

Review article

Techno-economic assessment of decarbonization pathways for a gas to liquid facility: A review

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ABSTRACT

An overview of gas-to-liquid (GTL) fuels which explores various approaches to decarbonizing gas-to-liquid facilities is here presented. The review discusses optimization of heat integration in the air separation unit (ASU) to reduce energy requirements, the implementation of loop reactor concepts and gas-to-liquid looping to decrease CO₂ emissions, the use of amine absorber/stripper systems and reforming configurations to enhance CO₂ consumption, and the utilization of staged Fischer-Tropsch (FT) reactors to improve CO₂ recovery and tail gas recycle performance. The integration of gas-to-liquid processes with power plants and ammonia/urea synthesis plants is also examined as a means of utilizing CO₂ and improving process economics. The review further highlights the potential of power-based oxygen and hydrogen in biomass-to-liquid (BtL) processes for higher carbon efficiency and reduced greenhouse gas emissions. Techno-economic assessments were reviewed to evaluate the feasibility and profitability of different decarbonization pathways, considering factors such as capital and operational expenditures, product prices, internal rates of return (IRR), and carbon efficiency. The review identified challenges in water treatment and hydrogen purification for gas-to-liquid and small-scale gas-to-liquid plants. The findings emphasized the need for a comprehensive framework to mitigate CO₂ emissions from gas-to-liquid facilities and facilitate the effective decarbonization of the oil and gas industry.

1. Introduction

CO₂ emissions as of mid-2024 amounted to 36.8 Gt [1–4]. therefore, emissions reduction is imperative to keep global temperature rise below 2°C, to meet the goals of the Paris Climate Agreement. In 2021, petroleum refining, cement, iron and steel, and pulp and paper industries accounted for 9.4 GtCO₂ of global emissions [5–10]. and 68 % of industrial direct emissions [10]. Oil and gas extraction contributed 15 % to global emissions [11] and 14.6 GtCO₂ was from the power sector. This implies that the decarbonization of the petroleum refining industry is critical to meeting net-zero emissions, as already reported elsewhere [12–14]. In 2023, the energy-related Global CO₂ emissions grew marginally by 1.1 % [14]. Although these publications comprehensively assessed the decarbonization pathways for the power, petroleum refining, iron and steel, cement, paper, and pulp industries, a limited amount of information has been reported on the gas-to-liquid (GTL) facilities. For instance, Zhang et al. [15] evaluated the decarbonization opportunity for the power and industry sector in Thailand. The study identified and evaluated the CCS opportunity of stationary CO₂ sources

from the power and industry sectors such as coal-fired, natural gas-fired and waste-to-energy power plants, cement factories, refineries, iron and steel mills, petrochemical plants, and natural gas processing plants. The study posits that natural gas-fired power plants were the biggest CO₂ emission in the power sector and did not cover implications for GTL industry. Yanez et al. [16] conducted a techno-economic analysis of thirteen pathways with different bio-oils and compared their corresponding GHG mitigation potential in oil refineries. The study found that bio-oil co-processing pathways can reduce CO₂ emissions by 6 %–8 % without adversely affecting production cost, energy, and mass yield. However, the study did not provide a structured approach to help identify and categorize emission reduction initiatives, which makes it difficult to scale up the co-processing routes. This suggests that while the study found promising results for CO₂ emissions reduction through bio-oil co-processing, there may be implementation challenges that need to be addressed to make it a viable solution for reducing emissions in the oil refining industry. Griffiths et al. [17] performed a systematic review of oil refining industry decarbonization which aimed to identify pathways for the oil refining industry to evolve in a carbon-constrained

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world, evaluate existing, projected technical solutions as well as innovations to make low to zero carbon refined oil products a reality. It assesses the benefits of decarbonization efforts, identify and address barriers to implementation. Overall, the review aimed to inform policymakers, researchers, and practitioners on how to advance the low-carbon transition of the oil refining industry. However, it did not review the techno-economics associated with the decarbonization pathways it identified for the oil refining industry. Roussanaly et al., [18] analysed the cost implication of retrofitting a CO₂ capture to an integrated oil refinery using four refineries in Europe as case studies. The study highlighted that the retrofitting cost of CO₂ capture varied widely depending on the specific refinery and its emission sources, indicating the need for a case-by-case analysis before making any decisions on retrofitting CO₂ capture. However, a GTL facility was not considered in the analysis. Leeson et al. [19] the furnace, boiler, and gasifier as lead sources of CO₂ emissions while conducting a techno-economic analysis review of a petroleum refinery. However, the systematic review did not consider a GTL scenario. Nwaoha and Wood [20] the gas utilization options, export potential, and government policies that aim to stimulate gas investments in Nigeria. In their study, the use of natural gas to produce liquid fuels through GTL process was touted as a viable strategy for monetizing natural gas resources in Nigeria. However, no techno-economic analysis was carried out relating to Decarbonization of the existing GTL facilities to ensure long-term sustainability. The scope and conclusion of reviews on the techno-economic assessment of decarbonization pathways are summarized in Table 1.

Accordingly, there is a gap in the critical review of techno-economic assessment of decarbonization pathways for GTL, as the FT synthesis of natural gas to synthetic diesel, SAF and naphtha has proven to be viable alternative for monetising natural gas. The reviewed studies have not explored this area in depth, despite evidence suggesting that CO₂ emissions from the sub-processes in GTL facilities are higher than those from oil production and refining. Furnace combustion emissions contribute approximately 60 % of the total emissions from GTL facilities, as energy from the furnace is required to increase the temperature of process feeds in the Autothermal Reforming (ATR) unit, the product upgrading/refining unit, and to generate steam that powers turbines for air and natural gas compression, power generation, and process steam for the ATR steam methane reforming (SMR). Other process related emission sources include flares from the Fischer-Tropsch process and product upgrading unit waste gases, as well as fugitive and startup/shutdown related flaring. [30,31]. This highlights the need for a comprehensive review of available frameworks to abate CO₂ emissions from GTL facilities being a very high energy intensive process in the oil and gas industry. GTL facilities can be retrofitted with bio-feed sources to generate sustainable fuels for hard to abate industries like the aviation sector. Hence, the current study aims to provide a comprehensive review of the techno-economic assessment of various decarbonization pathways for GTL facilities focussing on scope 1 and 2 emissions, noting that Scope 1 tackles direct emissions from the facility processes, Scope 2 addresses indirect emissions from the production of purchased energy such as electricity, and Scope 3 defines other indirect emissions associated with the final use of refining products [32].

2. Overview of emission reduction pathways in the oil and gas industry

Numerous studies examining the potential for CO₂ mitigation in refineries have proposed a range of decarbonization strategies. These include enhancing energy efficiency, implementing carbon capture and bio-oil co-processing, accurate quantification of GHG emissions, evaluating the feasibility of post-combustion capture, and adopting low-carbon pathways, with a particular emphasis on renewable energy sources. These studies consistently highlighted that a combination of these strategies can lead to substantial reductions in emissions. Moreover, they indicated that the cost of CO₂ mitigation (capture and

Table 1

A summary of the review studies about Techno-Economic assessment of decarbonization pathways for oil and gas industry.

Ref.	Review scope	Main conclusions
Kazemifar et.al [21]	Decarbonization cost for CO ₂ capture from combustion of fossil fuels. Decarbonization cost for direct removal of CO ₂ from the atmosphere using natural and engineered solutions. Technological readiness level for this Decarbonization pathways.	The development of cost-effective and environmentally friendly CO ₂ capture technologies is crucial to reducing greenhouse gas emissions and mitigating climate change. Liquid solvents and solid adsorption are currently the most commercially available technologies for CO ₂ capture, while Calcium Looping shows promise as a low-cost and environmentally friendly alternative. Continued research and development in CO ₂ capture technologies are necessary to improve their efficiency, reduce their costs, and make them more widely available for industrial applications. Gas-fired oxy-combustion technology shows enormous potential for achieving near-zero CO ₂ emissions with high net efficiency, making it a viable option for mitigating CO ₂ emissions in the energy sector. Several challenges need to be addressed for the technology to be successful on a commercial scale. These include the development of alternative O ₂ supply processes, reducing the need for EGR, optimizing cycle operating pressure, and reducing system complexity and associated costs. Novel cycles such as SOF-NGCC and CLC-s CO ₂ have been recommended to address these challenges and have shown promising performance and low LCOE of 40 £ /MWh
Khallaghi et.al [22]	Comprehensive analysis of gas-fired oxy-combustion cycles, with a focus on identifying the key parameters and challenges associated with their development, as well as their economic performance.	Variables such as the cost of capture technology, the cost of transportation and storage, the rate of learning and technological development, and the rate of interest were found to have a significant impact on the cost of CCS deployment in the industrial sector. The review captures a cost range of \$20–70 per tonne of CO ₂ capture, with cement industry being the lowest due to its less complexity and single flue gas stream.
Leeson et.al [23]	Review and analysis of current academic literature on carbon capture and storage (CCS) in the industrial sector, with a focus on identifying costs of capture and key knowledge gaps. Examined the costs of CCS from near-pure sources of CO ₂ from other industries as well. The study used scenarios to estimate the cost per tonne of CO ₂ avoided for the major industries up to 2050 with a large-scale deployment, with a sensitivity analysis used to determine the main contributors to the overall cost.	
Rissman et. al [24]	Focused on decarbonizing the global industry sector to achieve climate stabilization and limit global warming to	The paper emphasizes the need for strategic and well-designed policy to accelerate innovation and provide

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Table 1 (continued)

Ref.	Review scope	Main conclusions
	2°C. The paper highlights technical and policy interventions that can help achieve this goal, including energy efficiency, carbon capture, electrification, and the use of zero-carbon hydrogen as a heat source and chemical feedstock.	incentives for technology deployment, including carbon pricing with border adjustments, robust government support for research, development, and deployment, and energy efficiency or emissions standards.
Hanak et.al [25]	The study examined the use of cryogenic O ₂ storage in an oxy-combustion coal-fired power plant as a form of energy storage and evaluated the techno-economic performance of the system.	The Decarbonization pathway has a high energy density and specific energy, which compares favourably to other energy storage technologies. Investment in cryogenic O ₂ storage has only marginally increased the specific capital cost of the system. The benefits of energy storage can be incorporated into the power plant at a marginal capital investment, resulting in an increase in daily profit.
Santos et.al [5]	A review of the state-of-the-art CO ₂ capture technologies for Decarbonization of the iron and steel, cement, petroleum refining, and pulp and paper industries.	Amine scrubbing is the least feasible option, while retrofits of emerging calcium looping have shown to improve the overall viability of CO ₂ capture for industrial Decarbonization. Identifies standardising the techno-economic assessment of technologies for industrial Decarbonization as a critical area for further research.
Plazas-Niño et.al [26]	Discusses the importance of energy system models (ESOMs) in devising decarbonization pathways to mitigate climate change while meeting energy demand sustainably, affordably, and reliably	The study stresses the importance of policy instruments to materialize the insights given by the models and proposes that policy-oriented research could complement energy findings by proposing effective policy frameworks in conjunction with energy system modelling.
Lechtenböhrer et.al [27]	Discusses the options available for deep Decarbonization of energy-intensive industries, such as cement, steel, petrochemicals, and pulp and paper. Discusses a quantitative scenario analysis of the potential future electricity demand that would result from a complete electrification of seven key basic materials production processes in the EU28, assuming a fossil- and nuclear-free future.	Future electricity demand that would result from a complete electrification of basic materials production in EU28, assuming a fossil- and nuclear-free future is possible from a renewable energy resource and technology point of view, but it would require a significant increase in industrial electricity demand.
Bataille et.al [28]	Discusses the challenges and opportunities associated with decarbonizing energy-intensive industries from a macroeconomic perspective.	Hybridization techniques should be used to include the potential for transformative, deep decarbonization in all modelling types used for analysis of the Paris Agreement goals. Stresses the importance of a comprehensive industrial policy framework dedicated to decarbonization of energy-

Table 1 (continued)

Ref.	Review scope	Main conclusions
Ribun et.al [29]	Focuses on advancements in motor fuel synthesis using various types of gases: natural gas, associated gas, and biogas. These gases serve as raw materials for GTL technology. Discussed advancements in feed gas purification, the application of FT synthesis, and the reforming of liquid hydrocarbon mixtures in the context of motor fuel synthesis.	intensive industries, which would require stringent innovation and market uptake policies from production to end-use, prioritized research, and support for institutions and business models. The article emphasizes that FT-synthetic fuels have favourable environmental and operational attributes, such as being non-toxic, biodegradable, and low in sulphur. They also result in reduced emissions of pollutants when used in engines. However, further advancements in technology and catalyst development are needed to optimize the production process and enhance the formation of higher hydrocarbons for improved fuel properties.

sequestration) could potentially reach \$64 per ton by 2050 [33].

