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A commercialization strategy for carbon-negative energy

Daniel L. Sanchez and Daniel M. Kammen

Climate change mitigation requires gigatonne-scale CO₂ removal technologies, yet few examples exist beyond niche markets. The flexibility of thermochemical conversion of biomass and fossil energy, coupled with carbon capture and storage, offers a route to commercializing carbon-negative energy.

The Intergovernmental Panel on Climate Change (IPCC) envisages the need for large-scale deployment of net-negative CO₂ emissions technologies by mid-century to meet stringent climate mitigation goals and yield a net drawdown of atmospheric carbon. These CO₂ removal technologies complement low- or zero-carbon energy technologies^{1,2}. Industrial-scale sequestration of CO₂ from bioenergy production — a process known as bioenergy with carbon capture and sequestration (BECCS) — can produce fuels, chemicals and electricity while removing atmospheric CO₂. Yet there are few commercial deployments of BECCS outside of niche markets, creating uncertainty about commercialization pathways and sustainability impacts at scale³. This uncertainty is exacerbated by the absence of a strong policy framework, such as high carbon prices and research coordination. Here, we propose a strategy for the potential commercial deployment of BECCS via thermochemical co-conversion of biomass and fossil fuels, particularly coal, challenging governments, industry incumbents and emerging players to research and support these technologies.

Although biochemical conversion is a proven first market for BECCS, this trajectory alone is unlikely to drive commercialization of BECCS at the gigatonne scale. The early development of BECCS has been focused on biochemical facilities converting sugars to ethanol, a transportation fuel, for use in enhanced oil recovery and large-scale industrial sequestration demonstration⁴. Yet, biochemical conversion pathways are limited by the market size of fuel products, scale, sensitivity to biomass inputs, and throughput. For example, alcohol fuels from biochemical conversion processes face compatibility issues with existing transportation infrastructure, whereas

high lignin content inhibits biochemical conversion. Reaching gigatonne-scale carbon sequestration via this pathway will require at least fourfold higher ethanol production than current levels. Although proposals for large-scale bioenergy deployment focus on the conversion of lignocellulosic feedstocks to liquid fuels, BECCS is also valuable to the electricity sector^{2,5}.

Flexibility as a virtue

In contrast to biochemical conversion, thermochemical conversion of coal and biomass enables large-scale production of fuels and electricity with a wide range of carbon intensities, process efficiencies and process scales (Fig. 1). We focus on two representative thermochemical pathways: electricity production via integrated gasification combined cycle with CCS (IGCC-CCS), and long-chain hydrocarbon fuels production via gasification and the Fischer–Tropsch process with CCS (FT-CCS). Fischer–Tropsch and combined-cycle systems can be combined for polygeneration-CCS systems that produce both electricity and fuels. The energy and capital penalties of adding CCS are comparatively small for these processes, and, for FT, can reduce downstream equipment size requirements, further reducing capital costs⁶. Addition of biomass into coal gasification increases the ratio of H₂ to CO in syngas, which is beneficial for fuels production.

Other promising thermochemical pathways may complement IGCC-CCS and FT-CCS. For example, torrefaction — a mild thermal pre-treatment — improves biomass suitability for gasification⁷. Integration of reformed natural gas with syngas from coal and biomass presents further opportunities for electricity or fuels production, though this has been studied less extensively⁸. Likewise, synthetic gasoline production

via the methanol-to-gasoline process is a less widely implemented alternative to FT synthesis⁹. Alternatively, all of the carbon in the biomass feedstock could be converted to liquid fuels using external hydrogen and low-carbon electricity inputs from nuclear, renewable energy or hydropower¹⁰.

Thermochemical co-conversion creates flexibility for producers to balance product cost and carbon reduction goals. Incremental carbon reduction from these systems is cheaper when leveraging both CCS and biomass in concert^{6,11}. IGCC-CCS producers can adjust biomass, water–gas shift, and CCS integration to produce low-carbon or carbon-negative electricity, with lower-carbon-intensity systems having smaller scale and higher costs in the absence of supportive climate policy. Similarly, polygeneration producers can adjust biomass, CCS, or autothermal reformer integration (Fig. 1). Polygeneration systems with flexible ratios of fuel inputs or product outputs can increase profitability for producers, though at additional cost⁸. In addition to technical advantages, the flexibility of co-conversion is also advantageous for existing industries, supply chains and workforces. Here, firms can embrace a gradual transition pathway to deep decarbonization, limiting economic dislocation and increasing transfer of knowledge between the fossil and renewable sectors.

