An integrated techno-economic and environmental assessment for carbon capture in hydrogen production by biomass gasification

Na Wu[a], Kai Lan[a] and Yuan Yao[a,*]

[a] *Center for Industrial Ecology, Yale School of the Environment, Yale University, New Haven. CT 06514, United States of America*

*Corresponding author: Yuan Yao, email: y.yao@yale.edu, telephone: 01 203-432-5475

Abstract

Bioenergy with carbon capture and storage (BECCS) is a potential solution addressing climate change, regional wildfires, and circular economy. This study investigates the economic and environmental performance of a BECCS pathway implementing carbon capture (CC) in hydrogen production via gasifying forest residues in the American West, by developing a framework that integrates process simulations, techno-economic analysis (TEA), and life cycle assessment (LCA). The results show that forest residue-derived hydrogen is economically competitive (\$1.52– 2.92/kg H_2) compared with fossil-based hydrogen. Incorporating CC increases environmental impact due to additional energy and chemical consumption, which can be mitigated by the energy self-sufficiency design that also reduces CC cost to \$75/tonne of CO_2 for a 2,000 dry short ton/day plant, or using renewable energy such as solar and wind. Compared to electrolysis and fossil-based routes with CC, only BECCS can provide carbon-negative hydrogen and is more favorable regarding human health impact and near-term economics.

Keywords

Carbon capture, Hydrogen, Biomass gasification, Techno-economic analysis, Life cycle assessment, BECCS

1. Introduction

Bioenergy with carbon capture and storage (BECCS) has the potential to limit global warming by providing net negative greenhouse gas (GHG) emissions (Donnison et al., 2020). The Sixth Assessment Report recently published by IPCC (Intergovernmental Panel on Climate Change) estimated the global cumulative CO_2 removal from BECCS from 2020 to 2100 to be as high as 30–780 Gt CO_2 (IPCC, 2021), contributing to the Paris Agreement's target to limit the temperature increase to 1.5 °C (Torvanger, 2019). Furthermore, BECCS provides a non-fossil energy alternative and is vital in promoting energy security (Fajardy and Mac Dowell, 2018). The energy and climate benefits of BECCS have led to increasing interest in the research, development and deployment of BECCS, e.g., biomass carbon removal and storage ("BiCRS") systems in the United States (Fajardy et al., 2019; Galik, 2020; New Energy and Industrial Technology Development Organization, 2021; Rosa et al., 2021).

BECCS cover various biochemical (e.g., ethanol fermentation) and thermochemical conversion pathways (e.g., combustion, gasification, and pyrolysis (Bui et al., 2021; Cheng et al., 2021; Hanssen et al., 2020)). Compared to biochemical pathways, thermochemical pathways have many advantages, such as lower purification requirements and higher flexibility in feedstocks, products, and scalability (Sanchez and Kammen, 2016; Shahbaz et al., 2021). Among different thermochemical pathways, gasification is promising in fuel decarbonization and supporting circular economy (Nunes, 2022). Gasification thermally breaks down biomass into syngas, a mixture of gases such as CO, CO_2, and H_2. H_2 is an essential industrial gas in the oil and chemical industry and a carbon-free fuel (Salkuyeh et al., 2018). Hydrogen from biorenewable sources is considered more environmentally preferable than hydrogen made from fossil fuel resources. It was estimated that solid biomass in the United States can supply 48 million metric ton (MMT) of hydrogen per year (Connelly et al., 2020), which are larger than the hydrogen demand estimated in the literature (22 to 41 MMT/year) (U.S. DOE, 2020a). Given the high tolerance of heterogeneous biomass feedstock, gasification has been explored to convert various waste materials (e.g., municipal solid wastes) to H_2 and valuable chemicals as a circular economy enabling technology (Bhatia, 2014). The process is also less prone to emission problems (e.g., sulfur-containing emissions compared to the flue gas from post-combustion systems) for carbon capture (CC) since gas cleaning is already an essential part of the process (Neubauer and Liu, 2013). Some regional assessments show the advantages of gasification. For example, Baker et al. (2020) assessed different negative emissions pathways (natural solution, BECCS, and direct air capture) and concluded that gasification of the solid biomass types to produce hydrogen has the largest promise for CO_2 removal at the lowest cost in California. Given the growing interest in the circular economy and the urgent need for decarbonization, gasification-based BECCS to produce hydrogen shows great promise in contributing to a more sustainable, circular, and low-carbon society, yet needs more understanding for its impacts directed to these potentials.

Previous studies have used techno-economic analysis (TEA) or life cycle assessment (LCA) to assess the economic feasibility and environmental impacts of gasification-based BECCS (Andrea Corti, 2005; Ghiat et al., 2021; Oreggioni et al., 2017; Rhodes and Keith, 2005; Valente et al., 2019). These studies have focused on biomass-based integrated gasification combined cycle

(IGCC) systems with post-combustion CC. A systematic literature review on TEA and LCA of biomass gasification for hydrogen production is provided in Supplementary Materials (SM) Section 1 Literature Review. The review shows that most TEA and LCA studies of gasification systems focus on hydrogen production without considering CC. Several studies have mentioned the importance of electricity sources in biomass co-gasification/gasification systems (Arnaiz del Pozo et al., 2021a; Martín-Gamboa et al., 2016), yet the effect of energy supply choices and strategies have not been fully explored. For example, Susmozas et al. (2016) show that adding CC contributes to negative carbon impact but at the price of worse life cycle environmental impacts compared to the system without CC. The authors highlighted the improvement opportunities of minimizing external electricity demand and direct air emissions, although the study does not analyze specific strategies. BECCS systems consume energy not only in the hydrogen production steps such as gasification, product cleaning, and hydrogen purification (Ahmed et al., 2012), but also in the carbon capture steps, which are typically energy-intensive (Roussanaly et al., 2021). The means to provide energy (e.g., internal generation or external supply, renewable or fossil) are important to determine the economics (Arnaiz del Pozo et al., 2021b) and environmental impacts (Susmozas et al., 2016) associated with energy consumption. In addition, few studies (Antonini et al., 2021) have considered impact categories beyond climate impact. Process-level analysis for different energy supply strategies and a broad range of impact indicators are essential in understanding the practical decarbonization role of BECCS with a consideration of other environmental impacts.

Not all CO_2 emission sources within a biorefinery are considered in previous LCA and TEA of BECCS systems. For example, Antonini et al. (2021) investigated the life cycle environmental impact of hydrogen production from wood gasification systems by taking the hydrogen end-use into account, which shows possible negative total GHG emissions for fuel cell electric vehicles using hydrogen from biomass. This study includes CO_2 from syngas but not CO_2 from gas cleaning off-gas and energy generation (i.e., steam and electricity). Salkuyeh et al. (2018) performed a TEA and an LCA to compare different gasification systems with CC. Their system captured CO_2 from syngas and flue gas stream of the steam and power generation but did not capture CO_2 in gas cleaning and gasification off-gas. Susmozas et al. (2016) conducted an LCA for hydrogen derived from short-rotation poplar biomass through gasification coupled with CC, and the study only includes CO_2 from the exhaust gas of the boiler. Both Salkuyeh et al. (2018) and Susmozas et al. (2016) captured CO_2 emissions of internal energy generation, but they have not explored how different energy supply strategies would affect CO_2 capture and overall decarbonization potential of their BECCS systems. Holistic understandings of the complex interactions between energy supply strategies and CC implementation are critical to simultaneously maximize the carbon removal potential and energy efficiency of BECCS.

This study addresses these knowledge gaps by developing an integrated techno-economic-environmental assessment (TEES) framework. The framework integrates process simulations, TEA, and LCA for gasification-based BECCS using forest residues prevalent in the Pacific Northwest U.S., where large volumes of biomass are available, and there is a pressing need to thin forests to mitigate severe wildfire. Sensitivity and scenario analyses were conducted to identify critical driving factors and understand the impacts of different energy supply strategies. The analysis includes all CO_2 emission sources within a gasification biorefinery and explored how different energy supply strategies would affect CO_2 capture potential and costs. Process-level TEA and LCA examined how recent and future carbon prices and renewable energy access might incentivize BECCS deployment and affect the economic and environmental performances of different system design. In addition to climate impact, the LCA includes other environmental impact categories such as human health, eutrophication, acidification, ecotoxicity, and others. Although this study focuses on forest residues, the knowledge generated from this study can inform future research and large-scale deployment of BEECS for other waste feedstocks or in other regions.

