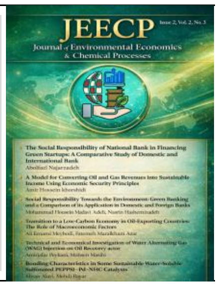
J. Environ. Econ. Chem. Process.,: Vol. 2, No. 3, (2025) 86–91

Journal of Enviromental Economics & Chemical Processes (JEECP)

Journal of Enviromental Economics & Chemical Processes (JEECP)

journal homepage: WWW.JEECPJournal.com



Technical and Economical Investigation of Water Alternating Gas (WAG) Injection on Oil Recovery Factor

Amirjafar Peykani , Mohammadali Hatefi *

Department of Energy Economics and Management, Tehran Faculty of Petroleum, Petroleum University of Technology (PUT), Abadan, Iran.

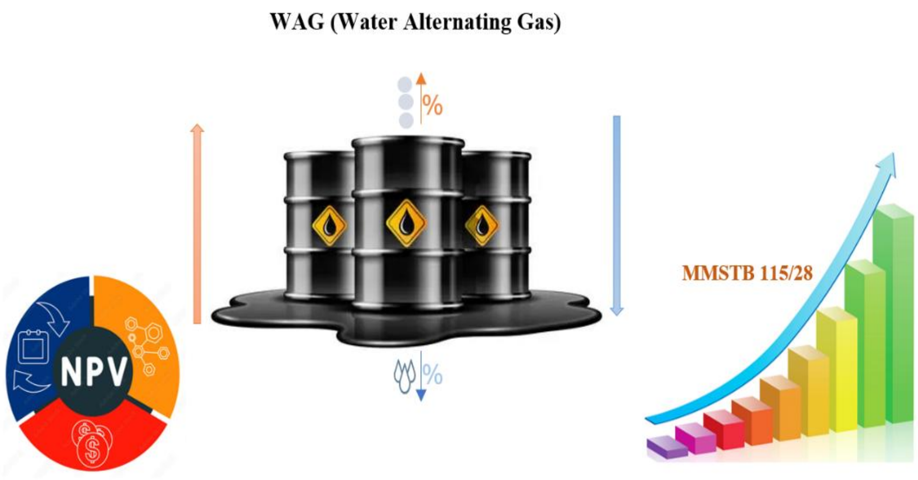
P A P E R I N F O

Paper history:
Received 4/20/2025
Accepted in revised form 6/28/2025

Keywords:
WAG
Gas injection
Economic Analysis of WAG
EOR

A B S T R A C T

One of the derivative methods of gas-injection techniques is the water alternate gas (WAG) injection methods, wherein water and gas are injected intermittently. Oil recovery by the WAG injection has been attributed to contact the upswept zones, especially recovery of attic or cellar oil by exploiting segregation of gas to the top or accumulation of water toward the bottom. In this study the process of water alternating gas injection in a petroleum reservoir has been simulated. For this purpose, existing laboratory data are used and then the injecting fluid in the reservoir is modeled. The results of this method are compared with other reservoir development methods, such as gas injection or natural depletion. Various injection scenarios have been considered. Among the optimized scenarios, the WAG injection with 0.2 PV, 1:1 WAG ratio and 5 months water and 3 months gas injection period had the highest cumulative oil production of 115.28 MMSTB. The economic analysis of WAG injection has been presented for the most optimum oil production scenario (i.e. WAG-1:1 Ratio-5:3 Period scenario). The impact of economic factors such as the oil price, discount rate, OPEX, and CAPEX on the net present value (NPV) has been studied. The sensitivity analysis showed that the oil price has the greatest impact on the NPV which was followed by the discount rate and OPEX. However, the CAPEX has shown to have the least effect on the calculated NPV.



1. Introduction

Enhanced oil recovery (EOR) techniques, additionally alluded to as tertiary oil recovery strategies, are utilized when essential and auxiliary recovery strategies don't improve the creation from brownfields. The world normal of oil recovery factor is assessed to be 35% in this way practically over 60% of the original oil in place (OIIP) stays in the supply after the essential and the optional recovery [1]. One of the subsidiary strategies for gas-injection procedures is the water alternating gas (WAG) injection techniques, wherein water and gas are injected irregularly. Oil recovery by the WAG injection has been credited to contact of upswept zones, particularly recovery of storage reservoir or basement oil by misusing isolation of gas to the top or aggregation of water toward the base. The WAG injection procedures has the potential for expanded minuscule removal effectiveness in light of the fact that the residual oil after gas flooding is regularly lower than the leftover oil after water flooding, and three-stage zones consequently got brings down the rest of the oil immersion. In this manner, the WAG injection can prompt improved oil recovery by consolidating better versatility control and reaching upswept zones, and by prompting improved microscopic displacement [2]. The successful management of an EOR project depends on suitable planning and, if the initial planning is comprehensive enough, it will prevent poor performance of the project. Simulation models provide the necessary information for conducting cost-benefit studies, and help reduce the risk of the project. Of course, the simulators

* masihi@sharif.edu

URL: https://jeecpjournal.com/index.php/jeecp/article/view/23

Please cite this article as: Peykani A., & Masihi, M., (2025). *Journal of Enviromental Economics & Chemical Processes (JEECP)*, *2*(3), 86-91.

