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Optimizing the operational efficiency of the underground hydrogen storage scheme in a deep North Sea aquifer through compositional simulations

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ABSTRACT

In this study, we evaluate the technical viability of storing hydrogen in a deep UKCS aquifer formation through a series of numerical simulations utilising the compositional simulator CMG-GEM. Effects of various operational parameters such as injection and production rates, number and length of storage cycles, and shut-in periods on the performance of the underground hydrogen storage (UHS) process are investigated in this study.

Results indicate that higher H_2 operational rates degrade both the aquifer's working capacity and H_2 recovery during the withdrawal phase. This can be attributed to the dominant viscous forces at higher rates which lead to H_2 viscous fingering and gas gravity override of the native aquifer water resulting in an unstable displacement of water by the H_2 gas. Furthermore, analysis of simulation results shows that longer and less frequent storage cycles lead to higher storage capacity and decreased H_2 retrieval. We conclude that UHS in the studied aquifer is technically feasible, however, a thorough evaluation of the operational parameters is necessary to optimise both storage capacity and H_2 recovery efficiency.

1. Background

The energy transition refers to the transition from fossil fuels as the primary energy source to the use of more sustainable and renewable energy sources. This shift is imperative to address climate change and reduce our reliance on finite resources. The transition entails the development of new technologies, changes in infrastructure, and modifications in the production, distribution, and utilization of energy [1]. Renewable energy sources, such as solar, wind, hydropower, and hydrogen, are some of the prominent examples. Hydrogen, being the most abundant element in the universe, is an environmentally friendly and versatile energy source with the potential to play a significant role in the energy transition. By using fuel cells, hydrogen can be converted to electricity without generating greenhouse gases, making it a potentially valuable medium for renewable energy [2–4].

Hydrogen can be produced in a number of ways, including the thermal breakdown of hydrocarbons, electrolysis of water, and steam reforming of natural gas. Currently, steam reforming is the most used method for producing hydrogen, but as a consequence, it also creates associated carbon dioxide. On the other hand, creating hydrogen through electrolysis is a clean process, but it uses a considerable amount of electricity [5–8]. Nonetheless, hydrogen has the potential to be a major player in the shift to a clean and renewable energy future.

In order to meet peak energy demands, hydrogen gas can be stored underground during periods of low energy demand and then withdrawn when demand increases. This can be achieved by injecting hydrogen gas into subsurface geological formations, such as aquifers, salt caverns, or depleted natural gas or oil reservoirs. Compared to surface storage methods, underground hydrogen storage offers several advantages. For instance, it allows for the storage of hydrogen in substantial volumes, which is essential for its widespread use as an energy source. Moreover, it reduces the risks associated with hydrogen gas leaks, making underground storage a safer option [9–13]. Underground hydrogen storage is an essential component of the infrastructure required to support the widespread use of hydrogen as a clean and renewable energy source.

Hydrogen can be injected underground into aquifers to store it for use as an energy store. Aquifers are attractive for hydrogen storage because they are typically abundant, stable, and capable of storing hydrogen at the high pressures needed for its efficient use [14–17]. Aquifers have been used to store hydrogen and natural gas mixtures in a number of instances such as Ketzin in Germany, Lobodice in Czech Republic and Beynes in France [18,19].

There are several parameters that affect underground hydrogen storage in aquifers including aquifer parameters and operational

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Fig. 1. UHS operational parameters investigated in this study.

Table 1
Summary of aquifer properties.

Property	Value
Depth (ft)	10,000
Temperature (°C)	110
Initial pressure (psi)	6000
Current pressure (psi)	2000
Salinity (ppm)	24,000
Water initially in place (billion ft^3)	2.1
Average porosity (%)	19
Average permeability (mD)	500
Aquifer gross thickness (depth 10,000 ft to 10,500 ft), ft	500

parameters. Aquifer parameters can be aquifer's structure type, relative permeability hysteresis, hydrogen solubility, diffusion, pressure, porosity and permeability [14,15,17,20–22]. Operational injection and production rates, number and storage length of cycles, and the number of utilised wells are some of the operational parameters that dictate underground hydrogen storage in aquifers.

Hagemann et al. [23] developed a mathematical model that was numerically implemented in DuMu^x to evaluate the effects of hydrodynamics in UHS. Their findings demonstrated that gravitational forces predominate at low injection rates, causing a uniform displacement of water. The viscous forces become more dominant with higher injection rates, which causes unstable water displacement and lateral gas fingering. Moreover, UHS in stratified aquifers may help to reduce the chance of gas loss from lateral spreading. However, this procedure calls for the injection of gas into lower structures, and it depends on how quickly the gas rises toward the cap rock seal. Feldmann et al. [24] investigated UHS hydrogeological effects through numerical modelling and observed that gravity override and viscous fingering phenomena during UHS was more impactful in aquifers compared to gas reservoirs. Bai & Tahmasebi [20] developed a 3D coupled hydro-mechanical model to assess the viability of UHS in a salinized aquifer at the Powder River Basin of Wyoming State and utilised the Peng-Robinson equation of state to evaluate the properties of H_2. By the end of the third cycle, their modelling findings indicated that a maximum of 75 % hydrogen could be recovered. Additionally, the Mohr-Coulomb criterion was used to assess the integrity of the formation and caprock, and the results demonstrated that UHS in the investigated structure is geomechanically safe.

Most of the learnings for underground hydrogen storage are adapted from natural gas storage and carbon dioxide sequestration and storage. The capacities of storing CO_2 and H_2 in a deep aquifer anticline were compared by Luboń & Tarkowski [25] using numerical simulation through PetraSim TOUGH2. They reported that the structure can store up to 1 million tonnes of CO_2 over a 31-year period as opposed to 4000 tonnes of H_2. This was explained by the fact that more CO_2 can be stored at a given pressure thanks to carbon dioxide's higher density when compared to H_2. Additionally, changing the threshold capillary pressure of the cap rock was found to have a significant impact on the modelling outcomes. The utilization as CO_2 as a cushion gas was also investigated for hydrogen gas storage providing pressure support and limiting the hydrogen lateral spreading [26,27]. Lubon and Tarkowski [28] investigated the impact of the initial filling period on underground hydrogen storage in deep aquifers. They found that increasing the initial filling period resulted in an improved working capacity and overall performance. A similar observation was made by Abdellatif et al. [30] where they reported that increasing the initial fill-up period enhanced the hydrogen gas recovery. Additionally, they found that increasing the injection rates resulted in a reduction in the hydrogen recovery such that increasing the injection rates from 20 MMscf/d to 30 MMscf/d resulted

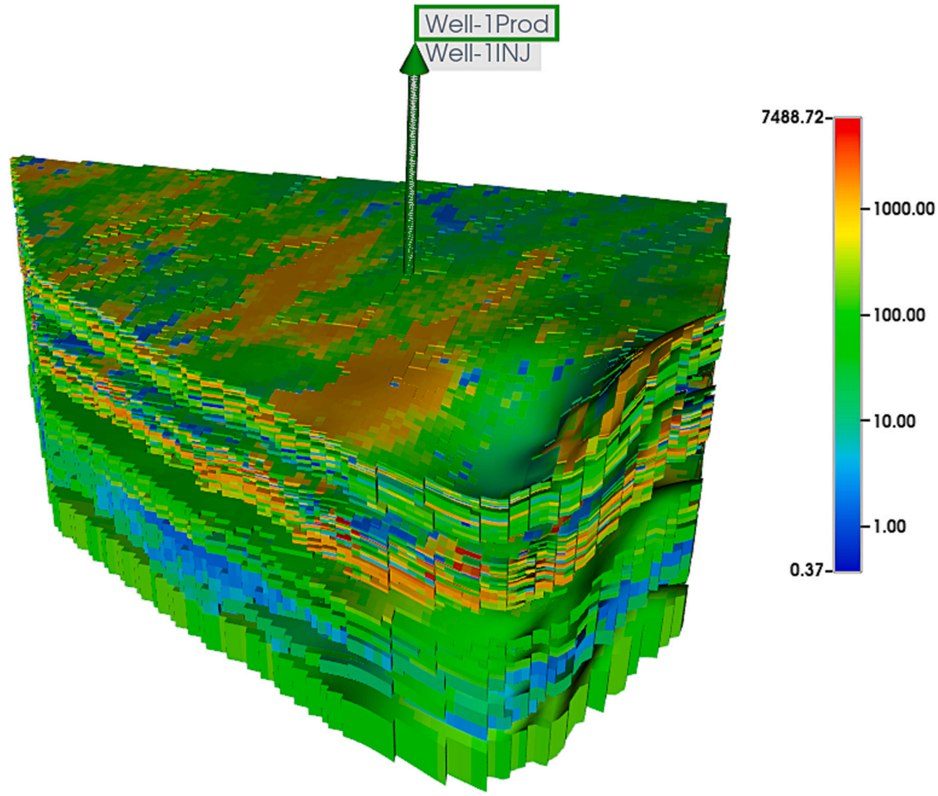

Fig. 2. A representative depiction of a 3D compositional aquifer model showing distribution of permeability and position of operating wells; injection well is shut-in during the H_2 production as of 1 Feb 2025 for the case Aq-9. A logarithmic colour scale is displayed to improve the clarity.

