Petroleum & Coal
ISSN 1337-702

Available online at www.vurup.sk/petroleum-coal
Petroleum & Coal 55 (2) 137-147, 2013

CONVERSION OF DEPLETED OIL RESERVOIRS FOR UNDERGROUND NATURAL GAS STORAGE

C. I. C. Anyadiegwu[1], E. E. Anyanwu[2]

[1]Department of Petroleum Engineering, Federal University of Technology, Owerri. Nigeria *drcicanyadiegwu@yahoo.com*; *[2]Department of Mechanical Engineering, Federal University of Technology, Owerri, Nigeria*

Received March 7, 2013, Accepted June 14, 2013

ABSTRACT

The storage of natural gas in depleted oil reservoir was examined with Z-16RS, a depleted oil reservoir located onshore, South-East, Nigeria. The geological information and the production history of the reservoir were gathered, which aided in the computation of the storage capacity at any given pressure of the storage vessel. The plot of well flowing pressure (Pwf) against flow rate (Q), shows the deliverability of the reservoir at various pressures. The study which was primarily, for checking the suitability of the reservoir for underground gas storage shows that the reservoir is fit for such purpose. Two basic requirements in underground storage of natural gas which are: verification of inventory and assurance of deliverability were evaluated for the reservoir. The storage capacity of the reservoir was estimated and the deliverability of the reservoir was also evaluated. The results of the estimated properties show that Z-16RS is a good candidate for conversion into storage reservoir.

Keywords: Natural gas; depleted reservoir; storage; underground; deliverability; injection; pressure; facility.

1. INTRODUCTION

Underground natural gas storage acts as the swing capacity due to the seasonal variations in demand. Natural gas is injected into the underground gas reservoirs for the purpose of storage for future use, during the second and third quarters when supply exceeds demand [1].

This injected gas is withdrawn from these reservoirs during the first and fourth quarters when demand is at the peak and exceeds supply.

There are 3 types of reservoirs commonly used for underground gas storage 1) depleted oil/ gas reservoir 2) aquifer and 3) salt cavern, each of the storage reservoirs has very specific producing parameters [2].

1.1. Storage in Depleted Oil Reservoirs

This is an underground gas storage that occurs in porous and high deliverability depleted reservoirs, which are close to the consumption centres. The conversion of the oil fields from the production to storage duty takes advantage of the existing wells, gathering systems and pipeline connections. Depleted oil reservoirs are used for underground gas storage due to their wide availability and well known geology. The requirements for each of the reservoirs vary since no two reservoirs are the same, typically these types of reservoirs require 50% base gas (ie equal amount of working gas) and one cycle per season [3]. Figure 1 is a representation of the 3 basic requirements in underground storage of natural gas.

1. Verification of inventory
2. Retention against migration
3. Assurance of deliverability

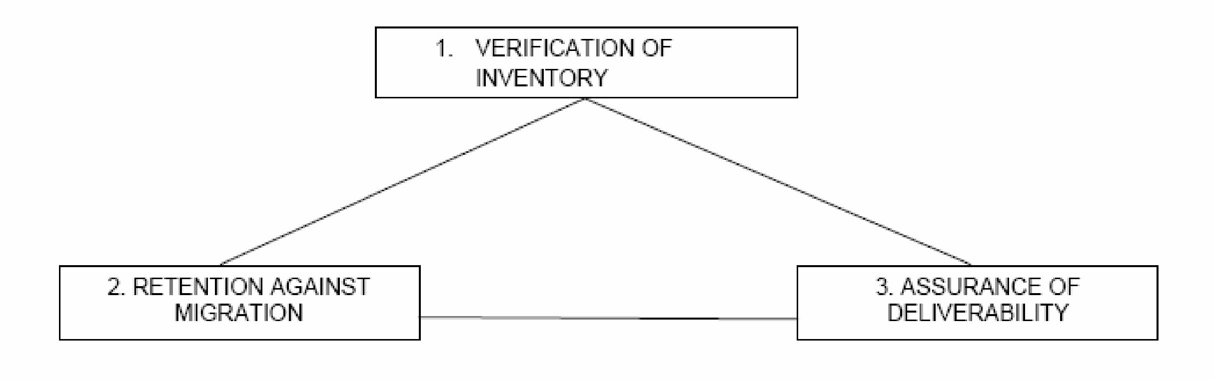


Fig 1. The three basic requirements in underground gas storage [4].

2. Procedures for choosing a candidate well for undergorund

Fig 2 shows a process flow diagram for the conversion of depleted oil/gas reservoir for natural gas storage. The following steps are followed in designing the storage facility.

