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Enhanced Oil Recovery and Gas Storage

Conversion of a Depleted Oil Field while Production: a Feasibility Study Comparing with Usual EOR Techniques

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Background

The oil field considered is located in the state of Gujarat (India), 45 km to the south of Ahmadabad city. It was discovered in 2004, the production started end of 2004 via four wells, and the cumulated volume of produced oil was 1.6 mmbbls (0.25 MMm^3) in summer 2013.

Figure 1 : Oil field location.

Aims

The aim is to study the feasibility of converting the oil field into an Underground Gas Storage (UGS), while maintaining the oil production, without degrading the oil recovery.
The main objectives of this feasibility study are thus:

- to detect any factor that could definitely prevent the field conversion,
- to estimate the UGS possible working volume and oil recovery,
- to provide recommendations to secure the project and to help the final investment decision.

A feasibility study was therefore carried out by Storengy and GSPC. A comparison with usual EOR techniques, i.e. continuous water or gas injection, has been performed. The main objective was to identify the key controlling parameters of the production behavior and UGS possible working volume, taking into account the uncertainties on the matrix and fracture properties.

Methods

This feasibility study involved the following analyses:

- A structural analysis has been performed from the interpretation of a 3D seismic cube provided by GSPC. The interpretation was carried out both at a regional scale, to identify the main structural features, and at a local scale, over the field area, to characterize the shape and extension of the trap, the local faults and the fracture network.
- Log and petrophysical interpretations were carried out on 11 wells to better understand the spatial distribution and the properties of the reservoir. The selected logging program was largely successful and did improve the formation evaluation. Based on past and new petrophysical analysis, prospective hydrocarbon bearing zones and key petrophysical reservoir parameters have been quantified and confirmed the presence of a porous matrix and a fracture network.
- Basic reservoir engineering analyses were carried out for verifying the Original-Oil-In-Place (OOIP) estimates, and for assessing the role of fractures on the production.
- Numerical dual-porosity reservoir modeling has been performed for assessing the UGS possible working volume and simultaneous associated oil recovery, taking into account the uncertainties in the matrix and fracture properties:
    - Three fractured models were defined according to the fracture properties uncertainty range:
        - Low fractured case: fracture porosity of 5e-3%, fracture equivalent permeability of 190 mD, shape factor of 3.6 ft^{-2}.
        - Mean fractured case: fracture porosity of 4e-2%, fracture equivalent permeability of 1000 mD, shape factor of 365 ft^{-2}.

        - High fractured case: fracture porosity of 4.4%, fracture equivalent permeability of 5000 mD, shape factor of 3.6e4 ft^{-2}.
        - The shape factor being estimated from Kazemi's formula and matrix block size estimates [6].
- Three production schemes were investigated: continuous water injection, continuous gas injection and UGS, over long forecasting periods (30 years). All schemes involved existing four wells i.e. no additional well was considered (cf. figure 2).
    - Water injection scheme:
        - A single well (well D) in the northern (lower) block was used as a water injector.
        - A continuous water injection rate of 2400 stb/day was imposed.
        - All other wells were used as producers.
    - Gas injection scheme:
        - A single well (well A) in the southern (upper) block was used as a gas injector.
        - A continuous gas injection rate of 610 MMscf/day was imposed.
        - Wells C and D in the northern (lower) block were used as producers.
    - UGS scheme:
        - A single well in the southern (upper) block was used as a gas injector/producer, all other wells were used as producers.
        - Two distinct phases were simulated:
            - Ramp-up phase: oil is progressively replaced by gas until the maximum possible working gas volume is reached.
            - Optimal phase: UGS operating phase with the maximum possible working gas volume.
        - Ramp-up phase operating conditions were:
            - a targeted BHP window defined as: 800-1600 psi,
            - an initial targeted gas injection rate of 16 MMscf/day, progressively increased during ramp-up,
            - an initial targeted gas production rate of 14 MMscf/day, progressively increased during ramp-up.
        - Optimal phase operating conditions were:
            - a targeted BHP window defined as: 800-3200 psi,
            - a targeted gas injection-production rate of 33 MMscf/day.
    - The targeted oil production rate is 2000 stb/day for all schemes.
- Oil recovery sensitivity to the capillary pressure uncertainties was also studied for the various production schemes. Capillary pressure was defined from the models of Kwon and Pickett [7] and Aguilera [8].
- Relative permeabilities were defined from Corey's model [9].

