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# Challenges and Prospects of Enhanced Oil Recovery Using Acid Gas Injection Technology: Lessons from Case Studies

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**Abstract**

Acid gas injection (AGI), which primarily involves injecting hydrogen sulfide ($H_2S$) and carbon dioxide ($CO_2$), is recognized as a cost-efficient and environmentally sustainable method for controlling sour gas emissions in oil and gas operations. This review examines case studies of twelve AGI projects conducted in Canada, Oman, and Kazakhstan, focusing on reservoir selection, leakage potential assessment, and geological suitability evaluation. Globally, several million tonnes of acid gases have already been sequestered, with Canada being a key contributor. The study provides a critical analysis of geochemical modeling data, monitoring activities, and injection performance to assess long-term gas containment potential. It also explores AGI's role in Enhanced Oil Recovery (EOR), noting that oil production can increase by up to 20% in carbonate rock formations. By integrating technical and regulatory insights, this review offers valuable guidance for implementing AGI in geologically similar regions worldwide. The findings presented here support global efforts to reduce $CO_2$ emissions, and provide practical direction for scaling-up acid gas storage in deep subsurface environments.

**Keywords:** acid gas injection; sour gas injection; case study; Enhanced Oil Recovery; geological storage



Academic Editor: Alireza Kazemi

Received: 20 April 2025
Revised: 23 June 2025
Accepted: 2 July 2025
Published: 10 July 2025

**Citation:** Hashemizadeh, A.; Aliasgharzadeh Olyaei, A.; Sedighi, M.; Hashemizadeh, A. Challenges and Prospects of Enhanced Oil Recovery Using Acid Gas Injection Technology: Lessons from Case Studies. *Processes* **2025**, *13*, 2203. https://doi.org/10.3390/pr13072203



## 1. Introduction

Acid gases, which are mainly hydrogen sulfide ($H_2S$) and carbon dioxide ($CO_2$), are formed in unconfined gas reservoirs or as a by-product of sour hydrocarbon extraction. Treating these acid gases and sour hydrocarbons is important, as they can be extremely corrosive and may lead to operational issues. In addition to their corrosive nature, acid gases, if not properly treated, can pose significant safety and environmental hazards. Typically, acid gases must undergo specialized treatment processes, commonly referred to as gas sweetening. Amine extraction remains the most widely applied method of gas sweetening globally, due to its practical efficiency and cost-effectiveness [1,2]. If acid gases are not treated correctly, serious issues, including corrosion, safety, and environmental issues, can occur. Therefore, addressing these factors is essential in developing efficient and effective treatment options, both for the safety of operations and for environmental protections.

The global surge in sour gas production has led to unprecedented management challenges, most notably an overabundance of sulfur and stored $CO_2$. To date, global CCS projects have injected and stored over 300 million tonnes of $CO_2$, and sulfur production now exceeds 80 million tonnes per year, resulting in an annual surplus of roughly 14 million tonnes above global demand [3]. This imbalance highlights the paramount need for new and effective acid gas injection (AGI) technologies that possess the dual capability of controlling excess sulfur and reducing greenhouse gas emissions. Recent work has primarily focused on geological $CO_2$ sequestration, particularly its feasibility and performance in carbonate reservoirs. Effective acid gas management under such conditions depends on accurate modeling to ensure compatibility with reservoir geology and to prevent economic risks associated with AGI [4,5]. The integrity of the cement sheath and other components is also crucial for ensuring long-term safe containment [6]. Thus, AGI represents a highly feasible alternative to conventional sulfur recovery and flaring operations, offering both environmental and economic benefits.

Injection pressure, reservoir permeability and porosity, and chemical compatibility between injected gases and reservoir formations are all very important technical characteristics for the successful use of AGI [7,8]. Core sensitivity tests are important in determining the most optimal injection conditions. Notably, the presence of $H_2S$ in injected gases appreciably reduces the minimum miscibility pressure (MMP) of $CO_2$ and thus enhances the oil recovery potential in Enhanced Oil Recovery (EOR) processes. The geochemical reaction between injected gases and reservoir rock formations can also influence the mechanical integrity of the caprock, which is of critical importance in achieving successful corrosion management and overall reservoir safety [9,10]. In low-permeability reservoirs, traditional methods such as waterflooding are less effective because they require closely spaced well patterns. AGI bypasses this limitation by maintaining high bottom-hole pressures, thereby preserving single-phase flow conditions and improving displacement efficiency [11,12]. AGI also reduces the risk of hydrate formation. Gas fields containing high levels of acid gas content are particularly found in marine environments, such as those in the Caspian Sea region of Kazakhstan, which offer ideal conditions for implementing AGI.

Regular surface facilities for AGI operations consist of a variety of necessary units including amine sweetening systems, compression and dehydration plants, and injection wells. Sulfur recovery through the Claus process is also part of the AGI operation [13]. The majority of the fields in the Caspian region, including top fields like Tengiz and Kashagan, lack direct connections to national gas distribution systems. Consequently, sour gases are primarily reinjected for the maintenance of reservoir pressure [14,15]. Twelve case studies, of which nine were Canadian and three were west Asian, are comprehensively reviewed in this article. These studies included deep comparisons of AGI performance and environmental compliance. One typical AGI system architecture, widely used in actual field operations, is depicted in Figure 1 [16,17].

