Green methanol production from biomass supporting China's carbon neutrality goals: Economic viability and regional deployment analysis

Marc Mate,[1,2] Bingyan Sun,[1,2] Bo Li,[1] Xiang Gao,[1] and Kaige Wang[1,*]

*Correspondence: kaigewang@zju.edu.cn

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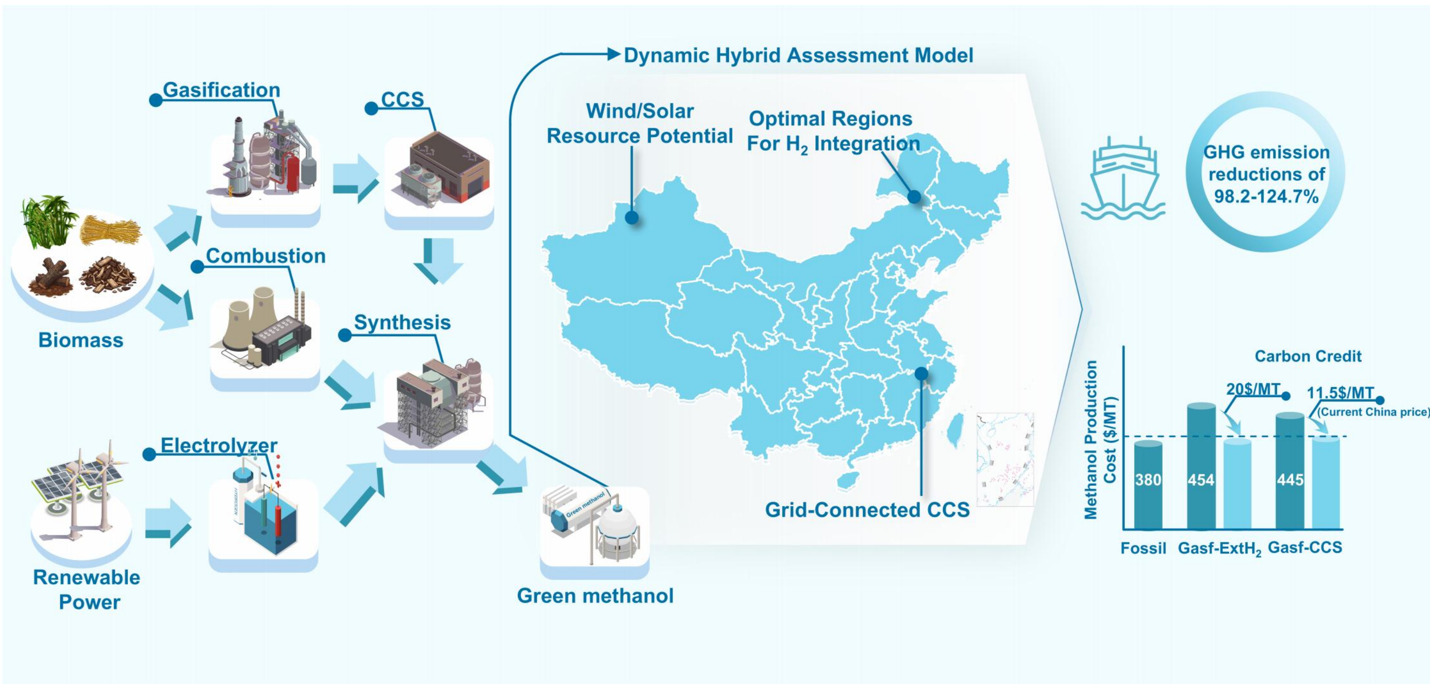
GRAPHICAL ABSTRACT



PUBLIC SUMMARY

- Green methanol serves as a key decarbonization route for China to balance energy security and 2060 carbon neutrality targets.
- Renewable hydrogen-gasification methanol costs 454–510 $/MT; gasification-CCS systems with grid power reach a lower 445–450 $/MT.
- Biomass methanol cuts GHG emissions by 98.2–124.7%, and carbon credits are vital to compete with fossil methanol economically.
- Strict decarbonization policies may slash production costs by 51–94% by 2060, and rational biomass supply can cover marine fuel needs with massive annual carbon mitigation.

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Marc Mate,[1,2] Bingyan Sun,[1,2] Bo Li,[1] Xiang Gao,[1] and Kaige Wang[1,*]
[1]State Key Laboratory of Clean Energy Utilization, Zhejiang University, Hangzhou 310027, China
[2]These authors contribute equally to this work
*Correspondence: kaigewang@zju.edu.cn
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To confront the dual challenges of energy security and ambitious carbon neutrality goals by 2060, green methanol projects are being prioritized as critical solutions for decarbonization in China. In this study, renewable hydrogen-integrated gasification systems were shown to achieve production costs in the range 454 – 510 $/MT in the best-performing provinces in the northeastern regions. However, gasification-only systems coupled with carbon capture and storage under a grid power regime achieve even lower costs, 445-450 $/MT. Compared to fossil methanol, biomass-based methanol systems can achieve GHG emission reductions of 98.2-124.7%, avoiding 335-522 ktCO_2-eq/yr. Carbon credit incentives will be critical in achieving cost parity with conventional methanol, as lower carbon prices currently favor hydrogen-integrated systems using variable renewable energy. Under aggressive decarbonization policies, cost reductions of 51-94% by 2060 can be achieved. Strategic biomass allocation could satisfy China's marine fuel demand while preventing 37-44 million tons CO_2 emissions annually.

INTRODUCTION

China's methanol production is predominantly coal-based, accounting for over 70% of national output, while the remainder comes from natural gas and coke-oven gas.[1] This results in approximately 256 million tons of CO_2 emissions annually, underscoring China's heavy reliance on fossil fuels.[2,3] Against this backdrop, renewable methanol pathways, which include biomass-to-methanol and CO_2-to-methanol via renewable hydrogen, present promising alternatives for carbon-neutral fuel production.[4] As an alternative energy carrier, methanol has the advantage of ease of transportation and storage, lower SOx and NOx emissions (99% and 60% reductions), and infrastructure compatibility, making it particularly attractive for hard-to-decarbonize sectors such as marine shipping.[5,6] With tightening emissions regulations in the maritime industry and CO_2 reduction targets of 20% and 70% by 2030 and 2040, respectively, relative to 2008 levels, green methanol has been identified as the most viable alternative fuel.[7–9]

Renewable methanol accounts for only about 0.2% of total methanol production globally.[10] It is estimated that by 2025, China will account for more than 60% of global green methanol production.[11] The positive outlook for green methanol projects stems from China's advanced gasification technology maturity and abundant biomass resources exceeding 1 billion metric tons.[12,13] Despite the recent developments and environmental benefits of green methanol, its production faces economic challenges. Production costs currently run 2-3 times higher than fossil alternatives[4] with bio-methanol prices in the range 480-820 USD/ton and e-methanol between 550-960 USD/ton.[14–16] Achieving competitive economic performance requires significant incentivization through carbon credits or other green energy subsidies.

An assessment by Wang eta al.[17] of the green methanol technologies in China revealed that the biomass gasification-to-methanol process and the biomass gasification-to-methanol process integrated with hydrogen production were the mainstream technologies for industrialization. The natural hydrogen deficiency in biomass renders integrating electrolytic hydrogen with traditional gasification processes beneficial for improving methanol production efficiency and output. Conversely, other pathways such as e-methanol production from CO_2 hydrogenation have not achieved widespread industrial implementation owing to high green hydrogen costs, limited and costly carbon capture methods, and the nascent state of the CO_2 hydrogenation technology. Biomass-based projects are favored as they present lower regulatory risk regarding green certification, thus making them more attractive to developers.[18] Additionally, China's extensive renewable energy base, with installed wind and solar capacity exceeding 1400 GW and the rapidly declining capital costs[19,20] provide an avenue for cheap green hydrogen production. However, realizing this potential requires comprehensive spatial analysis that most existing studies have not addressed.

