Integrating CCUS and Blue Hydrogen in Refining and Gas Processing: Pathways to Practical Decarbonization

Amirali Najjar[1], Mohammadreza Akbari[1*], Yasin Khalili[1].

[1]*Department of Petroleum and Geoenergy Engineering, Amirkabir University of Technology, Tehran, Iran.*

Corresponding Author Email Address: akbari.pe@aut.ac.ir

Abstract

Refining and natural gas processing industries are among the most carbon-intensive sectors due to energy-intensive operations and widespread reliance on fossil-based hydrogen and combustion systems. Achieving deep decarbonization in these facilities requires technically feasible and economically viable solutions that can be deployed at scale without disrupting operational reliability. This review examines carbon capture, utilization, and storage (CCUS) and blue hydrogen as integrated pathways for reducing CO_2 emissions in refineries and gas processing plants. Key CO_2 emission sources and stream characteristics are analyzed to identify priority capture opportunities, followed by a comparative assessment of major capture technologies, including post-combustion, pre-combustion, and oxy-fuel systems. The role of blue hydrogen produced via steam methane reforming and autothermal reforming with CO_2 capture is evaluated as a low-carbon fuel and feedstock capable of anchoring early CCUS deployment. CO_2 utilization and geological storage options, along with associated transport infrastructure, regulatory frameworks, and economic considerations, are reviewed to assess large-scale implementation potential. Lessons learned from industrial pilots and case studies are synthesized to highlight integration challenges, cost drivers, and scalability constraints. Finally, a phased decarbonization roadmap is proposed, outlining near-, mid-, and long-term strategies that combine CCUS, blue hydrogen, electrification, and efficiency improvements. The analysis demonstrates that integrated CCUS and blue hydrogen systems offer a pragmatic and scalable transition pathway toward net-zero emissions in refining and gas processing industries.

Keywords: Industrial decarbonization, Hydrogen production systems, Carbon management technologies, Refinery process integration, Low-carbon energy transition.

1. Introduction

Global efforts to mitigate climate change have intensified the pressure on carbon-intensive industries to adopt practical and scalable decarbonization strategies [1]. Among these sectors, refining and natural gas processing remain significant contributors to industrial CO_2 emissions due to their dependence on fossil-based feedstocks, energy-intensive unit operations, and complex process configurations [2]. As nations commit to net-zero pathways and increase regulatory and societal expectations for cleaner energy systems, refineries and gas processing plants face the dual challenge of maintaining operational reliability while substantially reducing their carbon footprint [3]. Within this evolving landscape, carbon capture, utilization, and storage (CCUS) and blue hydrogen production have emerged as pivotal transitional solutions capable of delivering meaningful emission reductions without compromising process continuity or product quality [4].

CCUS offers a technologically mature approach for capturing CO_2 from high- and medium-concentration process streams prevalent in refining operations, especially those associated with hydrogen production units, fired heaters, and catalytic processes [5]. When integrated effectively, CCUS can address a significant share of site-wide emissions and create opportunities for downstream utilization or secure long-term geological storage [6]. At the same time, the demand for hydrogen in refineries used extensively in hydrotreating and hydrocracking continues to grow as cleaner fuels and stricter product specifications become the norm. This trend elevates the importance of blue hydrogen, produced via reforming technologies coupled with CO_2 capture, as a pragmatic low-carbon alternative that can be deployed at scale with relatively lower cost and faster timelines compared to green hydrogen [7].

The integration of CCUS and blue hydrogen not only reduces direct emissions but also transforms the refinery into a more flexible, future-ready energy system [8]. By leveraging shared CO_2 handling infrastructure and aligning hydrogen production with decarbonization priorities, these technologies provide synergistic pathways that enhance overall process efficiency and accelerate progress toward net-zero objectives. Despite these advantages, deployment is often constrained by economic, technical, regulatory, and operational challenges that must be addressed before widespread adoption is feasible [9, 10].

This review article examines the key emission sources in refining and gas processing, assesses the technological readiness and integration potential of major carbon capture approaches, and evaluates the role of blue hydrogen as a low-carbon fuel and feedstock. It further explores CO_2 utilization and storage options, economic and policy drivers, and lessons learned from industrial case studies. Through this analysis, the paper aims to provide a comprehensive understanding of how CCUS and blue hydrogen can jointly support a phased and realistic decarbonization pathway for refining and gas processing industries.

Table 1 provides a high-level comparison of key decarbonization pathways for refining and gas processing, highlighting their relative technology maturity, cost, scalability, and potential for CO_2 emissions reduction.

Table 1 Comparison of Decarbonization Pathways for Refining and Gas Processing [11-14].

Decarbonization Pathway	Technology Readiness Level	Relative Cost	Scalability	Typical CO_2 Emissions Reduction Potential
CCUS (Carbon Capture, Utilization, and Storage)	High (commercially deployed in industrial settings)	Medium–High (capture, compression, transport, storage)	High for point sources with concentrated CO_2 streams	~50–90% reduction at targeted units (e.g., SMR, FCC, AGR)
Blue Hydrogen (SMR/ATR + CCUS)	High–Medium (commercial to early large-scale deployment)	Medium (lower than green hydrogen, higher than grey)	High (leverages existing gas and hydrogen infrastructure)	~60–90% reduction in hydrogen-related emissions

Green Hydrogen (Electrolysis + renewables)	Medium (rapidly advancing, limited large-scale industrial use)	High (electrolyzers + renewable electricity)	Medium (constrained by renewable power availability and cost)	~90–100% reduction (near-zero direct emissions)
Electrification (e-heaters, electric drives)	Medium (demonstration to early commercial)	Medium–High (equipment and power infrastructure)	Medium (limited by high-temperature heat demand and grid capacity)	~30–70% reduction depending on electricity carbon intensity
Energy Efficiency & Process Optimization	Very High (widely implemented best practice)	Low–Medium (often cost-effective)	High (applicable across all facilities)	~5–20% site-wide reduction

2. CO_2 Emission Sources in Refineries and Gas Processing Plants

Refineries and natural gas processing facilities are inherently energy-intensive operations characterized by numerous combustion-driven and process-related emission sources [15]. These emissions arise from both direct fuel combustion and chemical conversion pathways, making the sector one of the largest contributors to global industrial CO_2 output [16]. A significant portion of refinery emissions originates from stationary combustion units, such as fired heaters, boilers, and furnaces, which supply the high-temperature heat required for distillation, cracking, reforming, and other thermally demanding processes [17]. These units typically rely on natural gas or refinery fuel gas and generate large volumes of flue gas with relatively low CO_2 concentrations, posing challenges for cost-effective capture [18]. In natural gas processing plants, similar heater systems are employed for dehydration, regeneration, and gas sweetening processes, forming an important fraction of the site-wide carbon footprint.

Another dominant emission source is the production of hydrogen, primarily through steam methane reforming (SMR) or autothermal reforming (ATR) [19]. Hydrogen units are among the most carbon-intensive operations in a refinery because the reforming reactions inherently release CO_2, in addition to the combustion emissions from reformer heaters [20]. The process gas from SMR contains CO_2 at significantly higher concentrations than typical flue gas, making it a more attractive candidate for carbon capture, yet hydrogen demand continues to rise due to stricter fuel specifications and expanded hydrotreating capacity [21]. This trend places hydrogen production at the center of refinery decarbonization strategies [13].