- Gathering of geological and engineering information
- Assessing the mechanical condition of the well
- Determining the working storage content (storage capacity) of the reservoir
- Consider compression, field lines, and conditioning of the gas

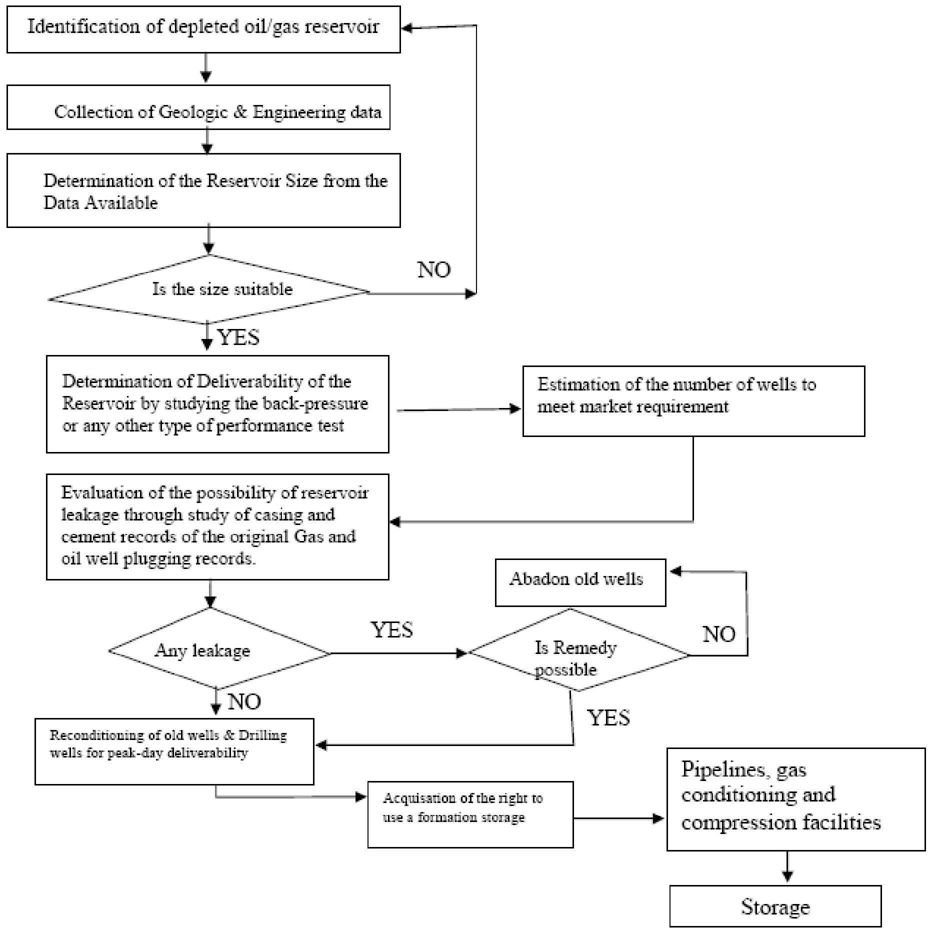


Fig 2. Flow Chart for the Conversion of a Depleted Gas or Oil Reservoir for Natural Gas Storage [2].

In order to find the working storage content of the reservoir, range of pressures used must be selected. The upper pressure selected is based upon the information available, particularly the mechanical condition of the well. The pressure range also has much to do with the flow capacity of the well.

According to Katz and Tek [4] the most essential features of the underground storage facility to be determined by equation (models) are

- Storage capacity (verification of inventory)
- Quantity to be injected at different pressures
- Storage retention against migration and determination of the amount of leakage
- Assurance of deliverability

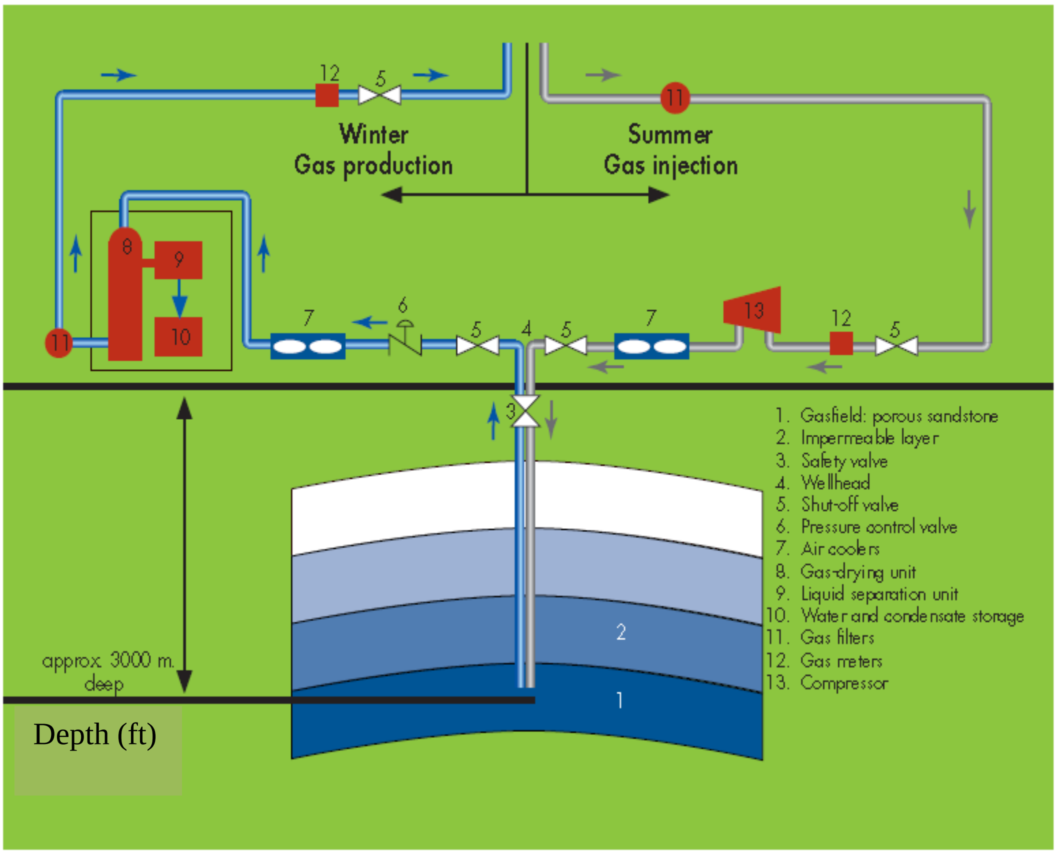
The storage container is a porous solid with a cap rock overhead to prevent vertical migration. Water in the storage zone underlies all or part of the gas-filled sand. Wells designated I/W (Injection and Withdrawal) are completed in the storage zone.