2. Methods

The TEES framework connects mass and energy flows from process simulation with engineering economics for TEA and life cycle inventories (LCI) for LCA. The process model was developed in Aspen Plus V11 (AspenTech, 2022). The detailed mass and energy balances from engineering rigorous process simulations provide physically sound data for TEA and LCA (Wu et al., 2021). A discounted cash flow rate of return analysis was conducted to calculate economic metrics, including CAPEX, OPEX, and minimum selling price (MSP) of H_2 and CO_2 (which is equivalent to the levelized cost of CC in this study (Lan et al., 2021a). A scenario analysis was developed to address the CC integration and energy supply strategies, which are often overlooked or insufficiently addressed in previous research (Roussanaly et al., 2021). For each scenario, TEA and LCA were performed to evaluate the process efficiency, financial performance, and life cycle environmental impacts. Moreover, a sensitivity analysis was applied to determine the effects of parameter variations on economic performances. The system boundary includes biomass production and transportation and all the unit operations in the biorefinery. CO_2 transportation and storage after CC is not considered.

2.1. Process description and simulation

Fig. 1 shows the system boundary of the BECCS system in this study. The process model within the plant boundary includes eight component subsystems: biomass preparation (size reduction and drying), gasification, syngas clean-up, water-gas shifting, CC, pressure swing adsorption, air separation unit, and heat power generation. After the feedstocks arrive at the plant, forest residues are crushed to reduce the particle size and dried from 25 *wt*% moisture (Cao et al., 2020; Haarlemmer, 2015; Motta et al., 2018) down to 10 *wt*% on a wet basis (Ståhl et al., 2004; Svoboda et al., 2009) to be suitable for gasification. After biomass preparation, dried forest residues are fed to the gasification system. The gasification system employs a dual fluidized bed gasifier/reactor (DFBR) consisting of a gasifier and a combustor. The combustor oxidizes the residual char from the gasifier to provide heat for the endothermic gasification reactions in this study. The gasifier and combustor are interconnected by circulating bedding-olivine with catalyst MgO (Spath and Ringer, 2005). Steam is used as the gasifying agent. The produced syngas and solids exit the gasifier and flow to the cyclone separators, where particulates are removed from the hot gas. The removed particles such as ash are landfilled. The raw syngas leaving the cyclone then passes through the tar removal system, where the tars and other unsaturated hydrocarbon compounds are converted into hydrogen and carbon monoxide using the alumina-based catalyst.

Syngas is then further cooled through a heat exchanger by cooling utilities. The Rectisol process® (developed by Linde and Lurgi) (Burr and Lyddon, 1998; Kohl and Nielsen, 1997; Taheri et al., 2018) is used to clean the syngas by removing acidic gas (sulfur) for syngas cleaning (see details in Section 2.1.2). The excess scrubber water is sent for wastewater treatment. After syngas clean-up, partial syngas (30%) is sent to combined heat and power generation (CHP) for power self-sufficiency, depending on the scenarios that are discussed in Section 2.1.3 The rest of the syngas goes through the water-gas shifting process, which includes the high-temperature shift (HTS) and low-temperature shift (LTS) to convert CO and water into CO_2 and H_2. The gas mixture then goes to the CC section, which uses amine-based scrubbing solvents for CO_2 capture. To obtain high purity hydrogen (99.9 *vol*%), a pressure swing adsorption (PSA) unit is used to separate the impurities such as CO_2, and CO, CH_4, and other hydrocarbons. The off gas from PSA is sent to CHP for energy recovery. For the combustion procedures (gasification and CHP), oxyfuel is deployed using an air separation unit (ASU) to enrich the CO_2 concentration in the flue gas (Borgert and Rubin, 2013; Kather and Kownatzki, 2011). The air separation unit also provides nitrogen to the Rectisol process for CO_2 and H_2S separation. The CO_2-enriched flue gas from gasification and CHP are also sent to the CC section to obtain purified CO_2 (more than 99.5 *mol*%).

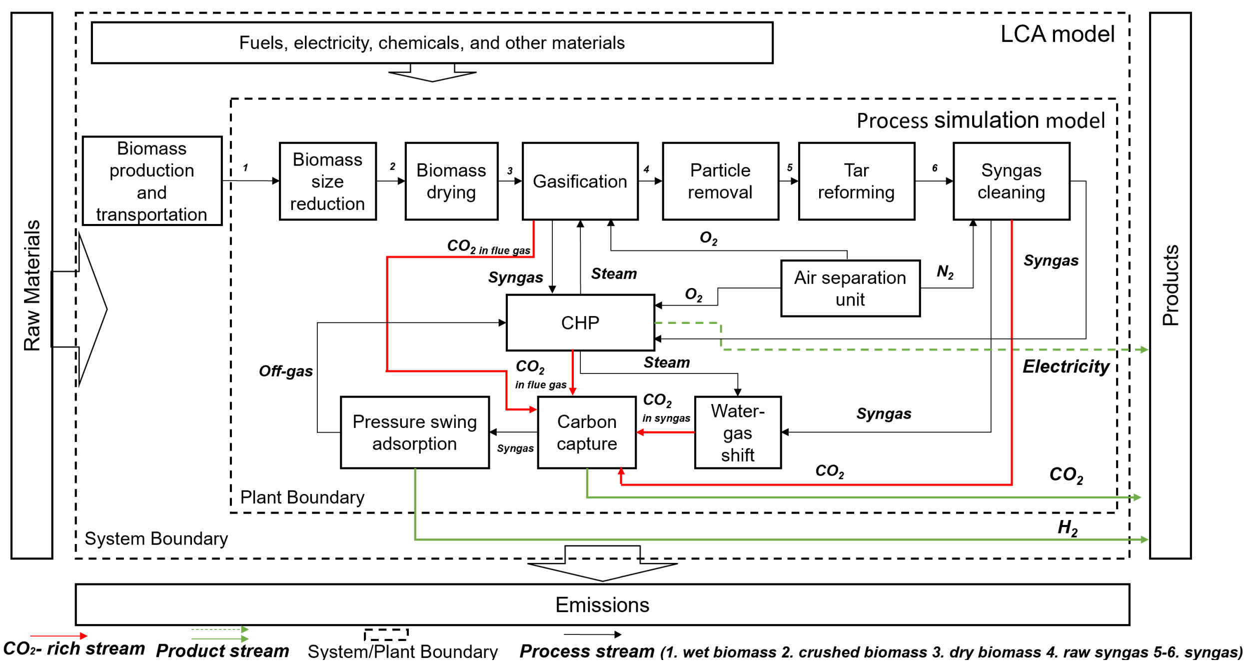

Fig. 1. The system boundary of hydrogen production by biomass gasification with CC. The system boundary represents the boundary of LCA and TEA. Plant boundary represents the boundary of process simulation for the biorefinery.

2.1.1. Biomass characteristics

Forest residues in the Pacific Northwest region are used as biomass feedstock, specifically, Douglas fir and Ponderosa pine (mass ratio 1:1 in this study). The average composition of forest residues is shown in Table 1.

Table 1. The average composition of forest residues used in this study.

Components	Value
Proximate analysis (wet basis, w%)	
Moisture	25.00
Fixed carbon	13.05
Volatile matter	61.50
Ash	0.45
Ultimate analysis (dry basis, w%)	
Carbon	52.34
Hydrogen	6.35
Oxygen	40.54
Nitrogen	0.14
Sulfur	0.03
Ash	0.60

Note: See Table S1 in SM for data references.

Feedstock particle size affects heat and mass transfer conditions. In general, the smaller particle size of feedstock contributes to higher syngas yield and conversion efficiency (Parthasarathy and Narayanan, 2014). However, an increased portion of particles with a size less than 1 mm results in less hydrogen in the product gas, while the other gases (CO and CH_4) are more along with increased tar concentration in DFBR (Wilk and Hofbauer, 2013). Fluidized bed gasifiers can handle fuels with particle diameters varying between 0.1 and 20 mm (Wood and Branch, 1986). The biomass particle size in this study is assumed to be less than 2 mm after biomass preparation for favorable conditions for product yields, process efficiency, and energy consumption (Andre et al., 2020; García-Labiano et al., 2016; Sansaniwal et al., 2017; Shahbaz et al., 2021).

2.1.2. Key modeling assumptions and methods

Process modeling and simulation have served as a powerful tool for analyzing gasification technology (Meramo-Hurtado et al., 2020). The plant scale in the process model in this study is assumed to be 1,500 dry short tons/day (1,361 dry metric tons/day) of feedstock. Different scales were explored to understand the impacts of scales (from 100 to 5,000 dry short tons/day). This study used the thermodynamic property package Peng-Robinson with the Boston-Mathias modifications (PR-BM) in Aspen Plus models, which have been widely recommended for high-pressure hydrocarbon applications such as gas-processing, refinery, and petrochemical processes (Gonzalez-diaz et al., 2021; Huang and Jin, 2019; Zhang et al., 2021). The process model employs different property methods to represent the thermodynamics associated with each process section.

