Feasibility Study of Both Carbon Dioxide Sequestration and Underground Gas Storage Combination

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Abstract

Underground gas storage (UGS) is a relatively modern technique for mitigation detrimental effect of the supply-demand misbalances that has been developing rapidly and is now an essential part of the gas chain. The original and primary scope was a modulation of peak demand and the optimization of the transport network. Nowadays more specific and differentiated functions are taking over. For example, this process can also be adapted to producing oil or condensate and can be considered as an IOR method.

The purpose of this study is to investigate the parameters affecting underground gas storage in gas condensate reservoirs in order to improve its performance. In this paper we considered the economic aspect of UGS and focused on engineering methods to reduce the cost of storage. This resulted in finding a new phenomenon in gas storage. Results of the study were directed toward replacing the cushion gas, which accounts for about 38% of the storage costs. Efforts for finding an appropriate alternative for cushion gas to maintain reservoir pressure in storage cycles led to recognition of CO_2 sequestration and finally with combining UGS and CO_2 sequestration the natural gas as in cushion gas replaced by CO_2 gas. In this case the natural base gas in the reservoir is drained and CO_2 sequestration begins. For improving the quality of production stream, the injection wells used for CO_2 sequestration separated from those which are used in UGS. Also CO_2 injection into lower layers delays the production of CO_2 in production times. Optimum limit for this is a place between minimizing CO_2 production and maximizing working gas capacity.

Carbon dioxide has higher miscibility than natural gas that causes an approximately 1.2 STB/MMSCF CO_2 increase in condensate production. This means a 1.3% increase in condensate recovery in addition to what we could have before with natural gas. Simulation Results confirm the success of the project as well as being economical. However, 16% of injected CO_2 produces in 20 years of gas storage, but over time, CO_2 production has a decreasing trend.

Keywords: Underground Gas Storage, Gas Condensate Reservoirs, Cushion Gas, CO_2 Sequestration

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1. Introduction

Gas storage is a beneficial economic method to compensate the imbalance between supply and demand and currently is considered as an important part of gas chain[1]. Storage reservoirs are stores that provide an easy supply of gas during the peak of consumption in cold periods of the year. The natural gas in the pipeline is injected to the underground storage reservoir during low consumption periods. Then, when demand surpassed the supply capacity of the pipeline, the storage reservoir starts to produce as a complementarity. The global increase in gas demand has made the storage development and optimum utilization of available reserves as an economic-engineering priority[2].

Despite dry gas reservoirs, the composition of the produces gas and injected gas is not the same in gas condensate reservoirs due to condensate dropout in reservoir. These condensates are not producible because of their low saturation. In order to avoid losing these valuable condensates, gas cycling is performed.

In recent years green house gases such as carbon dioxide have increased in the atmosphere and caused some concerns about climate change. CO_2 concentration in the atmosphere has drastically increased from 280 ppm to 380 ppm during countries' industrialization[3]. In this method, carbon dioxide is separated from atmosphere gases through a proper process so that prevents global warming and probable changes in climate. This knowledge is based on capturing CO_2 from emission sources and injecting it into deep geological structures. There are several options for CO_2 sequestration such as injection to deep saline aquifers, injection into mature gas or oil reservoirs for the purposes of both CO_2 sequestration and enhancing oil recovery, injection into depleted oil or gas reservoirs, and finally injection to coal seams. Among these choices, the estimated capacity of storage in oil and gas reservoirs is 300 Gigatons of carbon dioxide[4].

The objective of this part is better understanding of the available potential for underground gas storage by changing the base gas, increasing the condensate production from the gas condensate reservoirs, and CO_2 sequestration into these reservoirs in a wide range of variables. According to the studies performed by the Gas Industry Institution in United States, regarding storage expenditure after compression and refining, most operation's costs is for the base gas. In gas storing reservoirs, about 38% of the total costs is for the base gas, which should be remained in the reservoir or be injected for pressure maintenance[5]. In the studied reservoir, high amount of gas is remained in the reservoir because of its great depth. Thus, it not only maintains the pressure for high flow rate production, but also provides the necessary pressure for gas transmission from bottom-hole to the separator.

In this study the Guri gas condensate reservoir model was provided by a compositional simulator and three-parameter Peng-Robinson equation of state was utilized to predict phase behavior of fluids. In following, different methods to reduce cost of storage were studied through investigating economic aspects of storage so that the alternative method can be introduced.

2. Reservoir Properties

The studied reservoir is a gas condensate reservoir in south of Iran, the area of which is about 210 km^2. According to recent studies, the corresponding volume of gas in place is estimated about 4.7 TSCF. In this reservoir, the initial pressure, dew point pressure, and initial temperature are 5100 psia, 5100 psia, and 210 ˚F.

This field contains gas condensate. In this model, the block sizes are variable and as mentioned before, according to the fact that the reservoir is real, it is heterogeneous. Table (1) shows the composition of the fluid.

The reservoir rock in this field is a carbonate porous rock with average porosity and permeability of 10% and 20 mD, respectively. The reservoir thickness is about 200 ft, which is divided into four layers, all of which are perforated and are producing. Porosity and permeability are variable in horizontal and vertical directions in all over the field.