/© 2025 The Author(s). Published by Institute of Power, Movement, and Innovative Insight

are not complete. However they are very suitable for predicting the behavior of the reservoir and the processes based on existing data, but they cannot simulate what is not known. Therefore, good results can be achieved by using laboratory data and comparing them with the simulator data. The purpose of this study is to simulate the process of water alternating gas injection in petroleum reservoirs. For this purpose, existing laboratory data are used and then the injecting fluid data is modeled. The results of this method are compared with other common development methods, such as immiscible gas injection or natural depletion. In this research, it is tried to increase the recovery factor as much as possible. The economic studies also allow to examine the costs and benefits of the water alternating gas injection process and, ultimately choose the most optimum model based on the results of technical and economic studies as the reservoir management point of view. Since the rate of oil recovery used by different methods of gas injection is different, it seems that the gas injection method, whether miscible/immiscible, or even the water alternative gas injection is effective in the amount of oil recovery. Therefore, the results of increasing oil recovery due to common types of gas injection in a given field are investigated. Then, the difference of the rate of WAG injection from other gas injection methods is studied and it will be determined which method is more economical.
This research is done based on the following hypothesis:

1. There is no chemical reaction between the dissolved gas and heavy oil.
2. The gas is dissolved into the oil and the volume of oil does not change.
3. The reservoir pressure is less than the bubble point pressure.
4. The penetration coefficient does not change with time and is constant.

Primary recovery refers to the recovery of oil and/or gas that's recovered by either natural flow or artificial carry through one wellbore. Thus, primary recovery happens as a results of the energy ab initio gift within the reservoir at the time of discovery [3]. Because primary recovery leave most of oil behind, secondary recovery ways are utilized in most of fields to enhance final recovery and increase production rates [4]. Once the initial energy has been depleted and also the rate of oil recovery declines, production is raised by the injection of secondary energy into the reservoir. Secondary recovery is that the recovery of oil and/or gas that involves the introduction of artificial energy into the reservoir via one wellbore and production of oil and/or gas from another wellbore. Standard suggests that of secondary recovery embrace the incompatible processes of waterflooding and gas injection. Pressure maintenance comes, can nearly always recover a lot of oil reserves than are recoverable by primary manufacturing mechanisms [3]. It is the oldest of the fluid injection processes. This idea of employing a gas for the aim of maintaining reservoir pressure and restoring well productivity was urged as early as 1864 simply many years once the Drake well was trained. The primary gas injection comes were designed to extend the immediate productivity and were additional associated with pressure maintenance rather to increased recovery. Recent gas injection applications, however, are meant to extend the final word recovery and might be thought-about as increased recovery projects [5].
When gas injection takes place during a reservoir while not a gas-cap the injected gas flows radially from the injection wells, driving the oil towards the assembly wells.
The principal issue concerned within the call to begin gas injection is that the availableness of a close-by supply of low-cost gas in enough quantities. The use of created gas could be a major supply, however will solely impede the reservoir pressure decline, not halt it. Secondary gas must be obtained either from an adjacent gas reservoir or from a nearby gas pipeline[6].
Water injection has 2 priority relative to gas injection [6]:

(a) The capital Investment required for gas injection is usually higher than that required for water injection.

(b) The microscopic displacement potency of gas is way but that of water.