- Land's model [10] was used to estimate the residual gas saturation from the irreducible water saturation.
- Gravity drainage effects have been accounted for in cases involving gas injection or production.

Results

- The structural analyses indicated that the field is segmented into three connected compartments:
  - A north horst structure,
  - A central graben, partly filled by the Cambay shale,
  - A south horst, part of a larger tilted fault block.
  - The reservoir is approximately 1750m (GL) deep and 100m thick, and is distributed at the base of the Olpad formation and at the top of the Trap formation.

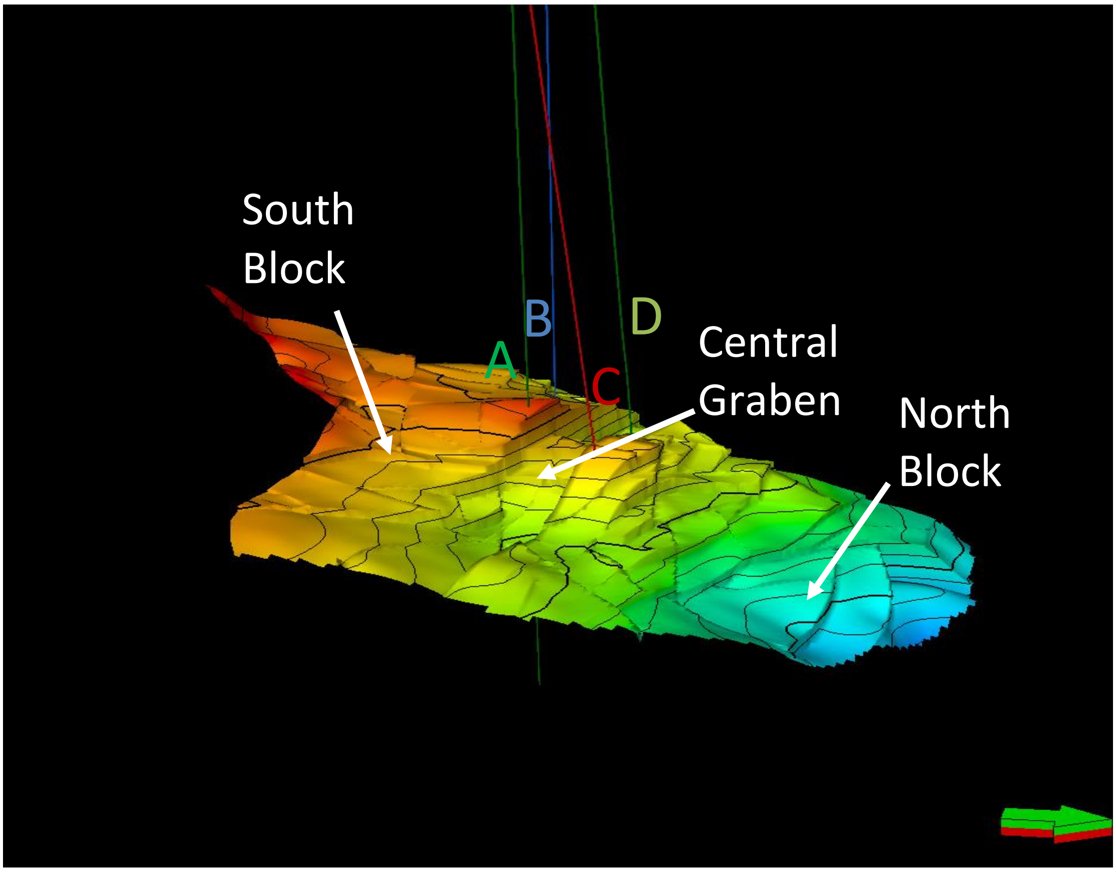

Figure 2 : 3D view of the structure at top Trap level.