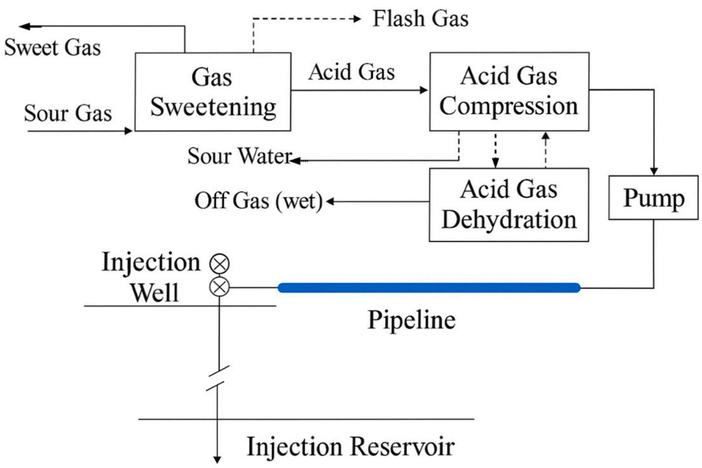


**Figure 1.** Schematic representation of the acid gas injection process [16].

This research is unique in its comprehensive approach, integrating geological, chemical, operational, and regulatory lessons learned from acid gas injection (AGI) projects in both North America and the Middle East. By synthesizing 12 diverse case studies from Canada, Oman, and Kazakhstan, this review offers unparalleled comparative insights into reservoir behavior, acid gas containment, and monitoring performance under different geological conditions. Additionally, it uniquely combines field data, simulation findings, and policy implications to present a holistic understanding of AGI. A key focus is AGI's dual role in enhancing oil recovery (EOR), with documented production increases of up to 20%, and mitigating $CO_2$ emissions through deep geological sequestration. This study is particularly relevant for countries like Iran and others in west Asia, where AGI implementation can address both environmental challenges and economic objectives in hydrocarbon production.

## 2. Gas Injection Fundamentals and Controlling Factors

### *2.1. Displacement Mechanisms*

Gas injection enhances oil recovery primarily through three displacement modes: miscible, near-miscible, and immiscible. In miscible displacement, the injected gas ($CO_2$ or an acid–gas mixture) mixes completely with reservoir fluids, reducing interfacial tension and allowing easier oil mobilization. In immiscible displacement, the injected and formation fluids remain as separate phases, and oil is displaced due to pressure maintenance and viscosity reduction [18].

### *2.2. Phase Behavior and Minimum Miscibility Pressure (MMP)*

The effectiveness of gas injection is closely linked to the Minimum Miscibility Pressure (MMP). The presence of $H_2S$ has been found to reduce the MMP of $CO_2$, thereby enhancing its miscibility and improving displacement efficiency [19,20]. Achieving miscibility at reservoir pressure is critical for maximizing recovery in carbonate systems.

### *2.3. Reservoir Properties*

Key geological factors such as porosity, permeability, and heterogeneity influence AGI performance. High-permeability formations allow better injectivity, while reservoir heterogeneity can lead to gas channeling and poor sweep efficiency [21].

### *2.4. Geochemical and Geomechanical Interactions*

Injected acid gases may interact with reservoir rocks, altering the mineral composition and affecting caprock integrity. Reactions such as mineral dissolution or precipitation can modify porosity and lead to long-term permeability changes. These interactions must be evaluated to ensure containment security [22].

### *2.5. Operational Considerations*

Designing successful AGI systems requires attention to surface-level facilities, including compression, dehydration, and sweetening units. Operating pressures and temperatures must be optimized to avoid hydrate formation and wellbore corrosion. Core sensitivity testing is essential for selecting suitable injection conditions [23].

## 3. Case Studies

This section examines twelve AGI projects. These are located in western Canada, primarily in Alberta, and in Oman, Kazakhstan, and Iran. The case studies evaluate operational performance, containment security, and environmental compliance across diverse geological settings. Table 1 summarizes key operational details, and more recent data are discussed, when available, to cover gaps in earlier datasets.

*3.1. Acid Gas Injection in Western Canada (Alberta Basin)*

The Alberta Basin in Western Canada is currently the global benchmark for acid gas injection (AGI) operations because of the extensive experience of local operators in managing sour gas vents and creating geological $CO_2$ storage. The geological heterogeneity and high sour gas content of the area, as well as the complexity of local regulation, have established the Alberta Basin as a strategic site for acid gas disposal as well as for carbon capture and storage (CCS) operations. One of the most advanced examples of these is the Shell Quest CCS project, which was established in 2015 and represents the transition from pilot-scale AGI to commercial-scale commercial $CO_2$ storage. Up to December 2018, the Quest project had injected a combined quantity of over 3.45 million tonnes of $CO_2$ at an average annual injection rate of approximately 1.07 million tonnes [24]. Seismic imaging, pressure monitoring, and geochemical profiling monitor programs have consistently confirmed that more than 99% of injected $CO_2$ was safely stored in the target formations (Energy Procedia, 2017) [25].

The Quest design built on previous AGI experiences at Albertan sites such as the Zama oil field and the Brazeau Nisku carbonate reservoir, where mixtures of $CO_2$ and $H_2S$ were co-injected into deep reservoirs. These earlier initiatives enabled an increasing understanding of the significance of geochemical compatibility, specifically for mineral trapping by the reduction of iron oxides and carbonates to gas-enriching sulfide minerals [26]. Research into well integrity has also shown that specially tailored $CO_2$ injection wells unequivocally outperform converted wells in terms of long-term containment and safety [27].

Containment risk modeling using ALOHA and SLAB gas dispersion models from the EPA of the United States has shown that, in the worst-case low-wind scenarios, $H_2S$ dispersion is contained within a few kilometers of the injection point, with further evidence confirming the safety of well-designed AGI systems [28]. This has informed regulatory requirements that today address site-specific risk assessments, robust monitoring plans, and the use of advanced materials to minimize corrosion. Quest data for 2015–2016 presented in Figure 2 show that the cumulative injected volume showed steady linear growth while the average daily injection rate remained near 140 tonnes per hour, with only minor operational interruptions. These trends confirm the robustness of the Quest project with respect to both technical delivery and long-term storage assurance. The use of purpose-drilled wells with high regulatory oversight resulted in superior containment performance compared to legacy well conversions, consistent with previous findings from Alberta-based injection programs [25].