Depleted gas reservoirs are prime candidates for conversion to storage. The size of the reservoir is determined by calculations from geological data or from the oil production reservoir pressures. In considering a depleted oil fields, it should be recognized that the gas withdrawal take about 120days in a given year. This requires more wells than used during oil production, and enlarged gathering and injection pipeline system from the well to the central station [5].

A delivery system can be installed to cover the market demand for the year. Some flexibility is needed, since variation in weather causes varying demands. Storage field pipelines may require some period of reduced load in summer for testing

Natural gas is injected into the porous sandstone through the surface facilities during the period when the demand is low and withdrawn for use during the period when the demand for gas is high. For temperate countries the periods correspond to summer and winter periods respectively.

A delivery system is installed to cover the market demand for the year. The typical injection and withdrawal trend in an oil-depleted underground gas storage reservoir is shown in the figure 2 below.



Schematic representation of natural gas storage.

Fig. 2 Schematic of Natural Gas Storage [1]

2.1 Determination of reservoir characteristics

2.1.1 Inventory Verification (Estimation of Storage Capacity)

To determine the volume of gas to be injected at different pressures of the storage reservoir, pressure is varied for fifteen different cases. At each pressure variation, new reservoir parameters, B_o, B_g, R_s and R_p were obtained. Table of values was generated for the plot of gas versus reservoir pressure which represents the volume to be injected at different pressures

The steps for the reservoir engineering calculation of the gas storage capacity of the reservoirs are as determined below. The total cumulative fluid production from depleted crude oil reservoir is given by the sum of the produced oil, dissolved gas, free gas and produced water. This is represented mathematically as:

Total cumulative production = produced oil + dissolved gas + free gas + produced water (2.1)

The produced oil and dissolved gas are assumed to be produced together as a component given by:

Produced oil + dissolved gas = $N_p B_o$ (2.2)

The other terms of the RHS of eq 2.1 are defined as

Free gas = $N_p (R_{p-} R_s) B_{gi}$ (2.3)

Produced water = $W_p B_w$ (2.4)

Substituting eqs 2.2, 2.3 and 2.4 into eq 2.1 gives the total cumulative fluid (oil + gas + water) production as:

P_{CUM} = $N_p B_o + N_p (R_{p-} R_s) B_{gi} + W_p B_w$ (2.5)

The total cumulative fluid production is in units of barrels of fluid (bbl) and may be converted to standard cubic feet (scf) using eq 2.6

$1bbl = 5.615scf$ (2.6)

For the purpose of underground natural gas storage, the depleted oil/gas reservoir must be reconditioned to contain a volume of gas equal to the volume of total cumulative fluid production [6]. This is the amount of natural gas to be injected into the reservoir for storage.

Therefore, the volume of gas to be injected in units of standard cubic feet (scf) into depleted reservoir to fill the space created from withdrawal of oil is given by:

Volume of gas to be injected = $V_{inj} B_{gi}$ (2.7)

This represents the cumulative production of natural gas from the reservoir. Equating volume of gas injected to total cumulative fluid production to obtain

$$V_{inj} B_{gi} (scf) = 5.615\,(N_p B_o + N_p (R_{p-} R_s) B_{gi} + W_p B_w) \quad (2.8)$$

Dividing through by B_{gi}

$$V_{inj} (scf) = 5.615\,(N_p B_o / B_{gi} + N_p (R_{p-} R_s) + W_p B_w / B_{gi}) \quad (2.9)$$

Storage capacity of the reservoir at a given pressure represents the amount of gas that can be injected into the storage reservoir at that pressure. It helps in the analysis of reservoir storage economics. It also guides the operator to know when the pressure of the storage vessel is at its maximum capacity for inventory verification. This helps in proper monitoring of injection and withdrawal program.

In estimating the storage capacity of the reservoir, reservoir pressure in psig is converted to pressure in psia using eq 2.10

$$P(psia) = P(psig) + 14.7 \quad (2.10)$$

The reservoir temperature is also converted to degrees Rankine (^{0}R) as in eq 2.11

$$ {}^0R = {}^0F + 460 \tag{2.11} $$

According to Katz and Lee [7] for the determination of gas compressibility factor, Z, of the natural gas in storage, the pseudo-reduced properties of the gas are used.

