INJECTION OF NATURAL GAS INTO RESERVOIRS: A FEASIBLE SOLUTION TO GAS FLARING IN NIGERIA

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ABSTRACT

This paper presents the results of a case study on the feasibility of injecting produced natural gas into depleted oil reservoirs as a feasible solution to flaring of gas, in Nigeria. We present the basic and easily indentifiable reservoir and fluid factors that determine suitability of a reservoir in the Niger Delta basin, as an underground storage unit. The results obtained show that injecting gas for storage as a solution to flaring, is feasible in a substantial number of reservoirs in the Niger Delta.

Keywords: Natural Gas, Depleted Oil Reservoirs, Reservoir and Fluid Factors, Gas Storage, Niger Delta

INTRODUCTION

A sustainable environment is a major millennium development goal of many countries, especially, Nigeria. Climate change is considered a major challenge facing the global environment. Nigeria is abundantly blessed with natural gas, a clean carbon fuel that has not been properly monetized. Table 1 shows the conventional natural gas reserves – proven and probable, of Nigeria by 2011 (1). However, for over 50 years, the produced associated natural gas has been flared, with serious socio-economic and environmental challenges. By 2002, about 2 bcf of produced associated gas was flared daily (2). At present, two major challenges face the petroleum industry in Nigeria, namely: the achievement of a complete gas flare down, and the emergence of a separate gas industry that will properly utilize the enormous volumes of natural gas in Nigeria.

Table 1. Gas Reserves in Nigeria (1)

Category	*Reserves (Tcf)*
Associated Gas (AG)	105.00
Non-associated Gas (NAG)	120.00
Total	225.00

TCF – Trillion Cubic Feet = 1,000,000,000,000 scf

To minimize the negative socio-economic and environmental impacts of gas flaring, the Federal Government had set a target date of December 31st, 2008, for a complete gas flare down. This was not achieved. With a commitment to the climate change conferences in Copenhagen, Holland, 2010, and South Africa, 2011, the Federal Government is seeking a new date with the petroleum industry for a complete gas flare down. How can this be achieved? Various projects have been initiated for the utilization of produced associated gas, namely:

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1. LNG projects,
2. GTL Projects,
3. Gas to Power (IPPs [3]), and
4. The West African Gas Pipeline Project.

However, the petroleum industry is still flaring over 1.0 bcf of produced associated gas daily. When there is no gas gathering facility in place, the gas is most often flared. We posit a more effective management of gas reserves [3], and think that one solution to gas flaring, and positive impact to climate change, is the injection of produced excess natural gas into subsurface reservoirs, for the:

a. Storage of the produced associated gas for future use, and/or complimenting
b. Pressure enhancement operations to improve crude oil production.

Our produced associated gas is very valuable, with the following attributes:

a. Very rich in hydrocarbon liquids – natural gas liquids (NGLs),
b. Low in oxides of carbon, notably carbon dioxide,
c. Low in sulphur compounds, notably hydrogen sulphide,
d. Low in the inert gases – Nitrogen, etc., and
e. High Heating Value.

The continued flaring of this gas impacts negatively on the economy and the environment. The NGLs are very valuable feedstock to various projects/industries. A good example is ethane; a raw material for the petro-chemical industry. At present, the petro-chemical industry is Nigeria is not very functional because of shortage of this feedstock. Why should this happen?

The primary objective of this study was the feasibility of injecting gas for storage into subsurface reservoirs, as an interim solution to the flaring of gas. The storage of gas in underground reservoirs is a delicate process and must be monitored to ensure that most gas stored will be recovered. A good understanding of reservoir and fluid properties are necessary to identify candidates as underground storage containers for gas.

By injecting the gas into the crest of the candidate reservoirs, crude oil recoveries can be improved through pressure enhancement. Simultaneously, we create gas caps – gas storage, if they were none (Secondary Gas Caps).

STUDY METHODOLOGY

To determine suitable candidates for gas injection, we need to understand the geology of the reservoir, various screening criteria used in the past to determine gas injection suitability, review production data, extent of reservoir depletion, etc., before gas injection is implemented. The methodology for the sudy involve undertaking

1. Review of historical studies & previous gas injection projects,
2. Developing a screening guide, and
3. Testing gas injection feasibility in a candidate reservoir in the Niger Delta basin of Nigeria, using an updated history matched dynamic model (for a 5 year period and continous injection).