Yanez et al., [30] study estimated the CO₂ mitigation potential for a medium-level conversion refinery using a bottom-up approach. It examined measures like energy efficiency, carbon capture and storage (CCS), bio-oil co-processing, blue and green hydrogen, green electricity imports, and electrification, focusing on the transition of Colombia's energy systems. The research assessed five deployment pathways: DP1 (Baseline – energy efficiency improvements (EEI)), DP2 (Less effort – EEI and bio-oil co-processing), DP3 (Maximum CO₂ reduction – includes CCS, green hydrogen, and electricity), DP4 (aligned with national contributions), and DP5 (Low-cost CO₂ mitigation below €200/t CO₂). The study found significant differences between the pathways, with DP3 and DP5 showing the most notable CO₂ reduction potential.

The study suggests that long-term options for CO₂ emission reduction show significant potential, with bio-oil co-processing accounting for around 60 % of the mitigation options portfolio for DP3 and DP5, followed by CCS with 23 %, GE with around 7 %, and H₂ measures with 6 %. It points out technical and economic constraints, such as competition for CO₂ streams and exclusion of certain CO₂ sources but notes that combined strategies can achieve substantial emissions reductions at competitive costs. However, refineries remain oil processing facilities, meaning fossil carbon is still present in their products. Yanez et al. [30] suggested that more research is required to investigate to what extent refurbishing existing refineries versus new low-carbon fuel facilities is viable from a technical, economic, and environmental point of view. Goret-Rana and Keeley [34] stress the importance of monitoring plant performance to reduce Scope 1 emissions, recommending steam methane reforming (SMR) to cut hydrogen plant emissions by up to 95 % through CO₂ capture. They also discuss blue and green hydrogen as methods to produce hydrogen without CO₂, which could aid in decarbonising fuel and chemical production. For Scope 2 emissions, they propose replacing imported electricity with low-carbon hydrogen and exporting excess low-carbon energy. Substituting natural gas with bio- and waste-derived fuels can help decarbonise production and reduce Scope 3 emissions. Griffiths et al. [12] argue that the oil refining industry will remain vital and can decarbonise while supplying low-carbon feedstocks and fuels to other industries. Despite drawbacks of alternative fuels, the study suggests focusing on sectors where these fuels are not yet viable and integrating low-carbon interventions into existing refining processes.

Berghout et al. [31] proposed an integrated method to identify

greenhouse gas emissions reduction pathways for a complex oil refinery by evaluating the techno-economic performance of various mitigation options at the core process level. This method considers synergies and negative interactions between options to provide realistic cost and risk insights. Applied to a large refinery in northwest Europe, the study examined four pathways: energy efficiency measures, carbon capture and storage (CCS), fast pyrolysis of biomass for transportation fuels, and gasification of torrefied wood pellets for electricity, hydrogen, or Fischer-Tropsch (FT) fuels. All pathways begin with energy efficiency measures, followed by various capture and gasification techniques. The most cost-effective pathway was biomass gasification with CCS, achieving significant emissions reductions (6.3 MtCO₂-eq/y, a 154 % reduction from 2012 levels) with an average avoidance cost of around −25 €2012/tCO₂-eq for a 75 % reduction target. The second most cost-effective pathway had an average cost of −5 €2012/tCO₂-eq, but the cost-effectiveness of pathways is highly dependent on future energy prices.

In another study, Yanez et al., [35] explored potential energy efficiency measures in the oil industry value chain in Colombia to reduce greenhouse gas (GHG) emissions and lower energy consumption. It identified key energy-intensive processes and proposed 20 measures to cut energy waste and emissions. Energy and GHG abatement curves were created to assess potential savings, revealing that energy use and CO₂ emissions could be reduced by 25 % and 19 %, respectively, with overall savings of 15 PJ. The study highlighted that cost-effective measures could lower CO₂ emissions by 700 kt per year. The most effective measure was improving the steam network in refineries. The use of organic rankine cycle (ORC) in gas-powered engines and transport was found to be highly cost-effective, while the highest investments were needed for optimizing the refinery gas network and improving gas turbine efficiency in power generation. The research suggests further investigation into the economic feasibility of these investments and potential deployment challenges to enhance GHG emission reductions. Forman et al., [36] studied the potential of the GTL pathway to achieve GHG emissions reductions and contribute to sustainable development and highlighted the need to comprehensively quantify and update the greenhouse gas (GHG) emissions benefits, associated with the GTL pathway, particularly about its coproduct emissions. The authors argued that by using the substitution method as seen in Fig. 3, which considers the emissions savings achieved by substituting conventional diesel fuel with GTL diesel, the downstream GHG emissions benefits of GTL coproducts can be accurately determined. This approach leads to a different result in terms of well-to-wheel (WTW) emissions compared to

the energy allocation method, which allocates GHG emissions based on the energy content of each product. It was suggested that understanding the GHG emissions benefits of GTL coproducts is essential to accurately assess the lifecycle GHG emissions of GTL diesel and to support the adoption of GTL as a lower-emission alternative to conventional diesel. However, the cost implication for implementing the GTL pathway was not captured in the study.

Straelen et al., [38] discussed a case study that evaluated the feasibility of installing a post-combustion CO₂ capture system at a complex shell refinery. The case study shows that it is technically feasible to use post-combustion capture to reduce greenhouse gas emissions in refining, with gasifiers being the cheapest source. However, the costs for capture and sequestration are currently 2–4 times higher than carbon trading values, making it economically unfeasible without significant regulatory incentives or technological advancements. The authors concluded that up to 50 % of emitted CO₂ from Shell refineries can be captured at comparable costs, but the rest would be significantly more expensive. The study suggests the need for a regulatory framework to create incentives for CO₂ capture and storage. A study by Gudde et al. [39] examined the impact of energy efficiency and CO₂ reduction measures on scope 1 and 2 CO₂ emissions using a top-down approach, as outlined in their report on low carbon pathways technologies. The study identified three primary pathways for reducing CO₂ emissions in refineries namely, (1) energy efficiency, which involves implementing activities to improve energy management and refinery process efficiency, such as utilizing improved catalysis, heat exchangers (HEX), motors, and creating new process plants; (2) the use of low carbon energy sources, including decarbonizing gas, burning liquid fuels, and recovering hydrogen and LPG from fuel gas; and (3) capturing portions of CO₂ emissions from refineries. However, the study highlighted a significant challenge in implementing these pathways due to the high cost associated with inadequate technological development. Belghazi et al., [40] conducted a study that explores different rates of technology deployment, energy prices, and decarbonization of the electricity grid to assess the potential reduction in CO₂ emissions and energy consumption in the EU refining sector. In the study, diverse options and their potential impact were identified, also the technologies involved, practical and financial factors, and the specific conditions of each asset was considered. Furthermore, Belghazi et al., [41] highlighted the potential for reducing CO₂ intensity in final fuels and non-fuel products through the recovery of low-grade heat, emphasizing the importance of CO₂ capture, energy efficiency improvements, and the use of low-carbon electricity in achieving emissions reductions. The findings suggest that by 2030, the

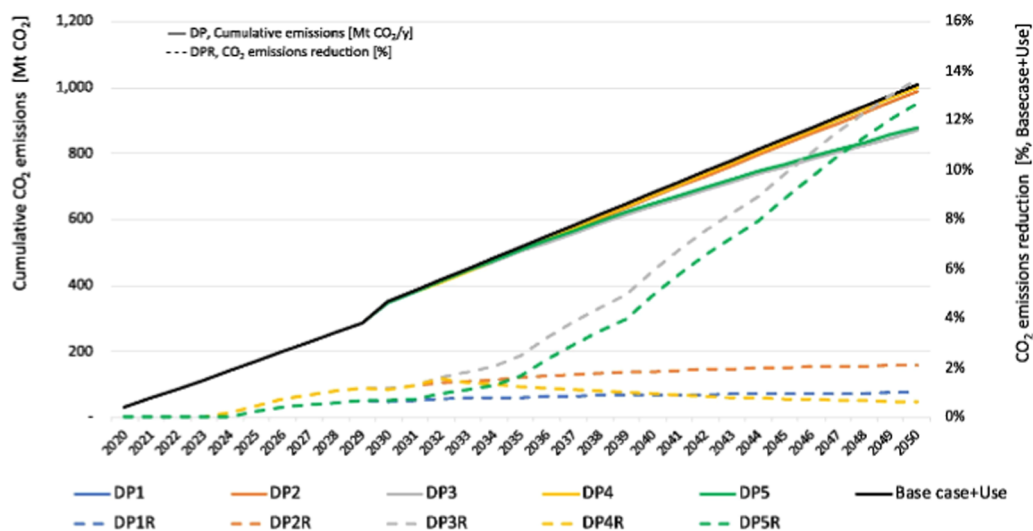


Fig. 1. Cumulative CO₂ emissions achieved for every DP compared to cradle-to-grave CO₂ emissions. Republished with permission from E. Yáñez et al. [30]. Copyright Elsevier.

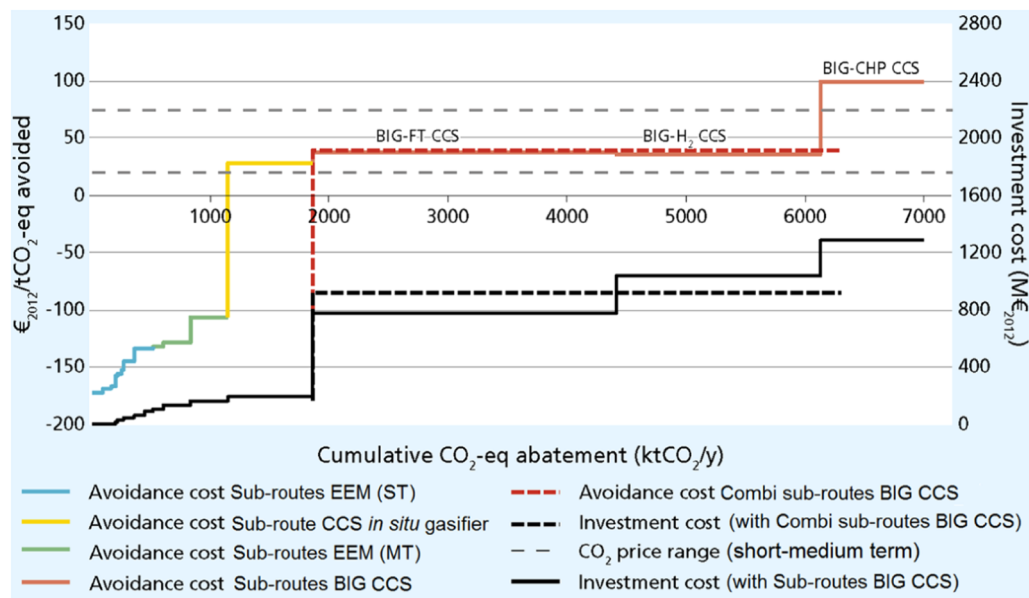


Fig. 2. Marginal abatement cost curve for EEM-BIG-CCS emission reduction deployment pathway Republished with permission from N. Berghout et al. [31]. Copyright Elsevier.