The scale of both biomass and co-utilization systems holds unique advantages. In the United States, dedicated biomass plants average half the efficiency of coal plants¹². Co-utilization systems can leverage economies of scale associated with coal inputs to increase efficiency and decrease unit costs, while lessening feedstock variability issues associated with biomass-only systems. Co-utilization also requires less biomass per unit product than biomass-only systems, which further extends

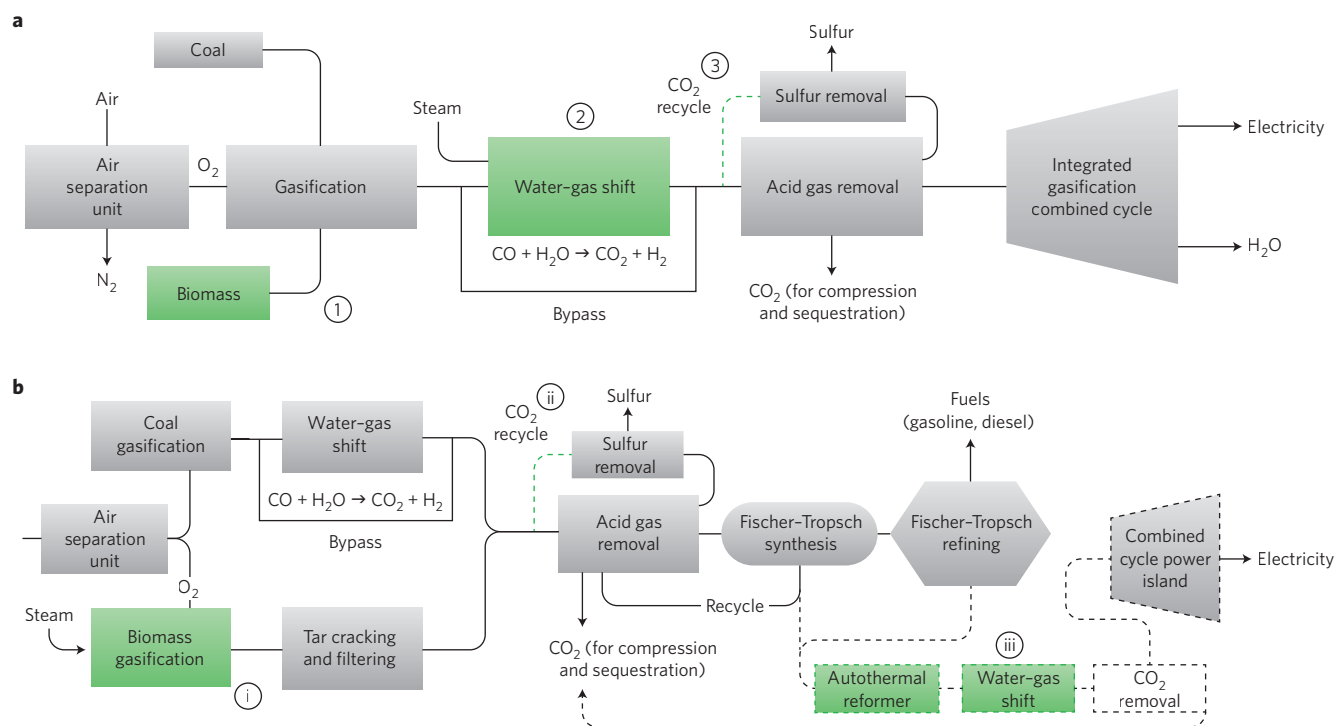


Figure 1 | Flow diagrams for carbon capture and storage processes. **a, b**, Simplified flow diagram for IGCC-CCS (**a**) and polygeneration-CCS (**b**) processes for production of electricity and fuels from coal and biomass. Green boxes and dashed green lines indicate options to decrease the carbon intensity of resulting fuel or electricity products. Dashed lines indicate optional process enhancements. Options to decrease the carbon intensity of products in IGCC-CCS systems include (1) increasing the ratio of biomass to coal inputs, (2) increasing the shift of syngas in the water-gas shift reactor, and (3) recycling CO_2 from the sulfur removal process to the acid gas removal system. For polygeneration-CCS, options include (i) increasing the ratio of biomass to coal inputs, (ii) recycling CO_2 from the sulfur removal process to the acid gas removal system, and (iii) autothermal reforming and shift prior to electricity production. Panel **a** is based on data from ref. 11 and panel **b** is based on data from ref. 6.

the impact of scarce sustainable biomass resources. Minimum capital expenditures for co-conversion systems are smaller than those for envisaged coal-to-liquid facilities, easing project finance⁶. In practice, many deployed biomass systems are several times smaller than coal-only systems, enabling greater experimentation at lower cost¹³.

