From the study by Doctor et al. of coal IGCC-CCS [4].

described below, were required to isolate the gasifier, reformer, and shift reactors from the PSA and balance of plant.

A steam dryer assembly from a more recent study of the BCL/FERCO system by the Weyerhaeuser Corporation [3], is substituted for the rotary dryer in the NREL study. Both use char combustor exhaust for biomass drying, but the steam system also provides gasifier steam, freeing up downstream process heat. The steam system has efficiency and emissions benefits as well. Syngas composition and production rates from the Weyerhaeuser study are integrated through downstream process blocks for consistency.

Heat for steam reforming is provided by combusting roughly 12% of unreformed syngas outside the reaction tubes. This was estimated by balancing the heat required for reform (change in enthalpy of formation and sensible enthalpy across the reformer) with the heat available from combustion (lower heating value of unreformed syngas minus the change in sensible enthalpy of combustion products to 100 °C above the syngas output). We assume 98% heat transfer efficiency throughout. An alternate design burning hydrogen-rich fuel gas to minimize carbon losses was also explored, as discussed below.

Finally, available process heat is applied to preheat the fuel gas and raise steam for the reformer, shift reactors, fuel gas humidification, and supplemental power generation, whereas the NREL study took an economic credit for steam as a co-product. Fig. 3 presents a schematic of the gasification and syngas conditioning subsystems.

The CO_2 capture sub-system is incorporated without modification from the design by Doctor et al. [4]. It is integrated after the low temperature shift heat recovery steam generator (LT HRSG in Fig. 3), where the modeled stream composition is nearly identical to that in the original design, as shown in Table 1. Minor pressure and temperature differences in these streams are addressed by incorporating additional compression and adjusting the heat rate of the capture system's heat exchanger. The flowrate difference in these streams is addressed by scaling up the gasifier and syngas conditioning sub-systems. Separated CO_2 is compressed to 145 bar for pipeline transport while the lean solvent is compressed, refrigerated, and recycled [4,21].

The GTCC system incorporates fuel gas humidification of 0.6 kg steam kg^{-1} fuel by blending the fuel with steam at the same pressure [18]. We assume net conversion efficiency of 60% (LHV) for the GTCC, consistent with current H-class technology [19]. We assume (optimistically) that comparable technology will be available at the 100 MW$_e$ scale within the time horizon of this analysis, though it is currently available only at the 400 MW$_e$ scale.

Table 2
Summary model results. The BIGCC-CCSr system includes steam reforming while BIGCC-CCS does not

System	BIGCC	BIGCC-CCS	BIGCC-CCSr
Process performance			
Capacity (MW$_{th}$)	444	444	444
Net generation (MW$_e$)	149	123	110
Net efficiency (HHV)	34%	28%	25%
C-capture rate (% input C)	0%	44%	55%
Net emissions (kgC kWh^{-1})[a]	0	−0.14	−0.20
Economic performance			
Capital cost ($ kW^{-1})	$1,250	$1,730	$1,980
Non-fuel O&M cost ($ kW^{-1}y^{-1})[b]	$100	$131	$146
Electricity cost (cents kWh^{-1})[c]	5.9	8.2	9.3
Cost of carbon mitigation ($ tC^{-1})[d]	$102	$123	$135

[a]Ignoring minor emissions from fossil energy consumed in biomass production, harvest, transport and processing, generally less than 5% of biomass energy [22].

[b]Assumes a capacity factor of 0.8.

[c]Assumes Biomass fuel cost and CO_2 sequestration cost of $50 per dry ton and $10 per ton, respectively, as well as amortization of capital costs at 10% interest over 20 years.

[d]Computed relative to pulverized coal power generation with fuel, capital, non-fuel O&M cost, and net efficiency of 1.0 $ GJ^{-1}, 1.2 $ W^{-1}, 8 $ MWh^{-1}, and 40% (HHV), respectively; coal and biomass carbon intensities of 24 and 25 kg C^{-1} GJ^{-1}, respectively, with the same amortization and utilization assumptions outlined above. These assumptions yield coal electricity cost of 37 $ MWh^{-1}.