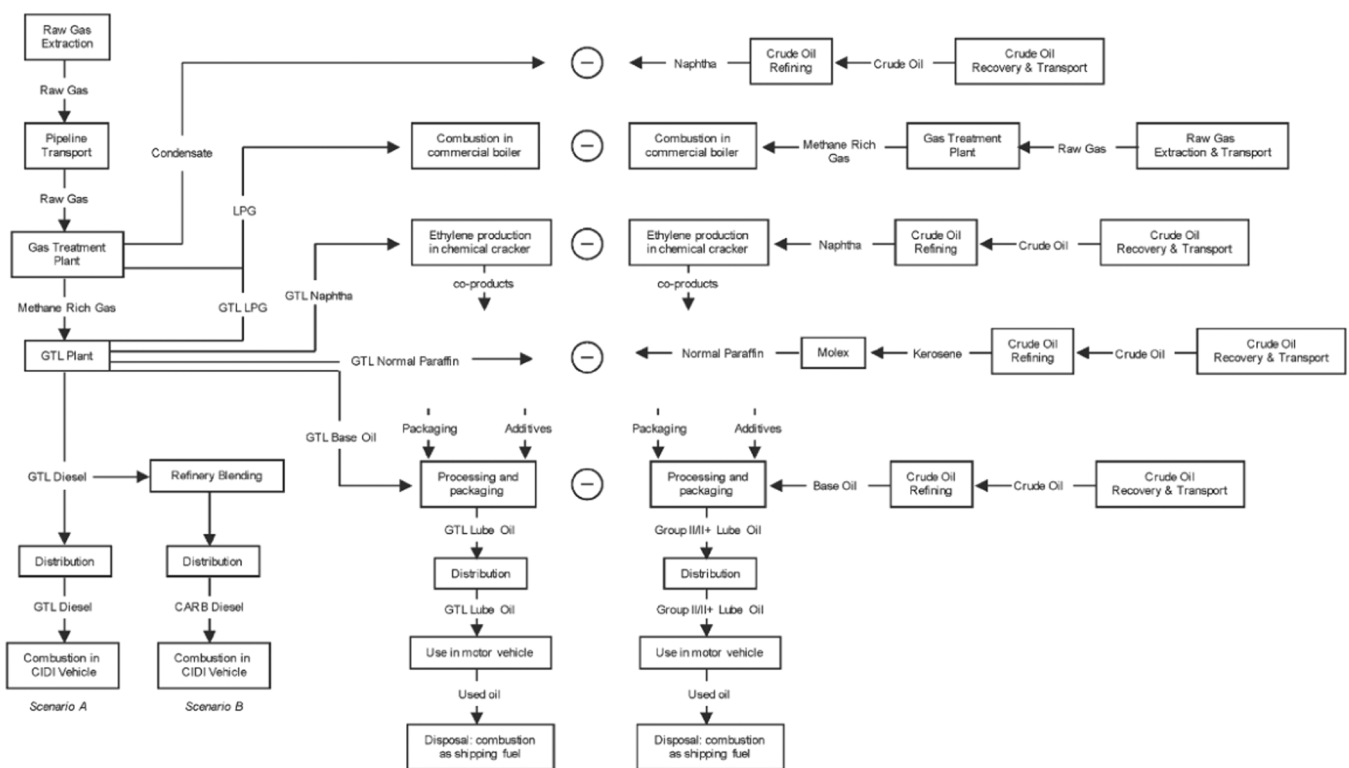


Fig. 3. Substitution method model of GTL pathway Republished with permission from Forman et al. [36] Copyright Elsevier.

EU refinery CO₂ emission intensity could be reduced by 20–30 %, and by 2050, up to 70 %, compared to the reference case. The estimated cost for implementing these options is at least €40,000 million. Saygin and Gielen [40], identified 20 options for reducing CO₂ emissions, grouped into five strategies: energy efficiency, renewable-based heating, biomass feedstocks, circular economy approaches, and synthetic hydrocarbons from green hydrogen and CO₂. These, along with carbon capture and storage (CCS) and proper carbon accounting, could significantly cut emissions. However, product costs may rise by over 35 %, necessitating

a green product premium or pricing of fossil fuel environmental impacts. Renewables will cover 70 % of energy use, and electrification and renewable feedstocks will contribute 40 % of emission cuts. The transition, costing \$4.5 trillion with \$64 per ton CO₂ mitigation cost by 2050, faces challenges, including limited large-scale experience.

In summary, the works highlighted the potential of decarbonizing refineries but also acknowledged the obstacles that need to be addressed, such as the viability assessment of refurbishing existing refineries or establishing new low-carbon fuel facilities. The successful

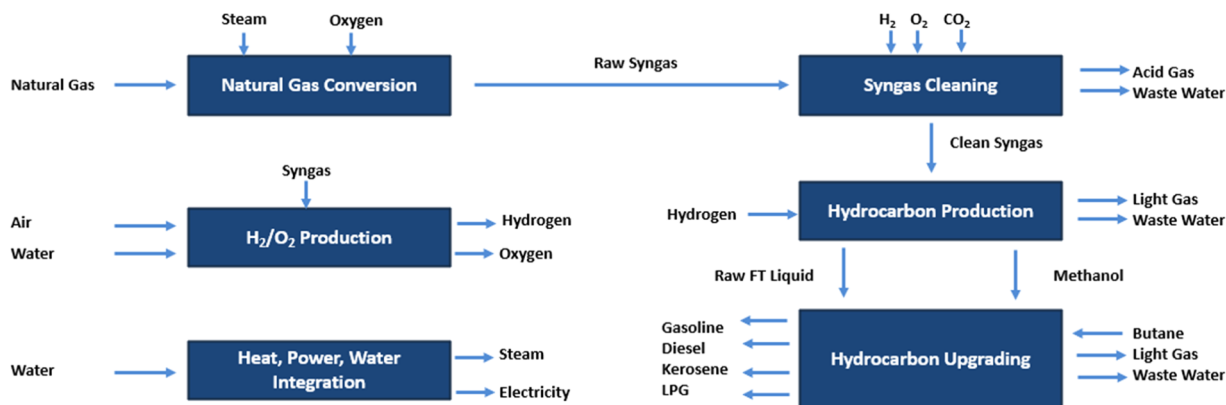


Fig. 4. Overview of GTL facility. Republished with permission from Tso et al. [37] Copyright Elsevier.

implementation of these strategies depends on overcoming technical, economic, organizational, policy, and social barriers. The ranking of pathways in terms of cost-effectiveness appears to be sensitive to future energy prices, hence, additional research is needed to understand the investment requirements and potential bottlenecks for deploying energy efficiency measures. It was also emphasized the need for a regulatory framework to incentivize carbon capture and storage. However, the high costs associated with inadequate technological development pose challenges. Limited experience beyond demonstration plants and the need for scaling up operations further complicate the transition. It is noted that achieving these decarbonization goals will require commitment from industrial sector operators, policymakers, and investors.

3. Decarbonization pathways for GTL facilities

GTL fuels are derived from the conversion of gaseous fuels, such as natural gas or biogas, into liquid forms, including clean-burning diesel fuel, liquid petroleum gas, gasoline, and naphtha. The resulting diesel can be used as a high-quality blending component for traditional diesel grades produced in conventional crude oil refineries [39,41,40]. The production process of GTL fuels involves several steps, including syngas generation, FT synthesis, and product upgrading [40,42–45]. In the syngas generation step, impurities are removed from the feed gas (natural gas) after which it is converted to syngas by either an autothermal reforming (ATR), SMR, gas-heated reforming (GHR) process or a combination of any two mentioned processes [46–48]. The resulting syngas is compressed to increase its pressure and moves to the F-T reactor. In the reactor, the syngas is converted to liquid hydrocarbons in the presence of a cobalt, ruthenium or iron catalyst through a process known as FT synthesis [49,50]. Finally, the liquid hydrocarbons are refined to produce the desired product [42–48,51,52,37,53–55]. GTL fuels have several potential applications, including in the transportation sector as well as power generation. In the transportation sector, GTL diesel can be used as a blend component or a standalone fuel, while GTL gasoline can be used as a premium blend component [51,56]. In the power generation sector, GTL fuels can be used to generate electricity in gas turbines, resulting in lower emissions and greater efficiency [57,58].

Typical GTL facility is made up of ASU, ATR, FT unit, refining unit, utilities and power, and the hydrogen production unit [59–62]. Approximately 60 % of CO₂ emitted in a typical GTL plant is from furnace operation, for steam boilers and process fired heaters. Steam boilers produce steam for turbines, process steam for SMR and utilities steam. Process Fired Heaters provide the heat of reaction needed for natural gas feed treatment (sulphur removal), pre-reforming of natural gas and hydro-processing of produced synthetic wax to GTL products), additional 30 % of emitted CO₂ are from the unconverted syngas (Tail gas) ex the Fischer Tropsch reactor, emissions from the refining unit as well as continuous purge accounts for the balance 10 % [63].

Reduction of these major emission sources provide a pathway for a comprehensive Decarbonization of the GTL facility. Studies have been carried out on scope 1 and 2 emission reduction for GTL units. Darde et al., [64] achieved a 20 % reduction in the energy requirement for ASU by optimizing the cryogenic air separation process through heat integration which involves transferring heat from the ASU compressor to the steam cycle. This process reduced the energy losses associated with compression and preheating boiler feed water. However, it did not consider the Integration of waste heat from the partial oxidation and SMR of pre-reformed natural gas from the ATR reactor to produce high-pressure saturated steam. This is proven to effectively reduce the steam boiler fuel consumption. Rahimpour et al., [53] carried out a study which aimed at an alternative to gas flaring and achieved a 10 % decrease in the CO₂ emission rate associated with the FT process for a GTL facility and recovering energy through a loop reactor concept for FT synthesis and a GTL loop as shown in Fig. 5. The performance of the GTL loop was evaluated through mathematical modelling, using a waste natural gas stream from a specific refinery in Iran. It was observed that the GTL loop system can recycle unreacted methane (CH₄), carbon monoxide (CO), and hydrogen (H₂) by circulating them, and enhance the yield of desired hydrocarbon products, particularly gasoline while reducing the production of undesired products like CO₂, however, it did not consider the utilisation of the flared unconverted stream from the FT reactor as a source of fuel for both the utilities and process furnaces.