Refineries also generate CO_2 from fluid catalytic cracking (FCC) regenerators, where coke deposited on catalyst surfaces is burned off, producing a concentrated CO_2 stream mixed with nitrogen and flue gases [22]. Although the FCC regenerator contributes a relatively smaller share of total emissions compared to combustion units or hydrogen plants, its high CO_2 concentration stream is of strategic interest due to its capture potential [23]. Additional emissions arise from amine-based acid gas removal (AGR) and sulfur recovery units (SRUs), where CO_2 is co-produced during the removal of H_2S from natural gas or refinery off-gases [24, 25]. These streams can vary in concentration depending on feed composition and operating conditions, adding complexity to capture system integration [26].

In gas processing plants, acid gas removal systems used for treating sour natural gas are among the most consistent point sources of process CO_2 [27]. The regeneration of solvents (such as MEA, MDEA, or hybrid solvents) releases

CO_2-rich gas streams that may be vented or directed to sulfur recovery units [28]. Depending on reservoir conditions and gas composition, these emissions can be substantial. Plants also rely on compression, dehydration, and liquefaction systems, which require significant power, often supplied by gas turbines or engines that add further combustion-related CO_2 emissions [29].

Overall, the emission profile of refineries and gas processing plants is diverse, comprising both concentrated and dilute CO_2 streams [30]. Concentrated sources such as SMR syngas, FCC regenerator off-gas, and amine regeneration vents present clear opportunities for efficient carbon capture [12]. In contrast, dilute and distributed sources, especially combustion flue gases, remain more technically and economically challenging [31]. Understanding the relative contribution of each emission source is essential for designing an optimized carbon mitigation strategy that integrates capture technologies with minimal disruption to plant operations. As the industry moves toward net-zero objectives, prioritizing high-purity CO_2 streams while advancing technologies for lower-concentration sources becomes a critical step in achieving meaningful emissions reductions [32].

Table 2 summarizes the typical CO_2 concentrations, operating conditions, and capture potential of major emission streams in refinery and gas processing facilities.

Table 2 CO_2 Concentrations and Flow Characteristics of Key Process Streams in Refineries and Gas [33-35].

Process Stream	Typical CO_2 Concentration (vol%)	Temperature Range (°C)	Pressure Range (bar)	Capture Potential
SMR Syngas	15–25%	200–400	15–30	Very High – high CO_2 partial pressure and stable flow make it highly suitable for pre-combustion capture
CCR/FCC Regenerator Off-Gas	10–20%	650–750	~1–2	High – relatively concentrated CO_2 stream, though high temperature and particulates require conditioning
Flue Gas from Heaters and Boilers	3–8%	120–250	~1	Moderate – dilute CO_2 concentration leads to higher capture cost and energy penalty
Amine Regeneration Vents (AGR)	5–15%	90–120	~1–2	High – consistent, moderately concentrated CO_2 stream well suited for post-combustion capture
Gas Turbine Exhaust	3–5%	450–550	~1	Low–Moderate – low CO_2 concentration and high exhaust temperature challenge economic capture

Note: Actual CO_2 concentrations and flow conditions vary with feedstock composition, operating severity, and plant design. High-pressure and high-concentration streams such as SMR syngas and amine regeneration vents generally offer the most cost-effective capture opportunities, while combustion-based sources remain more challenging.

Figure 1 shows the main CO_2 emission sources in refinery and gas processing facilities, highlighting the contrast between concentrated process streams and dilute combustion-related emissions.

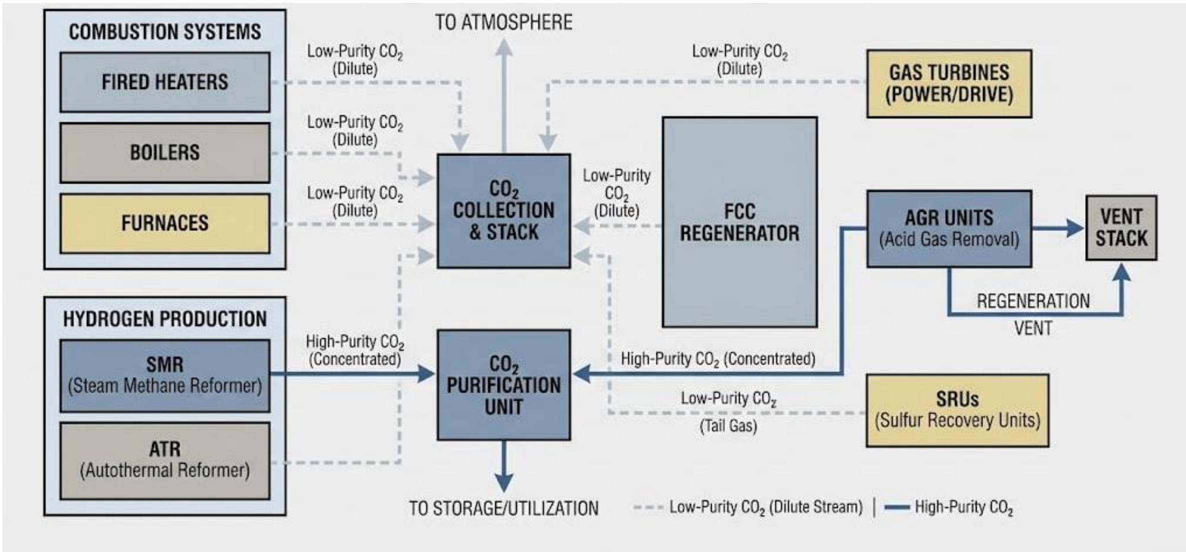

Fig. 1 Schematic of CO2 emission sources in refinery & gas processing facilities.

3. Carbon Capture Technologies: Applicability and Integration

Carbon capture technologies have evolved significantly over the past two decades, offering a diverse suite of solutions capable of addressing the wide range of CO_2 concentrations present in refineries and natural gas processing plants. These technologies are broadly classified into post-combustion, pre-combustion, and oxy-fuel methods, each with distinct operating principles, technical maturity levels, and integration requirements. Among these, post-combustion capture remains the most widely deployed in industrial decarbonization due to its compatibility with existing combustion-based infrastructure [36]. These systems typically employ chemical solvents such as amines, ammonia, or emerging non-aqueous blends to selectively absorb CO_2 from flue gas streams [37]. Their ability to retrofit onto diverse emission points makes them a flexible option for refineries; however, the relatively low CO_2 concentration of flue gas increases energy consumption for solvent regeneration, contributing to the overall energy penalty of capture [38].

Pre-combustion capture, by contrast, targets CO_2 before combustion occurs and is particularly well-suited for processes involving synthesis gas production, such as SMR, ATR, and gasification. In these systems, CO_2 is removed from a high-pressure, high-concentration syngas mixture using physical solvents or adsorption-based technologies, resulting in more efficient and cost-effective capture compared to post-combustion methods. This makes pre-combustion capture a strategic lever in facilities with large hydrogen production units, where integrating CO_2 removal from process gas can significantly reduce the carbon intensity of hydrogen forming the basis of blue hydrogen pathways. Moreover, because capture occurs upstream of combustion, the resulting fuel typically hydrogen can then be used in low-carbon energy systems across the refinery [36].

Oxy-fuel combustion represents another pathway in which fuel is burned in nearly pure oxygen instead of air, resulting in a flue gas stream composed mainly of CO_2 and water vapor. Although this simplifies downstream CO_2 separation, the technology is less commonly applied in refineries due to the high capital cost and energy requirements of air separation units [39]. Nevertheless, oxy-fuel systems remain of interest for certain process heaters and FCC units where streamlined CO_2 separation could justify the investment, particularly when integrated with broader facility electrification strategies [40].