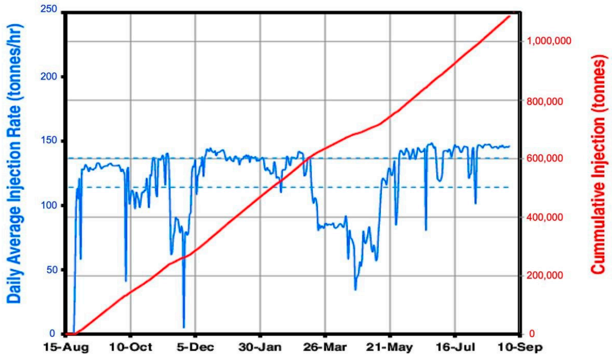


**Figure 2.** Daily average $CO_2$ injection rate (blue, tonnes/h) and cumulative injected volume (red, tonnes) at the Shell Quest CCS project during its first year of operation (August 2015 to September 2016) [25].

In summary, Alberta's AGI plants have evolved from low-volume acid gas disposal plants to globally acclaimed CCS facilities. The success of the Quest project not only attests the technical feasibility of long-term $CO_2$ storage in the province, but also Alberta's commitment to environmentally friendly energy strategies [29].

### 3.2. Expansion of the Strasshof Tief Sour Gas Reservoir

OMV is currently managing two active sour gas reservoirs in Lower Austria—namely, the Reyersdorfer dolomite (a shallow formation) and the Schoenkirchen Uebertief dolomite (a deeper reservoir). OMV is an Austrian energy company responsible for managing oil and gas operations, including sour gas reservoirs and acid gas injection projects in Austria.

A newly identified formation, the Perchtoldsdorfer dolomite (referred to as the Strasshof Tief field), is under evaluation for acid gas management options. At present, gas from the two existing reservoirs is processed at a plant equipped with a 30-tonne-per-day sulfur recovery unit which cannot handle the increased output. To address this issue, the OMV is evaluating acid gas injection as a viable alternative to investing in additional sulfur recovery services. Potential injection targets include the Reyersdorfer and Schoenkirchen Uebertief dolomites, with injection expected to occur in parallel with ongoing production activities. Three injection rates are under consideration—200, 400, and 800 $\times$ $10^3$ STD $m^3$/day (equivalent to 6.4, 12.8, and 25.6 MMcf/D). The acid–gas blend proposed for injection consists of approximately 80% $CO_2$, 16% $H_2S$, 3% $N_2$, and 1% $CH_4$. The primary objective of the case study was to assess, at a preliminary level, whether the targeted formations offered adequate injectivity and storage potential. Simulation efforts involved compositional modeling to predict the production composition and rate changes during simultaneous injection and production, analyzing in situ miscibility and density-driven separation, and assessing potential contamination risks to optimize the injection strategy [30].

### 3.3. Sour Gas Injection in Oman

The Birba A4C field in southern Oman, discovered in 1978 and put on stream in 1982, was one of the sites in the region where sour gas injection was first implemented systematically. The reservoir is contained within the intra-salt carbonates of the Ara Group and is surrounded by impermeable salt, forming a naturally contained reservoir. Throughout its existence, the reservoir has gone through three major development phases: initial pressure depletion; sour and sweet gas reinjection for pressure maintenance; and, finally, pressure support using imported sour gas from nearby fields [31]. As shown in Table 1, the Birba A4C field in Oman achieved a positive dynamic model despite a low-permeability carbonate reservoir. Dynamic modeling confirmed good injectivity and containment performance despite the unfavorable conditions [31]. The reservoir contains a gas cap overlying an oil column with a steep fluid composition gradient. The injected sour gas mixture typically contains 3–4% $H_2S$ and 10–15% $CO_2$, which is favorable for miscible displacement and improved recovery [32]. The cluster is situated in southern Oman, approximately 80 km from the closest structure (Figure 3).

To mitigate the operational risks of this high-pressure sour environment, facilities were developed with corrosion-resistant infrastructure and carbon-steel tubing. No serious corrosion or integrity failure has been reported to date, exemplifying the effectiveness of the monitoring and material-selection strategies [34]. This illustrates the merit of a rigorous risk-based design methodology for extreme sour service conditions.

In tandem, a nearby carbonate "stringer" reservoir, a 100-m or so thick and 2.5–5 km deep reservoir, has been the focus for Oman's first full-field miscible sour gas injection project. Cluster development has been carried out in phases. The early depletion stage, with goals of data acquisition and feasibility assessment, utilized a combined workflow of

3D seismic interpretation, pressure-transient analysis, PVT measurements, and log-derived petrophysical modeling [32].

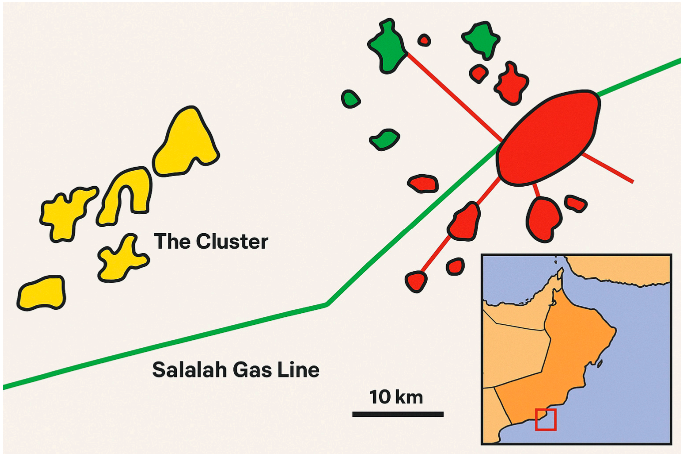


**Figure 3.** Location and distribution of oil reservoirs in southern Oman [33].

Recent advances in hybrid machine learning and deep learning modeling, such as U-Net-based surrogate models, have enabled the more accurate prediction of reservoir performance in gas injection cases [35]. Such models have helped in the optimization of the development strategy of the cluster, guiding surface facility design and the understanding of fluid behavior in tight carbonate environments.