- The petrophysical analyses indicated:
  - The oil viscosity varies from 1.33 cP (reservoir conditions) up to 104 cP at 50^{o}C.
  - The oil compressibility was estimated to be around 1e-5 psi^{-1} .
  - Consistent rock compressibility estimates were obtained from compressibility-porosity correlations for consolidated sandstones [5]: it ranges from 1 to 4e-6 psi^{-1}.
  - The presence of a porous matrix, that can be associated with several types of facies (sedimentary deposits of basaltic sand, volcanic breccias, vesicular basalt, pyroclastic deposits…). The effective reservoir matrix exhibits quite a high porosity (between 15-25%) but a very low permeability (between 0.01 – 2 mD). These values are in rather good agreement with "analogues" reported in the literature [2][3][4].
  - The presence of a fracture network:
    - Two main orientation trends: along the graben and orthogonal to the graben.
    - Conductive fracture densities vary between 1 and 10 fractures/m. These are rather low values, probably due to the fact that wells are verticals. Thus these are considered as under-estimates of fracture density values.
    - The mean fracture aperture is about 0.6 mm. It varies between 0.25 mm and 1 mm. However these are considered as over-estimates since fractures are filled according to FMI.
  - The oil saturation estimates remain quite uncertain due to the unconventional nature of the reservoir mineralogy and the complexity of the pore system.
  - The height of the oil column is estimated around 195 m with a probable oil/water contact around -1870m tvdss.
- The basic reservoir engineering analyses indicated that:
  - the bubble pressure was at around 550 psi. This was checked using an abacus and Lasater's method [1] and confirmed by PVT analyses.
  - The high productivity of the wells could not be explained by the low matrix permeability, but rather by the fracture network.
  - Well tests interpretation provide estimates of fracture permeability: ranging from 200 up to 10 000 mD.
  - The average volume of initial oil in place was estimated to be around 30 mmbbls (4.8 MMm^3). Considering that 1.6 mmbls (0.25 MMm^3) have been produced until summer 2013, the recovery factor is around 5%, which is considered to be close to the maximum reachable target for the natural depletion of such a field.

- The dual-porosity simulation results indicated that:
  - In the case of a continuous water injection, the oil recovery varies from 8 to 55%, depending on the wettability conditions and the fracture intensity (figures 3 and 4).
  - There is a lower oil recovery sensitivity to oil-gas capillary pressure uncertainties, in the case of UGS and/or continuous gas injection: recovery varies from 35 to 48% depending on capillary conditions and fracture intensity (figures 5 and 6).
  - The possible UGS working gas volume increased with oil production as the following (cf. figures 7 and 8):

	Working Gas Volume (MMSm^3)		**Oil Recovery (%)**	
Cases	Mean Fractured	High Fractured	Mean Fractured	High Fractured
After 5 years	34	42	18	18
After 10 years	73	78	27	31
After 30 years	172	170	35	38

Table 1 : UGS scheme: Working Gas Volumes and Oil Recoveries.

  - The UGS solution could maintain a better, steady, oil recovery rate than a continuous gas injection scheme, in the early production period (7 years) as well as on the long-term period (20 years i.e. time at which gas will break at well oil producers in the case of a continuous gas injection). This is achievable provided that a careful monitoring of Gas-Oil contact (high injection rates) and adapted operations strategy (injecting at the top, producing from the bottom, reducing oil rate targets after gas breakthrough) are performed in the UGS case. Indeed the producer used for UGS is still producing oil after the ramp-up phase, at a rate of 800-1000 stb/day for the mean fractured case, and at a rate of 400-600 stb/day for the high fractured case.
  - The low fractured case is a limiting case for which fast breakthroughs occur at producers, for all schemes. These breakthroughs are due to the low fracture porosity and the relatively high fracture permeability, that result in a quick lateral spread of the injected fluid, thus quickly reaching the producers. As this low fractured case is not the most representative case of the current data, it was therefore discarded.