The pseudo-reduced properties are pseudo-reduced temperature and pseudo-reduced pressure. The values of Z for natural gas mixtures have been experimentally correlated as functions of pressure, temperature and composition. This correlation is based on the well known Theorem of Corresponding States which states that the ratio of the volume of a particular substance to its volume at its critical point is the same for all substances at the same ratio of absolute pressure to critical pressure, and absolute temperature to critical temperature. This theorem is not completely true but may satisfactorily be applied to compounds of similar molecular structure such as the light paraffins and natural gases. In preparing a correlation for hydrocarbon mixtures, the ratios of actual pressure and temperature to the modal average critical or pseudo-critical pressure, (P_{pc}) and pseudo-critical temperature, (T_{pc}) have been used. These ratios are called pseudo-reduced pressures, (P_{pr}) and pseudo-reduced temperatures, (T_{pr}) [8].

The pseudo-critical pressure and temperature are evaluated using eqs 2.12 and 2.13 resp.

$$ P_{pc} = 709.604 - 58.718 * SG \tag{2.12} $$

$$ T_{pc} = 170.491 - 307.344 * SG \tag{2.13} $$

Accordingly, the pseudo-reduced pressure and temperature are determined from eqs 2.14 and 2.15 respectively

$$ P_{pr} = P / P_{pc} \tag{2.14} $$

$$ T_{pr} = T / T_{pc} \tag{2.15} $$

The following equations were used to estimate B_g, B_o and R_s. The gas formation volume factor is given by eq 2.16 and the oil formation volume factor is given by eq 2.17.

The gas formation volume factor, B_g, is estimated from eq 2.16

$$ B_g = 0.02827\frac{zT}{p} \tag{2.16} $$

The oil formation volume factor, B_o, is estimated from eq 2.17 [9].

$$ B_o = 1.0 + C_1R_s + (T - 520)\left(\frac{API}{\gamma_{gs}}\right)[C_2 + C_3R_s] \tag{2.17} $$

The gas-oil-ratio, R_s, is estimated from eqn 2.18 [10].

$$ R_s = SG[(P/18.2 + 1.4)10^x]^{1.2048} \tag{2.18} $$

where SG = gas specific gravity, γ_{gs} = solution-gas specific gravity

With $x = 0.0125API - 0.00091(T - 460)$ (2.19)

There is no water production, ie $W_p = 0$, eq 2.9 becomes:

$$ V_{inj} = 5.615\ [N_pB_o/B_{gi} + N_p(R_p - R_s)] \tag{2.20} $$

This is the volume of gas required to replace the produced oil. It is also called the working gas capacity.

Eq 2.20 which is the equation for estimating working gas capacity is converted to the equation for total storage capacity by replacing the cumulative production term, N_p with stock tank oil in place, N.

Volume of gas required to replace the entire producible oil in the reservoir which is the total storage capacity is given below:

$$ V_{total} = 5.615\ N[B_o/B_{gi} + (R_p - R_s)] \tag{2.21} $$

As stated in this section, the storage capacities at various pressures represent the volume of gas to be injected into the storage reservoir at the various pressures. It guides the operator of the gas storage facility in choosing the initial injection pressure.

A Microsoft Visual Basic Program was developed using eq 2.20, and was used to obtain the volume of gas injected into the reservoirs at various pressures and presented in a table which was used to make a plot of volume of gas injected against Reservoir pressure.

2.1.2 Performance and Deliverability of Reservoir

In evaluating the performance of a storage reservoir, a deliverability test (back pressure test) is carried out on the reservoir for the prediction of well flow rate against any pipeline back pressure.

It has been observed that a plot of $P_R^2 - P_{WF}^2$ (difference of the squares of reservoir pressure and well flowing pressure) versus Q_{sc}, (flow rate at standard condition) yields a straight line on logarithm plot, which represents the reservoir performance curve.

The straight line relationship for a particular well applies throughout the lifetime of the well, as long as the production remains in single phase (gas or liquid). The back-pressure (deliverability) equation as developed by Rawlins and Schellhardt [11] is expressed as:

$$Q_{sc} = C[\Delta P]^n \qquad (2.22)$$

Also given as:

$$Q_{sc} = C[P_R^2 - P_{WF}^2]^n \qquad (2.23)$$

C is the reservoir flow coefficient and n is the inverse of the slope of the curve.

By extending the performance curve, the absolute open flow, (AOF) is obtained. Although this AOF does not reflect reality, it does approximate the capacity of the well.

The slope of the plot of Log $(P_R^2 - P_{WF}^2)$ versus Log Q is computed and used to obtain the back-pressure exponent as:

$$n = 1/slope \qquad (2.\ 24)$$

Also the flow capacity at standard condition is given as:

$$Q_{sc} = C[P_R^2 - P_{WF}^2]^n \qquad (2.25)$$

At $P_{WF} = 0$, eq 2.25 reduces to:

$$Q_{sc} = C[P_R^2]^n \qquad (2.26)$$

But the reservoir flow coefficient, C is expressed as:

$$C = Q/[P_R^2 - P_{WF}^2]^n \text{ [11]}. \qquad (2.27)$$

According to Katz and Coats [12] flow tests on individual wells are employed for gas storage obtained as in gas production operations. From gas inventory and/or reservoir pressure measurements plus deliverability data, it is possible to predict the field flow at several stages of the storage cycle.