For example, the "SOLIDS" property method (Aspen Technology Inc., 2001) is used for biomass size reduction since it is designed for solids processing, where biomass and ash were specified as non-conventional components. The HCOALGEN and DCOALGEN models (Aspen Technology Inc., 2001) were used for calculating the enthalpy and density of the solids, respectively. The CC section uses "ELECNRTL" to handle molecular interactions for electrolyte solutions where monoethanolamine (MEA) is the solvent, this method was chosen given its capability to handle mixed solvent systems at any concentration (Aspen Technology Inc., 2001). The "Peng-Robinson" model was used for the syngas cleaning and air separation sections, and this method uses advanced alpha function and asymmetric mixing rules to accurately model polar, non-ideal chemical systems (Bisotti et al., 2021; Yu et al., 2021). An overview of the units and operating conditions in each section is presented as in SM Section S2 Units and Operating Conditions.

2.1.3. Scenario analysis

Separating CO_2 from different gas streams requires additional energy and expenditure, and generates environmental footprints. At the same time, the energy supply and fuel options for hydrogen plants have direct impacts on CO_2 quantity and sources (biomass versus fossil fuels). To investigate these complex interactions in the poly-generation system, the scenario analysis emphasizes CC implementation and energy supply options, as well as evaluates economic metrics and environmental impacts of different scenarios. The results of the scenario analysis will contribute to a better understanding of implementing heat and power supply strategies and the choice of CC. Table 2 outlines the scenario analysis settings adopted in this study.

Table 2. Scenario analysis settings.

	Scenario 1 Fully Electricity Self-Sufficient	Scenario 2 No CC	Scenario 3 Partially Electricity Self-Sufficient	Scenario 4 External Electricity
CC	Yes		Yes	Yes
CHP	Yes	Yes	Yes	
Combusting partial syngas for energy self-sufficiency	Yes			

Note: CC: Carbon Capture. CHP: Combined Heat and Power. Energy self-sufficiency: The biorefinery fulfills its energy requirement.

Scenario 1 includes CC and CHP, and combusts partial syngas in CHP to reach electricity self-sufficiency. As electricity is a valuable co-product that is often explored in previous TEA and LCA for biomass-based systems (Echeverria et al., 2021; Lan et al., 2021a), 30% of syngas (International Energy Agency Greenhouse gas R&D Programme, 2008) was modeled in Scenario 1 that not only meets the internal electricity demand but also provides electricity surplus. Surplus electricity can be sold to the grid and bring additional revenue. For Scenario 2, the hydrogen production system does not consider CC, which is a baseline to understand the impacts of implementing CC in other scenarios. A CHP is deployed to burn the off gas from PSA (e.g., containing CO, CH_4, and remaining H_2) to reduce the overall system energy requirement. Grid electricity from US West is imported externally if the electricity supply is not sufficient. When surplus electricity is produced (Scenario 1), it is assumed to substitute grid electricity production mix from US West (WECC). Similar to Scenario 1, Scenario 3 considers CC technology to separate CO_2 from different CO_2 sources, including syngas, gasification off-gas, syngas cleaning off-gas, and CHP flue gas (as discussed in S2 of SM). Scenario 3 uses CHP to combust the off gas from PSA, representing a partially energy self-sufficient case (as the electricity generated from CHP is not sufficient to meet all internal electricity demand). Different from Scenario 1, all the syngas product is used for hydrogen production in scenario 3. Scenario 4 adopts CC technology but does not deploy the CHP plant. Instead, a combustor is used to recover heat from PSA off-gas and generate steam. All electricity demand in Scenario 4 is met by external CHP plants. Scenario 4 represents the least energy self-sufficient scenario.

2.2. Techno-economic analysis

The mass and energy balance data from the Aspen model were used to size, map the equipment, and build the capital and operating cost profiles. Additionally, the capital costs of gasifiers were collected from the literature (data in Table S2 of SM). Once the capital and operating costs were determined, a discounted cash flow rate of return analysis was conducted to calculate the minimum selling price (MSP) of hydrogen. The minimum selling price (MSP) corresponds to the product selling price that makes net present value (NPV) equal to zero, considering all cash inflows and outflows from capital repayments, operation and maintenance, revenues, income tax rates and tax reductions due to plant depreciation (Nguyen and Clausen, 2019). MSP is widely used by the U.S. Department of Energy (DOE) for funding decisions related to biofuels (U.S. DOE, 2022) and establishing technical targets for hydrogen technology development (U.S. DOE, 2020b).

2.2.1. Financial assumptions

Table 3 shows the financial assumptions used in this study, which are consistent with the previous process simulation studies by the U.S. national laboratories (Humbird et al., 2011; Jones et al., 2013; Spath and Mann, 2004). The chemical/material/energy prices are documented in Table S3 in SM. The prices are adjusted to 2018 USD using the Producer Price Index (PPI) (US bureau of labor statistics, 2022).

Table 3. Parameters for the discounted cash flow analysis.

Parameters	Value/assumptions	References
Location	U.S.	
Plant life	30 years	(Spath and Ringer, 2005)
Year of analysis	2018	
Plant capacity	1500 dry short tons of feedstock/day	
Operating hours	8410 hrs/year	(Humbird et al., 2011)
Discount rate	10%	(Spath and Ringer, 2005)
Federal tax rate	21%	(IRS, 2022)
Depreciation method	USA IRS Modified Accelerated Cost Recovery System (MACRS)	(Humbird et al., 2011)
Depreciation Period (Years)		(Humbird et al., 2011)

General Plant	7	
Steam/Electricity System	20	
Equity	40%	(Jones et al., 2013)
Loan Interest	8%	(Jones et al., 2013)
Loan Term, years	10	(Jones et al., 2013)
Working Capital (% of FCI*)	5%	(Humbird et al., 2011)
Salvage Value		(Humbird et al., 2011)
General Plant	0	
CHP Plant	0	
Construction Period (Years)	3	(Spath and Ringer, 2005)
% Spent in Year -2	8%	
% Spent in Year -1	60%	
% Spent in Year 0	32%	
Start-up Time (Months)	6	(Spath and Ringer, 2005)

*FCI is the total fixed capital investment, which is the sum of direct and indirect capital costs.

2.2.2. Cost metrics

This study includes several cost metrics, including CAPEX, OPEX, MSP of H_2, and CC cost. BECCS often produces multiple products, including hydrogen, carbon dioxide, electricity, and other products (char and hydrogen sulfide). Determining the cost metrics for a multi-product system is complicated as the production cost of one product is affected by the revenue of selling other products made in the same system. Therefore, in this study, we first analyzed CAPEX and OPEX for the entire BECCS biorefinery without distinguishing the cost of individual products, then the MSPs of H_2 and CO_2 were quantified to explicitly explore the hydrogen and carbon economics and their interactions with each other.

As a by-product of BECCS, the CO_2 price needs to be determined when estimating the MSP of hydrogen. Carbon prices have different types, such as an emission trading system, carbon tax, and carbon offset (The world bank, 2022). For example, in the U.S., the sequestration tax credit 45Q provides tax credits for carbon captured and sequestered, and the credit amount depends on the type of project (Congressional Research Service, 2021). Different carbon prices have been reported globally, depending on the policy and specific carbon programs. With this complexity in mind, this TEA study explored a range of carbon prices reported in the literature, which can help inform business and investment decisions by evaluating the impact of carbon prices on their operations, identifying potential revenue opportunities/risks, and testing the potential impact of climate change policies on their investment portfolios. In addition to geological storage, high purity CO_2 (more than 99.5%) can be sold as an industrial gas, although geological storage is more climate favorable and contributes to net carbon removal. Different CC and utilization pathways have been explored in previous studies, therefore not included in this study (Zimmermann et al., 2020).

2.3. Life cycle assessment

2.3.1 Goal and scope

We performed an ISO 14040 standard series compliant, attributional LCA of forest residue gasification with and without CC (depending on the scenarios).

The functional unit is 1 kg H_2 at a pressure of 30 atm with a purity higher than 99.9%. H_2 is usually the determining product given its mature market, choosing 1 kg H_2 as the functional unit allows for benchmarking and cross-reference comparisons with previous literature (Salkuyeh et al., 2018; Susmozas et al., 2016). To better understand the functionality of CO_2 removal, an additional functional unit of 1 kg CO_2 captured was included, allowing future studies for investigating different carbon negative technologies. The system boundary is cradle-to-gate, including raw material acquisition, transportation, and hydrogen production (see Fig. 1).

2.3.2. Inventory analysis

The LCI data of background processes were mainly obtained from ecoinvent database v3.6, unit model "allocation, cut-off by classification" (Wernet, et al., 2016), while the forest residue preprocessing and transportation data are from USLCI (National Renewable Energy Laboratory, 2012). The preprocessing includes collection, chipping (to improve transportation efficiency), and field drying. The transportation mode is a combination truck powered by diesel, the transportation distance is 68 km that covers the steps from the collection site to the regional storehouse and from the regional storehouse to the conversion facility. The LCI data of the foreground process (e.g., gasification) are from process simulations discussed above, and have been normalized based on 1 kg of hydrogen (the functional unit). The forest residue used for gasification is a product of sustainable forestry of two species (Douglas fir and Ponderosa pine) grown in the Pacific Northwest U.S. The CO_2 captured are assumed to be geologically stored permanently, but the costs and environmental impacts of further transportation to geological sites and storage are not included in this study. The electricity co-product credits (in Scenario 1) were estimated based on the substitution of grid electricity production mix in the western U.S. (WECC). The system expansion is used by following ISO standard 14044 to avoid allocation wherever possible (International Organization for Standardization, 2006). Other products such as biochar and hydrogen sulfide are cut off due to less than 0.1% contribution to the mass of total product outputs.