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Screening Criteria for Reservoirs

From a review of various gas injection projects, namely in:

1. The Gannet A Field in UK,
2. The Rabi-kounga Field in Garbon,
3. The Biram Delta Fields in Malaysia, and
4. Some Fields in Nigeria.

The factors that control response of oil production to gas injection and those necessary for gas storage include the following:

a. Dip of the Reservoir(8),
b. Reservoir Geometry,
c. Primary Drive Mechanism,
d. Good Reservoir Continuity,
e. Relative Homogeneity,
f. Presence of Gas Cap,
g. Pressure Decline/Reservoir Depletion,
h. Large Reservoir Size,
i. Closure(7), and
j. Fault / Seal Intergrity.

From all these factors above, the screening criteria were developed and are shown below. Basically we are looking for suitable candidate reservoirs that meet the following criteria:

I. Oil rim reservoirs with sizeable gas caps
II. Pressure Decline/Reservoir Depletion
III. OIIP > 30MMbbls
IV. Dip Angle>2.5^{o}
V. Permeability distribution (Reservoir homogeneity classification).

More emphasis was placed on the first and second criteria above because they are the most important criteria. A brief explanation of the importance of the first two criteria is given below along with some information on the last criterion.

Oil Rim Reservoir with Gas Cap

This screening criterion is very important because the gas must be injected into the gas cap. This is to take advantage of the increased benefits from crestal gas injection such as less injector well density, better conformance efficiency and gravity drainage drive. The requirement of a gas cap will also lead to lower initial injector pressures since there will be no need for the high pressures necessary to form an initial gas saturation around the injector's well bore. Injecting into the gas cap also ensures we can recover most of the gas later when there's an avenue to transport or utilise the gas. Injecting elsewhere might lead to a loss of some of the injected gas since we cannot predict to what location up dip the gas will migrate to (gravity segregation). To access the new location of the stored gas might entail drilling a new well, which may not be economically feasible.

Pressure Decline/Reservoir Depletion

This screening criterion is very important because from case studies and field experiences generally, gas injection leads to negative oil recovery in reservoirs with low pressure decline (strong aquifer support). This has been attributed to re-saturation losses as oil is driven into the aquifer and becomes trapped residual oil that is not producible. Reservoirs with strong pressure decline are good candidates for gas injection/storage because such reservoirs undergo rapid depletion providing more space for storing gas and cumulative gas injected would be higher for such reservoirs before it's pressure reaches its initial pressure, P_i. For the purpose of this study, over pressuring the reservoir is not desired from an operational and reservoir management point of view. Reservoirs with weak or poor aquifer support are the best candidates for produced associated gas (re-) injection and the injected gas can also act as a sort of pressure enhancement for such reservoirs. Knowing the pressure decline rate of a reservoir gives an indication of the strength of it's aquifer (preferably weak aquifer support).

Reservoir Heterogeneity Classification

It is generally found that for relatively homogenous reservoirs, there is less tendency for gas to bypass oil in flooding operations. If a reservoir is relatively heterogeneous and contains high perm streaks, injected gas tends to flood out areas preferentially leading to uneven flooding of the reservoir. This is known to occur even in cases where there is favorable mobility ratio. This characteristic of the rock affects the efficiency of flooding operations (water injection or gas injection). There are two ways to classify rocks as being either relatively homogeneous or relatively heterogeneous in terms of vertical permeability. Prominent among the methods used is the Dysktra-Parsons coefficient, which is a statistical coefficient, used to represent the variation of the vertical permeability in a rock sample. Mathematically, it is given as:

$$V_{dp} = (K_{50} - K_{84.1}) / K_{50} \; \ldots\ldots\; 1$$

Where V_{dp} is Dysktra-Parsons coefficient, K_{50} is the mean of the permeability distribution and $K_{84.1}$ is the permeability at 84.1% (% height with greater permeabilty) of the cumulative sample permeability distribution.

As V_{dp} approaches zero, the rock becomes more relatively homogeneous and vice- versa. It should be noted that no reservoir rock is truly homogeneous hence the word 'relatively homogeneous'. Dysktra – Parsons method is also called permeability ordering technique. Another method that is used is Lorenz coefficient.