The performance of storage reservoirs become less predictable during high withdrawal rates due to pressure sinks which develop as a result of heterogeneities. Another problem of continuing interest relates to interference by water reaching the wellbore. The presence of water not only reduces the permeability to gas but also effectively cuts down the bottomhole pressure drawdown available for gas flow due to increased density of well fluid. For aquifers, water interference problems are likely to subside as the gas bubbles thickens with growth in stored gas. Each reservoir and set of wells must be tested to give assurance for future years with regard to which well will have water intrusion at a given stage of the withdrawal cycle. Deliverability of storage wells after several years of repetitive use decreases as a result of sandface contamination. For the purpose of this work, a duration of eight years of running the gas storage reservoir was assumed.

In gas storage reservoirs, injection pressures of approximately 0.55 psi/ft are often used, but pressures as high as 0.7 psi/ft have been used. In other words, an approximate injection rate can be estimated using the relationship below [12].

$$P_{inj} = I_{rate} / hk \tag{2.28}$$

A Microsoft Visual Basic Program was developed using eq 2.23, and was used to obtain the deliverabilities of the depleted reservoirs, Q (MMscf/d) at different well flowing pressures, P_{wf} (psig) and presented in a table which was used to make a plot of P_{wf} against Q.

3. Results

3.1. Estimation of Storage Capacity of Reservoir Z-16RS

The storage capacity of Z-16RS is evaluated below. From Table 3, the discovery pressure of this reservoir is 3000 pounds per square inch gauge (psig).

From eqs 2.10 and 2.11, Discovery pressure, P = 3000 psig = 3000 + 14.7 = 3014.7 psia and reservoir temperature, T = 200^0F = 200 + 460 = 660^0R

Table 3 Reservoir and Fluid Data for Reservoir Z-16RS

Parameter	value
Discovery pressure, P	3000 psig
Reservoir temperature, T	200^of
Stock tank oil initial in place, N	0.7714 MMstb
Cumulative oil produced, N_p	0.3857 MMstb
Initial oil formation volume factor, B_{oi}	1.319
Specific gravity, SG	0.9
Thickness, h	44 ft
Porosity, Ø	0.25
Initial oil water saturation	20 %
Density	8.141 lb/cu.ft
Well depth, D	9000 ft
Remaining gas in formation	4.43 Bscf
Oil API gravity	26^0 API
Solution-gas specific gravity	0.91

Substituting the appropriate values of data in eqs 2.12 to 2.15, the values of P_{pc}, T_{pc}, P_{pr} and T_{pr} are determined as indicated below:

P_{pc} = 709.604 – 58.718 * 0.9 = 656.8 psia

T_{pc} = 170.491+ 307.344 * 0.9 = 447.1^0R

P_{pr} = 3014.7 psia/656.8 psia = 4.59

T_{pr} = 660/447.1 = 1.48

Compressibility factor, Z is indicated in [13]. At pseudo-reduced pressure of 4.59 and pseudo-reduced temperature of 1.48 compressibility factor becomes, Z at (4.59; 1.48) = 0.78

At the pressure of 3000 psig, the cumulative oil production, N_p is 0.3857 MMstb. Substituting the values of Z, T and P into eq 2.16, we obtain: B_g = 0.02827*0.78*660/3000 = 0.004851; C_1, C_2 and C_3 are obtained from Table 3.2.

Table 3 Values for the Coefficient C_1, C_2 and C_3 [9]

Coefficient	API$\leq$30	API>30
C_1	$4.677\text{x}10^{-4}$	$4.670\text{x}10^{-4}$
C_2	$1.751\text{x}10^{-5}$	$1.100\text{x}10^{-5}$
C_3	$-1.811\text{x}10^{-8}$	$1.337\text{x}10^{-9}$

From eq 2.17, $B_o = 1.0 + 4.677*10^{-4}*633.95+(660 - 520)(26/0.91)(1.751*10^{-5} + (-1.811*10^{-8}*633.95)) = 1.319$ while from Table 3, API = 26 and T = 200^0f which is 660^0R

Substituting the values of API and T into eq 2.19; x = 0.143

From eq 2.18, $R_s = 0.9[(3000/18.2 + 1.4)10^{0.143}]^{1.2048} = 633.9512$ and R_p = 3180

Substituting the values of all the parameters in eq 2.20 gives:

$V_{inj} = 5.615 * 0.3857 * 10^6 [1.319/0.004851 + [3180 - 633.95]] = 6.1$ Bscf
The value of N_p is gotten from Table 3 as 0.3857 MMstb. N is the stock tank oil in place and it is given as 0.7714 MMstb in Table 3
From eq 2.21, $V_{total} = 5.615 * 0.7714 * 10^6 [1.319/0.004851 + [3180 - 633.95]] = 12.20$ Bscf
% storage volume = 6.1 Bscf/12.2 Bscf * 100 = 50%
From the calculation above, **Working gas capacity = 6.1 Bscf; Total storage capacity = 12.2 Bscf**

3.2 The volume of gas injected into reservoir Z-16RS at various pressures

At 3000 psig, the estimated values for gas formation volume factor, B_g, oil formation volume factor, B_o, gas-oil-ratio, R_s and R_p are 0.004851, 1.319, 633.95 and 3180 respectively. At 3000 psig, the cumulative oil production, N_p is 0.3857 MMstb. Therefore, the volume of gas that can be injected at this pressure is 6.1 Bscf as evaluated above.