2.3.3. Impact assessment

The TRACI 2.1 method (EPA, 2022) was used for life cycle impact assessment (LCIA). The environmental impact categories cover ozone depletion, global warming, acidification, eutrophication, smog formation, human health impacts, ecotoxicity, and fossil fuel depletion.

3. Results and discussion

Based on the simulation results (mass and energy balance) of the biomass gasification plant, the TEA and LCA results are reported in this section. The technical parameters of the process model are presented and compared to the literature in the first section for model validation. Subsequently, the economic and environmental performance for different scenarios are presented. In addition, the trade-off impacts of CC integration into hydrogen production are discussed.

3.1. Process model and result validation

The syngas composition result of the process simulation is: 40.6 mol% of hydrogen, 14.7 mol% of CO, 10.4 mol% of CO_2, 34 mol% of water, and small amounts of other gases, which are consistent with the literature (Göransson et al., 2011; Pala et al., 2017). The mass and energy balance results are documented in Table S5 in SM. The carbon distribution is reported in Fig. S1 in SM and used to calculate the carbon capture rate that reflects the fraction by which carbon emissions are captured relative to the total carbon inputs (Trinks et al., 2020). The carbon capture rate of this study is 87% calculated by dividing the amount of carbon captured by the total amount of carbon inputs, including carbon in biomass and lean MEA solvent (0.3 mol%). The carbon capture rate in this study is higher than the literature value 31%–60% (Fernanda Rojas Michaga et al., 2022; Salkuyeh et al., 2018; Susmozas et al., 2016) because previous studies only considered one or two carbon emission sources (e.g., boilers or syngas). In contrast, this study considers all carbon emission sources in the biorefinery, including gasification, syngas, gas cleaning, and CHP. The carbon capture rate for BECCS in this study is also comparable with direct air capture (e.g., 85.4% and 93.1% depending on the electricity source) (Deutz and Bardow, 2021).

3.2. TEA Results

3.2.1 Production cost profiles

Fig. 2 presents capital expenditure (CAPEX) and yearly operating expenditure (OPEX) for all scenarios. Fig. 2 (a) shows that the gasification section is the major contributor to CAPEX for all scenarios. This agrees with previous studies on biomass gasification for other products such as electricity/hydrocarbon or coal-biomass co-gasification systems (Arnaiz del Pozo et al., 2021b; Schweitzer et al., 2018; Wang et al., 2013). The second-largest contributor to CAPEX is ASU. Similar high CAPEX of ASU have been reported in the literature (AlNouss et al., 2020; Ebrahimi et al., 2015; Ebrahimi and Ziabasharhagh, 2017; Prakash Rao and Michael Muller, 2007; Young et al., 2021). ASU provides pure oxygen instead of air to the combustion process so that a higher CO_2 concentration in the flue gas is obtained, facilitating the following CC. Moreover, ASU provides nitrogen for the gas cleaning section, which benefits the entire system through service sharing. Removing ASU will reduce CAPEX but significantly increase OPEX, given the need to purchase nitrogen and oxygen. To quantitatively explore this impact, a comparison of the BECCS system with and without the ASU was made (Table S7 of SM). It shows that the absence of ASU can increase or decrease the MSP of H_2 depending on the trade-offs between the increased cost for purchased O_2 and N_2 and decreased electricity cost and CAPEX.

Across four scenarios, Scenario 1 (Fully Electricity Self-Sufficient) has the highest CAPEX due to the additional capital needed for electricity self-sufficiency. The CAPEX is reduced as the electricity self-sufficiency is decreased in Scenario 3 (partially self-sufficient, 13% reduction of CAPEX) and Scenario 4 (all externally purchased electricity, 15% reduction of CAPEX). The highest CAPEX of Scenario 1 (Fully Electricity Self-Sufficient) is attributed to CHP and ASU. This is due to the higher capacity of CHP and ASU, which burn syngas and provide more oxygen for burning syngas, respectively. The benefit of electricity self-sufficiency is reduced OPEX, as shown in Fig 2.(b). Scenario 2 (No CC) has the lowest CAPEX, given the absence of CC. The incorporation of the CC section increases the total CAPEX by 9% (comparing Scenarios 2 and 3). Another CAPEX contributor is the PSA unit (8%–10% of the total CAPEX). The contribution of the rest of the operating units is minor. For Scenario 1, the annualized CAPEX (calculated using Equation S1 in SM) takes about 36% of the total hydrogen production cost.

Compared with CAPEX, OPEX results in Fig. 2(b) show different trends of scenarios. Scenario 1 (Fully Electricity Self-Sufficient) has the lowest OPEX because of the lowest utilities achieved by the full electricity self-sufficiency. In contrast, Scenario 4 (External Electricity) has the highest OPEX caused by the highest utilities, most from electricity purchases (75%). Another 25% of utility costs are for heat/cooling energy. The main contributors to electricity consumption are ASU (71%), PSA (18%), CO_2 compression (8%), biomass preparation (2%) and CC (1%). Although CC does not consume much electricity, it is the major contributor to heat/cooling energy (51%), followed by ASU (26%) and gas cleaning (23%). This is why the inclusion of the CC section increases the utilities by 20%, comparing Scenario 3 (Partially Electricity Self-Sufficient) with Scenario 2 (No CC). Including CC also increase the usage of other raw materials such as solvent and water by 1.8 folds.

In addition to utilities, the major contributor to the OPEX is feedstock cost (forest residues). The high contribution of biomass feedstock is consistent with previous studies (Li et al., 2020; Wang et al., 2019), where the cost of biomass accounts for at least 30% of the total production cost. Given the large contribution of feedstock costs, forest residue price is included in the sensitivity analysis to understand the impacts of varying feedstock prices.

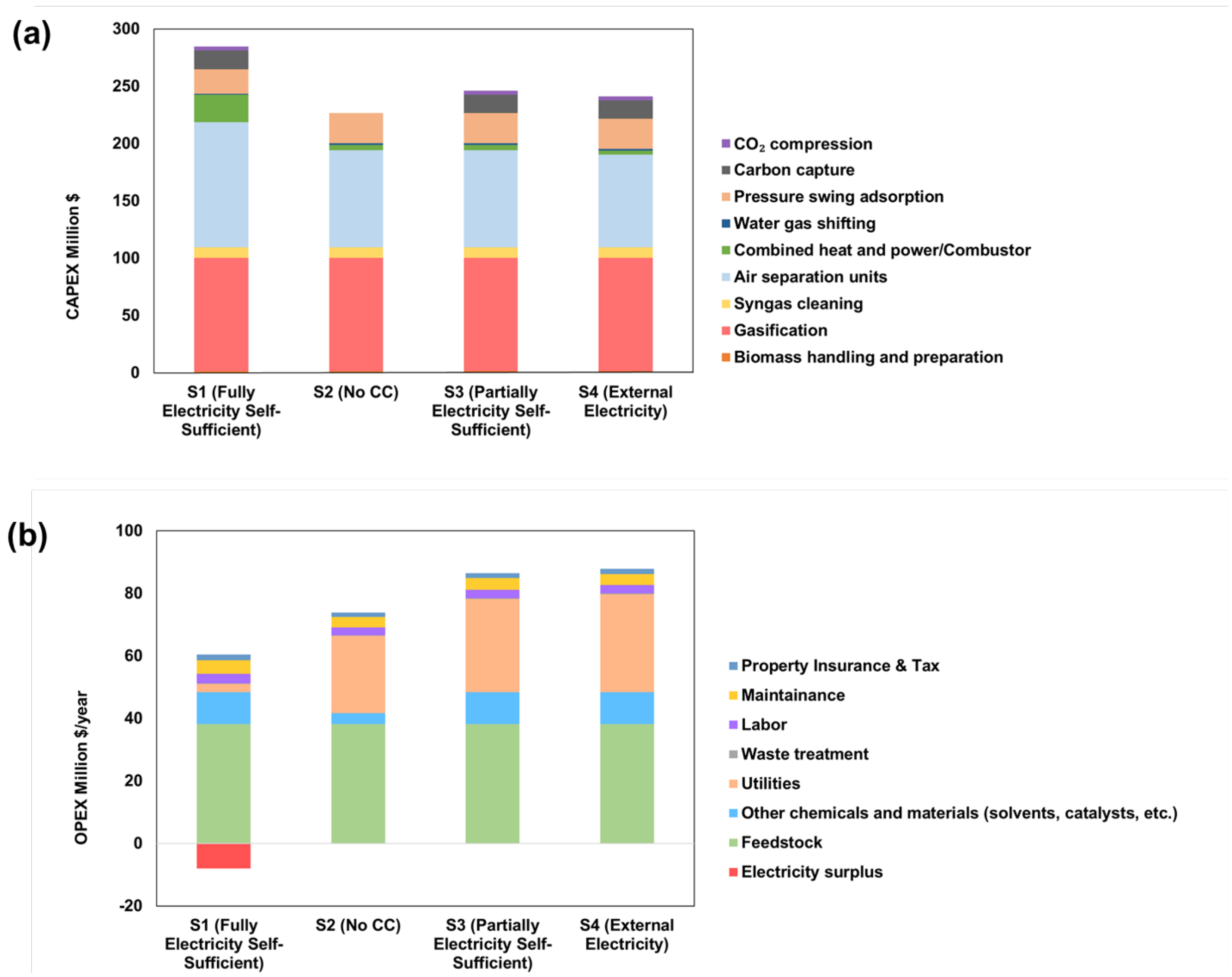

Fig. 2. Results of CAPEX (a) and OPEX (b) breakdown for four scenarios.