Despite the favorable conditions, significant knowledge gaps remain in understanding how to optimally deploy biomass-to-methanol technologies. Most studies have primarily focused on discrete production pathways and limited geographical analyses, with minimal evaluation of region-specific renewable energy capacities (wind and solar resources) and accessible biomass feedstocks, which are crucial for a thorough and detailed assessment of national methanol production potential.[12,14,15,21–23] Comprehensive analyses that integrate process modeling, lifecycle assessment, and spatially explicit resource and economic evaluation of renewable methanol production across China remain scarce.

In this study, a dynamic hybrid assessment model that incorporates process modeling using Aspen Plus and hybrid lifecycle analysis is performed to evaluate the techno-economic viability and carbon mitigation potential of renewable methanol production pathways across China's provinces. A comparative study of various production pathways is conducted, which includes biomass gasification to methanol, both with and without external hydrogen, and a biomass power plant with carbon capture utilizing external hydrogen, all evaluated under VRE or grid connection scenarios. A spatially explicit assessment of the renewable methanol production potential is performed, based on provincial renewable resources and VRE/grid power characteristics. Additionally, we project future costs and performance over 2030–2060 time horizon, accounting for anticipated changes in carbon pricing, power costs, biomass costs, electrolyzer technology, and policy frameworks.

The primary contribution of this work is a unified, location-specific techno-economic and life cycle assessment framework for the evaluation of biomass-derived green methanol production across China's 31 provinces. This research offers critical insights for policymakers and industry stakeholders by mapping production potential and optimum methanol-integrated renewable power systems, facilitating China's transition to carbon-neutral fuel systems.

MATERIALS AND METHODS

System description

The green methanol production system is a location-specific integrated system that incorporates a power generation subsystem, a water electrolysis unit, gasification/combustion plant, carbon capture, and a methanol production plant. Electricity used for the systems is produced from a local off-grid solar or wind-based power generation system. This is compared to a grid-connected system. To mitigate the variability and intermittency of renewable energy and enhance reliability, temporary electricity (battery) and hydrogen storage is connected.

Process modelling

To obtain accurate TEA data, detailed process modeling was conducted using Aspen Plus V14. Energy and mass balances were generated and further validated with experimental data.[24] Four methanol production routes were simulated.

a) Biomass Gasification with carbon capture and storage without external hydrogen (Gasf)

b) Biomass Gasification with carbon capture and external hydrogen (GasfC-ExtH2)

c) Biomass Gasification without WGS and carbon capture, with external hydrogen (Gasf-ExtH2);

d) Biomass combustion plant with carbon capture with external hydrogen (Comb-ExtH2).

All systems were assessed under VRE (solar and onshore wind) and grid power regimes. External hydrogen is provided by an alkaline electrolyzer modeled as a black box. A comprehensive summary of model assumptions, parameters, inputs, and outputs related to materials and energy for the methanol processes is provided in Supplemental Notes 1 and 2.

VRE integration and storage requirements assessment

VRE intermittency limits annual plant utilization, with average capacity factors of 28% and 16% for solar and wind in China,[25] respectively, necessitating energy storage under 100% VRE operation. Battery storage is employed for the Gasf system, while hydrogen storage is preferred for external hydrogen systems given their substantially higher power demands. A 60% capacity factor is adopted for VRE scenarios, representing an economically reasonable balance that avoids the prohibitive storage costs associated with higher utilization rates[26,27] while a 90% capacity factor is applied under grid power to account for routine downtime. NREL analysis demonstrates that increasing VRE capacity factors from 60% to 90% can triple storage requirements, significantly escalating costs.[28] Commercial time-of-use electricity rates across provinces were used to calculate power costs.[29] The formulation used in calculating storage requirements across all systems is shown in Equations S.8 and S.9 in the Supplemental Information.

Levelized cost analysis and economic modeling

An economic analysis of the production pathways was performed to assess the cost of methanol production, articulated in terms of the minimum fuel selling price (MFSP). The MFSP was derived from the levelized lifetime cost framework using the discounted cash flow (DCF) method (Equation (1)).

The variable costs took into account the VRE LCOEs. Although the total VRE potential is high in China, the spatial distribution and corresponding LCOEs are not uniform and are significantly misaligned with the electricity load centers. Zhou et al.[30] estimated provincial LCOEs using VRE supply curves, indicating that onshore wind costs are distributed over a large range (2.6 - 7.6 $¢/kWh), while solar costs were relatively concentrated (1.7 - 4.5 $¢/kWh). For the general analysis, average LCOE values of 2.7 and 3.7 $¢/kwh are used for solar and wind energy, respectively. Energy storage costs are considered separately. The assumptions and financial parameters used in the DCF are listed in Supplemental Note 3.

$$MFSP = \frac{\sum_{i=1}^{n} \frac{(CP_i + CO_i + CF_i + CU_i + CL_i + CX_i + CS_i)}{(1+r)^i}}{\sum_{i=1}^{n} \frac{Q_i}{(1+r)^i}} \tag{1}$$

Where *CP* is the capital investment, *CO* is operational and maintenance expenses, *CF* is feedstock cost, *CU* is utility costs, *CL* is labor costs, *CX* is tax expenses and *CS* is other costs such as salvage, replacement. r is the discount rate (weighted average cost of capital), *i* is time period index with n being the project lifetime (30 years in this study).

The fixed capital investment, which aggregates equipment procurement and associated installation costs across all subsystems, was determined. The study utilized costs from equipment vendors and from numerous reports.[31] Equipment costs that were not readily accessible through published reports or vendor quotations were derived from Aspen Process Economic Analyzer (APEA) utilizing Q1 2022 cost data as the baseline reference. All equipment costs were updated to 2023 prices using the Chemical Engineering Plant Cost Index (CEPCI).[32]

The following scaling law correlation was used:

$$C_2 = C_1\left(\frac{S_2}{S_1}\right)^n \tag{2}$$

Where C_2 is the new equipment cost to be determined with a capacity of S_2, and C_1 is the initial equipment cost having a capacity of S_1. n is the scaling factor, typically 0.6.[33]

Biomass resource assessment

A comprehensive biomass resource dataset, comprising agricultural wastes, forestry residues, and energy crops, was utilized to evaluate the national and provincial potential for green methanol.

The study considered 8 types of agricultural residues (rice, wheat, corn, soybeans, peanuts, rapeseed, sesame, and cotton), which together account for about 90% of China's agricultural production.[34,35] The most recent crop production dataset from the National Bureau of Statistics in China across all provinces was used to estimate available bioresource for methanol production considering the crop collectable ratios and current usage.[35,36]

The annual forestry residue production was measured using forestry data parameters, including forest area, seedling yields, log yields, firewood, large-diameter bamboo, log imports, and the amount of wood and bamboo products. The forest area data was sourced from the 9th National Forest Resources Inventory.[37] Additional forestry statistical data were sourced from the China Forestry Statistical Yearbooks and the China Forestry and Grassland Yearbooks.[38–41] The residue coefficient data was obtained from literature.[42,43]

Given the limited availability of bioresources sourced from agricultural and forestry residues, this study quantified the marginal land area technically available for dedicated energy crop production.[44] The analysis focused on Miscanthus as the primary feedstock, selected for its exceptional biomass yield potential and low-input cultivation requirements, characteristics that position it as an optimal candidate for sustainable methanol production pathways.[45] The detailed analysis of the bioresource potential can be found in Supplemental Note 4.

We consider two scenarios. The 'Sustainable Potential' scenario restricts biomass access to feedstocks that can be harvested using existing technology and practices, without competing with present applications such as animal feed, industrial raw materials, rural household use and organic fertilizer. This scenario is broadly analogous to the technically and economically exploitable resource under current conditions. The 'High Potential' scenario represents the theoretical upper bound, in which all crop and forest residues that are used by different energy utilization technologies can be allocated to methanol production.