### *3.4. Sour Gas Injection Operations at the Tengiz Field, Kazakhstan*

The Tengiz field, located on the southern margin of the Pri-Caspian Basin in western Kazakhstan, is the world's largest carbonate reservoir and a major sour gas injection (SGI) site. Sweet gas injection started in January 2007 as an initial stage in a pilot SGI project. Sour gas injection recommenced in January 2008 after some technical modifications which followed a brief shutdown late in 2007 [36]. Figure 4 demonstrates the designated SGI area.

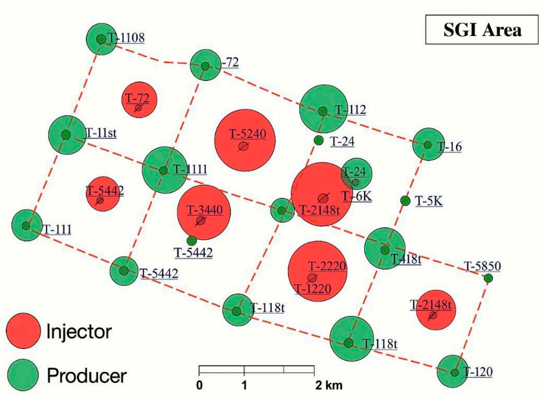


**Figure 4.** Relative production and injection volumes [37].

The reservoir is characterized by a grossly thick oil column from a depth of approximately 3850 m to the location of an oil–water contact at 5450 m. The reservoir structure is characterized by a classic mesa-type carbonate buildup, with steeply dipping flanks (~25°) and a gently sloping platform (<1°) [36,38]. Geologically, this formation was deposited in the Late Devonian to Middle Carboniferous period, and it is composed mainly of lime mud and skeletal components of marine origin. The $H_2S$- and $CO_2$-content sour gas injected into Tengiz varies in composition with field conditions and processing constraints. Precise details of gas composition are not publicly available; however, miscible gas flooding simulations have been studied recently with 15% to 30% $CO_2$ and 2% to 10% $H_2S$ ranges, optimized to match phase behavior and miscibility characteristics for Tengiz's matrix-dominated platform core [38]. These simulations are usually optimized for pressure support and recovery.

Injection is into the platform interior, where matrix porosity dominates, so there is more containment and less risk of leakage. The fracture-rich reservoir flanks are primarily reserved for production wells. Dual-porosity and subsurface cavern features observed in drilling and pressure tests suggest a complex reservoir structure, which impacts injection response and sweep efficiency [39].

Modeling studies conducted as recently as 2023 sought to investigate the impact of sour gas composition, and the heterogeneity of the reservoir, on flood efficiency. This research confirmed that injection design will need to accommodate variations in permeability and gas solubility in space, and further confirmed Tengiz as a strong candidate for long-term $CO_2$ storage and sour-gas EOR application, if it is managed with adequate reservoir monitoring [38].

The Tengiz SGI pilot remains one of the most prominent field-scale demonstrations of sour gas reinjection for high-pressure, high-temperature (HPHT) oil recovery worldwide. It continues to impact the design of SGI projects in complicated carbonate reservoirs globally.

### 3.5. Feasibility Study of AGI in Iran and Its Neighboring Regions in West Asia

Acid gas injection (AGI) is a highly promising technique for Iranian reservoirs due to favorable local reservoir and geological conditions. The feasibility of the technique and possible impacts resulting from its usage have been evaluated in recent studies using information from some Iranian fields.

The authors of one study assessed the injectivity of a mixed $CO_2$–$H_2S$ acid gas stream into the Surmeh formation, a saline aquifer (Figure 5). The study used detailed reservoir simulations and geomechanical investigations to conclude that the reservoir was of sufficient capacity and integrity to safely store acid gas [16]. It examined the injection potential for gas and the associated risk of caprock leakage in the Yort-e-Shah aquifer. Another study utilizing numerical modeling methodology and actual reservoir data to demonstrate the effectiveness of long-term acid gas storage with low-level leakage risks on well-controlled terrains [40,41].


**Figure 5.** Surmeh site, Bushehr, Iran (red arrow) [16].

The authors of another study [42] investigated the impacts of reservoir salinity and natural convection on the injection of acid gases into the deep brine-bearing formations of Bushehr. They established effective containment, and augmented the dissolution of the injected gases, thus affirming the suitability of the aquifer for extensive acid gas storage. Another recent study investigated the potential for the underground storage of sour gas in a depleted, fractured gas-condensate reservoir located in southern Iran. The obtained simulation results indicated that it was possible to conduct cyclic injection and withdrawal operations safely and economically, findings which were of significant interest for the viable operating policies of acid gas storage in Iranian depleted reservoirs [42]. In conclusion, these studies show that acid gas injection is a viable and advantageous solution in Iran. Application of this technique has the potential to reduce the significant environmental impacts associated with sour gas production while making efficient use of the region's available geological storage capacity.

### *3.6. Cross-Case Comparisons and Geographic Insights*

AGI projects across Canada, Oman, Kazakhstan, and Iran have demonstrated how injection schemes are affected by regional geology and operating environment. Canada's mature infrastructure allows for safe operations, while Oman's salt-bound carbonates require advanced modeling to manage low permeability. The Tengiz field in Kazakhstan is challenging due to fractured carbonates, but offers great EOR potential. Iranian simulation studies of the Surmeh Formation and the Yort-e-Shah aquifer confirm high injectivity and low leakage risk, demonstrating the feasibility of AGI usage in west Asian reservoirs. Despite variations in formations and gas mixtures, all regions are subject to the same needs for appropriate reservoir characterization, good regulatory policies, and long-term monitoring to ensure the safe and effective deployment of AGI.