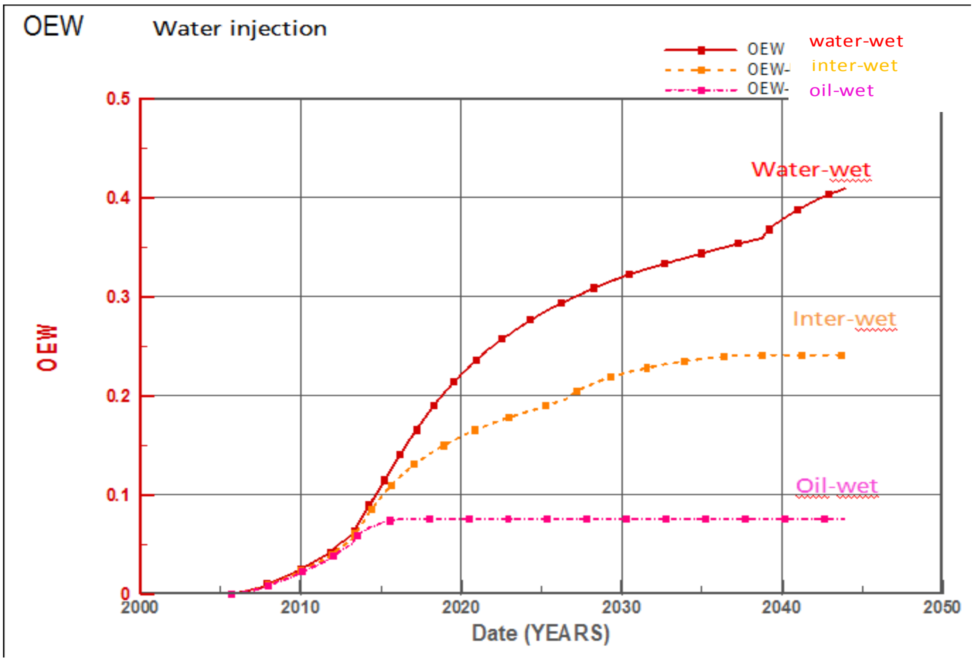

Figure 3 : Water injection scheme, mean fractured case: Oil recovery for different wettabilities.

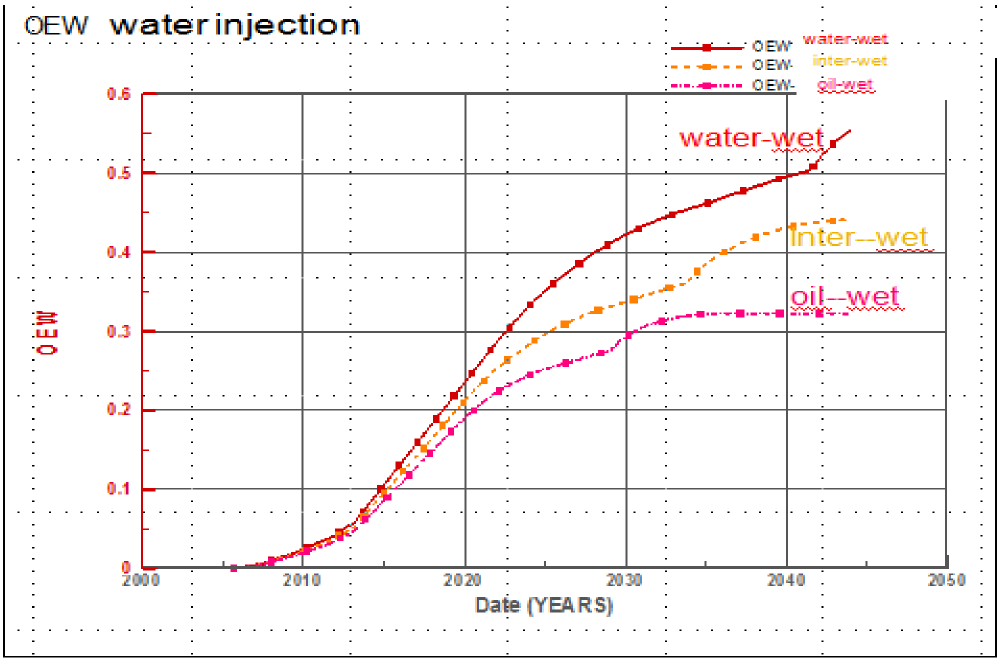

Figure 4 : Water injection scheme, high fractured case: Oil recovery for different wettabilities.