Generally, water injection is that the chosen recovery technique within the case of water-wet reservoirs, and gas injection is equally most popular for oil-wet reservoirs. However, Water Alternating Gas (WAG) processes offer higher recovery than injecting gas or water alone by utilizing the benefits of each gas and water injection at a similar time. Water alternating gas injection (WAG), is one amongst the various increased recovery method. WAG injection involves drain (D) and imbibition (I) going down at the same time or in cyclic alternation within the reservoir [7]. Once water and gas injection ar enforced at the same time, the front stability will increase, leading to higher sweep potency. WAG injection is currently applied wide to enhance oil recovery from matured fields by re-injecting created gas into water injection wells [8]. Thanks to their low viscosities, gases have high quality which ends up in poor large sweep efficiency [9].
WAG injection will be classified into completely different forms reckoning on however the fluids square measure injected. Generally, WAG injection is assessed as either miscible or incompatible. Miscible or incompatible injections square measure perform of the properties of the displaced oil and injected gas also because the pressure and temperature of the reservoir. Hybrid WAG injection, synchronous WAG injection (SWAG), Water Alternating Steam method (WASP) and foam assisted WAG injection (FAWAG) square measure alternative completely different WAG injection classification [10].
SWAG is associate degree increased oil recovery method within which gas is mixed with water outside and therefore the mixture is then injected as a 2 part mixture within the well or, as an alternative, each gas and water area unit injected at constant time into the well to induce higher oil recovery. Water and gas injection area unit the simplest resolution to address the issues like early breakthrough that occur only gas is injected one by one thanks to unfavorable oil-gas quality magnitude relation. Hence, synchronic injection of gas and water would be of bigger importance to boost the sweep potency by rising the displacement front. SWAG combines the advantages of microscopic sweep potency obtained from mixable gas injection with higher economic science and frontal stability obtained from water flooding. Water and gas will be injected as an alternative in slugs or at the same time. The expertise of SWAG is a smaller amount however the experiments in several fields have prompt that use of SWAG as EOR method will be terribly crucial because it has been seen, less well injectivity and reduce in associated issues have occurred [11]. Spontaneous imbibition is that the mechanism wherever one fluid displaces another from a porous medium as a results of capillary forces solely. The matrix is a porous medium with a capillary pressure, and the fractures have approximately zero capillary pressure [12].
The most important oil recovery mechanisms for gas injection into a fractured reservoir are condensation of gas into oil, vaporization of oil, gravity drainage, diffusion and viscous displacement. Viscous displacement, gravity drainage and diffusion are mechanisms for gas to enter the matrix blocks, while condensation and vaporization are the mechanisms for oil to expel into the fractures to be produced. The mechanism of viscous displacement for gas is such as described for water and will not be presented [13]. Condensing gas-drive is the mechanism of oil displacement by condensation of intermediate hydrocarbons components, ethane to pentane, from injected gas going in solution with the reservoir oil [14].
The diffusion process is of molecular nature and results from random motion of molecules in a solution. Molecular diffusion is present in all systems in which miscible fluids are brought into physical contact, and is an important phenomenon for dispersion of fluids [15]. The diffusion process may be described quantitatively using Fick's first law. Fick's first law relates the diffusion of a fluid into another fluid as proportional to the concentration gradient between the fluids.
Relative permeableness is understood to be dependent not solely on part saturation, however conjointly part saturation history. Generally this is often painted by differing imbibition and voidance curves in simulation models. Most studies work relative permeableness physical phenomenon have found that the physical phenomenon result is massive for the non-wetting part and tiny for the wetting phase [16].
Several studies have coupled crude oil saturation to the treed gas saturation, however the impact is nine most dominating in water-wet reservoirs. Element, Masters, Sargent, Jayasekera & discoverer (2003) noted that treed gas failed to considerably have an effect on crude oil saturation in intermediate wet cores, whereas Kralik, Manak, Jerauld & Spence (2000) found no impact in Associate in Nursing oil-wet system. The reduction in crude oil saturation is usually a very important contributor to progressive recovery in incompatible WAG, however as mentioned later in three.1.4 the reservoir in question is taken into account a lot of intermediate wet. As a consequence the crude oil won't be directly coupled to treed gas during this thesis. an extra profit is that this allows sensitivity to look at the impact of reducing water and gas relative permeabilities within the presence of treed gas [17]. In WAG method, gas and water slugs square measure alternately or at the same time injected during a mounted quantitative relation known as the WAG quantitative relation. In keeping with Wu dialect (2004), WAG quantitative relation may also be outlined because the quantitative relation of the amount of water injected inside the reservoir compared to the amount of injected gas. WAG quantitative relation represents, one vital parameter to optimize throughout WAG process [18].
The choice of the wells spacing, in WAG method style, is additionally important as a result of the sweep potency of the oil is powerfully laid low with the space between the gismo and also the producer well [2]. In several cases, a Five-spot injection pattern is extremely in style, because it will give higher management on frontal displacement [19]. AN ANalysis of various eventualities would go a protracted thanks to facilitate verify an optimum pattern [18].
Other variable which will be thought of in optimizing WAG theme includes the temporal arrangement of the switch from gas to water in schemes wherever Associate in nursing alternating pattern is applied. What is more, the sequencing of gas, water and WAG injection across an oversized field offers vital opportunities for will increase gas storage [21]. Previous WAG cycle style procedures used steady state methodology and accepted business rules of thumb. The employment of a machine allows an additional rigorous analysis to

optimize WAG cycle parameters like cycle time [22]. The optimum slug sequence in their experiments was zero.08 PV water injection followed by zero.35 PV gas slug injection. During this method, the matrix sweep potency was enlarged and gas/water production was reduced at the outlet [23].

Fatemi and Sohrabi [24] according laboratory results of a comprehensive series of coreflood tests dispensed underneath water-wet and mixed-wet conditions. Waterflooding, gas flooding, and WAG injection were conducted by victimisation arenaceous rock core samples in their study. The wettability of core sample will be turned into mixed-wet by victimisation Associate in nursing acceptable fossil oil to age the core. Also, in their experiments, X-Ray scanner was accustomed live the distributions and saturations of various phases (e.g., water, oil, and gas) on the core sample. The experimental results indicated that in each the water-wet and mixed-wet cores, WAG injection gave the most effective performance within the 3 injection schemes. Waterflooding had a better oil RF in mixed-wet condition. The oil RFs of water, gas, and WAG injection processes were powerfully laid low with the wattability of core sample [25].

Zuo et al. [26] studied the result of three-phase relative porosity model on the simulation of WAG injection underneath numerous conditions. In their study, incompatible and miscible WAG injection processes were simulated by victimisation black-oil and integrative models in each 2-D undiversified cases and actual 3D field sector models. They found that three-phase relative porosity model had stronger result on incompatible WAG injection (black-oil simulations) as a result of the dimensions of three-phase flow region within the incompatible case is often larger. For near-miscible cases, the selection of Associate acceptable three-phase relative porosity model considerably affected the ultimate oil RF. once the miscibility was totally developed, the result of the three-phase relative porosity models can be negligible [26].