Table 1 summarizes a set of acid gas injection projects across Canada, Oman, and Kazakhstan, highlighting variations in formation types, porosity, permeability, and intended outcomes. These parameters provide context for assessing the geological feasibility, environmental safety, and EOR potential of AGI across diverse reservoir settings.

**Table 1.** Summary of Case Studies.

| Ref. | Field/Country | Formation Type | Permeability (md) | Porosity (%) | Purpose | Outcome |
|---|---|---|---|---|---|---|
| [43] | Zama, Canada | Carbonate | 150 | 6 | $CO_2$ sequestration | Positive |
| [26] | Brazeau NiskuQ, Canada | Carbonate | 60 | 6.6 | Reservoir repressuring | Positive |
| [44] | West Stoddart, Canada | Sandstone | 5 | 11 | Geological sequestration | Technically feasible |
| [45] | Thompson Lake, Canada | Carbonate | --- | --- | Enhanced oil recovery (EOR) | Negative |
| [28] | Wabamun2, Canada | Unknown | 67 | 14.8 | Leakage risk assessment | Smaller leakage rate |
| [37] | Reyersdorfer, Canada | Dolomite | 6 | 4 | Gas recovery | Recommended |
| [30] | Birba A4C, Oman | Carbonate | 2 | 8 | Pressure maintenance, oil recovery | Positive dynamic model |
| [36] | Tengiz, Kazakhstan | Carbonate | Single-digit | 10–15 | Enhanced reservoir performance | Successful |
| [32] | Cluster, Oman | Carbonate | --- | --- | EOR, reduced uncertainty | Reduced uncertainties |

## 4. Results and Discussion

### *4.1. Results*

Figure 6 shows simulated gas saturation distribution with a secondary gas cap developing in a reservoir after prolonged $CO_2/H_2S$ injection. High-temperature colors (green/yellow) indicate extreme gas saturation developing at the top of the structure, and low-temperature colors (blue/pink) indicate lower saturation. In structural trapping, the injected buoyant gas moves up beneath the low-permeability cap rock and develops as a gas cap over the formation brine. Color contours represent levels of gas saturation (SGAS), ranging from 0.00 (purple) to 0.70 (red), with higher values indicating a greater gas presence near the top of the structure. The model grid is shown in 3D, with depth along the *Z*-axis (in meters) and *X*–*Y* coordinates representing spatial location within the reservoir domain [16]. In AGI, the injected gases are stored safely by different trapping mechanisms: initially, as a free mobile gas phase; then, and increasingly with time, as residual (immobile) gas trapped in pore volumes and dissolved gas in brine. Surprisingly, the simulation indicates that solubility trapping (solution into formation water) dominates in the long run; for example, in one study, 85% of the injected $H_2S$ and ~71% of the $CO_2$ was dissolved after 1000 years, and only a low percentage remained mobile. Mineral trapping (deposit as solid minerals) is minimal in most instances over the injection timescales. These processes, along with an intact caprock, ensure that $CO_2$ and $H_2S$ can be safely stored underground for geologic time scales [46,47].

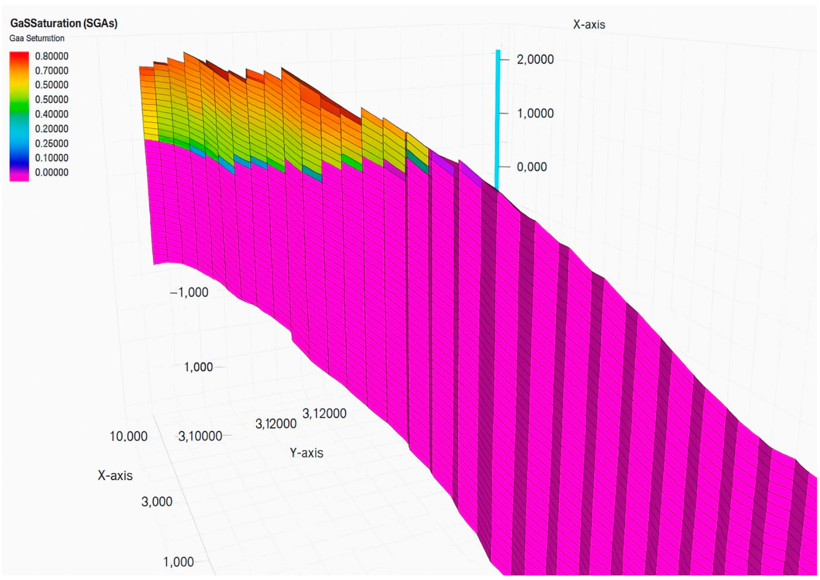


**Figure 6.** Secondary gas cap after acid gas injection (AGI) operation [16].

Acid gas injection, which simultaneously serves EOR, waste-disposal, and $CO_2$-sequestration purposes, is emerging as a transitional technology. It offers a practical bridge between small-scale $CO_2$ pilot projects and the eventual deployment of full-scale injection systems aimed at reducing emissions from major industrial sources [13]. Over time, acid gas injection has developed into a dependable and eco-friendly technique. Depending on the characteristics of the available wastewater, the acid gas may be injected either in its dry form or as a dissolved solution. When compared to alternatives such as sulfur recovery, which poses a risk of groundwater contamination through sulfur leaching or flaring, which releases $CO_2$ and replaces $H_2S$ with $SO_2$ in the atmosphere, acid gas injection presents significantly lower environmental impacts [48]. Table 2 summarizes the key reservoir characteristics of the fields where AGI has been implemented, including fluid type, formation type, permeability, and porosity.