Net lifecycle GHG emissions

This study computed the net lifecycle GHG emissions by considering multiple components: the life-cycle greenhouse gas emissions related to feedstock cultivation, transportation, distribution, storage, and the production processes of material inputs.

A comparative well-to-wheel analysis was performed using Argonne's Greenhouse Gas, Regulated Emissions, and Energy use in Transportation 2023 model (GREET 2023).[46] The analysis compared emissions from conventional shipping fuels (MGO, HFO), emerging low-carbon alternatives (LNG), and methanol produced from coal and natural gas feedstocks. The GREET model framework was adapted with China-specific datasets to derive precise, comprehensive lifecycle emission estimates covering the entire process chain from resource extraction to end-use fuel consumption. Within this framework, the life-cycle greenhouse gas emissions for the methanol plants were evaluated by combining process modeling results for operational emissions with literature-derived GHG emission coefficients for material inputs across each sub-process. The net lifecycle GHG emissions (E_{net}) associated with the green methanol plant are given in Equation (3);

$$E_{net} = E_{BC} + E_{BT} + E_C + E_{O\&M} + E_{MTS} + E_{CTS} \tag{3}$$

Where $E_{BC}, E_{BT}, E_C, E_{O\&M}, E_{MTS}, E_{CTS}$ is the emissions from biomass cultivation, transport, plant construction, operation and maintenance, methanol and carbon dioxide transport and storage respectively.

CO_2eq abatement credits were calculated based on lifecycle GHG emissions reductions (E_{Red}) achieved through CO_2 geologically sequestered or utilized.

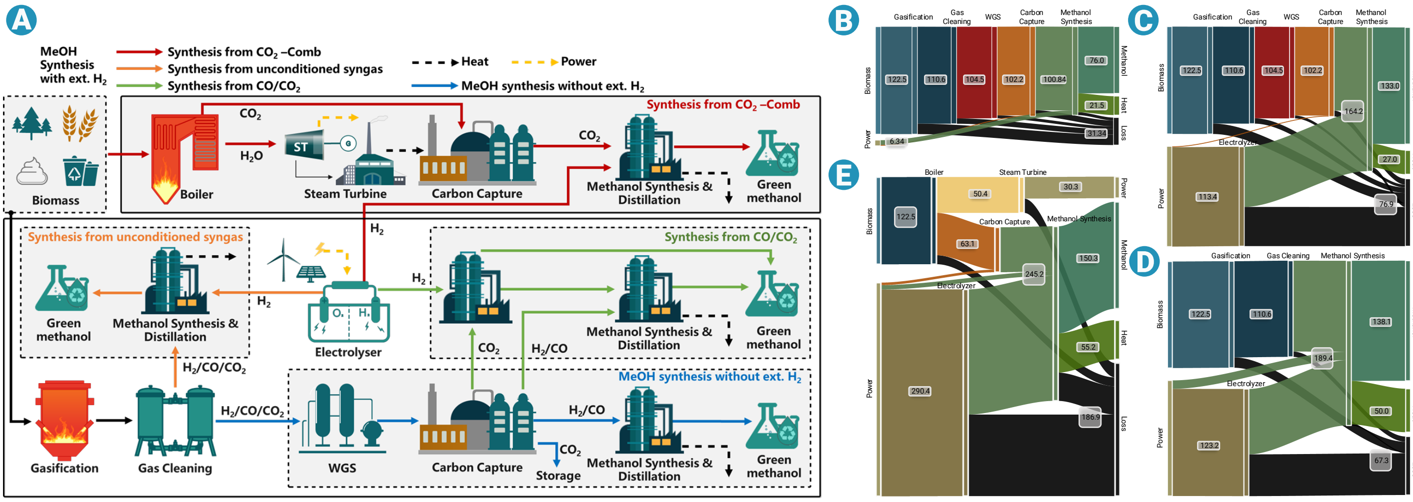

Figure 1. Process flow diagrams and energy balances for the biomass-to-methanol production pathways (A) Process flow diagrams for the green methanol production processes. (B) Gasification without external hydrogen (Gasf). (C) Gasification with carbon capture (GasfC-ExtH2) incorporating additional electrolytic hydrogen production to enhance methanol yield through a second synthesis reactor. (D) Direct electrolytic hydrogen pathway (Gasf-ExtH2) (E) Combustion power plant with external hydrogen pathway (Comb-ExtH2), power generation through steam turbine. All diagrams show energy flows in MW.

The avoided emissions ($E_{Avoided}$) from replacing coal-based methanol production are calculated and used to estimate reductions from which carbon credits can be obtained. The goal was to determine how these credits impact the revenue of methanol production systems and to identify the credit amounts at which methanol produced in all systems becomes cost-competitive with other shipping fuels. Data and formulae used in calculating the life-cycle emissions across all sub-processes are shown in Supplemental Note 5. The reduction in emissions was determined using Equation (4).

$$E_{Red} = E_{Avoided} - E_{net} \tag{4}$$

Provincial ranking - integrated MCDA and goal programming

To assess the potential of individual provinces in China to produce green methanol, we performed a spatially explicit analysis using an integrated framework combining Multi-Criteria Decision Analysis (MCDA) and Goal Programming (GP). The methodology is outlined in Supplemental Note 6 and the sequential approach used is shown in Figure S13.

MFSP cost projections

The MFSP projections were made using the DCF model incorporating technology learning curves and temporal cost projections over the period 2023-2060 (see Supplemental Note 7). Technology cost projections incorporate experience curve analysis tailored to China's manufacturing capabilities and deployment scales. The price projections are made under two scenarios; Business-as-Usual (BAU) and Deep Carbonization (DC) Scenarios (See Table S3 & S4).

RESULTS

System configuration and performance analysis

The gasification system without external hydrogen (Gasf) (Figure 1B) exhibits the highest single-pass conversion efficiency at 36.9%, with an overall conversion rate of 99.4% and methanol selectivity of 98.5%. This baseline configuration attains a methanol production of 0.46 kg MEOH/kg-biomass while maintaining the lowest power requirements at 6.3 MW total. The methanol yield is within range of existing studies, 0.31-0.55 kg-MEOH/kg-biomass.[47–50] These efficiency values align with reported biomass-to-methanol processes, which have been shown to suffer from low carbon efficiency, with more than 50% of carbon in biomass exiting as CO_2.[31,51,52]

The integration of carbon capture with an external hydrogen system (GasfC-ExtH2) (Figure 1C) exhibits similar conversion characteristics to the baseline gasification system, while necessitating a significant additional power input of 113 MW for hydrogen production using alkaline electrolysis. This system attains a total methanol yield of 0.81 kg MEOH/kg biomass by integrating gasification-derived syngas (0.46 kg MEOH/kg biomass) and CO_2 conversion (0.35 kg MEOH/kg biomass), yielding an enhanced carbon efficiency of 68%, albeit with a diminished overall energy efficiency of 68%.

The direct external hydrogen integration system (Gasf-ExtH2) (Figure 1D) represents the most energy-intensive configuration, requiring 123 MW for hydrogen production. This system attained an improved methanol yield of 0.84 kg MEOH/kg biomass and exceptional carbon utilization efficiency at 70% and an overall energy efficiency of 74%. This configuration minimizes carbon losses by eliminating intermediate process units, specifically the water-gas shift reactor and carbon capture system, allowing purified syngas to proceed directly to the methanol synthesis reactor. Hydrogen addition has been shown to increase carbon efficiency by 11-15% compared to gasification-only systems.[53,54] Existing commercial methanol production pathways achieve carbon conversion efficiencies between 68% and 75%.[12]

The combustion-integrated external hydrogen system (Comb-ExtH2) (Figure 1E) demonstrates the highest methanol productivity at 0.91 kg MEOH/kg biomass. The large H_2 demand significantly increases the power requirement, resulting in a power input of 290 MW. This system has the highest carbon efficiency of 77%, while overall energy efficiency is 56% due to the high energy losses in the turbine system and boiler.[55]

System selection for economic analysis

When comparing external hydrogen gasification configurations, the Gasf-EXTH2 system exhibits superior thermal efficiency with a 7-percentage point improvement and enhanced economic viability with a 10.9% and 1.8% reduction in levelized methanol production costs (MFSP) under renewable and grid power sources, respectively.