3.2. Economics

Our economic model is consistent with estimates and assumptions in the original literature. Cost estimates for components in the gasification and syngas conditioning systems are developed from those in the NREL and Weyerhaeuser studies [2,3]. Cost estimates for the carbon capture system are from those by Doctor et al. [4]. All capital cost scaling was calculated using scaling factor of 0.7 (component costs are assumed to be proportional to the equipment size raised to the 0.7 power).

Capital costs were converted to year 2000 dollars using the Component Cost Index for Chemical Processes. Economic assumptions for contingencies and other allocations from individual studies were applied to their respective components to estimate the total capital requirement. The total capital requirement for the GTCC system is assumed to be $550 per installed kW$_e$. We assume a CO_2 sequestration cost of $10 ton^{-1}, to pay for pipeline transport to an appropriate storage facility, final compression, and geological sequestration [11].

Non-fuel operation and maintenance cost estimates are also developed from the original literature [2–4]. Cost drivers include labor, consumable material (catalysts, sorbent, etc.), ash and sand disposal, maintenance, insurance and local taxes, royalties, and other operating costs. A capacity factor of 0.8 is assumed for all calculations.

4. Results

Summary cost and performance results are presented in Table 2 for two biomass IGCC systems with carbon capture—BIGCC-CCSr with steam reforming and BIGCC-CCS without—and the base case system without carbon capture. All three systems assume a thermal capacity of 444 MW$_{th}$, equivalent to roughly 2100 bone-dry t d^{-1}. Net generation for the three systems are 110, 123, and 149 MW$_e$, respectively, and carbon capture rates—equal to the fraction of fuel carbon captured as CO_2—are 55%, 44%, and 0%, respectively. Not surprisingly, net generation and
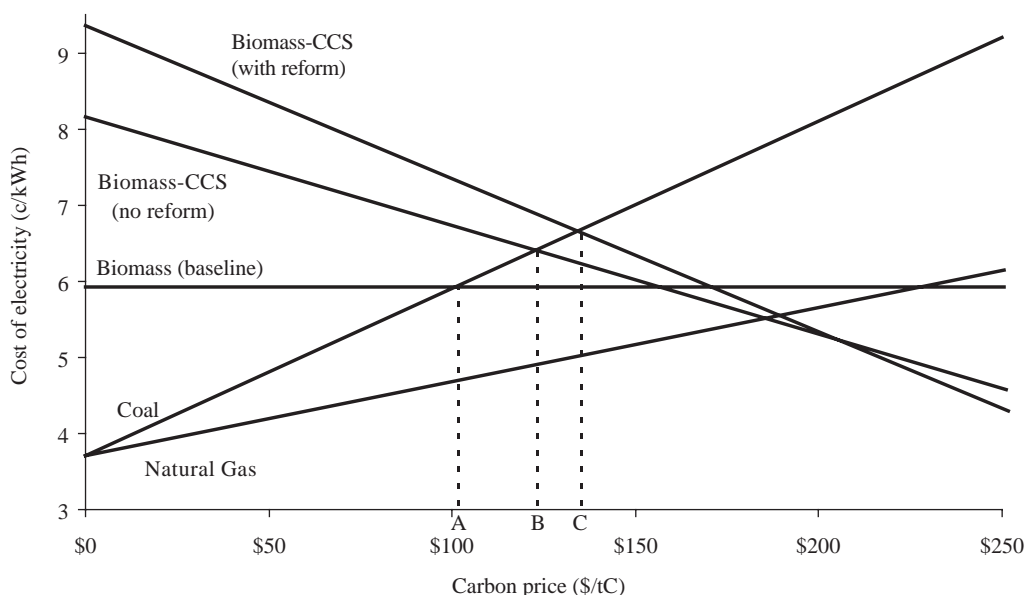
Fig. 4. Cost of electricity as a function of carbon price. Electricity costs are plotted for biomass-CCS with steam reform, biomass-CCS without steam reform, biomass without CCS, conventional pulverized coal, and conventional natural gas combined cycle technologies. The decreasing electricity cost with increasing carbon price from the two biomass-CCS cases reflects the net negative carbon emissions from these technologies. The relative slopes and electricity costs at zero carbon prices illustrate the trade-off between cost and carbon capture efficiency. Carbon mitigation costs are equal to the carbon price associated with the intersection of electricity costs from a mitigation technology and the base case technology, defined as coal within this context. As such, the mitigation costs for non-capture biomass IGCC, biomass-CCS without steam reform, and biomass-CCS with reform are equal to points "A", "B", and "C" respectively. Note that as carbon prices approach $200 \, \$ \, tC^{-1}$, biomass-CCS becomes the least cost technology. Parameter values for the biomass technologies are taken from Table 2. To simplify the graph, parameter values for conventional technologies are deliberately set to yield equal electricity costs with zero carbon price—specifically capital costs, fuel costs, non-fuel O&M costs, and energy efficiencies (HHV) for coal and natural gas are 1200 and $550 \, \$ \, kW^{-1}$, 1.00 and $3.46 \, \$ \, GJ^{-1}$, 8 and $3 \, \$ \, MWh^{-1}$, 40% and 50%, respectively.