This strategy is likely to work best in developed economies, such as the US. The US has relatively advanced bioenergy, hydrocarbon production and CCS sectors. Its advanced engineering, construction and financial industries are capable of commercializing new, risky, capital-intensive technologies. Other regions, such as Scandinavia and British Columbia, have considerable expertise in thermochemical conversion of biomass. Following technology development, other developing countries, particularly rapidly expanding economies dependent on coal, could deploy BECCS and avoid lock-in with conventional fossil fuel infrastructure. International development finance could help promote BECCS in these locations. In contrast, certain regions with large biomass resources and advanced alcohol fuel industries, such as Brazil, may rely on biochemical conversion

for BECCS in the future. Other developing countries could embrace biochar production for CO_2 removal¹. Spatial optimization can account for biomass supply limitations, transportation logistics, and geological CO_2 storage capacity, and help balance economies- and diseconomies-of-scale inherent in bioenergy production, including gasification^{2,8}.

Research and policy needs

Although most system components for fossil CCS systems are technologically mature, there are very few commercial deployments at scale. We expect near-term deployment of co-conversion systems to demonstrate technical feasibility and reduce investment risks. For example, the Buggenum IGCC project in the Netherlands has studied both biomass and CCS integration, whereas Total's BioTFuel project is focused on commercial deployment of torrefaction, entrained-flow biomass co-gasification, and FT synthesis^{9,14}. However, IGCC-CCS systems under construction in the US have faced cost overruns, construction delays and regulatory uncertainty. Alternative electricity system CCS configurations, including post-combustion capture or

oxycombustion systems, may face lower commercial hurdles while still maintaining the flexibility of IGCC-CCS.

Aside from systems integration, primarily technical barriers are involved in large-scale biomass logistics, gasification and gas cleaning. Ultimately, commercial-scale BECCS will require high-temperature, oxygen- or steam-blown, pressurized, entrained-flow gasification of multiple biomass streams⁷. Although fluidized-bed gasifiers are most commonly used for biomass gasification, coal-based entrained-flow gasifiers are more commercially advanced and exist at larger scale⁹. In addition to the logistical challenges in feedstock management of both coal and biomass, multiple revenue streams from polygeneration systems complicate business models for producers. Business models may be informed by existing multi-output bioenergy systems, like sugarcane biorefineries or pulp and paper mills, which produce electricity and heat in addition to their primary product.

In contrast, large-scale CO_2 storage faces deployment barriers. Delivery of identified, accessible, and permitted CO_2 storage requires upfront investment of monetary

and human resources¹⁵. This is a particular challenge in regions without a developed hydrocarbon exploration and production industry, which lack regulation, finance, knowledge, public trust and skills for geological sequestration. Natural analogues demonstrate the security of long-term CO₂ storage, but social acceptance remains a barrier in many regions¹⁶.

Existing policies and R&D programmes largely ignore the synergies enabled by co-conversion. At the US Department of Energy, the Office of Fossil Energy supports CCS demonstration and clean coal efforts, but does not focus on stand-alone biomass gasification. Similarly, the Biomass Energy Technologies Office focuses on feedstock logistics and biomass conversion, but does not support upstream fossil energy integration or CCS. Given their distinct expertise, future Department of Energy deployment programmes should take the form of a cross-cutting initiative. US biofuel policy, such as the Renewable Fuels Standard or California's Low-Carbon Fuel Standard, does not recognize co-conversion or the benefits of CCS integration. In the European Union, current EU Emissions Trading System policy does not recognize the potential for CO₂ removal from BECCS¹⁷. This can be remedied by revising accounting principles to include biogenic carbon storage. In addition to carbon pricing, policymakers can de-risk BECCS technologies by providing credit subsidies to first-of-a-kind plants, or tax credits for geological CO₂ sequestration. Like conventional CCS technologies, BECCS deployment may require a stable investment climate, such as price guarantees, in the absence of a sufficiently high carbon price¹⁸. Public-private partnerships may be an attractive vehicle to reduce risks and increase financing. Performance standards, rather than quantity mandates, can better recognize the performance of multiple process configurations to produce low-carbon or carbon-negative electricity or fuels.