the recovery to reduce from 70 % to 54 %. The decrease in hydrogen recovery because of increasing the hydrogen injection rates was also reported by Mahdi et al. [31] due to gas fingering and overriding of resident reservoir fluids. Ershadnia et al. [32] studied the effect of various geological and operational conditions and parameters on underground hydrogen storage. Their results showed that the increase of the shut-in period between H_2 injection and production stages enhanced the H_2 recovery efficiency. Moreover, they reported utilising bottom injection perforation and top production perforations resulted in the highest H_2 recovery efficiency compared to other perforation configurations.

In a typical underground hydrogen storage project, the key operational parameters needing a thorough evaluation, as depicted in Fig. 1, are the rates of hydrogen injection for low demand season and its production (or withdrawal) during the high energy demand period, number of cycles and length of hydrogen injection and production time, the presence of shut-in periods between injection and production cycles, and the number of wells employed in these operations. Their interplay will determine the efficiency of the hydrodynamic, geochemical fluid-fluid and rock-fluid interactions, and caprock integrity during the hydrogen gas migration in porous media upon entry into the reservoir from the injection wells [23,24,26,27]. Hence, these operational parameters drive the overall UHS performance in a hydrogen storage project needing a thorough understanding of their impact. The objective of this study is to evaluate the technical feasibility of UHS in a deep North Sea aquifer through the investigation of the effects of these operational parameters on the performance of UHS using the numerical modelling and simulations approach.

This study presents a novel approach by being the first, to our knowledge, to investigate this set of diverse operational parameters that play a pivotal role in designing an efficient underground hydrogen storage process. The approach employs a mechanistic numerical method to thoroughly analyse how these operational factors influence the overall effectiveness of the storage process. This innovative investigation is carried out by utilising a simulation model based on a real deep aquifer associated with a history matched depleted oil reservoir, enabling us to better anticipate how an underground hydrogen storage (UHS) system might perform in real-world scenarios.

The insights garnered from this study hold significant value, particularly in designing efficient UHS scheme within aquifers. Furthermore, the implications extend to the potential repurposing of depleted oil and gas reservoirs. By scrutinizing this varied set of operational parameters, we pave the way for a more comprehensive and nuanced understanding of UHS processes. Further details on the methodology and scenarios simulated are given in the next section.

2. Methodology

A series of numerical simulations are performed in this study using the commercial compositional reservoir simulator GEM™ from the Computer Modelling Group (CMG) to evaluate the feasibility of underground hydrogen storage in a deep North Sea aquifer focusing on investigating the effects of operational parameters on the performance of UHS process in the aquifer. This simulator is based on the space and time discretization of material balance and energy balance equations through finite volume and finite difference methods [29].

2.1. Aquifer model description

A model of an aquifer located to the south of a depleted oil reservoir in the North Sea, situated at a depth of 10,000 ft was employed to evaluate the UHS feasibility. The oil reservoir is part of the Brent Group, a significant stratigraphic unit in the North Sea basin. The Brent Group comprises a series of sedimentary rock formations that were deposited during the Middle Jurassic period. These rocks consist primarily of sandstones, interbedded with shales and mudstones [33–35]. The Brent

Table 2
Summary of simulated cases model details, injection and production rates, and cycles set-up.

Case	Model details	Hydrogen gas injection and production rates	Cycles
Case Aq - 1	1 well, completions in all 3 formations	Injection rate 35 MMscf/D Production 20 MMscf/D	1st cycle: 7 months injection +7 months production Other cycles: 5 months injection, 7-month production Extended 3 years production
Case Aq - 2		Injection rate 43 MMscf/D Production 20 MMscf/D	1st cycle: 6 months injection + shut in 1 m + 7 months production. Other cycles: 4 months injection + shut in 1 months +7-month production. Extended 3 years production
Case Aq - 3		Injection rate 55.73 MMscf/D Production 20 MMscf/D	1st cycle: 5 months injection + shut in 2 m + 7 months production. Other cycles: 3 months injection + shut in 2 months +7-month production. Extended 3 years production
Case Aq - 4		Injection rate 35 MMscf/D Production 21.8 MMscf/D	1st cycle: 7 months injection + shut in 1 m + 6 months production. Other cycles: 5 months injection + shut in 1 months +6-month production. Extended 3 years production
Case Aq - 5		Inj rate 35 MMscf/D Production 24 MMscf/D	1st cycle: 7 months injection + shut in 2 m + 5 months production. Other cycles: 5 months injection + shut in 2 months +5-month production. Extended 3 years production
Case Aq - 6		Injection rate 35 MMscf/D Production 26.6 MMscf/D	1st cycle: 7 months injection + shut in 3 m + 4 months production. Other cycles: 5 months injection + shut in 3 months +4-month production. Extended 3 years production
Case Aq - 7		Injection rate 35 MMscf/D Production 20 MMscf/D	1st cycle: 4 months injection +4 months production Other cycles: 2 months injection +4-month production Extended 3 years production
Case Aq - 8			7 months injection +12 months production
Case Aq - 9			7 months injection +12 months shut-in+12 months production
Case Aq - 10	2 wells, completions in all 3 formations	Injection rate 17.5 MMscf/D/D/well Production rate 10 MMscf/D/D/well	H_2 cycles: 5 months injection + shut in 2 months +7 months production. Other cycles: 3 months injection + shut in 2 months +, 7 months production. Extended 3 years production
Case Aq - 11	3 wells, completions in all 3 formations	Injection rate 11.67 MMscf/D/D/well Production rate 6.67 MMscf/D/D/well	

Group's sandstone reservoirs are known for their high porosity and permeability, making them conducive to the accumulation and production of hydrocarbons [35,36]. The distinctive sedimentary characteristics of the Brent Group have made it a key target for oil and gas exploration and production activities in the North Sea region. Subsequently, the associated aquifer utilised for simulation in this study also possess good permeability and porosity making it a good candidate for underground hydrogen storage.

Due to increased oil production in 1997, the aquifer's pressure support gradually declined, resulting in the depressurization of both the oil field and its associated aquifer. The study aims to evaluate underground hydrogen storage in three sandstone formations within the aquifer, assuming similar conditions to the present pressure and temperature of the depleted oil reservoir at 2030 psi and 110 °C, respectively. Table 1 presents a summary of the aquifer's properties, while the fluid compositional model considers water and hydrogen gas, utilising the Peng-Robinson Equation of State to calculate fluid properties. The hydrogen gas solubility in water is considered by applying Henry's Law, assuming thermodynamic equilibrium between the two phases. The H_2 diffusion coefficient in water is assumed to be 8.5×10^{-5} cm^2/s. The original salinity of the aquifer water is low at 24,000 ppm. The H_2-water relative permeability curves used in this study were adapted from Yekta et al. [37] to account for the hysteresis effect. Based on the relative permeability curves, the irreducible water saturation during drainage is 0.15, while the trapped gas saturation between drainage and imbibition processes is 0.18, as shown in Fig. 2. The reservoir's rock compressibility is pressure-dependent with a compressibility of 6.12×10^{-12} psi^{-2} and a rock compressibility of 3.5×10^{-6} psi^{-1}. The average rock permeability of the aquifer was 500 mD over 877,340 grid cells providing the total pore volume of 11.7 billion cubic feet.