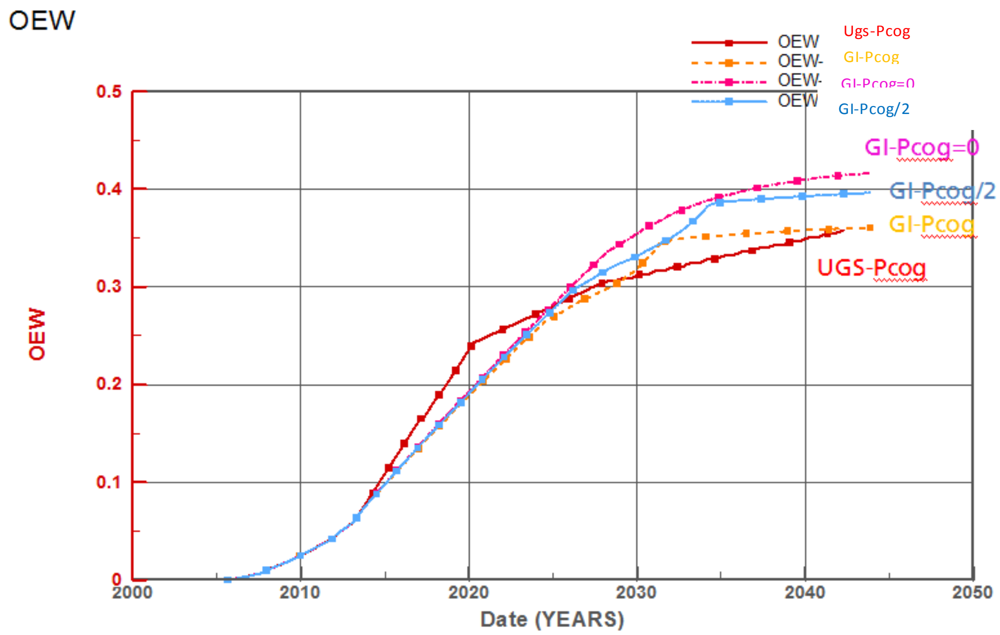

Figure 5 : Gas injection (GI) & UGS schemes, mean fractured case: Oil recovery for different oil-gas capillary pressures (reference Pcog, Pcog/2 and Pcog=0).