In a study carried out by Baltrusaitis et al., [65] a quantitative economic comparison of five different processes for producing synthesis gas with a hydrogen-to-carbon monoxide ratio of 2, which is appropriate for the FT GTL process is presented. The research incorporated the use of an amine absorber/stripper system for Decarbonization while exploring various combinations of SMR, dry methane reforming (DMR), ATR, and reverse water gas shift (RWGS). It has been reported that the configuration of SMR/DMR not only consumes more methane than its nearest competitors but also acts as a net consumer of CO₂, which makes it an appealing option from a Decarbonization, sustainability, and environmental protection standpoint. Rafiee et al. [66] conducted a separate study showcasing how the implementation of a staged F-T reactor can optimize the GTL process. This optimization enables a significant reduction in the CO₂ recovery percentage and an impressive enhancement in tail gas recycle performance, reaching up to 80 %. As a result, the carbon footprint of the GTL facility can be substantially reduced. Corroborating the result of Raffie et al. [66], Panahi et al., [67] demonstrated that Decarbonization of GTL facilities could also be achieved when captured CO₂ from the flue gas of the steam reformer is fed to a SMR to reduce the H₂/CO molar ratio of the fresh syngas. Another study, conducted by Rafiee et al., [68], investigated the effect of CO₂ removal from tail gas through a case study. The findings showed that an optimized ATR-based process achieves carbon efficiencies of 73.5 % and 77.3 % with and without CO₂ removal, respectively. Fazeli et al., [69]

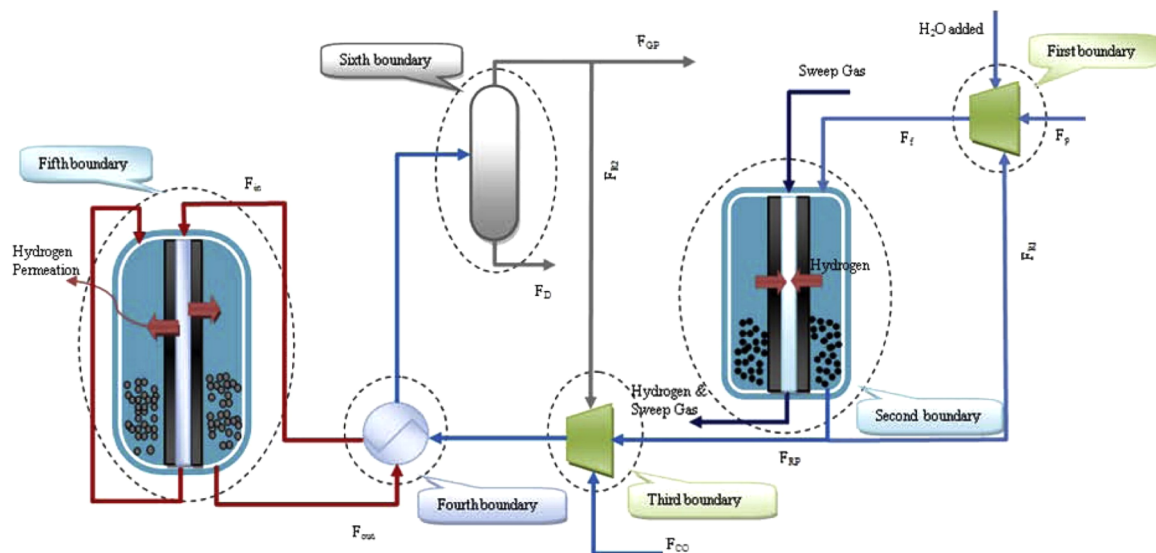


Fig. 5. Schematics of GTL loop system, Republished with permission from Rahimpour et al. [53].

focused on the simulation and optimization of an iron-based GTL plant, aiming to maximize the rate of wax production and carbon efficiency. Two methods of syngas production, namely SMR and ATR, were evaluated. The findings revealed that in the SMR-based GTL process, a total of 178 tons per hour of pure CO_2 can be consumed from a co-located power plant thereby improving decarbonization efforts of the GTL facility. Rafiee et al. [70] conducted a study to explore the integration potential of a fossil fuel-based power plant with a GTL plant. They specifically investigated the impact of introducing captured CO_2 into an existing FT-GTL process. The results indicate that when using a stand-alone SMR-based reformer, the captured CO_2 from the power plant can be efficiently employed as a feed to adjust the H_2/CO ratio. This suggests that in regions where carbon-rich raw materials such as natural gas and coal are readily available at low prices, the co-production of power and GTL fuels integrated with a CO_2 capturing plant is a viable option for effectively utilizing a substantial amount of CO_2 emitted by power plants. Ziaei et al., [71] carried out a study which focused on integrating a GTL process with an iron-based FT(FT) reactor, ammonia synthesis, and urea synthesis plants to convert carbon dioxide (CO_2) into beneficial products. The goal was to reuse CO_2 released from the GTL process and improve the process economy. Solar-powered polymer electrolyte membrane (PEM) electrolyzers were used to generate the required hydrogen for ammonia production. Optimization techniques were applied to maximize carbon efficiency and profitability. The results showed that the integrated system could produce 48 tons per hour of urea and utilize 35 tons per hour of CO_2 from the GTL process. A comparison was made with a configuration using a cobalt-based FT reactor, revealing higher profitability, carbon efficiency, and urea production for the cobalt-based system, while the iron-based system had a higher wax production rate. The study also indicated the techno-economic feasibility of achieving around 100 % carbon efficiency in a zero CO_2 emission process. Study on decarbonising GTL units through colocation with a urea and ammonia synthesis units for the purpose of utilizing the CO_2 in GTL tail gas for urea and ammonia synthesis have been carried out by Ziaei et al., [72]. The study concluded that about 13.71 % (37 tonnes/h) of the CO_2 produced in the GTL process can be utilized in the urea production unit, leading to an 8 % enhancement in the profitability of the integrated process.

Optimizing GTL processes to achieve improved high wax and CO₂ removal using Hybrid artificial neural network-genetic algorithm-based technique was carried out by Khezri et al. [73]. The passage discussed the importance of process optimization in achieving energy efficiency, cost reduction, and maximizing product generation, specifically in GTL

process. The results show that the artificial neural network-genetic algorithm (ANN-GA) approach improves the wax production and CO₂ removal rate and significantly reduces the optimization time.

Yaeshi et al. [65] focused on the impact of CO₂ injection on GTL performance. Their work suggested that incorporating CO utilization within the GTL process has the potential to optimize product output and reduce carbon emissions. The study assumes that the injected CO₂ is captured from the GTL facility using amine solvents, with a CO₂ capture efficiency of 90 % and a target of capturing 15 % of emissions. The simulations conducted in the study explore three scenarios. In Scenario 1, the captured CO₂ is directly fed into the ATR. In Scenario 2, the captured CO₂ is also fed into the ATR, but the study monitors the ratio of hydrogen to carbon monoxide (H₂:CO) before and after the ATR, considering the recycle tail gas from the separator that feeds the FT reactor. In Scenario 3, the captured CO₂ is directly fed into the SMR. The results indicate that Scenario 2, where a limited CO₂ feed rate of 1500 tons per day is introduced, performs the best. This configuration demonstrates enhanced performance in terms of product output. On the other hand, Scenario 3, which incorporates the SMR, leads to increased product output but records the lowest performance. Overall, the study suggests that utilizing CO₂ can improve the profitability of the GTL process while minimizing its environmental impacts.

Another option for decarbonising GTL facilities would include a BtL process that incorporates power-based oxygen and hydrogen to enhance its performance. Dosow et al., [74] showed this in a study which aimed at improving product yield, carbon efficiency, and the integration of renewable power generation into sectors that are challenging to decarbonize. Compared to a highly integrated BtL process, the novel PbtL

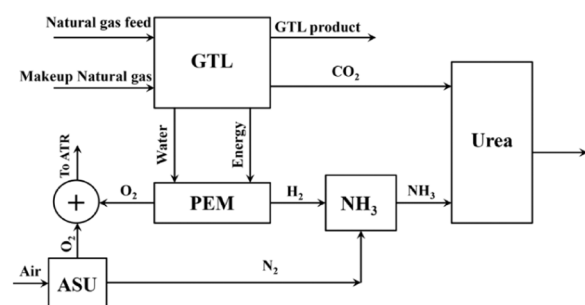


Fig. 6. Schematic diagram of integrated process Republished with permission from Khezri et al. [63].

process pathway (utilizes green hydrogen to convert biomass to renewable liquid fuels) as shown in Fig. 8 achieves a significant increase in carbon efficiency, ranging from 67 % to 97 %, compared to the 40.5 % carbon efficiency of the traditional process. Additionally, the required size of the electrolyzer, (a device used for electrolysis to produce hydrogen) is reduced by about 34 % compared to PBtL processes while producing the same amount of FT fuels. The investigated PBtL process can achieve greenhouse gas (GHG) emission reductions of about 76–78 % compared to fossil gasoline or heavy oil.

Based on the literature review, decarbonizing GTL facilities offers numerous benefits, including reduced energy requirements and decreased CO₂ emissions, a summary of key decarbonization approaches are discussed in Table 3.

3.1. Decarbonization of GTL – Bioenergy Pathway for Sustainable Aviation Fuel (SAF)

The conversion of captured or generated CO₂ into methane or alcohols, a process known as hydrogenation, is recognized as a significant challenge. This difficulty arises primarily from the inert characteristics of CO₂ and the rapid utilization of surface-adsorbed hydrogen. Consequently, the predominant outcome of CO₂ hydrogenation is the production of short-chain hydrocarbons, including methane, methanol, and olefins typically found within the liquefied petroleum gas (LPG) range [78]. Decarbonizing the aviation industry is a pressing concern, given its substantial contribution of approximately 1 gigaton (1 Gt) of CO₂ emissions, equivalent to 2.5 % of global CO₂ emissions [79].

Green hydrogen a zero-carbon fuel option that can be generated from electrolysis of produced water from GTL ATR and FT reactor, was considered as an aviation fuel, due to its large energy per mass and its smaller energy density per volume the tank configuration would be larger and its wall thickness bigger, this would significantly increase the plane weight [80] Biofuels from biomass feedstocks for aviation are the commercially viable and cost-effective option to produce (Bio-SAF) this is due to its less hydrogen requirement (5–30 lesser electricity demand as compared to SAF produced from electrolysis (e-SAF)), Boter et.al [81] results highlights e-SAF uses (10–20) times less land for the same product volume when compared to Bio-SAF, considering the land requirement to produce e-SAF from renewable electricity, which is approximately 5–7 acres for 1 MW of solar PV plant [82] land consideration would no longer be a major value driver. To tackle this challenge, the most promising pathways involve enhancing process efficiency and substituting conventional or synthetic jet fuel with jet fuel derived from sustainable bio-sources. Fig. 9 highlights the harmonized GTL decarbonization pathways that contains utilization of existing GTL facilities as a CO₂ sink, with the potential to loop in CO₂ from biogenic

sources to produce syngas and synthetic natural gas. CO₂ captured from GTL furnace and tail gas to flare can be utilized with additional green hydrogen to produce Synthesis gas, this replaces the high energy intensive ATR and ASU, the sustainable syngas is then oligomerised in the FT reactor to produce synthetic wax that is hydro processed to produce e-SAF.