2.2. Operation scenarios

Multiple scenarios were examined to investigate the effects of various operational parameters on the performance of underground hydrogen storage (UHS) in aquifers. The parameters included injection rate, production rate, length and frequency of storage cycles, shut-in periods, and the number of wells. The base case (Case Aq - 1) involved the use of a single well for injecting hydrogen during the first cycle, for a period of 7 months at a rate of 35 MMscf/d, followed by production at a rate of 20 MMscf/d for 7 months. From the second cycle, H_2 was injected at a rate of 35 MMscf/d for 5 months, followed by production at a rate of 20 MMscf/d for 7 months. This injection and production process was repeated for 7 cycles, followed by an extended production period of three years to extract the largest quantities of H_2 as possible by depleting the aquifer's pressure. The injection and production were conducted via perforations at the top layers of each of the three sandstone formations. The injection was performed with maximum bottomhole pressure (BHP) constraints of 4500 psi, which is below the formation's fracture pressure of 5100 psi. Production was also simulated with a constraint on the bottomhole pressure, where the minimum operational pressure for fluid

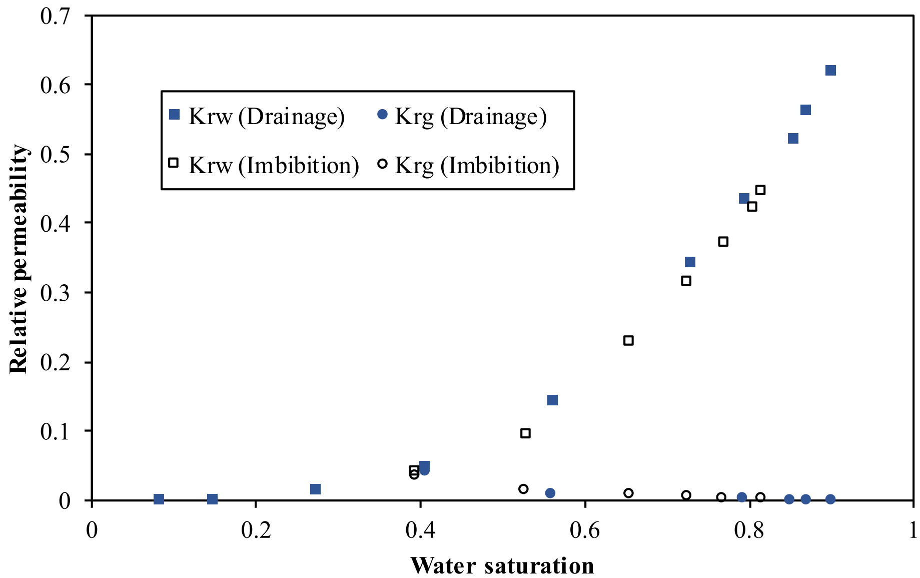

Fig. 3. H_2-water relative permeability curves for drainage and imbibition used in the model [37].

production was 1900 psi.

To investigate the impact of injection rate on overall UHS performance, cases Aq - 2 and Aq - 3 involved increasing the injection rate to 43 MMscf/d and 55.73 MMscf/d, respectively. To maintain the maximum injected volumes similar in all cases, the injection period in each cycle was reduced by one month in Case Aq - 2 and by three months in Case Aq - 3. Production rate was evaluated by maintaining the injection rate at 35 MMscf/d and increasing the production rates to 21.8 MMscf/d, 24 MMscf/d, and 26.6 MMscf/d in cases Aq - 4, Aq - 5, and Aq - 6, respectively. To maintain the maximum cumulative H_2 production similar, the production periods in cases Aq - 4, Aq - 5, and Aq - 6 were reduced.

The length and frequency of storage cycles were also examined as operational parameters that impact storage capacity and recoverable hydrogen. Case Aq - 7 was run with a cycle length half that of the base case (Case Aq - 1) and 14 total storage cycles, which is double the 7 cycles modelled in Case Aq - 1. The presence and absence of a shut-in period between injection and production were also evaluated by comparing the results of cases Aq - 8 and Aq - 9, which considered H_2 injection and production in a single cycle. The number of cyclic injection/production wells used in UHS was investigated as well. In cases Aq - 10 and Aq - 11, two and three wells were used for cyclic hydrogen injection and production, respectively, compared to the single well used in Aq - 1. The injection and production rates of the entire field remained the same as in Case Aq - 1, which were 35 MMscf/d and 20 MMscf/d. A detailed description of these total eleven cases is presented in Table 2, summarising the well configurations, injection and production rates, and the respective combination of cycles.

3. Results and discussion

The present section will describe, analyse, and discuss the outcomes of the numerical simulation cases previously defined. Initially, the feasibility of the base case (Case Aq – 1) will be assessed to determine the technical viability of UHS in the studied aquifer. Subsequently, a comparative analysis among the different cases investigated will be presented to assess how the storage capacity and H_2 recovery are influenced by operational parameters such as injection rate, production rate, length and frequency of storage cycles, presence or absence of shut-in periods, and number of wells utilised.

3.1. Base case

The base case (Case Aq – 1) simulated in this study consists of injecting hydrogen at a rate of 35 MMscf/d and producing at a rate of 20 MMscf/d through a single well for seven cycles. Results in Fig. 4a show that over a period of 10 years, the cumulative H_2 injected was 38.8 Bscf and the amount of hydrogen recovered from the that was 29.5 Bscf. This constitutes a recovery factor of 76.4 %. From Fig. 4b it is worth noting that the hydrogen recovery continuously improves with number of storage cycles indicating that the hydrogen recovery would be higher if the storage cycles beyond the currently studied scenario. At the beginning of the UHS operation, the average pressure in the aquifer was recorded at 2030 psi, as demonstrated in Fig. 3b. After the initial injection of hydrogen in the first cycle, the pressure increased to 2568 psi, followed by a pressure drop of 116 psi to 2452 psi due to hydrogen production in the same cycle. Throughout the injection and production stages of subsequent cycles, the pressure inside the aquifer fluctuated, but exhibited an overall upward trend due to the accumulation of residual hydrogen gas. By the end of the seventh cycle's injection stage, the pressure inside the aquifer reached its maximum at 3068 psi. This pressure was then utilised to produce hydrogen gas for a continuous three-year period, causing the aquifer's pressure to drop to 2547 psi at the end of the extended production period.

3.2. Injection rate effect

The H_2 injection rate dictates the manner by which H_2 gas displaces resident water inside the aquifer. To understand the effect of injection rates, three scenarios were run where the UHS performance is evaluated at 35 MMscf/d (Case Aq – 1), injection rate is 43 MMscf/d (Case Aq – 2) and 55.37 MMscf/d (Case Aq – 3) (see Fig. 5a). For comparable results, the overall targeted injected H_2 volume was maintained similar in each case by reducing the injection time and introducing a shut-in period instead. Hence, in the case of increasing the injection rate from 35 MMscf/d to 43 MMscf/d, in each injection cycle a month of injection was replaced by a month of shut-in period. However, the overall injected and produced volume would still vary slightly per case based on the limiting bottomhole operation pressures. The minimum operating BHP was 1900 psi and the maximum BHP of 4500 psi which is just below the formation's fracture pressure of 5100 psi.

The cumulative injection and production volumes in Fig. 5b show that, the lower injection rate of 35 MMscf/d in Case Aq – 1, lead to