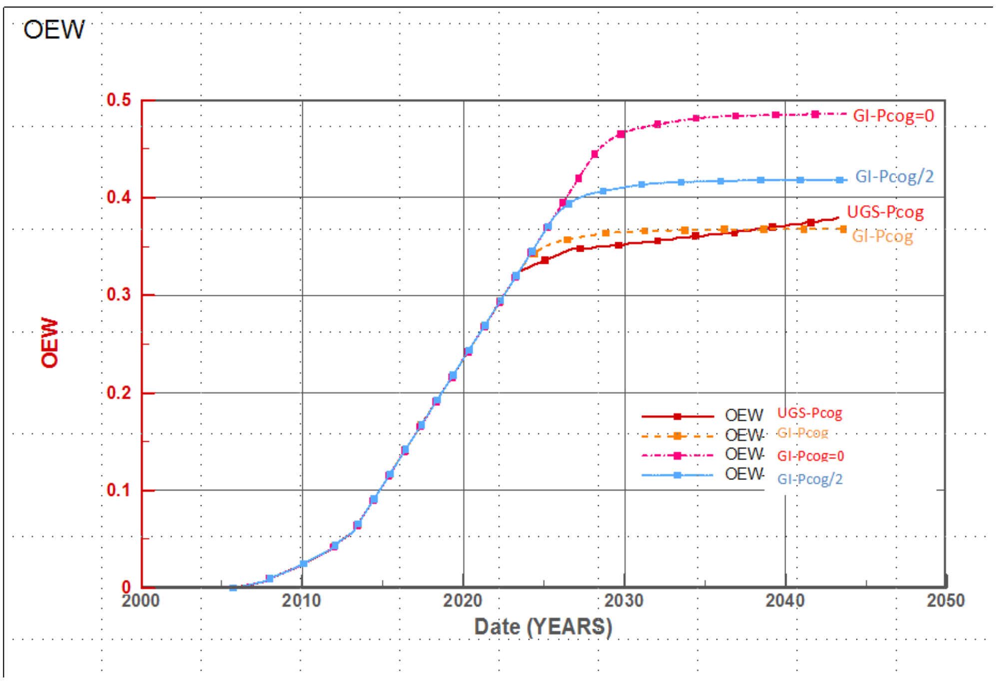

Figure 6 : Gas injection (GI) & UGS schemes, high fractured case: Oil recovery for different oil-gas capillary pressures (reference Pcog, Pcog/2 and Pcog=0).

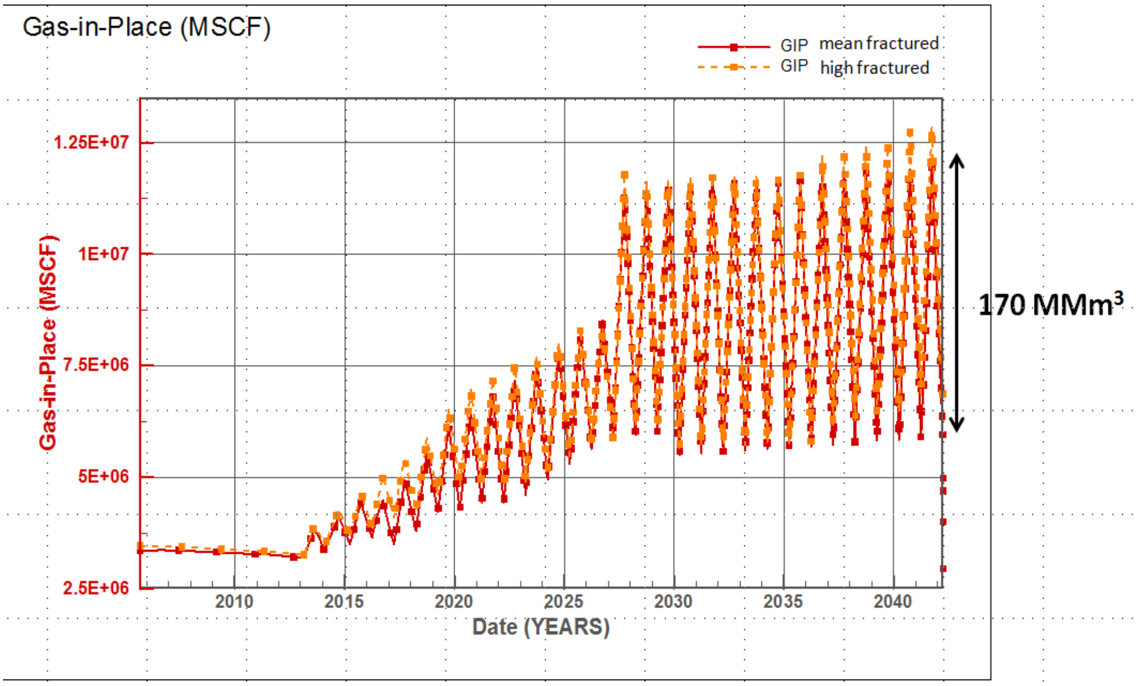

Figure 7 : UGS scheme: Gas-In-Place for the mean and high fractured cases.