Chen and painter (27) argued that, within the case of irregular well placements in heterogenous reservoirs, ever-changing the length of the water or carbonic acid gas injection periods had very little result on the rise of the best NPV [26]. Revenue of the field is earned by selling crude oil. To determine total cash inflow, yearly production of each well and predicted oil price till 2045 are used. Cash inflow can be calculated from:

$$Cash\ inflow\ (\$) = \left[oil\ price\ \left(\frac{\$}{bbl}\right) \times total\ production\ in\ a\ year\ (bbl)\right]$$

3. Method

3.1. Methodology

The studied reservoir is an asymmetric anticline with a length of 10 km and a width of 10 km. A single-porous sandstone reservoir and its high quality oil with 34 API. The gas/oil ratio is 700 Scf/STB and the oil formation volume factor of 1.39 Rbbl/STB (Table 1). The reservoir has not been producing so far. The reservoir is initially in super-saturated condition and lacks a gas cap. The reservoir has a weak marginal and underlying aquifer. The reservoir rock is oil wet. The field is divided into four sectors, the studied sector dimensions are 3.5 km length and 3.2 km width and 150 m thickness. It is a petroleum field with a high grade light oil and 36 API. The initial pressure of the reservoir is 5300 psi, its porosity is between 18% and 23%, and its permeability is between 0.38 to 3 mD. This field was initially produced under super-saturated conditions and decreased over time as a result of production, and this led to saturation condition of the field and the formation of a gas cap. The general characteristics and composition of the reservoir fluid are presented in Tables ۱ and 2, respectively.

Table 1 :Reservoir rock and fluid properties

Property	values	Property	values
∘API	34	FVF,Rbbl/STB oil	1.39
Total thickness,ft	642	Water FVF, Rbbl/STB	1.01
GOR, Scf/STB	700	Oil Viscosity, cp	0.68
Rock Compressibility, × 〖10〗^(-6),1/psi	2.8	Gas Viscosity,cp	0.021
Water Compressibility, × 〖10〗^(-6),1/psi	3.28	Water Viscosity,cp	0.468
Oil density, lbm/ft3	53.35	Oil Saturation,%	0.215
Gas density, lbm/ft3	0.042	Water Saturation,%	0.32
Datum depth,ftss	7950	WOC,ftss	8200
Average Reservoir Pressure@datum depth,psi	5230	Reservoir Temperature,∘F	140
Reservoir Top Depth,ftss	7586	Average Matrix Porosity%	16

Source: Research findings

Table 2 :Mole fraction and molecular weight of the reservoir fluid

Component	'H2S'	'CO2'	'C1'	'C2'	'C3'	'IC4'	'NC4'
Mole Fraction	0.01476	0.0128	0.34567	0.06142	0.04293	0.01097	0.02921
Molecular Weight	34.076	44.01	16.043	30.07	44.097	58.123	58.124

Source: Research findings

Table 3 :Mole fraction and molecular weight of the reservoir fluid (Continued)

Component	'IC5'	'NC5'	'C6'	'C7+'	'C14+'	'C25+'
Mole Fraction	0.01488	0.0195	0.02694	0.29257	0.10792	0.02042
Molecular Weight	72.15	72.151	84	127.75	232.88	401.75

The initial pressure and temperature of the reservoir are 5300 psia and 140 F respectively. The bubble point pressure of the reservoir fluid is calculated as 1961 psia. The selected model for adjusting the equation of state is PVTi software. Information of the saturation pressure, constant composition expansion, differential liberation and viscosity tests were extracted from the fluid study report and entered into the software. Figures ۱ to ۴ show the porosity and permeability maps. In this network, the reservoir was divided into 24 and 25 grids in a longitudinal and transverse direction respectively. Given the variety of rock types in the vertical direction, 12 layers were defined for the reservoir.

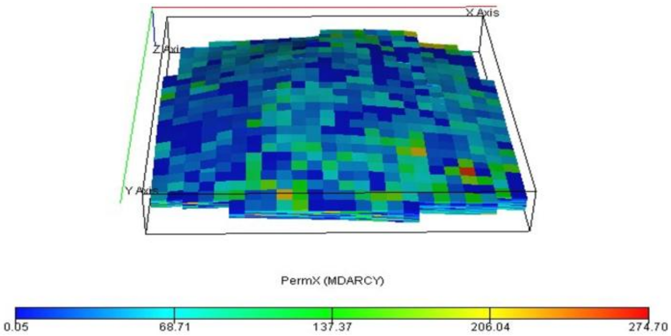


Figure 1: Porosity distribution in 3D model of the reservoir

Source: Research findings

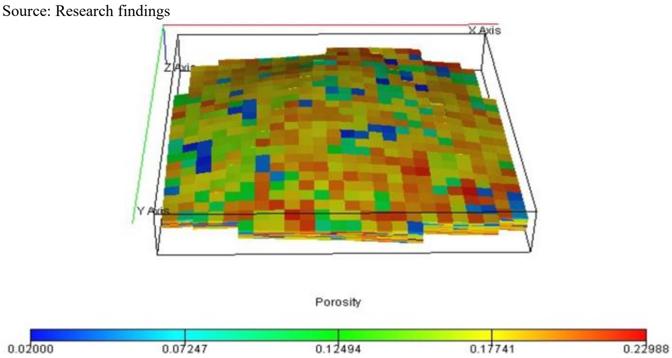


Figure 2: Permeability distribution in 3D model of the reservoir (X-direction)