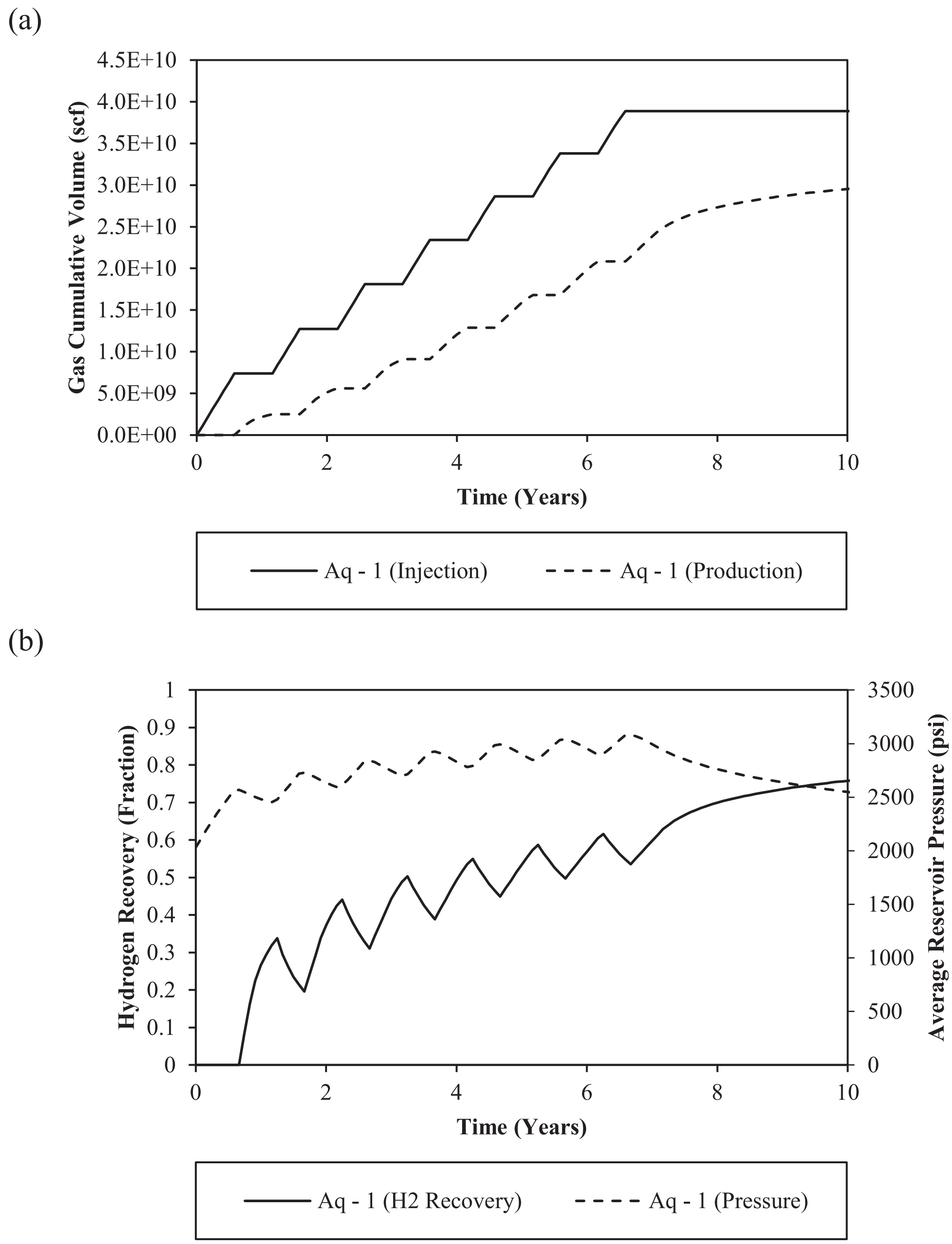

Fig. 4. (a) Cumulative H_2 injected and produced, and (b) H_2 recovery and average aquifer pressure predicted for base case of UHS in aquifer.

higher cumulative H_2 gas volumes stored and produced (38.8 Bscf and 29.5 Bscf, respectively) compared to the higher injection rates of 43 MMscf/d in Case Aq – 2 (36.4 Bscf injected and 27.6 Bscf produced) and 55.37 MMscf/d in Case Aq – 3 (31.4 Bscf injected and 23.7 Bscf produced). Hence, higher injection rates resulted in less operating storage capacity and cumulative hydrogen gas produced. However, hydrogen recovery expected from the three cases were very comparable which ranged from 76.38 % (Case Aq – 1) to 76 % (Case Aq – 3) as depicted in Fig. 5c. Average reservoir pressure data show that the overall reservoir pressure increases with cycles and is highest in the case of Case Aq – 1, followed by Case Aq – 2 and Case Aq – 3. This can be attributed to the higher volume of gas left unproduced in reservoir in Case Aq – 1 than in the other two cases.

Analysis of the results indicate that the lower injection rate of 35 MMscf/d is more favourable than the higher injection rates because of the improved working capacity and hydrogen recovered. The improved working capacity can be explained by the fact that at lower injection rates the wellbore bottom hole pressures rise slowly compared to higher injection rates. This allows for higher volume of hydrogen to be injected before we reach the maximum permissible BHP without fracturing the formation (see Fig. 5d). The BHP increases more rapidly when the injection rate is higher and reaches the maximum BHP of 4500 psi faster than the lower injection rate. Hence, the BHP in Case Aq – 3 reaches the maximum BHP faster than the other cases, Case Aq – 2 and Case Aq – 1. Lower injection rates do not only improve storage capacity, but they also improve the subsequent withdrawal/production process. This can be explained by the fact that the at lower injection rates gravity forces are more dominant leading to limiting the H_2 gas lateral spreading. As the injection rates increase as in Cases Aq – 2 and Aq – 3, the viscous forces become more dominant than the gravity forces result in gas viscous fingering and lateral spreading to be more pronounced due to H_2 gas extremely lower viscosity and density compared to the resident water. This is in line with observations from results of modelling of UHS in aquifer reported by Hagemann et al. [23], Wang et al. [38], and

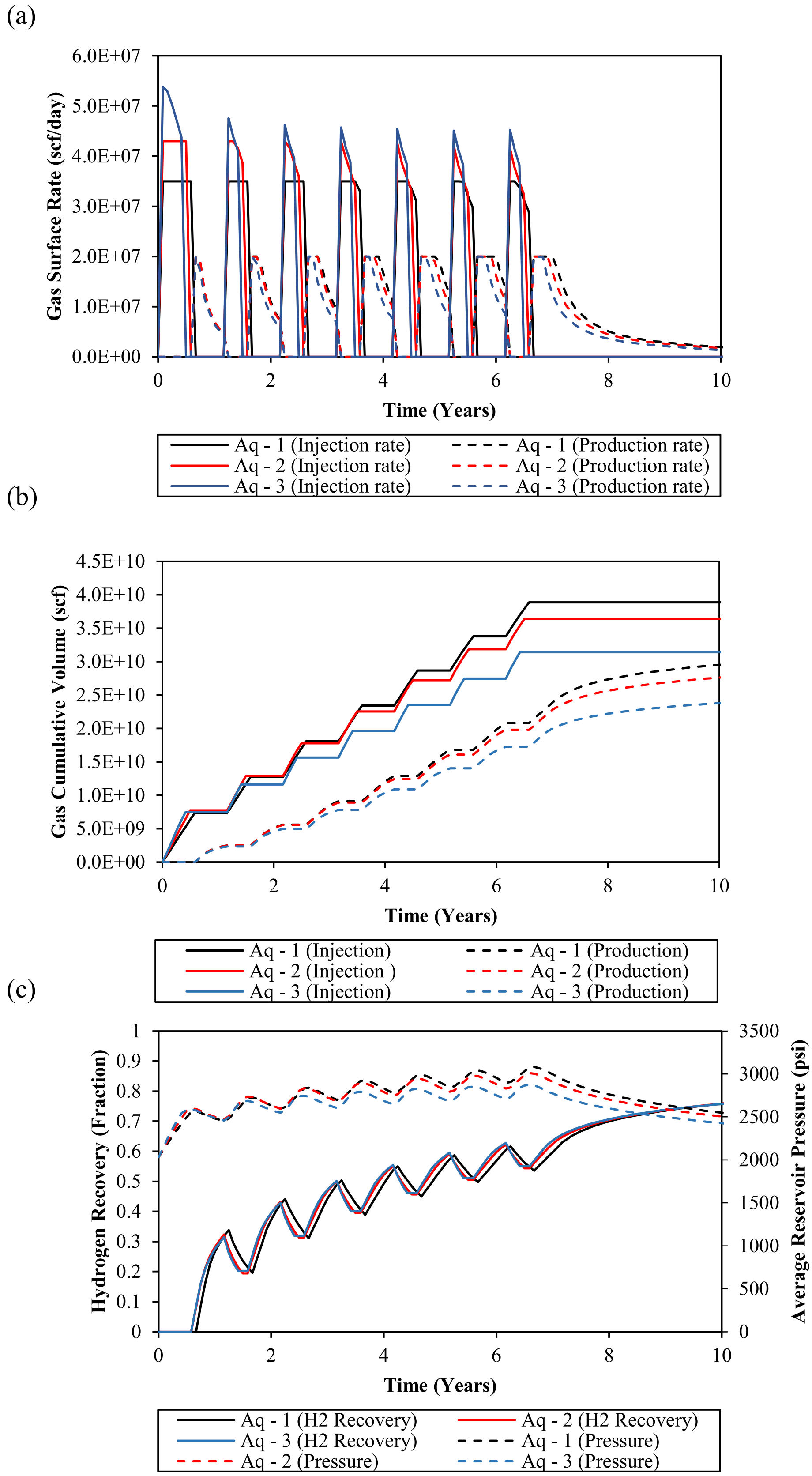

Fig. 5. Effect of injection rates during UHS in aquifer on (a) H_2 injection and production rates, (b) cumulative H_2 injected and produced, (c) H_2 recovery and average aquifer pressure, and (d) well bottomhole pressure.