A potential approach entail utilizing CO₂ obtained from the fermentation process and integrating it into existing GTL facilities to produce SAF. During the production of bioethanol through fermentation, the resulting CO₂ boasts a high concentration, approximately 96 %, with impurities that can be efficiently treated using the existing purification unit in GTL processes [12]. This approach presents a practical solution, as the concentrated CO₂ generated during bioethanol production can be repurposed and processed within GTL facilities to produce SAF. By harnessing CO₂ as a feedstock in this manner, the aviation industry can make substantial strides in reducing its carbon footprint and transitioning to a more sustainable and eco-friendly fuel source. Importantly, the cost of purifying one ton of CO₂ obtained from bioethanol production is significantly lower, varying between \$12.7 to \$25, in comparison to the future (2035–2040) cost of between \$200 to \$600 per ton of CO₂ associated with direct air capture (DAC) technologies. The reduced purification cost linked to CO₂ from bioethanol is attributed to its relatively high concentration, approximately 96 %, acquired from the fermentation process. This high concentration facilitates easier and more cost-effective impurity treatment, utilizing existing GTL feed purification units. In contrast, DAC technologies aim to capture CO₂ directly from the ambient air, where the concentration of CO₂ is much lower, approximately 400 parts per million. This process involves more complex and energy-intensive methods, resulting in significantly higher costs compared to the purification of CO₂ from bioethanol. Given this substantial cost disparity, utilizing CO₂ from bioethanol production for various applications, such as sustainable aviation fuel production, presents a potentially more economically viable and efficient path toward reducing CO₂ emissions and achieving decarbonization objectives [83, 84]. Table 4 displays projected expenses for the separation of CO₂ from various origins.

Indeed, the CO₂ generated from several bioethanol producing facilities can be seamlessly aggregated, compressed and piped into an existing GTL facility, leading to a range of potential applications. One particularly promising pathway involves the conversion of CO₂ through the reverse water gas shift (RWGS) reaction Eq. 1. This chemical transformation entails converting CO₂ into carbon monoxide (CO), a crucial component of synthesis gas. The RWGS reaction offers an attractive avenue for decarbonization by utilizing CO₂ as a valuable feedstock, thereby reducing overall emissions and the carbon footprint. The synthesis gas produced through this process holds significant utility,

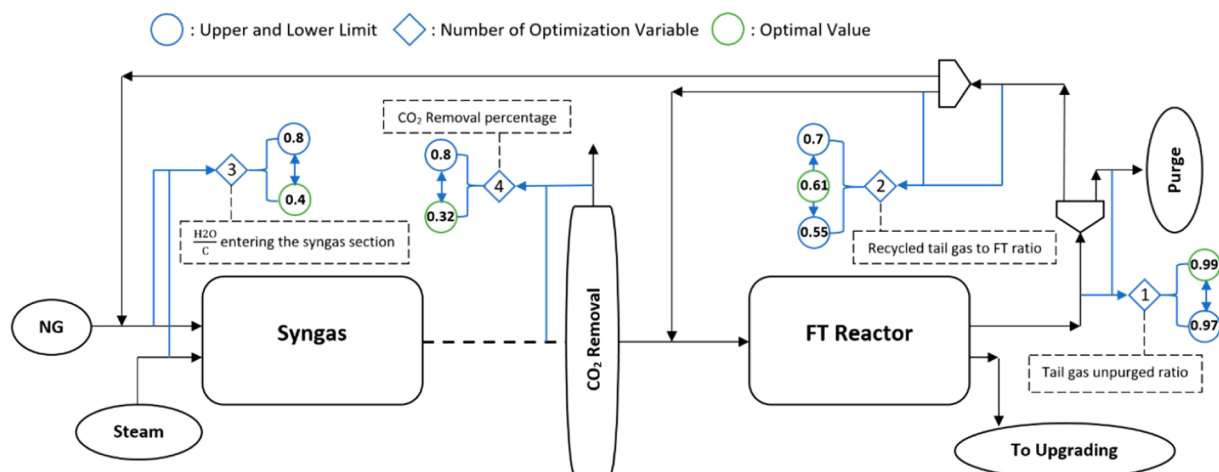


Fig. 7. GTL process flowsheet showing optimization variables, intervals, and optimal values Republished with permission from Khezri et al. [63].

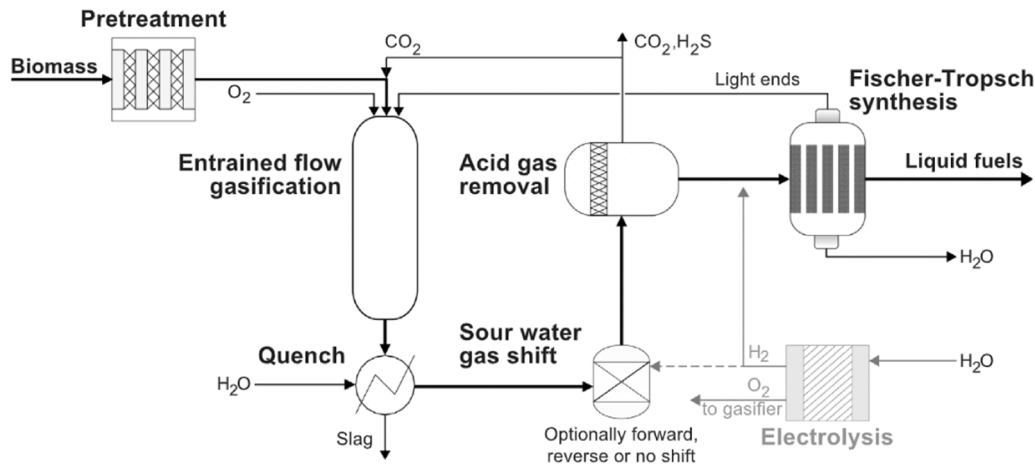


Fig. 8. PBtL process flowsheet [74].

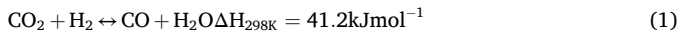
Table 2
A summary of emission reduction pathways in the Oil and Gas industry.

Pathway	Description	Potential Emission Reduction	Cost-Benefit Analysis	Ref.
Methane Leak Detection and Repair (LDAR)	Implementing regular inspections and repairs to reduce methane leaks from equipment.	40–50 % reduction in methane emissions.	High benefit-to-cost ratio; relatively low-cost implementation with significant emission reductions.	[42]
Electrification of Operations	Replacing gas-powered equipment with electric alternatives, powered by renewable energy.	Up to 100 % reduction in direct emissions from affected operations.	High initial costs, but long-term benefits in emission reduction and potential energy savings.	[43]
Carbon Capture and Storage (CCS)	Capturing CO ₂ emissions and storing them underground.	80–90 % reduction in CO ₂ emissions from point sources.	High capital costs but becoming more economically viable with technological advancements and policy support.	[44]
Flare Gas Recovery	Capturing and utilizing gas that would otherwise be flared.	Up to 90 % reduction in flaring emissions.	Moderate costs with potential for revenue generation from recovered gas.	[45]
Energy Efficiency Improvements	Implementing more efficient processes and equipment.	10–20 % reduction in overall energy-related emissions.	Often cost-effective with short payback periods.	[46]
Renewable Energy Integration	Incorporating renewable energy sources for power generation in operations.	Up to 100 % reduction in emissions from power generation.	High initial costs but decreasing over time; long-term benefits in emission reduction and energy security.	[47]
Process Optimization and Digitalization	Using AI and machine learning to optimize operations and reduce waste.	10–15 % reduction in overall emissions.	Moderate initial costs with potential for significant operational savings and emission reductions.	[48]

Table 3
Summary of the decarbonization approaches discussed in the literature and their corresponding outcome.

Ref	Decarbonization pathway	Outcome
Darde et. al [75]	Optimization of heat integration from ASU compressor to steam cycle	20 % ASU energy requirement
Rahimpour et. al [46]	Loop reactor FT and GTL looping	10 % reduction in CO ₂ emission rate
Baltrusaitis et. al [76]	Amine absorber/stripper system and SMR/DMR configuration	Effective CO ₂ consumption
Rafiee et. al [56]	Staged FT reactor	80 % tail gas recycle performance
Panahi et. al [57]	SMR flue gas recycle	Reduction in syngas H ₂ /CO molar ratio
Rafiee et. al [77]	Tail gas CO ₂ removal using ATR-based process	73.5 % carbon efficiency
Fazeli et. al [60]	Optimized SMR-based GTL process with CO ₂ from co-located power plant flue gas	Utilized 178 tons/hr of CO ₂ at 100 % plant capacity
Rafiee et. al [66]	Standalone SMR-based reformer with CO ₂ from co-located power plant flue gas	Reduction in syngas H ₂ /CO molar ratio
Ziae et. al [71]	GTL integration with iron-based FT reactor ammonia and urea synthesis plant	Utilized 35 tons/hr of CO ₂
Ziae et. al [72]	GTL co-location with ammonia and urea synthesis plant	Utilized 37 tons/hr of CO ₂ representing 13.7 % of the GTL produced CO ₂
Dossow et. al [74]	BtL process which incorporates power-based oxygen and hydrogen	97 % carbon efficiency and 76 % – 78 % reduction in GHG emission at 100 % capacity

serving as a precursor to produce fuels, chemicals, or even bio natural gas through the Sabatier Power-to-Gas route. Through the integration of CO₂ into existing GTL facilities and the application of chemical conversions like the reverse water gas shift reaction, the CO₂ derived from bioethanol production becomes a valuable resource for generating useful gases and compounds. This approach not only contributes to decarbonization efforts but also mitigates the environmental impact of CO₂ while providing sustainable and alternative energy sources [87].



The existing fired heaters in the autothermal reforming loop of the GTL facility can be retrofitted to provide the needed heat required to facilitate the formation of CO from RWGS. Produced hydrogen from the electrolysis of treated process condensate from the ATR would be used for the RWGS reaction. The hydrogen comingles with the CO stream from the RWGS Knock Out Drum (KOD) to meet the syngas H₂:CO ratio

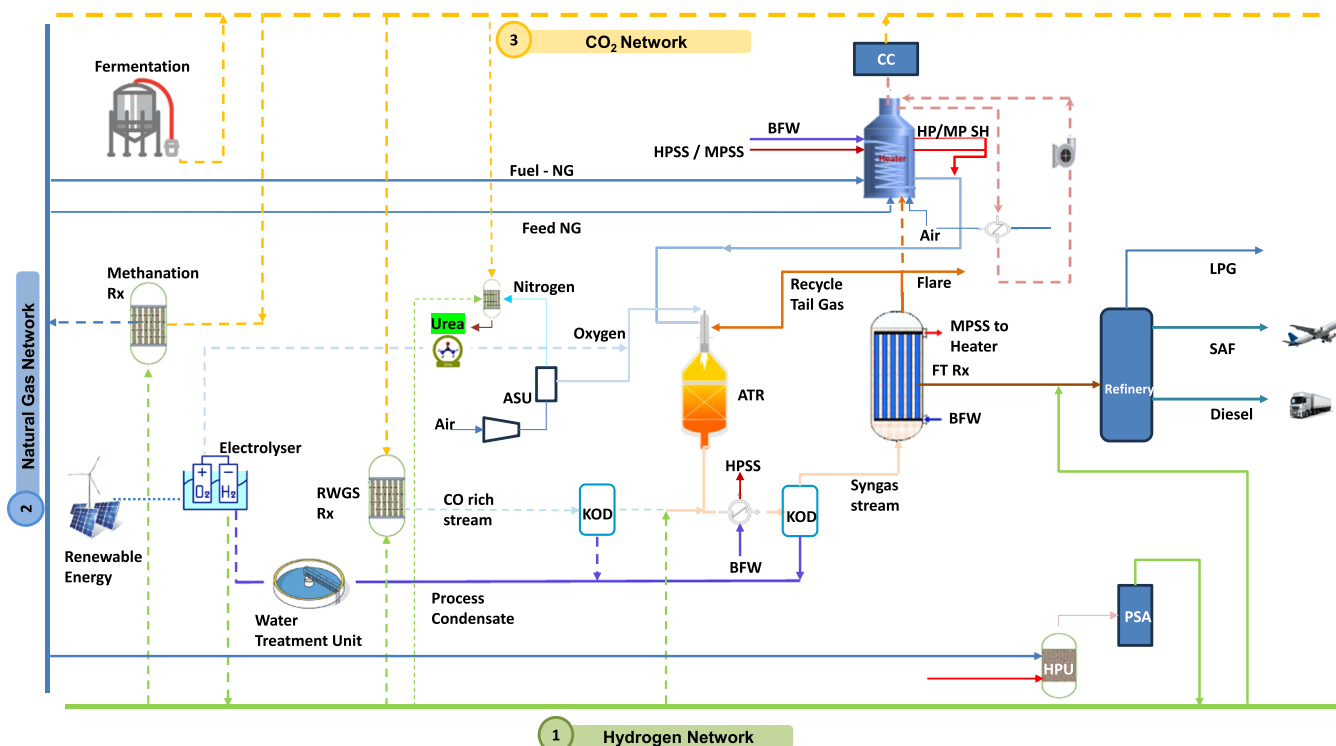


Fig. 9. Harmonized Decarbonization GTL Pathways to produce SAF.