Based on the technical performance and minimal distinction from the direct integration approach, further analysis of methanol production routes focused on the three configurations: Gasf, Gasf-EXTH2, and Comb-EXTH2. A summary of the systems' technical performance is shown in Table S7 in the Supplemental Information.

Process efficiency and resource utilization

The analysis reveals fundamental trade-offs between maximizing methanol yield and optimizing energy efficiency across the assessed configurations. Systems utilizing external hydrogen exhibit increased methanol yields of 82-98% compared to the gasification-only route, accomplished by improved carbon utilization from biomass-derived CO_2. Nonetheless, these yield enhancements require 10–24 times more power consumption, illustrating the importance of relying on affordable renewable electricity for economic feasibility.

The carbon efficiency improvements in Gasf-EXTH2 and Comb-EXTH2

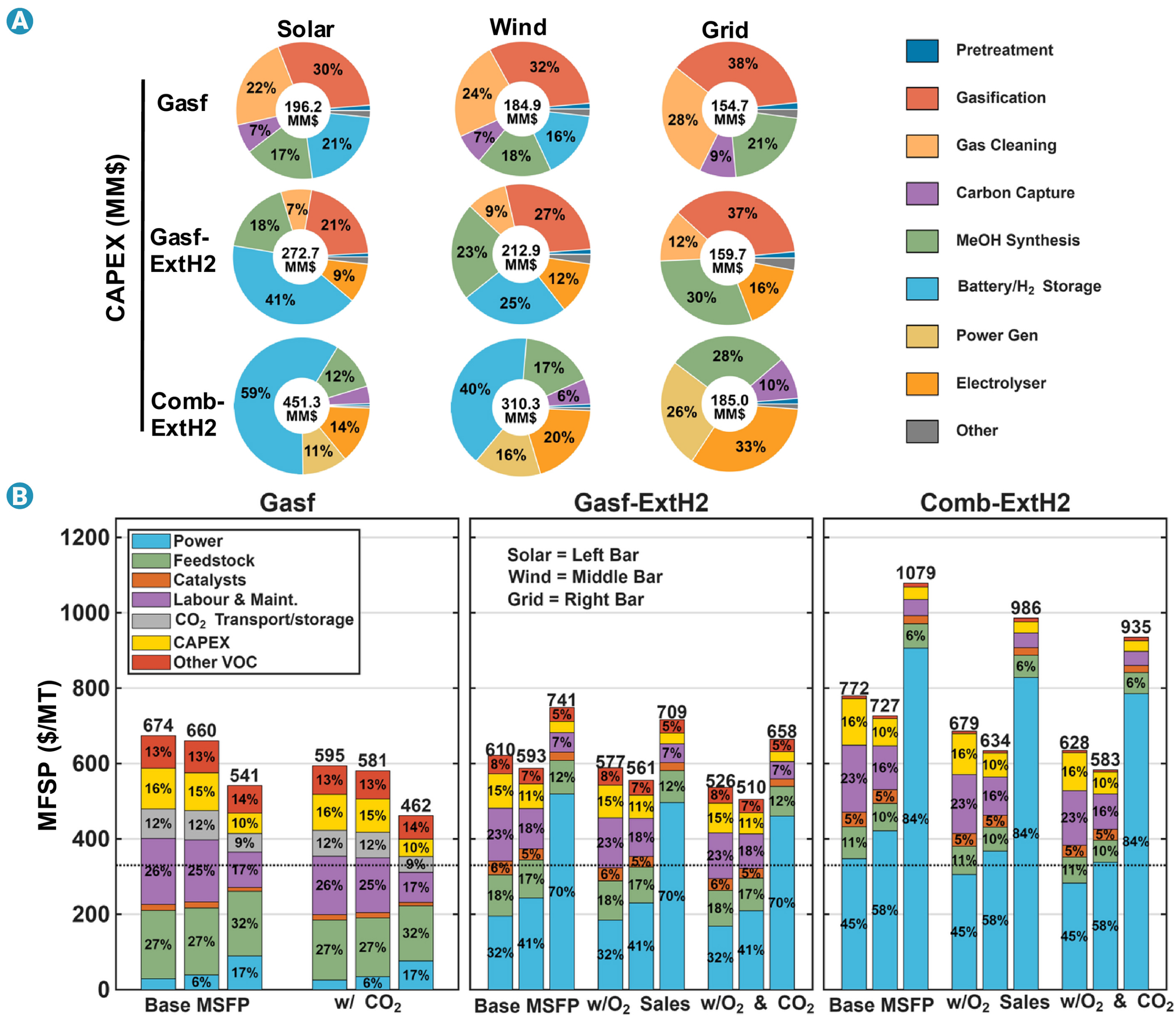

Figure 2. Techno-economic analysis of renewable energy pathways for green methanol production (A) Capital expenditure (CAPEX) breakdown for solar, wind, and grid-powered production systems (B) MFSP analysis comparing Gasf, Gasf-ExtH2, and Comb-ExtH2 pathways across solar, wind, and grid power sources.

systems ranging from 68% to 77%, compared to 39% in Gasf, demonstrate the potential for improved CO_2 utilization via renewable hydrogen integration. Maximizing value extraction from biomass resources, while preferable, requires rigorous economic justification. The hydrogen demand varies from 0.05 to 0.18 kg H_2/kg biomass, determining the extent of renewable electrolysis infrastructure necessary for extensive implementation.

Capital cost structure and economic drivers

The capital expenditure analysis reveals distinct cost structures across the three power sources and systems, as shown in Figure 2A. In 100% VRE scenarios, energy and hydrogen storage costs constitute a large share of the total CAPEX, representing 59% and 41.4%, respectively, in Gasf-EXTH2 and Comb-EXTH2 solar configurations. This is consistent with other studies[15,56] where hydrogen storage has been shown to account for 40-60% capital expenditure. Wind-powered systems exhibit lower total CAPEX and reduced storage cost proportions due to higher capacity factors that minimize required storage capacity. CAPEX variations between configurations are negligible when using grid power, with Comb-EXTH2 showing slightly higher costs because of additional capital-intensive process equipment like the 40 MW steam turbine. CAPEX differences between systems increase with lower VRE capacity factors, with Comb-EXTH2 reaching over two times the CAPEX of the Gasf system in the solar scenario. The CAPEX unit cost for the Gasf system is 1.42 $/kg-MeOH, which falls below the reported range of 1.56-2.22 $/kg-MeOH.[4] The reduced cost reflects the competitive equipment pricing in the Chinese market. The unit costs for the Gasf-EXTH2 and Comb-EXTH2 systems are in the range of 0.81-2.1 $/kg-MeOH and 0.87-3.2 $/kg-MeOH, respectively. The lower limits reflect the grid-powered systems, making this the most competitive CAPEX performance. Under 100% VRE scenarios, the electrolyzer cost (Stack and BOP) of the Comb-EXTH2 system takes up the second largest share of CAPEX costs due to its large size (290 MW). The integration of external hydrogen significantly modifies the capital cost structure, with electrolyzers and energy/hydrogen storage emerging as the primary cost components.