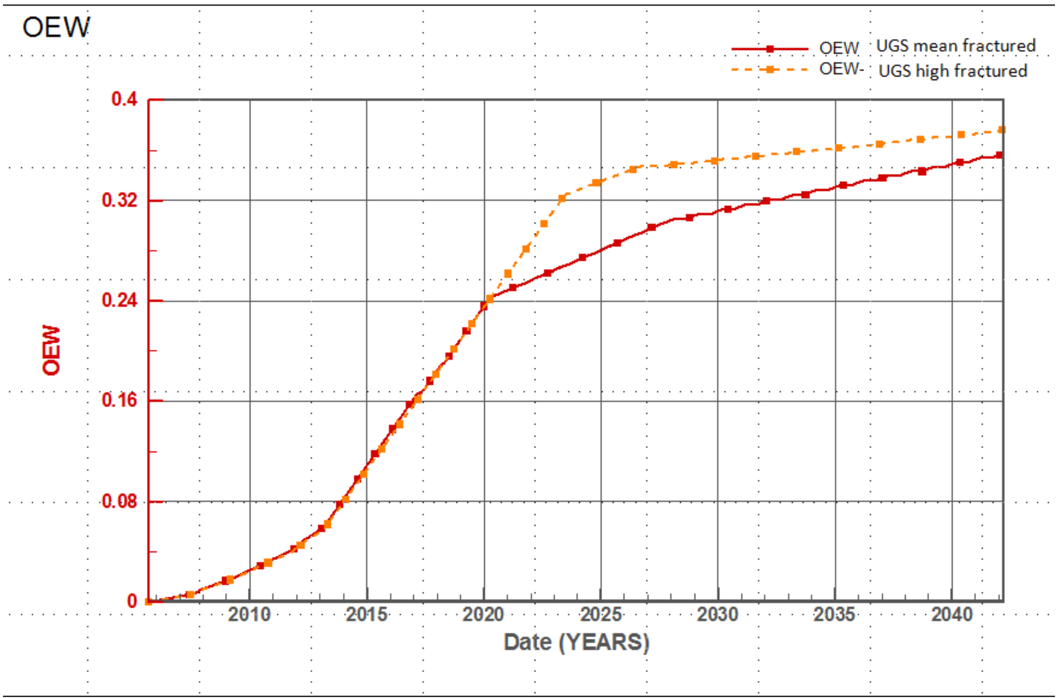

Figure 8 : UGS scheme: oil recovery for the mean and high fractured cases.

Conclusions

A joined Storengy-GSPC feasibility study was performed in order to determine whether the depleted oil field could be converted into an UGS, while maintaining the oil production, without degrading the oil recovery. This study has involved a structural analysis, a petrophysical analysis , an in-depth basic reservoir engineering analysis and a 3D dual porosity reservoir modeling.

At the present stage, the field seems to be a viable structure to be converted into an UGS. Indeed, the presence of an effective trap is confirmed by the presence of the oil accumulation. However, uncertainties remain concerning its southern extension, as well as its connected oil volume.

A comparison with usual EOR techniques, i.e. continuous water or gas injection, has been performed. The main objective was to identify the key controlling parameters of the production behavior and UGS feasibility, and to estimate the possible size of the UGS, taking into account uncertainties on the matrix and fracture properties.

It was shown that the production behavior strongly depends on several key parameters that remain uncertain, such as the fracture density, the capillary pressure, the relative permeability, and the rock wettability. The rock wettability strongly impacts the oil recovery, especially in the case of water injection (recovery variations between 8-40% depending on wettability). On the other hand, it was shown that oil-gas capillary pressure uncertainties have less impact on oil recovery in the cases of UGS and/or continuous gas injection (recovery variations between 35-42%) solutions. Gas injection and a fortiori UGS development appear to be the less risky solution in regard to the rock wettability uncertainties. Moreover the current four active oil producer wells of the field could be already well positioned to turn the operations towards a combined UGS/EOR mode without drilling new wells.

It was also shown that, compared with a continuous gas injection scheme, UGS performs a better oil recovery solution in the early period (7 years) as well as on the long-term period (20 years i.e. time at which gas will break at well oil producers in the case of a continuous gas injection).

Recommendations to secure the project and to help final investment decision were the following:

- Pressure measurements acquisition at existing wells (or additional control wells) to infer the field extension and connectivity in the southern area.
- Laboratory measurements on the available cores in order to narrow the uncertainties on key petrophysical parameters, e.g. rock wettability.
- Production logging measures (PLT) to identify the productive intervals and to better characterize fracture flow properties.

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