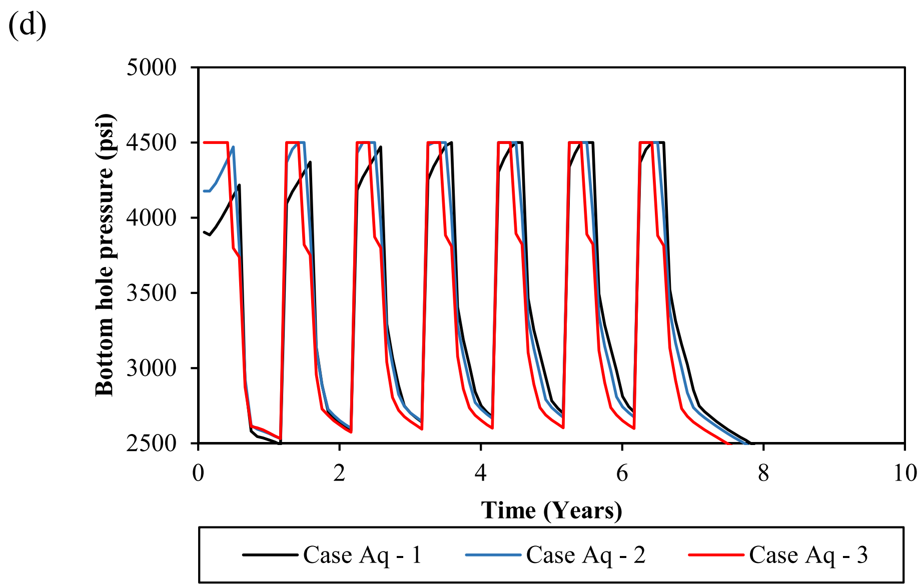

Fig. 5. (*continued*).

Abdellatif et al. [30] where the higher injection rates also lead to gas lateral spreading and depreciated the performance of UHS in aquifers. Overall, lower injection rates are more favourable for UHS in aquifer as they improve both the aquifer storage capacity and the percentage of hydrogen gas recovered.

3.3. Production rate effect

Production rates affect the gas-water displacement inside the aquifer and consequently the hydrogen recovery. The effect of production rate on the performance of UHS in aquifer was evaluated by comparing four scenarios Aq – 1 (production rate = 20 MMscf/d), Aq – 4 (production rate = 21.8 MMscf/d), Aq – 5 (production rate = 24 MMscf/d) and Aq – 6 (production rate = 26.6 MMscf/d). Similar to the injection rate investigation, the overall target of production was fixed by reducing the production time in each cycle while increasing the production rates as shown in Fig. 6a. The average aquifer pressure remained higher than the initial aquifer pressure in the studied cases. The pressure curve shifts higher as the production rate increases due to the higher residual H_2 gas inside the aquifer, where Case Aq – 6 exhibits the higher aquifer pressure throughout the storage process.

Results of cumulative volumes (Fig. 6b) showed that production rate had a slight effect on the overall injected volume but a significant effect on the H_2 production. In Case Aq – 1, the lower production rate of 20 MMscf/d of lead to a higher volume of H_2 produced (29.5 Bscf) compared to the higher production rates cases, for example 26.6 Bscf in Case Aq – 6 where the production rate was 26.6 MMscf/d. This is also reflected in the efficiency of hydrogen recovery as indicated in Fig. 6c, where hydrogen recovery efficiency was 76.38 % at 20 MMscf/d, 75.5 % at 21.8 MMscf/d, 74.5 % at 24 MMscf/d, and 73.4 % at 26.6 MMscf/d. This shows a clear trend where the hydrogen recovery was inversely correlated with the production rate.

An interpretation of the results above indicate that the lower production rates are more favourable than higher production rates. This can be attributed to the fact that at lower production rates the gravity forces are more dominant than viscous forces allowing for a stable withdrawal of the hydrogen gas from the storage aquifer [23,38]. Moreover, the wellbore bottomhole pressure (Fig. 6d) decreases gradually with lower production rates before reaching the minimum BHP below which the reservoir is not capable of lifting the aquifer fluids to surface naturally. Thus, it is more favourable to produce/withdraw hydrogen in a lower rate over a longer period than abruptly in a shorter period. Therefore, production rates should be optimized with the energy/hydrogen supply and demand periods throughout the year to maintain an efficient storage process.

3.4. Cycles frequency effect

The effect of the frequency and length of cycles on UHS is evaluated. To observe the impact of this parameter, Case Aq – 7 was run where the number of cycles was doubled (14 cycles) while the injection and production periods were halved. The injection and production rates remained the same as Case Aq – 1 for comparison i.e. 35 MMscf/d injection rate and 20 MMscf/d production rate. Fig. 7 shows the injection and production rates of Case Aq – 7 compared to Case – 1 and it also indicates the injection and production cycles adopted in each case.

The comparison between the cumulative volumes of Case Aq – 1 and Case Aq – 7 shown in Fig. 7b reveals that the amount of hydrogen that can be stored is inversely correlated with the frequency of cycles. In Case Aq – 1, the cumulative injected H_2 volume was 38.8 Bscf compared to 31.9 Bscf in Case Aq – 7. However, the increase in cycles frequency had a positive effect on the recoverable H_2 gas and can be observed in Fig. 7c. The percentage of H_2 recovery in Case Aq – 7 which was 81.2 % at the end of the 10-year period was better than that of Case Aq – 1 which was 76.4 %. This can be explained by the fact that shorter injection and production cycles will limit the lateral spread of H_2 gas reducing the residual hydrogen gas remaining in the aquifer. Moreover, due to the higher residual H_2 gas inside the aquifer in Case Aq – 1 compared to Case Aq – 7, the aquifer pressure in Case Aq –1 remains higher throughout the storage cycles than in Case Aq – 7. Therefore, an optimization involving the desired H_2 gas stored, recoverable H_2 volumes, and supply and demand periods throughout the year should be carried out to determine the optimum frequency and length of injection/production cycles.

3.5. Shut-in period effect

To understand the impact of shut-in periods on the UHS performance, a single injection/production cycle was considered. In both Cases Aq – 8 and Aq – 9, the injection and production rates were 35 MMscf/d and 20 MMscf/d, respectively, and length of the injection and production periods were 7 months and 12 months, respectively. The only difference between the two cases, is that in Case Aq – 9 a 12-month shut in period was introduced between injection and production as can