In parallel with these established methods, emerging capture technologies including advanced polymeric and inorganic membranes, solid sorbents, ionic liquids, and cryogenic separation systems are being developed to improve efficiency, reduce energy consumption, and lower overall costs [41]. Membrane-based capture, for example, offers a compact and modular option ideal for process gas streams with elevated CO_2 concentrations, though performance limitations at low partial pressures remain a challenge. Solid sorbents and metal–organic frameworks (MOFs) present opportunities for high-selectivity, low-energy CO_2 capture, while cryogenic systems may provide competitive solutions for natural gas processing applications where low temperatures are already integral to operations [42].

Integrating carbon capture technologies into refinery and gas processing plant operations involves careful consideration of energy balance, equipment layout, and process interactions. Capture systems increase overall energy demand, often requiring additional steam, electricity, or heat, which can alter utility configurations and necessitate new low-carbon energy sources. Space constraints within existing units can limit the feasibility of large capture installations, especially in older facilities with tightly packed process areas. Additionally, the introduction of CO_2 compression, dehydration, and transportation systems requires coordination with downstream infrastructure for pipeline or storage integration. Despite these challenges, successful deployment of capture technologies can significantly reduce facility-wide emissions, especially when prioritized for high-purity process streams such as hydrogen reformer syngas, FCC regenerator off-gas, and amine regeneration vents [43].

Ultimately, the selection and integration of carbon capture technologies must balance technical feasibility, cost-effectiveness, energy impacts, and alignment with long-term decarbonization strategies. As innovations continue to reduce energy penalties and enhance capture efficiency, the compatibility of these systems with existing refinery and gas processing operations will strengthen, enabling wider adoption and accelerating the transition toward low-carbon industrial systems.

Table 3 compares major carbon capture technologies in terms of efficiency, energy demand, cost, maturity, and suitability for different refinery and gas processing emission streams.

Table 3 Comparison of Carbon Capture Technologies for Refining and Gas Processing Applications [44-46].

Capture Technology	Capture Efficiency	Energy Requirement	Integration Complexity	Typical Cost Range (USD/tCO_2)	Technology Maturity	Suitable Emission Streams
Post-combustion (Chemical Absorption – Amines)	High (85–95%)	High (solvent regeneration)	Medium–High (retrofit challenges, utilities demand)	~50–120	Commercial	Flue gas from heaters, boilers, gas turbines
Pre-combustion (Physical Solvents / Shift + Capture)	Very High (90–95%)	Medium	Medium (best integrated with reforming units)	~30–70	Commercial	SMR/ATR syngas, hydrogen production units

Oxy-fuel Combustion	Very High (>95%)	Very High (air separation unit)	High (major process modification)	~70–150	Demonstration–Early commercial	Heaters, FCC units (select applications)
Membrane Separation	Medium–High (60–90%)	Low–Medium	Low–Medium (modular design)	~40–90	Pilot–Early commercial	Syngas, high-pressure process gas
Solid Sorbents / Adsorption	High (80–95%)	Medium–Low	Medium	~40–100	Pilot–Demonstration	Flue gas, process vents
Cryogenic Separation	Very High (>95%)	High (cooling demand)	High	~60–130	Pilot	High-CO_2 natural gas, low-temperature process streams

Note: Cost ranges and performance depend strongly on CO_2 concentration, pressure, scale, energy prices, and integration level. In refinery and gas processing applications, pre-combustion capture is generally the most cost-effective for hydrogen units, while post-combustion capture offers the greatest retrofit flexibility.

Figure 2 illustrates the main carbon capture technology pathways in refinery applications, comparing post-combustion, pre-combustion, and oxy-fuel combustion in terms of capture location and energy requirements.

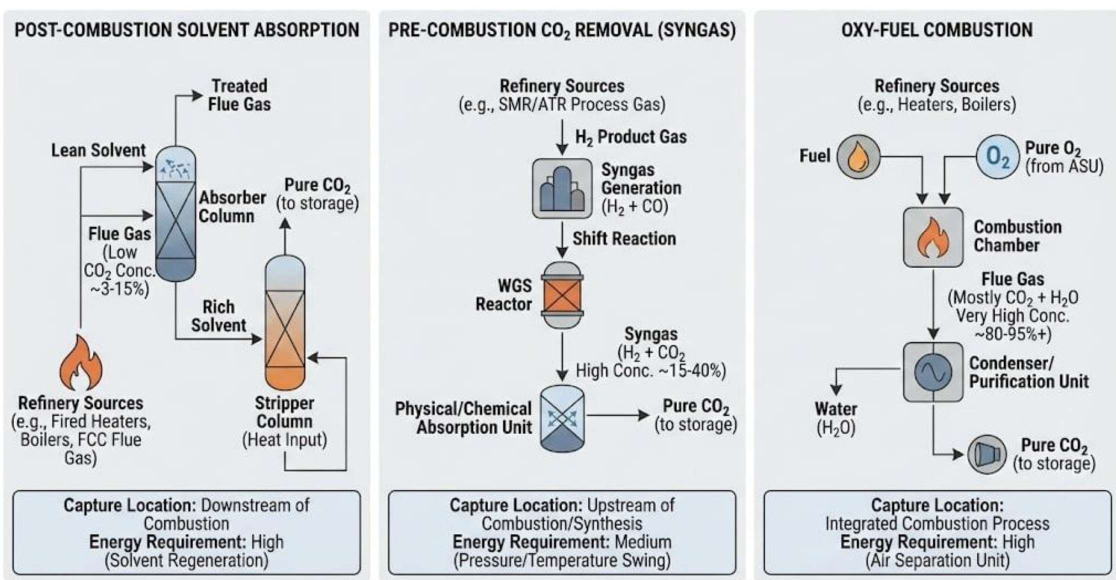

Fig. 2 Comparison of carbon capture technologies in refinery applications.

4. Blue Hydrogen as a Low-Carbon Fuel and Feedstock

The growing emphasis on decarbonizing industrial sectors has positioned blue hydrogen produced from fossil fuels with integrated carbon capture as a central component of low-carbon strategies for refineries and natural gas processing plants. Hydrogen has long played a critical role in refining operations, particularly in hydrotreating and hydrocracking units that remove sulfur, saturate aromatics, and upgrade heavy fractions into lighter, cleaner fuels. As energy transition policies tighten fuel specifications and demand for low-emission products increases, hydrogen consumption within refineries continues to rise. However, conventional hydrogen production through SMR or ATR remains carbon-intensive due to both process-related emissions and combustion requirements. Blue hydrogen pathways mitigate these emissions by integrating CO_2 capture into hydrogen production systems, thereby significantly lowering the carbon intensity of an essential industrial feedstock [47].

SMR-based blue hydrogen typically leverages two main CO_2 capture points: the high-concentration syngas stream leaving the reformer and the lower-concentration flue gas from reformer heaters. Capturing CO_2 from syngas is generally more efficient due to its elevated pressure and higher CO_2 content, allowing for the use of physical solvents or advanced capture technologies with lower energy consumption. ATR-based blue hydrogen offers an even more favorable configuration because it produces a syngas stream with higher CO_2 partial pressure and reduced dependency on fired heaters, resulting in a more capture-friendly process layout [48]. These features have elevated as a preferred technology for large-scale blue hydrogen projects, especially in regions prioritizing deep decarbonization [49, 50].