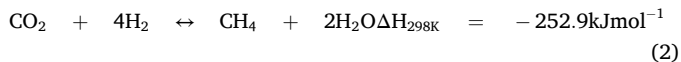
Table 4

Estimated cost of CO₂ separation cost from various sources [85,86].

Source of CO ₂	CO ₂ Concentration %	Separation Cost [\$/ton CO ₂]
Bioethanol	99	12.7 – 25
Ammonia	30–99	21.2
Cement	14–33	54.8–95.3
Iron & Steel	20–27	32.6 – 44

needed for the FT synthesis.

3.1.1.1 Methanation of CO₂ The process of hydrogenating CO₂ in the presence of a catalyst was originally pioneered by Sabatier and is commonly known as Power-to-Gas (PtG), Eq. 2. PtG serves as an innovative energy carrier, effectively integrating surplus renewable energy into the existing gas network. It offers a practical avenue for CO₂ utilization by combining green hydrogen, produced through the electrolysis of water [88], with CO₂ sourced from industrial or biogas streams. This combination results in the production of synthetic natural gas (SNG), providing a versatile and environmentally friendly energy solution [89]



Produced biogas from the breakdown of organic matter can be integrated into existing gas infrastructure and serve as a feed for existing GTL plants as shown in Fig. 9.

3.1.1.1. Methanol to Gasoline (MTG)

An alternative pathway for utilizing biogenic or captured CO₂ involves the Methanol-to-Gasoline (MTG) synthesis, which presents distinct advantages compared to the FT synthesis. While FT synthesis yields a broad spectrum of straight-chain olefinic and paraffinic products requiring additional hydro-processing to become synthetic fuels, MTG directly produces refinery-grade synthetic gasoline alongside a stream of liquefied petroleum gas (LPG) and off-gas. MTG technology has undergone successful demonstrations by several companies, including ExxonMobil, UOP Honeywell, LanzaTech, and Sinopec. These

demonstrations have underscored the feasibility of converting methanol, derived from biogenic or captured CO₂, into high-quality synthetic gasoline compatible with existing infrastructure and vehicles. The resulting synthetic gasoline closely resembles conventional gasoline, eliminating the need for extensive refining or further processing [90]

The MTG synthesis pathway stands out as an efficient and economically viable means of harnessing CO₂, transforming it into a valuable fuel resource. This method offers a more direct and efficient route to producing synthetic gasoline, rendering it an attractive choice for sustainable fuel production and simultaneously reducing the carbon footprint related to transportation. A consortium led by LanzaTech has successfully conducted a pilot project, converting CO₂ from biogas into synthesis gas. Their approach provides a practical alternative to the cost-intensive FT process by upgrading synthesis gas to ethanol and 2,3-Butanediol (2,3-BDO). With higher natural gas prices (3–4.5 \$₂₀₂₃/MMBTU, Henry Hub), the OPEX for existing GTL facilities can be reduced if the innovative LanzaTech approach as seen in Fig. 10 can be integrated, substituting GTL natural gas feed with cheaper biogenic captured CO₂ in regions like the United States where fermentative CO₂ are easily accessible or utilization of cheaper biomass residue with price ranging between (1.8–2.2 Nm³/kg dry biomass), this will cater for the growing demand for SAF [91]

In a comprehensive study conducted by Brynolf et al. [93], an analysis of the production costs associated with utilizing captured CO₂ and renewable hydrogen generated through electrolysis to produce electrofuels intended for the transport sector was carried out. This analysis revealed a significant reduction in the production cost range, which shifted from €10–€3500 per MWh of fuel (in 2015) to a considerably narrower band of €200–€280 per MWh of fuel (also in 2015). Projections indicate a further decrease in these costs to a range of €160–€210 per MWh of fuel by the year 2030. The study conducted a sensitivity analysis to identify key parameters exerting the most substantial impact on electrofuel production costs. Notable factors include the cost of renewable hydrogen production, electrolyzer capacity, their lifespan, and prevailing electricity prices. Furthermore, the selection of decarbonization technology pathways plays a crucial role in cost

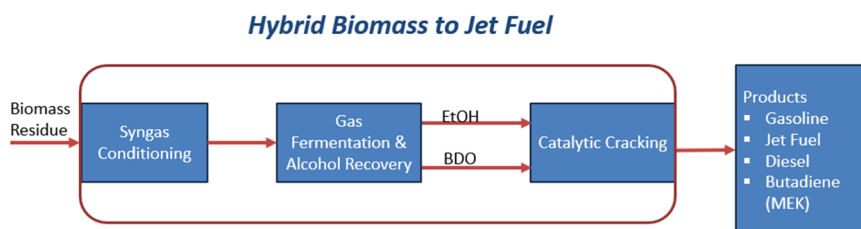


Fig. 10. Cost effective Biogas to Liquid Process [80,81,92].

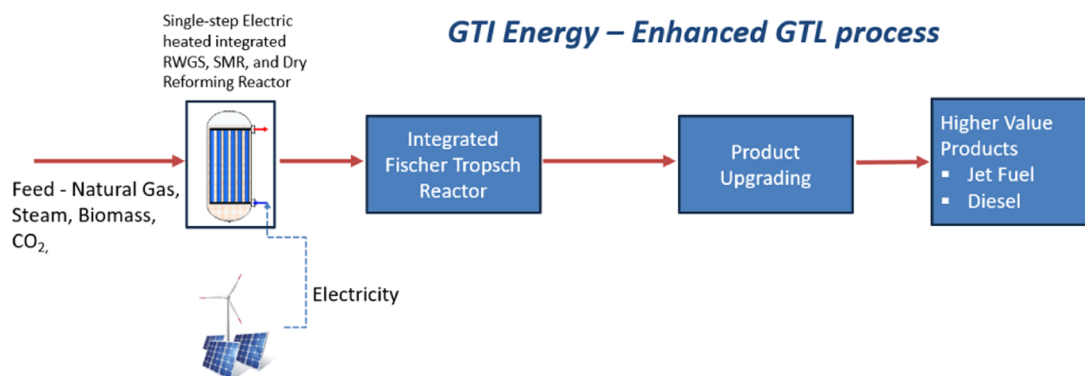


Figure 11. Low Carbon GTL process – Culled from GTI Energy CoolGTL [103].

considerations, while the choice of energy carrier and external factors exert comparatively lesser influence. The primary objective of this research is to reduce carbon footprint through the adoption of low-carbon fuels, specifically electrofuels. Within this context, the PtL approach employs similar feedstock to electrofuels. PtL encompasses two major pathways: FT synthesis and Methanol synthesis, both capable of producing nearly carbon neutral SAF. These pathways share similarities in energy efficiency and the potential for waste heat integration and recovery. To address the intermittent nature of renewable energy sources, the implementation of backup hydrogen tanks is deemed necessary. SAF generated through the FT pathway, specifically FT-SPK (FT Hydro processed Synthesized Paraffinic Kerosene), has met the ASTM D7566 standard for synthesized jet fuel evaluation and has been blended with conventional jet fuel since 2009. However, SAF produced through the methanol pathway is yet to receive approval for commercial use. In a report by Ludwig-Bolkow-Systemtechnik GmbH [94], the production scale was increased to 100,000 tons of SAF annually.

This review estimated the production cost of SAF, the cost of renewable electricity was based on data from IRENA renewable power generation cost in 2022 [95], where an estimated cost of 3.5 cents per kWh of electricity was factored in.

As technology in the renewable energy sector continues to advance, we can anticipate a significant reduction in the price disparity per ton between traditional aviation fuel and renewable jet fuel.

3.1.2. Low carbon state-of-the art GTL process

The transformation of GTL technologies represents a critical frontier in addressing global energy transition and carbon mitigation challenges. Recent technological innovations have fundamentally redefined synthetic fuel production through advanced electrification, catalysis, and integrated conversion strategies. Two pioneering technologies have emerged as transformative solutions, at the forefront of these developments are: GTI Energy's GTLSM process and COOLGTL's electric tri-converter technology.

GTI Energy introduced a groundbreaking approach that utilizes more carbon than it produces, efficiently converting natural gas, biomass, renewable natural gas (RNG), and CO₂ into high-quality liquid fuels with zero byproducts [96]. The GTLSM process represents a modular,

low-cost solution that minimizes the carbon footprint of GTL conversion by combining innovative low-temperature natural gas reforming with a novel Fischer-Tropsch reactor. A significant milestone in this development is the Department of Energy (DOE)-funded project, which aims to validate the technology's scalability through a fully integrated pilot-scale unit capable of producing 100 gallons of sustainable aviation fuel (SAF) [97].

Complementing this innovation, COOLGTL's electric tri-converter technology revolutionizes fuel synthesis by integrating electric heating, biomass conversion, and e-fuel production into a single platform [98]. Unlike traditional Fischer-Tropsch systems that rely on natural gas-fired furnaces, this approach eliminates fossil fuel combustion for process heating, substantially reducing carbon intensity. The technology's advanced catalytic systems enable precise molecular composition control, facilitating the production of high-value fuels such as sustainable jet fuel. The product streams are diesel and jet fuel with no low-value Naphtha, which is typically produced from traditional FT processes.

The landscape of fuel production has witnessed remarkable advancements in alcohol-to-fuel conversion technologies. Companies like Topsoe and LanzaJet have demonstrated sophisticated capabilities in oligomerizing ethene to produce targeted hydrocarbons with superior molecular weight control [99,100]. Electrification strategies have emerged as a pivotal technological vector, with Sunfire's solid-state electrolysis cells achieving unprecedented electrical-to-fuel conversion efficiencies of up to 80 % in laboratory settings [101,102]. Concurrently, Topsoe's electric reverse water-gas shift (RWGS) reactor has improved hydrogen production efficiency by 35 % compared to traditional GTL processes [100].

A particularly compelling development is the integration of artificial intelligence in catalyst design. High Alpha's proprietary Fischer-Tropsch catalysts exemplify how machine learning can enhance selectivity and efficiency in hydrocarbon synthesis [103]. This approach represents a significant leap in catalytic optimization, enabling more precise and controlled fuel production processes [104–106].

