King Saud University
Petroleum and Natural Gas Engineering Department
Production of Naturally Flowing Wells – Course (PGE 481)
Sheet # 1

Question 1:

In casing or tubing selection three principal types of loading most considered:

- Tensile load.
- Collapse pressure.
- Burst pressure.

Write briefly about it?

Question 2:

Compute the collapse – pressure for $2_{3/8}$-in, H-5.5 casing with a nominal wall thickness casing of 0.190-in and nominal weight per foot of 4.7 lb/ft.?

Question 3:

Interpret the attached charts of DST?

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Sheet # 2

Pressure Chart DST is given other data are:
Interval tested (9990-10000) ft
Drill pipe = 4.5 in (ID = 3.826 in)
Mud density = 9.8 ppg
Recovery:

- 200 ft mud
- 7500 ft clean oil of 40 API

Viscosity = 0.4 cp

Shut in period pressure (Build up pressure obtained from DST chart):

Index	Pressure, psig	Δt, min
P1	3460	10
P2	3900	20
P3	4190	30
P4	4300	40
P5	4375	50
P6	4400	60
P7	4410	70

Evaluate:

A) Formation Pressure (P_e)
B) Oil flow rate (q_o)
C) Formation permeability (K)
D) Productivity index (J)
E) Productivity ratio (PR)
F) Skin factor (S)
G) Radius of investigation
H) Do you think this well will flow naturally, and what is flow rate?

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The production data for an oil reservoir are as follows:

Time (t), year	Production rate (q), bbl/year	Cumulative production (Q), bbl
1	7150	7150
2	6456	13606
3	5844	19450
4	5328	24778
5	4860	29638
6	4440	34078
7	4092	38170
8	3750	41920

- Make a scatter plot of the data.
- Find the Regression Equation in deferent form.
- Graph the Regression Equation on your scatter plot to make sure it looks like the best - fitting line.

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Sheet # 4

Problem 1

The production rate of Crazy Dog pool was held constant at its allowable of 2500 bbl/day for some years. Recent production rate figures, expressed in terms of the cumulative oil production from the pool, have been as follows:

Cumulative Production from pool 10^6 bbl	**Oil production rate Bbl/day**
3.20	1920
3.45	1645
3.70	1650
4.10	1230
4.40	1095

Assuming a pool economic limit of 200 bbl/day, determine the future life of the pool, the total life of the pool, the future production to be expected, and the ultimate cumulative production.

Problem 2

A new oil field is thought to have recoverable reserves of 10 million bbl, and from information on a similar neighboring pool it is estimated that the average well will come in at 100 bbl/day, flowing a decline rate of 17 percent/year. It is expected that the wells will flow down to a production rate of 40 bbl/day and that they will then be put to the pump for an average initial pumping rate of 60 bbl/day. Taking the economic limit for pumping wells to 3bbl/day. How many producing wells should be drilled to exploit the field and what will be its life.

Problem 3

Reservoir pressure has in the pool declined linearly with cumulative oil withdrawal since the pool was first put into production, the rate of pressure drop being 1 psi per 5000 bbl of oil produced. The pool drained by 12 wells, the average PI being 0.3 bbl/(day)(psi) per well, and as a matter of policy, these wells are produced at a drawdown equal to 50 percent of the prevailing static reservoir pressure. Show that the wells have a straight-line decline, the annual decline rate being 12.3 percent.
It is estimated that the reservoir pressure will have fallen to 300 psi after a total producing life of 16 years. What was the initial reservoir pressure?

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The production data for an oil reservoir are as follows:

Time (t), year	**Production rate (q) Bbl/year**
1	7140
2	6456
3	5844
4	5328
5	4860
6	4440
7	4092

If the well was declining exponentially, determine the value of constant a, b and c of the exponential equation by least square method.

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Problem 1

A flowing well with 5540 ft of tubing in the hole is completed without a casing – tubing packer. The CHP is 480 psig when the production rate is 750 bbl/day and 760 psig when the production rate is 525bbl/day. What are the PI, static pressure, and potential of the well?

Problem 2

Well is flowing at 1120 bbl/day through $2_{7/8}$ -in tubing. There is zero water cut, and the GLR is 820 cu ft /bbl. A pressure survey on the well shows that the flowing pressure at 6470 ft is 675 psig ,while the pressure buildup survey gives a static pressure of 2080 psig at a datum level of 6500 ft. Using Vogel's method, draw the IPR curve, and estimate the well's potential.

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Problem 1

A flowing well is producing 160 bbl/day of 42 API oil and 240 bbl/day of water (γ_w = 1.07) from 2 $_{3/8}$ in. OD tubing (ID = 2 in.). The producing GOR = 600 SCF/STB of oil. The gas specific gravity is γ_g = 0.67. The average temperature is 150 ^oF, base pressure = 14.65 psia at 60 ^oF. Neglect gas compressibility. The following additional information is known:

P_1 = 1200 psig	P_2 = 1600 psig
Rs_1 = 160	Rs_2 = 240
B_{o1} = 1.13	B_{o2} = 1.16

What would be the approximate depth interval between these two points using Poettman and carpenter's method?