Comparatively, grey hydrogen produced without any CO_2 capture remains the most carbon-intensive and is increasingly incompatible with long-term emissions reduction goals. Green hydrogen, produced via electrolysis powered by renewable energy, offers a near-zero-carbon alternative but currently faces economic and scalability constraints due to high capital costs, variable renewable energy availability, and the need for substantial grid or renewable energy expansion [51, 52]. Blue hydrogen therefore occupies a pragmatic middle ground, providing substantial emissions reductions while leveraging existing natural gas supply chains and reforming infrastructure [53]. This balance makes it particularly attractive for refineries and gas processing plants seeking low-carbon solutions that can be deployed within short to medium timeframes [54].

Beyond its use as a feedstock, blue hydrogen can also serve as a low-carbon fuel within refineries, replacing natural gas and refinery fuel gas in fired heaters, boilers, and other combustion systems [55]. While challenges remain including burner retrofits, flame stability, NO_x emissions control, and hydrogen distribution infrastructure this fuel-switching strategy offers a promising pathway to reduce combustion-related emissions, which represent a considerable portion of refinery CO_2 output. Additionally, blue hydrogen aligns naturally with CCUS deployment, as the CO_2 captured from hydrogen production can be routed into shared compression, transportation, and storage infrastructure, enhancing economies of scale and reducing project-level costs [4].

The synergistic relationship between hydrogen demand and carbon capture infrastructure strengthens the case for blue hydrogen as an enabling technology for refinery decarbonization. By anchoring early CCUS investments, hydrogen production can provide consistent, high-purity CO_2 streams that justify the development of broader CO_2 pipeline and storage networks. In turn, these networks can later support additional capture projects across other refinery units or neighboring industrial facilities, accelerating regional decarbonization. This interoperability positions blue hydrogen not only as a fuel and feedstock solution but also as a strategic foundation for long-term low-carbon industrial ecosystems [56].

Nevertheless, the deployment of blue hydrogen is not without challenges. High capital costs, energy penalties associated with capture and compression, uncertainties in natural gas pricing, and evolving policy frameworks all influence project viability [57, 58]. Ensuring that methane leakage throughout the natural gas supply chain remains minimal is also essential for blue hydrogen to deliver genuine climate benefits. Despite these hurdles, continued technological advancements, supportive policies, and economies of scale are expected to strengthen the competitiveness of blue hydrogen and secure its role as a cornerstone of near-term refinery and gas processing decarbonization efforts [59, 60].

Table 4 compares SMR-CCUS and ATR-CCUS blue hydrogen systems, highlighting differences in capture configuration, efficiency, carbon intensity, and integration characteristics.

Table 4 Key Parameters for SMR-CCUS and ATR-CCUS Blue Hydrogen Systems [61, 62].

Parameter	**SMR-CCUS**	**ATR-CCUS**
Reformer Type	Steam Methane Reformer with fired tubular reactor	Autothermal Reformer with partial oxidation
Typical Hydrogen Output	Medium–High (widely used in refineries)	High (suited for large-scale hydrogen production)
Main CO_2 Capture Points	Syngas CO_2 + reformer flue gas	Syngas CO_2 (single, high-concentration stream)
Typical CO_2 Capture Rate	60–90% (higher with dual-point capture)	90–95%
Resulting Hydrogen Carbon Intensity	~2–5 kg CO_2/kg H_2	~1–3 kg CO_2/kg H_2
Energy Requirement	High (steam generation + fired heaters)	Medium (reduced external firing)
Integration Complexity	Medium–High (multiple capture units, retrofits)	Medium (simpler capture configuration)
Scalability	High (established technology base)	Very High (favored for hydrogen hubs)
Typical Applications	Existing refineries and gas processing plants	New-build or large-scale blue hydrogen projects

Note: Actual capture rates and carbon intensities depend on natural gas composition, methane leakage, capture scope (process-only vs. full-system), and downstream CO_2 transport and storage infrastructure.

Figure 3 illustrates an integrated decarbonization framework for refineries and gas processing plants, combining CCUS with blue hydrogen production and shared CO_2 transport and storage infrastructure.

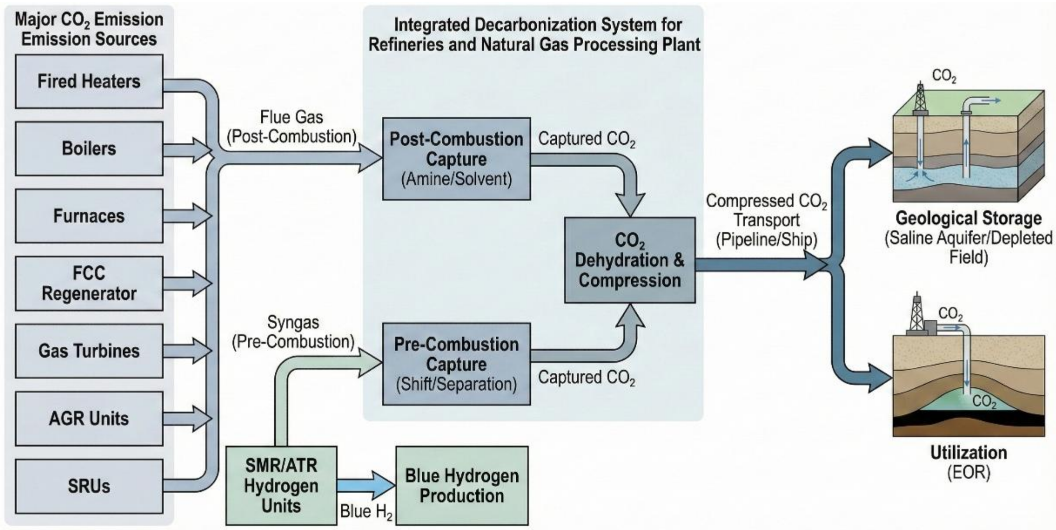

Fig. 3 Integrated decarbonization system using CCUS and blue hydrogen.

5. CO_2 Utilization and Storage Options

The successful implementation of carbon capture technologies in refineries and gas processing plants depends not only on the ability to capture CO_2 efficiently but also on the availability of viable pathways for its utilization or long-term storage. Once captured, CO_2 can be routed toward utilization, where it serves as a feedstock in industrial processes, or toward geological storage, where it is sequestered in subsurface formations for permanent removal from the atmosphere. Each pathway presents distinct opportunities and challenges, and selection often depends on regional infrastructure, regulatory frameworks, and market conditions [63].

CO_2 utilization has gained considerable attention as a means of transforming captured CO_2 into valuable products, thereby offsetting some capture and compression costs. In the oil and gas sector, enhanced oil recovery (EOR) remains the most mature utilization pathway. EOR operations inject CO_2 into depleted oil reservoirs to mobilize residual hydrocarbons, improving extraction efficiency while storing a portion of the injected CO_2 underground. Although EOR can provide near-term economic incentives, its deployment is geographically constrained to regions with suitable reservoirs and may be viewed as counterproductive to long-term climate goals due to the additional oil produced [64]. Beyond EOR, emerging utilization routes include methanol synthesis, urea production, carbonation of industrial wastes, and mineralization for concrete curing. These processes demonstrate potential for integrating captured CO_2 into chemical and building material value chains; however, their global scale remains limited compared to the volume of CO_2 generated by refineries and gas plants, making them complementary rather than comprehensive solutions [65-67].