At 2854 psig, similar calculations are performed to estimate B_g, B_o, R_s and R_p as follows:
From eqn 2.16, $B_g = 0.02827*0.78*660/2854 = 0.005099$
From eqn 2.18, $R_s = 0.9[(2854/18.2 + 1.4)10^{0.143}]^{1.2048} = 597.278$
From eqn 2.17, $B_o = 1.0 + 4.677*10^{-4}*597.278+(660 - 520)(26/0.9)(1.751*10^{-5} + (-1.811*10^{-8}*597.278)) = 1.3048$; $R_p = 3460$ and $N_p = 0.5957$ MMstb

From equation 2.20, the volume of gas that can be injected at 2854 psig is
$V_{inj} = 5.615 * 0.5957 *10^6 [1.305/0.005099 + (3460 - 597.278)] = 11.04$ Bscf

At 2769 psig, $N_p = 0.7043$ MMstb, $B_o = 1.296387$, $R_p = 3960$, $R_s = 576.1006$ and $B_g = 0.005256$, the volume of gas that can be injected is:
$V_{inj} = 5.615 * 0.704 [1.2964/0.005256 + (3960 - 576.1006)] = 15.56$ Bscf

The storage capacities at various pressures of Reservoir Z-16RS were determined using Microsoft Visual Basic Program. The volume of gas that can be injected at various reservoir pressures are presented in Table 4 which is used to obtain the plot of the storage capacities at various injection pressures as shown in Fig 3.

Table 4 Vol. of gas injected at various pressures of Reservoir Z-16RS

P (psig)	Np (MMstb)	B_g (scf/scf)	Bo (rb/stb)	Rs (scf/rb)	R_p (scf/rb)	Vinj (Bscf)
3000	0.385699	0.004851	1.319455	633.9512	3180	6.103024642
2854	0.595726	0.005099	1.304832	597.278	3460	10.96538814
2769	0.704363	0.005256	1.296387	576.1006	3960	15.55671766
2693	0.907035	0.005404	1.288882	557.2769	4940	26.21895271
2619	1.511843	0.005557	1.281614	539.0518	6020	55.53911222
2542	2.127159	0.005725	1.274097	520.1984	9310	127.0378934
2500	2.454853	0.005821	1.270015	509.9632	11840	191.0164923
2467	2.963669	0.005899	1.266819	501.9457	12080	238.6428146
2427	3.356545	0.005996	1.262955	492.2566	14760	337.2974746
2237	3.700801	0.006506	1.244782	446.6822	15440	423.1610534
2145	4.286732	0.006785	1.236093	424.8908	16900	560.7567656
2057	4.774711	0.007075	1.227852	404.2231	18760	724.5082584
1950	5.308994	0.007463	1.217927	379.3336	20030	908.6939062
1842	5.786465	0.007901	1.208021	354.4901	22880	1200.071872
1712	6.413535	0.008501	1.196252	324.9753	23000	1439.790901
1042	6.80748	0.013967	1.138724	180.7019	23140	2535.641012

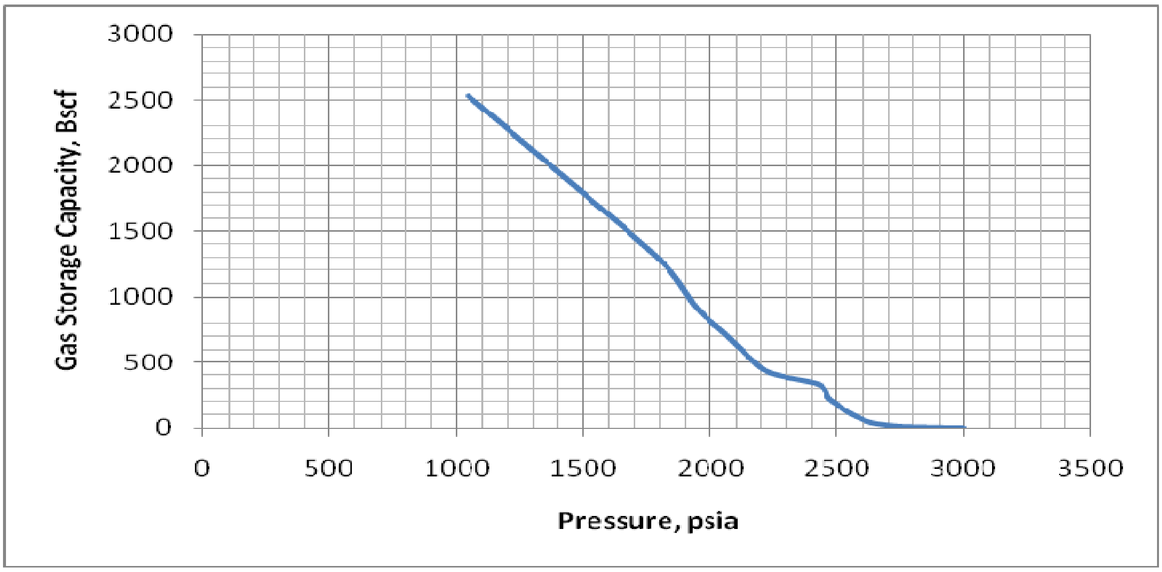


Fig 3 Volume of gas to be injected into reservoir Z-16RS at various pressures

Evaluation of the Deliverability of Reservoir Z-16RS at Given Well Flowing Pressure

To evaluate the performance of reservoir Z-16RS, the performance history was generated from the production data given in Appendix A.4 of Anyadiegwu (2012) [2] and the slope of the performance curve;

Log (P_R^2 – P_{WF}^2) versus Log Q shown in Fig 3.3 is obtained as 0.92

From equation 3.24; n = 1.000 / 0.92 = 1.087;From equation 2.28, C = 0.0340

Then from equation 2.23, Q_{sc} = 16635.19 MMscf/yr = 45.576 MMscf/d which is the AOF

Values of Q, P_R and P_{WF} were chosen from the Appendix A.6 at 8th year of operating the storage vessel as stated by Anyadiegwu, (2012) [2] and substituted into eq 2.27.