SIMULATION STUDY AND RESULTS

The screening criteria were applied to reservoirs in six (6) fields from an area of operation in the Niger Delta region of Nigeria. After screening, a candidate reservoir was obtained which we shall call D4.1 (not real designation for confidentiality issues), with data shown in Table 2. Figure 1 shows the pressure decline and cumulative oil production for the candidate reservoir.

A dynamic model was obtained for the reservoir and it's history match was updated using the reservoir's production history. This model was built using a reservoir simulator software to represent as close as possible, the subsurface conditions including the uncertainities such as the faults, flow barriers, layering (heterogeneity) etc. Figure 2 shows the initial reservoir phase saturation before the start of gas injection.

An injector well was placed at the crest of the structure, a lift table was assigned to it and gas injection feasibility was determined by runing various gas injection scenarios among which included different gas injection rates and GOR (gas – oil ratio) controls. The following results were obtained:

1. Cumulative gas volume that could be injected into the candidate reservoir was 15.8Bscf of produced associated gas,
2. Recovery factor of the injected gas when back produced is high, typically greater than 70%,
3. Gas injection led to effective pressure support and improved oil recovery, due to the steeply dipping reservoir with limited aquifer support,
4. The maximum gas injection rate is 11MMscf/d for 3yrs, but must be reduced to 4MMscf/d over the next 2yrs or 8MMscf/d for 5 yrs before the reservoir pressure reaches it's initial value Pi.

Figures 4 to 7 show the results of the simulation runs on the candidate reservoir. Figure 4 clearly shows:

4. Feasibility of Storage of Gas in the candidate reservoir
5. Improved oil recovery by the present position of the gas-oil contact, compared to Figure 1.

CONCLUSIONS

From the simulation studies on the feasibility of gas storage in reservoirs in the Niger Delta basin of Nigeria, we posit that:

1. Gas injection for storage is feasible in reservoirs in the Niger Delta basin since a substantial number of reservoirs are depleted and already have gas caps.
2. Because of the complex faulting system in the basin, gas injection should be done only up to the initial pressure Pi to avoid problems with fault/seal intergrity.
3. Gas injection for storage is a best practice, especially, to the environment. Sustainable environment is now, a global challenge, and a major millennium development goal for Nigeria.
4. At present, gas injection as an improved oil recovery process has little scope in the Niger Delta basin, because a good number of the producing reservoirs have strong pressure support i.e. strongly pressured – strong aquifer systems.
5. For a greater corporate social responsibility, the elimination of gas flaring should bring about better acceptance of the producing E & P companies in the oil producing communities.
6. At present, most Gas to Power projects [3], are not working because of the shortage of gas. The stored gas can be safely produced in the future for other Gas to Products projects.
7. Crude oils with lower than 25^{o} API gravity are increasingly being discovered and targeted for development in Nigeria [6]. The crude oil containers – the reservoirs, have weak aquifer support, and thus, are very good candidates for improved oil recovery using gas.
8. Gas injection for storage will eliminate the penalties paid as a result of routine gas flaring.

In light of these facts, gas injection is a feasible solution to gas flaring and should be implemented especially in areas of operation where there's no gas gathering system.

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Nomenclature

BSW - Basic Sediments & Water

GIIP - Gas Initially In Place

G_p - Gas Produced

N_p - Oil Produced

STOIIP- Stock Tank Oil Initially In Place

UR - Ultimate Recovery

Table 2. Reservoir data for the candidate reservoir (D4.1)

Reservoir Summary	*Reservoir Name: D4.1*
Volumetric Data (Mmstb, Mmscf) Stoiip= 46 Mmstb Oil Ur= 29.0 Mmstb N_p = 11.8 Mmstb (31/12/2005) Giip= 46.4 Mmscf (Associated Gas) G_p = 7.7 Mmscf	Reservoir Development Reserves = 17.2 Drainage Point = 2 Existing (Not Perf =3, Prod. =2, Total Thru Reservoir =5) Repairs = Nil Water Injection =Nil Gas Injection =Nil Dump Flood =Nil
Reservoir And Fluid Data (Ranges) Initial Pressure = 4093 Psia Bubble Point Pressure= 2664 Psia Tank Oil Specific Gravity = 0.84 Live Oil Visc. = 0.47 Cp (Reservoir Condition) Proven Oil Column = 286 Ftss R_{si} (Ranges) = 796 Scf/Stb B_{oi} = 1.509 Rbbls/Stb Av. Porosity = 0.25 Av. S_w = 0.21 Av. Permeability, = 1500 Md Api (Oil) = 35.3 ^{O}	Rates Oil Prod. Before Shut-In = 2,105 Bopd Bsw = 2 % Current Liquid Production Rate = 2150 Bbl/D Gor = 1130 Scf/Stb (31/10/2005) Predominant Drive = Aquifer