We estimate cumulative capital investment needs for BECCS through 2050 to be over US\$1.9 trillion (in 2015 dollars with a 4% real interest rate) under stringent climate change mitigation scenarios, based on existing cost estimates and deployment values from IPCC Representative Concentration Pathway 2.6, which is likely to limit global warming to 2 °C (refs 2,19). This stabilization scenario envisages deployment of as much as 24 GW yr⁻¹ of BECCS by 2040, if installed as IGCC-CCS, at costs similar to current global cleantech investment rates. Regional allocation of carbon removal, a subset of all emissions reduction, is not yet established. To achieve

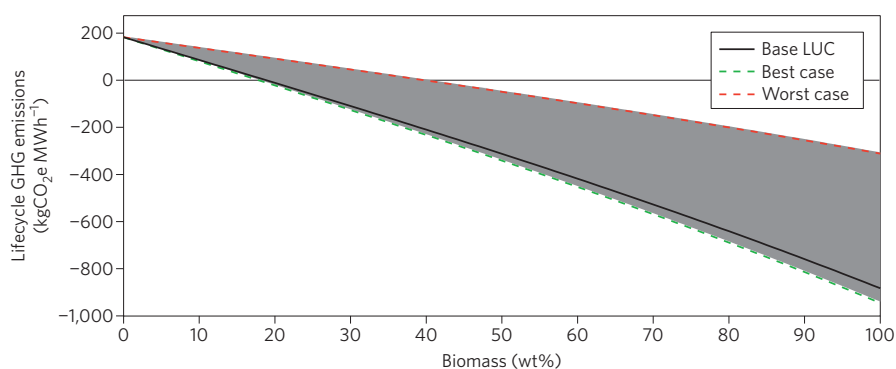


Figure 2 | Lifecycle GHG carbon intensity for IGCC-CCS facilities. Base (black line), best-case (green dashed line), and worst-case (red dashed line) lifecycle GHG performance intensity for coal and biomass IGCC-CCS facilities. The shaded region represents the range of carbon intensity. Biomass is assumed to be switchgrass (*Panicum virgatum*) grown in the United States. The IGCC-CCS facility is assumed to capture 90% of gross emissions¹¹. Assessment accounts for emissions in feedstock production, as well as modelled direct and indirect land use change (LUC) scenarios evaluated in GREET 2014²⁰, and assumes biomass regrowth. LUC scenarios contain differing assumptions about soil carbon sequestration (best case has deeper soil depth), crop yields (best case includes 1% yield increase each year), carbon in harvested wood products (best case includes credits for carbon sequestered in products), and emissions from land conversion (worst case includes more forest conversion for cropland). Performance intensity scenarios were modelled in GREET's Carbon Calculator for Land Use Change from Biofuels Production²⁰ over a thirty-year production period. Flexible generation systems can alter their levels of coal and biomass to achieve different lifecycle impacts.

this rate of deployment within 15–20 years, governments and firms must commit to research, development and demonstration on an unprecedented scale.

Uncertainty clouds deployment at scale

Key uncertainties around large-scale BECCS deployment are not limited to commercialization pathways; rather, they include physical constraints on biomass cultivation or CO₂ storage, as well as social barriers, including public acceptance of new technologies and conceptions of renewable and fossil energy, which co-conversion systems confound³. Lifecycle greenhouse gas (GHG) impacts of coal and biomass systems at scale are uncertain, due in large part to variation in estimates of direct and indirect land use change (LUC) resulting from biomass cultivation²⁰ (Fig. 2). Nevertheless, we find that switchgrass (a dedicated feedstock) integration decreases lifecycle GHG impacts of IGCC-CCS systems, across a wide range of LUC scenarios. Polygeneration systems may not be carbon-negative due to tailpipe CO₂ emissions⁶. Assumptions about counterfactuals and timing of emissions further complicate analysis of lifecycle impacts.

Other risks in large-scale biomass cultivation include adverse effects on food security, land conservation, social equity and biodiversity, as well as competition for water resources. Fuel and electricity from biomass may also face competition from heating

and manufacturing demands. Although modelling can help reduce uncertainty, actual measurement will be necessary to generate knowledge around the impacts of BECCS deployment²¹. An emerging biomass industry can embrace sustainability standards to help ensure environmental and social benefits. We envisage an iterative approach to sustainability, with standards being updated as more knowledge is gained through deployment. The IPCC and others have embraced iterative risk management as a framework for managing uncertainty and new information.

An agenda for transition

Despite sustainability risks, this commercialization strategy presents a pathway where energy suppliers, manufacturers and governments could transition from laggards to leaders in climate change mitigation efforts. Using the flexibility of thermochemical co-conversion, these entities could meet increasingly stringent climate policy, ultimately deploying commercial-scale BECCS facilities and transitioning away from fossil fuels. This transition strategy holds advantages for existing industries, supply chains, and workers, while sharing knowledge between the fossil and renewable energy sectors. Future plants would be able to avoid technology lock-in or unfavourable economics after policy changes by installing systems that can embrace biomass and CCS.

All stakeholders in the energy technology innovation system can work in concert to support this end, employing stable policy support, targeted and cross-cutting research and development, iterative risk management and commercial deployment. □

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