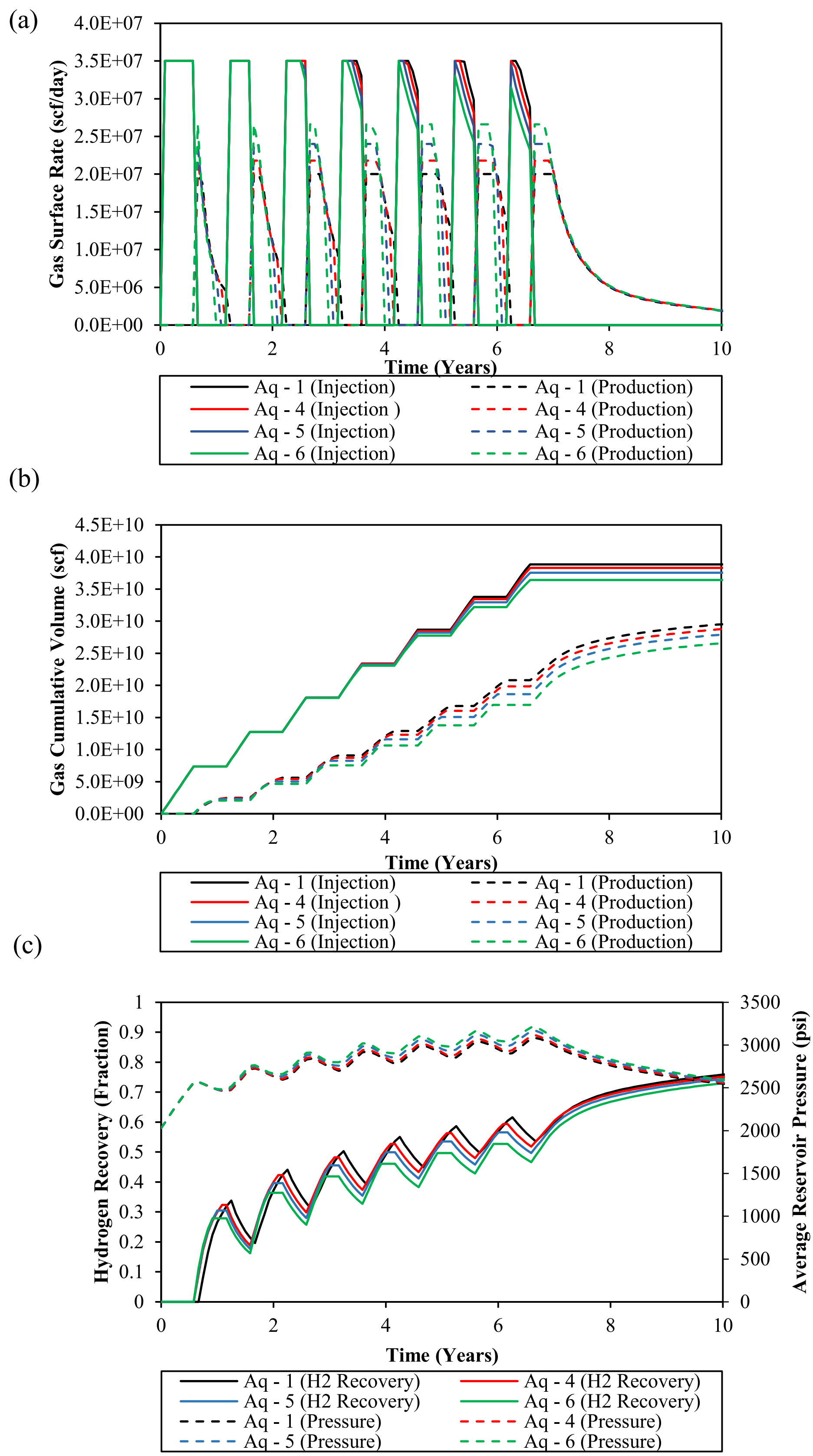

Fig. 6. Effect of production rates during UHS in aquifer on (a) H_2 injection and production rates, (b) cumulative H_2 injected and produced, (c) H_2 recovery and average aquifer pressure.

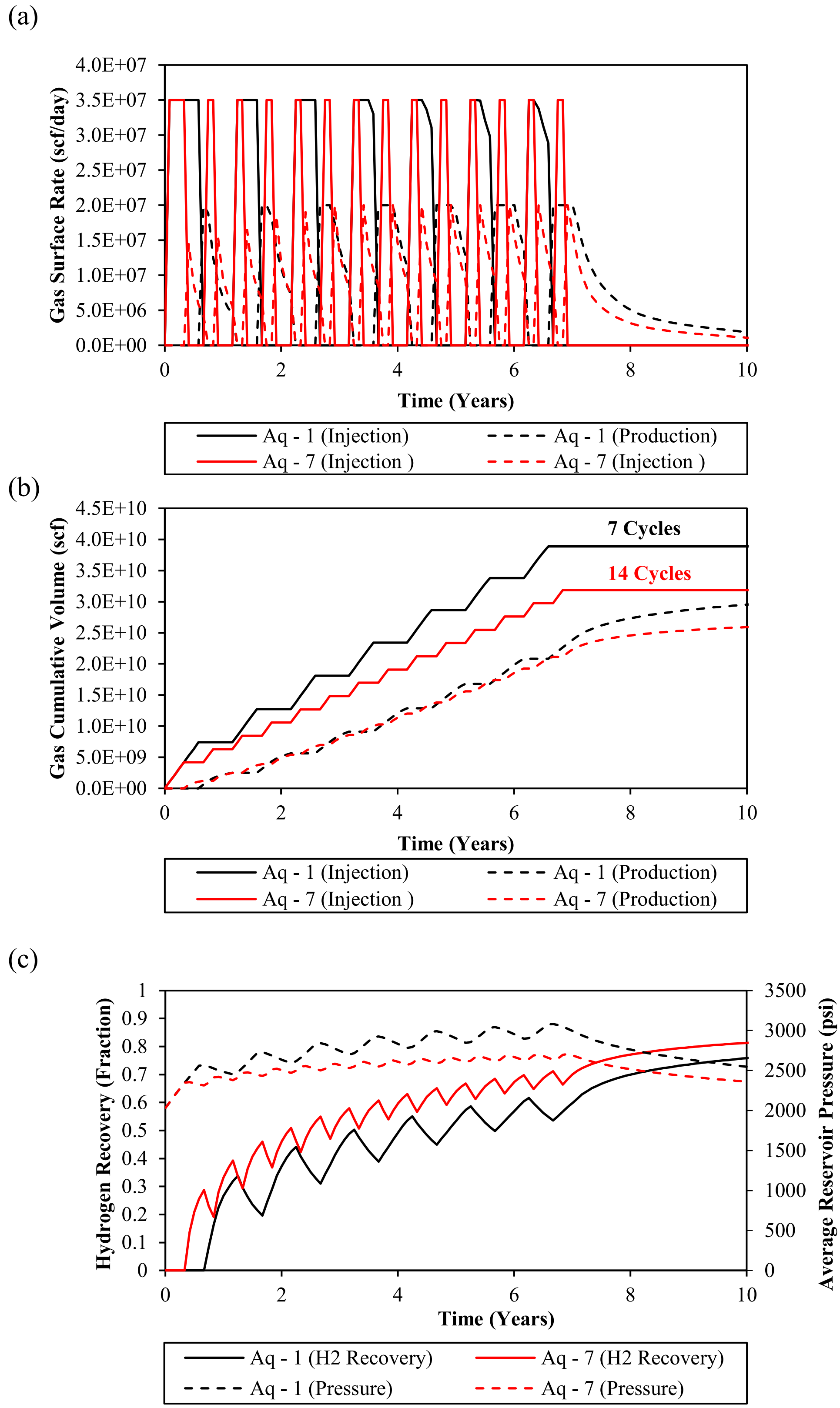

Fig. 7. Effect of number and length of cycles during UHS in aquifer on (a) H_2 injection and production rates, (b) cumulative H_2 injected and produced, and (c) H_2 recovery and average aquifer pressure.

be observed in Fig. 8a.

Results in Fig. 8b show that the amount of hydrogen recovered when a shut in period was introduced (Case Aq – 9) was slightly lower than that in the absence of a shut-in period. Where in Case Aq – 9 the produced H_2 was 1.9 Bscf and in Case Aq – 8 was 2.9 Bscf. This signifies an incremental 4 % increase in the recovered hydrogen gas in the absence of a shut-in period as shown in Fig. 8c. This might be attributed to the gas migrating upwards and laterally away from the wellbore