3.2.2. MSP of Hydrogen and carbon price

As discussed in Section 2.3, hydrogen cost depends on CO_2 price. Fig. 3 presents the effect of the CO_2 price on the hydrogen MSP in different scenarios. Scenario 2 (No CC) is a flat line as the exclusion of CC. Scenarios 3 (Partially Electricity Self-Sufficient) and 4 (External Electricity) are almost overlapped because of their similar CAPEX and OPEX (as demonstrated in Fig. 2). Blue areas represent benchmarked price ranges of H_2 made from fossil fuels with and without CC. The price of fossil-based hydrogen without CC ranges from \$0.9-1.78/kg H_2 (steam methane reforming, SMR) to \$1.2-2.2/kg H_2 (coal gasification) (IEA, 2020; National Research Council, 2004). When CC is included in SMR and coal gasification, their prices increase to \$1.2-2.6/kg H_2 (IEA, 2020; Parkinson et al., 2019). SMR and coal gasification were chosen as benchmark technologies because SMR contributes to 76% of the global H_2 production and coal gasification contributes to 22% (Lepage, et al. 2021). The carbon price benchmark (orange area in Fig. 3) uses the effective carbon rate of the U.S. reported by OECD (Organisation for Economic Co-operation and Development), which estimates an average carbon price from taxes and emission trading systems in different countries (OECD, 2021). According to this study, the carbon price in the U.S. is \$16.5/tonne in 2021 and the OECD benchmarked rate for the U.S. in 2030 is projected to be \$65/tonne.

Fig. 3 leads to two conclusions. First, forest residue-derived H_2 is economically competitive with current fossil-based H_2 with CC. The MSP of H_2 ranges from \$1.52 – 2.92/kg H_2 when the carbon price is \$0–65/tonne of CO_2. Scenarios 3 (Partially Electricity Self-Sufficient) and 4 (External Electricity) have similar MSP to coal-based H_2 with CC at a price of \$0 – 19/tonne of CO_2. With a carbon price higher than \$19/tonne of CO_2, Scenarios 3 and 4 are more economically favorable than coal-based H_2 with CC. Scenario 1 (Fully Electricity Self-Sufficient) has a similar MSP with fossil-based systems (SMR and coal gasification) with CC at \$16.5 – 85/tonne of CO_2. The benchmarked CO_2 price range (\$16.5 – 65/tonne of CO_2) is within the CO_2 price range which makes Scenario 1, 3, and 4 economically feasible. When the CO_2 price is higher than \$89/tonne of CO_2, all scenarios are more economically attractive than fossil H_2 with CC. Retrofitting CC from existing fossil-based facilities can be less feasible than newly built plants (Arasto et al., 2013), thus integrating CC into bio-based H_2 production can be practically attractive. Compared to coal gasification without CC, Scenarios 3 and 4 can be economically feasible with a CO_2 price higher than \$18.3/tonne. Scenario 1 needs a higher CO_2 price (≥\$33/tonne of CO_2) to achieve similar economic feasibility. Compared to SMR without CC, Scenario 1 needs a price higher than \$55/tonne of CO_2, and Scenarios 3 and 4 need a price higher than \$47/tonne of CO_2. These CO_2 prices are still within the benchmarked CO_2 price range (\$16.5 – 65/tonne of CO_2).

The second conclusion is that CO_2 prices determine the comparative economic competitiveness of three scenarios with CC. Scenario 1 (Fully Electricity Self-Sufficient) is less economically favorable when CO_2 price is low but more attractive when CO_2 price is higher than \$70/tonne of CO_2. The lower production rate of H_2 can explain this in Scenario 1, where syngas is combusted to achieve electricity self-sufficiency and thus a higher CO_2 price is needed to compensate H_2 loss (see Table S4 in SM for the production rate of H_2 and CO_2 in four scenarios). The incorporation of CC increases the hydrogen MSP by 7% by comparing Scenarios 2 (No CC) and 3 (Partially Electricity Self-Sufficient) at a CO_2 price of \$0/kg. However, revenue from CO_2 more than fully offsets the additional cost of CC when the carbon price is greater than \$12/tonne. Fig. 3 also includes a benchmark for electrolyzed H_2 with a much higher price (~\$3.2-7.7/kg H_2) (IEA, 2020; IRENA, 2020). Forest residue-derived H_2 is much more economically feasible based on the MSP shown in Fig. 3, compared to the current cost of electrolyzed H_2.

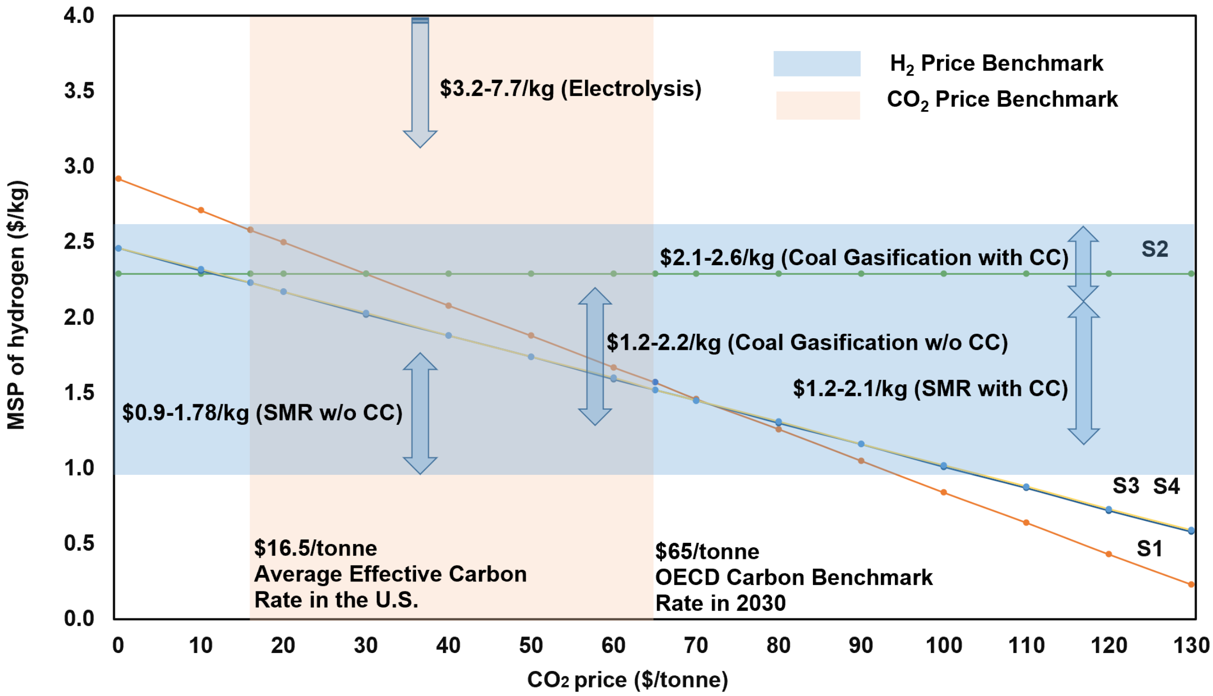

Fig. 3. Effect of the carbon price on the Minimum Selling Price (MSP) of hydrogen.

3.2.3. *Sensitivity analysis*

The sensitivity analysis focuses on understanding the effects of plant sizes and financial parameters with variations in this TEA. These parameters include financial assumptions that significantly impact the economic feasibility of biomass conversion technologies in general (Lan et al., 2021a), and prices of material and energy inputs, as listed in Table S3 in SM.