carbon capture rates scale in opposite directions as increasing carbon capture is associated with decreasing thermal efficiency and increasing parasitic load. This efficiency penalty, combined with increasing capital requirements, causes specific capital costs ($\$ \, kW^{-1}$) and electricity costs to increase with carbon capture rate, as illustrated in Table 2. The trade-off between cost and carbon capture in the two CCS cases provides an example of how CCS deployment will be dominated by economic optimizations rather than fundamental technological constraints.

The economic implications of these results are ambiguous absent comparison to competitive electric sector technologies. Fig. 4 provides this context by plotting the cost of electricity for the systems modeled here as well as for conventional coal and natural gas technologies as a function of carbon price.

Electricity costs for the two fossil fuel technologies are low with zero carbon price, around $3.7 \, cents \, kWh^{-1}$ (note that the parameters have been adjusted to yield equal electricity costs absent carbon constraints to simplify the figure). However, fossil fuel electricity costs increase in proportion to their fuel carbon intensity divided by their net (HHV) efficiency. As a result, costs increase much faster for coal than natural gas. The cost of biomass electricity without CCS, the conventional view of biomass electricity, is higher than that of fossil fuels with zero carbon price, but has zero slope, reflecting the general balance in carbon emissions and CO_2 uptake during biomass production. Fossil emissions associated with

biomass production, harvest, and transport are generally small—representing fossil energy less than 5% of biomass energy—and are ignored here [22]. As an aside, note that this curve is broadly similar to those expected from fossil fuel technologies with CCS [23]. Finally, the two biomass-CCS cases have electricity costs substantially higher than the base line biomass technology due to their higher capital costs and lower net efficiencies. However, their costs decrease in proportion to their carbon capture rate, reflecting an economic credit for negative carbon emissions. As carbon prices increase, biomass-CCS becomes increasingly cost effective and with sufficiently high prices ($\sim 200 \, \$\, tC^{-1}$) biomass-CCS becomes the least-cost electric sector technology.

Mitigation costs can be read directly from Fig. 4 as the carbon price where electricity costs from a particular mitigation technology equals that of the conventional baseline generation technology. From the case illustrated, the mitigation costs are calculated as 102, 123, and 135 $ tC^{-1} for the base case, capture system without reform, and capture system with reform, respectively—assuming pulverized coal as the conventional baseline technology. These results should not be interpreted too precisely, due to our simplified modeling techniques. However, they do indicate mitigation costs for BIGCC-CCS to be somewhat higher than those expected from fossil fuel systems with CCS [23]. While we believe that process and component technology optimization will likely improve these economics, our results do not suggest that biomass-CCS will dramatically reduce mitigation costs from biomass or in the electric sector more generally. However, even without substantial improvements, biomass-CCS will likely be cost-competitive, and substantially reduce total mitigation costs, for mitigation beyond the electric sector (via emissions offsets)—where, as discussed above, costs may exceed 1000 $ tC^{-1}. In this context, biomass-CCS may eventually face competition from technologies for direct capture of CO_2 from the air. However, such systems are substantially less proximate and more uncertain than biomass-based options. As such, biomass-CCS has the potential to expand the niches available for biomass-based mitigation.