MFSP analysis across energy sources

The MFSP analysis demonstrates significant variations based on energy source and co-product credit scenarios, as shown in Figure 2B. The Gasf system achieves MFSP values ranging from 462-674 $/MT across different power sources, with grid power providing the most economical option at 462 $/MT, while the wind-powered Gasf-ExtH2 represents the most competitive renewable option with the lowest cost at 510 $/MT. This MFSP is 55% higher than the average methanol market price (330 $/MT)[57] in China, represented by the dashed horizontal line in Figure 2B. The MFSP in the Gasf system is driven by feedstock costs and fixed operating costs, which together account

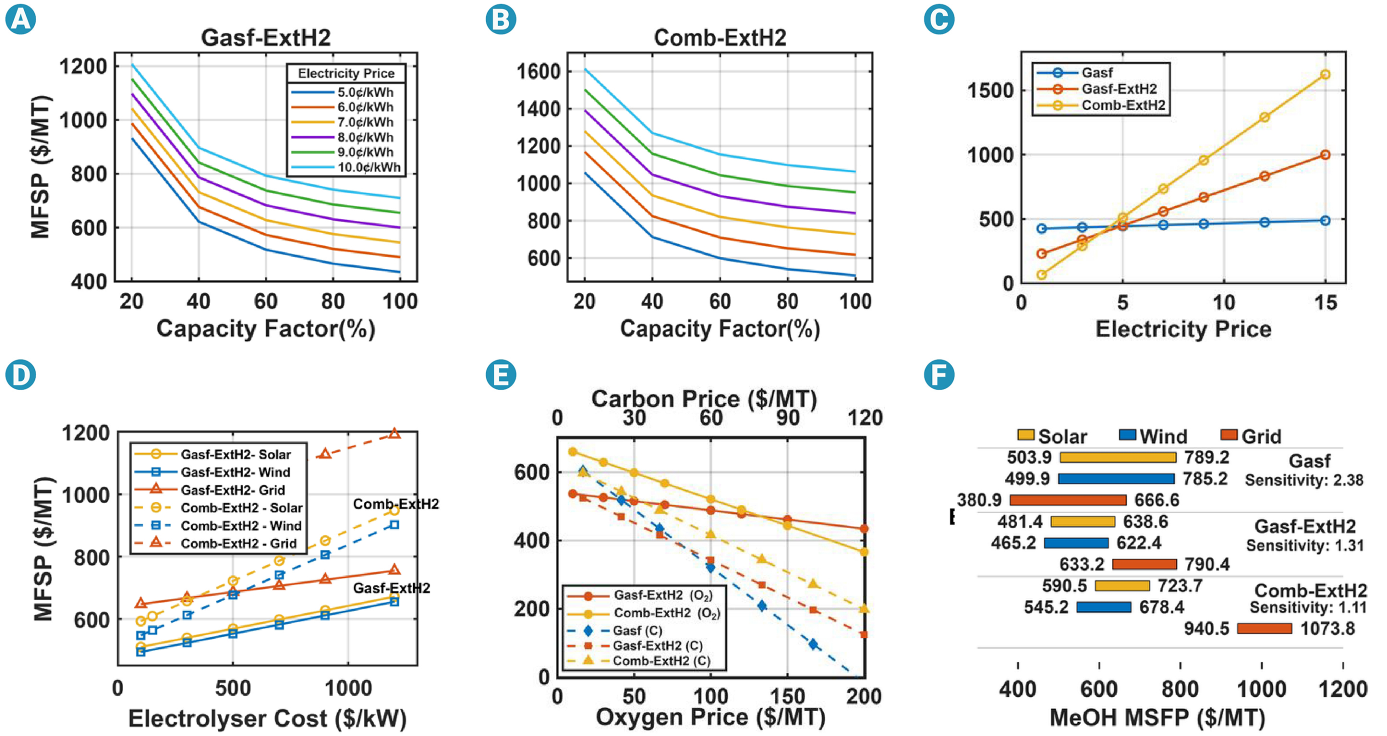

Figure 3. **(A&B) Sensitivity analysis showing MFSP variation with capacity factor for Gasf-ExtH2 and Comb-ExtH2 pathways at different electricity prices (D) Comparative MFSP trends across electricity prices for the three main pathway configurations. (D) Impact of electrolyzer capital costs on MFSP (E) Effect of oxygen and carbon price on the pathway economics. (F) Biomass price sensitivity analysis.**

for over 50% of the cost. This contrasts with the other systems, where power costs are the main driving factors. Co-product credits significantly improve economics across all systems, with oxygen sales and CO_2 credits reducing MFSP by 68-152 $/MT, representing 10-20% cost reductions.

Sensitivity analysis and economic resilience

Capacity factor analysis reveals critical operational dependencies, particularly for external hydrogen systems. Capacity factor is a critical factor in methanol plant economics.[58,59] Figures 3A & B show how capacity factor affects the MFSP at different electricity prices within the China tariff range.[60] At 60% capacity factor, the Gasf-EXTH2 system demonstrates an MFSP range from 518-793 $/MT, in contrast to the Comb-EXTH2 system in the range 599-1155 $/MT over a price range of 5-10¢$/kWh. When the capacity factor increases to 90%, the MFSP decreases by 13%.

The Comb-EXTH2 system shows higher sensitivity to electricity prices, with MFSP changes that are twice as large as those of the Gasf-EXTH2 system for every 1¢/kWh change in electricity price. However, at a power price lower than 4¢$/kWh, the Comb-EXTH2 system becomes competitive.

Electrolyzer cost sensitivity analysis indicates economic improvement potential as technology costs decline (Figure 3D). Across the electrolyzer cost range of 100-1200 $/kW, MFSP demonstrates significant sensitivity with increases of 31.6-64.8%, which is consistent with global estimates.[61] Meanwhile, oxygen price variations (50-200 $/MT) demonstrate limited impact on overall economics, contributing 20-50 $/MT MFSP variations across systems (Figure 3E).

Carbon pricing policies significantly influence the economic viability hierarchy of different methanol production pathways. As shown in Figure 3E, carbon credit sales have a positive impact on MFSP with reductions of 83.9%, 62.4%, and 54.6% for the Gasf, Gasf-ExtH2, and Comb-ExtH2 systems, respectively, for a carbon price increase from 10 to 100 $/MT-$CO_2$ under wind power. At carbon prices greater than 15 $/MT CO_2, the Gasf system becomes increasingly cost-competitive in comparison to Comb-ExtH2. The Gasf-ExtH2 pathway achieves market parity at a carbon price of 63.5 $/MT-$CO_2$, while Gasf requires 58.60 $/MT-$CO_2$. These results indicate that at current carbon prices in China, Gasf-ExtH2 offers the most promising route for near-term commercial viability of green methanol. Gasf and Comb-ExtH2 require carbon pricing policies that are 89.7% and 143.2% higher to achieve market competitiveness with Gasf-ExtH2. However, at a carbon price greater than 49.60 $/MT- CO_2, the Gasf system performs better than the other systems.

Gasf exhibits greater sensitivity to biomass prices, revealing a 57-75% increase in MFSP over a biomass price range of 30-150 $/MT (Figure 3F). In contrast, Comb-ExtH2 and Gasf-ExtH2 have lower sensitivity with increases of 14-23% and 25-33% respectively.

Life cycle carbon assessment

Greenhouse gas emission performance. Life cycle analysis reveals substantial differences in greenhouse gas emission profiles between the methanol production pathways. A feedstock resource analysis distinguishing crop residues (Figure 4A) and dedicated energy crops (Figure 4B) revealed significant implications for carbon storage and emission profiles under renewable and grid electricity scenarios. Figure 4 illustrates systems powered by renewable energy that exhibit minimal lifecycle emissions, with emission reductions exceeding 90%. This is consistent with multiple other studies that have documented emission reductions exceeding 90% in renewable methanol systems.[62]

Overall crop residue utilization demonstrates superior performance, with lifecycle emissions being 66-77% lower than energy crop emissions. Energy crop cultivation represents the main source of elevated emissions, accounting for 13.6-62.3% of overall GHG emissions compared to crop residue in the range 1.9-20.2%. Fertilizer and pesticide use in energy crop production contribute significantly to carbon intensity.[63] The high emissions reflect the land use change implications and cultivation material requirements associated with dedicated biomass production. Grid-powered Comb-ExtH2 and Gasf-ExtH2 pathways have GHG emissions of 3142 and 1487 kg CO_2-eq/t-MeOH, respectively, which is significantly higher due to China's high grid carbon intensity of 0.68 kg CO_2eq/kWh.[64] See Figure S10 in the Supplemental Information.