Fig. 4 (a-b) shows the hydrogen MSP and levelized cost of cost when the plant size varies from 150-7500 dry short ton/day of biomass for all scenarios. The levelized cost of CC was estimated as detailed in Section S7 of SM (Keith et al., 2018), which is the cost required for building and operating the CC units to the physical amount of CO_2 captured from the given point of hydrogen plant (IEA, 2021; Roussanaly, 2019; Roussanaly et al., 2021).The CAPEX of different plant sizes was estimated using a scaling factor of 0.6, the most commonly used value for chemical engineering unit operations (Tribe and Alpine, 1986). The OPEX components such as materials cost, waste streams, utilities, maintenance (OPEX except for labor), and production rate have been assumed proportional to the size of the plant and linearly adjusted based on the plant capacity. The labor cost was re-calculated for each case by using the empirical relationship between labor and plant capacity, process section number and operating hours of the plant (Peters, et al., 2003) (documented in Section 5 in SM). Fig. 4 (a) shows the MSP of hydrogen as a function of the plant capacity, where the carbon price is fixed at $16.5/tonne. The slope for plant's capacities between 150 and 2000 dry short ton/day is steep, resulting in a significant decrease in the MSP of hydrogen. For a plant size beyond 2,000 dry short ton/day, the MSP of hydrogen continues to drop but at a slower rate. On the other hand, increased size requires more biomass feedstock, which may be limited in some regions. In conclusion, the results show that it may not be optimal to build such BECCS biorefineries larger than 2,000 dry short ton/day from an economies of scale point of view.

Similar trends are observed in Fig. 4(b) where hydrogen price is fixed at the market price of \$1.26/kg (SMR w/o CC). Economies of scale have a more significant impact on CC cost at smaller sizes (150 and 1,000 dry ton/day), as shown in Fig. 4 (b). Although CC has a relatively low contribution (9%) to the total CAPEX, CO_2 is a primary product whose production increases in a greater proportion than the increase in its cost at smaller sizes. The comparisons among four scenarios show different trends in Fig.4 (a-b). In Fig. 4(a), Scenario 1 (Fully Electricity Self-Sufficient) has the highest hydrogen MSP, and the differences between Scenario 1 and other scenarios are diminished as plant size increases. However, the opposite trend is observed in Fig. 4(b), where Scenario 1 shows a lower levelized cost of CC than Scenario 3 (Partially Electricity Self-Sufficient) and 4 (External Electricity) (Scenario 2 is not included due to the exclusion of CC), and the differences between Scenario 1 and others increase as plant sizes increases. The different trends in Fig. 4 (a) and (b) can be explained by different product focuses. When the product focus is H_2, Scenario 1 is less favorable due to lower H_2 production (Table S4 in SM); on the contrary, when the product focus is CO_2, scenario 1 is more favorable given lower utility costs (as demonstrated in Fig. 2.b).

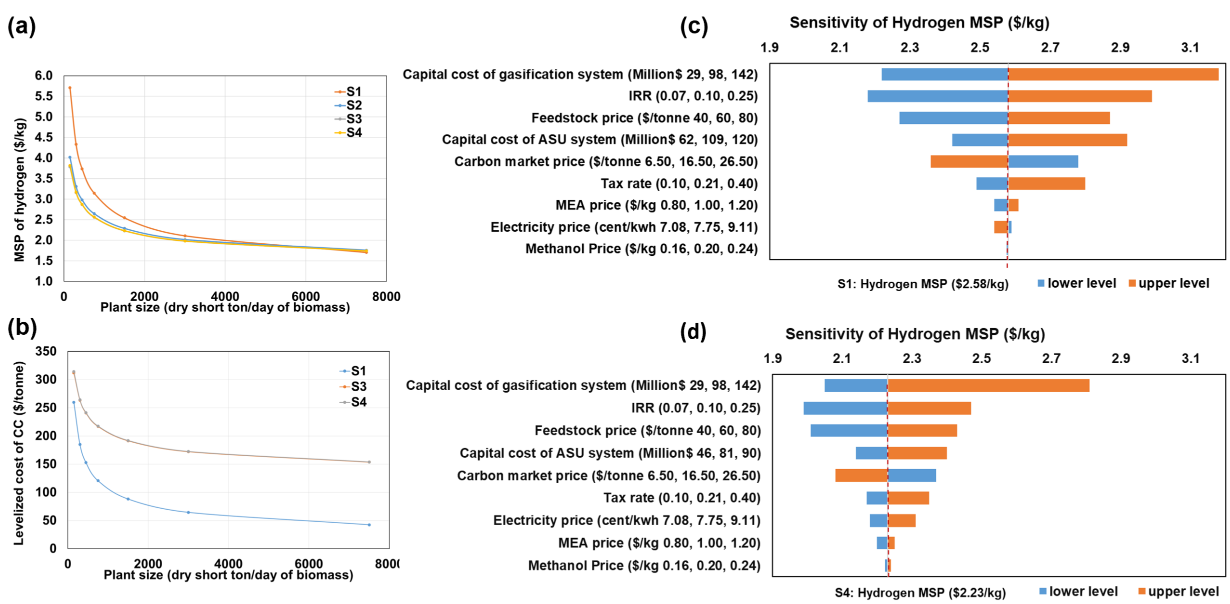

Fig. 4. Effect of plant size on the MSP of hydrogen (a) and the levelized cost of CC (b); Sensitivity (considering maximum and minimum values) of key parameters in Scenario 1 (Fully Electricity Self-Sufficient) (c) and Scenario 4 (External Electricity) (d). References for the uncertainty range of parameters are in Table S2 and Table S9 in SM.

Results from the sensitivity analysis of key parameters are presented in Fig. 4 (c) and (d) for the two extreme cases – Scenario 1 (electricity self-sufficient) and Scenario 4 (all electricity externally supplied). The uncertainty range of each parameter is based on the data points collected from the literature (Table S2 for gasification price data, Table S9 for other parameters). Only parameters with significant impacts on the results are shown (lead to > 0.1% variation of the results). The two scenarios have similar ranks for most parameters except electricity price that has opposite effects in Scenarios 1 and 4. Electricity price affects the revenue of selling surplus electricity in Scenario 1, therefore increasing electricity price decreases hydrogen MSP as shown in Fig. 4 (c). As electricity is purchased externally in Scenario 4, increasing electricity price raises hydrogen MSP, as demonstrated by Fig. 4(d). When more electricity is internally produced (Scenario 1), the biorefinery is more resilient to the electricity price fluctuations, although internal electricity production has higher hydrogen MSP at fixed and moderate electricity prices than other scenarios (discussed in Section 3.2.2 for Fig. 3.). It also indicates that hydrogen economics of Scenario 4 will likely be more sensitive to renewable energy access given its high sensitivity to electricity price. The gasification system can be of the greatest uncertainty due to the wide range of gasifier cost estimates from different literature (Table S2 in SM). The MSP of hydrogen is also sensitive to feedstock price, which is influenced by regional supply and demand, e.g., demand for alternative uses of forest residues such as for electricity and fuel production (Daioglou et al., 2016). The risk of volatilities in the feedstock price can be limited by developing partnerships with biomass suppliers (e.g., forest management corporations, communities) and establishing reliable logistic infrastructure for a steady cost. Following feedstock price, the MSP of hydrogen is also sensitive to CAPEX of ASU. With technology improvement, CAPEX could decrease and improve the economic feasibility of hydrogen. The substantial impacts of CO_2 prices have already been demonstrated in the previous section when CO_2 prices have large variations. Finally, the IRR (discount rate) has a significant impact on the MSP of hydrogen, this is due to the contribution of CAPEX, which directly connects to profitability. The tax rate and prices of chemicals such as MEA and methanol have minor influences on the MSP of hydrogen.

3.3. LCA Results

3.3.1. Life cycle impact assessment results of hydrogen production pathways

Fig. 5 presents the LCA results of four scenarios of biomass gasification and the comparison with alternative hydrogen pathways (hydrogen from electrolysis and fossil fuels with CC) based on the functional unit of 1 kg of H_2. The LCA results of scenarios with 1 kg of CO_2 as the functional unit are shown in SM Fig. S2. Across four scenarios in Fig 5 (a), Scenario 1 has the lowest environmental impacts on GWP, eutrophication, human health impacts (including carinogenics and non-carcinogenics, and respiratory effects), and ecotoxity. LCA results with 1 kg of CO_2 show similar trends (see SM Fig. S2). For the other environmental impact categories (i.e., ozone depletion, smog, acidification, and fossil fuel depletion), Scenario 2 without CC is the lowest. Excluding Scenario 1, Scenario 2 has the lowest results across all environmental impact categories compared to Scenario 3 and 4. The higher environmental impacts of Scenarios 3 and 4 are caused by increased energy and chemical (e.g., solvent) consumption, which are further discussed in Section 3.3.2. This observation concludes that implementing CC in gasification increases environmental impacts in general, however, some increased impacts can be substantially mitigated by self-sufficient energy design.