Thermal management innovations distinguish these emerging technologies. COOLGTL's electric heating system offers greater control over process dynamics while simultaneously reducing carbon emissions. By

combining renewable electricity with biomass feedstocks, the technology enables carbon-neutral or even carbon-negative fuel production pathways that transcend traditional fossil fuel limitations [98].

The convergence of these technological innovations illustrates a new paradigm in sustainable fuel synthesis. GTI Energy's Cool GTLSM process and COOLGTL's tri-converter technology provide scalable, efficient, and economically viable solutions that address both climate goals and growing energy demands. These approaches achieve substantial reductions in carbon intensity while maintaining fuel quality and production flexibility [96].

4. Techno-economic assessments of GTL decarbonization pathways

A strategic approach that considers techno-economic feasibility is required to reduce CO₂ emission in GTL. These strategies discussed include small-scale GTL technology for flare gas reduction, integration of GTL with biogenic/ concentrated CO₂ sources to produce SAF, integration of GTL with CO₂ from DAC, Coal-to-Liquid (CTL) with CCS, post-combustion CO₂ capture at an oil refinery, Micro-refinery unit (MRU) for gas treatment, and flare gas reduction offshore. Techno-Economic Models for GTL and CTL Plants, as well as life-cycle assessment for synthetic fuel GTL plants were also discussed in this section.

Utilization of CO₂ from biogenic/concentrated sources as well as DAC can be utilized to decarbonize GTL, the assumptions in Table 5 were used to generate the results shown in Table 6.

Table 6 presents the techno-economic outlook regarding the production cost of SAF through PtL, employing various decarbonization pathways. The equivalent annual full load period for PtL was assumed to be 43 % (3750 hours), The annualised plant cost is a product of total

Table 5
Assumption basis used for TEA Related to the Production Costs of SAF via Methanol and FT Pathway.

Variables	Symbol	Unit	FT Pathway	Methanol Pathway	Reference
Project Interest Rate	r	%	8	8	[107]
Project Lifetime	T	Yrs	30	30	[107]
Electrolyzer Lifespan	T _{elec}	hrs	15	15	[93]
Annual Full Load of PtL	Load	hr	3750	3750	[93]
Fuel/Natural Gas Cost	C _{fuel}	\$/GJ	3.3	3.3	Average Henry Hub 2023 [107]
Indirect Capital Cost	ICC	% of Purchase Cost	30	30	[107]
Owners Cost	OC	% of Purchase Cost	15	15	[107]
Fixed O&M cost	F _{O&M}	% of Capital Cost	1	1	[107]
Variable O&M cost	V _{O&M}	% of Capital Cost	2	2	[107]
Capacity Factor	CF	%	80	80	[108, 109]
Annual Capacity Charge	FCF/		0.083	0.083	[108, 109]
No. of direct personnel			130	110	
Labor cost		\$/Person/year	85,000	85,000	
Plant Maintenance Cost		% of Capex/yr	2.5	2.5	

investment plant cost and the fixed capacity factor (FCF). Notably, the table demonstrates that the levelized price of sustainable aviation jet fuel is at its lowest when high-temperature electrolysis is coupled with a concentrated CO₂ source (\$1478/ton), as is the case with bioethanol-derived CO₂.

The projected costs in Table 5 when compared with prevailing cost of jet fuel 1071\$/ton [110] The IEA's projection for the jet fuel price in 2040 is approximately 920 \$/ton, it's important to note that this forecast does not account for carbon pricing or incremental carbon taxes.

Zayer et al., [111] conducted a techno-economic evaluation of implementing small-scale GTL technology to reduce flaring. The study simulated the units of a small-scale GTL plant to convert high-pressure flare gas from a natural gas refinery into liquid hydrocarbons, specifically diesel and propane. The economic feasibility of the suggested plant was evaluated based on technical results, considering factors such as capital expenditure (CapEx) and operational expenditure (OpEx). Various scenarios were analysed, including different product prices, and the internal rate of return (IRR). The study found that the estimated CAPEX of building a small-scale GTL is \$100,000 per BBL of GTL fuel produced and an estimated OpEX of \$10 to \$25 on a per BBL basis, to offset these costs HOP (High Oil Price) > \$55/ BBL would increase the profitability of small-scale GTL plants. However, the IRR for the reference case scenario was 22.18 %, indicating economic feasibility under current conditions and showed that decreasing capital costs of renewable energies did not significantly affect the economic feasibility of the small-scale GTL plant. Also, the highest IRR of 39.99 % was observed in the HOP scenario, indicating that rising oil prices significantly improve profitability. Water treatment units and equipment for hydrogen purification were identified as important challenges for GTL and small-scale GTL plants. The sensitivity analysis considered the impact of feed gas prices on economic feasibility, it is termed economically viable when the calculated IRR is higher than the discount rate, a discount rate of 15 % was used. The plant remained economically viable for feed gas prices up to US\$0.27 under the HOP scenario and up to US\$0.08 under the reference case scenario. However, under the LOP (Low Oil Price) scenario, profitability was not achieved even with low feed gas prices. CapEx's effect on IRR was analyzed. Reducing CapEx cost from \$100,000 to lesser than US\$75,000 improved IRR by 5 %. At US\$100,000 CapEx, the IRR only slightly increased, indicating that the development of renewable energies had minimal impact. Operational Expenditure (OpEx) changes had a less pronounced effect on profitability compared to CapEx. Reducing OpEx to US\$5 per barrel (BBL) led to profitability under the LOP scenario. Lastly, due to the high flow rate of flare gas in some oil and gas fields, the maximum capacity of small-scale GTL plants (5000 barrels per day) may limit their suitability for flaring reduction in certain cases.

A techno-economic optimization of the integration of a GTL process with an iron-based FT reactor, ammonia, and urea synthesis plants to convert CO₂ into useful products was carried out by Ziaei et al. [62]. This integration aims to reduce CO₂ emissions and improve the process's economic viability. Solar-powered PEM electrolyzers provide the necessary hydrogen for ammonia production. The profitability and carbon efficiency of the integrated process were modelled using LHD and optimized using the MBC toolbox. The results indicate that the integration can produce 48 tons per hour of urea and utilize 35 tons per hour of CO₂. At a rate of approximately 35.2 tonnes per hour (t/h), the GTL plant could recycle recovered CO₂ as feedstock for the urea synthesis plant. This integration led to a noteworthy reduction of about 48.2 t/h in CO₂ emissions compared to stand-alone processes. Moreover, the integrated approach exhibited a significantly lower total fixed capital cost, amounting to roughly 58 million USD less than that of the stand-alone processes. The profit index for the integrated system demonstrated a notable increase of approximately 30 % compared to the stand-alone processes. It is important to note that the profit index was notably influenced by the CO₂ tax rate, with the most lucrative scenario observed at a CO₂ tax rate of \$200/tonne. The possibility of substituting

Table 6

A Projection of the Techno-Economic Aspects Related to the Production Costs of SAF via Methanol and FT Pathway c.

Key Technical Indicator	Unit	Methanol Pathway				FT Pathway			
Source of CO ₂		Direct Air Capture		Biogenic		Direct Air Capture		Biogenic	
Electrolysis Type	-	Low Temp	High Temp	Low Temp	High Temp	Low Temp	High Temp	Low Temp	High Temp
Input – Electricity	MW	902	1031	705	766	866	992	698	727
Output - Fuel	MW _{LHV}	379	481	379	481	368	467	368	467
	ton/h	31	40	31	40	30	39	30	39
	kton/y	118	149	118	149	114	145	114	145
Efficiency	%	47	55	61	75	50	56	63	76
Investment Cost									
Electrolysis	M \$	176	200	176	200	176	200	176	200
Storage System – Hydrogen	M \$	4.384	0	4.384	0	38.36	0	38.36	0
CO ₂ Supply	M \$	468	565	59	69	468	565	59	69
Synthesis & Conditioning	M \$	135	158	135	158	125	148	125	148
Total		792	934	379	435	819	924	405	423
Renewable Jet Fuel	\$/GJ _{LHV}	52	50	36	34	55	51	41	34
	\$/ton	2222	2159	1559	1493	2379	2165	1748	1478

ASUs with PEM electrolyzers of varying capacities was also explored. This substitution had a marked impact on the profit index, with the most profitable point being achieved by replacing the smallest ASU. When comparing the two integrated processes, the CO₂-based approach exhibited approximately 5 % higher carbon efficiency than the iron-based one, given the same natural gas input. However, the iron-based process demonstrated a higher wax production rate. To further enhance carbon efficiency, the study considered integrating with a solar PV power plant. While eliminating specific ASUs notably increased carbon efficiency, it also resulted in a higher total capital investment. A sensitivity analysis indicated that profitability showed an upward trend with higher CO₂ tax rates, with a substantial 65 % improvement observed at a \$200/tonne CO₂ tax rate when the largest ASU was eliminated. The techno-economic feasibility study suggests that a zero CO₂ emission process could achieve a carbon efficiency of approximately 100 %.

Bassano et al. [80] discussed the technical and economic feasibility of using coal as feedstock in syngas production, while integrating with FT process and CCS. To assess the feasibility, the paper conducts a screening of suitable technologies and proposes a coal-to-liquid (CTL) facility based on commercial coal gasification and FT technologies. The performance and configuration of the plant evaluated using Aspen Plus software, with a plant size of approximately 10,000 barrels per day of liquid fuel products. The objective is to evaluate the plant's potential and conduct an initial economic assessment, focusing on determining the specific cost of produced liquid fuels and assessing the economic performance of the system. The economic analysis is conducted to estimate key indicators such as the internal rate of return (IRR), payback period, and net present value for configurations with or without CO₂ capture. For an 8530 barrels per day (bbl/d) plant, the Total Operating Cost (TOC) amounts to approximately \$812 million, equivalent to around \$95,000 per bbl/d. Upon integrating CCS into the plant, the TOC slightly increases to approximately \$829 million, or about \$97,000 per bbl/d. To achieve a 20 % IRR, the selling price of FT fuels needs to be \$122.5 per bbl, resulting in a 7-year payback period for the base scenario. The cost of CO₂ emissions mitigation through CCS is estimated at \$7 per ton of CO₂. The specific cost of the liquid product, considering fuel expenses, operational and maintenance costs, capital expenditures, and CO₂ capture expenses, is approximately \$68 per barrel or \$13 per GJ for the base case, with a slight increase for the CCS scenario. The analysis covers various CO₂ allowance prices, with the plant configuration without CCS exhibiting a better IRR at a CO₂ allowance price of \$10 per ton of CO₂. However, when the CO₂ allowance price rises to \$28 per ton of CO₂, CCS becomes the economically favourable choice. Sensitivity analyses reveal the impact of FT fuels selling price fluctuations, with IRR being highly dependent on this price. A 40 % change significantly affects IRR, and at a selling price of \$74 per bbl, both investments show negative Net Present Value (NPV), and IRR falls below the interest rate.

The analysis also assesses the influence of TOC cost, with a 50 % increase leading to a notable IRR decline for both scenarios, resulting in negative NPV and IRR below the interest rate. In summary, the analysis underscores the significance of key economic parameters, including CO₂ allowance price, FT fuels selling price, and TOC cost, in CTL plant investments. CCS enhances competitiveness under specific CO₂ allowance price conditions, but elevated TOC costs and reduced FT fuels selling prices can impact project economic viability.