**Table 2.** Reservoir characteristics of fields in which acid gas was injected.

| Ref. | Fluid Type (Crude Oil/Natural Gas) | Formation Type | Permeability | Porosity |
|---|---|---|---|---|
| [43] | Crude oil | Dolomite reservoir | --- | --- |
| [26] | Natural gas | Carbonate reservoir | 60 md | 6.6% |
| [44] | Crude oil | Sediments and sandstones | 5 md | 11% |
| [45] | Natural gas | Sandstone | 10 md | 30% |
| [45] | Crude oil | Carbonate | 150 md | 6% |
| [28] | Natural gas | Unknown | 67 md | 14.8% |
| [37] | Crude oil and natural gas | Sandstone | 5 to 4250 md | 4–30% |
| [30] | Natural gas | Dolomite | 6 md | 4% |
| [30] | Natural gas | Dolomite | 1 md | 4% |
| [31] | Sour crude oil | Carbonate | 2 md | 8% |
| [33] | Crude oil and natural gas | 29 cases of carbonate and 19 cases of siliciclastics | 1 to 4250 md | 4–30% |
| [36] | Crude oil | Carbonate | Single digit | 10–15% |
| [32] | Crude oil | Carbonate | --- | --- |

Operational experience with acid gas injection at West Stoddart and other sites in the Alberta Basin has demonstrated that injecting $CO_2$ into deep aquifers is a technically viable approach. Comprehensive geological and hydrogeological assessments of the West Stoddart site indicate that the injected acid gas is likely to remain confined within the sandstone layers of the Triassic Halfway Formation [15]. Acid gas injection across the Alberta Basin in western Canada has been implemented under a wide variety of geological settings, acid–gas mixtures, and operational practices. By the close of 2003, approximately 2.5 million tonnes of $CO_2$ and 2 million tonnes of $H_2S$ had been successfully injected into deep hydrocarbon reservoirs and saline aquifers throughout Canada. When combined with similar projects in the United States, these operations demonstrate that acid gas injection is a well-established and safe technique—one that is increasingly applicable worldwide as the production of sour gas from deep reservoirs continues to increase [45,49]. By the close of 2002, nearly 1.5 million tonnes of $CO_2$ and 1 million tonnes of $H_2S$ had been successfully injected into deep saline aquifers and hydrocarbon reservoirs across Canada. When similar initiatives in the United States are included, the accumulated evidence confirms that the geological storage of $CO_2$ is a well-established and scalable technology. This approach holds significant potential for widespread deployment aimed at reducing atmospheric emissions from major stationary $CO_2$ sources [48]. A summary of further experiences is presented in Table 3.

**Table 3.** Experiences of acid gas injection (AGI) in 12 case studies.

| Ref. | Country | Field Name | Purpose of AGI | Results |
|---|---|---|---|---|
| [43] | Canada | Zama | $CO_2$ sequestration within mixed gas streams | Confirmed |
| [26] | Canada | Brazeau NiskuQ Pool | Repressuring of the reservoir | Positive |
| [44] | Canada | West Stoddart | Geological sequestration of $CO_2$, EOR | Technically feasible |
| [45] | Canada | Thompson Lake | | Negative |
| [28] | Canada | Wabamun2 | Reduced rate of leakage through wellbores, repressuring of the reservoir | Reduced leakage rate |
| [37] | Canada | Western Canada | Safe disposal of acid and greenhouse gases | Successfully injected |
| [30] | Canada | Reyersdorfer-schonkirchen | Improved gas recovery | Recommended |
| [31] | Oman | A4C reservoir | Pressure maintenance, increased oil recovery | Led to past dynamic model |

**Table 3.** *Cont.*

| Ref. | Country | Field Name | Purpose of AGI | Results |
|---|---|---|---|---|
| [33] | Canada | Western Canada | Reduction in atmospheric emissions of hydrogen sulfide | Successfully injected |
| [27] | Canada | Alberta | Storage of $CO_2$, EOR | Acid gas wells showed greater reliability compared to $CO_2$ injection wells |
| [36] | Kazakhstan | Tengiz | Increasing reservoir performance | Gas injection project was successful |
| [32] | Oman | Cluster | Reduction in uncertainties, EOR | Certainly helped in reducing uncertainties |

Overall, the findings indicate that the safety of $CO_2$ and acid gas injection wells is significantly improved when a dedicated regulatory framework is established to specifically govern and manage this category of wells, and when injection wells are drilled, completed, operated and monitored for their purpose [43]. We state the advantages and disadvantages of AGI in all 12 cases in Table 4.

**Table 4.** Opportunities and challenges of acid gas injection (AGI).

| Ref. | Name | Advantages | Disadvantages |
|---|---|---|---|
| [43] | Zama | Economically viable, with limited impact on current oil extraction operations | Needs a lot of monitoring |
| [26] | Brazeau NiskuQ Pool | Increased reservoir pressure, storage of acid gas | Hydrogeological traps, solubility trapping, mineral trapping |
| [44] | West Stoddart | Reduced emissions into the atmosphere | Acid gas solubility, saturation of remaining gas |
| [45] | Thompson Lake | Desulphurization was uneconomic | Requires complex facility design and operation; acid gas leaks can cause fatalities, dehydration, and hydrate blockages |
| [28] | Wabamun2 | Carbon storage achieved in the area | Acid gas leakage, risk of detriment |
| [37] | Western | Increased capacity and decreased buoyancy, increased injectivity | Corrosion, cavitation |
| [30] | Reyersdorfer-schonkirchen | Favorable mobility ratio, higher recovery of natural gas, premature watering out of producing well prevented | Risk scenarios must be evaluated, needs extensive modeling of operation |
| [31] | A4C | Low level of produced GOR, increased reservoir pressure, absence of corrosion when carbon-steel materials used | Reliability problems with compressor |
| [33] | Western Canada | Potential for future use at sites for geological sequestration and storage of CO2, EOR, gas recovery, no safety incidents recorded over the past 15 years | Key concerns that require attention moving forward include ensuring long-term containment of injected gases underground and maintaining the safety of large-scale injection operations |
| [27] | Alberta, Canada | Enhanced oil recovery | Common issues involve surface-casing venting, casing or tubing rupture, packer integrity loss, compromised zonal isolation, gas migration |
| [36] | Tengiz | Due to the absence of fractures, the platform was ideal for gas injection. Injection wells demonstrated good performance, with consistent injectivity and no significant change in well skin over time, | Probability of breakthrough of gas |
| [32] | Cluster | Execution of miscible gas flood project required substantial resources, and was sometimes a complex undertaking, but did lead to sustainable production and high recovery; increased RF | Needs highly advanced monitoring and modeling. |