Problem 2

Well depth	= 5200 ft
7-in. Casing	= 5050 ft
Static pressure at 5000 ft	= 1850 psig
GLR	= 0.4 MCF/bbl
2 $_{3/8}$-in. Tubing set at	= 5000 ft

No casing-tubing packer

The well is currently flowing at 250 bbl/day with a CHP of 1245 psig, but the tubing is corroded and must be pulled and replaced. In addition to 2 $_{3/8}$- in., 1.9-in. and 3 $_{1/2}$-in. tubing strings are available. Which size of tubing should be run if it is desired to flow the well at the maximum possible rate with a THP of 170 psig?

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Problem 1

A well came at 116 bbl/day and by the end of the first year had declined to 94 bbl/day. It was found that, at a cumulative production of 143,500 bbl, the productivity index was 0.053 bbl/day/psi and the static pressure of the formation was 770 psi. What was the bottom-hole flowing pressure at that time? Assuming that the same bottom-hole flowing pressure will prevail at abandonment, what will be the static pressure of the formation at abandonment if the well's economic limit is taken as 2 bbl/day?

Problem 2

A series of tests is made on a certain well with the following results:

Oil rate bbl/day	WOR	Bottom-hole flowing pressure, psi
40	0	2360
56	0.785	1950
61	1.440	1524
70	1.855	1000

Draw the curve of water cut vs. gross production rate and the oil, water and gross inflow-performance relationships. Might any harm result from shutting this well in for a few days?

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Problem 1

A certain well is completed with 7500 ft of 3.5 in. tubing in the hole, the tubing shoe being located just above the top perforations. The well is flowing 130 bbl/day of oil with a water cut of 25% and GOR of 1200 ft^3/bbl. If the well's static pressure is 2800 psig and its gross PI is 0.32 bbl/(day)(psi), estimate the size of choke in the flow line. At what oil rate would the well flow if a 1/2-in. bean were substituted for the current one?

Problem 2

A well was completed with 7-in. casing perforated (2 shots/ft) from 7216 to 7253 ft with 7000 ft of 2 $_{3/8}$-in. tubing in the hole. The well was flowing steadily at 320 bbl/day of clean oil, GOR 800 ft^3/bbl, against an 11/16-in. choke when a smaller choke was accidentally inserted in the flow line. When the well stabilized against the new choke, it was flowing with a THP of 300 psig and a CHP of 993 psig. Determine the new bean size, the well's static pressure, and the PI. (Assume no annulus packer.)

Problem 3

A new flowing well completed with 2 $_{7/8}$-in. tubing hung at the top of the perforations at 5500 ft was initially produced on 1/4-in. choke, the THP stabilizing at 400 psig. After a few days production the choke size was increased to 1/2-in. and the THP stabilized at 270 psig. One week later the choke size was again increased, and the well then gauged at 600 bbl/day of clean oil, GOR 800 ft^3/bbl, THP 140 psig. Estimate the well's static pressure and its pumped-off potential.

Problem 4

A well completed over the interval 2994 to 3032 ft (below Kelly bushing) has 2 $_{3/8}$-in. tubing hung at 3000 ft. The well is flowing 320 bbl/day, zero water cut, at a GOR of 400 ft^3/bbl with a CHP of 920 psig. The static pressure is 1850 psig at 3000 ft. Determine the THP and the size of the flow-line choke. What would be the effect of changing the choke size to 1/2-in.?

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Problem 1

Well data:

Production interval	6507-6551 ft
Tubing depth	6500 ft
Static pressure at 6500 ft	2000 psig
Flow-line pressure	100 psig

The well is currently flowing 200 bbl/day of clean oil with GOR of 600 ft^3/bbl and CHP of 1225 psig.

a. If it were decided to gas-lift this well, what would be the maximum gas-lift rate through 2 $_{3/8}$ –in. tubing, assuming a THP of 250 psig? What would be the required horsepower of the compressor if input gas were available at (i) 15-psig and (ii) 100 psig?

b. If the supply gas were limited to 180 mcf/day, what would be the maximum production rate on gas lift through 2 $_{3/8}$ –in? Tubing at a 250 psig THP? What horsepower would be required in this case if gas were available at 15 psig?

Problem 2

Well data:

Depth	9200 ft
7-in. Casing	9100 ft
GOR	450 ft^3/bbl
Water cut	10%
PI	0.333 bbl/(day)(psi)
Static pressure at 9000 ft	3000 psig
Flow-line pressure	60 psig

Available equipment includes 1.9, 2 $_{3/8}$, 2 $_{7/8}$ & 3.5 –in. tubing and a compressor of 135 hp and 2000 psig outlet pressure. Input gas is available at 35 psig.

a. What size tubing will give the maximum rate on natural flow, and what bean size is required THP 100 psig?

b. What maximum rate of flow could be obtained by gas lift through 2 $_{7/8}$ – in. tubing at 9000 ft? What horsepower would be required? (THP 100 psig, & assume that the compressor outlet pressure is equal to the flowing BHP).