A study which highlights the feasibility and cost implications of implementing post-combustion carbon capture at an oil refinery was carried out by Andersson et al., [112] This paper focuses on analysing the costs associated with different setups. The study considers the utilization of excess heat from the refinery process, adjusting the temperature of the stripper reboiler, and incorporating a heat pump for additional heating. The number of chimneys in the capture process is also considered, resulting in varying CO₂ concentrations and amounts at the plant's inlet. The study emphasizes the importance of optimizing excess heat utilization and considering variations in CO₂ concentration and temperature and concludes that utilizing low-cost excess heat can make post-combustion CO₂ capture feasible at an oil refinery. Also, the authors noted that the specific cost for CO₂ capture decreases when capturing smaller amounts of CO₂ with a higher concentration in the flue gas, compared to capturing larger amounts at a lower concentration.

Galli et al., [113] conducted a techno-economic analysis of the application of the MRU for treating biogas, natural gas, and landfill gas. The analysis incorporates different raw material and product price scenarios, representing optimal, average, and worst-case scenarios. An inflation rate of 2 % and an income tax rate of 28 % are assumed. The MRU's operational capacity is considered to increase gradually over time. The results of the analysis include the Net Present Value (NPV) and payback time calculations, which are influenced by factors such as equipment costs, labour costs, utility expenses, and the varying capacity of the MRU. The results obtained from the study indicate that the nature of the feedstock has a limited impact on the economics of the MRU. The MRU performs well with feedstocks rich in methane, but it also operates effectively across a wide range of natural gas compositions. Emissions from flared stranded gas are identified as the main environmental threat in terms of volume. The operating conditions of the MRU were optimized for this feedstock source. Galli et al., [82] also explored the influence of the scale of the MRU and found that a lower gas flow rate resulted in insufficient production to achieve a positive net present value. On the other hand, numbering up the MRU was found to be beneficial, with a larger plant requiring additional capital costs and personnel. The study suggests that the MRU offers a cost-effective and modular solution for oil companies to address carbon tax and environmental concerns. Compressors were identified as the main source of fixed costs for the MRU, and the total fixed investment varied depending on the feedstock. The MRU demonstrated a payback time of less than 10

years, regardless of the assumed fuel price. Overall, the study concludes that the MRU provides a viable solution for converting stranded gas into liquid hydrocarbons, generating additional revenue for producers, and mitigating environmental impacts.

A study carried out by Farhan and Purwanto [114] focused on a small-scale associated gas flaring in an offshore platform. It evaluates the techno-economic aspects of different technologies, including power generation, mini liquefied natural gas (LNG), and mini-GTL. The research aimed to identify the optimal technology for reducing flaring in this specific context. The methodology involves process simulation to assess the technical performance and plant size for each technology option. Economic assessment is then performed using cash flow analysis, considering capital expenditure, fixed operating expenditure, variable costs, and minimum acceptable rate of return. The results of the simulation show that power generation using gas turbine generators can generate 4.99 MWe of electricity with a net electrical energy of 3.092 MWe. The mini-LNG option can produce 20 tons per day (tpd) of LNG with an energy consumption rate of 0.866 kWh/kg LNG. The mini-GTL option can produce 80 barrels per day (bpd) of syncrude, with a carbon efficiency of 76.68 % and a thermal efficiency of 54.24 %. Results show that mini-GTL facility has a lower capital expenditure than LNG but approximately five times more than power generation. However, mini-GTL has the least IRR, netback price and highest payback time. The study did not discuss CO₂ abatement cost and further analysis, and considerations would be required to determine the most suitable option for a specific offshore platform.

Mohajerani et al. [84] Utilised a bottom-up techno-economic model to calculate the capital cost, which involved identifying and sizing the main equipment in each unit process. Data from published research and expert discussions were utilized for equipment sizing. A capacity of 50,000 barrels per day was chosen as the base value for both GTL and CTL (coal-to-liquid) plants. The capital costs were estimated by summing up the plant's equipment costs, direct plant costs (e.g., instruments, control, utilities, buildings), and indirect costs (e.g., engineering, start-up, contingencies). Other input data considered in the analysis, includes production capacity, feedstock flow rate, plant lifetime, interest rate, maintenance cost, and location factors. Scale factors for different equipment were calculated based on previous studies and industry data. The analysis revealed economies of scale for larger plant sizes, with the capital cost per unit output decreasing as the capacity increased. The production cost of the GTL plant also decreased with increasing capacity, indicating strong economies of scale up to a capacity of 50,000 bbl/day. The capital investment cost for a 50,000 bbl/day GTL plant was estimated to be C\$4.3 billion. Natural gas was identified as the most cost-intensive parameter, accounting for 42 % of the production cost.

A techno-economic evaluation and a life-cycle assessment for a 45,000 barrels per day synthetic fuel GTL plant was conducted by [85]. The study highlights that the GTL plant has the highest generating cost among the technologies studied, primarily due to the significant feedstock costs associated with natural gas compared to coal. It further explains that by 2025, for a GTL plant, a large portion (94 %) of the generating costs for synthetic fuel is attributed to feedstock costs. The study also provides generating cost figures for the year 2040, indicating that the costs for coal-consuming plants remain comparable to those in 2025, while the generating costs for the GTL plant increase due to expected price increases in natural gas. When CCS is applied, the generating costs increase for both CTL and GTL plants, but the GTL plant has the lowest additional costs for CCS adoption. In terms of cost and emissions analysis, it is evident that plants incorporating CCS exhibit higher generation costs compared to those without CCS. The additional expenses associated with CCS vary, ranging from 1.25 to 7.3 \$/GJSynfuel for different plant types. Plants without CCS, such as CTL and electricity-generating plants, maintain relatively stable generation costs over time. In 2025, generation costs for these plants hover around 10 \$/GJSynfuel for CTL, 10.8 \$/GJelec (38.7 \$/MWhelec) for

IGCC, and 10 \$/GJelec (39.8 \$/MWhelec) for USC plants. By 2040, these values experience slight fluctuations, with CTL at 9.3 \$/GJSynfuel, IGCC at 11 \$/GJelec (39.6 \$/MWhelec), and USC at 10 \$/GJelec (36.6 \$/MWhelec). However, the GTL plant's generation costs with CCS see a significant rise due to anticipated feedstock price increases. Notably, USC and IGCC plants, lacking CCS, exhibit the highest specific GHG emissions at 197 gCO₂eq/MJelec and 186 gCO₂eq/MJelec by 2040, while the CTL plant without CCS emits approximately 111 gCO₂eq/MJSynfuel, and the GTL plant has lower GHG emissions at 19 gCO₂eq/MJSynfuel. Introducing CCS increases total GHG emissions due to energy requirements for CO₂ sequestration, compression, transport, and storage. In terms of CO₂eq abatement potential, USC and IGCC plants demonstrate the highest at 164 gCO₂eq/MJelec and 156 gCO₂eq/MJelec, respectively. The CTL plant's CO₂eq abatement potential is around 69 gCO₂eq/MJSynfuel, while the GTL process with CCS shows the lowest at 12 gCO₂eq/MJSynfuel. Considering GHG abatement costs in 2040, the IGCC plant exhibits the lowest at 23.3 \$/t CO₂eq, followed by the USC plant at 30.7 \$/t CO₂eq, whereas the CTL and GTL plants face considerably higher abatement costs, standing at 103 \$/t CO₂eq and 106 \$/t CO₂eq, respectively. Furthermore, the GHG abatement costs, highlight that the GTL plant has the highest abatement costs, primarily due to its lower specific CO₂ emissions and higher plant efficiency.

Based on the literature reviewed, it is evident that there is a significant gap in having a shared reference point to identify and prioritize implementable emission reduction initiatives for GTL decarbonization pathways, leading to a lack of consistency and standardization in processes and operations.

5. Conclusion

Decarbonization pathways for energy-intensive industries (EII) and GTL facilities in the oil and gas sector have been reviewed. It was found that:

1. Various techno-economic CO₂ mitigation strategies from a review of the literature highlight the importance of implementing diverse approaches, including energy efficiency improvements, carbon capture and storage (CCS), and transitioning to low-carbon pathways, to reduce CO₂ emissions in energy-intensive industries. These strategies show significant potential for achieving net-zero targets in GTL (gas-to-liquids) facilities. As a result, the levelized cost of electricity (LCOE) has been reduced to less than £ 25/MWh, with CO₂ capture costs falling below \$50 per tonne
2. Numerous creative and doable decarbonization pathways, including bio-oil co-processing, CCS, green hydrogen, and electrification, have been explored to lower emissions in EIIs, the levelized cost of renewable jet fuel (1478 \$/ton) from FT pathway coupled with concentrated CO₂ source is the most promising, it is still circa. 20–25 % higher than current conventional jet fuel.
3. Suitable decarbonization options for aviation industry considers sensitivity to weight and volume, making integration of green hydrogen and GTL facilities to produce SAF a technically viable alternative to reduce emissions before 2050.
4. The attainment of emissions reduction targets in EIIs presents economic complexities, given that the cost of CO₂ capture and sequestration frequently surpasses the value of carbon credits. The establishment of robust regulatory frameworks and incentives is indispensable for steering emissions reduction initiatives.
5. The enhancement of energy efficiency assumes a pivotal role in emissions reduction especially waste heat integration, furnace optimization and tail gas utilization, as emissions from furnace and FT tail gas accounts for 90 % of GTL emissions. Identifying the most economically viable investments and potential bottlenecks for the deployment of energy efficiency measures are areas for further research.

- The transition to low-carbon pathways might lead to elevated product costs. Hence, the implementation of appropriate pricing mechanisms for environmental impacts or green product premiums may become imperative.
- Feed gas cost accounts for over 50 % of GTL total cost, utilization of Renewable bio feed sources, in conjunction with CCS and green hydrogen would help improve returns and reduce emissions to meet net zero target.
- The integration of advanced catalysis, electrification, and flexible feedstock strategies demonstrates the potential to fundamentally redesign fuel conversion processes, maximizing both environmental sustainability and economic potential.

Despite these insightful findings, several knowledge gaps persist:

- Retrofit vs. New Facilities:** Further investigation is warranted to assess the technical, economic, and environmental merits of retrofitting existing facilities versus establishing entirely new low-carbon facilities in EIs, potential utilization of high EIs waste streams like nitrogen for the generation of valuable products like urea should be evaluated.
- Regulatory Frameworks:** While regulatory frameworks are acknowledged as pivotal, additional research is required to devise effective policies and incentives conducive to promoting carbon capture and storage and other emissions reduction strategies.
- Technological Development:** Bridging the divide between existing technologies and scaling up operations beyond demonstration plants remains a formidable challenge. Specific focus on industrial challenges from deployment of several decarbonization pathways in existing high EI industries as well as the impact of compositional changes on existing unit operations. Therefore, intensified research and development efforts are imperative to address this disparity.
- Investment Requirements:** A comprehensive comprehension of the investment prerequisites and potential bottlenecks for deploying energy efficiency measures is imperative for the efficacious realization of decarbonization objectives.
- Lifecycle Assessment:** There exists a need for further research on the lifecycle assessment of emissions reductions, particularly concerning coproduct emissions within GTL pathways, to facilitate accurate evaluations of environmental impacts.

CRedit authorship contribution statement

Kelvin Offioritse Awani: Writing – review & editing, Writing – original draft, Visualization, Resources, Project administration, Methodology, Investigation, Formal analysis, Conceptualization. **Vinod Kumar:** Supervision. **Ali Nabavi:** Writing – review & editing, Supervision. **Dawid Hanak:** Writing – review & editing, Supervision.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this article.

Data Availability

No data was used for the research described in the article.

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Further reading

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