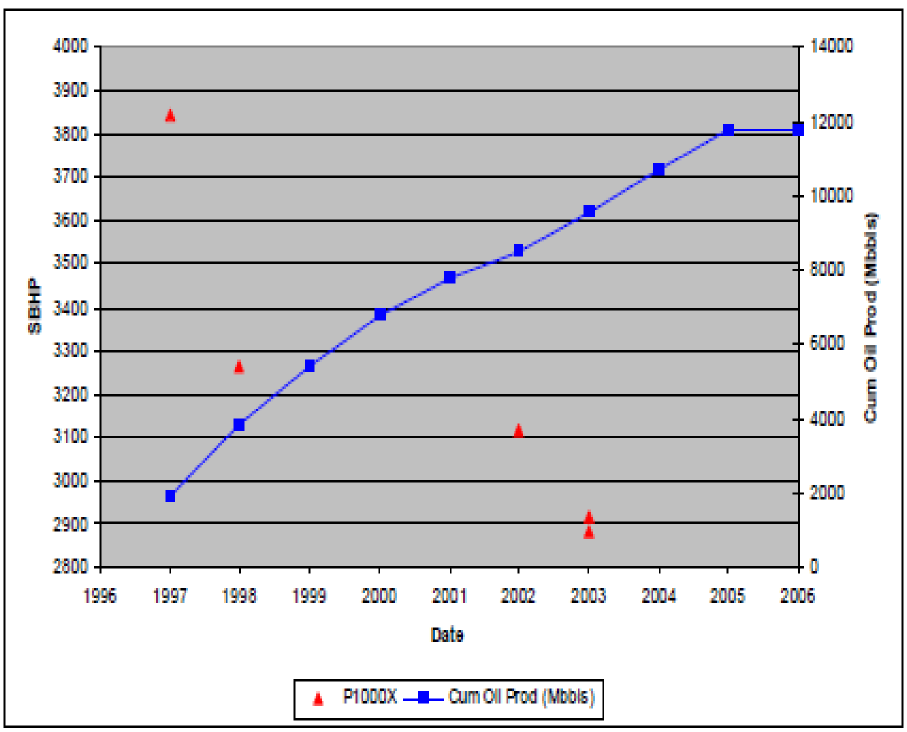


Figure 1. Pressure decline plot for the candidate reservoir

- Shows high pressure decline for cummulative oil production from the candidate reservoir.