The Gasf system in Figure 4A demonstrates significant carbon storage potential of 89.6%, resulting in net negative emissions of -914 kgCO_2-eq/t-MeOH.

Comparative environmental performance. Comparison of avoided emis-

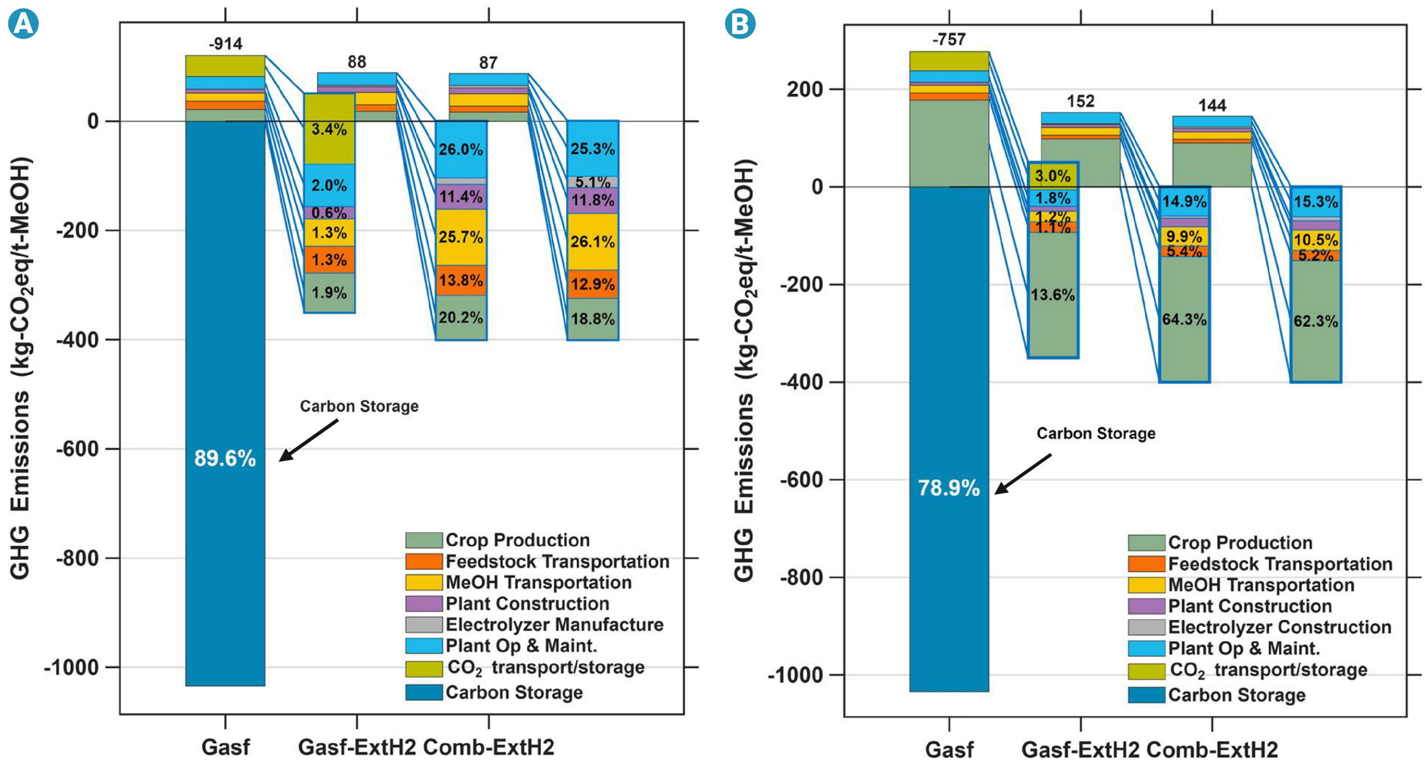

Figure 4. Lifecycle greenhouse gas emissions analysis and fossil fuel displacement potential. Cradle-to-gate GHG emissions breakdown for production pathways (Gasf, Gasf-ExtH2, Comb-ExtH2) using (A) crop residues and (B) dedicated energy crops.

sions from substituting conventional marine fuels with green methanol shows that coal-based methanol systems achieve GHG emission reductions of 98.2-124.7%, avoiding 335-522 ktCO_2-eq/yr (Figures 5A-D). LNG demonstrated the least avoided emissions of 168-192 ktCO_2-eq/yr, as it produces significantly lower emissions when combusted compared to other fuels. HFO, MGO, and very low sulfur fuel oil (VLSFO) account for 96% of marine fuel consumption in China, emitting 78 million tons of carbon dioxide annually[65]. Green methanol has the potential to reduce emissions by 96.2%, with each green methanol plant resulting in 193-246 ktCO_2-eq/yr avoided emissions.

Spatial distribution and technology deployment optimization

Resource assessment and deployment suitability. As shown in Figure 6, the comprehensive resource assessment reveals significant regional variations in deployment suitability based on integrated scoring of biomass availability under the sustainable potential scenario and renewable energy resources. It should be noted that marginal score differences (<5) between adjacent provinces lie within the uncertainty of the composite input data. Nonetheless, the northern provinces of Xinjiang, Inner Mongolia, and Gansu achieve the highest suitability scores (67.2-76.5) due to exceptional solar and wind resources, including high biomass availability. The Northern regions dominate with 73.1% of total wind capacity, with Northeastern regions (Liaoning, Jilin, and Heilongjiang) achieving the highest capacity factors, averaging 32%.[25] However, under broad ambitious installed solar and wind targets of 39 and 26.4 GW respectively, the Northeastern provinces have low GP scores (39-50), which reveal a gap in actual RE infrastructure compared to other regions (see Figure S14 in the Supplemental Information). See Supplementary Note 6 for further discussion.

Regional MFSP analysis and economic competitiveness. Analysis of regional MFSP reveals considerable geographical cost disparities influenced by local resource availability and energy costs (see Figure S16B-D in the Supplemental Information). Grid power scenarios indicate consistent MFSP distributions across systems, with differences mostly influenced by regional electricity pricing and biomass costs. The Gasf system sustains competitive MFSP values of 445-474 $/MT under the grid scenario throughout all the provinces, which is on average 30% lower compared to MFSP values from the grid-connected Gasf-ExtH2 system. Xinjiang also offers the lowest MFSP at 445 $/MT using the Gasf system.

Under wind energy, Inner Mongolia has an average MFSP of 458 $/MT in the Gasf-ExtH2 system, representing a 25.5% improvement from Gasf values. Resource-abundant regions such as Inner Mongolia, Gansu, and Xinjiang provide the most cost-effective MFSPs for both solar and wind energy compared to all other provinces, with production costs in the range 487.3 - 502.3 $/MT for solar and 454 - 473 $/MT for wind power.

Scenarios for solar power deployment indicate greater economic performance in western provinces, which have elevated sun irradiation, resulting in MFSP savings of 100-200 $/MT relative to grid power options. Regions like Tibet have enormous solar potential but harsh climatic conditions, low biomass output, and infrastructural barriers making it unfavorable for green methanol production.[66,67] Xinjiang, Inner Mongolia, and Gansu exhibit exceptionally advantageous conditions for solar-powered external hydrogen systems that rival Gasf options in resource-rich areas.

Temporal MFSP evolution

The temporal analysis of MFSP evolution from 2023 to 2060 reveals significant cost reduction potential driven by technology learning effects and renewable energy cost declines (Figure 6B-E). Under the business-as-usual (BAU) scenario, grid-powered Gasf and Gasf-ExtH2 systems demonstrate relative MFSP stability with 2060 values in the range 608 ± 176 $/MT and 662 ± 114 $/MT, which reflects a 21.6% increase and a modest decline of 4%, respectively. Due to renewable energy penetration, electricity prices are projected to increase by 3.8% and 18% in 2030 and 2060 respectively[68,69]. Rising tariffs will drive MFSP across all systems. Furthermore, the expansion of the bioenergy industry will create competition for feedstock, leading to increased costs as we approach mid-century, with price increases accelerating toward 2060 by 40%.[70–72] The biomass effects are greater in the Gasf system, as shown in Figure 3F. Collectively, these factors offset any benefits that might arise from modest carbon price increases under the BAU scenario.