Given the limited capacity of utilization markets, geological storage is expected to play a dominant role in large-scale decarbonization efforts. Suitable storage formations include deep saline aquifers, depleted oil and gas reservoirs, and unmineable coal seams [68]. Saline aquifers in particular offer vast storage potential and broad geographic availability, positioning them as the backbone of long-term CO_2 sequestration strategies [69, 70]. Safe and effective storage requires careful site selection, reservoir characterization, and long-term monitoring to ensure containment integrity and mitigate risks of leakage. Regulatory frameworks governing CO_2 injection wells, environmental impact assessments, and pore space ownership vary across jurisdictions, influencing project timelines and permitting complexity [71]. Despite these challenges, successful commercial-scale storage projects have demonstrated the technical feasibility and long-term reliability of geological CO_2 sequestration [72].

Transport infrastructure represents an essential link between capture sites and utilization or storage facilities [73]. CO_2 can be transported via pipelines, shipping, or truck-based systems, with pipelines being the most efficient option for continuous high-volume flows [74]. Developing CO_2 pipeline networks involves substantial capital investment and regulatory review but provides the backbone for regional industrial decarbonization hubs [75]. In many regions, shared CO_2 transportation corridors are being proposed to reduce costs and enable multiple emitters to access storage sites [76]. Shipping offers a flexible alternative for long-distance or offshore transport, especially where pipeline routes are impractical. However, liquefaction, port infrastructure, and logistics requirements can increase overall system complexity [77].

The integration of CO_2 utilization and storage pathways strengthens the feasibility of CCUS at refineries and gas processing plants by ensuring that captured CO_2 has a reliable and economically viable destination. While utilization pathways may evolve as new markets and technologies emerge, geological storage will remain central to achieving meaningful global CO_2 reductions due to its scalability and permanence. As CCUS deployment grows, coordinated development of capture technologies, transportation infrastructure, regulatory frameworks, and storage capacity will be essential to support sustained decarbonization across the refining and gas processing sectors.

Table 5 compares major CO_2 utilization routes based on their maturity, scale potential, economic value, and suitability for refinery and gas processing CO_2 streams.

Table 5 Comparison of CO_2 Utilization Routes Relevant to Refining and Gas Processing [78-80].

CO_2 Utilization Route	**Technology Readiness Level (TRL)**	**Scale Potential**	**Typical CO_2 Consumption Rate**	**Economic Value**	**Applicability to Refinery CO_2 Streams**
Enhanced Oil Recovery (EOR)	High (Commercial)	High (regional, reservoir-dependent)	High (0.3–0.6 t CO_2/bbl oil)	High (oil revenue)	High – compatible with large, continuous CO_2 flows
Methanol Synthesis	Medium–High	Medium	Moderate (1.4–1.6 t CO_2/t methanol)	Medium	Moderate – requires high-purity CO_2 and hydrogen
Urea Production	High (Commercial)	Medium	High (0.7–0.8 t CO_2/t urea)	Medium	Moderate – limited by ammonia demand and market size
Mineralization / Carbonation	Medium	Low–Medium	Low–Moderate	Low–Medium	Low – better suited for niche or local applications

Synthetic Fuels (Power-to-Liquids)	Low–Medium	Low (early-stage)	Moderate	Low (high cost)	Low – constrained by hydrogen availability and cost

Note: While CO_2 utilization can provide economic benefits and support early CCUS deployment, its overall capacity is limited relative to refinery-scale CO_2 emissions, making geological storage essential for large-scale decarbonization.

Figure 4 illustrates the CO_2 utilization and storage pathways following capture, highlighting compression, transport, industrial utilization options, and long-term geological sequestration.

Figure 5 shows the schematic of CO_2 injection and long-term storage in a deep saline aquifer with caprock containment and monitoring.

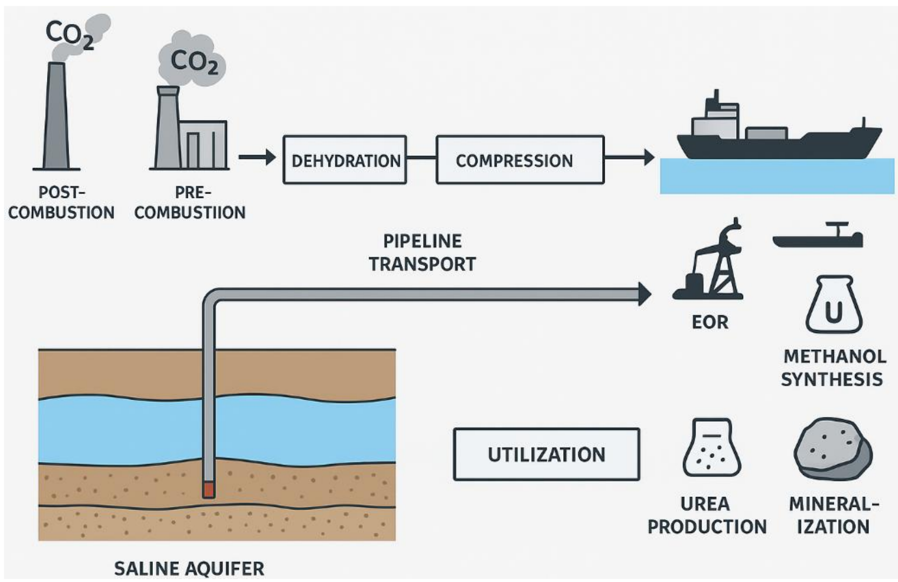

Fig. 4 CO_2 capture, transport, utilization, and storage pathways in refinery and gas processing decarbonization.

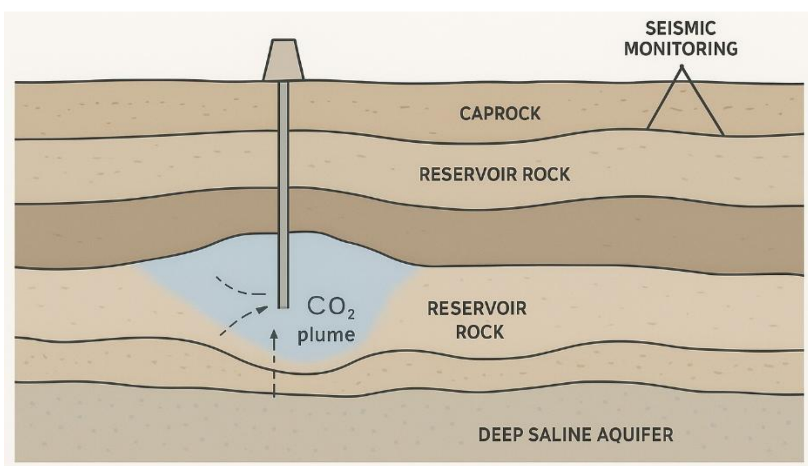

Fig. 5 Geological CO_2 storage in a deep saline aquifer showing plume migration and caprock containment.

6. Economic, Policy, and Regulatory Landscape

The economic feasibility of deploying CCUS systems and blue hydrogen production in refineries and gas processing plants is shaped by a complex interplay of capital costs, operational expenditures, energy requirements, and evolving policy incentives. CCUS projects typically involve substantial upfront investment for capture units, CO_2 compression, transportation, and storage infrastructure. Operating costs are heavily influenced by energy consumption particularly for solvent regeneration and CO_2 compression which can significantly affect the marginal cost of captured CO_2. The resulting levelized cost of CO_2 abatement varies widely depending on the concentration of CO_2 sources, plant configuration, regional energy prices, and integration opportunities [81]. Blue hydrogen economics similarly depend on reformer efficiency, natural gas pricing, and the cost and scale of CO_2 capture systems [82]. Despite these costs, CCUS and blue hydrogen often remain among the most cost-effective pathways for reducing emissions in hard-to-abate industries, especially when compared to deeper structural changes such as full electrification or rapid green hydrogen substitution.