Source: Research findings

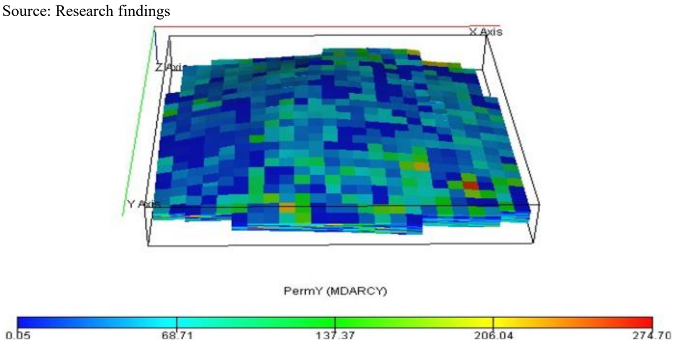


Figure 3: Permeability distribution in 3D model of the reservoir (Y-direction)

Source: Research findings

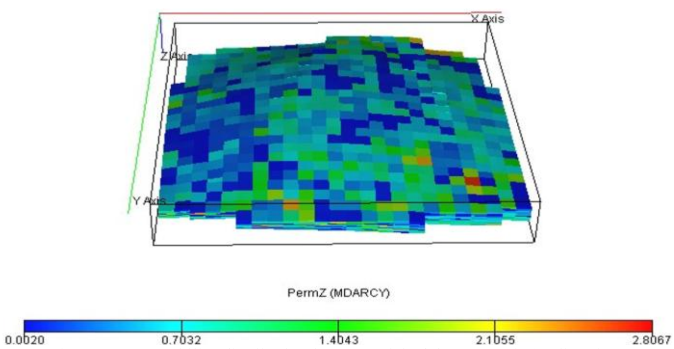


Figure 4: Permeability distribution in 3D model of the reservoir (Z-direction)

ource: Research findings

In order to obtain the minimum miscible pressure (MMP) of the injected gas, the results of a available slim tube simulation was used. As shown in Figure 5, the minimum miscible pressure for methane (C1) injection was 6100 Psi. The initial pressure of the reservoir is 5230 Psi, so the process of injecting methane (C1) into the reservoir will be immiscible for the pressures below 5230 Psi and will be miscible for the pressures above the 5230 Psi.

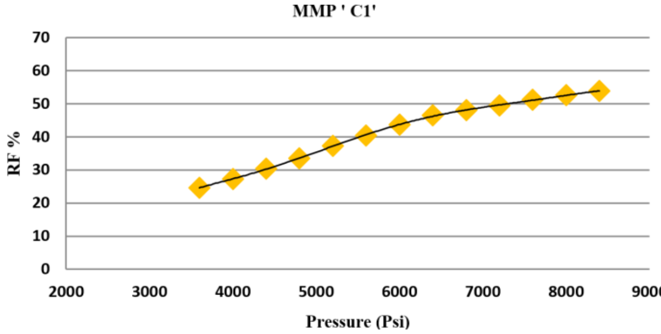


Figure 5: Determining the MMP of the methane (C1) using slim tube test

Source: Research findings

4. Results and Discussion

1-4. WAG injection (0.2 PV[2])

First, the injection volume has to be determined, which given that the reservoir is under saturated conditions and the results obtained from gas injection scenarios, the volume of injection is 0.2 of the reservoir pore volume. Then we need to calculate how much injection rate of water and gas is equivalent to this injection volume. In order to reach this injection volume, a water injection rate of 15000 STB/day should be injected into the reservoir which is equivalent to the gas injection rate of 25000 Mscf/Day. Generally, in the water alternating gas injection scenario, considering the injection volume of 0.2 PV in a dual 5spot pattern and in the optimal injection ratio, sensitivity to the number of injection cycles and the duration of water and gas injection produced in each cycle is run and the optimal case is obtained.

2-4. Effect of WAG ratio

Due to the fact that in the oil reservoirs, the stability of the water and gas front plays a very significant role in the early coning of gas and water, so the optimal water-gas ratio should be calculated. Because the reservoir is oil wet, it is important to note that gas should be injected first. In this process, first, the gas is injected to sweep the oil coated reservoir grains and oil existing in the small pores, then the water is injected to sweep the oil existing in the large pores, so higher recovery will be achieved. According to the calculated flow rate in the ratio of 1:1 (15000 STB/day:25000 Mscf/Day), gas and water injection rates are calculated in the ratios of 2:1, 3:1, 4:1, 1:2, 1:3, 1:4. In this part, the effect of WAG ratio on the performance of WAG injection is investigated. We perform the simulation using seven different WAG ratios that are shown in table 4.