We assume pulverized coal combustion (PC coal) as the baseline electric sector technology for mitigation cost calculations. As shown in Fig. 4, however, switching from PC coal to combined cycle natural gas turbines (GTCC) could provide zero cost mitigation, and would push the mitigation cost of biomass up to nearly 200 $ tC^{-1}—with or without CCS.

This interpretation hinges on the cost of natural gas. Natural gas prices are historically variable and estimates of future prices are highly uncertain. The natural gas price used here, 3.46 $ GJ^{-1}, is likely optimistic given current futures market expectations [24]. Moreover, a wholesale conversion of the electric sector to natural gas, implied by the interpretation outlined above, would dramatically increase demand and drive up fuel costs. Under our assumptions, GTCC is *never* the least cost technology if the natural gas price were to increase by 40%. Uncertainty about gas prices may encourage power companies to maintain significant coal generation in their portfolios as a hedge against natural gas price fluctuations. Of course, uncertainty about future carbon constraints will weigh against building new PC coal, but not against maintaining existing units. In short, while GTCC is very important, we believe PC coal is the appropriate baseline for mitigation cost estimates, as presented in Table 2.

As noted above, a design alternative providing reformer heat by diverting and burning a portion of hydrogen-rich fuel gas (post carbon capture), rather than unreformed syngas, was explored to increase the carbon available for capture. This option yields net efficiency, carbon capture rate, specific capital cost, and mitigation cost of 21% (HHV), 62%, 2.29 $ W^{-1}, and 152 $ tC^{-1}, respectively, continuing the trend of increasing carbon capture with increasing cost.

Finally, experimental data from the Battell/FERCO designed pilot plant facility in Burlington, Vermont, show that the syngas composition from the pilot plant matches closely with that modeled here and that this composition is relatively insensitive to variations in fuel type, moisture, or feed rate [20]. However, the data do suggest two possible updates to the model presented here. First, the maximum capacity of the pilot plant has

been demonstrated to be 75% greater than the design capacity. This suggests a potential 32% reduction in the gasifier's specific capital cost $[1-(1/1.75)^{0.7}]$ relative to the current modeling assumptions. Second, the carbon conversion rate of the pilot plant is closer to 60% compared with nearly 70% currently modeled. This decreased carbon conversion would translate into decreased net plant efficiency, decreased carbon capture efficiency, and increased specific capital costs. Incorporating these values yields net efficiency, carbon capture rate, specific capital cost, and mitigation cost of 21% (HHV), 47%, $1.84\,\$\,W^{-1}$, and $152\,\$\,tC^{-1}$, respectively, for the biomass-CCS system with steam reform.

5. Conclusions

The general arguments presented in Sections 1 and 3, and the specific system design of Section 2 demonstrate that the generation of negative atmospheric carbon emissions by integrating CCS and biomass energy technologies is both feasible and potentially important. The design discussed here represents one possible system; other designs will likely have technical and economic advantages (e.g., oxygen-blown gasification) and be easier to deploy in the near term (e.g., capture of bio-ethanol fermentation off-gases).

Regardless of the specific route, the ability of biomass-CCS to generate negative atmospheric carbon emissions could fundamentally change the role of biomass in achieving deep emissions reductions by providing a mechanism to offset emissions anywhere in the economy. These offsets provide additional flexibility to a broader portfolio of carbon mitigation strategies. Moreover, the well-mixed nature of atmospheric CO_2 implies that biomass-CCS offsets could mitigate emissions anywhere in the world, providing opportunities to affect agricultural economics in developing countries by subsidizing domestic consumption of primary agricultural commodities (i.e., energy products) with exported emissions offsets.

Finally, the mitigation costs associated with electric sector biomass-CCS appear similar to more conventional electric sector technologies.

Therefore, biomass-CCS should be considered more generally in the context of achieving deep emissions reductions. However, the mitigation costs associated with biomass-CCS are likely to be more compelling as emissions targets force mitigation beyond the large-scale, centralized sources of the electric sector.

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