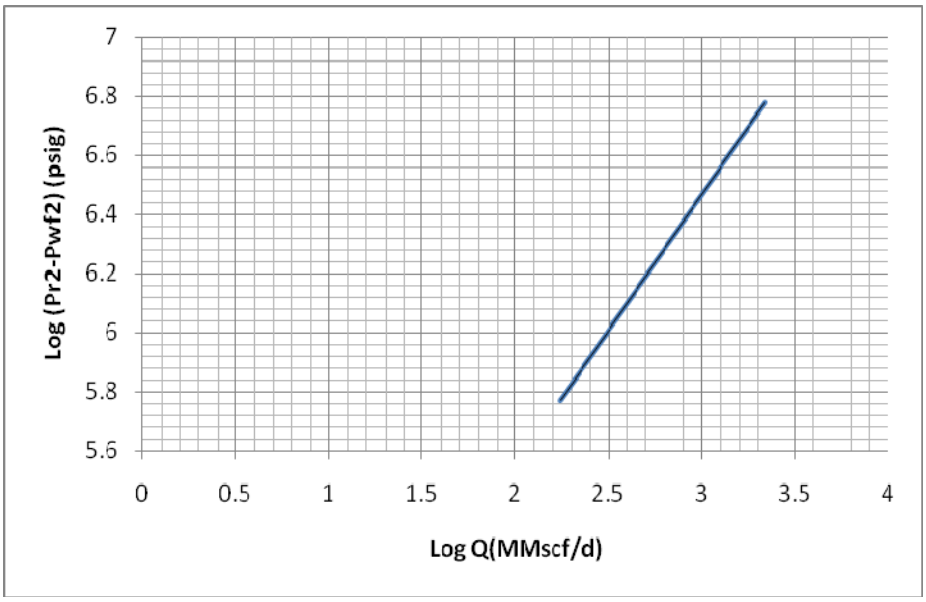


Fig 4 Plot of Log (P_R^2 – P_{wf}^2) VS Log Q for Reservoir Z-16RS

Following the reservoir performance of reservoir Z-16RS, the back pressure exponent, n, is 1.087, C = 0.0340 and the AOF = 38.29 MMscf/d

The deliverability of reservoir Z-16RS at reservoir pressure of 3000psig and at a given well flowing pressure is calculated from eqn 2.23,

$Q = C\,[P_R^2 - P_{WF}^2]^n$

In the equation, Q is the deliverability in MMscf/yr.

At P_{wf} of 2900 psig, $Q = 0.0340\ [3000^2 - 2900^2]^{1.087}$
Q = 63737.50 MMscf/yr
Then Q in MMscf/d = 63737.50 MMscf/yr /365 = 174.62 MMscf/d
The deliverability of Z-16RS was also evaluated using Microsoft Visual Basic Program.

The deliverabilities of reservoir Z-16RS at various withdrawal pressures are presented in Table 5 which is used to obtain the plot of the deliverabilities at various well flowing pressures as shown in Fig 5.

Table 5 Deliverability of Reservoir Z-16RS

P_{wf} (psig)	P_{wf}^2 (psig^2)	P_R^2-P_{WF}^2 (psig^2)	Q (MMscf/yr)	Q (MMscf/d)
2900	8410000	590000	63737.50422	174.6232992
2816	7929856	1070144	121753.8242	333.5721212
2795	7812025	1187975	136393.7449	373.6814927
2730	7452900	1547100	181754.5965	497.9577986
2655	7049025	1950975	233874.3102	640.7515349
2579	6651241	2348759	286141.1512	783.9483594
2501	6255001	2744999	338980.1583	928.7127625
2432	5914624	3085376	384907.8944	1054.542176
2300	5290000	3710000	470314.4874	1288.532842
2105	4431025	4568975	589796.1493	1615.879861
1982	3928324	5071676	660660.8912	1810.029839
1801	3610000	5390000	705855.6653	1933.851138
1722	3437316	5562684	730471.1171	2001.290732
1600	3359889	5640111	741529.7745	2031.588423
1550	3316041	5683959	747798.3199	2048.76252
1500	3225616	5774384	760738.8066	2084.215908
1311	3171961	5828039	768425.5904	2105.27559
1100	3111696	5888304	777066.6852	2128.949822
900	3062500	5937500	784126.3619	2148.291402
567	2999824	6000176	793127.8018	2172.952882