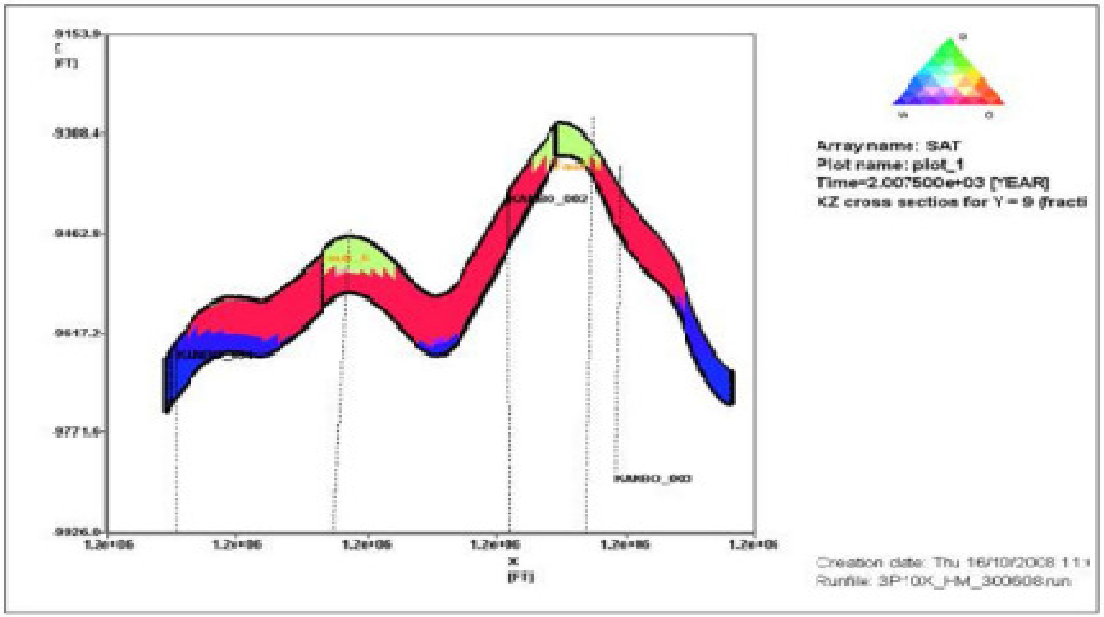
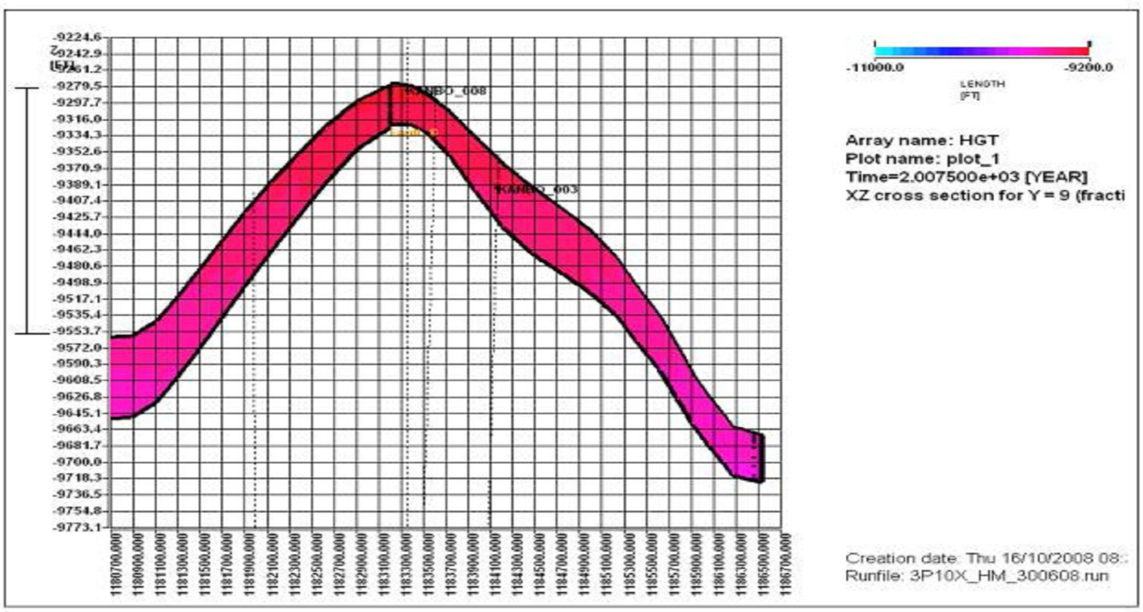


Figure 2. Dynamic model showing initial reservoir saturation before the start of gas injection