Policy mechanisms play a critical role in improving CCUS and blue hydrogen project viability by addressing economic barriers and creating long-term investment certainty [83]. Carbon pricing instruments such as emissions trading systems, carbon taxes, or performance-based standards directly influence the competitiveness of CCUS by increasing the cost of emitting CO_2 [84]. In regions with stringent carbon pricing, investment in capture technologies becomes increasingly attractive as companies seek to minimize compliance costs. Beyond carbon pricing, government incentives and subsidies have emerged as powerful drivers of deployment. For example, the U.S. federal 45Q tax credit provides substantial financial support for each tone of CO_2 stored or utilized, dramatically improving the economics of large-scale CCUS installations [85, 86]. Similar mechanisms are being implemented globally, including contracts for difference (CfDs), low-carbon hydrogen production credits, and capital grants supporting early-stage infrastructure development [87]. These policies form the backbone of market creation for low-carbon hydrogen by narrowing the cost gap between blue, grey, and green hydrogen pathways.

Regulatory frameworks surrounding CCUS and hydrogen infrastructure significantly affect project timelines, risk profiles, and investor confidence. Permitting requirements for CO_2 injection wells, subsurface storage, and pipeline construction involve rigorous environmental assessments, long-term monitoring plans, and demonstration of geological integrity [88]. These regulatory processes, while essential for ensuring safety and environmental protection, can extend project development cycles and introduce uncertainty. In addition, policies governing pore space ownership, liability for long-term CO_2 storage, and financial responsibility for post-closure monitoring vary across jurisdictions, influencing the attractiveness of CCUS investments. For blue hydrogen, regulations concerning hydrogen purity standards, safety codes for high-pressure storage and transport, and certification schemes for "low-carbon" labeling are still evolving, which can create ambiguity for producers and end users.

Market structure and infrastructure readiness also shape the deployment landscape. Regions with existing CO_2 pipelines, favorable geology, and supportive policy frameworks are better positioned to develop CCUS hubs that aggregate emissions from multiple industrial sites. These hubs reduce transportation and storage costs through economies of scale and foster cross-sector collaboration [89]. Likewise, the emergence of hydrogen hubs regions where hydrogen production, distribution, and consumption are co-located supports the commercialization of blue hydrogen by providing reliable demand and reducing logistical challenges. However, in regions lacking these shared infrastructures, standalone projects may face higher costs and greater financial risk.

Despite clear progress, a number of challenges persist. Uncertainty in long-term carbon pricing, variability in policy support across regions, and public perception concerns surrounding geological CO_2 storage can limit deployment [90]. Moreover, global inconsistencies in hydrogen certification standards may impede market harmonization and international trade of low-carbon hydrogen [91]. Addressing these barriers requires coordinated action from policymakers, industry stakeholders, and regulatory agencies to establish predictable frameworks that support investment, streamline permitting, and create robust markets for low-carbon products.

Overall, the economic, policy, and regulatory landscape plays a decisive role in enabling the large-scale adoption of CCUS and blue hydrogen technologies. With well-designed incentives, stable regulations, and coordinated infrastructure development, these solutions can become integral components of cost-effective decarbonization strategies for refineries and gas processing facilities.

Table 6 presents a comparison of the levelized cost of CO_2 abatement for major decarbonization options in refineries, highlighting relative cost-effectiveness and deployment readiness.

Table 6 Levelized Cost of Abatement for Major Decarbonization Options in Refineries [11, 12, 92].

Decarbonization Option	Typical Abatement Cost (USD/tCO_2)	Cost Drivers	Technology Maturity	Deployment Outlook
CCUS on SMR (Process Gas Capture)	~30–70	High CO_2 concentration, compression, storage access	Commercial	Highly attractive for near-term deployment
CCUS on Flue Gas (Heaters/Boilers)	~60–120	Low CO_2 concentration, energy penalty	Commercial	Moderate, dependent on carbon pricing
Blue Hydrogen (SMR/ATR + CCUS)	~40–90	Natural gas price, capture scope, scale	Commercial–Early large-scale	Strong near- to mid-term option
Green Hydrogen (Electrolysis)	~100–250	Electricity cost, electrolyzer CAPEX	Early commercial	Long-term potential as costs declines
Energy Efficiency Upgrades	~0–40	Retrofit scope, operational optimization	Very high	First priority, limited total impact

Table 7 summarizes key regional regulatory requirements governing CO_2 transport and storage, including permitting processes, monitoring obligations, liability arrangements, and pore space ownership.

Table 7 Regulatory Requirements for CO_2 Transport and Storage Across Regions [93-95].

Region	CO_2 Transport Permitting	Monitoring Duration	Long-Term Liability	Pore Space Ownership
United States	Federal & state permits (e.g., Class VI wells)	20–50 years post-closure	Transfer to state after closure (varies)	Generally surface owner

European Union	EU CCS Directive + national permits	≥20 years (site-specific)	Operator initially, potential state transfer	State-owned or regulated
United Kingdom	North Sea Transition Authority (NSTA)	Decades, risk-based	Government after transfer	Crown/state ownership offshore
Canada	Provincial regulation (e.g., Alberta)	Long-term, defined by regulator	Liability transfer to province	Crown ownership
Middle East (GCC)	Emerging frameworks	Case-by-case	Typically, state-owned	State ownership

7. Case Studies and Industrial Pilots

Industrial case studies and pilot projects provide critical insights into the practical implementation of CCUS and blue hydrogen systems, demonstrating both the feasibility and challenges of integrating these technologies into complex refinery and gas processing operations. Across the globe, several pioneering initiatives have shown how large-scale CO_2 capture and low-carbon hydrogen production can be successfully executed when supported by adequate infrastructure, technical expertise, and policy frameworks. These real-world examples serve as benchmarks for future deployments and illustrate the lessons learned from early adopters.

One of the most notable examples is ExxonMobil's Baytown CCS initiative in the United States, which has explored capturing CO_2 from hydrogen production units within one of the largest integrated refining and petrochemical complexes in the world. The project highlights the potential of targeting concentrated CO_2 streams from SMRs, where capture efficiency is high and integration with existing hydrogen production infrastructure is relatively straightforward. Lessons from Baytown emphasize the importance of careful heat integration, optimization of steam supply, and rigorous assessment of CO_2 compression and pipeline design. The initiative has also contributed to the conceptual development of large-scale industrial CO_2 hubs along the U.S. Gulf Coast, demonstrating how anchor projects in the refining sector can catalyze broader regional CCUS deployment [96].

In Europe, Equinor, Shell, and TotalEnergies have advanced blue hydrogen production through the Refhyne and broader Northern Lights/Longship initiatives, which form part of Norway's flagship national decarbonization strategy. These projects integrate large-scale electrolyzers and reforming units with CO_2 transport and offshore geological storage. Although Refhyne is primarily focused on green hydrogen, it provides essential operational experience related to hydrogen integration into refinery processes, which directly informs the design of blue hydrogen systems. Meanwhile, the Northern Lights project represents one of the world's first open-access CO_2 transport and storage networks, offering a scalable model for regional CO_2 handling infrastructure [97]. The initiative demonstrates how coordinated policy support and public-private partnerships can overcome early-stage financial risks and facilitate multi-industry decarbonization.