As Scenario 4 relies on imported electricity, environmental impacts could be much lower in the future if the electricity grid is deeply decarbonized or have a high degree of energy generated from renewable and low carbon sources. To explore the impact of renewable energy access, two additional cases were analyzed for Scenarios 1 and 4 by changing the electricity source from the current grid to solar and wind. The results are shown in SM Fig. S5 and S6. The results show that the electricity self-sufficiency design in Scenario 1 is no longer preferable when the biorefinery has access to solar and wind in Scenario 4. These results highlight the need to consider renewable energy access in biorefinery energy design. Future research can investigate the impacts of different grid decarbonization scenarios (Phadke et al., 2020; United States Department of State, 2021) on the optimal energy design of BECCS.

The life cycle GWP of Scenario 2 (No CC) is 2.99 kg CO_2 equivalent per kg of hydrogen produced (see LCIA results in Table S6). The life cycle GWP results in other scenarios are negative (-18.8, -9.71 and -9.56 kg CO_2 equivalent per kg of hydrogen produced for S1, S3 and S4, respectively), which are attributed to carbon sequestrated by biomass and captured by CC. Scenario 1 has more negative GWP than Scenario 3 and 4 since electricity is self-sustained instead of importing from the grid and CO_2 emissions from internal electricity generation in Scenario 1 are also captured. This result highlights the climate benefits of self-sufficient energy design for forest residue-based BECCS.

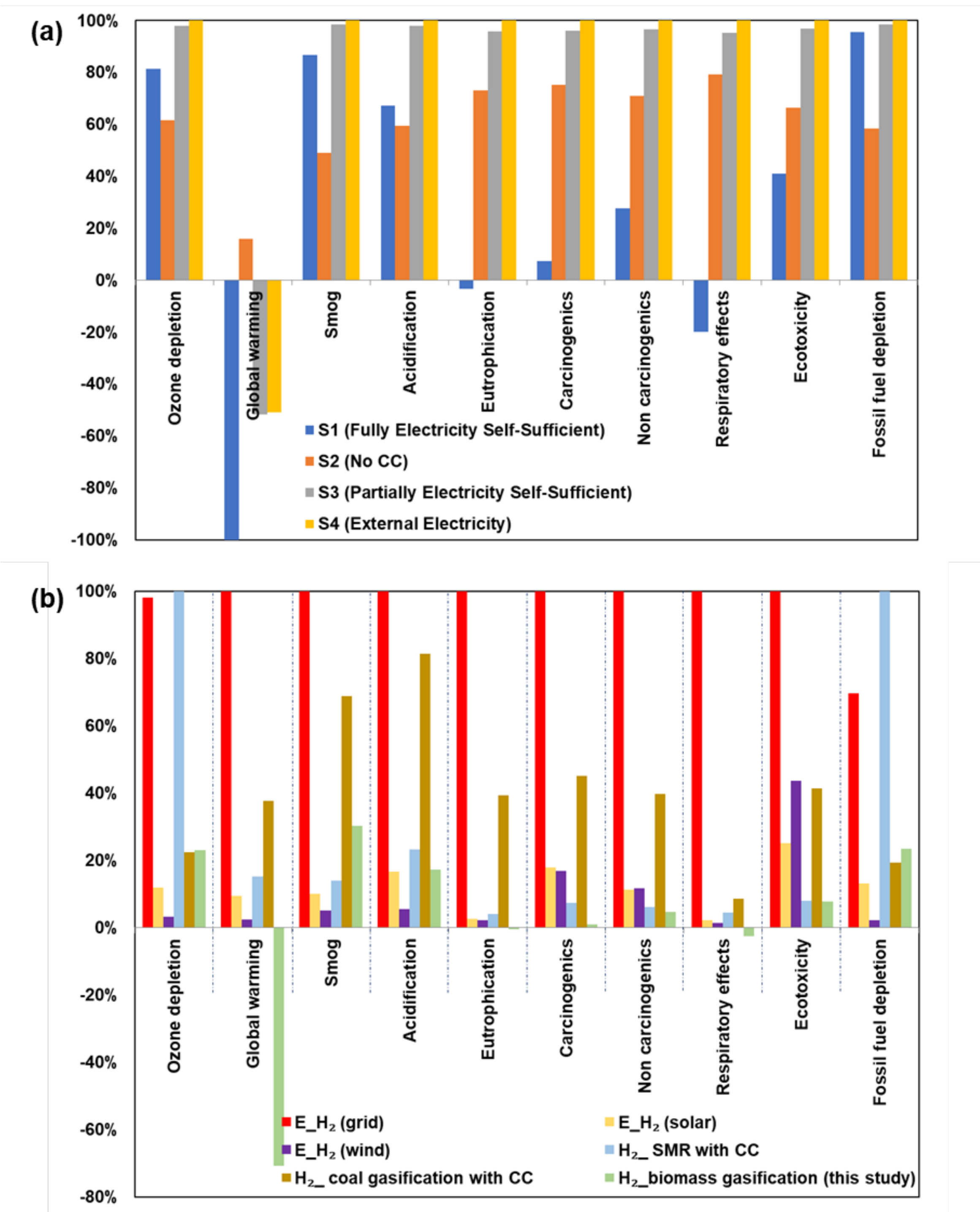

Fig. 5. Comparisons of LCA results of 1 kg of hydrogen (a) from biomass gasification in four scenarios. (b) from biomass gasification in Scenario 1, electrolysis (E represents electrolysis), and fossil-based routes.

Currently, hydrogen can be made from different sources, including SMR, coal gasification, and electrolysis from different electricity sources (grid, solar, and wind). In Fig. 5 (b), the life cycle environmental profiles of different hydrogen production alternatives based on harmonized literature data (Al-Qahtani et al., 2021) are compared at the same functional unit, 1 kg of hydrogen. The result shows that forest residue-derived H_2 has the greatest decarbonization potential compared to other alternative technologies. BECCS is the only pathway that provides carbon-negative hydrogen. Compared to fossil-based H_2, forest residue-derived H_2 has the lowest impacts across all categories, except ozone depletion, smog, and fossil fuel depletion, where BECCS has slightly higher results than SMR/coal gasification with CC, indicating the co-benefits of BECCS in decarbonizing and reducing environmental impacts of current hydrogen production. Compared to H_2 relying on grid electricity, forest residue-derived H_2 has lower impacts across all categories. Compared with H_2 using wind and solar, BECCS has advantages in GWP, eutrophication, ecotoxicity, and human health impacts, including carcinogenics, non-carcinogenics, and respiratory effects. However, these advantages do not hold for the other environmental impact categories (ozone depletion, smog, acidification, and fossil fuel depletion). Note that electrolyzed H_2 is much more expensive (3.2-7.7$/kg H_2) than other options, and the significant cost reduction needs to come from electrolyzer and electricity (IRENA, 2020), which are challenging to achieve in the near term. Therefore, BECCS is still a promising option for clean H_2 in the near term.

3.3.2. Contribution analysis

Contribution analysis of life cycle environmental impacts is presented in Fig. 6 (a) and (b) for the two extreme cases – Scenario 1 (electricity self-sufficient) and Scenario 4 (all electricity externally supplied), respectively. CC is the most significant contributor to all impacts in Scenario 1 due to its direct emissions (e.g., the solvent MEA evaporation, wastewater generation) and intensive energy and solvent consumption. For Scenario 4, electricity is the largest contributor, and this contribution can be reduced using renewable energy such as solar and wind (SM Fig. S3 and S4). Other than CC and electricity, gas cleaning and air separation make significant contributions to the results in both scenarios. The impacts of biomass feedstock production (shown as "Forest residue" in Fig. 6) are two-fold. On the one hand, it accounts for a favorable decarbonization contribution (i.e., negative percentage) due to CO_2 sequestration during biomass growth. On the other hand, biomass production has a relatively high contribution to smog formation and acidification that can be caused by machinery energy consumption (e.g., diesel) at the landing system where the forest residues are preprocessed (e.g., chipping) and logging residue are extracted (Ranius et al., 2018).