In an aquifer system, the acid gas behaves as a separate-phase flow due to the combined influence of the injection dynamics, the aquifer's natural hydrodynamic movement, and buoyancy forces. The velocity of the acid gas flow in a sloped aquifer, relative to the reference fluid density $\rho_0$, can be expressed as follows:

$$v = \frac{q}{\Phi} = -\frac{kk_{rag}\rho_0 g}{\mu_{ag}}\left(\nabla H_0 + \frac{\rho_0 - \rho_{ag}}{\rho_0}\nabla E\right) \quad (1)$$

where $q$ represents the specific discharge, $\Phi$ is the porosity, $g$ is the gravitational acceleration, $\mu_{ag}$ denotes the viscosity of the acid gas, $k$ is the aquifer's permeability, and $k_{rag}$ refers to the relative permeability to the acid gas. $\rho_0$ the brine density, $\rho_{ag}$ the acid gas density, $\nabla H_0$, is the hydraulic head gradient, and $\nabla E$ represents the slope of the aquifer. It should be noted that Equation (1) relies on simplified assumptions, such as constant fluid densities and permeability, and is therefore primarily useful for estimating the general direction of acid gas migration rather than providing precise flow predictions and determining flow velocity to an order of magnitude.

### 4.2. Discussion

#### 4.2.1. Key Outcomes from AGI Case Studies

AGI is widely seen as a practical method for managing sour gas. It helps improve oil recovery and supports carbon storage efforts. A large share of AGI use has taken place in western Canada. There, injection into deep aquifers and depleted reservoirs has been backed by strong geological studies. Table 1 summarizes reservoir properties, including formation type, porosity, and permeability, as well as project objectives and field-scale outcomes, across 10 AGI projects in Canada, Oman, and Kazakhstan. These case studies demonstrate the diversity of geological settings, operational goals, and technical performance associated with AGI deployment. They also provide comparative insights into project feasibility and containment success under varying conditions (e.g., carbonate vs. sandstone reservoirs, different $CO_2/H_2S$ ratios, and regulatory contexts).

Field performance evaluations support the conclusion that AGI can be conducted safely and cost-effectively when proper engineering and regulatory practices are followed. The West Stoddart site, for example, demonstrated long-term containment of acid gas within the Triassic Halfway Formation [44]. Also, the Zama oil field case study confirmed that injection into purpose-drilled wells, under tailored regulatory frameworks, significantly reduces leakage risks [43].

Despite these achievements, challenges remain. The success of AGI is highly reliant on reservoir type, injection protocols, and gas composition, all of which differ by location and project objectives.

#### 4.2.2. Technical and Operational Considerations

Technically, AGI is multi-dimensionally complex. Acid gas injection in a dry or solution form calls for an accurate prediction of geochemical interaction between gas and reservoir rock. For instance, carbonate reservoirs may see porosity alterations due to the dissolution and precipitation of minerals, rendering long-term storage predictions complicated [5]. Furthermore, simulation of hydrodynamic response in sloping aquifers is itself uncertain because assumptions within flow equations can be unrepresentative of site heterogeneity [9].

Operational constraints, as highlighted in many Canadian and international case studies, also limit AGI scale-up. Injection wells can reach capacity levels, necessitating shut-ins or increased numbers of well completions [48]. Elevated injection pressure can risk reservoir integrity and necessitate careful monitoring and adaptive operation [8]. Moreover, because acid gas composition is highly variable, ranging widely in $CO_2/H_2S$ ratios, flexible and robust injection protocols are required [17].

Corrosion from $H_2S$ and $CO_2$ poses a significant threat to subsurface wellbore equipment and pipeline infrastructure, necessitating use of corrosion-resistant materials and advanced management systems [50]. In addition, in some pressure–temperature conditions, hydrate plugging can clog flowlines and disrupt operations [51].

#### 4.2.3. Economic and Policy Considerations

The economic and policy environment is important in the feasibility and sustainability of AGI operations. In Canada, particularly in Alberta, robust regulatory frameworks and economic incentives have been instrumental in facilitating AGI deployment. The decades-long regulatory oversight of the province, which includes stringent well-integrity monitoring and transparent reporting requirements, has enabled safe injection operations in fields like the Brazeau Nisku and Zama oil fields. Case studies of these fields demonstrate how policy clarity and enforcement can benefit both environmental safety and operational efficiency, especially in managing high $H_2S$ concentrations in AGI streams [27,43].

Contrarily, studies of west Asian projects such as Kazakhstan's Tengiz field and Oman's Birba field demonstrate how infrastructural limitations or gaps in policy can introduce uncertainties. In Oman, the absence of an integrated AGI policy initially necessitated extensive internal evaluation to cope with a high-pressure, sour environment. However, targeted investment and phased development strategies, supported by internal risk evaluation and the presence of indigenous resources, enabled successful deployment. Likewise, operation of Kazakhstan's Tengiz project was delayed by technical and regulatory issues in its early stages, highlighting the necessity for robust permitting and environmental-governance frameworks to oversee subsurface risks [32,36].