Dip angle (crest to spill point) – 7.87°

Closure is about 274.2ft

Figure 3. Dip of a Section of the candidate reservoir model

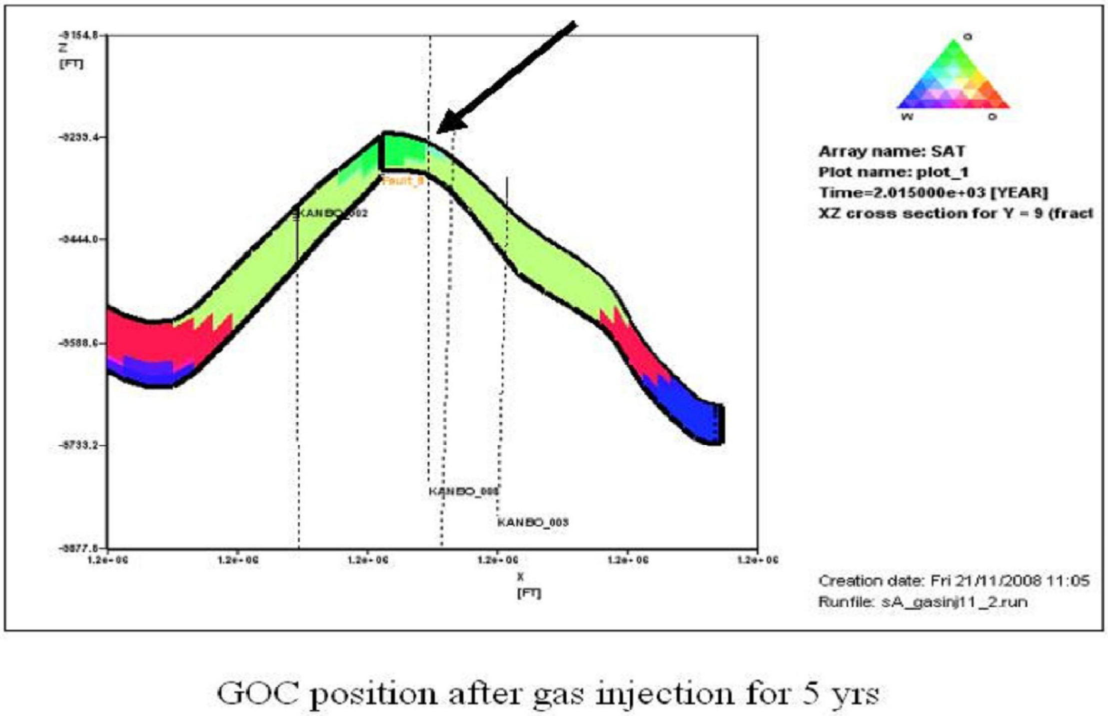


Figure 4. A plot showing gas – oil contact position after injecting gas for 5 years

- Notice gas has pushed GOC (gas-oil contact) showing good sweep and improved oil recovery.
- The figure also shows good gas storage capacity of the reservoir i.e. good closure.