Table 4 :Effect of WAG ratio on cumulative oil production in WAG injection scenario

Case No.	WAG Ratio	Np (MMSTB)
1	1:1	107.22
2	1:2	111.94
3	1:3	110.06
4	1:4	100.82
5	2:1	107.91
6	3:1	102.35
7	4:1	96.31

Source: Research findings

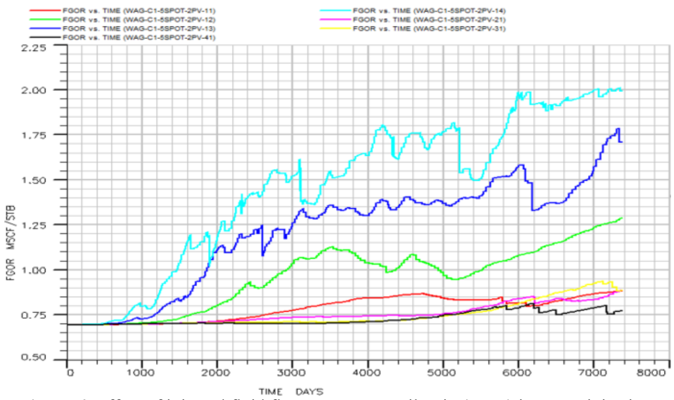


Figure 6: Effect of injected fluid flow rate on Gas oil ratio (GOR) in WAG injection scenario (until 2032)

Source: Research findings

3-4. Effect of WAG period

In this part, the effect of WAG period on the performance of WAG injection is investigated. In general, the comparison was made for cycles of 8 and 12 months. We perform the simulation using ten different WAG periods that are shown in table 5. As it can be observed, the WAG period of 5:3 (5 months water and 3 months gas) has the highest cumulative oil production and is the most optimal WAG period. However, equal periods of water and gas injection, have considerable and appropriate cumulative oil production. Also, if we increase the gas injection period, it will be caused of noticeable reduction in cumulative oil production and WAG injection performance. It should be mentioned that the gas and water injection rates are equal to 25000 Mscf/Day and 15000 STB/Day respectively.

Table 5: Effect of WAG period on cumulative oil production in WAG injection scenario

Case No.	Water flooding period (month)	Gas injection period (month)	Np (MMSTB)
		8 months cycle	
1	2	6	71.76
2	3	5	95.74
3	4	4	111.09
4	5	3	115.28
5	6	2	113.07
		12 months cycle	
6	6	6	110.78
7	8	4	114.91
8	10	2	108.64
9	2	10	63.79
10	4	8	88.28

Source: Research findings

4-4. Effect of first gas injection pore volume

In this case, the effect of cyclic gas pore volume injected on the performance of WAG injection has been investigated. Here, the gas has been injected with the injection volumes of 0.025, 0.05, 0.1 and 0.15 PV in the first 2.5 years and next (remaining 17.5 years), the process of WAG injection is continued with 1:1 WAG ratio. The amount of water and gas injection rates are calculated for all scenarios individually, until the volume of the WAG injection is maintained at 0.2 PV in the remaining 17.5 years.. As it can be observed, the gas injection PV of 0.05 has the highest cumulative oil production and is considered as the most optimal PV. However, all of the three first cases, have almost equal cumulative oil production. In the case of 0.15 PV a considerable reduction in cumulative oil production can be observed which is mainly because of gas over ride and fingering phenomenon. So there is a limitation in the PV of first injected gas. Also, it can be concluded that for injected PVs less than 0.1 the first gas injection PV has not considerable effect on WAG injection performance. It should be mentioned that the period of gas injection is equal to 30 month for all cases.

Table 6: Effect of first gas injection pore volume (PV) on cumulative oil production in Gas-WAG injection scenario

Case No.	Gas injection PV for the first slug	Gas injection rate for the first slug (Mscf/Day)	WAG injection (0.2 PV)	Np (MMSTB)
1	0.05	50000	17000 STB/Day 28500 Mscf/Day	109.43
2	0.025	25000	17000 STB/Day 28500 Mscf/Day	109.05
3	0.1	100000	17000 STB/Day 28500 Mscf/Day	103.53
4	0.15	150000	17000 STB/Day 28500 Mscf/Day	90.12

Source: Research findings

5-4. Comparison of optimal scenarios of gas injection processes

Various scenarios of injection were performed. Among the optimized scenarios, the WAG injection with 0.2 PV, 1:1 WAG ratio and 5 months water and 3 months gas injection period had the highest cumulative oil production which is equal to 115.28 MMSTB. In table ۷, a statistical comparison of the optimal scenarios of gas injection processes is presented.

Table 7: Comparison of optimal scenarios of gas injection processes

Scenario	Natural depletion-6 well	Gas-18000	WAG-1:2 Ratio-6:6 Period	WAG-1:1 Ratio-5:3 Period	HWAG-30 Months 0.05 PV
Np (MMSTB)	61.98	85.37	111.94	115.28	109.43

Source: Research findings

[2] Pore Volume

In this section the economic analysis of WAG injection are presented for the most optimum oil production that was WAG-1:1 Ratio-5:3 Period scenario. In this scenario the Np was 115.28 (MMSTB).

In this study 7 scenarios are investigated for economic analysis:

1- Base case
2- oil price (low and high)
3- A different discount rate (low and high)
4- Different OPEX (low and high)
5- Different CAPEX (low and high)
6- Sensitivity analysis

The Economic analysis are calculated for 20 years since 2013 to 2032. The oil production, gas production, water production of the selected scenario are shown below. These values are used in the economic analysis.