Table 1. Reservoir Fluid Composition

Name of compound	Molar fraction of reservoir's fluid
N_2	0.046930
H_2S	0.000004
CO_2	0.003460
C_1	0.866916
C_2	0.036580
C_3-C_5	0.029230
C_6-C_7	0.015180
C_{8+}	0.001700

3. Using Carbon Dioxide as the Cushion Gas

The main objective to replace reservoir natural gas with CO_2 is to use it as the base gas. This paper itself is beneficial and is economically justified. For this aim, aspects of CO_2 injection and EOR were investigated along with storage purpose. In this process, the key point is to maintain CO_2 in the reservoir as the base gas and not to produce it. Next step is studying effective scenarios on optimizing oil recovery and CO_2 storage. For this, several plans for injection to and production from the field and well and different wellhead and bottom-hole limitations in postponing CO_2 production were investigated.

The main problem in CO_2 injection to reservoir is its high miscibility with the reservoir base gas, which decreases the quality of the produced gas. However, CO_2 gas owns some features that make it a suitable candidate for injection in gas reservoirs such as:

- The CO_2 density in reservoir condition is 2-6 times greater than methane density, which results in CO_2 settling on bottom of the reservoir and easier production of natural gas.
- The movement process is more stable in comparison with methane due to lower mobility ratio of carbon dioxide (because of its high viscosity).
- Greater solubility of CO_2 in the water than methane leads to later breakthrough of CO_2 in the production wells and also increases the amount of stored CO_2.
- Higher injectivity of carbon dioxide (due to lower reservoir pressure because of different compressibility factors) provide the desired condition for injection process and EOR [6, 7]

According to Oldenburg [6], it is possible to use carbon dioxide for injection into the depleted gas reservoirs due to its specific characteristics and slow miscibility with methane with the purpose of enhancing gas recovery. Miscibility between methane and carbon dioxide takes place slowly due to reservoir repressurization. The difference in density of these two gases leads to their gravitational segregation, which makes it suitable for enhanced gas recovery projects.

To perform this method, firstly, it was necessary to deplete the reservoir. In this respect, the reservoir underwent natural depletion for 30 years. 2.6 MMMSCF gas was produced during 30 years. After reservoir depletion, it is time to inject carbon dioxide. After installation of necessary facilities and starting CO_2 transmission to the wellhead it is only necessary to utilize an optimum scenario for CO_2 injection to the field. For this aim and as the base for starting the process, 200 MMSCF/d of CO_2 was injected to reservoir for 3 years. In this scenario, all the available wells were used for injection. CO_2 injection took place in each four layers through wells and after finishing the injection period, all the well were closed for one year. Finally, after performing this process, gas storage begins as a one-year period such that six month is for injection and the rest six months is for production.

It was proved that it is possible to replace the natural gas by carbon dioxide as the base gas, thus, several different scenarios are studied to investigate the effects of mentioned parameters on the efficiency of storing process. In this scenario, by varying the value of an involved parameter, its effect on the results was investigated to find the optimum solution using a combination of involved parameters. For this aim, natural gas storage process was performed for 20 years and in the same condition as the previous scenarios was. In other scenarios, the effective parameters and limitations were varied and the results were compared with the base scenario.

Table 2. Different studied scenarios for natural gas storage with carbon dioxide as the base gas.

No.	Changing Parameter
1	Base Model
2	Injection Layers
3	Primary Injection Time
4	Gas Production Rate in First 5 Years
5	CO_2 Injection Rate
6	Injection Gas Composition

The purpose for this comparison is to identify factors that are favorably effective on optimization of injected volume of CO_2 and minimization its return in production periods. On the other hand, the volume of produced gas was monitored to assure that it is not decreased and also the condensate production is increased. The investigated scenarios and corresponding altered parameters and results are listed in table (2).

At the end, the results of each scenario was analyzed in the table and parameters with positive effect, which were justifiable regarding economic and engineering considerations, were selected. Different effective scenarios on reducing carbon dioxide production during storing period were combined and in further investigations leads to more proper scenarios.

Ultimately, in this section, the desired and acceptable output was acquired by separation of injection and producing wells. In this respect, 5 wells among producing wells were allocated for CO_2 injection and the other 13 wells were used as observation wells. After finishing CO_2 injection, these 13 wells were allocated for storage. This scenario tremendously influenced the efficiency in which CO_2 production reduced to 13%.. It is worthy to note that in CO_2 sequestration projects CO_2 production through compressor's power consumption is about 6% of the CO_2 being compressed[8]. In this scenario, we will have 28.2 MMSTB of condensate and 2.76 MMMSCF of cumulated gas production. Finally, about 16% of the injected carbon dioxide to the reservoir will return in 20 years.

4. Conclusion

Carbon dioxide has the capability to be used instead of available natural cushion gas in UGS.

Replacement of the base gas with carbon dioxide not only reduces the costs of the base gas, but also increases the gas condensate production.

In this process, it is possible to sequestrate a huge amount of carbon dioxide deep in the earth and considering the descending trend in carbon dioxide production, it can be used as the base gas in long-term periods.

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