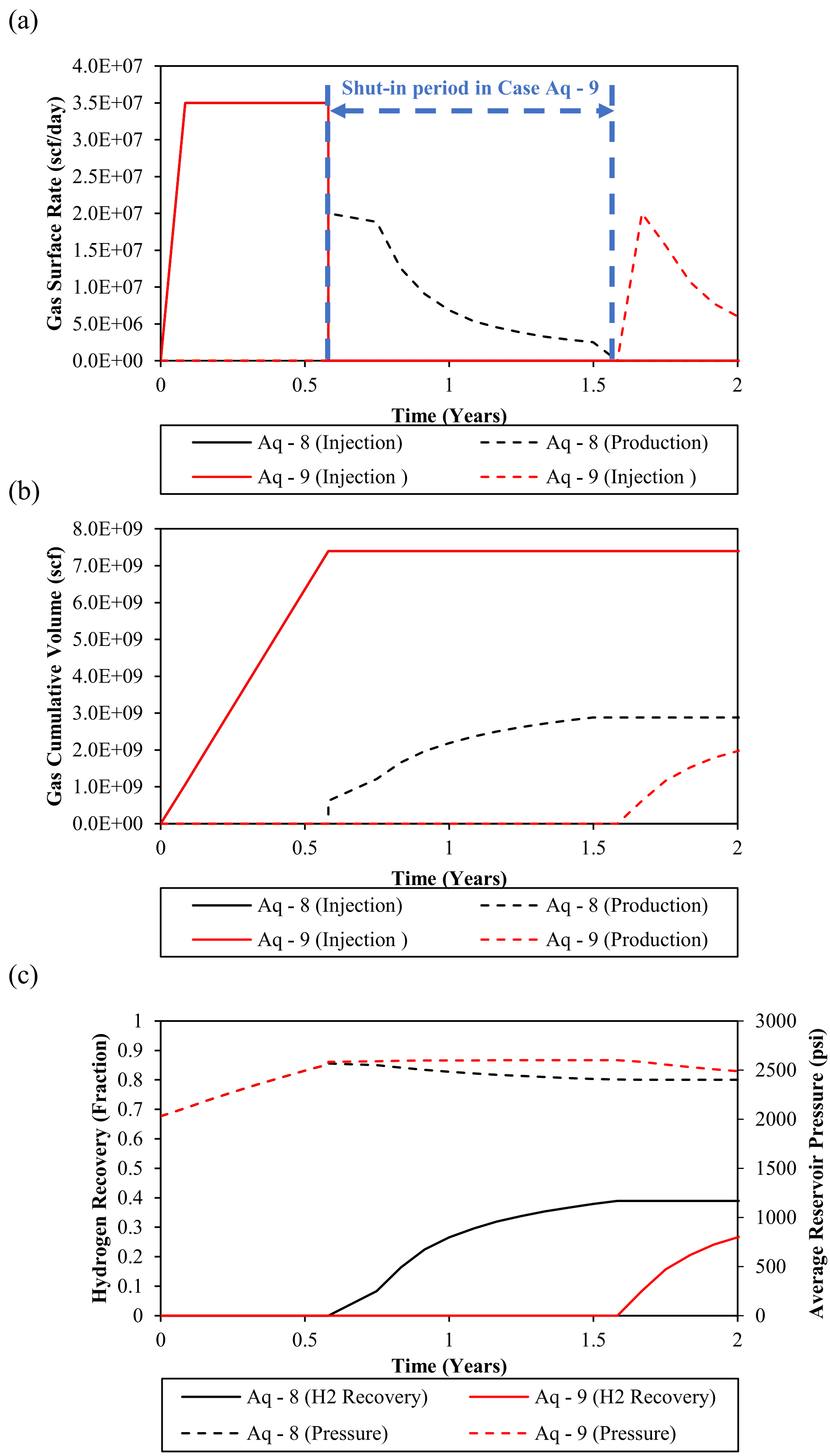

Fig. 8. Effect of shut-in period between H_2 injection and production during UHS in aquifer on (a) H_2 injection and production rates, (b) cumulative H_2 injected and produced, and (c) H_2 recovery and average aquifer pressure.

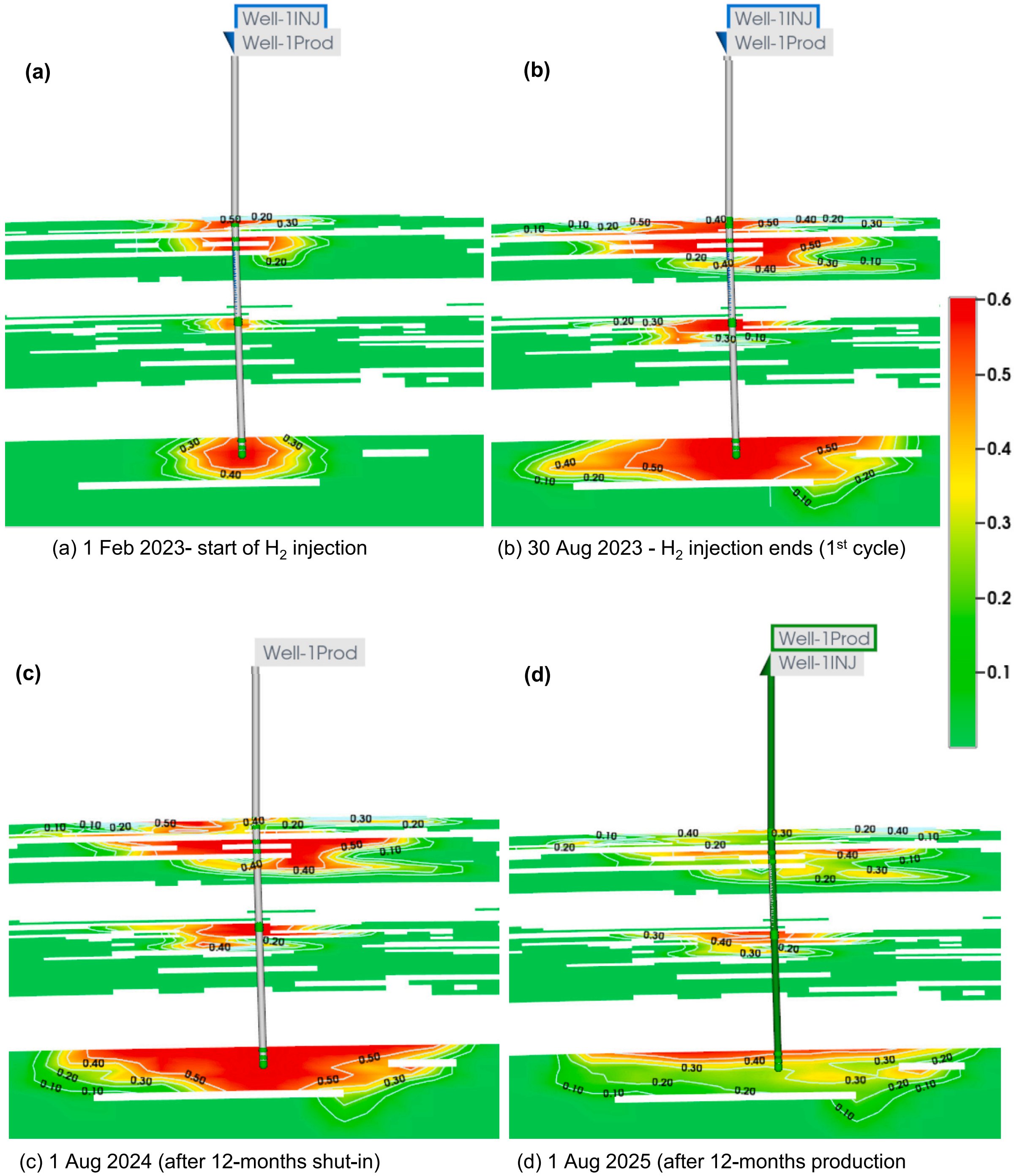

Fig. 9. Representation of gas (H_2) saturations in Aq case-9 showing the hydrogen gas fingering effect through the high permeability layers during the injection (see Fig. 9b), which then vertically migrate upward (overriding the formation brine) during the 12-month shut-in period (Fig. 9c). In the later production phase this hydrogen then produced through these layers. Please note the white colourless cells in the figure are the shale layers.

during the shut-in period, resulting in a higher residual unrecoverable H_2 as observed from the H_2 gas saturation visualization shown in Fig. 9 (d).

As shown in Fig. 9 (Aq case-9), the injected hydrogen gas flow through the high permeability layers during the injection (see Fig. 9b), representing of H_2 gas fingering effect clearly seen by the increased H_2 saturation from the saturation contours. This H_2 then vertically migrate upward (overriding the formation brine) during the 12-month shut-in period (Fig. 9c). In the later production phase this hydrogen then produced through these layers. White colourless cells in the figure are the impermeable shale layers.

These visual 2D observations indicate that the shut-in periods should be minimised to avoid the loss of H_2 to lateral spreading, hence, to improve the H_2 recovery. Similar conclusions were made in other studies [39] where they reported that the presence of a 2-month shut-in period between injection and production phases resulted in a decreased hydrogen recovery. They also attributed this effect to the hydrogen dispersion during well shut-in period, which intensifies the negative impact of gravity segregation.