Table 8 :Results of economic analysis for WAG injection 2013-2032 (Optimistic oil price)

YEAR	Oil Price($)	Gas Price($/ MSCF)	Income($)	Cash Flow ($)	PW ($)
2013	50.00	8.33	320463412.5	-913618990.7	-913,618,990.7
2014	53.00	8.83	352052177.6	165902837.1	150,820,761
2015	53.06	8.84	355615221.4	165497574.4	136,774,854.8
2016	43.43	7.24	276151738.3	97744579.54	73,436,949.32
2017	98.02	16.34	663996325.6	467045199	318,998,155.1
2018	119.91	19.99	774377226.9	593749424.2	368,671,678.1
2019	139.35	23.22	963265462.1	768209683.1	433,634,338.9
2020	152.68	25.45	1010637185	830738872.5	426,300,396.6
2021	163.49	27.25	1163523306	964232425.2	449,821,542.6
2022	172.16	28.69	1167780771	987105364.2	418,629,034
2023	178.09	29.68	1214846737	1030921591	397,464,901.3
2024	182.45	30.41	1301134072	1109759902	388,964,075.5
2025	188.30	31.38	1339641181	1139355519	363,033,780.8
2026	192.40	32.07	1296616894	1115389097	323,088,490.9
2027	194.84	32.47	1376501902	1180759802	310,930,959.6
2028	197.61	32.94	1322466891	1141866230	273,353,696.9
2029	199.25	33.21	1426596722	1225423744	266,687,910.5
2030	201.48	33.58	1363566912	1183595780	234,168,115.2
2031	204.27	34.04	1331108367	1154075200	207,570,568.9
2032	207.68	34.61	1028281480	897385169.4	146,729,646
			NPV		4,775,460,865
			IRR		39%
			PI		4.54
			MIRR		21%

Source: Research findings

In this case the whole situation is like the base case but the oil price and gas price are estimated to be less than Base Case. The data are as follows:

Table 9: Results of economic analysis for WAG injection 2013-2032 (Pessimistic oil price)

YEAR	Oil Price($)	Gas Price($/MSCF)	Income($)	Cash Flow ($)	PW ($)
2013	26.70	4.45	171127462.3	-1062954941	-1,062,954,941
2014	27.00	4.50	179347335.8	-6802004.72	-6,183,640.655
2015	53.06	8.84	355615221.4	165497574.4	136,774,854.8
2016	43.43	7.24	276151738.3	97744579.54	73,436,949.32
2017	24.54	4.09	166245992.2	-30705134.44	-20,972,019.97
2018	27.89	4.65	180098886.1	-528916.595	-328,415.592
2019	28.80	4.80	199051567.6	3995788.608	2,255,518.499
2020	29.40	4.90	194578307.3	14679994.99	7,533,158.603
2021	29.63	4.94	210852790.1	11561909.78	5,393,716.243
2022	29.95	4.99	203132003.4	22456597.08	9,523,789.34
2023	29.97	4.99	204433648.5	20508502.92	7,906,915.677
2024	30.11	5.02	214711026.1	23336855.76	8,179,425.577
2025	30.87	5.15	219629668.3	19344006.67	6,163,596.664
2026	31.65	5.27	213270404.4	32042606.95	9,281,601.866
2027	32.61	5.43	230379129	34637028.57	9,121,012.18
2028	33.75	5.63	225881840.8	45281179.71	10,839,954.41
2029	34.87	5.81	249652017.4	48479039.53	10,550,451.48
2030	36.24	6.04	245229241.4	65258108.82	12,910,968.93
2031	37.20	6.20	242445172.5	65412005.27	11,764,924.11
2032	38.19	6.37	189111989.8	58215679.54	9,518,728.796
		NPV			-759,283,450.6
		IRR			-4%
		PI			-0.72
		MIRR			3%

Source: Research findings

6-4. Sensitivity Analysis

In this case the NPV of the previous cases are compared and it is shown that which of the variable items has the most effect on NPV. The results are shown in table 10 and figure 7.

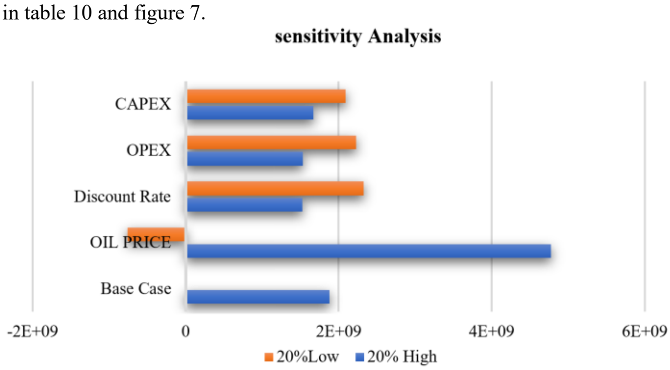


Figure 7: Effect of variable items on NPV.

Source: Research findings

Table 10: Results of economic analysis for WAG injection 2013-2032 (Different CAPEX)

Parameter	NPV($) (20% High)	NPV($) (20%Low)
Base Case	1,877,893,324	
OIL PRICE	4,775,460,865	-759,283,451
Discount Rate	1,523,534,478	2,326,136,597
OPEX	1,529,391,085	2,226,395,563
CAPEX	1,667,421,324	2,088,365,324

Source: Research findings

As it can be seen the change of oil price has the most effect on the NPV in comparison to base case. After that discount rate and OPEX changes effect the NPV respectively. CAPEX change had the least effect on NPV in comparison to the other items.