In the Middle East, the Al Reyadah project in the United Arab Emirates developed by ADNOC and Masdar stands out as the first commercial-scale CCUS project in the region capturing CO_2 from a steel production facility and integrating it into EOR operations [98]. Although not refinery-based, Al Reyadah provides valuable lessons on CO_2 capture from high-purity industrial streams, large-scale compression and dehydration systems, and long-distance CO_2 transport. Its success demonstrates the viability of CCUS in regions with strong EOR demand and suitable geological reservoirs, paving the way for future refinery-specific applications across the Gulf region. ADNOC is currently expanding CCUS deployment to its gas processing operations, showing how captured CO_2 from amine regeneration units can be efficiently routed into regional sequestration networks [99].

Other notable industrial pilots including Canada's Shell Quest CCS project, the Port Arthur hydrogen capture system, and various refinery-scale pilot plants in Asia underscore the importance of long-term monitoring, solvent management, operational reliability, and the need for skilled workforce training. These pilots have consistently shown that targeting high-purity CO_2 sources yields the most cost-effective capture performance, while retrofitting distributed combustion sources remains technically feasible but economically challenging [100]. They also highlight the significance of modular system design, adaptability to varying CO_2 load conditions, and the benefits of digital monitoring tools for predictive maintenance and process optimization.

Collectively, these case studies illustrate that the technology for CCUS and blue hydrogen is commercially available and capable of integrating into existing refinery and gas processing systems. However, their success depends heavily on supportive government policies, robust CO_2 transport and storage infrastructure, and long-term economic certainty. The lessons learned from these early deployments provide invaluable guidance for scaling up CCUS and blue hydrogen across the global refining sector and help refine best practices for future large-scale decarbonization projects.

Table 8 summarizes key lessons from industrial CCUS and hydrogen pilot projects, highlighting integration challenges, performance outcomes, cost drivers, and scalability considerations.

Table 8 Key Lessons Learned from Industrial CCUS and Hydrogen Pilot Projects [8, 101, 102].

Aspect	Key Lessons Learned	Implications for Future Deployment
Integration with Existing Units	Retrofit complexity is high, particularly in space- and utility-constrained refineries	Early integration planning and modular designs are critical
CO_2 Capture Performance	High-purity, high-pressure streams consistently achieve the highest capture efficiencies	Prioritizing SMR syngas and AGR vents improves cost-effectiveness
Capital and Operating Costs	Energy demand for capture and compression dominates operating costs	Access to low-carbon energy and heat integration is essential
Operational Reliability	Solvent management and corrosion control are key to long-term stability	Robust materials selection and monitoring reduce downtime
CO_2 Transport and Storage Interface	Lack of shared infrastructure limits scalability	Industrial hubs and common pipelines enable economies of scale
Hydrogen System Performance	Blue hydrogen systems show strong reliability at scale	ATR-based systems favor large, hub-based deployment
Scalability and Replication	Pilot success does not automatically translate to rapid scale-up	Standardization and policy support are required for replication

8. Challenges and Research Gaps

Despite the growing momentum behind CCUS and blue hydrogen deployment, several technical, economic, and societal challenges continue to impede large-scale adoption within refineries and gas processing plants. These facilities possess complex, highly integrated systems that require careful coordination when introducing new technologies, and the resulting constraints often influence both operational feasibility and project economics. Understanding these barriers and the research gaps that must be addressed is essential for enabling the next generation of low-carbon industrial solutions.

One of the most significant challenges is the high capital and operating cost associated with CO_2 capture systems. Energy penalties for solvent regeneration, CO_2 compression, and reformer integration remain substantial, often requiring upgrades to utility systems or the addition of new low-carbon energy sources to avoid offsetting emissions reductions [103]. These energy requirements not only increase operating expenses but also complicate heat integration efforts within refineries, where utility systems are already tightly optimized. Research is therefore needed to develop low-energy solvents, advanced sorbents, and high-selectivity membranes that can provide effective separation at lower thermal and electrical loads. Additionally, improved process intensification methods such as catalytic membrane reformers and electrified reforming technologies hold promise for reducing the overall energy footprint of blue hydrogen production [104].

Operational integration poses another set of challenges, particularly in older refineries with constrained layouts, legacy equipment, and limited space for additional infrastructure [47]. Retrofitting existing units with capture technology requires detailed engineering to ensure compatibility with flue gas conditions, utility demands, and safety requirements [105]. Variability in refinery operating conditions driven by changes in crude feedstocks, product slates, and throughput adds further complexity to designing capture systems that can maintain stable performance. Research in dynamic process modeling, flexible solvent systems, and adaptive control strategies is essential to address these real-world operational uncertainties.

From a systems perspective, the availability and reliability of CO_2 transport and storage infrastructure remain major bottlenecks. Many regions lack dedicated CO_2 pipeline networks or accessible geological storage sites, which limits the feasibility of stand-alone CCUS projects. Developing shared transport and storage hubs requires significant upfront investment and long-term policy coordination, yet these hubs are critical for enabling economies of scale. Moreover, long-term storage introduces technical uncertainties related to reservoir behavior, monitoring technologies, and the management of potential leakage risks. Research into subsurface modeling, real-time monitoring techniques, and risk assessment frameworks is vital to strengthen confidence in long-term storage integrity.

Environmental and societal considerations also present important challenges. Ensuring low methane leakage across the natural gas supply chain is essential for blue hydrogen to deliver meaningful climate benefits [106]. Public acceptance of CO_2 storage particularly concerns surrounding induced seismicity, leakage, and long-term liability can hinder project development despite strong technical foundations [107]. Addressing these concerns requires transparent communication, robust regulatory frameworks, and continued research into environmental impact assessment and community engagement strategies.

Lastly, the refinement of techno-economic analyses, policy mechanisms, and market structures remains a critical research gap. Uncertainties around future carbon pricing, taxation policies, hydrogen certification standards, and international trade rules can limit investment in CCUS and blue hydrogen. Advanced economic modeling tools that capture dynamic energy markets, evolving regulatory environments, and cross-sectoral interactions are needed to guide decision-making at both project and policy levels [108].

In summary, while CCUS and blue hydrogen technologies are technically viable and increasingly demonstrated at commercial scale, numerous challenges still constrain their widespread adoption. Addressing these research gaps through advancements in capture technologies, system integration, storage reliability, environmental safeguards, and policy frameworks will be essential for enabling robust, cost-effective, and socially acceptable decarbonization pathways for the refining and gas processing industries.

9. Future Outlook and Strategic Recommendations

The transition toward low-carbon refining and gas processing will rely heavily on the coordinated advancement of CCUS and blue hydrogen technologies, both of which are poised to play foundational roles in near- and mid-term decarbonization strategies [109]. Looking ahead, the integration of these technologies is expected to evolve from discrete, project-level deployments to system-wide decarbonization frameworks embedded across industrial clusters and regional energy networks. This shift will be driven by technological innovation, supportive policy environments, and growing demand for low-carbon fuels and products. As these pressures intensify, refineries and gas processing plants will need to adopt flexible, scalable solutions that balance operational reliability with ambitious emissions-reduction targets.

A key element of future decarbonization will involve the development of hybrid systems that combine CCUS, blue hydrogen, and renewable energy integration [110]. For example, leveraging renewable electricity to partially complement or displace steam and power demands can reduce the energy penalty traditionally associated with solvent regeneration and CO_2 compression [111]. Similarly, blending blue and green hydrogen enables refiners to progressively reduce carbon intensity while preparing for broader adoption of renewable hydrogen as costs decline. In parallel, the electrification of refinery heaters, compressors, and auxiliary systems paired with low-carbon hydrogen for high-temperature duties can support a phased approach to decarbonization that optimizes both technical feasibility and cost-effectiveness [112].