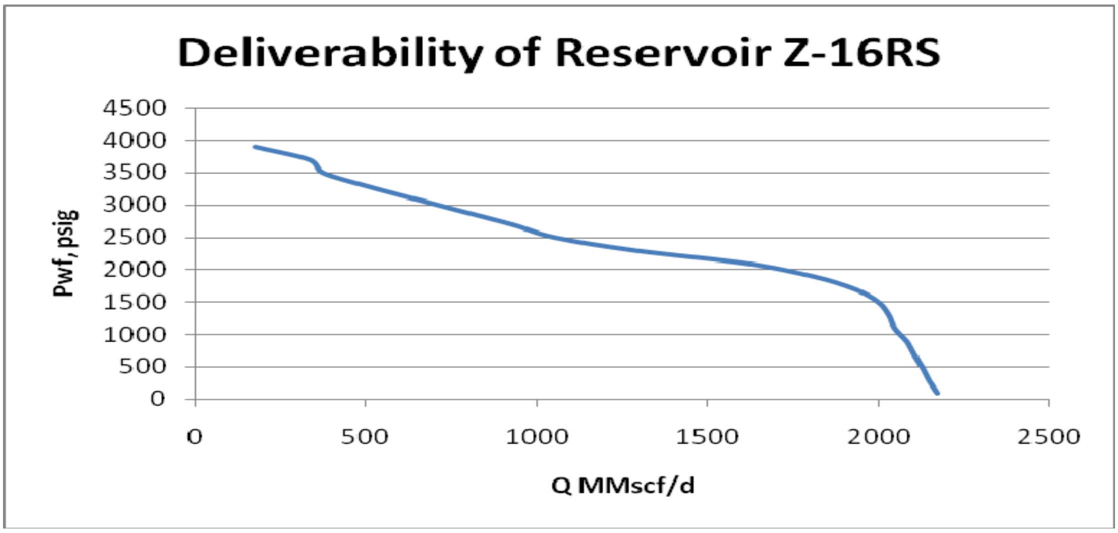


Fig. 5 A Plot of Well Flowing Pressure versus Deliverability

4. Conclusion

At the end of this study, it has shown that in developing depleted oil reservoirs for underground gas storage, three basic requirements were considered and evaluated, they include storage capacity estimation, amount of leakage determination and evaluation of deliverability. From the analysis of the storage capacity of reservoir Z-16RS and evaluation of deliverability of reservoir Z-16RS, it is shown that reservoir Z-16RS is if developed, suitable for underground natural gas storage.

Nomenclature

API	American Petroleum Institute	Psia	Pounds per square inch (atmospheric)
Bbl	Barrel	Psig	Pounds per square inch (gauge)
B_o	Oil formation volume factor	P_{wf}	Well flowing pressure
B_g	Gas formation volume factor	Q	Flow rate
Bscf	Billion standard cubic foot	Q_{sc}	Flow rate at standard condition
B_w	Water formation factor	R_s	Gas solubility
C	Reservoir flow coefficient	R_p	Gas-oil-ratio
MMSTB	Million stock tank barrel	Scf	Standard cubic foot
MMscf	Million standard cubic foot	SG	Specific gravity
N	Back-pressure exponent	T_{pc}	Pseudo-critical temperature
N	Stock tank oil-in-place	T_{pr}	Pseudo-reduced temperature
N_p	Cumulative oil production	V_{inj}	Volume of gas injected
P_{pc}	Pseudo-critical pressure	Z	Gas compressibility factor
P_{pr}	Pseudo-reduced pressure	^0F	Degree Fahrenheit
P_r	Reservoir pressure	^0R	Degree Rankine

Reference

[1] Dietert J. and Pursell D., (2008): Underground Natural Gas Storage, Houston, Texas: Simmons and Company International.

[2] Anyadiegwu C.I.C., (2012): Development and Performance Analysis of Depleted Crude Oil Reservoirs for Underground Natural Gas Storage: Ph.D Thesis, Nigeria: Department of Petroleum Engineering, Federal University of Technology, Owerri.

[2] Energy Information Administration/Natural Gas Division, (2002): The Basics of Underground Natural Gas Storage, Available at: www.eia.doe.gov.

[4] Katz D. L. and Tek, M.R., (1981): Overview on Underground Storage of Natural Gas, Texas: Journal of Petroleum Technology.

[5] Okwananke A., Adeboye Y.B. and Sulaiman L.A., (2011): Evaluation and Performance of Natural Gas Storage in Depleted Gas Reservoirs, Slovakia: Petroleum & Coal.

[6] Brown K.G. and Sawyer W.K., (1999): Practical Methods to Improve Storage Operations – A Case Study, Charleston, West Virginia, U.S.A: SPE Paper. (Presented at the SPE Eastern Regional Conference and Exhibition).

[7] Katz D.L. and Robert L., (1990): Natural Gas Engineering Production and Storage, New-York, U.S.A: McGraw-Hill Book Company.

[8] Ikoku C.U., (1984): Natural Gas Production Engineering, New York: John Wiley and Sons Publishing Company.

[9] Vasquez M., and Beggs D., (1980): Correlations for Fluid Physical Properties Prediction, Texas: Journal of Petroleum Technology.

[10] Tharek Ahmed (2001): Reservoir Engineering Handbook, Elsevier: Amsterdam.

[11] Rawlins E.L., and Schellhardt M.A., (1935): Back-pressure Data on Natural Gas Wells and their Application to Production Practices, United States of America: Lord Baltimore Press.

[12] Katz, D.L. and Coats, K.H., (1968): Underground Storage of Fluids, New Jersey, U.S.A: Ulrich's Book Inc, Ann Arbor.

[13] Standing M.B. and Katz D.L., (1942): Density of Natural Gases: United States of American: Trans. AIME.