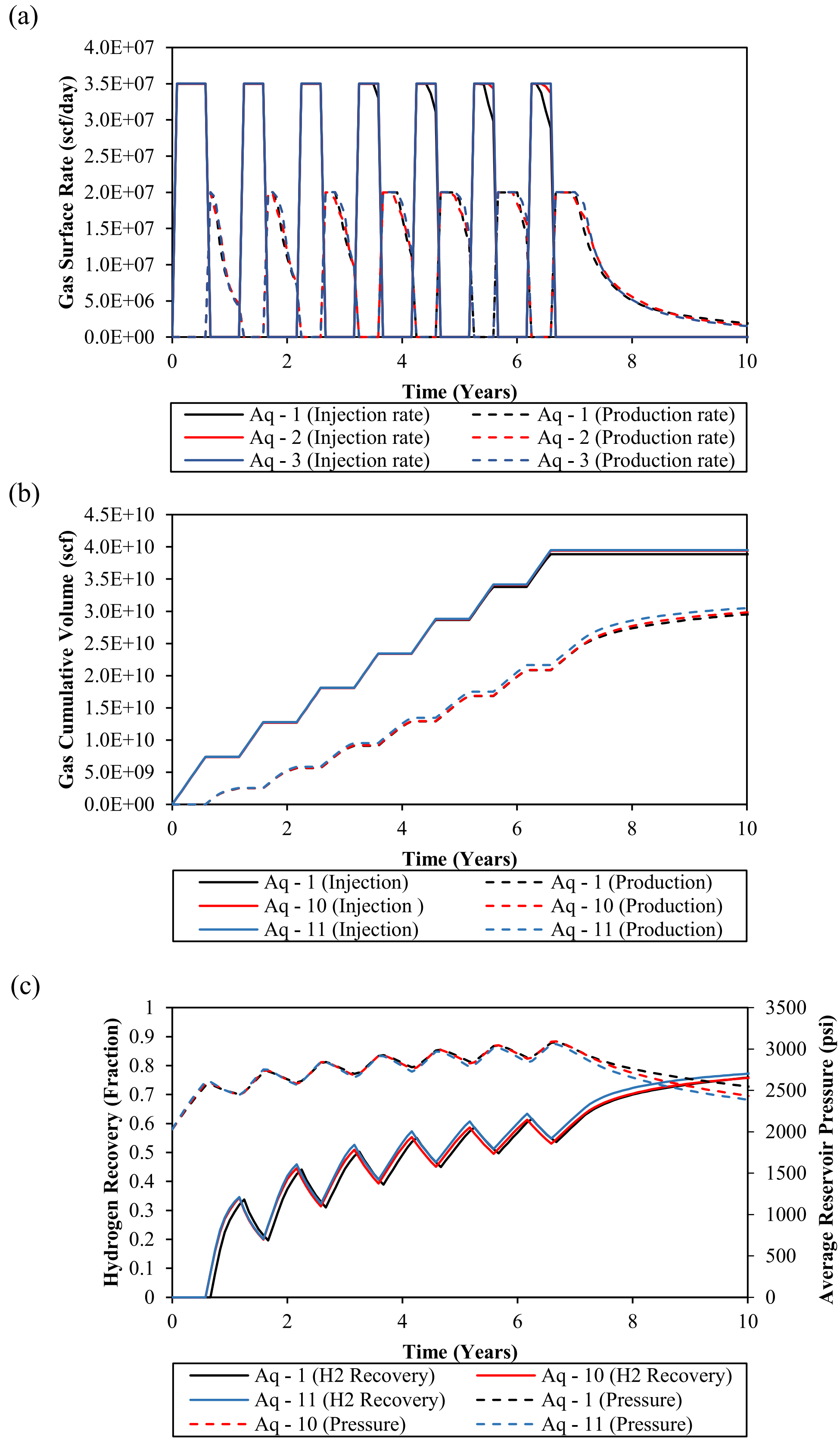

Fig. 10. Effect of number of operating wells during UHS in aquifer on (a) H_2 injection and production rates, (b) cumulative H_2 injected and produced, and (c) H_2 recovery and average aquifer pressure.

Table 3
Summary of operational parameters impact on aquifer capacity and H_2 recovery efficiency during UHS in aquifers.

Parameter	Effect on aquifer storage capacity	Effect on H2 recovery
Lower injection rate	⬆	⬆
Lower production rate	↑	↑
Presence of shut-in period	—	↓
Shorter and higher number of cycles	⬇	⬆
Higher no. of wells	↑	↑
⬆ : High Impact ↑ : Low Impact — : No Impact		

3.6. *Number of wells effect*

The number of cyclic wells impact was investigated to provide an insight into the technical benefits of increasing operational wells. In this investigation, two additional scenarios were run. In Case Aq – 10, two wells were used for H_2 gas injection and production instead of 1 well as in Case Aq – 1, and in Case Aq – 11, three wells were used. The overall maximum injection and production rates in the field were fixed the same as in Case Aq – 1 where the injection rate was 35 MMscf/d and the production rate was 20 MMscf/d as shown in Fig. 10a. The field injection and production rates were divided equally by the number of wells in Cases Aq – 10 and Aq – 11.

Fig. 10b exhibits the cumulative volume of each case, and it reveals that both injection and production volumes improve with the increase in number of wells. The total volume of H_2 injected has increased from 36.3 Bscf when a single well was used to 38.9 Bscf when two wells were used and 39.5 Bscf when a third well is added. A similar observation is made regarding the total amount of hydrogen recovered and the percentage of hydrogen recovered (Fig. 10c), where increasing the number of wells from 1 well to 3 wells slightly improves the hydrogen recovery from 76.4 % to 77.5 %, respectively. This can be explained by the fact that the distributing the injection and production throughout an increased area of the reservoir, allows the reservoir pressure and bottomhole pressure to rise and fall more uniformly. Thus, allowing for more H_2 to be injected before reaching the formation fracturing pressure and more volume of H_2 to be recovered before reaching the minimum operatable bottomhole pressure. Moreover, pressure inside the aquifer increase during the injection stage and drops as hydrogen is being withdrawn. In the first storage cycles, the aquifer pressure is nearly similar in all three cases (Case Aq – 1, Case Aq – 10, and Case Aq – 11). However, during the extended production period the cumulative H_2 gas produced divergence in the three cases becomes more pronounced. Where the hydrogen production in Case Aq – 11 becomes higher than that of Cases Aq – 10 and Aq – 1. This indicates a higher residual H_2 gas in Case Aq – 1, followed by Case Aq – 10 and Case Aq – 11. Consequently, this is reflected in the aquifer pressure where the pressure is higher in Case Aq - 1 compared to other cases due to the higher residual gas saturation. Nonetheless, the technical benefit of adding more wells should be evaluated economically by balancing the incremental amounts of stored and recoverable H_2 with the costs of developing additional wells.

The above-mentioned discussion of the results obtained in this study revealed that the increase in injection rates and increase in production rates had a negative impact on the aquifer storage capacity and recoverable H_2 gas. The presence of shut-in period between the injection and production cycles had a negative impact on the recoverable H_2 gas. Moreover, shorter and more frequent cycles resulted in a drop in the aquifer capacity and an increase in the overall H_2 recovery. It was also found that adding more wells increased both the working capacity and H_2 recovery. A summary of the studied operational parameters is depicted in Table 3 which highlights the impact of each parameter on the overall performance of the UHS in deep aquifers.

4. Conclusion

Numerical simulations of underground hydrogen storage in a deep North Sea aquifer were conducted using the compositional reservoir simulator CMG-GEM. The technical feasibility of storing hydrogen in the studied aquifer was investigated. Simulations were extended to evaluate the effects of various operational parameters and aspects on the UHS process. The studied operational are H_2 injection rate, H_2 production rate, cycle length and frequency, the presence of a shut-in period between injection and production, and the number of cyclic wells used in the storage process. By analysing the results of aquifer modelling, we make the following conclusions:

- The cyclic storage of hydrogen in the studied aquifer is technically feasible, however, a thorough optimization of the operational parameters should be carried out prior to the storage process. In the case of utilising a single well for UHS, a maximum of 38.8 Bscf H_2 gas was stored in the aquifer using a single well and 75 % of the stored H_2 was recovered during the withdrawal stages.
- The increase in injection and production rates negatively affect the aquifer's working capacity and H_2 recovery. This was attributed to the dominance of viscous forces rather than gravity forces at higher injection and production rates which amplifies gas viscous fingering and gas gravity overriding.
- A shorter length and higher number of storage cycles decrease the working capacity and improve the hydrogen recovered during the withdrawal process. Moreover, the presence of a shut-in period between the injection and production stages negatively affects the amount of hydrogen recoverable because of the hydrogen spreading during the shut-in period resulting in hydrogen migration laterally throughout the reservoir.
- The higher number of storage wells distributed throughout the aquifer leads to a better performance in terms of H_2 storage and recovery. This can be explained by the enhanced uniform change in

aquifer's pressure during the injection and production phases leading to delay the violation of the minimum and maximum bottomhole pressure constraints in each well. Thus, allowing for more hydrogen to be injected or produced during the various storage cycles.

CRediT authorship contribution statement

Prashant Jadhawar: Writing - original draft, Visualization, Investigation, Methodology, Software, Data curation, Writing - review & editing Formal Analysis Funding Acquisition, Project management (PI). Motaz Saeed: Writing - original draft, Visualization, Investigation, Methodology, Software, Data curation, Writing - review & editing, Formal Analysis.

Declaration of competing interest

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

Data availability

The authors do not have permission to share data.

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