At the infrastructure level, the emergence of CO_2 transport and storage hubs will be vital for enabling widespread CCUS deployment. These shared backbone networks reduce costs through economies of scale and open participation to smaller emitters who would otherwise face prohibitive barriers to entry. Refinery-based CO_2 capture projects, particularly from hydrogen units and amine regeneration systems, can serve as anchor loads that justify investment in new pipeline systems and geological storage developments. Over time, these hubs can expand to incorporate multiple sectors such as cement, steel, and power generation creating integrated industrial ecosystems that steadily decarbonize entire regions.

Policy frameworks will continue to play an indispensable role in shaping the pace and scope of CCUS and blue hydrogen adoption [113]. Clear, stable long-term carbon pricing mechanisms, hydrogen certification standards, and permitting processes are essential to stimulating investment and reducing uncertainty. Financial incentives, such as tax credits, capital grants, and contracts for difference, will remain critical tools for bridging cost gaps during the early phases of deployment. International cooperation will also become increasingly important as cross-border hydrogen trade expands and global markets for low-carbon products emerge. Ensuring consistent carbon accounting methodologies and emissions verification standards will help avoid market fragmentation and strengthen investor confidence.

From a research and innovation standpoint, continued progress is needed in advanced capture technologies, low-energy separation methods, and novel reactor designs that improve the overall efficiency of blue hydrogen production. Digitalization including machine learning, real-time optimization, and predictive maintenance will play a growing role in enhancing operational performance and reducing downtime [114]. In addition, research into the long-term behavior of geological formations, enhanced monitoring technologies, and risk mitigation methods will further reinforce public trust in CO_2 storage as a safe and permanent solution.

Strategically, refineries and gas processing plants must adopt a phased decarbonization roadmap that prioritizes high-purity CO_2 sources, aligns investments with evolving policies, and prepares infrastructure for future scaling [115]. Early adoption of CCUS on hydrogen production and gas processing units will deliver significant early emissions reductions, while broader deployment across combustion-based systems can follow as technologies mature and infrastructure expands. Collaboration among industry stakeholders, policymakers, technology developers, and research institutions will be essential to overcoming shared barriers and accelerating innovation [116].

Overall, the future of decarbonization in the refining and gas processing sectors will be defined by integrated, flexible, and forward-looking strategies that combine CCUS, blue hydrogen, and renewable energy solutions. As these technologies mature and supportive market conditions strengthen, they will form the backbone of a resilient and sustainable industrial energy system capable of meeting global climate goals while maintaining the essential role of refineries and gas processing plants in the energy landscape.

Figure 6 presents a phased refinery decarbonization roadmap, illustrating short-, medium-, and long-term deployment of CCUS, blue hydrogen, and complementary low-carbon technologies.

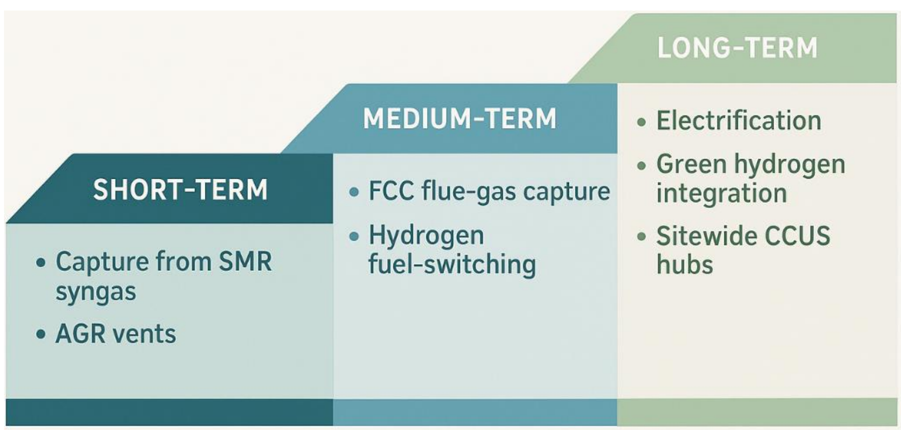

Fig. 6 Strategic roadmap phased refinery decarbonization (CCUS & blue Hydrogen).

10. Conclusion

The refining and natural gas processing industries face mounting pressure to reduce greenhouse gas emissions as global commitments to net-zero targets continue to strengthen. Within this context, CCUS and blue hydrogen production have emerged as pragmatic, scalable, and technologically mature pathways capable of delivering substantial near- and mid-term emission reductions. Together, these solutions address both process-related and combustion-related CO_2 sources, offering a comprehensive approach to lowering the carbon intensity of essential industrial operations without requiring wholesale transformation of existing infrastructure. The analysis presented in this review illustrates that when strategically integrated, CCUS and blue hydrogen can play complementary and reinforcing roles in refineries and gas processing plants, enabling meaningful progress toward decarbonization while maintaining operational continuity and economic viability.

Capture technologies whether post-combustion, pre-combustion, or emerging alternatives provide flexible options for targeting the diverse CO_2 concentration streams found across industrial sites. Blue hydrogen, in particular, offers a low-carbon pathway for meeting the ever-increasing hydrogen demand in refineries, while simultaneously serving as a low-carbon fuel source for heaters and boilers. The synergies enabled by shared CO_2 handling infrastructure and hydrogen production create a strong foundation for multi-unit decarbonization and can catalyze the development of broader regional CCUS networks [95]. Likewise, CO_2 utilization pathways and geological storage provide the essential downstream components needed to ensure that captured CO_2 is managed safely, reliably, and sustainably.

Despite the clear potential of these technologies, significant challenges remain. High capital and operating costs, integration complexities, infrastructure limitations, regulatory uncertainties, and public acceptance issues must be addressed before large-scale deployment can be fully realized. The case studies highlighted in this review demonstrate that while early projects have validated the technical feasibility of CCUS and blue hydrogen, broader adoption will require continued innovation, policy support, and coordinated development of shared transportation and storage systems. Investments in research particularly in low-energy capture systems, flexible integration strategies, and advanced monitoring technologies will be crucial to overcoming existing barriers and improving system-level performance.

Looking forward, CCUS and blue hydrogen are poised to become central pillars in the decarbonization strategies of carbon-intensive industries. Their deployment offers a realistic and actionable pathway for achieving substantial emission reductions while bridging the transition toward a more renewable-energy-dominated future. By adopting phased implementation roadmaps, leveraging cross-sector collaboration, and aligning with evolving policy and market frameworks, refineries and gas processing plants can transform their operations to meet climate objectives while maintaining their vital role in global energy and materials supply chains. Ultimately, the integration of CCUS and blue hydrogen represents not only a technical solution but also a strategic opportunity to enable a more resilient, sustainable, and low-carbon industrial future.

Abbreviation

Abbreviation	Full form
CCUS	Carbon Capture, Utilization, and Storage
SMR	Steam Methane Reforming
ATR	Autothermal Reforming
FCC	Fluid Catalytic Cracking
AGR	Acid Gas Removal
SRU	Sulfur Recovery Unit
MEA	Mono-ethanolamine
MDEA	Methyl-diethanolamine
MOF	Metal-Organic Framework

NO_x	Nitrogen Oxides
EOR	Enhanced Oil Recovery
CfD	Contract for Diffrence

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