5. Conclusions

The results obtained from this study in various injection scenarios are listed as follows:

1. Among the gas injection scenarios, the best scenario is gas injection at the rate of 18000 Mscf /Day which has the highest cumulative oil production and is the most optimal injection rate. Due to the high mobility of gas, the surface and vertical efficiency of the gas injection method is limited and because of the constraints on the gas-oil ratio, the wells perforations and gradually the whole wells with high gas-to-oil ratio will be closed and cause reducing daily and cumulative production of oil. That's why the injection rates above the 18000 Mscf/day not only does not increase the oil recovery, but also reduce it.

2. Among all injection scenarios, including gas injection, WAG injection and hybrid WAG, the most effective scenario was WAG injection. It is due to the obstruction of the fingering phenomenon of the gas in the production wells and mobility control of the displacing and displaced phases.
3. Among the WAG injection scenarios with various WAG ratios, the highest recovery was for the WAG ratio of 1:2 which is consistent with literature.
4. Among the WAG injection scenarios with various WAG periods, the highest recovery was for the injection period of 5 months water and 3 months gas.
5. Among all scenarios, the WAG injection scenario had the highest oil recovery, which is due to the more stable front and the prevention of early fingering.
6. Among all scenarios, the gas injection scenario had the lowest oil recovery, which is mainly due to the high mobility of the gas and limited vertical and horizontal efficiency.
7. The change of oil price has highest effect on the NPV of WAG injection in comparison to base case.
8. After the oil price, discount rate and OPEX changes effect the NPV of WAG injection respectively.
9. CAPEX change had the least effect on NPV of WAG injection in comparison to the other items.

All of the injection scenarios can be repeated using other gases including N2, C3, LPG, Lean gas and etc. and their effects on increasing or decreasing the amount of oil recovery can be surveyed. Surfactant solution can be replaced with water in WAG injection scenarios. A comparative simulation of the WAG injection and the hybrid WAG injection process in a fractured reservoir can be done and compare the results.

References

[1] T, Babadagli. Journal of Petroleum Science and Engineering, 2007, **57(3-4)**, 221-246.
[2] J.R, Christensen. E.H, Stenby. A, Skauge. in International Petroleum Conference and Exhibition of Mexico, 1998, Society of Petroleum Engineers.
[3] W, Lyons. Gulf Professional Publishing, 1996, **2**.
[4] C, Brown. World Energy Resources: International Geohydroscience and Energy Research Institute, 2012.
[5] E.C, Donaldson. G.V. Chilingarian. T.F. Yen. Enhanced Oil Recovery, II: Processes and Operations,1989.
[6] M, Latil. Gulf Publishing Co,1980.
[7] S, Tabatabaei Nezhad. A.R., et al. in International Oil Conference and Exhibition in Mexico, 2006. Society of Petroleum Engineers.
[8] P, McGuire et al. in SPE Western Regional Meeting, 2005. Society of Petroleum Engineers.
[9] T, Holt. E. Lindeberg. D. Wessel-Berg. Energy Procedia, 2009. **1(1)**, 4159-4166.
[10] M, Cobanoglu. Kozluca Field, Turkey. in SPE Asia Pacific Improved Oil Recovery Conference, 2001. Society of Petroleum Engineers.
[11] Y, Gong. Y. Gu. Energy & Fuels, 2015, **29(9)**, 5655-5665.
[12] J.C, Heeremans. T.E. Esmaiel. C.P. Van Kruijsdijk. in SPE/DOE Symposium on Improved Oil Recovery, 2006. Society of Petroleum Engineers.
[13] N, Jakobsson. T. Christian. in SPE Annual Technical Conference and Exhibition, 1994. Society of Petroleum Engineers.
[14] L.W, Holm. Miscible Displacement, 1987. PEH Chapter 45..
[15] D, Element et al. in IEA Collaborative Project on Enhanced Oil Recovery, 19th International Workshop, Carmel, California, 1998.
[16] E, Braun. R. Holland. SPE Reservoir Engineering, 1995, **10(03)**, 222-228.
[17] J, Sørbel. NTNU, 2015.
[18] F.O, John. Optimization of A Water Alternating Gas Injection, 2015.
[19] M, Zahoor. M. Derahman, M. Yunan. Brazilian Journal of Petroleum and Gas, 2011. **5(2)**.
[20] M.J, Darvishnezhad et al. in Trinidad and Tobago Energy Resources Conference, 2010. Society of Petroleum Engineers.
[21] X, Wu et al. in Canadian International Petroleum Conference, 2004. Petroleum Society of Canada.
[22] D, Pritchard. R. Nieman. in SPE/DOE Enhanced Oil Recovery Symposium, 1992, Society of Petroleum Engineers.
[23] A, Dehghan. S. Ghorbanizadeh. S. Ayatollahi. Transport in porous media, 2012, **93(3)**, 577-595.
[24]
[25] S.M, Fatemi et al. Energy & Fuels, 2012. **26(7)**, 4366-4382.
[26] L, Zuo et al. SPE Reservoir Evaluation & Engineering, 2014, **17(03)**, 326-339
[27] B, Chen. A.C. Reynolds. SPE Journal, 2016, **21(03)**, 786-798.