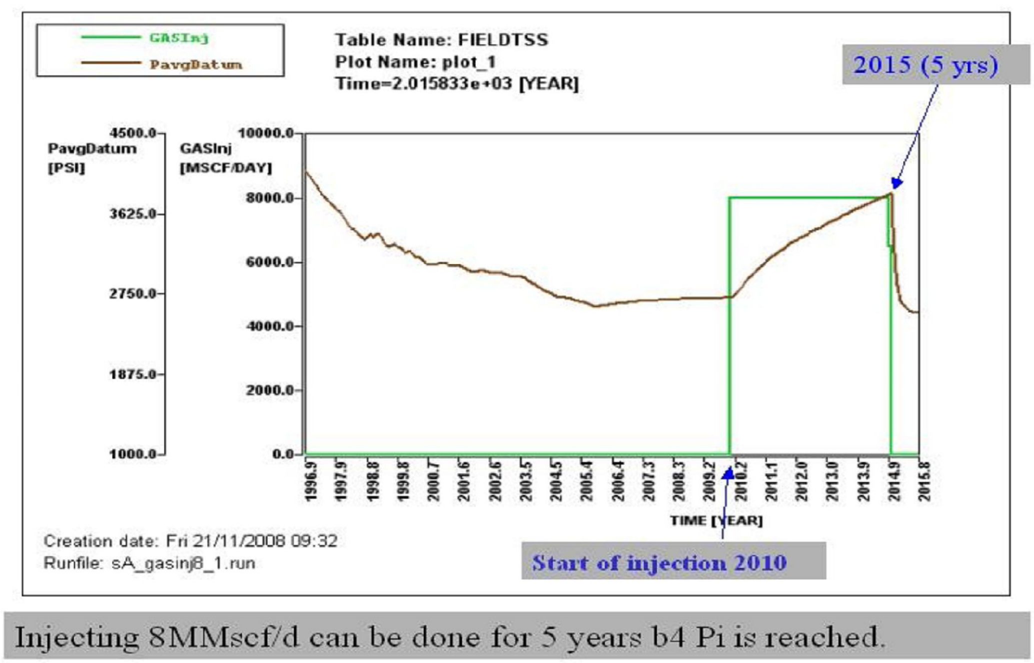


Figure 5. Pressure profile with an injection rate of 8MMscf/d

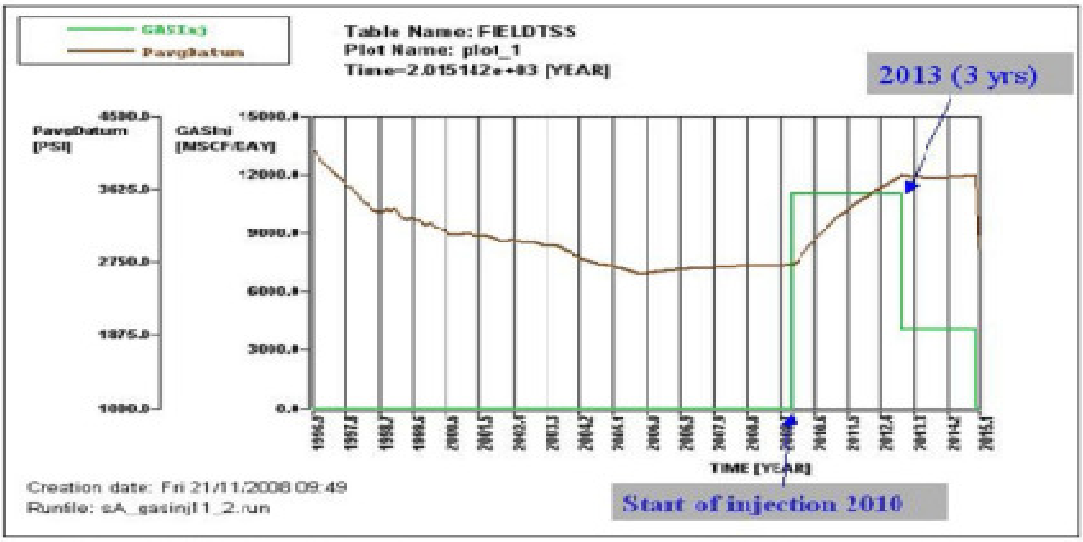
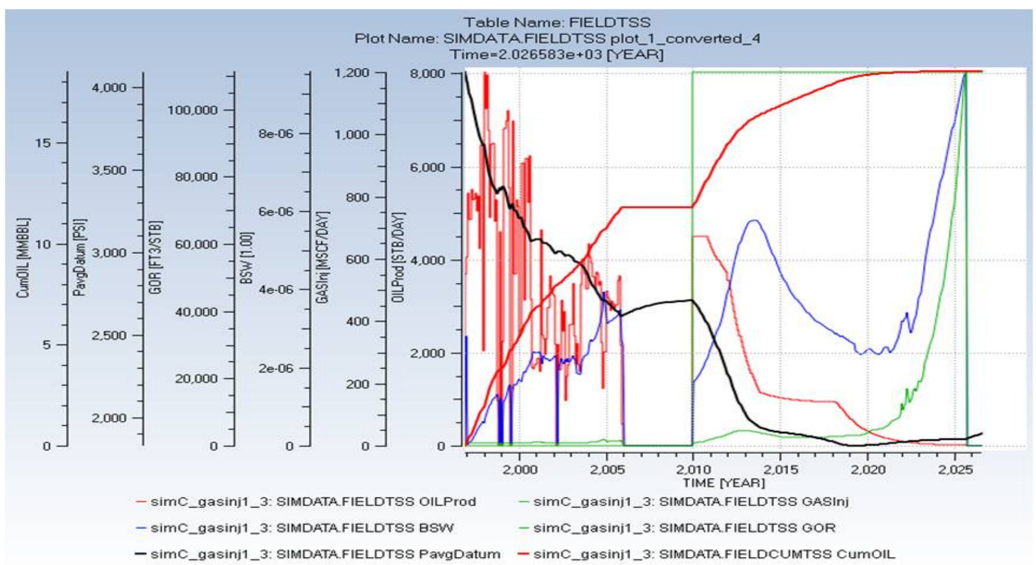


Figure 6. Injecting 11MMscf/d of gas can be done for 3 years after which the gas injection rate must be reduced to 4MMscf/d so that Pi is not exceeded



Production profile for 1.2MMSCF/d @ 3000stb/day well2 // 1500stb/day well3

Figure 7. Production profile for continous gas injection (1.2MMscf/d injection rate)

- Production stops due to lift die out. (loss of lift due to excessive production of gas)
- Additional oil recovery due to gas injection (pressure enhancement).