Economic limitations are especially crucial in areas where there is no subsidized access to processing facilities or inexpensive gas supplies. For instance, while proximity to processing facilities and existing oil infrastructure have been of assistance in western Canada, these circumstances may not be replicable in the less-developed regions of the MENA. Nevertheless, Iranian research shows that, through good reservoir characterization and regulatory frameworks, saline aquifers like Surmeh or Yort-e-Shah might be able to host safe and scalable AGI if priority is given to investment in simulation tools and environmental assurance mechanisms [16,40].

Overall, the successes and limitations of AGI projects observed in different locales underscore the imperative balance among economic feasibility, technological readiness, and policy governance. Lessons from the cases examined here repeat the necessity of comprehensive approaches to reconciling regulatory enforcement, financial sustainability, and public trust as a means to scale up AGI as a viable climate and resource management solution.

### *4.3. Challenges of AGI in Enhanced Oil Recovery (EOR)*

Despite the fact that acid gas injection is a mature technique of oil recovery enhancement, it still involves a number of technical and economic challenges that must be addressed.

#### 4.3.1. Operational Challenges

1. Corrosion: Gaseous corrosive materials, such as hydrogen sulfide ($H_2S$) and carbon dioxide ($CO_2$), pose a significant corrosion threat to subsurface wellbore facilities, pipeline networks, and surface equipment. To effectively avoid such corrosion, highly resistant materials must be used in corrosive environments, along with advanced corrosion management systems [50].

2. Safety risks: The handling and injecting of toxic gases, such as hydrogen sulfide ($H_2S$), poses a serious health and safety concern. A risk of gas leakage risk exists, with the potential for toxic exposure; therefore, rigorous safety protocols, a good emergency response system, and constant monitoring are all of the utmost importance.
3. Gas distribution and injection control: Navigating the complications of subsurface structures, especially those which exhibit variability in their properties, continues to present a lot of challenges in achieving gas injection velocities and a spread of gas throughout the reservoir.
4. Hydrate formation: Under specific thermodynamic-pressure and temperature conditions, gas hydrates may be nucleated and grown by the introduction of gaseous molecules. Gas hydrates pose a severe operating threat in pipeline systems via the formation of occluding blockages [50].

4.3.2. Economic Challenges

1. High capital costs: Gas injection calls for a large initial capital outlay. This entails the establishment of large compression facilities, redesign of existing wells, and the utilization of specialized corrosion-resistant equipment and materials.
2. Uncertain recovery efficiency: The effectiveness of gas injection for oil recovery is very variable, depending on the specific characteristics of the subsurface reservoir. Such variability in reservoir properties creates uncertainty in predictions of ultimate recovery.
3. Operating costs: Operational costs include ongoing surveillance and maintenance, in addition to the implementation of chemical agents specially crafted to prevent corrosion and the formation of hydrates.
4. Gas sourcing and availability: Availability of a low-cost and reliable supply of suitable injection gas ($CO_2$, $N_2$, or acid gas) can be a significant financial barrier [52].

## 5. Conclusions

Acid gas injection (AGI) is a well-tried, secure, and green technology for enhanced oil recovery (EOR) and $CO_2$ sequestration. It has several unique operational and economic advantages, such as reduced sulfur emissions, $CO_2$ sequestration, and operational expenditure which is normally low. By the end of 2003, an estimated 2.5 million tons of $CO_2$ and 2 million tons of $H_2S$ had been successfully stored in deep geological reservoirs and aquifers across Canada, affirming the technology's large-scale feasibility. Detailed geochemical modeling and experimental validation demonstrated that more than 85% of the injected $H_2S$ and approximately 71% of the $CO_2$ were retained through solubility trapping over a long time period, indicating long-term containment. Despite the benefits of AGI, there are still formidable challenges associated with its use; these include the detection of geologically secure storage units, dealing with potential subsurface migration, the need for more elevated levels of safety, and addressing the economic consequences arising from the loss of sulfur revenue. These are the main drivers that need to undergo difficult economic analysis, as well as environmental and safety evaluations, when planning AGI deployment. Successful existing AGI operations have primarily been driven by economic profitability, good environmental regulation, and location in geologically favorable areas. This has been particularly true in Canada. These findings demonstrate the need for good regulatory design and prudent operating practices in future AGI activities globally. Recent feasibility studies indicate significant potential for AGI in Iran and west Asia due to favorable geological formations and reservoir properties. Successful application, supplemented by regulatory systems and thorough geological assessment, would enable the mentioned countries to manage sour gas venting successfully, and thus benefit economically from enhanced gas storage and environmental acceptability.

**Author Contributions:** Conceptualization, A.H. (Abbas Hashemizadeh); Methodology, A.A.O.; Investigation, A.H. (Ali Hashemizadeh); Writing—original draft, A.A.O.; Writing—review & editing, A.H. (Abbas Hashemizadeh) and M.S.; Supervision, A.H. (Abbas Hashemizadeh) and A.H. (Ali Hashemizadeh); Funding acquisition, A.H. (Ali Hashemizadeh). All authors have read and agreed to the published version of the manuscript.

**Funding:** This research received no external funding.

**Data Availability Statement:** The original contributions presented in this study are included in the article. Further inquiries can be directed to the corresponding author.

**Conflicts of Interest:** The authors declare no conflict of interest.

## Abbreviations

| | |
|---|---|
| AGI | Acid Gas Injection |
| $CO_2$ | Carbon Dioxide |
| $H_2S$ | Hydrogen Sulfide |
| EOR | Enhanced Oil Recovery |
| BHP | Bottom-Hole Pressure |
| MMP | Minimum Miscibility Pressure |

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