Under the DC scenario, high carbon prices (average values of 22.3 $/MT and 310 $/MT by 2030 and 2060)[73] lead to significant MFSP reduction by 51.3% to 329 ± 66 $/MT in the Gasf-ExtH2 system, with declining electrolyzer costs further contributing to this reduction. In contrast, the Gasf system shows a dramatic 90.8% reduction to 46 ± 26 $/MT due to its higher

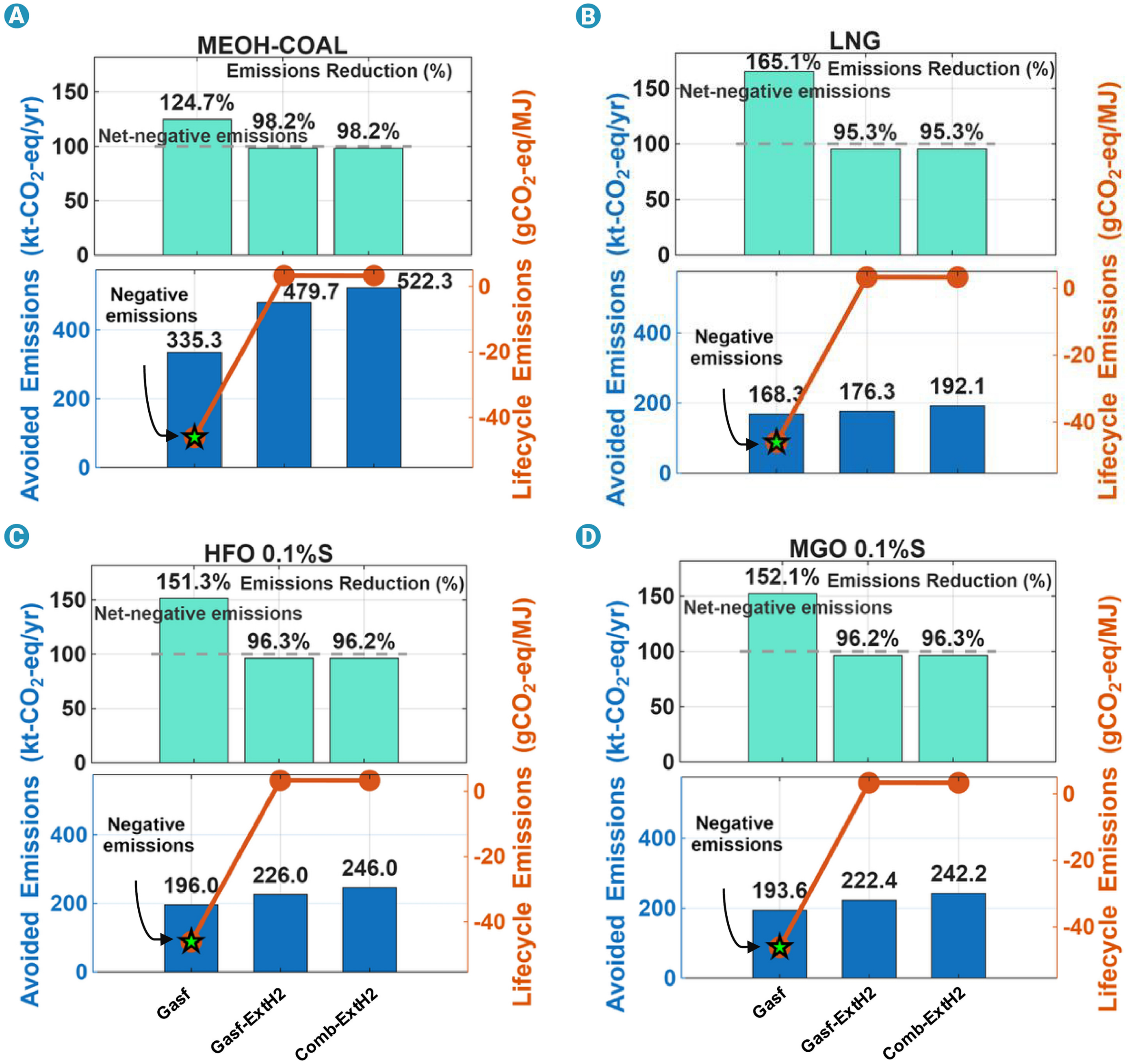

Figure 5. Fossil fuel displacement potential Avoided emissions and lifecycle emissions comparison when biomass methanol displaces fossil fuels in marine industry (A) methanol from coal (MEOH-COAL), (B) liquefied natural gas (LNG), (C) heavy fuel oil (HFO 0.1% S), and (D) marine gas oil (MGO 0.1% S).

sensitivity to carbon prices.

Renewable energy integration cost dynamics. Wind power scenarios demonstrate unique cost evolution trends, characterized by significant reductions in the early stages, followed by a gradual stabilization. Gasf-ExtH2 system MFSP declines from 510 \$/MT in 2023 to 420-463 \$/MT by 2030 under BAU conditions but slightly increases to 482 ± 25 \$/MT by 2060. The stable price range reflects the limited carbon pricing levels, moderate LCOE reduction, and increasing feedstock and labor costs. The carbon price effect on the Gasf system results in a relatively steeper decline in MFSP from 640 to 541± 37 \$/MT.

Under DC, the Gasf and Gasf-ExtH2 systems show MFSP reductions of 94% and 88% from 2023 values, as shown in Figure 6C. Wind power shows a dramatic improvement potential under aggressive decarbonization, with the pronounced cost reduction reflecting rapid decreases in wind turbine costs, improved capacity factors, and reduced balance-of-system costs in China's expanding wind energy sector.

Solar power integration demonstrates similar cost trajectories, with MFSP values declining by 2-10% by 2060 for both systems under BAU scenarios. Deep carbonization scenarios enable solar-powered Gasf-ExtH2 systems to achieve 49 ± 22 \$/MT by 2060, driven by continued photovoltaic cost reductions and improved electrolyzer efficiency. The convergence of solar and wind costs by 2050–2060 reflects technological maturation and diminishes marginal improvement rates for both renewable energy sources.

DISCUSSION AND CONCLUSION

This study combines process modelling, LCA, spatial optimization, and temporal cost projections to evaluate the economic viability and carbon mitigation potential of biomass-based green methanol across China. Building on the technical characterization, the following discussion synthesizes the key findings and draws an overall judgment on regional deployment viability.

The economic analysis demonstrates that the Gasf-ExtH2 system is the most viable renewable pathway, achieving the lowest renewable MFSPs of 454–510 \$/MT in the best-performing northern provinces of Inner Mongolia, Heilongjiang, Jilin, and Xinjiang under wind power, and 487–533 \$/MT under