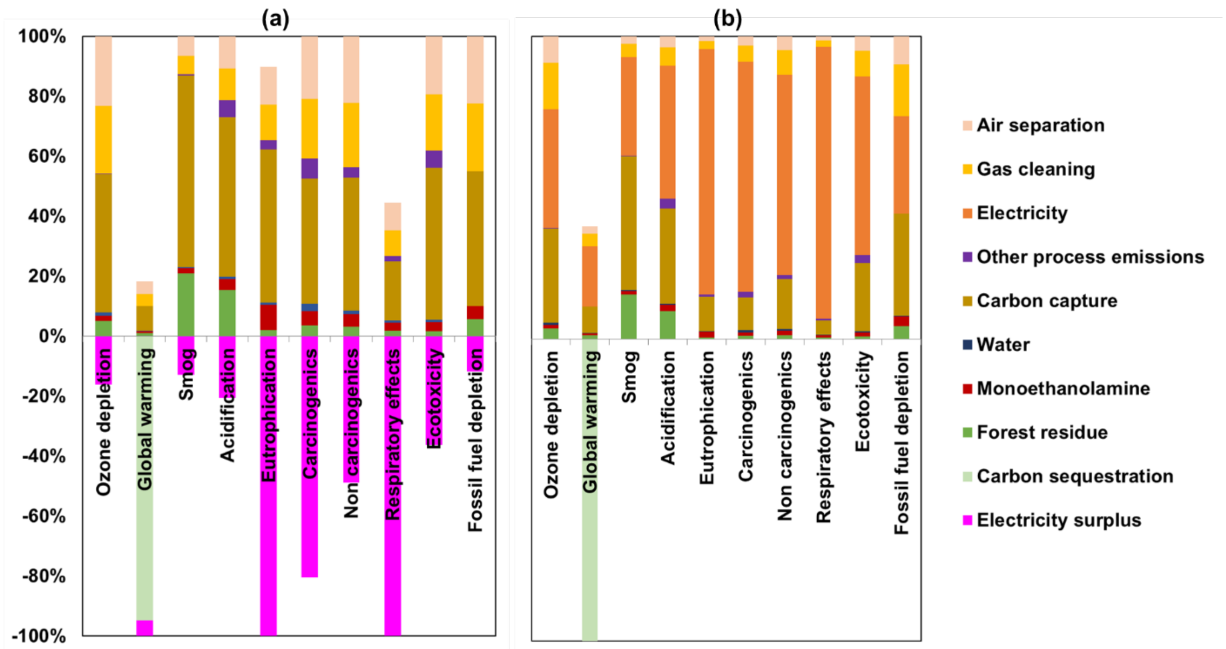

Fig. 6. Contribution analysis for the life cycle environmental impacts of S1 Fully Electricity Self-Sufficient (a) and S4 External Electricity (b).

3.4. Trade-offs and Co-Benefits between economics and environmental impacts

The different options for designing biomass gasification as a BECCS pathway result in trade-offs and co-benefits between economics and environmental impacts. Incorporating CC into biomass gasification increases environmental impacts, CAPEX, and OPEX; however, it improves H_2 economics, depending on the CO_2 prices. Energy self-sufficiency allows for maximum decarbonization and mitigates the increase in environmental burdens of the BECCS system caused by the CC section. It also reduces CC costs. These are co-benefits of energy self-sufficiency in carbon economics and environmental impact. However, energy self-sufficiency worsens H_2 economics due to the reduced H_2 production, and this is a trade-off. Decision-makers could use these results to support the economic mechanisms for shared investments in CC and hydrogen production, considering carbon price, hydrogen and electricity market, and environmental regulations.

More recently in 2022, the U.S. government published the Inflation Reduction Act of 2022 that presents the modified credit for carbon dioxide capture in section 45Q and credit for producing clean hydrogen in section 45V, although two credits cannot be used simultaneously (The U.S. Government Publishing office, 2022). Based on 45Q, carbon credits can be as high as \$85/ton CO_2 which can bring the MSP of H_2 to \$1.2/kg in S1, \$1.4/kg in S3 and S4 as shown in Fig. 3 (estimated in 2018 \$). Based on 45Q future section in 2023, H_2 credits can be up to \$3.00 for life cycle GHG emissions less than 0.45 kg CO_{2e}/kg H_2, \$1.00 for 0.45–1.5 kg CO_{2e}/kg H_2, \$0.75 for 1.5–2.5 kg CO_{2e}/kg H_2, and \$0.60 for 2.5–4.0 kg CO_{2e}/kg H_2 (The U.S. Government Publishing office, 2022). Hence, in this study, the potential credit is \$3.00 for S1, S3, and S4 (life-cycle GWP for S1, S3, and S4 is -18.8, -9.71, -9.56 kg CO_{2e}/kg H_2, respectively, see Section 3.3.1), and is \$0.60 for S2 (no CCS) (life-cycle GWP 2.99 kg CO_{2e}/kg H_2). In this way, even without CO_2 credit (CO_2 price equals \$0 in Fig. 3), the MSP of hydrogen can be profitable. Hence, in the future, with 45V credit, hydrogen production with BECCS has huge potential economic advantage over current fossil fuel-based hydrogen. This also highlights the importance of biomass gasification hydrogen plant to meet the life-cycle GWP requirement of 0.45 kg CO_{2e}/kg H_2 for securing hydrogen credits.

4. Conclusion

This study evaluated the techno-economic feasibility and environmental impacts of gasification-based BECCS using forest residues. Different scenarios of incorporating CC and energy supply strategies were investigated and compared. Specifically, this study used the integrated TEES framework to quantify the economic and environmental impacts of such a biorefinery for its full decarbonization potential at the process level. The production cost profiles (CAPEX and OPEX) were built based on the mass and energy balance results from process simulations. While it is evident that the gasifier and ASU are the major CAPEX contributors, the inclusion/exclusion of ASU has different impacts on CAPEX and OPEX given its complex interactions with other process units in the biorefinery, highlighting the need for future research focusing on integrated system design instead of separated components.

CC incorporation increases the CAPEX and decreases the OPEX, yet resulting in an overall higher cost of hydrogen under current carbon prices. However, with increasing interest in decarbonization, CC incorporation is attractive and economically competitive with fossil-based routes with CC. Electricity supply is a crucial factor in determining OPEX. When electricity self-sufficiency is fully reached, the OPEX is lower than other cases. However, this benefit is not sufficient to fully offset CAPEX contribution to the overall economics when the carbon price is lower than \$70/tonne of CO_2.

The economic competitiveness of forest residue-derived H_2 depends on CO_2 prices and H_2 price benchmarks. For example, the MSP of H_2 are \$1.52 – 2.92/kg H_2 with carbon prices of \$0–65/tonne of CO_2. Compared to fossil-based H_2 with CC, BECCS with a self-sufficient electricity supply provides competitive H_2 at price higher than \$16.5/tonne of CO_2; while BECCS with partial or no internal electricity supply has similar MSP of H_2 with coal gasification at low carbon prices \$0–19/tonne of CO_2 and MSP of H_2 with SMR at higher carbon prices (\$19–89/tonne of CO_2). Compared to fossil-based routes without CC, higher CO_2 prices are needed for BECCS to be economically competitive, but these prices are still within the benchmarked CO_2 price range (\$16.5 – 65/tonne of CO_2). In a conclusion, with the benchmarked CO_2 prices, forest residue-derived H_2 is economically competitive compared with fossil-based H_2.

The H_2 from BECCS is more cost-effective than current electrolyzed H_2 regardless of CO_2 prices. The sensitivity analysis shows that a plant size of 2,000 dry short ton/day can be the upper threshold to take advantage of the economies of scale. Establishing a reliable logistic infrastructure of feedstock supply is essential since hydrogen MSP is highly sensitive to forest residue price.

The LCA shows that implementing CC in gasification increases environmental impacts in general. Such increases can be mitigated by the self-sufficient energy design, although the self-sufficient design is no longer preferable when the biorefinery has access to solar and wind. The environmental impacts are dominated by electricity consumption and CC process. Hydrogen production via BECCS is a promising option in the near term in terms of economics and the co-benefits of decarbonizing and reducing environmental impacts in categories such as human health impacts (including carcinogenics, none-carcinogenics, and respiratory effects), comparing to fossil-based and electrolysis routes for hydrogen production. The complex trade-offs in technical, economic, and environmental aspects highlight that the deployment of this BECCS approach requires endeavors from multi-players from analytics, sustainable biomass supply, chemistry and engineering, business, and policies.

This study has several limitations. CO_2 transportation and storage are not included in this study, but the LCA and TEA results can lay the foundation for future research comparing BECCS with other CO_2 removal technologies. Another limitation is the exclusion of hydrogen transportation that needs to be determined based on hydrogen end use. Risks associated with the handling, storage and transportation of both H_2 and CO_2 (e.g., hydrogen safety and gas transportation infrastructure issues) should be considered in future research. It should also be noted that other carbon capture technologies exist and can be used in combination with gasification (e.g., chemical looping). Although this study only includes MEA given its high technology maturity, the integrated modeling approaches presented in this work can be applied to gasification coupled with other carbon capture technologies. Besides, this study uses process-based TEA and attributional LCA, therefore economic constraints related to market supply and demand, as well as competing uses of these biomass are not considered. Future research can include resource constraints and market effects using ecological-economic models and consequential LCA. Moreover, this study focuses on the Pacific Northwest, BECCS systems built in other regions may have different environmental and economic performance due to differences in biomass characteristics and background processes. The geographic variations should be considered when applying the conclusions of this study to other regions. Similar to previous LCAs of forest residue utilization (Lan et al., 2022, 2021b), the impacts of forest residue removal on forest ecosystems, e.g., biodiversity, forest fires, and soil carbon, are not included due to the lack of quantitative data. Recent studies (Dale et al., 2017; James et al., 2021; Kenderdine et al., 2022) show potential benefits/risks of removing excessive forest residues, which should be explored in future LCA and TEA.

Declaration of Competing Interest

The authors declare no competing financial interests to affect the work reported in this paper.

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Supplementary materials

Supplementary material associated with this article is available.

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