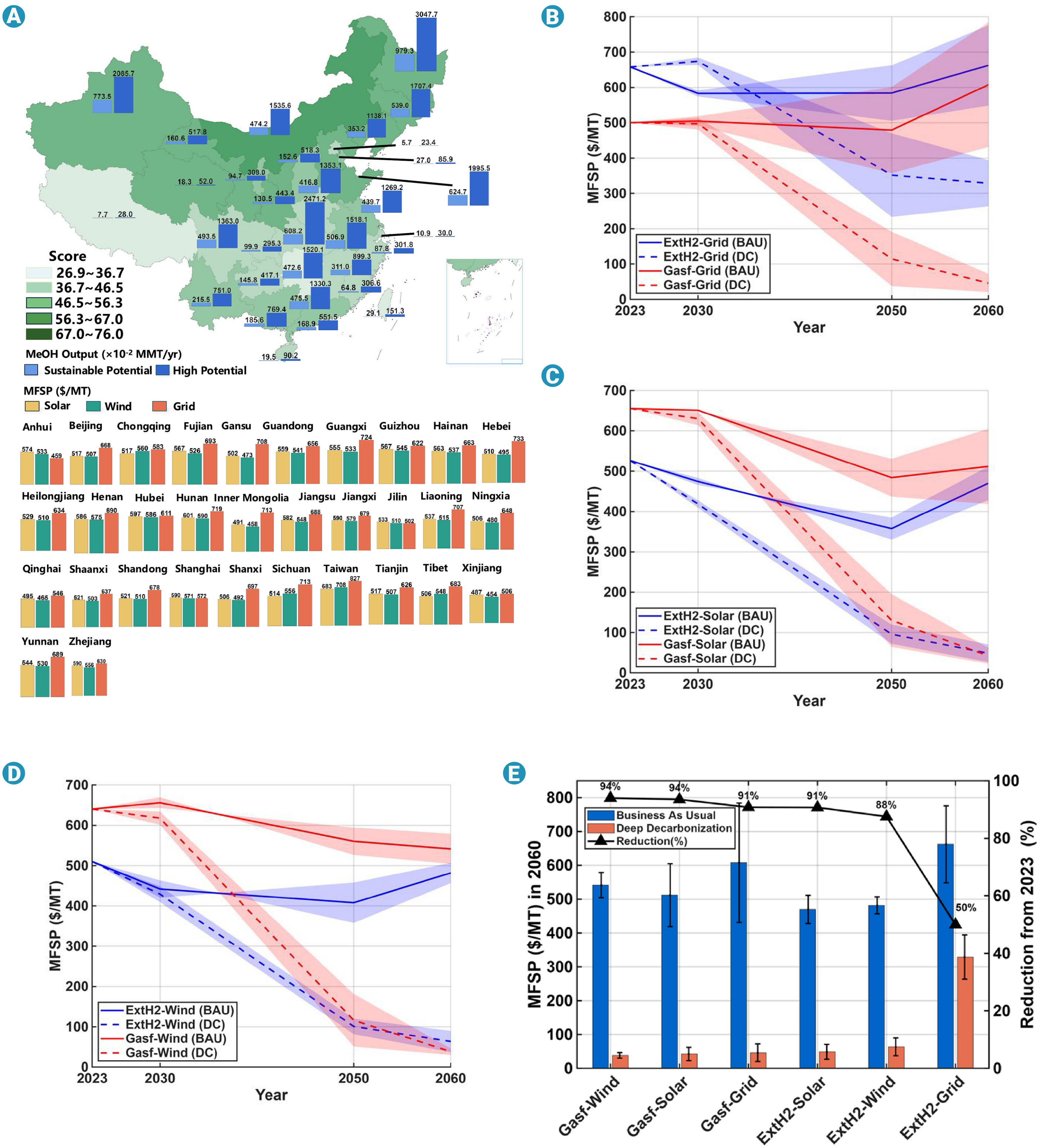

Figure 6. Geospatial analysis of methanol production potential and MFSP across China using the Gasf-ExtH2 system and temporal projections of methanol production costs and decarbonization potential (2023-2060) (A) Regional optimal weighting scores indicated by gradient strength (26.9 to 76). Regional methanol production potential (MMT/yr) based on sustainable biomass is shown and bar charts show comparative MFSP values for each power source. MFSP trajectories for different power sources and production pathways: (B) grid, (C) solar, and (D) wind. Shaded regions represent uncertainty bands. (E) Cost comparison and reduction potential in 2060, showing MFSP values and percentage reduction from 2023 baseline.

solar. However, hydrogen storage presents a major economic barrier, accounting for 25–59% of capital costs in external hydrogen systems and creating scale reversal effects above 150–250 kt/yr plant capacity, where levelized costs increase rather than decrease with scale.[56,74,75]

Grid-powered Gasf achieves the lowest absolute MFSPs of 445–450 $/MT in resource-rich provinces, though its near-term deployability is constrained by China's underdeveloped CCS infrastructure and by grid electricity prices projected to rise as renewable penetration deepens. Collectively, this favours external hydrogen integration as the more pragmatic near-term pathway. Wind-powered Gasf-ExtH2 in resource-abundant regions achieves performance levels comparable to the best grid-powered Gasf outcomes, reinforcing the strategic priority of these regions for early deployment.

Carbon prices will become critical in achieving economic viability in green methanol projects. The analysis indicates that current carbon pricing mechanisms in China (<50 \$/MT-CO_2) would favor the adoption of the external hydrogen integration pathway, Gasf-EXTH2 under renewable energy, while higher carbon prices incentivize the Gasf pathway, which exhibits superior performance above 50 \$/MT-CO_2, reaching an MFSP of 97 \$/MT at 100 \$/MT- CO_2. However, under an alternate pricing mechanism that incentivizes negative emissions, the Gasf pathway would be more competitive at lower carbon prices. In the Gasf and Gasf-EXTH2 systems, price parity with conventional methanol is achieved with carbon prices in the range 58.6-63.5 \$/MT-CO_2 compared to EU and USA regions, which require prices in the range 150-300 \$/MT- CO_2.[76]

These economic and carbon performance findings directly motivate the spatial deployment strategy. Success is dependent on aligning technology pathways with regional resource endowments: wind-powered external hydrogen systems in the northeast, solar-integrated systems in the northwest, and efficiency-optimized gasification in biomass-abundant eastern provinces. By implementing sustainable biomass in the Gasf-EXTH2 system nationwide, China could achieve an 88% reduction in CO_2 emissions from conventional fossil-based methanol production, as each plant prevents about 480 kt-CO_2eq/yr. Furthermore, allocating 23.3-27.7% of sustainable methanol output from the Gasf-EXTH2 system to marine applications would satisfy all of China's shipping fuel needs[77] and prevent 37-44 million tons of CO_2 emissions. This presents a viable marine decarbonization pathway.

The temporal projections establish the conditions under which this deployment becomes self-sustaining. Under deep decarbonization scenarios, aggressive renewable cost reductions, declining electrolyzer costs, and rising carbon prices enable external hydrogen systems to reach cost parity with conventional methanol by 2030–2035, well ahead of BAU timelines.

Taken together, the findings of this study support the conclusion that biomass-based green methanol is technically mature, regionally deployable, and economically achievable in China within this decade under supportive policy conditions. As China advances toward its 2060 carbon neutrality target, renewable methanol offers not merely an alternative fuel but a scalable, negative-emission solution capable of transforming hard-to-decarbonize sectors while delivering measurable and spatially targeted contributions to national climate goals.

List of Abbreviations

Acronym	Definition
BAU	Business-as-Usual
BECCS	Bioenergy with Carbon Capture and Storage
BOP	Balance of Plant
CCS	Carbon Capture and Storage
Comb-ExtH2	Biomass Combustion with External Hydrogen
DC	Deep Decarbonization
DCF	Discounted Cash Flow
Gasf	Biomass Gasification with CCS, no external hydrogen
GasfC-ExtH2	Biomass Gasification with Carbon Capture and External Hydrogen
Gasf-ExtH2	Biomass Gasification with External Hydrogen
GHG	Greenhouse Gas
GP	Goal Programming
GREET	Greenhouse Gas, Regulated Emissions, and Energy use in Transportation
HFO	Heavy Fuel Oil
LCA	Life Cycle Assessment
LCOE	Levelized Cost of Energy
LNG	Liquefied Natural Gas
MCDA	Multi-Criteria Decision Analysis
MFSP	Minimum Fuel Selling Price
MGO	Marine Gas Oil
TEA	Techno-Economic Analysis
VLSFO	Very Low Sulphur Fuel Oil
VRE	Variable Renewable Energy

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AUTHOR CONTRIBUTIONS
All authors contributed to the manuscript and approved the final version.

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The authors declare no competing interests.

DATA AND CODE AVAILABILITY
Data are available from the corresponding author upon reasonable request.

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